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Sent via eFile

BC HYDRO F2020–F2021
REVENUE REQUIREMENTS EXHIBIT A-15

Mr. Fred James
Chief Regulatory Officer
Regulatory & Rates Group
British Columbia Hydro and Power Authority
16th Floor - 333 Dunsmuir Street
Vancouver, BC V6B 5R3
bchydroregulatorygroup@bchydro.com

Re: British Columbia Hydro and Power Authority – F2020–F2021 Revenue Requirements Application – Project No. 1598990 – Information Request No. 3

Dear Mr. James:

Further to British Columbia Utilities Commission Order G-218-19, enclosed please find BCUC Information Request No. 3 on evidentiary updates to British Columbia Hydro and Power Authority. In accordance with the Regulatory Timetable, please file your responses no later than Thursday, October 10, 2019.

Sincerely,

Original Signed By:

Patrick Wruck
Commission Secretary

/nd
Enclosure

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British Columbia Hydro and Power Authority
F2020-F2021 Revenue Requirements Application

INFORMATION REQUEST NO. 3 TO BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

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A. CHAPTER 3 – LOAD FORECAST – EVIDENTIARY UPDATE

288.0 Reference: FISCAL 2019 VARIANCE EXPLANATIONS
Exhibit B-11, Evidentiary Update, Appendix G, p. 2
Residential sales variance

British Columbia Hydro and Power Authority (BC Hydro) states in Appendix G to the Evidentiary Update:

> The residential sales variance was related to a lower than expected usage per residential account. The lower usage per account is likely due to a number of factors including higher Demand-Side Management savings, denser housing development (more multiple unit dwellings), fewer people per account, and changes in appliance mix resulting in more efficient appliances (appliance stock turnover).

288.1 Please explain whether the factors attributable towards a lower usage per residential account in Fiscal 2019 (F2019) is expected to have a one-time impact on residential sales or is the reduction in usage per residential account expected to persist.

288.1.1 If the impacts from the factors list above are expected to persist, please discuss whether, and if so how, these factors have been accounted for in the residential load forecast for F2020 and F2021.

288.1.2 Please discuss, and quantify where possible, the magnitude of the expected reduction in usage per residential account and the total demand from residential customers in F2020 and F2021 from the impact experienced in F2019.

288.2 Please discuss whether BC Hydro expects there to be a further increase in Demand-Side Management savings, denser housing development, fewer people per account and more efficient appliances to further decrease the usage per residential account in F2020 and F2021.

288.2.1 If yes, please explain whether the expected impact has been reflected in the demand forecast for residential customers in F2020 and F2021. If so, please explain how.

288.2.2 If yes, please discuss, and quantify where possible, the magnitude of the expected reduction in usage per residential account and the total demand from residential customers in F2020 and F2021 from this expectation.

B. CHAPTER 5 – OPERATING COSTS – EVIDENTIARY UPDATE

289.0 Reference: OPERATING COSTS
Exhibit B-11, p. 12; Workshop Transcript Volume 1, p. 80
Storm restoration costs

In the Evidentiary Update, BC Hydro states:

> …storm restoration costs were higher than planned in fiscal 2019 due to more severe storms, including the December 2019 storm. These costs were deferred to the Storm Restoration Costs Regulatory Account and are amortized over the test period, which increases the required recovery in fiscal 2020 and fiscal 2021.

At the BC Hydro Workshop held on March 15, 2019, BC Hydro confirmed that the costs of the December 2018 storm are not included in the current Test Period revenue requirement forecasts, stating:

> …And the reason for that is because we use only completed fiscal years in calculating the five-year average, and so I referenced, I think it was table 7-6, which shows that we will use fiscal '14, '15, '16, '17 and '18, as those are completed years. So that drives the average.

289.1 Given that F2019 is now a completed fiscal year, please confirm, or explain otherwise, that BC Hydro uses F2015 to F2019 (including the restoration costs of the December 2018 storm) to calculate the storm restoration costs forecast for the Test Period. If not, please explain why not.

290.0 Reference: OPERATING COSTS
Exhibit B-11, Appendix G, p. 6
Net provisions and other

In Appendix G to the Evidentiary Update, BC Hydro states that the variance of $30.2 million related to net provisions and other were partially due to "[h]igher litigation costs of $5.2 million related to a capital project."

290.1 Please elaborate on the litigation costs mentioned in the preamble. As part of the response, please discuss whether litigation costs related to this capital project have been forecast in the Test Period. Please explain why or why not.

290.1.1 If litigation costs related to this capital project have been forecast in the Test Period, please explain how the forecast costs were determined.

C. CHAPTER 6 – CAPITAL EXPENDITURES – EVIDENTIARY UPDATE

291.0 Reference: CAPITAL EXPENDITURES
Exhibit B-1, Appendix G, Section 5.3, pp. 28–29;
Exhibit B-11, Appendix G, Section 5.3, pp. 17–18;
Transmission capital expenditures and additions variance explanations

In Appendix G to the Evidentiary Update, BC Hydro states:

Transmission Growth – Regional System Reinforcement
Fiscal 2019 capital expenditures were $110 million or 166 per cent above the fiscal 2019 RRA [Revenue Requirements Application] Plan primarily due to a property purchase that was planned in fiscal 2017 but completed in fiscal 2019 and due to the advancement of definition phase activities related to the Peace Region Electrical Supply [PRES] project from later years into fiscal 2019. Fiscal 2019 capital additions were comparable with the fiscal 2019 RRA Plan.

291.1 Please confirm, or explain otherwise, that the property purchase discussed in the preamble was not related to the PRES project.

291.2 Please identify the property that was purchased, the capital expenditure attributed to the acquisition of the property, and the name of the related transmission growth project.

291.3 Please provide the PRES project capital expenditures allocated to Transmission Growth - Regional System Reinforcement in F2019.

In Appendix G to the Application, BC Hydro states the following regarding its Transmission Growth Regional System Reinforcement Capital Expenditure Variances for 2017:

Capital Expenditure Variances
Fiscal 2017 capital expenditures were $28.6 million (31 per cent) above the fiscal 2017 RRA Plan primarily due to the fiscal 2017 RRA Plan amounts for a land purchase being included in Business Support – Other, while the actual expenditures are reported as Transmission as the land purchase relates to a future substation development.

291.4 Please further explain why the land purchase described in the preamble was included in Business Support – Other in the BC Hydro F2017-F2019 RRA and then later attributed to Transmission Growth Regional System Reinforcement.

291.5 Please identify the property that was purchased in F2017, the capital expenditure attributed to the acquisition of the property, and the name of the related transmission growth project.

291.6 Given that the property purchase referred to in IR 291.1 above was planned for F2017 but delayed to F2019, please discuss whether the funds planned for the property purchase in F2017 were spent on other projects. If so, please elaborate.

291.7 Please provide a schedule showing actual and planned Transmission Growth Regional System Reinforcement capital expenditures and additions for projects and programs with expected costs greater than $5 million for F2017 to F2019. Please explain any variances greater than 10 percent between planned and actual capital expenditures and additions.

291.7.1 Please identify and explain any projects listed in response to the preceding IR that were planned and deferred or not completed.

D. CHAPTER 7 – REGULATORY ACCOUNTS

292.0 Reference: REGULATORY ACCOUNTS
Exhibit B-11, Appendix A, Schedule 2.2
Debt Management Regulatory Account

Line 152 of Schedule 2.2 of Appendix A to the Evidentiary Update shows additions to the Debt Management Regulatory Account of $100.9 million in F2020.

292.1 Given that the Debt Management Regulatory Account is a variance account, please explain why there is a $100.9 million variance forecast for F2020. As part of the explanation, please explain why it would not be appropriate to adjust the forecast revenue requirement for F2020 by that amount to avoid the addition to the regulatory account.

293.0 Reference: REGULATORY ACCOUNTS
Exhibit B-1, p. 7-34; Exhibit B-5, BCUC IR 140.1, 140.5;
Direction No. 8 to the BCUC, OIC 51/2019, Section 4(1)(c)
Debt servicing costs

In the Application, BC Hydro states:

> Approved additions to this regulatory account from fiscal 2015 to fiscal 2019 total $1.136 billion. As a result of the Comprehensive Review, BC Hydro ceased using the Rate Smoothing Regulatory Account at the end of the third quarter of fiscal 2019. The balance of the Rate Smoothing Regulatory Account was written-off in December 2018 in the amount of $1.044 billion, resulting in a reduction to BC Hydro's retained earnings and a forecast net loss for BC Hydro in fiscal 2019.

In Direction No. 8 to the BCUC, it states:

> 4 (1) In setting rates for the authority, the commission must not disallow for any reason the recovery in rates of the balance of the authority's regulatory accounts as at March 31, 2019 and the costs incurred by the authority with respect to the following: […]
>
> (c) debt servicing costs on amounts borrowed <u>in relation to the rate smoothing regulatory account</u>.[1]

In response to BCUC IR 140.1, BC Hydro stated:

> As a result of the write-off of the balance of the Rate Smoothing Regulatory Account, BC Hydro will collect $1.136 billion less cash from ratepayers than if the total forecast transfers to the account had continued to the end of fiscal 2019 and had been recovered in customer rates in future periods. BC Hydro's debt is therefore $1.136 billion higher than it otherwise would be, all other things equal.
>
> BC Hydro uses its forecast weighted average cost of debt to calculate the annual debt servicing costs associated with this debt.

$ millions	Reference Appendix A	F2020	F2021
Forecast weighted average cost of debt	Sch 8.0, L52	3.88%	3.82%
Debt related to the Rate Smoothing Regulatory Account		$1,136	$1,136
Annual debt servicing costs		$44.1	$43.4

293.1 Given section 4(1)(c) of Direction No. 8 to the BCUC and the fact that BC Hydro ceased using the Rate Smoothing Regulatory Account (RSRA) at the end of the third quarter of F2019 and wrote off the $1.044 billion balance in the account, please explain why the annual debt servicing costs of the RSRA should be calculated based on $1.136 billion instead of $1.044 billion.

[1] Emphasis added.

293.2 Please explain why BC Hydro ceased using the RSRA in the third quarter of F2019 instead of at the end of F2019.

In response to BCUC IR 140.5, BC Hydro stated:

> …these higher debt servicing costs are $44.1 million in fiscal 2020 and $43.4 million in fiscal 2021 and are expected to persist until BC Hydro pays down the debt related to the Rate Smoothing Regulatory Account.
>
> Since BC Hydro's debt is managed on a portfolio basis, we do not specifically allocate debt repayment to specific drivers of debt. Although there is no specific target year for repayment, the incremental debt associated with the account will be repaid over time.
>
> This is because, all other things being equal, the write-off of the balance of the Rate Smoothing Regulatory Account increases BC Hydro's debt:equity ratio and will restrict BC Hydro from paying dividends (currently until its debt:equity ratio reaches 60:40) for a longer period of time. The additional cash from retaining net income will be available to pay down debt.

293.3 Please confirm, or explain otherwise, that the annual debt servicing costs of the RSRA would be calculated as $1.136 billion multiplied by the forecast weighted average cost of debt for as long as BC Hydro's total debt is above $1.136 billion.

293.3.1 If confirmed, please explain why this method is appropriate. Please also discuss whether it would be appropriate to decrease the annual debt servicing costs as BC Hydro reduces its total debt (i.e. allocate a portion of BC Hydro's annual debt repayment as repayment of amounts borrowed in relation to the RSRA).

293.3.2 If not confirmed, please explain how the annual debt servicing costs of the RSRA would be calculated as BC Hydro's total debt decreases.

