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October 10, 2019

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

Dear Mr. Wruck:

RE: Project No. 1598990
British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2020 to Fiscal 2021 Revenue Requirements Application
Responses to Round 3 Information Requests on Evidentiary Update

BC Hydro writes in compliance with BCUC Order No. G-218-19 to provide its responses to Round 3 information requests on its Evidentiary Update as follows:

Exhibit B-16	Responses to BCUC IRs (Public Version)
Exhibit B-16-1	Responses to BCUC IRs (Confidential Version)
Exhibit B-17	Responses to Interveners IRs (Public Version)
Exhibit B-17-1	Responses to Interveners IRs (Confidential Version)
Exhibit B-18	Responses to BCUC Confidential IRs (Confidential)

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

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

Yours sincerely,

Fred James
Chief Regulatory Officer

cs/rh

Enclosure

288.0 A. CHAPTER 3 – LOAD FORECAST – EVIDENTIARY UPDATE

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).

3.288.1 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.

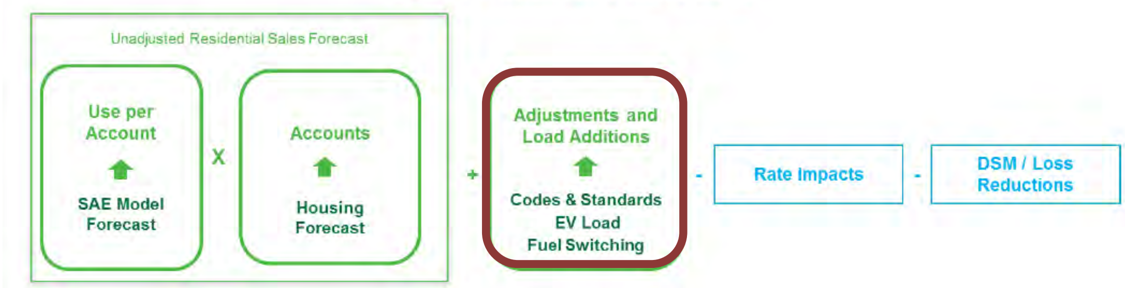
RESPONSE:

This response also provides the answers to BCUC IRs 3.288.1.1, 3.288.1.2, 3.288.2, 3.288.2.1 and 3.288.2.2 and ZONE II RPG IR 3.62.1.

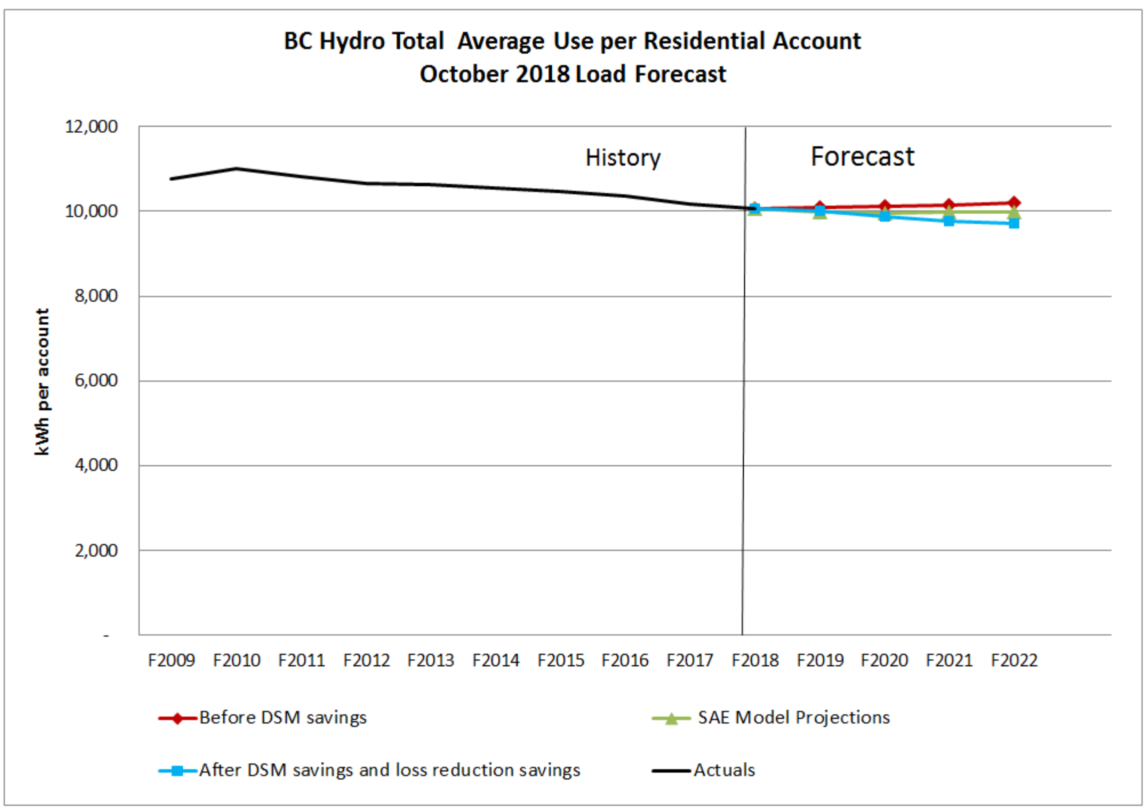
As discussed in section 4.1 of Appendix O of the Application, there is a declining trend in the average use per account over time and we expect that trend to continue over the test period, rather than being a one-time occurrence. We believe that the factors referenced in the preamble to this question account for this declining trend, and the effect of these factors has been incorporated in the October 2018 Load Forecast.

As shown in Figure 4-1 from Appendix O of the Application, which is reproduced below, the residential forecast is built up by taking the SAE model projections and adding adjustments and load additions for Codes & Standards, Electric Vehicle (EV) load, and fuel switching, and then subtracting rate impacts, Demand-Side Management (DSM) savings and loss reduction savings.

Figure 4-1 Residential Forecast Build-up



The graph below shows the historical and forecast temperature normalized residential average use per account at each of these stages, per the October 2018 Load Forecast.



In the above graph, the green line reflects the unadjusted SAE Model projections, the red line reflects the adjustments made to account for Codes & Standards, EV

load, and fuel switching, and the blue line is the net forecast after rate impacts, DSM savings and loss reduction savings have been incorporated.

The graph shows that while the SAE model projections for the average use per account are forecast to remain flat, BC Hydro expects there will be a further decrease in the average use per account after other adjustments, load additions, rate impacts, DSM savings, and loss reduction savings. The flat SAE model projections reflect all drivers, including a decline in people per account and increased average end use appliance efficiencies.

The forecast decline in people per account is shown in Table F-1 of section 20 of Appendix O of the Application, and the projection of residential average end use appliance efficiencies is shown in Table F-3 of Appendix O of the Application.

Between fiscal 2018 and fiscal 2019, the actual billed sales use per account declined from 10,138 kWh per account to 9,909 kWh per account or 2.3 per cent. The materiality of this decline will not be known until BC Hydro updates the SAE model calibration period to incorporate actual use per account through to fiscal 2019. The October 2018 and June 2019 20-year Load Forecasts have calibration periods ending in fiscal 2018 and therefore do not incorporate the fiscal 2019 actual average use per account or total sales. Future load forecast updates will incorporate fiscal 2019 actuals. However, as shown above, BC Hydro had already forecast a decline in average use per account from fiscal 2019 onward. While the average use per account is declining, the number of accounts is forecast to increase, resulting in a forecast increase in residential sales for fiscal 2020 and fiscal 2021.