293.3.2.1 Please discuss whether the calculation in the response to the preceding information request (IR) would be different under the following scenarios:

i. where BC Hydro's total debt has been reduced to below $1.136 billion; and

ii. where BC Hydro's total debt has been reduced to below $1.136 billion but then increases.

293.3.3 Please discuss whether there are any legal or legislative restrictions for the BCUC to direct the method for calculating BC Hydro's annual debt servicing costs of the RSRA. Please explain why or why not.

294.0 Reference: REGULATORY ACCOUNTS
Exhibit A2-2, BC Hydro F2017-F2019 RRA Compliance Filing to Order G-47-18, p. 5;
Exhibit B-5, BCUC IR 142.3; Exhibit B-6, AMPC IR 10.1;
Direction No. 7 to the BCUC, OIC 97/2014, Section 7(a), Appendix A, Schedule A
Heritage Deferral Account

On page 5 of BC Hydro's compliance filing to Order G-47-18 dated April 27, 2018, it states:

> Energy study models are also used by BC Hydro for the ongoing financial forecasting of the Cost of Energy, which is used in revenue requirements proceedings to set rates. In this regard, <u>the definition of Heritage Energy only influences the calculation of actual Heritage Energy costs, which impacts how costs are allocated to the Heritage and Non-Heritage energy deferral accounts.</u> Those accounts are prescribed by Direction No. 7.

> Ultimately, this allocation between the accounts has no impact on ratepayers as the recovery mechanism for the heritage and non-heritage deferral accounts is the same.[2]

In response to BCUC IR 142.3, BC Hydro stated: "The repeal of the Direction No. 7 and Heritage Contract has no impact on the components subject to deferral treatment in the Heritage Deferral Account…"

In response to AMPC IR 10.1, BC Hydro confirmed that its Cost of Energy restructuring does not result in any forecasting methodology changes and/or any financial changes for the current RRA Test Period.

294.1 Please explain how the repeal of the definition of Heritage Energy influences the calculation of actual Heritage Energy costs and how it impacts the allocation of costs to the Heritage and Non-Heritage energy deferral accounts. Please provide an illustrative example of this calculation before and after the repeal.

Section 7(a) of Direction No. 7 states:

> When regulating and setting rates for the authority, the commission must allow the authority to continue to defer to the heritage deferral account the variances between the actual and forecast heritage payment obligation.

Schedule A to Appendix A to Direction No. 7 states:

> The heritage payment obligation for any Year is the amount determined by
>
> (a) adding those of the following costs incurred by BCH Generation in the Year that the Commission orders may be included in the heritage payment obligation:
>
> (i) cost of energy such as the cost of water rentals and energy purchases, including purchases of gas and electricity, required to supply heritage electricity;
>
> (ii) operating costs such as the costs of operating and maintaining the heritage resources, including an allocation of corporate costs;
>
> (iii) all costs of owning the heritage resources, including, without limitation, depreciation, interest, finance charges and other asset related expenses;
>
> (iv) all costs or payments related to generation-related transmission access required by the heritage resources, and
>
> (b) subtracting from the sum obtained under paragraph (a) any revenues BCH Generation receives from other services provided from the heritage resources, including, without limitation,
>
> (i) revenues related to Skagit Valley Treaty obligations,
>
> (ii) revenues from provision of ancillary services to the transmission operator in respect of third party use of the transmission system, and
>
> (iii) revenues from the sale of surplus hydro electricity under section 5 of the Transfer Pricing Agreement.

294.2 Please provide a schedule showing the variances between actual and forecast of each of the cost components that make up the heritage payment obligation for the past five years (i.e. F2015 to F2019).

[2] Emphasis added,

294.3 Please discuss why it is appropriate to continue to defer the variances between actual and forecast of each of the cost components that make up the heritage payment obligation. Please discuss each cost component individually.

294.3.1 Please discuss how deferral of the variances between actual and forecast of each of the cost components that make up the heritage payment obligation meets BC Hydro's criteria as set out on in Sections 7.6 and 7.5.1 of the Application. For each cost component, please ensure to address each of the five items listed and the $10 million threshold.

294.3.2 Please discuss and quantify the impact to the Test Period revenue requirement and rates under the scenario that the variance treatment for each of the cost components that make up the heritage payment obligation is disallowed beginning in the current Test Period. Please discuss and quantify the impact of each cost component individually.

294.3.3 Please provide a high-level discussion of the impact to the subsequent test periods' revenue requirements under the scenario that the variance treatment for each of the cost components that make up the heritage payment obligation is disallowed beginning in the current Test Period. Please discuss the impact of each cost component individually.

295.0 Reference: REGULATORY ACCOUNTS
Exhibit B-1, pp. 8-16–8-17; Exhibit B-5, BCUC IR 143.3, 143.4
Trade Income Deferral Account

In the Application, BC Hydro states:

> Although Direction No. 7 has been repealed, BC Hydro continues to include the net income of BC Hydro's subsidiaries in its revenue requirements and continues to define Trade Income on the same basis as previously defined in Direction No. 7.

In response to BCUC IR 143.3, BC Hydro stated:

> With the repeal of Direction No. 7, the definition of Trade Income is no longer enshrined in legislation. However, Powerex's net income continues to be included in Trade Income by BC Hydro to the benefit of ratepayers, and therefore, BC Hydro continues to include forecast Trade Income in its revenue requirement on the same basis as the Previous Application…

In response to BCUC IR 143.4, BC Hydro stated:

> …if actual Trade Income in a given fiscal year is less than zero (i.e. a net loss), the minimum transfer to the Trade Income Deferral Account will be the difference between the forecast Trade Income and zero. This means that a net loss in Trade Income will be borne [by] the Government of B.C., as BC Hydro's shareholder, and therefore ratepayers do not bear the risk of losses in Trade Income.

295.1 Please confirm, or explain otherwise, that BC Hydro plans to continue to include the net income of its subsidiaries in all future revenue requirements based on the definition of Trade Income from Direction No. 7.

295.2 If confirmed, please discuss whether BC Hydro's shareholder has approved the treatment of including Trade Income, as defined in Direction No. 7, in BC Hydro's future revenue requirements and therefore bearing all future net losses in Trade Income.

295.3 Please discuss whether the BCUC has the authority to define “Trade Income.” If so, given that the Trade Income Deferral Account captures the variances between forecast and actual Trade Income, please discuss the pros and cons of the BCUC defining “Trade Income.”

296.0 Reference: REGULATORY ACCOUNTS
Exhibit B-5, BCUC IR 148.1, 148.3, 148.4; Exhibit B-11, Figure 1, p. 1
Deferral Account Rate Rider (DARR)

In response to BCUC IR 148.1, BC Hydro stated:

> …The DARR table mechanism referenced in the preamble, and which was approved by the BCUC in its Decision to the Fiscal 2009-Fiscal 2010 Revenue Requirements Application, is different from the mechanism described in paragraph 10(3) of Direction No. 7 for the reasons outlined below.
>
> The DARR table mechanism approved by the BCUC in the Fiscal 2009-Fiscal 2010 Revenue Requirements Application set the specific DARR percentage amount to be collected from BC Hydro customers in order to amortize the Cost of Energy Variance Accounts. The DARR table mechanism described in paragraph 10(3) of Direction No. 7 assumes a 5 per cent rate rider indefinitely, and then is used to allocate a portion of the Deferral Account Rate Rider revenue collected from BC Hydro customer to amortize the Cost of Energy Variance Accounts.
>
> Additionally, the DARR table mechanism approved by the BCUC in its Decision on the Fiscal 2009–Fiscal 2010 Revenue Requirements Application sets the percentage of Deferral Account Rate Revenue used to amortize Cost of Energy Variance Accounts based on the net balance of the Cost of Energy Variance Accounts at September 30th of the previous year, as per Page 6-9, line 24 of the Fiscal 2009-Fiscal 2010 Revenue Requirements Application. Conversely, the DARR table mechanism described in paragraph 10(3) of Direction No. 7 allocates a portion of the 5 per cent rate rider revenue used to amortize the Cost of Energy Variance Accounts based on the forecast net balance of the Cost of Energy Variance Accounts at the end of the preceding fiscal year.

296.1 Please discuss why BC Hydro would propose to return to the DARR table mechanism approved by the BCUC in the F2009 to F2010 RRA (F2009-F2010 DARR Mechanism) rather than the mechanism described in paragraph 10(3) of Direction No. 7 in the subsequent test period.

296.2 Please discuss the rationale for the F2009-F2010 DARR Mechanism setting the percentage of the Deferral Account Rate Revenue based on the net balance of the Cost of Energy (COE) Variance Accounts at September 30th of the previous year instead of either the forecast or actual net balance of the COE Variance Accounts at the end of the preceding fiscal year.

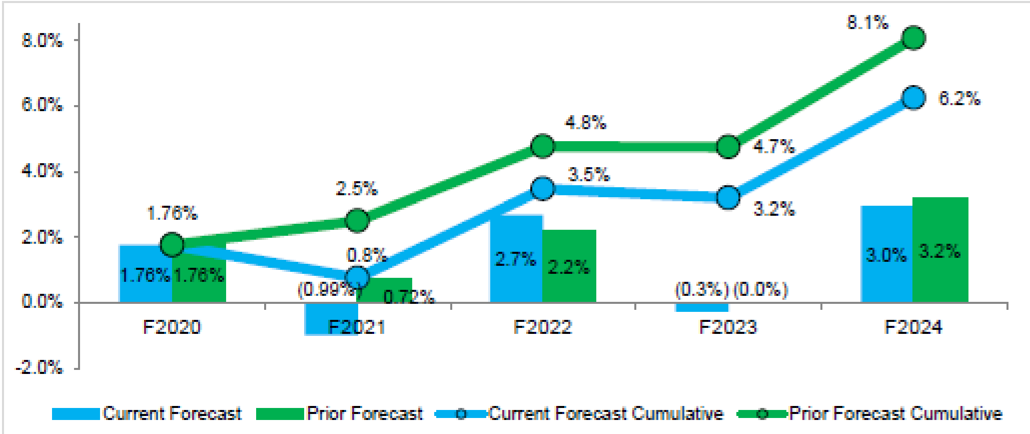
296.2.1 Please discuss the pros and cons of using the net balance of the COE Variance Accounts as at September 30th of the previous year compared to using either the forecast or actual net balance of the COE Variance Accounts at the end of the preceding fiscal year.

In response to BCUC IR 148.3, BC Hydro provided an analysis based on a scenario that the BCUC does not approve the requests described on page 7-26 of the Application.

In response to BCUC IR 148.4, BC Hydro stated it would propose to return to the F2009-F2010 DARR Mechanism if the BCUC does not approve the requests described on page 7-26 of the Application.

BC Hydro provides the following graph on page 1 of the Evidentiary Update:

Figure 1 Five Year Net Bill Increases Forecast



296.3 Please update Figure 1 to include the five-year net bill impact under the scenario that the BCUC does not approve the requests described on page 7-26 of the Application and directs BC Hydro in the current Test Period to return to the F2009-F2010 DARR Mechanism. Please also identify the amount of the DARR revenue, the revenue shortfall and the DARR percentage applicable for each fiscal year.

296.4 Please update Figure 1 to include the five-year net bill impact under the scenario that the BCUC does not approve the requests described on page 7-26 of the Application and directs BC Hydro in the current Test Period to return to the F2009-F2010 DARR Mechanism but modified to use:

i. the forecast net balance of the COE Variance Accounts at the end of the preceding fiscal year. Please also identify the amount of the DARR revenue, the revenue shortfall and the DARR percentage applicable for each fiscal year.

ii. the actual net balance of the COE Variance Accounts at the end of the preceding fiscal year. Please also identify the amount of the DARR revenue, the revenue shortfall and the DARR percentage applicable for each fiscal year.

296.5 Please provide similar figures as in the response to the two preceding IRs (i.e. IR 296.3 and 296.4), but with the five-year rate impact instead of the net bill impact.

296.6 Given that BC Hydro forecasts a cumulative net bill increase in F2024, please discuss the pros and cons to BC Hydro seeking a rate decrease in F2021.

297.0 Reference: REGULATORY ACCOUNTS
Exhibit B-5, BCUC IR 149.1
Dismantling Cost Regulatory Account

In response to BCUC IR 149.1, BC Hydro stated:

> …The large negative variance in fiscal 2018 was largely due to the decommissioning of the Salmon River Diversion, which was originally planned to be upgraded. By Order No. G-96-17, the BCUC approved BC Hydro's request to decommission the Salmon River Diversion and allowed the decommissioning costs to be transferred to the Dismantling Costs Regulatory Account. There is no net aggregate variance for the period from fiscal 2012 to fiscal 2019, excluding the fiscal 2018 variance…

297.1 Please provide the net aggregate variance for the period from F2012 to F2019, excluding the F2018 variance, updated for the information in the Evidentiary Update.

297.1.1 Please discuss whether BC Hydro considers the updated net aggregate variance for the period from F2012 to F2019, excluding the F2018 variance, to be material or significant. Please explain why or why not.

297.2 Given that the large negative variance in F2018 was largely due to one project or event (i.e. the decommissioning of the Salmon River Diversion), please discuss the pros and cons of discontinuing the Dismantling Cost Regulatory Account and BC Hydro applying for variance treatment on a case-by-case basis when it expects a significant variance to occur due to an unexpected event.

298.0 Reference: REGULATORY ACCOUNTS
Exhibit B-1, p. 10-37; Exhibit B-5, BCUC IR 150.2, 150.4.1, 150.5.1, 150.6, 150.7; BC Hydro 2004/05 and 2005/06 RRA and British Columbia Transmission Corporation Application for Deferral Accounts (F2005-F2006 RRA) proceeding, Exhibit B1-1, Chapter 8, Section 1.5.1, p. 8-6; BC Hydro F2009/F2010 RRA proceeding, Exhibit B-1, Section 6.4.1, pp. 6-10–6-11; BC Hydro 2008 Long Term Acquisition Plan proceeding, Exhibit B-1, Section 6.2.1.2, p. 6-6
Demand-Side Management (DSM) Regulatory Account

In response to BCUC IR 150.6, BC Hydro stated:

> …The amortization period for the DSM Regulatory Account was changed from 10 years to 15 years pursuant to Direction No. 3 and BCUC Order No. G-77-12A to the Fiscal 2012 to Fiscal 2014 Amended Revenue Requirements Application.

In response to BCUC IR 150.7, BC Hydro stated:

> BC Hydro defers all of its DSM costs described in Chapter 10 of the Application into the DSM Regulatory Account….
>
> This approach aligned with Direction No. 7 to the BCUC, which stated that costs arising from 'development, implementation and administration of demand-side measures, including costs arising from specified demand-side measures and public awareness programs' are to be deferred to the DSM Regulatory Account. Direction No. 7 to the BCUC did not change the scope of costs deferred to the DSM Regulatory Account. Rather, Direction No. 7 continued BC Hydro's existing approach, which had been approved pursuant to BCUC Order No. G-55-95.

298.1 With respect to the DSM Regulatory Account, please confirm, or explain otherwise, that Directions No. 3, 6 and 7 to the BCUC only directed the BCUC to approve a 15-year amortization period and did not direct any other changes to the regulatory account.

In Section 1.5.1 of the application to BC Hydro's F2005 to F2006 RRA, BC Hydro states:

> The majority of Power Smart costs are capitalized and amortized to appropriately match the costs with the energy savings benefits over future years, in any case not to exceed ten years. Costs incurred in the concept development phase are not capitalized as there is no assurance that any program will be accepted for development and implementation. Program-specific and non-specific portfolio development and implementation costs are capitalized and amortized over the period of benefit of the respective programs. Amortization commences in the year following the year in which the expenditure is incurred. DSM expenditures associated with cancelled programs are written off in the year in which the program is cancelled.
>
> Costs that are not capitalized are expensed as OMA in the period incurred.

In Section 6.4.1 of the application to BC Hydro's F2009 to F2010 RRA, BC Hydro states:

> To better align BC Hydro's accounting practices with GAAP, in this application BC Hydro is presenting these DSM costs as a regulatory account, rather than as a property account.
>
> This is a change in presentation only, and has no impact on BC Hydro's revenue requirements.

298.2 Please confirm, or explain otherwise, that in the current Test Period, BC Hydro follows the accounting policy quoted in the preamble for the deferral of DSM expenditures to the DSM Regulatory Account, namely that costs incurred in the concept development phase are not capitalized or deferred and DSM expenditures associated with cancelled programs are written off in the year in which the program is cancelled.

298.2.1 If not confirmed, please identify and quantify the differences and explain why the methodology used in the current Test Period is appropriate. Using a 15-year amortization period, please provide the incremental impact to the Test Period's rates if BC Hydro were to apply in the current Test Period the accounting policy or methodology used in the F2005 to F2006 RRA and F2009 to F2010 RRA as quoted in the preambles.

In response to BCUC IR 150.2, BC Hydro stated:

> Effective measure life (EML) is used by a range of utilities involved in Demand-Side Management activities to calculate the cost-effectiveness of DSM programs, track against cumulative savings, and inform amortization periods. Utilities use a combination of historical review, industry research and engineering estimates to estimate EMLs which aligns with BC Hydro's approach…

In response to BCUC IR 150.4.1, BC Hydro stated:

> The DSM Regulatory Account is a Benefit Matching Account which means that its amortization should be based on the average measure life of the expenditures in the account. Further details are provided in Chapter 7, section 7.5.2 of the Application.
>
> As both low-carbon electrification expenditures and demand-side measures expenditures are deferred to the DSM Regulatory Account, it is appropriate to include both in the calculation of the average measure life.

Footnote 371 on page 10-37 of the Application states:

> The average measure life is based on the median number of years that the measure installed is still in place and operable. Factors considered include field conditions, obsolescence, building remodeling, renovation, demolition and occupancy changes. Measure life assumptions are documented in the Demand-Side Management Standard, 'Effective Measure Life and Persistence.'

298.3 Please discuss the methodology or approach used to determine the average energy-weighted average measure life and cost weighted average measure life of BC Hydro's low-carbon electrification expenditures in the Test Period, if different from the methodology or approach used for BC Hydro's DSM portfolio. Please compare and contrast the two methodologies/approaches, if applicable.

On page 6-6 of BC Hydro's 2008 Long Term Acquisition Plan (LTAP), BC Hydro states:

> In BC Hydro's F09/F10 RRA, BC Hydro proposed to continue amortizing DSM costs over a

ten-year period to provide a better matching of costs and benefits for customers and committed to provide further details on the persistence of DSM energy savings in the 2008 LTAP.

The average persistence of energy savings from DSM Plan program activity in F2009-F2011 is 11 years. BCUC Order No. G-55-95 provides for an amortization period of up to ten years. BC Hydro is of the view that a ten-year amortization period remains appropriate for DSM expenditures in F2009-F2011 because the resulting energy savings persist for more than ten years.

Table 10-14 of the Application shows the average measure life of the DSM expenditures proposed for the Test Period weighed by energy and by cost as 17.1 and 15 years, respectively.

In response to BCUC IR 150.5.1, BC Hydro provided the average measure life of all DSM measures in the DSM Regulatory Account at the end of F2021 weighted by energy and by cost as 14.5 and 14 years, respectively.

298.4 Given that the average measure life of all DSM measures in the DSM Regulatory Account at the end of F2021 is above 10 years but below 15 years, please explain the appropriateness of amortizing the balance in the regulatory account over 10 years.

298.5 Please confirm, or explain otherwise, that the methodology or approach used to calculated the 11-year average persistence of energy savings from DSM plan program activity in F2009 to F2011 is the same methodology or approach used to calculate the average measure life of the current Test Period DSM portfolio shown in Table 10-14 of the Application.

298.5.1 If not confirmed, please identify the differences, and recalculate the average measure life of the current Test Period DSM portfolio using the methodology or approach from the 2008 LTAP for F2009 to F2011. As part of the response, please explain why BC Hydro changed its methodology.

298.5.2 If not confirmed, please recalculate the average measure life of all the DSM measures in the DSM Regulatory Account at the end of F2021 using the methodology or approach from the 2008 LTAP for F2009 to F2011.

298.6 Please provide the Test Period incremental rate impact of reducing the 15-year amortization period for the DSM Regulatory Account to a 10-year amortization period and the forecast balance of the DSM Regulatory Account at the end of F2020 to F2024.

298.7 Please provide a high-level discussion of the magnitude of the incremental rate impact for every one-year change to the amortization period for the DSM Regulatory Account.

Section 60(1)(b)(ii) of the *Utilities Commission Act* (UCA) states: “In setting a rate under this Act, the commission must have due regard to the setting of a rate that provides to the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demands.”

298.8 In consideration of BC Hydro’s return on equity of $712 million for each of F2020 and F2021 as prescribed by section 3 of Direction No. 8, please discuss whether BC Hydro and its shareholder agree that the “fair and reasonable return” requirements of the BCUC under section 60(1)(b)(ii) of the UCA are not applicable in the Test Period.

299.0 Reference: REGULATORY ACCOUNTS
Exhibit B-1, Section 7.8.7, p. 7-41; Exhibit B-5, BCUC IR 151.1, 151.3, 151.4, 151.5; Exhibit B-11, Appendix D, Table D-2, p. 4
Real Property Sales Regulatory Account

In Section 7.8.7 of the Application, BC Hydro states:

> The timing of completion of real estate transactions is difficult to forecast accurately. The Real Property Sales Regulatory Account smooths the recognition of gains and losses from real property sales that could otherwise impact rates in a particular year.

In response to BCUC IR 151.1, BC Hydro provided the following table:

Real Property Sales Net Gains

$ million	F2015	F2016	F2017	F2018
Actual	2.1	0.5	0.2	1.6
RRA Plan	10.0	10.0	10.0	10.0
Variance	7.9	9.5	9.8	8.4
Interest	0.0	0.3	0.7	1.1
Cumulative Balance Real Property Sales Regulatory Account	7.9	17.7	28.2	37.7

Table D-2 of the Evidentiary Update shows $49 million as the balance in the Real Property Sales Regulatory Account at the end of F2019.

299.1 Please discuss the reasons for the lower than planned gains from real property sales from F2015 to F2019 and provide further details of variances that were due to the timing or the amount of the net sales proceeds. For example, if the variance was due to surplus property sales being delayed to future years, please discuss the reason for the delay and when it is expected to be resolved.

299.2 Please discuss why BC Hydro believes that the variances experienced from F2015 to F2019 won't be experienced in F2020 to F2024.

In response to BCUC IR 151.4, BC Hydro stated:

> There are several factors beyond BC Hydro's control that could result in the balance in the Real Property Sales Regulatory account having a balance either greater than zero or less than zero at the end of fiscal 2024…

In response to BCUC IR 151.5, BC Hydro stated:

> The purpose of the Real Property Sales Regulatory Account is to ensure ratepayers benefit from planned sales of surplus property. The timing of individual sales transactions has proven to be highly uncertain and the annual net gains difficult to forecast. BC Hydro expects that it would recommend that the Real Property Sales Regulatory Account remain in place until the properties are sold and customers have realized the intended benefits.
>
> Subsequent to that, BC Hydro considers that the treatment of gains on property sales (i.e., after the program or beyond fiscal 2024) would be the subject of future revenue requirement applications.