BCUC IR 3.288.2 asks whether BC Hydro expects there to be further increases in DSM savings, denser housing, fewer people per account, and increases in end use efficiency which lead to further decreases in the use per account. We cannot determine whether this will be the case at this time because we have not yet incorporated the fiscal 2019 actuals or updated drivers into the current forecast. However, relative to the May 2016 forecast, BC Hydro has updated the load forecasting models for all drivers. The table below shows that the October 2018 average use per account, after DSM savings and loss reductions, is lower than the May 2016 forecast for the test period.

	October 2018 Forecast Average Residential Use per Account (kWh/account)	May 2016 Forecast Average Residential Use per Account (kWh/account)
Fiscal 2019	10,011	10,034
Fiscal 2020	9,884	9,940
Fiscal 2021	9,780	9,831

As such, the lower use per account forecast is consistent with the historical trend, and with the factors which we believe to be impacting this trend, such as average efficiency, denser housing mix, and lower people per account. Despite these factors, there are other considerations for the overall use per account which may put upward pressure on sales and usage, including further penetration of EV load and future CleanBC electrification programs and initiatives.

288.0 A. CHAPTER 3 – LOAD FORECAST – EVIDENTIARY UPDATE

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Exhibit B-11, Evidentiary Update, Appendix G, p. 2
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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).

3.288.1 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.

3.288.1.1 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.

RESPONSE:

Please refer to BC Hydro’s response to BCUC IR 3.288.1.

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3.288.1 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.

3.288.1.2 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.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.288.1.

288.0 A. CHAPTER 3 – LOAD FORECAST – EVIDENTIARY UPDATE

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3.288.2 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.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.288.1.

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3.288.2 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.

3.288.2.1 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.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.288.1.

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3.288.2 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.

3.288.2.2 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.

RESPONSE:

Please refer to BC Hydro’s response to BCUC IR 3.288.1.

289.0 B. CHAPTER 5 – OPERATING COSTS – EVIDENTIARY UPDATE

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.

3.289.1 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.

RESPONSE:

Not confirmed. Storm restoration costs for the Test Period were forecast using a five-year average of historical actuals over the period from fiscal 2014 to fiscal 2018.

Please refer to BC Hydro's response to BCUC IR 3.313.2, where we explain why we did not update the forecast Trade income and forecast storm restoration costs for the Test Period based on a five-year average of the actual results from fiscal 2015 to fiscal 2019.

290.0 B. CHAPTER 5 – OPERATING COSTS – EVIDENTIARY UPDATE

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."

3.290.1 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.

RESPONSE:

This answer also responds to BCUC IR 3.290.1.1, CEC IR 3.101.1, AMPC IR 3.15.4, and BCSEA IR 3.81.1.

The litigation costs (or costs of litigation) referenced in the preamble are not for the Site C Project. The litigation costs are for the Interior to Lower Mainland Transmission project and refer to the cost awards associated with the conduct of the litigation which must be borne by BC Hydro. The litigation concluded prior to the Test Period and accordingly, BC Hydro has not included any additional forecast litigation costs in the Test Period.

BC Hydro had a provision of $6.9 million based on a preliminary estimate pending the resolution of the litigation costs. This amount was included in the F2018 Actual column on Line 71 of Schedule 5 and on Line 14 of Schedule 8 of Appendix A of the Application. The $5.2 million referenced in the preamble to the question is in addition to the provision amount.

290.0 B. CHAPTER 5 – OPERATING COSTS – EVIDENTIARY UPDATE

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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."

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

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.290.1.

291.0 C. CHAPTER 6 – CAPITAL EXPENDITURES – EVIDENTIARY UPDATE

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.

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

RESPONSE:

Confirmed.

291.0 C. CHAPTER 6 – CAPITAL EXPENDITURES – EVIDENTIARY UPDATE

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3.291.2 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.

RESPONSE:

The fiscal 2019 purchase referenced in the preamble to the question relates to the acquisition of the underground property rights from the Vancouver School Board at the location presently occupied by the existing Lord Roberts Annex School.

The project is the DVES: West End Substation - Property Purchase. The purpose of this project is to acquire property rights to allow construction of a new substation in the West End of downtown Vancouver to replace the existing Dal Grauer substation. For additional information on the project, please refer to page 69 of Appendix J of the Application.

The total capital expenditure to the end of fiscal 2019 for this project was $66.8 million.

291.0 C. CHAPTER 6 – CAPITAL EXPENDITURES – EVIDENTIARY UPDATE

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

RESPONSE:

The Peace Region Electrical Supply project capital expenditures included in Transmission Growth - Regional System Reinforcement in fiscal 2019 was $48.4 million compared to the fiscal 2019 plan of $6 million.

291.0 C. CHAPTER 6 – CAPITAL EXPENDITURES – EVIDENTIARY UPDATE

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

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.

3.291.4 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.

RESPONSE:

For capital planning purposes, BC Hydro includes potential land purchases in "Business Support – Other" as this is the capital category that includes buildings and land held for future use. However, once the purchase is complete, the assets are classified for reporting purposes with the functional capital area where the asset will be utilized in the future if specifically known.

This reclassification does impact amortization as land is not amortized for both capital planning purposes and for land in-service.

291.0 C. CHAPTER 6 – CAPITAL EXPENDITURES – EVIDENTIARY UPDATE

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3.291.5 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.

RESPONSE:

The fiscal 2017 purchase referred to in the preamble above relates to the property purchase in East Vancouver for the DVES: New Murrin Strategic Property Purchase project. The purpose of the project is to secure a property to replace the existing Murrin substation with a new substation in East Vancouver.

The total capital expenditure for this project is $46.6 million.

291.0 C. CHAPTER 6 – CAPITAL EXPENDITURES – EVIDENTIARY UPDATE

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3.291.6 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.

RESPONSE:

As discussed in section 6.3.5 of Chapter 6 of the Application, the capital plan is monitored on an ongoing basis by the Capital Delivery Management Committee. The committee focuses on the early years of the capital plan so that actual and forecast capital expenditures remain aligned with the original capital plan. This management is done at a portfolio level so that, if required, adjustments can be made to re-direct the capital budget, as new information becomes available.

As these decisions are made at the portfolio level and because total actual fiscal 2017 capital expenditures, net of contributions-in-aid, were $221 million less than the planned amount, there is no specific link between the funds planned for the property purchase in fiscal 2017 and the approval of new projects, the advancement of existing projects or the increase of funding to existing programs, in fiscal 2017.

291.0 C. CHAPTER 6 – CAPITAL EXPENDITURES – EVIDENTIARY UPDATE

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3.291.7 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 per cent between planned and actual capital expenditures and additions.

RESPONSE:

This answer also responds to BCUC IR 3.291.7.1.

The attachment to this response provides the requested information for the Transmission Growth Regional System Reinforcement capital expenditures and capital additions with expected costs greater than $5 million for fiscal 2017 to fiscal 2019. Variance explanation for projects with variances greater than 10 per cent between planned and actual expenditures and additions are included in the schedule.