299.3 Please discuss whether BC Hydro had considered alternative approaches to the Real Property Sales Regulatory Account to achieve smoothing the recognition of gains and losses from real property sales and ensuring that ratepayers benefit from planned sales of surplus property. If so, please discuss the alternatives considered. If not, please explain why not.

299.4 Given that the balance in the Real Property Sales Regulatory Account at the end of F2019 is $49 million and the balance is not expected to self-clear until F2024, please discuss whether the Real Property Sales Regulatory Account would result in intergenerational equity issues.

299.5 Please discuss whether BC Hydro had considered an alternative approach to forecasting the annual gains for F2020 to F2024. If so, please discuss the alternatives considered. If not, please explain why not.

299.6 Given that the balance in the Real Property Sales Regulatory Account at the end of F2019 is $49 million, please discuss the pros and cons of forecasting zero gains/losses from real property sales in the Test Period and whether this approach would help mitigate intergenerational equity issues and decrease the carrying costs of the deferral account.

In response to BCUC IR 151.3, BC Hydro stated:

> BC Hydro has been preparing surplus properties for sale since fiscal 2015. Activities have included market value appraisals and estimates, investigation and remediation of environmental contamination work, working with municipalities on subdivision requirements, and consultation with First Nations.
>
> These activities have informed our estimates of net sales proceeds and associated target which was changed to $100 million. The timeline was extended by a further five years to fiscal 2024 to reflect the length of time to complete sales due to environmental remediation and certification, subdivision requirements, consultation with First Nations, and negotiating purchase and sales agreements with potential buyers.

299.7 Please provide details of each of the surplus properties prepared for sale since F2015, including the location, the estimated net gains or losses, the degree of readiness for sale and the reason they are considered "surplus." Please also identify the surplus properties that have been sold, the actual net gains or losses and the fiscal year that the properties were sold.

299.8 Based on the response to the preceding IR, please discuss whether the forecast annual gain differs from $10 million in the Test Period.

299.8.1 If so, please discuss the pros and cons of forecasting the gains and losses from real property sales for the Test Period based on the properties that BC Hydro expects to sell in the Test Period rather than forecasting a $10 million gain every year from F2020 to F2024.

300.0 Reference: REGULATORY ACCOUNTS
Exhibit B-1, Section 7.5.1, p. 7-15; Section 7.8.11, p. 7-44; Direction No. 3 to the BCUC, OIC 314/2012, Section 3(2); Direction No. 7 to the BCUC, OIC 97/2014, Section 7(g); BC Hydro F2012-F2014 RRA proceeding, Exhibit B-1-3, Section 1.7, p. 1-43
Non-Current Pension Costs Regulatory Account

In Section 7.8.11 of the Application, BC Hydro states:

> BCUC Order No. G-77-12A extended the account for fiscal 2012 to fiscal 2014, and expanded the scope of the account to include the difference between forecast and actual non-current other post-employment benefit costs, beginning in fiscal 2012. In accordance with Direction No. 7, BCUC Order No. G-48-14 authorized BC Hydro to

continue to defer to the account variances between forecast and actual non-current pension costs, on an ongoing basis.

In section 3(2) of Direction No. 3 to the BCUC, it states: "…the commission must also issue the final orders requested in section 1.7 of the application…"

Section 1.7 of BC Hydro's F2012-F2014 RRA states the following regarding the Non-Current Pension Cost Regulatory Cost:

> The continuation for F2012 of the deferral of the differences between forecast and actual non-current pension costs; the deferral in F2013 and F2014 of the differences between forecast and actual net interest expense or income on the pension and other post employment benefits plan obligations and benefits; <u>the inclusion of the actual experience gains or losses related to BC Hydro's pension and other post employment benefit plans in the regulatory account beginning in F2012</u>; and the amortization of the closing F2011 balance in the regulatory account over a five-year period beginning in F2012 (Non Current Pension Cost Regulatory Account).[3]

Section 7(g) of Direction No. 7 states that the BCUC "must allow the authority to continue to defer to the non-current pension costs regulatory account the variances between actual and forecast non-current pension costs."

300.1 Please elaborate on the difference between "the actual experience gains or losses related to BC Hydro's pension and other post employment benefit plans" and "the variances between actual and forecast non-current pension costs."

300.2 Please confirm, or explain otherwise, that in the current and future test periods, the only items that can be deferred to the Non-Current Pension Costs Regulatory Account are "the actual experience gains or losses related to BC Hydro's pension and other post employment benefit plans" and "the variances between actual and forecast non-current pension costs."

300.2.1 If not confirmed, please describe the other items that can be deferred to the Non-Current Pension Costs Regulatory Account and the BCUC order(s) approving the deferral treatment.

300.3 Please discuss how each of the items described in response to the previous IRs (i.e. IR 300.2 and 300.2.1) would be treated if they were not provided deferral treatment to the Non-Current Pension Costs Regulatory Account. As part of the response, please also discuss the impact to the Test Period revenue requirement and rates and quantify where possible.

300.4 Please provide the actual amounts deferred to the Non-Current Pension Costs Regulatory Account broken down by each item identified in the response to the preceding IR for each of F2015 to F2019 and the forecast amounts for F2020 and F2021, as applicable. For variances that have been deferred, please explain the reasons for each of the variances.

In Section 7.5.1 of the Application, BC Hydro describes its criteria for assessing whether a risk is controllable or non-controllable.

300.5 Irrespective that the Non-Current Pension Costs Regulatory Account has been established, please discuss how each item identified in response to IR 300.2 and 300.2.1 meets BC Hydro's criteria as set out on in sections 7.6 and 7.5.1 of the Application. Please ensure you address each of the five items listed and the $10 million threshold.

[3] Emphasis added.

301.0 Reference: REGULATORY ACCOUNTS
Exhibit B-1, Section 7.5.1, p. 7-15; Section 7.6, p. 7-21; Exhibit B-5, BCUC IR 139.1; Direction No. 7 to the BCUC, OIC 97/2014, Section 1, 7(c); BCUC Order G-48-14 with reasons for decision dated March 24, 2014, Directive 5
Repeal of Directions No. 1, 3, 6 and 7 to the BCUC

In response to BCUC IR 139.1, BC Hydro stated:

> The following regulatory accounts were established by BCUC Order No. G-77-12A pursuant to Direction No. 3:
>
> - IFRS Property, Plant, and Equipment Regulatory Account (section 3(2))
> - IFRS Pension Regulatory Account (section 3(2))
>
> The following regulatory accounts were established by BCUC Order No. G-48-14 pursuant to Direction No. 7:
>
> - Rate Smoothing Regulatory Account (section 7(h)(i))
> - Real Property Sales Regulatory Account (section 7(h)(ii)) […]
>
> The following regulatory accounts were continued by BCUC Order No. G-48-14 pursuant to Direction No. 7:
>
> - Heritage Deferral Account (section 7(a))
> - Trade Income Deferral Account (section 7(b))
> - Rock Bay Remediation Regulatory Account (section 7(e))
> - Asbestos Remediation Regulatory Account (renamed Remediation Regulatory Account by BCUC Order No. G-47-18) (section 7(f))
> - Non-Current Pension Costs Regulatory Account (section 7(g))

In Section 7.6 of the Application, BC Hydro states:

> …should a new regulatory account be required in the future, BC Hydro believes that the criteria discussed in section 7.5 continue to be appropriate. With respect to the deferral of differences between forecast and actual costs, BC Hydro continues to believe that it should assume financial responsibility for controllable risks and use regulatory accounts for non-controllable risks. However, to limit the number of regulatory accounts, an objective measure should be used as a threshold for creating a new regulatory account. BC Hydro believes that un-forecast and non-controllable expenditures of greater than $10 million in a fiscal year would be considered material. Therefore, in these cases, a new regulatory account would be warranted to defer the impact for future recovery.

In Section 7.5.1 of the Application, BC Hydro describes its criteria for assessing whether a risk is controllable or non-controllable.

301.1 Irrespective that the following regulatory accounts have been established, please discuss how each of these accounts meet BC Hydro's criteria as set out on in Sections 7.6 and 7.5.1 of the Application. Please ensure you address each of the five items listed and the $10 million threshold:

a) Real Property Sales Regulatory Account; and
b) Remediation Regulatory Account

301.2 Please provide a schedule showing the variance between: (i) the forecast and actual asbestos remediation costs; and (ii) the forecast and actual polychlorinated biphenyl regulations compliance costs for each fiscal year since F2015. Please also explain the reasons for the variances.

Section 7(c) of Direction No. 7 to the BCUC states:

> When regulating and setting rates for the authority, the commission must, in regard to the non-heritage deferral account, allow the authority to
>
> (i) continue to defer to that account the variances between actual and forecast cost of energy arising from differences between actual and forecast domestic customer load, and
>
> (ii) defer to that account the Burrard costs

Section 1 of Direction No. 7 to the BCUC defines Burrard costs as:

> …the costs incurred by the authority in F2014 or a later fiscal year arising from the decommissioning of those portions of Burrard Thermal that are not required for transmission support services, including, without limitation, employee retention costs incurred as a result of the decommissioning, costs incurred as penalties or damages that arise in consequence of the decommissioning, and the net increase in amortization expense in F2015 and F2016 arising from a commission order under section 15 of this direction.

301.3 Please confirm, or explain otherwise, that there are no additional costs related to the decommissioning of Burrard Thermal planned for deferral treatment to the Non-Heritage Deferral Account (NHDA) in the Test Period.

301.3.1 If not confirmed, please provide the amount of these costs planed for deferral treatment in each of F2020 and F2021 and explain the rationale for deferring these costs. As part of the response, please explain how these costs meet BC Hydro's criteria for deferral as set out on in Sections 7.6 and 7.5.1 of the Application. Please ensure you address each of the five items listed and the $10 million threshold.

Directive 5 in Order G-48-14 approved the continual deferral of the variances between the actual and forecast cost of energy arising from differences between forecast and actual domestic customer load to the NHDA pursuant to Direction No. 7, section 7(c)(i).

301.4 Please provide a schedule showing the variances between the actual and forecast cost of energy arising from differences between actual and forecast domestic customer load for the past five years (i.e. F2015 to F2019). Please also explain the reasons for the variances.

301.5 Irrespective of Directive 5 in Order G-48-14, please discuss why it is appropriate to continue to defer the variances between the actual and forecast cost of energy arising from differences between actual and forecast domestic customer load to the NHDA.

301.5.1 Please discuss how deferral of the variances between the actual and forecast cost of energy arising from differences between actual and forecast domestic customer load meets BC Hydro's criteria as set out on in Sections 7.6 and 7.5.1 of the Application. Please ensure you address each of the five items listed and the $10 million threshold.

301.5.2 Please discuss and quantify the impact to the Test Period revenue requirement and rates under the scenario that the deferral of the variances between the actual and forecast cost of energy arising from differences between actual and forecast domestic customer load is disallowed beginning in the current Test Period.

301.5.3 Please provide a high-level discussion of the impact to subsequent test periods' revenue requirement and rates under the scenario that the deferral of the variances between the actual and forecast cost of energy arising from differences between actual and forecast domestic customer load is disallowed beginning in the current Test Period.

301.6 Please identify the regulatory accounts where the scope, recovery period, recovery mechanism, or application of carrying costs were directed by Directions No. 1, 3, 6 and 7 for approval by the BCUC and not continued by Direction No. 8. As part of the response, please describe the change in scope, recovery period, recovery mechanism, or application of carrying costs and identify the corresponding BCUC order number and directive that approved these changes.

301.6.1 For the scope, recovery period, recovery mechanism, or application of carrying costs identified in the response to the preceding IR, please discuss why those should be continued in the current and future test periods.

301.6.2 For the scope changes discussed in the response to the preceding IR where the scope of an existing deferral account was expanded, please discuss how each of these scope expansions meet BC Hydro's criteria as set out on in Sections 7.6 and 7.5.1 of the Application. Please ensure you address each of the five items listed and the $10 million threshold.

302.0 Reference: REGULATORY ACCOUNTS
Exhibit B-1, Section 8.13.3, p. 8-30; Exhibit B-5, BCUC IR 146.1, 146.8;
Exhibit B-11, Appendix F, p. 1
New Leasing Standard (IFRS 16)

In Appendix F to the Evidentiary Update, it shows a debit adjustment of $64.8 million (from a forecast credit adjustment of $18.0 million in the Application) to BC Hydro's balance sheet resulting from the adoption of International Financial Reporting Standard 16 (IFRS 16) with respect to electricity purchase agreements. BC Hydro also states that the $82.8 million net change has been included as an addition to the Non-Heritage Deferral Account.

302.1 Please describe the differences between BC Hydro's preliminary assessment used to forecast the adjustment in the Application and the assessment used to calculate the actual adjustment in the Evidentiary Update. In other words, please identify what has changed to result in a $82.8 million difference in the Evidentiary Update compared to the Application.

On page 8-30 of the Application, BC Hydro states:

> BC Hydro has deferred positive variances related to EPA [Electricity Purchase Agreement] capital leases into the Non-Heritage Deferral Account in order to provide the benefit to ratepayers, even though this was not required under existing orders. Accordingly, BC Hydro requests BCUC approval to defer to the Non-Heritage Deferral Account, any variances related to the accounting for EPAs determined to be leases under IFRS 16, that are not eligible for deferral treatment under existing orders.

In response to BCUC IR 146.1, BC Hydro stated:

> …the expenses attributable to EPAs recognized on the balance sheet as leases under IFRS 16 are classified as depreciation expense and finance charges and not as Cost of Energy. Variances related to depreciation expense and finance charges are not eligible for deferral to the Non-Heritage Deferral Account based on existing orders. Therefore, the variances attributable to EPA leases are not required to be deferred to the Non-Heritage Deferral Account.

302.2 Please confirm, or explain otherwise, that BC Hydro is now requesting to defer to the NHDA a one-time debit adjustment of $64.8 million and it is not expecting any further variances related to the accounting for EPAs determined to be leases under IFRS 16.

302.3 Please confirm, or explain otherwise, that the variances related to EPA capital leases are now negative (i.e. debit adjustment of $64.8 million) and thus the deferral of the variance to the NHDA would not provide the same benefit to ratepayers as a positive (i.e. credit) deferred variance.

302.3.1 If confirmed, please provide the rationale for deferring the negative $64.8 million variance to the NHDA.

Further in response to BCUC IR 146.1, BC Hydro stated:

> Finance charge variances attributable to EPA leases are eligible for deferral as they are within the scope of the Total Finance Charge Regulatory Account. However, depreciation variances attributable to EPA leases are not eligible for deferral as these variances are not within the scope of existing regulatory accounts. BC Hydro considers that the depreciation variances attributable to EPA leases are out of scope of the Amortization of Capital Additions Regulatory Account. If the BCUC considers that the depreciation expense related to leased asset additions should be within the scope of the Amortization of Capital Additions Regulatory Account, BC Hydro would not be opposed to a directive requiring these depreciation variances on leased asset additions be deferred to this regulatory account.

302.4 Please discuss the pros and cons of deferring the eligible portion of the variances attributable to the EPA leases to the Total Finance Charge Regulatory Account and the remaining variance to the NHDA.

302.5 Please explain why BC Hydro considers depreciation variances attributable to EPA leases to be out of scope of the Amortization of Capital Additions Regulatory Account.

302.6 In the event that the BCUC does not approve BC Hydro's request for deferral treatment to the NHDA, please explain how the $64.8 million debit adjustment would be treated in the Test Period revenue requirement and the rate impact under the following scenarios:

a) The BCUC provides a directive requiring the depreciation variances attributable to EPA leases be deferred to the Amortization of Capital Additions Regulatory Account; and

b) The BCUC does not provide a directive requiring the depreciation variances attributable to EPA leases be deferred to the Amortization of Capital Additions Regulatory Account.

In Appendix F to the Evidentiary Update, BC Hydro states that it has now completed its implementation of IFRS 16.

In response to BCUC IR 146.8, BC Hydro stated:

> As BC Hydro is required to adopt IFRS 16 for the year ending March 31, 2020, we have not obtained formal confirmation from our external auditor regarding its adoption. The Auditor General of BC (BC Hydro's external auditor effective for fiscal 2020) will provide confirmation of their views as part of their review and audit of BC Hydro's financial statements.

302.7 Please discuss whether BC Hydro has discussed its implementation of IFRS 16 and its revised impact assessment with the Auditor General of BC.

302.7.1 If so, please discuss whether the Auditor General of BC agrees with BC Hydro's implementation of IFRS 16 and the revised impact assessment.

302.7.2 If during the Auditor General of BC's review and audit of BC Hydro's financial statements, it does not agree with how BC Hydro has implemented IFRS 16 regarding BC Hydro's EPA leases, please discuss how those variances (i.e. the difference between BC Hydro's adjustment of $64.8 million and the Auditor General of BC's adjustment) would be treated. Would this treatment be different depending on whether the BCUC approved or didn't approve BC Hydro's request to defer variances related to the accounting for EPAs determined to be leases under IFRS 16 to the NHDA? Please discuss.

On page 8-31 of the Application, BC Hydro provides its forecast adjustment for its significant non-EPA agreements that are potentially within the scope of IFRS 16.

302.8 Please provide an update of the adjustment for the significant non-EPA agreements that are potentially within the scope of IFRS 16 and discuss the impact to the Test Period revenue requirement and rates.

E. CHAPTER 4 – COST OF ENERGY

303.0 Reference: COST OF ENERGY
Exhibit B-1, Appendix C, p. 2; Exhibit B-5, BCUC IR 15.1.1, 15.2, 15.2.1
EPA renewal assumptions

The Comprehensive Review of BC Hydro: Phase 1 Final Report attached as Appendix C to the Application states: "The government intends to introduce legislation to restore the BCUC's authority to review and approve BC Hydro's Integrated Resource Plan (IRP). The IRP will be submitted to the BCUC by February 2021. This timing enables development of the IRP to be informed by Phase 2 of the Review and the CleanBC plan."

BC Hydro's response to BCUC IR 15.1.1 stated:

> The $1.3 million in net increase in costs for EPAs expected to be renewed between F2019 and the end of F2021 results from changes in renewal assumptions as follows:
>
> - Renewal of run of river hydro projects at 100 per cent, as compared to the 75 per cent renewal assumption in the F2019 RRA Plan.
> - With the establishment of the Biomass Energy Program, biomass projects are assumed to be renewed at 80 per cent, in aggregate, of historical volumes as compared to the assumption of 50 per cent, in aggregate, used in developing the F2019 RRA plan.

BC Hydro's response to BCUC IR 15.2 stated:

> For EPA renewals in the integrated system, we have assumed the following which has been applied to those EPAs that are expiring during the test period:
>
> - Hydro run of river EPA renewals:
>   - 75 per cent of the aggregate historical energy and capacity volumes are renewed, consistent with what was assumed in the 2013 IRP.

303.1 Please reconcile the responses to BCUC IR 15.1.1 and 15.2 quoted in the preambles above regarding the renewal assumptions used in the Test Period for run of river hydro EPAs being at 100 percent and 75 percent, respectively.

303.2 Please discuss how much weight should be given to the 2013 IRP in this proceeding given that the renewal assumptions for both run of river EPAs and biomass EPAs have changed.

BC Hydro's response to BCUC IR 15.2.1 stated:

> During the test period a total of eight EPAs are due to expire, including:
>
> - Six biomass EPAs for facilities that are eligible for the biomass Energy Program, which represent a total of 389 MW in capacity; and
> - Two run of river hydro EPAs totaling less than 4MW in capacity are due to expire.
>
> However, with respect to the run of river hydro EPA renewals noted above, the 75 per cent assumption is no longer applicable. This is because BC Hydro recently adopted the use of market price as a conservative interim assumption for evaluating cost-effectiveness of EPAs on the integrated system (other than those for facilities eligible for the Biomass Energy Program or facilities with other benefits) during surplus and deficit periods, and as a result we do not have certainty as to whether the 75 per cent is achievable. BC Hydro notes this change in approach for run of river hydro renewals would not have a material impact on the cost of energy during the test period.

303.3 Prior to the recent adoption of market price, please explain what criteria was used in evaluating the cost-effectiveness of an EPA on the integrated system during surplus and deficit periods.

303.4 Please clarify what it meant by the statement: "we do not have certainty as to whether the 75 percent is achievable." In the response, please explain the use of market price for evaluating cost-effectiveness of EPAs, as well as how an increase in renewal rates for run of river EPAs to 100 percent relates to the 75 percent renewal assumption.

304.0 Reference: COST OF ENERGY
Exhibit B-1, p. 2-9; Appendix A, Schedule 4.0; Exhibit B-6, AMPC IR 18.2; CEABC IR 21.1; BC Hydro Application for Electricity Purchase Agreement Renewals for Sechelt Creek Hydro, Brown Lake Hydro and Walden North Hydro (EPA Renewals Application) proceeding, Exhibit B-1, pp. 15, 21, 34; Appendix D, pp. 13, 34, 41
Independent Power Producer (IPP) costs

The following is stated in Exhibit B-1 of the EPA Renewals Application proceeding:

> Page 15: Some of the IPPs renewing their EPAs with BC Hydro require upgrades to their system (which is a cost borne by the IPP) and/or upgrades to BC Hydro's network system (which is a network upgrade cost covered by BC Hydro pursuant to its Standard Generator Interconnection Agreement). Generally these upgrades are minor, such as upgrades to the communications and protection systems or metering equipment. This is the case with the required Sechelt Creek upgrades, and the network upgrade costs that BC Hydro is responsible for are estimated at [redacted].
>
> Page 21: The Brown Lake facility requires minor upgrades, and the BC Hydro network upgrade costs for the Brown Lake facility is estimated to be [redacted].
>
> Page 34: The Walden North facility requires minor upgrades, and the BC Hydro network upgrade costs for the Walden North facility are estimated to be [redacted].

Lines 5 and 29 of Schedule 4.0 in Appendix A to the Application reflects the volume (GWh), unit cost ($/MWh) and nominal cost ($ million) of IPP's and Long-Term Commitments, respectively, as summarized below:

	F2017 Actual	F2018 Actual	F2019 Forecast	F2020 RRA	F2021 RRA
GWh (Line 5)	13,644	14,354	14,631	15,449	16,040
Total Cost (Line 29)	$1,213.1	$1,311.6	$1,326.6	$1,538.5	$1,601.1

304.1 Please provide the total number of IPP locations where BC Hydro is scheduled to perform network upgrades, as well as the total dollar amount of these costs, in each of F2020 and F2021.