Transmission Growth Regional System Reinforcement Capital Expenditures

	($ millions)	F2017			F2018			F2019			
IPID	Transmission	RRA	Actual	Variance	RRA	Actual	Variance	RRA	Actual	Variance	Variance Explanation
92525	Fort St. John and Taylor Electric Supply	2.2	0.5	(1.6)	22.2	4.7	(17.5)	15.1	27.1	12.0	Fiscal 2019 capital expenditures were $12 million above plan due to schedule delays. The contract for the Site C substation wasn't awarded until February of 2018 resulting in expenditures being delayed until fiscal 2019.
900219	DVES: West End Strategic Property Purchase	65.0	-	(65.0)	-	-	-	-	66.8	66.8	Fiscal 2019 capital expenditures were $66.8 million above plan as the land purchase was not completed as planned in fiscal 2017
92216	Peace Region Electric Supply (PRES)	1.5	6.2	4.7	2.0	10.7	8.7	6.0	48.4	42.4	Fiscal 2019 capital expenditures were $42.2 million above plan due to advancement of definition phase activities from later years into fiscal 2019
93845	Metro North Transmission (MNT)	2.5	1.6	(0.9)	4.2	3.9	(0.3)	9.9	1.0	(8.9)	This project has been deferred due to the expected change in the load forecast. Please refer to BC Hydro's response to BCUC IR 1.108.1.
94034	West Kelowna Transmission and Westbank Upgrade Projects	1.6	0.5	(1.1)	13.6	3.0	(10.6)	25.1	5.8	(19.3)	Fiscal 2019 capital expenditures were $19.3 million below plan as the Identification Phase for both projects was deferred to fiscal 2020. Additional work is required to determine the preferred alternative for the West Kelowna Transmission Line Project and to complete Feasibility Design work for the Westbank Upgrade Project.
93569	Horne Payne Substation Upgrade	18.6	17.9	(0.7)	29.0	31.0	1.9	21.9	11.1	(10.8)	Fiscal 2019 capital expenditures were $10.8 million below plan primarily because of the overall project being completed at $10.7 million below the approved project budget of $81 million.
93544	Kamloops Substation	11.4	11.1	(0.3)	16.9	24.7	7.7	9.7	8.7	(1.0)	Fiscal 2018 capital expenditures were above plan by $7.7 million due to design specification changes and increased costs due to higher than expected market prices for equipment and materials.
900222	DVES: New Murrin Strategic Property Purchase	25.0	46.5	21.5	-	0.1	0.1	-	-	-	Fiscal 2017 capital expenditures were $21.5 million above plan as an acceptable property could not be acquired at the amount included in the Previous Application.
900272	South Vancouver Island Reactor Addition	0.2	0.0	(0.2)	6.0	-	(6.0)	1.8	-	(1.8)	This project was initiated in response to high voltage concerns on the SVI 230 kV cable system. Subsequently, there were a number of changes to the system that helped system voltage controls. BC Hydro will monitor and determine at a later date if the modifications are sufficient to offset the need for a new reactor.

Transmission Growth Regional System Reinforcement Capital Additions

	($ millions)	F2017			F2018			F2019			
IPID	Transmission	RRA	Actual	Variance	RRA	Actual	Variance	RRA	Actual	Variance	Variance Explanation
900219	DVES: West End Strategic Property Purchase	65.0	-	(65.0)	-	-	-	-	-	-	Property was purchased in 2019. Capital addition will not be completed until right of ways through Nelson Park are acquired.
94034	West Kelowna Transmission and Westbank Upgrade Projects	-	-	-	23.0	-	-	-	-	-	See capital expenditure explanation above.
93569	Horne Payne Substation Upgrade	-	-	-	-	-	-	74.6	65.1	(9.6)	See capital expenditure explanation above.
93544	Kamloops Substation	-	-	-	-	-	-	43.8	50.2	6.4	Fiscal 2019 capital additions were above plan by $6.4 million due to design specification changes and increased costs from higher than expected market prices for equipment and materials.
900221	Project D: DVES: New DGR Strategic Property Purchase	65.0	-	(65.0)	-	-	-	-	-	-	Fiscal 2017 capital additions were $65.0 million below plan as the related substation project has been cancelled.
900222	Project D: DVES: New Murrin Strategic Property Purchase	25.0	46.5	21.5	-	0.1	0.1	-	0.1	0.1	Fiscal 2017 capital additions were $21.5 million above plan as an acceptable property could not be acquired at the amount included in the Previous Application.
900272	South Vancouver Island Reactor Addition	-	-	-	-	-	-	8.0	-	(8.0)	See capital expenditure explanation above.

291.0 C. CHAPTER 6 – CAPITAL EXPENDITURES – EVIDENTIARY UPDATE

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> 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.

3.291.7 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 per cent between planned and actual capital expenditures and additions.

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

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.291.7 for the listing of projects that were planned and deferred or not completed.

292.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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.

3.292.1 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.

RESPONSE:

There is a $100.9 million variance forecast for the Debt Management Regulatory Account in fiscal 2020 as BC Hydro's Evidentiary Update included year to date actuals for unrealized losses on interest rate hedges to May 31, 2019 (i.e., April and May 2019) as noted on page 3 of the Evidentiary Update, and also includes $5.7 million related to three financial contracts that settled in June prior to the completion of the forecast. During this time, there was a decrease in forward interest rates which resulted in a decrease in the value of the financial contracts that hedge the interest rate risk on future debt issuances, which makes up the majority of this balance.

In accordance with BCUC Order No. G-42-16, gains and losses from future debt hedges are not included in the revenue requirement in the year in which there is a gain or loss. Rather, the Order requires that these amounts are recorded in the Debt Management Regulatory Account, and amortized over the remaining term of the associated long-term debt, commencing at the beginning of the test period subsequent to the test period in which the long-term debt to which the future debt hedge is associated is issued.

BC Hydro requested the Debt Management Regulatory Account as it is a more efficient and cost effective way to achieve a very similar result to hedge accounting under IFRS. Under both IFRS hedge accounting and the Debt Management Regulatory Account, unrealized gains and losses on debt hedges are recorded on the balance sheet and do not flow directly to the income statement and therefore are not included in rates. It is only once the gains or losses become realized and start to amortize that they will be included in rates.

293.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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 in relation to the rate smoothing regulatory account.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.

[1] Emphasis added.

$ 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

3.293.1 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.

RESPONSE:

As shown in BC Hydro's response to BCUC IR 1.140.1, annual debt servicing costs were calculated based on $1.136 billion instead of $1.044 billion because this is the total amount of BC Hydro's approved revenue requirement which was approved to be transferred to the Rate Smoothing Regulatory Account (RSRA) over the fiscal 2015 to fiscal 2019 period for collection in rates in future fiscal years. As a result of the write-off of the balance in the account, the entire $1.136 billion of incurred costs will not be recovered from ratepayers thus increasing BC Hydro's debt balance, all else being equal, and not providing for as fast of a paydown of debt for previously incurred costs.

The $1.136 billion is based on the December 31, 2019 balance of $1.044 billion that was written off plus $0.092 billion of planned transfers to the RSRA in the fourth quarter of fiscal 2019 based on approved revenue requirements. This $0.092 billion was not part of the write-off as it had not yet been transferred into the RSRA as of December 31, 2019.

BC Hydro notes that the debt servicing costs related to the RSRA is an estimated amount based on BC Hydro's Weighted Average Cost of Debt. Ratepayers are only paying for actual debt servicing costs based on actual long-term debt.

293.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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 in relation to the rate smoothing regulatory account.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.

[1] Emphasis added.

$ 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

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

RESPONSE:

Prior to the end of the third quarter of fiscal 2019, BC Hydro had discussions with the Government of B.C. regarding the pending outcomes of Phase 1 of the Comprehensive Review of BC Hydro. While the outcomes were not announced until the following quarter, based on these discussions with the Government of B.C., BC Hydro no longer considered collection of the balance in the Rate Smoothing Regulatory Account to be probable and therefore was required to write-off the balance in the third quarter under BC Hydro’s accounting standards.

293.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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 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.

3.293.3 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.

RESPONSE:

This answer also responds to BCUC IRs 3.293.3.1, 3.293.3.2 and 3.293.3.2.1.

Not confirmed. The question implies that the debt associated with the Rate Smoothing Regulatory Account will be the last debt BC Hydro pays down, which would also imply that future debt repayments will be allocated to specific drivers of debt. Please refer to BC Hydro's response to BCUC IR 1.140.5, where we explain that our debt is managed on a portfolio basis and that we do not specifically allocate debt repayments to specific drivers of debt.