304.1.1 Please discuss whether the network upgrades on BC Hydro's system identified in response to the preceding IR are required regardless of whether an IPP renews its EPA.

304.2 Please confirm that network upgrade costs are included in Line 5 of Schedule 4.0 in Appendix A. If not, please identify where they are reflected in the Application.

304.3 Please explain the nature the network upgrades included in the Application, as well as the qualitative benefits that ratepayers receive from these upgrades once completed (i.e. safety, reliability, etc.).

304.4 Please discuss the frequency of BC Hydro's network (i.e. annual, bi-annual), and the reason for such frequency.

BC Hydro states on page 2-9 of the Application:

> Section 4 of Direction No. 8 provides direction in this area to recover costs related to previous policy decisions by the Government of BC. It states that the BCUC must not disallow recovery in rates of the balance of BC Hydro's regulatory accounts as at March 31, 2019. It also states that the BCUC must also not disallow 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;
> - Energy supply contracts entered into before fiscal 2017, and
> - Debt servicing costs related to the Rate Smoothing Regulator Account approved by Order No. G-48-14.

BC Hydro's response to AMPC IR 18.2 with respect to the costs incurred for the three items listed in the preamble immediately above stated: "The BCUC must allow recovery of these costs regardless of whether they are incurred before or after March 31, 2019."

304.5 Please complete the below table showing the total forecast annual volume and cost for all energy supply contracts entered into by BC Hydro <u>after</u> F2017 for each of F2020 and F2021.

	F2020 RRA	F2021 RRA
GWh		
Total Cost ($ millions)		

Appendix D to the EPA Renewals Application states the following with respect to EPAs for existing run-of-river projects:

Page 13: Section 7.1 states 'Without limiting the Seller's obligation to deliver Energy in compliance with the Project Standards, the Seller will, at the Buyer's request, use commercially reasonable efforts to apply for, and diligently pursue and maintain, any certification, licensing or approval offered by any Governmental Authority or independent certification agency that is identified by the Buyer evidencing that the Seller's Plant and the Delivered Energy has Environmental Attributes, and the Buyer will reimburse the Seller for any certification, audit and licensing fees charged by the applicable Governmental Authority or independent certification agency for such certification, licensing or approval that the Buyer requires the Seller to obtain.'

Page 34: 'Buyer' means British Columbia Hydro and Power Authority and its successors and permitted assigns.

Page 41: 'Seller' means the Party so identified on page one of this EPA, and its successors and permitted assigns.

BC Hydro's response to CEABC IR 21.1 stated:

- In general, RECs [Renewable Energy Credits] sold in energy markets can be bundled with the energy, or unbundled and sold separately from the energy in different markets.
- At this time only wind facilities in BC are both eligible for the California Renewable Portfolio Standard [RPS] and registered to create RECs in WREGIS [Western Renewable Energy Generation Information System]. The CEC [California Energy Commission] currently does not consider BC run-of-river hydro-electric facilities nor BC biomass facilities to be renewable and therefore those facilities may not participate in California's RPS market.
- To be eligible for the highest value products under the California RPS, RECs must be bundled with energy and delivered to the state grid. Delivery of energy to the state grid requires incremental costs for transmission service, losses and often congestion payments.

304.6 Please clarify whether any IPP facility in BC that is eligible to participate in California's RPS market has been reimbursed by BC Hydro for certification, audit and licensing fees associated with its Environmental Attributes.

304.6.1 If yes, please provide the aggregate cost of these reimbursements forecast in each of F2020 and F2021, as well as the number of IPP facilities that are both eligible for California RPS and registered to create RECs in WREGIS.

304.6.2 If yes, please also confirm that these reimbursements are included in Line 5.0 of Appendix A to the Application. If not, please identify where in the Application these reimbursements are included.

304.7 Please explain the process to confirm that RECs are bundled with energy and originate from a facility in BC. In the response, please discuss how a facility in BC is determined to be eligible to participate in California's RPS market and identify the authority who determines this.

305.0 Reference: COST OF ENERGY
Exhibit B-6, CEABC IR 6.4
Market energy – net purchases (sales) from Powerex

Attachment 1 to CEABC IR 6.4 provided, on a monthly basis, BC Hydro's Market Electricity Purchases, Surplus Sales and Net Purchases (Sales) from Powerex, for the previous ten fiscal years, from F2010 to F2019.

305.1 Please update the response to CEABC IR 6.4 to provide BC Hydro's Market Electricity Purchases, Surplus Sales and Net Purchases (Sales) from Powerex, on a gross basis to reflect volumes from the Evidentiary Update for the F2019 Actual, F2020 Update, and F2021 Update on a monthly and annual basis.

306.0 Reference: COST OF ENERGY
Exhibit B-1, pp. 4-6–4-7, 4-13; Exhibit B-5, BCUC IR 20.1
Water inflow conditions and reservoir levels – Kinbasket and Williston

On page 4-13 of the Application, BC Hydro states:

> The primary objectives of the Energy Study are to forecast:
>
> - The marginal value of water in BC Hydro's two largest reservoirs (Williston and Kinbasket) that is used to inform operational dispatch decisions; and
> - The Cost of Energy for financial reporting.

BC Hydro further states on page 4-6 of the Application: "Market Energy is electricity purchased from or sold to Powerex through transfer pricing arrangements between Powerex and BC Hydro. The costs or revenues associated with these transactions are allocated to the following categories…Market Electricity Purchases…Surplus Sales…Net Purchases (Sales) from Powerex…"

BC Hydro's response to BCUC IR 20.1 stated:

> All else being equal, lower inflows across the system (including reservoirs besides Williston and Kinbasket) will result in lower end of year energy content in System Storage (i.e., the Williston and Kinbasket reservoirs). Similarly, all else being equal, higher inflows would result in higher end of year energy content in System Storage.
>
> The energy in System Storage is directly related to the difference between inflow and generation at GM Shrum (GMS) and Mica (MCA) generating stations (assuming no spill). Generation at GMS and MCA depends, in turn, on load, exports (or imports), and remaining system resources (other BC Hydro assets, coordination agreements, and IPP energy).

306.1 Please confirm, or explain otherwise, that all import and export activity, including Net Purchases (Sales) from Powerex, has a direct effect on both the energy and water levels associated with System Storage.

307.0 Reference: COST OF ENERGY
Exhibit B-11, pp. 7, 9
Monthly energy study – Evidentiary Update

BC Hydro states on page 7 of the Evidentiary Update: "The Cost of Energy forecast in the Application was based on BC Hydro's October 2018 energy study, The Cost of Energy forecast in the Evidentiary Update is based on the June 2019 energy study."

BC Hydro further states on page 9:

> The primary driver of the decreased cost of energy is lower costs for IPPs and Long-Term Commitments. These costs have decreased for two reasons:
>
> - First…supply from IPPs and Long-Term Commitments is lower. This is due to:
>   - dry conditions and low water inflows, which decrease hydro generation; and
>   - lower forecast deliveries, based on updated historical delivery averages and delayed commercial operation dates.
> - Second, the full implementation of IFRS 16, discussed further in Appendix F, shifts costs from IPPs and Long-Term Commitments (Cost of Energy) to Amortization and Finance Charges.

307.1 Other than the reasons stated on pages 7 to 9 of the Evidentiary Update, please describe any other parameters that have changed between the June 2019 and October 2018 energy studies.

307.2 Please discuss whether the changes due to dry conditions and lower water inflows, delayed IPP commercial operation dates, and if lower forecast IPP deliveries had any impacts on the prices at which the lower planned surplus sales and higher planned market electricity purchases transactions are expected to occur, as forecast in the Evidentiary Update. Please explain why or why not, and if applicable, please quantify these impacts where possible.

308.0 Reference: COST OF ENERGY
Exhibit B-5, BCUC IR 21.1
Monthly energy study – Enbridge T-South rupture

BC Hydro's response to BCUC IR 21.1 stated:

> The disruption of natural gas supply related to the Enbridge T-South rupture reduced the availability of electricity in the Pacific Northwest because it limited the ability for utilities, including BC Hydro, to rely on natural gas to generate electricity. This likely contributed to increased demand for market energy, decreased availability of market energy and increases in the market price of both natural gas and electricity.
>
> The reduced availability of natural gas created the potential for increased electrical heating load due to fuel switching. This potential increase was not included in the load forecast for the test period.
>
> Capacity on the Enbridge T-South pipeline has been partially restored, which has reduced the impacts and uncertainty relative to the period immediately after the rupture. There are many factors that can affect the future natural gas and electricity supply and prices, of which the timing of when the pipeline may be restored to full capacity is just one factor.

308.1 Please discuss whether BC Hydro expects market conditions consequent to the disruption of natural gas supply related to the Enbridge T-South rupture to continue until the T-South pipeline is fully restored.

308.1.1 If so, please discuss whether the June 2019 Energy Study incorporates anticipated effects of constrained natural gas supply. If not, please explain why not.

309.0 Reference: COST OF ENERGY
Exhibit B-1, p. 4-16; Appendix DD, p. 12; Exhibit B-5, BCUC IR 29.1, 29.1.1, 30.1, 30.2
Monthly energy study – risk management

On page 4-16 of the Application, BC Hydro states: "[a]s part of minimizing costs to ratepayers, BC Hydro's objective is to maximize 'expected consolidated net revenue from operations.'"

Page 12 of Appendix DD to the Application states: "The forecasted power prices for different US markets such as California are a significant factor for the calculated BC Hydro marginal prices, and decisions on import/export and generation."

BC Hydro's response in BCUC IR 29.1 stated that BC Hydro's objective to maximize expected consolidated net revenue is "done on a risk-neutral basis and is therefore the same as the objective to maximize risk neutral long-term net revenue."

BC Hydro's response in BCUC IR 29.1.1 stated: "A risk-neutral operating strategy is based on achieving the expected outcome, assuming each of the modeled possible outcomes is equally likely, and does not bias towards or against favourable or unfavourable outcomes."

309.1 Please explain whether the level of risk undertaken by BC Hydro increases as a function of maximizing expected consolidated net revenue. As part of the response, please explain how this level of risk is allocated between BC Hydro's shareholders and ratepayers.

309.2 Please discuss any trade-offs in short-term and long-term risk that BC Hydro and ratepayers are exposed to when maximizing risk-neutral long-term net revenue. As part of the response, please discuss the amount of risk exposure faced by each of BC Hydro and ratepayers in both the short-term and long-term.

BC Hydro's response to BCUC IR 30.1 in Exhibit B-5 stated:

> BC Hydro does not participate in external markets, and transacts exclusively with Powerex Corp. at the BC Border. BC Hydro does not include market prices in, or transmission transfer capability to, more remote markets, including California, in the Energy Study models that inform BC Hydro's Cost of Energy forecast. The availability of supply and the market prices at Mid-C reflect expected demand and supply conditions in the Pacific Northwest, which in turn is from others regions such as California or the Desert Southwest to or from the Pacific Northwest. Therefore, BC Hydro currently does not intend to explicitly incorporate California market prices into the Energy Study.

309.3 Please discuss whether there are external market risks that BC Hydro is exposed to that are not associated with participation in external markets. For example, how would the Energy Study consider the effect of a sudden increase in demand in the Desert Southwest, or the effect of an increase in supply from solar energy in California?

309.4 Please discuss what strategies BC Hydro has in place to protect its shareholder and ratepayers from the external market risks discussed in the response to the preceding IR.