The calculation in the table in BC Hydro's response to BCUC IR 1.140.1 was done on an illustrative basis to show the magnitude of the write-off of the Rate Smoothing Regulatory Account at that time. BC Hydro does not allocate debt drawdowns and repayments to specific drivers of debt. Under the current

regulatory framework, ratepayers pay the actual finance charges over time. Accordingly, BC Hydro considers it unnecessary in the ordinary course to calculate an arbitrary amount of finance charges related to a specific driver of debt such as the debt related to the Rate Smoothing Regulatory Account.

BC Hydro notes that section 4 of Direction No. 8 specifies that in setting rates for BC Hydro, the BCUC must not disallow debt servicing costs on amounts borrowed in relation to the rate smoothing regulatory account.

293.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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 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.

3.293.3 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.

3.293.3.1 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).

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.293.3.

293.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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 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.

3.293.3 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.

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

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.293.3.

293.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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 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.

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

3.293.3.2.1 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.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.293.3, where we explain that we do not specifically allocate debt repayments to specific drivers of debt, nor do we calculate the balance of debt related to the Rate Smoothing Regulatory Account

on an ongoing basis after the write-off, or the associated annual debt servicing costs.

The debt servicing cost related to the Rate Smoothing Regulatory Account referenced in the preamble to the question is an estimated amount based on BC Hydro's Weighted Average Cost of Debt. Under the current regulatory framework, ratepayers are paying actual finance charges over time. Accordingly, BC Hydro considers it unnecessary in the ordinary course to calculate an arbitrary amount of finance charges related to a specific driver of debt such as the debt related to the Rate Smoothing Regulatory Account.

With respect to the scenarios suggested in (i) and (ii) of the question, BC Hydro does not expect a situation in the foreseeable future where BC Hydro's total debt is reduced to below $1.136 billion.

293.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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 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.

3.293.3 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.

3.293.3.3 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.

RESPONSE:

Section 4 of Direction No. 8 requires that the BCUC must not disallow recovery of the debt servicing costs on amounts borrowed in relation to the Rate Smoothing Regulatory Account. Therefore, the calculation of BC Hydro's debt servicing costs for the purpose of setting rates must provide BC Hydro with a reasonable opportunity to recover its costs. As long as this requirement is satisfied and BC Hydro is able to recover its costs, there are no legal or legislative restrictions as to the method for calculating these costs.

294.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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.[1]

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.

3.294.1 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.

RESPONSE:

The repeal of the Heritage Contract and the definition of Heritage Energy does not change the calculation of actual Heritage Energy costs. The definition of Heritage

[1] Emphasis added,

Energy has no practical implications for how BC Hydro's system is planned or operated, as BC Hydro manages all sources of energy supply as a single portfolio.

Energy study models are used to forecast Cost of Energy in the revenue requirement proceedings. The repeal of the Heritage Contract does not impact the optimization methodology in the energy study, which assesses the resources of BC Hydro's system as a whole for operational purposes by types (such as hydro generation, energy purchases from independent power producers, and thermal energy). Therefore, the repeal does not change the calculation of actual Heritage Energy costs as the forecast methodology in the energy study models remains unchanged.

Similarly, the repeal of the definition of Heritage Energy does not impact the allocation of costs between the Heritage Deferral Account (HDA) and the Non-Heritage Deferral Account (NHDA). The repeal facilitated an improved presentation of Cost of Energy, which is now categorized as Heritage Energy, Non-Heritage Energy, and Market Energy. The intention of these categories is to provide better clarity of presentation. The repeal did not change the deferrable components within HDA and NHDA. For example, previously, Market Electricity Purchases were categorized under Heritage Energy and any variances between actual and forecast market purchases were deferred to the HDA. While Market Electricity Purchases are now categorized under Market Energy, any variances between actual and forecast market purchases are still deferred to the HDA.

Since there are no differences between the allocation of costs to the Heritage and Non-Heritage Deferral Accounts before and after the repeal, no illustrative examples can be provided in this response to illustrate differences.

294.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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

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.

3.294.2 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).

RESPONSE:

Please refer to Attachment 1 to this response for the schedule requested in the question.

BC Hydro notes that the Fiscal 2016 Revenue Requirements Application amounts in Appendix A of the Evidentiary Update of $13.7 million as shown on line 25 of Schedule 4.0 (Domestic Transmission – Other) and $12.0 million as shown on line 37 and line 60 of Schedule 4.0 (Domestic Transmission – Export) are incorrect. The correct amount for the Fiscal 2016 Revenue Requirements Application amount on line 25 is $16.4 million and the correct amount for line 37 and line 60 is $9.3 million. The total amount for Domestic Transmission costs did not change. This correction is reflected in Attachment 1 to this response.
BC Hydro will make this correction in its Compliance Filing.

BC Hydro
F20-F21 RRA Evidentiary Update

Appendix A
Schedule BCUC 3.294.2
Page 1

Cost of Energy
($ million)

			F2015			F2016			F2017			F2018			F2019		
		Reference	RRA	Actual	Diff	RRA	Actual	Diff	RRA	Actual	Diff	RRA	Actual	Diff	RRA	Actual	Diff
Line	Column														1	2	3 = 2 - 1
	Cost of Energy ($ million)																
	Heritage Energy																
1	Water Rentals	Sch 4.0 L23	392.8	368.7	(24.1)	391.9	365.3	(26.6)	386.7	387.0	0.4	356.8	361.6	4.8	356.4	363.1	6.7
2	Natural Gas for Thermal Generation	Sch 4.0 L24	26.6	24.0	(2.6)	26.9	20.0	(6.9)	14.9	9.5	(5.4)	10.5	3.4	(7.1)	10.7	7.6	(3.1)
3	Domestic Transmission - Other	Sch 4.0 L25	16.3	18.3	1.9	16.4	21.5	5.1	22.6	22.5	(0.1)	22.3	22.5	0.2	22.1	22.3	0.2
4	Non-Treaty Storage and Libby Coordination Agreer	Sch 4.0 L26	(7.8)	13.7	21.5	(19.8)	(14.4)	5.4	(23.1)	(23.3)	(0.2)	(10.4)	(40.6)	(30.2)	(7.2)	(181.9)	(174.7)
5	Remissions and Other	Sch 4.0 L27	(44.9)	(34.4)	10.5	(32.1)	(38.6)	(6.5)	(37.3)	(41.3)	(4.0)	(37.8)	(38.0)	(0.1)	(33.1)	(33.9)	(0.8)
6	Total	Sch 4.0 L28	383.0	390.3	7.2	383.3	353.9	(29.4)	363.8	354.4	(9.3)	341.5	309.0	(32.5)	349.0	177.2	(171.8)
	Heritage Payment Obligation																
7	Heritage Energy	Line 6	383.0	390.3	7.2	383.3	353.9	(29.4)	363.8	354.4	(9.3)	341.5	309.0	(32.5)	349.0	177.2	(171.8)
8	Less: F15-F19 Water Rentals (Waneta 1/3)	Sch 4.0 L57	(7.7)	(7.3)	0.4	(7.4)	(7.6)	(0.2)	(6.8)	(7.0)	(0.1)	(6.4)	(6.5)	(0.1)	(6.3)	(6.6)	(0.3)
9	Market Electricity Purchases	Sch 4.0 L58	44.7	6.0	(38.7)	56.6	2.8	(53.8)	8.6	3.4	(5.2)	30.2	3.7	(26.6)	35.9	125.0	89.1
10	Surplus Sales	Sch 4.0 L59	(122.6)	(0.2)	122.4	(84.2)	(174.1)	(89.9)	(118.1)	(132.8)	(14.6)	(150.4)	(139.4)	11.0	(129.2)	(115.0)	14.2
11	Domestic Transmission - Export	Sch 4.0 L60	14.2	0.1	(14.1)	9.3	31.1	19.1	31.8	28.3	(3.5)	35.4	25.2	(10.2)	29.9	18.5	(11.4)
12	Costs in Operating/Amortization	Sch 4.0 L61	15.7	17.4	1.7	13.0	15.4	2.4	12.3	12.1	(0.2)	12.4	12.5	0.1	12.9	12.0	(0.9)
13	Notional Water Rentals	Sch 4.0 L62	(1.4)	3.7	5.1	1.9	(0.0)	(1.9)	(1.9)	0.8	2.7	(1.7)	(3.7)	(2.0)	0.7	4.1	3.5
14	Skagit and Ancillary Revenue	Sch 4.0 L63	(16.2)	(18.6)	(2.4)	(16.5)	(18.2)	(1.7)	(12.6)	(13.0)	(0.5)	(12.0)	(11.9)	0.1	(12.1)	(29.6)	(17.5)
15	Other	Sch 4.0 L65	43.5	43.5	0.0	43.2	44.1	0.9	28.2	27.9	(0.3)	36.5	36.3	(0.2)	36.2	36.2	(0.0)
16	Total	Sch 4.0 L66	353.2	434.9	81.7	399.2	247.3	(154.6)	305.3	274.3	(31.0)	285.4	225.1	(60.4)	317.1	221.9	(95.2)

294.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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

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.

3.294.3 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.

RESPONSE:

BC Hydro provides the analysis requested in the question in relation to the five criteria from section 7.5.1 of the Application:

1. **BC Hydro's ability to directly or indirectly influence the cost category;**
2. **The volatility of the cost category;**
3. **The predictability of the cost category;**
4. **The materiality of the cost category to the revenue requirement; and**
5. **The frequency of major exceptions within the cost category.**

BC Hydro considers that the assessment of the heritage payment obligation in aggregate is more appropriate than assessing the individual components. Accordingly, a response to this question at the aggregate level is provided in Part A below while a response to this question, at the individual component level, is provided in Part B below.

Part A

The Heritage Deferral Account captures variances between the forecast and actual cost of Heritage Energy, Market Electricity Purchases, Surplus Sales and Domestic Transmission costs related to Surplus Sales. In addition, the Heritage Deferral Account captures variances between forecast and actual costs and revenues for items approved by BCUC Order No. G-96-04, which includes Skagit Valley Treaty revenues.

Heritage payment obligation costs vary due to uncontrollable factors that are difficult to predict such as water inflows, system load requirements, market commodity prices, exchange rates and transmission rates. From fiscal 2015 to fiscal 2019 Heritage Payment Obligation variances have ranged from ($154.6) million to $81.7 million and variance percentages have ranged from -38 per cent to 23 per cent.

Part B

Criteria two, three and five all relate to variances.

Attachment 1 to BC Hydro's response to BCUC IR 3.294.2 sets out the cost components that make up the Heritage Payment Obligation and the variances between planned and actual amounts for fiscal 2015 through fiscal 2019.

- **Heritage Energy – Heritage Energy consists of water rentals, natural gas for thermal generation, other domestic transmission, costs for non-treaty storage and short-term coordination agreement related to the Libby Coordination Agreements, and remissions and other costs. Heritage energy costs vary due to uncontrollable factors that are difficult to predict such as water inflows, system load requirements, market commodity prices, exchange rates and transmission rates. From fiscal 2015 to fiscal 2019, Heritage Energy costs have been volatile and variances between planned and actual Heritage Energy costs have ranged from $(171.8) million to $7.2 million.**

- **Market Electricity Purchases - These costs represent purchases of electricity from Powerex by BC Hydro to meet domestic load requirements. These costs are frequently volatile and unpredictable due to uncontrollable factors such as market electricity prices, weather and water inflows. From fiscal 2015 to fiscal 2019, variances between planned and actual Market Electricity Purchases ranged from $(53.8) million to $89.1 million.**

- **Surplus Sales – These costs represent sales of electricity to Powerex, when BC Hydro has generation in excess of its domestic load requirements. These sales are frequently volatile and unpredictable due to uncontrollable factors such as market electricity prices, weather and water inflows. From fiscal 2015 to fiscal 2019, variances between planned and actual Surplus Sales ranged from $(89.9) million to $122.4 million.**

- **Domestic Transmission – Export – These costs represent transmission costs within British Columbia related to Surplus Sales and are frequently volatile and unpredictable due to the same uncontrollable factors that affect Surplus Sales. From fiscal 2015 to fiscal 2019, variances between planned and actual Domestic Transmission – Export ranged from $(14.1) million to $19.1 million.**

- **Costs in Operating/Amortization – Costs associated with compensation and mitigation efforts to fund fish and wildlife programs, Water Use Plan amortization, and Water Use Plan licence costs are reclassified from cost of energy to other line items on the financial statements under International Financial Reporting Standards. Since the nature of these costs has not changed, they continue to be treated as Heritage cost of energy for deferral accounting purposes. From fiscal 2015 to fiscal 2019, variances between**

planned and actual Costs in Operating/Amortization have ranged between $(0.9) million and $2.4 million.

- **Notional Water Rentals – This relates to water rentals associated with trade income (displaced hydro generation). The Notional Water Rental mechanism is described in BC Hydro's response to BCUC IR 1.2.36 dated January 23, 2004. The transactions relating to the Notional Water Rental are eliminated on consolidation and there is no net impact on the combined HDA and NHDA as the transactions are mirrored within each account. Notional water rentals are volatile as they vary with trade activity. From fiscal 2015 to fiscal 2019, variances between planned and actual Notional Water Rentals have ranged between $5.1 million and $(2.0) million.**

- **Skagit and Ancillary Revenue – This represents revenue attributable to the Skagit Valley Treaty. Skagit revenue will vary annually due to fluctuations in foreign exchange associated with annual lump sum payments. The variances could be positive or negative. If variance deferral is not continued, ratepayers would not receive the benefits associated with positive variances such as the significant impact on adoption of IFRS 15 discussed in section 8.13.2 of Chapter 8 of the Application. From fiscal 2015 to fiscal 2019, variances between planned and actual Skagit revenue have ranged between $0.1 million and $(17.5) million.**

- **Other – Other amounts deferred to the Heritage Deferral Account include amortization of First Nations settlement and prior negotiation costs and variable costs relating to thermal generation. From fiscal 2015 to fiscal 2019, variances between planned and actual Other costs have ranged between $0.9 million and $(0.2) million.**

Criteria one can also be broadly considered to be related to variances as variances are indicative of BC Hydro's ability to influence the costs related to the account. As identified above, Heritage Payment Obligation costs vary due to a number of factors beyond BC Hydro's control.

Criteria four relates to materiality. There is no clear way to define materiality for this purpose. In section 7.6 of the Application, BC Hydro notes that:

> **"…expenditures with a net income impact of greater than $10 million in a fiscal year would be considered material."**

However, this section relates to the establishment of new regulatory accounts. It also assumed the continuation of existing regulatory accounts – which capture the variances which entail the most risk, and the sum of which is very significant. If this were not the case, the $10 million figure proposed in respect of proposed new regulatory accounts would need to be revisited (and lowered).

Notwithstanding that BC Hydro considers that the materiality threshold does not apply to existing regulatory accounts or their components, the variances in Heritage Payment Obligation costs that have ranged from ($154.6) million to $81.7 million are material.

294.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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

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.

3.294.3.1 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.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.294.3 where we provide an explanation of why it is appropriate to continue to defer the variances for each of these cost components, considering the criteria set out in section 7.5.1 of Chapter 7 of the Application and explain why BC Hydro does not consider a threshold of $10 million to be appropriate for individual cost components within an existing regulatory account.