BC Hydro's response to BCUC IR 30.2 stated:

> The current Energy Study market model forecasts import and export activity at the B.C. border, and includes forward market prices at Henry Hub and forward prices for electricity at Mid-C.
>
> Trading activity by Powerex Corp. in external markets, including in the Energy Imbalance Market, is not captured in the modeling. Market risks associated with participation in

external markets are not included in the current Market Model as these market risks are risks managed by Powerex as the entity that participates in external markets.

309.5 Please explain why Henry Hub forward market prices are included in the Energy Study, but forward market prices from regions such as California or the Desert Southwest are excluded, given that both forward market prices are not directly associated with import and export activity at the BC Border.

309.6 Please provide a chart for the period F2015 to F2019 that graphs the actual monthly Henry Hub price against each of the Sumas gas price and the Mid-C spot price. As part of your response, please explain any correlations or relationships between Henry Hub and Sumas, and Henry Hub and Mid-C.

310.0 Reference: COST OF ENERGY
Exhibit B-1, pp. 4-16–4-17; Exhibit B-5, BCUC IR 163.1, Attachment 3, Table 1, p. 2; Attachment 7, p. 1; BCUC IR 163.1.1
Exports from BC

BC Hydro's response to BCUC IR 163.1 stated:

> …BC Hydro also notes that in any scenario where Point B is at the U.S. border, this indicates that the Transmission Customer intends to export electrical energy from Canada for sale in the U.S. In order to do so, the Transmission customer also requires an export sales permit or licence from the National Energy Board (NEB), which has jurisdiction to regulate electricity energy exports from Canada.

Excerpts from Table 1 of Attachment 3 in response to BCUC IR 163.1 is provided below, and identifies the potential Path Name and Point of Receipt (POR) and Point of Delivery (POD) Combinations for exports from the BC Hydro System to the U.S. and Alberta:

Table 1: Valid Path Name and POR/POD Combinations on the BC Hydro System

Path Name	POR	POD
BC – US		
W/BCHA/BCHA – BPAT/KI – BC.US.BORDER/	KI	BC.US.BORDER
W/BCHA/BCHA – BPAT/GMS.MCA.REV – BC.US.BORDER	GMS.MCA.REV	BC.US.BORDER
W/BCHA/BCHA – BPAT/BCHA.INT.SYS – BC.US.BORDER/	BCHA.INT.SYS	BC.US.BORDER
W/BCHA/BCHA – BPAT/BCHA.LM.SYS – BC.US.BORDER/	BCHA.LM.SYS	BC.US.BORDER
W/BCHA/BCHA–BPAT/POWELL.RIVER – BC.US.BORDER	POWELL.RIVER	BC.US.BORDER
BC – AB		
W/BCHA/BCHA – AESO/KI – AB.BC/	KI	AB.BC
W/BCHA/BCHA – AESO/GMS.MCA.REV – AB.BC/	GMS.MCA.REV	AB.BC
W/BCHA/BCHA – AESO/BCHA.INT.SYS – AB.BC/	BCHA.INT.SYS	AB.BC
W/BCHA/BCHA – AESO/BCHA.LM.SYS – AB.BC/	BCHA.LM.SYS	AB.BC
W/BCHA/BCHA – AESO/POWELL.RIVER – AB.BC/	POWELL.RIVER	AB.BC

Page 1 of Attachment 7 to BCUC IR 163.1 stated:

- BC Hydro requires the use of eTags to schedule energy in both Pre-schedule and Real-time for all interchange energy transactions, including internal paths.
- An important element of the eTag is its specification of which transmission reservation the energy is to be scheduled on.

BC Hydro's response to BCUC IR 163.1.1 stated:

> In this scenario, Point A could be the Point of Receipt for a generator located in BC Hydro's Service area while Point B could be the Point of Delivery at a border for the Point to Point reservation.
>
> For example, the path, Point of Receipt, and Point of Delivery could be as follows:
>
> Path = W/BCHA/BCHA-BPAT/GMS.MCA.REV-BC.US.BORDER
>
> In the above example, the path is from BC Hydro's service area to the U.S. Border.
>
> This scenario represents all transmission exports from BC Hydro's service area because Network Integration Transmission Service cannot be used for third party sales.

310.1 Please provide an eTag that reflects an export of electricity from BC Hydro's system to the U.S., using each of the applicable export paths reflected in Table 1 of the preamble. As part of your response, please explain any terms on the eTag that have not been explained in either the Application or in the responses to IR No. 1 or 2 of this proceeding.

310.2 Please provide an eTag that represents an export of electricity from BC Hydro's system to Alberta, using each of the applicable export paths reflected in Table 1 of the preamble. In your response, please explain any terms that have not been explained in the Application or in the responses to IR No. 1 or 2 of this proceeding.

311.0 Reference: COST OF ENERGY
Exhibit B-1, p. 4-38; Exhibit B-6, CEABC IR 7.4
Market electricity purchases

BC Hydro states in its Application: "Powerex may elect to purchase energy from BC Hydro when the system has flexibility for energy to be drawn from storage, and to sell energy to BC Hydro when the system has flexibility for energy to be stored."

BC Hydro's response to CEABC IR 7.4 stated:

> With regard to the volumes imported, please refer to BC Hydro's response to BCUC IR 1.3.2 with respect to the Letter Agreement between BC Hydro and Powerex – Forward Electricity Purchases (the Agreement) for electricity imported in each month from December 2018 through March 2019. In November 2018, 555 GWh of electricity was imported, consisting of 363 GWh of Domestic Electricity Purchases, 286 GWh of Trade Electricity Purchases, and 94 GWh of Trade Electricity Sales. Appendix 2 of the Agreement contains the set of contract electricity delivery volumes by delivery profile (off-peak vs. peak hours), quantity (MWh) and price (USD/MWh).
>
> A summary table is provided below:

Delivery period	Delivery profile	Contract price (USD)	Total
Feb. 1- Feb. 28	Heavy load hours	$55.83/ MWh	96,000 MWh
Mar. 1 – Mar. 31	Heavy load hours	$47.73/ MWh	520,000 MWh
Apr. 1 – Apr. 30	Heavy load hours	$30.96/ MWh	624,000 MWh
Jan. 1 – Jan. 31	Light load hours	$51.77 MWh	164,000 MWh
Feb. 1 – Feb. 28	Light load hours	$40.87/ MWh	158,400 MWh
Mar. 1 – Mar. 31	Light load hours	$36.36/ MWh	408,750 MWh
Apr. 1 – Apr. 30	Light load hours	$26.14/ MWh	456,000 MWh
Total:		$37.59/MWh *(Average)*	2,427,150 MWh

311.1 Please provide an example of an eTag that indicates the volume of electricity purchased by BC Hydro under the Agreement, that was used to supply domestic load.

312.0 Reference: COST OF ENERGY
Exhibit B-11, p. 8; Appendix A, Schedule 4.0;
Exhibit B-6, BCOAPO IR 24.1, CEC IR 78.4, INCE IR 13.4
Line losses

Lines 1 to 15 of Schedule 4.0 in Appendix A to the Evidentiary Update are provided below:

Cost of Energy ($ 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
	Sources of Supply (GWh)										
	Heritage Energy										
1	Water Rentals		46,368	42,341	-4,027	44,262	[redacted]	[redacted]	44,999	[redacted]	[redacted]
2	Natural Gas for Thermal Generation		234	191	-43	192	[redacted]	[redacted]	193	[redacted]	[redacted]
3	Exchange Net		-354	-155	200	-171	[redacted]	[redacted]	-196	[redacted]	[redacted]
4	Total		46,248	42,377	-3,871	44,283	[redacted]	[redacted]	44,996	[redacted]	[redacted]
	Non-Heritage Energy										
5	IPPs and Long-Term Commitments		15,199	14,248	-951	15,449	[redacted]	[redacted]	16,040	[redacted]	[redacted]
6	Non-Integrated Area		120	103	-17	118	[redacted]	[redacted]	120	[redacted]	[redacted]
7	Total		15,320	14,351	-968	15,566	[redacted]	[redacted]	16,159	[redacted]	[redacted]
	Market Energy										
8	Market Electricity Purchases		934	2,035	1,101	1,504	[redacted]	[redacted]	648	[redacted]	[redacted]
9	Surplus Sales		-4,517	-2,230	2,287	-2,409	[redacted]	[redacted]	-3,087	[redacted]	[redacted]
10	Net Purchases (Sales) from Powerex		105	647	542	177	[redacted]	[redacted]	90	[redacted]	[redacted]
11	Total		-3,478	452	3,930	-727	[redacted]	[redacted]	-2,349	[redacted]	[redacted]
12	**Total Sources of Supply**	L4+L7+L11	58,089	57,181	-908	59,121	58,630	-492	58,806	58,806	1
13	**Less Line Loss and System Use**		-5,425	-4,768	657	-5,554	-5,334	220	-5,553	-5,553	-1
14	**Total Domestic Sales**	14.0 L10	52,664	52,413	-251	53,567	53,296	-271	53,253	53,253	0
15	**Line Loss as % of Sales**		10.30%	9.10%	(1.20%)	10.37%	10.01%	(0.36%)	10.43%	10.43%	0.00%

312.1 Please discuss whether distribution line losses are included in Line 15 of Schedule 4.0.

312.2 Please explain whether Line 15 represents average line losses or peak period losses as a percentage of sales.

BC Hydro states on page 8 of the Evidentiary Update: “The decrease in hydro electric generation and purchases from IPPs and Long-Term Commitments results in lower planned surplus sales and higher planned market electricity purchases.”

312.3 Please explain why line loss and system use decreased from a volume of 5,425 GWh in F2019 RRA to a volume of 4,768 GWh in F2019 Actual (line 13). As part of the response, please comment on how hydro electric generation, purchases from IPPs and Long-Term Commitments, surplus sales and market electricity purchases affect the volume of line losses.

312.4 Please explain why line loss and system use increases from a volume of 4,768 GWh in F2019 Actual to a volume of 5,334 GWh in the F2020 Update volume (line 13). As part of the response, please comment on how hydro electric generation, purchases from IPPs and Long-Term Commitments, surplus sales and market electricity purchases affect the volume of line losses

312.5 Please explain why line loss and system use remains relatively flat, from a volume of 5,334 GWh in the F2020 Update to a volume of 5,553 GWh in F2021 (line 13). As part of the response, please comment on how hydro electric generation, purchases from IPPs and Long-Term Commitments, surplus sales and market electricity purchases affect the volume of line losses.

BC Hydro’s response to INCE IR 13.4 stated: “The cost of procuring this energy is at the Mid-C index price plus transmission and wheeling charges to the BC border (currently $5.16 USD per MWh and 1.9 per cent for losses).”

312.6 Please explain why BC Hydro’s estimated line losses as a percentage of sales over the F2020 and F2021 Test Period (line 15) are more than five times greater than the 1.9 percent loss percentage used in wheeling energy from Mid-C to the BC border.

312.7 Please discuss and quantify the impact to the Test Period revenue requirement and rates of a 1 percent change in line loss as a percentage of sales (i.e. F2020 = 9.01 percent or 11.01 percent instead of the current forecast of 10.01 percent).

312.8 Please identify and provide a high-level discussion of any initiatives or projects BC Hydro currently undertakes to minimize transmission line losses.

312.9 Please discuss BC Hydro’s incentives to minimize transmission and distribution line losses. What are the expected results?

BC Hydro’s response to BCOAPO IR 24.1 stated:

> Fiscal 2017 and 2018 are actual losses, where as the subsequent fiscal years are forecast line losses.
>
> The actual losses and share of losses are percentage of sales for fiscal 2017 and 2018 are calculated as the difference between actual total gross system requirements and actual total firm sales. Actual losses are impacted by a variety of factors, including the real time dispatch of generation to meet to [sic] load, imports and exports, real time operations of the distribution and transmission system, and variations in temperature.
>
> The forecasts are developed using sector specific loss factors that are based on historic averages. The losses and the share of losses as percentage of sales vary according to the increases or decreases in the forecast sales to the major customer sectors. The forecast loss percentages in fiscal 2019 reflect the methodology of applying the loss factors to the sales as well as six months of actual sales and total load.
>
> The small increase in the loss percentage over the test period reflects the expected increase in sales to the major distribution sectors (residential, commercial and light industrial) which is approximately two-thirds of the sales. These distribution loads have a proportionally greater impact on the loss percentage than the large industrial sales, which are expected decrease between fiscal 2020 to fiscal 2021.

312.10 Please explain whether the methodology used in estimating forecast losses remains consistent with prior RRAs. As part of the response, please explain any changes in methodology, if any, including the rationale for the change.

Regarding the inclusion of line losses in the DSM plan for F2020 and F2021, BC Hydro’s response to CEC IR 78.4 stated:

> Distribution losses are based on the Load Forecast loss calculation of 4 per cent for the distribution system. Inter-regional transmission losses represent losses associated with the transfer of power between BC Hydro’s regions and are based on power flow simulations. Intra-regional transmission losses of 3 per cent is an estimate based on the Load Forecast loss calculation of 7 per cent for the total transmission losses and the inter-regional transmission losses from the power flow simulations.

312.11 Please explain why the line losses used in the DSM Plan for F2020 and F2021 are lower than what is reflected on line 15 of Schedule 4.0.

313.0 Reference: COST OF ENERGY
Exhibit B-5, BCUC IR 143.1; Exhibit B-6, AMPC IR 8.1.3; Exhibit B-11, p. 15; Appendix A, Schedule 1.0, 2.1; Exhibit B-1, Appendix E, p. 34
Powerex net income

BC Hydro's response to AMPC IR 8.1.3 stated: "Natural gas costs is comprised of gas purchases from Powerex which are intercompany transactions and included in Powerex net income. All intercompany transactions are eliminated upon consolidation."

BC Hydro's response to BCUC IR 143.1 stated:

> The volatility in Powerex's net income is evidenced by the historic volatility of BC Hydro's Trade Income. The inherent difficulty in accurately forecasting Powerex's net income based on its participation in dynamic and volatile markets, causes BC Hydro to use a five-year average for rate setting in the test year period, coupled with a Trade Income Deferral Account to capture inevitable variances. This approach ensures that the all benefits of Trade Income pass to the ratepayers.

On page 15 of the Evidentiary Update, BC Hydro states:

> In the Application, Powerex Net Income was forecast to be $205.3 million in fiscal 2019. Actual Powerex Net Income in fiscal 2019 was $435.7 million or $230.4 million higher than the forecast. This difference increases the credit balance in the Cost of Energy Variance Accounts, which BC Hydro has proposed to refund to ratepayers over the test period. In the Current View, this refund is reflected in BC Hydro's revenue requirements as Subsidiary Net Income. As a result, Subsidiary Net Income is $151.6 million higher in fiscal 2020 and $92.6 million higher in fiscal 2021, which decreases BC Hydro's revenue requirements.

Schedule 1.0 of Appendix A to the Evidentiary Update shows the following:

- Line 1: F2019 Actual Cost of Energy was $244.2 million lower than the F2019 RRA Plan.
- Line 17: the forecast Powerex Net Income has remained flat at $120.6 million for each of F2020 and F2021 and is unchanged from the planned amounts for those years.

Line 18 on Schedule 2.1 of Appendix A shows that total refunds in the Test Period from the Trade Income Deferral Account has increased by $244.2 million ($151.6 million in F2020 and $92.6 million in F2021).

313.1 Please explain why the Cost of Energy (COE) variance in F2019 of $244.2 million is equal to the increase in Powerex Net Income over the Test Period. As part of the response, please discuss whether either or both of the COE and Powerex net income excludes "intercompany transactions that are eliminated upon consolidation."

313.2 Please discuss whether the entire F2019 actual Powerex net income is used to forecast the F2020 and F2021 Powerex net income for inclusion in the Test Period revenue requirement.

313.2.1 If so, please explain why the forecast Powerex net income for F2020 and F2021 in the Evidentiary Update is unchanged at $120.6 million annually compared to the Application.

313.2.2 If not, please explain why not and recalculate the forecast Powerex net income for each of F2020 and F2021 to include the entire F2019 actual Powerex net income and calculate the impact to the Test Period revenue requirement and rates.

BC Hydro states on page 34 of Appendix E to the Application: "The Service Plan forecast includes annual net income from Powerex of approximately $125 million per year for 2019/20 to 2021/22."

313.3 Please explain why the Powerex net income included in the Application is not equal to the annual net income included in the Service Plan for the same periods.

314.0 Reference: COST OF ENERGY
Exhibit B-11, pp. 7–8; California Independent System Operator (ISO), Western Energy Imbalance Market (EIM), Quarterly Gross Benefits;[4] BC Hydro Letter Agreement between BC Hydro and Powerex Corp. – Forward Electricity Purchases, as amended (Amended 2018 Letter Agreement), dated May 23, 2019,[5] p. 2; BC Hydro Application for 2019 Letter Agreement with Powerex Corp. (2019 Letter Agreement) proceeding, Exhibit B-1, p. 4
Market opportunities

BC Hydro states on page 2 of its Amended 2018 Letter Agreement:

> The financial implications of the Agreement and the changed operating conditions over the winter period are addressed in BC Hydro's F2020–F2021 Revenue Requirements Application. Although the purpose of the Agreement was to ensure reliable supply for BC Hydro's load at as reasonable a price as possible, there was a potential for BC Hydro to acquire the forward energy at prices that would be higher than the ultimate market prices. However, in light of the colder than expected February and the shortfall of supply in the market, the Agreement was a financial success for BC Hydro.

314.1 Please quantify the "financial success" that BC Hydro generated as a result of the Amended 2018 Letter Agreement. As part of the response, please describe what proportion of the COE variance between the 2019 RRA and actual costs was attributable to the Amended 2018 Letter Agreement.

On page 4 of the application to the BC Hydro 2019 Letter Agreement proceeding, it states:

> As noted above, and in contrast to the 2018 Letter Agreement, BC Hydro's intention in entering into the 2019 Letter Agreement was to proactively ensure appropriate measures are in place to respond to future physical supply issues.

BC Hydro states in the Evidentiary Update:

> The Cost of Energy forecast in the Application was based on BC Hydro's October 2018 energy study, The Cost of Energy forecast in the Evidentiary Update is based on the June 2019 energy study.
>
> Dry conditions and lower water inflows have decreased planned hydroelectric generation (water rentals) and purchases from IPPs and Long-Term Commitments.

[4] https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.
[5] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-filings/fep/00-2019-05-23-bchydro-bcuc-wm.pdf.

314.2 Please provide a table in Excel format that identifies the heavy-load and light-load Mid-C forward price for each month of the F2020 and F2021 Test Period, as used in each of the October 2018 and June 2019 Energy Studies. In the response, please explain any factors that may have contributed to a change in the heavy-load and light-load Mid-C forward price.

314.3 Please explain whether water inflows per the June 2019 Energy Study are higher or lower relative to what was forecast in the energy study used to inform the Amended 2018 Letter Agreement. As part of the response, please discuss why forecast water inflows in the June 2019 Energy Study are higher or lower.

314.4 Please confirm, or explain otherwise, that the June 2019 Energy Study was used as a basis for the BC Hydro 2019 Letter Agreement Application. As part of the response, please discuss whether transactions expected to occur under the 2019 Letter Agreement Application have been included in the updated estimate of market energy purchase volumes and costs in each of F2020 and F2021.

314.5 Please explain whether BC Hydro expects a similar level of "financial success" with the 2019 Letter Agreement. In the response, please discuss whether expected financial results of the 2019 Letter Agreement have been factored into either of the Powerex net income or COE estimates. If not, please quantify both the total volume and cost of market electricity purchases that are anticipated in each of F2020 and F2021.

The California ISO publishes a table that presents the gross benefits of the EIM Market to participants since November 2014 and shows positive gross benefits to each participant. The table also shows that Powerex had entered the EIM market in April of 2018.

314.6 Please discuss the pros and cons of including estimated financial implications of current market opportunities, such as the benefits of participating in the EIM, when forecasting Powerex's net income instead of using a historical five-year average.

315.0 Reference: COST OF ENERGY
EPA Renewals Application, Exhibit B-1, p. 27; Exhibit B-12, BCUC IR 22.1
Commercial contracts

BC Hydro states on page 27 of the EPA Renewals Application: "The original Walden North EPA, and its related Forbearance Agreement, have not been terminated and will continue in accordance with their respective terms unless the renewed EPA is accepted by the Commission."

The response to BCUC IR 22.1 in Exhibit B-12 of the EPA Renewals Application stated:

> Portions of the background information provided by the BCUC as preamble to its BCUC CONF IR 1.3.1 included information that BC Hydro considers confidential. As a result, BC Hydro is only including in this response the question asked by the BCUC in BCUC CONF IR 1.3.1 and BC Hydro's response to that IR.
>
> The question asked was,
>
>> 1.3.1 Please explain why the Forbearance Agreement was never filed for acceptance with the BCUC.
>
> BC Hydro's response was as follows:
>
>> 'The Forbearance Agreement was not filed pursuant to section 71 of the UCA because it is a stand-alone commercial arrangement entered into by the parties and does not constitute an energy supply contract or an amendment to an energy supply contract.

> Under the terms of the Forbearance Agreement, BC Hydro agreed to refrain from exercising its right to terminate the EPA for a period of time in consideration of payments being made to BC Hydro. Notwithstanding this arrangement, the EPA continues to exist, unamended, during the term of the Forbearance Agreement and will continue to exist, unamended, following the expiry of the Forbearance Agreement.'

315.1 Please confirm whether payments being made to BC Hydro under the terms of the Forbearance Agreement are included in the COE forecasts in this Application. If not confirmed, please state where in the Application these payments are included.

315.2 Please identify whether there are any other EPA-related commercial contracts that provide ratepayer benefits similar to those provided in the Forbearance Agreement. As part of the response, please indicate where in the Application the payments to BC Hydro are included and identify and quantify whether these payments benefit ratepayers.

316.0 Reference: COST OF ENERGY
Exhibit B-5, BCUC IR 23.2; Exhibit B-6, AMPC IR 8.1.4
Natural gas purchases – Island Generation

BC Hydro's response to BCUC IR 23.2 stated: "…The purchase of gas for BC Hydro's thermal generating assets categorized under 'Natural Gas for Thermal Generation', as well as the purchase of gas for Island Generation categorized under IPPs and Long-Term Commitments, also fall under the Transfer Pricing Agreement."

BC Hydro's response to AMPC IR 8.1.4 stated: "Powerex purchases natural gas for the Island Generation facility on behalf of BC Hydro. BC Hydro secures the gas transportation service for the delivery of gas to the generating facility."

316.1 Please confirm, or explain otherwise, that the volume and cost of natural gas associated with purchases that Powerex makes on behalf of BC Hydro for the Island Generation facility is included in Lines 5 and 29 of Schedule 4.0 of Appendix A to the Evidentiary Update.

316.1.1 If not confirmed, please identify where in Schedule 4.0 these costs and volumes are presented.

316.2 Please identify where revenues received from the sale of natural gas to the Island Generation facility are captured in Appendix A to the Evidentiary Update.