294.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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

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.

3.294.3.2 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.

RESPONSE:

There would be no impact to the Test Period revenue requirement or rates.

If the variance treatment for each of the cost components that make up the Heritage Payment Obligation is disallowed beginning in the current Test Period, then any variances between actual and planned amounts for fiscal 2020 and fiscal 2021 related to these individual components would not be eligible for deferral to the Heritage Deferral Account, and would be to the account of the shareholder. Any such variances would impact BC Hydro's actual net income (as opposed to being recovered from ratepayers through rates).

This applies to each of the cost components comprising the Heritage Payment Obligation.

It is not possible to quantify the impact of such a scenario in the Test Period because actual results for fiscal 2020 and fiscal 2021 are not yet known.

Please refer to Attachment 1 to BC Hydro's response to BCUC IR 3.294.2, which shows the magnitude of the variances between actual and plan of each of the cost components that make up the Heritage Payment Obligation for the fiscal 2015 to fiscal 2019 period.

Additionally, as explained on page 8-27 of Chapter 8 of the Application, BC Hydro recognized a $319 million reduction in unearned revenue, at April 1, 2018, as a result of the financing adjustment under IFRS 15. The impact of this adjustment was deferred to the Heritage Deferral Account, to the benefit of ratepayers, and in accordance with BCUC Order No. G-96-04. In the absence of variance treatment, this adjustment would have been to the account of the shareholder (increasing net income by $319 million), with no benefit to ratepayers.

294.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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

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.

3.294.3.3 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.

RESPONSE:

There would be no impact to the revenue requirement or rates in subsequent test periods.

If the variance treatment for each of the cost components that make up the Heritage Payment Obligation is disallowed beginning in the current Test Period, then any variances between actual and planned amounts for subsequent test periods related to these individual components will not be eligible for deferral to the Heritage Deferral Account, and will be to the account of the shareholder. Any such variances will impact BC Hydro's actual net income (as opposed to being recovered from ratepayers through rates in future years).

This applies to each of the cost components comprising the Heritage Payment Obligation.

295.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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.

3.295.1 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.

RESPONSE:

Confirmed. BC Hydro currently plans to continue to include the net income of its subsidiaries in a manner consistent with the definition of Trade Income from Direction No. 7 in future revenue requirements applications.

295.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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.

3.295.2 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.

RESPONSE:

BC Hydro confirms that its shareholder is aware of BC Hydro's proposed treatment of Trade Income whereby a net loss in Trade Income in a given fiscal year would not be deferred to the Trade Income Deferral Account and hence would be to the account of the shareholder.

295.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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.

3.295.3 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."

RESPONSE:

Yes, the BCUC has the authority to define Trade Income for the purpose of setting BC Hydro's rates.

BC Hydro has defined Trade Income as the greater of (a) the amount that is equal to BC Hydro's consolidated net income, less BC Hydro's non-consolidated net income, less the net income of BC Hydro's subsidiaries except Powerex, less the

amount that BC Hydro's consolidated net income changes due to foreign currency translation gains and losses on intercompany balances between BC Hydro and Powerex; and (b) zero. Given BC Hydro's current intent to have any loss by Powerex incurred by the shareholder, BC Hydro is not aware of any alternative definition of Trade Income that would be more appropriate.

As discussed in BC Hydro's response to BCUC IR 3.314.6, BC Hydro believes the use of a five year average for rate setting in the test year period, coupled with a Trade Income Deferral Account to capture variances, remains the most reasonable and appropriate methodology for forecasting Trade Income.

As discussed in BC Hydro's response to AMPC IR 3.3.2, the specific conditions that led to the exceptional Trade Income in fiscal 2019 are unlikely to reoccur to the same extent going forward.

296.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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.

3.296.1 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.

RESPONSE:

The mechanism described in paragraph 10(3) of Direction No. 7 is premised on the DARR percentage being set at 5 per cent for all future years, regardless of the net balances in Cost of Energy Variance Accounts. BC Hydro cannot presume that the BCUC will set the DARR percentage at 5 per cent indefinitely, which BC Hydro believes is required if the DARR mechanism in paragraph 10(3) of Direction No. 7 is to function as written.

It is only the presumption of a permanent 5 per cent DARR percentage which prevents BC Hydro from recommending a return to the DARR table mechanism described in paragraph 10(3) of Direction No. 7.

Otherwise, BC Hydro notes that the DARR table mechanism approved by the BCUC in the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application will result in the same forecast amortization or refund of the Cost of Energy Variance Accounts as the mechanism described in paragraph 10(3) of Direction No. 7, with one further exception that the DARR table mechanism approved by the BCUC in the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application amortizes or refunds balances in the Energy Variance Accounts based on actual net balances as of September 30 of the previous fiscal year, whereas Direction No. 7 amortizes or refunds the balances based on the forecast net balance in the Cost of Energy Variance accounts as of March 31 of the previous fiscal year.

BC Hydro is proposing to return to the DARR table mechanism approved by the BCUC in the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application, but notes that this mechanism could be set such that either forecast year-end or actual mid-year balances could be used to set the DARR percentage. Please refer to BC Hydro's response to BCUC IR 3.296.2 where we discuss the rationale, and pros and cons, of these different approaches to setting the DARR percentage.

296.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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.

3.296.2 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.

RESPONSE:

When BC Hydro proposed the Deferral Account Rate Rider (DARR) table mechanism in its Fiscal 2009 to Fiscal 2010 Revenue Requirement Application, we proposed that when BC Hydro filed its Quarterly Deferral Account Report with the BCUC each September 30, BC Hydro would seek an order from the BCUC approving a change to the DARR to be effective the following April 1 in accordance with the threshold table.

This approach would satisfy the objective set forth in the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application that the process of updating the level of the DARR each year should be simple and transparent.

The table below shows the pros and cons of different approaches to setting the DARR percentage.

Approach	Pros	Cons
DARR set based on actual September 30 balance	**Simple and transparent as on September 30th, BC Hydro would seek an order from the BCUC approving a change to the DARR to be effective the following April 1st in accordance with the threshold table.**	**It does not consider amortization and forecast additions or reductions to the Cost of Energy Variance Accounts for the remaining six months of the fiscal year and therefore may be less accurate.**
DARR set based on forecast March 31 balance	**Includes amortization and forecast additions or reductions for the remaining six months of the fiscal year based on more up-to-date information available at September 30 and therefore may be more accurate.**	**There remains forecast uncertainty with respect to year-end balances in Cost of Energy Variance Accounts. Variances between forecast and actual could be significant. As a result, the DARR percentage collected in the Test Period may be based on forecast amounts that did not materialize.**
DARR set based on actual March 31 balance	**Simple, transparent and the most accurate as the balances to be recovered through the DARR mechanism will be based on actual results and will be more current than using September 30 amounts.**	**Not administratively feasible as BC Hydro will not know the March 31 actual balances until after its application and therefore will not know the correct amounts to include in its revenue requirements application. Furthermore, it will not be possible to start collecting the DARR on April 1 of the following fiscal year, until the March 31 actual balances are known and BC Hydro's financial statements are final.**

BC Hydro notes that with regards to the Application, we used the DARR refund based on forecast March 31 balances (i.e., the second approach in the table above) and later replaced those balances with actual March 31 balances in the Evidentiary Update (i.e., the third approach in the table above), as those balances became available at that time and were more accurate to use.

296.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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.

3.296.2.1 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.

RESPONSE:

Please refer to BC Hydro’s response to BCUC IR 3.296.2, where we discuss the pros and cons of these different approaches to setting the DARR percentage.

296.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

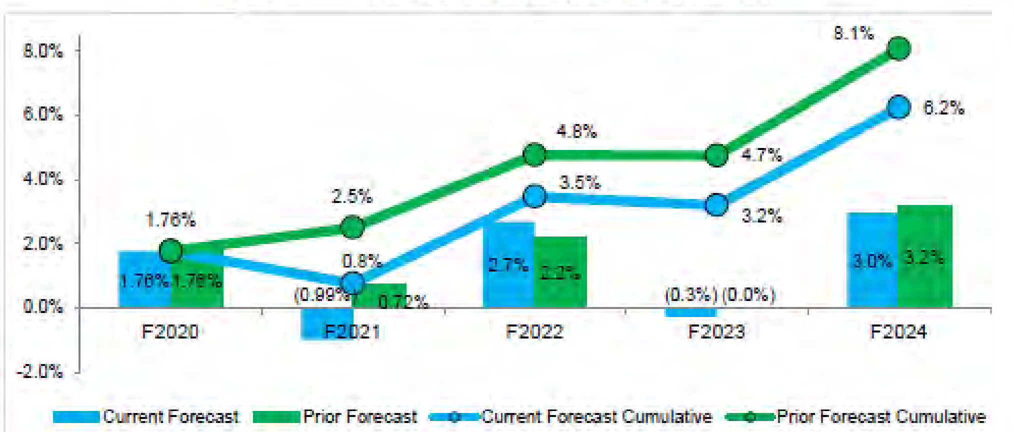
Reference: REGULATORY ACCOUNTS
Exhibit B-5, BCUC IR 148.1, 148.3, 148.4; Exhibit B-11, Figure 1, p. 1
Deferral Account Rate Rider (DARR)

In response to BCUC IR 148.3, 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



3.296.3 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.

RESPONSE:

BC Hydro believes it will be efficient for the BCUC and interveners to review and compare all bill impact scenarios in a consistent format and in a single response.

Accordingly, this answer also responds to BCUC IRs 3.296.4 and 3.296.5, AMPC IR 3.12.1, BCOAPO IR 3.162.1, BCSEA IRs 3.76.1 and 3.76.4, CEC IRs 3.95.3, 3.95.4 and 3.95.5, INCE IRs 3.1.0, 3.2.0 and 3.3.0, and ZONE II RPG IRs 3.57.2 and 3.60.2.

BC Hydro considered a number of the bill impact options in its proposal in the Evidentiary Update. Please refer to ZONE II RPG IR 3.57.2 for further discussions of these options. All of these options are included in the scenarios presented below.

BC Hydro's proposal in the Evidentiary Update was based on the following principles:

1. **<u>Cost of Service</u>: BC Hydro should recover its revenue requirements (i.e., its cost of service), in each Test Period and not an amount more or less than that;**

2. **<u>Rate Stability</u>: BC Hydro's rates should be set in a way that reduces year over year volatility where possible. Undue or unnecessary volatility can create hardship for ratepayers;**

3. **<u>Bill adjustments</u>: Adjustments to rates for a fiscal year that occur after that fiscal year has completed can also cause hardship to ratepayers because of the occurrence of (what BC Hydro assumes would be) a one-time true-up bill adjustment covering the whole impact caused by the change in rates for the fiscal year already completed. In the case of the Test Period, this would apply to fiscal 2020 final rates, which we expect the BCUC to determine early in fiscal 2021. BC Hydro expects the one-time true up bill adjustment for fiscal 2020 would be issued early in fiscal 2021; and**

4. **<u>Rate Smoothing</u>: While rate smoothing within a test period may sometimes be beneficial for ratepayers, rate smoothing that spans beyond a test period may not be considered appropriate and is typically infeasible to implement. The reason for this is that revenue requirements for future test periods not before the BCUC will, necessarily, change. Further, when the revenue requirements for such future test periods change, it is not possible to keep rates in these future test periods at the same smoothed rate from the preceding test period without the possibility of a remaining balance in a rate smoothing regulatory account after the entire smoothed period.**

BC Hydro considers that its proposal in the Evidentiary Update achieves these principles better than other available options. BC Hydro considers that Scenario L most closely aligns to BC Hydro's proposal in terms of achieving the principles outlined above. BC Hydro outlines some differences between its proposal and Scenario L later in this response but the main difference is that Scenario L uses rate smoothing during the test period. BC Hydro notes above in respect of principle 4 that rate smoothing within a test period can sometimes be beneficial to ratepayers. However, BC Hydro has not proposed rate smoothing in the test period as we did not consider it appropriate for BC Hydro to do so given the recent write-off of the Rate Smoothing Regulatory Account as an outcome of Phase One of the Comprehensive Review of BC Hydro.

Financial information and bill impacts from the Evidentiary Update are included directly below as a reference as the related information is included with each scenario.

Evidentiary Update: Rate Impacts, Deferral Account Rate Rider, Bill Impacts

Per Cent Increase / (Decrease)	F2020	F2021	F2022	F2023	F2024
Rate Impact	6.85	(0.99)	2.69	(0.26)	2.95
Cumulative Rate Impact	6.85	5.79	8.64	8.35	11.55
Deferral Account Rate Rider	0.00	0.00	0.00	0.00	0.00
Bill Impact	1.76	(0.99)	2.69	(0.26)	2.95
Cumulative Bill Impact	1.76	0.75	3.46	3.19	6.24

Evidentiary Update: DARR Revenue and Revenue Shortfall

$ million	F2020	F2021	F2022	F2023	F2024
DARR Revenue - Collected / (Refunded)	0	0	0	0	0
Revenue Shortfall	335	285	424	412	580

Evidentiary Update: Cost of Energy Variance Accounts Balance

$ million	F2020	F2021	F2022	F2023	F2024
Per Evidentiary Update	(219)	(0)	(16)	(22)	(24)

Summary of Bill Impact Scenarios

Forecast Annual Bill Impacts Per Cent Increase / (Decrease)	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**Cost of Energy Variance Accounts Refund**
Original Application	1.76	0.72	2.20	(0.02)	3.18	Over F2020 and F2021
Evidentiary Update	1.76	(0.99)	2.69	(0.26)	2.95	Over F2020 and F2021, bill impact 1.76% in F2020
Scenarios - IR reference(s)						
A - BCUC IRs 3.296.3, 3.296.5	8.03	(7.48)	(0.60)	2.32	4.00	Based on mid-year balances
B(i) - BCUC IRs 3.296.4.i, 3.296.5	6.92	(6.04)	0.43	1.26	2.95	Based on F2019 forecast year-end balances
B(ii) - BCUC IRs 3.296.4.ii, 3.296.5	4.16	(2.05)	(0.09)	0.24	3.47	Based on F2019 actual year-end balances
C - AMPC IR 3.12.1, BCOAPO IR 3.162.1, CEC IR 3.95.3, ZONE II RPG IR 3.60.2.i	3.47	(4.30)	4.49	(0.26)	2.95	Equal amounts over F2020 and F2021
D - BCSEA IRs 3.76.1, 3.76.4, INCE IR 3.3	1.76	0.00	0.66	0.74	2.95	Bill impacts 1.76% in F2020, 0% in F2021
E - CEC IR 3.95.4	(2.53)	7.86	(1.59)	(0.26)	2.96	100% in F2020
F - CEC IR 3.95.5	1.01	1.01	1.01	1.01	1.01	N/A (smoothed bill impacts, F2020 to F2024)
G - INCE IR 3.1	1.76	0.72	(0.57)	0.74	3.47	F2020 and F2021 bill impacts per Application
H - INCE IR 3.2	1.76	0.64	0.64	0.64	0.64	N/A (bill impacts 1.76% in F2020, smoothed F2021 to F2024)
I - ZONE II RPG IR 3.60.2.ii	0.44	1.65	1.33	(0.26)	2.95	75% in F2020, 25% in F2021
J - ZONE II RPG IR 3.60.2.iii	6.55	(10.02)	7.92	(0.26)	2.95	25% in F2020, 75% in F2021
K - ZONE II RPG IR 3.57.2	4.16	(4.08)	1.49	1.77	2.95	Based on F2019 actuals, then mid-year balances
L - ZONE II RPG IR 3.57.2	0.84	0.84	1.74	(0.26)	2.95	Smoothed bill impacts, F2020 and F2021

Scenario A: BC Hydro's response to BCUC IR 3.296.3 and BCUC IR 3.296.5

BCUC IR 3.296.3 contemplates a scenario where the Deferral Account Rate Rider (DARR) mechanism from the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application sets the DARR percentage over the Test Period.

For the purpose of the five-year forecast requested in this scenario, BC Hydro assumes that the DARR mechanism from the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application also sets the DARR percentage over the fiscal 2022 to fiscal 2024 period.

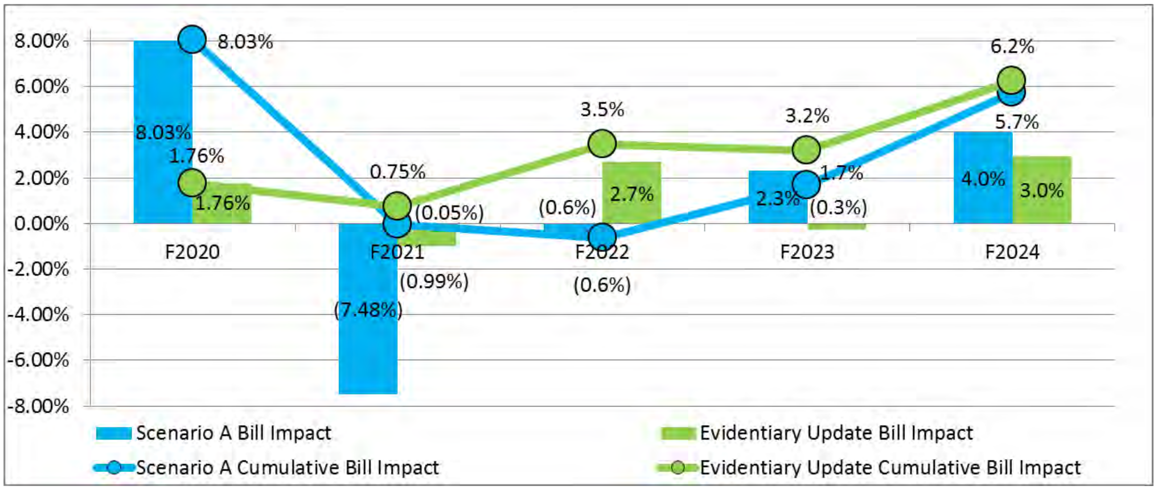
Please refer to the graphs and tables below for the results of this scenario.

BC Hydro notes that the use of the DARR mechanism from the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application in this scenario is forecast to leave a credit balance in the Cost of Energy Variance Accounts at the end of fiscal 2021 that would need to be refunded in future periods, subject to the BCUC's approval.

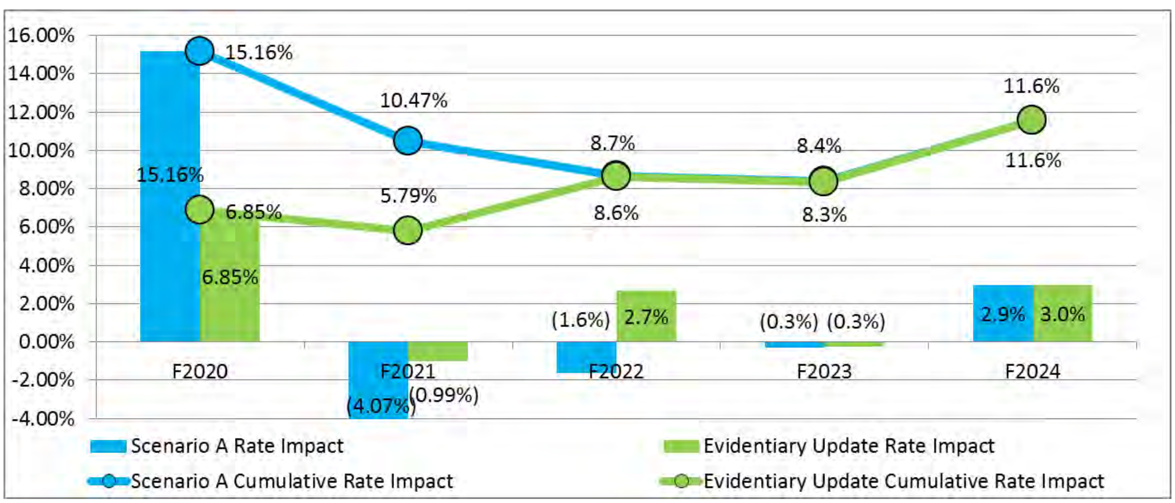
BC Hydro considers its proposed approach to be preferable to Scenario A because BC Hydro's proposal better achieves Principle 2 in that it provides less rate volatility. Further, BC Hydro's proposal will not require a one-time true-up bill adjustment in respect of fiscal 2020. Scenario A would require such an adjustment for fiscal 2020. The adjustment would be significant (6.27 per cent, which is equal to 8.03 per cent minus 1.76 per cent) and would therefore create hardship for

some ratepayers, as BC Hydro assumes the adjustment would appear for customers on one bill sometime in fiscal 2021. Therefore, Scenario A is also less desirable with respect to Principle 3.

Scenario A: Five-Year Net Bill Impact Forecast



Scenario A: Five-Year Rate Forecast



Scenario A: Rate Impacts, Deferral Account Rate Rider, Bill Impacts

Per Cent Increase / (Decrease)	F2020	F2021	F2022	F2023	F2024
Rate Impact	15.16	(4.07)	(1.64)	(0.28)	2.95
Cumulative Rate Impact	15.16	10.47	8.66	8.36	11.56
Deferral Account Rate Rider	(1.50)	(5.00)	(4.00)	(1.50)	(0.50)
Bill Impact	8.03	(7.48)	(0.60)	2.32	4.00
Cumulative Bill Impact	8.03	(0.05)	(0.65)	1.66	5.72

Scenario A: DARR Revenue and Revenue Shortfall

$ million	F2020	F2021	F2022	F2023	F2024
DARR Revenue - Collected / (Refunded)	(84)	(271)	(213)	(80)	(28)
Revenue Shortfall	741	515	425	413	580

Scenario A: Cost of Energy Variance Accounts Balance

$ million	F2020	F2021	F2022	F2023	F2024
Per Scenario	(545)	(292)	(101)	(29)	(3)
Per Evidentiary Update	(219)	(0)	(16)	(22)	(24)
Difference	(326)	(292)	(86)	(7)	21

<u>Scenario B(i): BC Hydro's response to BCUC IR 3.296.4.i and BCUC IR 3.296.5</u>

BCUC IR 3.296.4.i contemplates a scenario where the DARR mechanism from the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application sets the DARR percentage over the Test Period using the forecast net ending balances of the Cost of Energy Variance Accounts from the preceding fiscal year.

For the purpose of the five-year forecast requested by this scenario, BC Hydro uses the forecast fiscal 2019 net ending balances of the Cost of Energy Variance Accounts from the Application to set the fiscal 2020 DARR percentage. The Cost of Energy Variance Accounts from this scenario are then recast accordingly, so that the forecast net ending balances of Cost of Energy Variance Accounts from the preceding fiscal year are used to set the DARR percentage from fiscal 2021 to fiscal 2024.

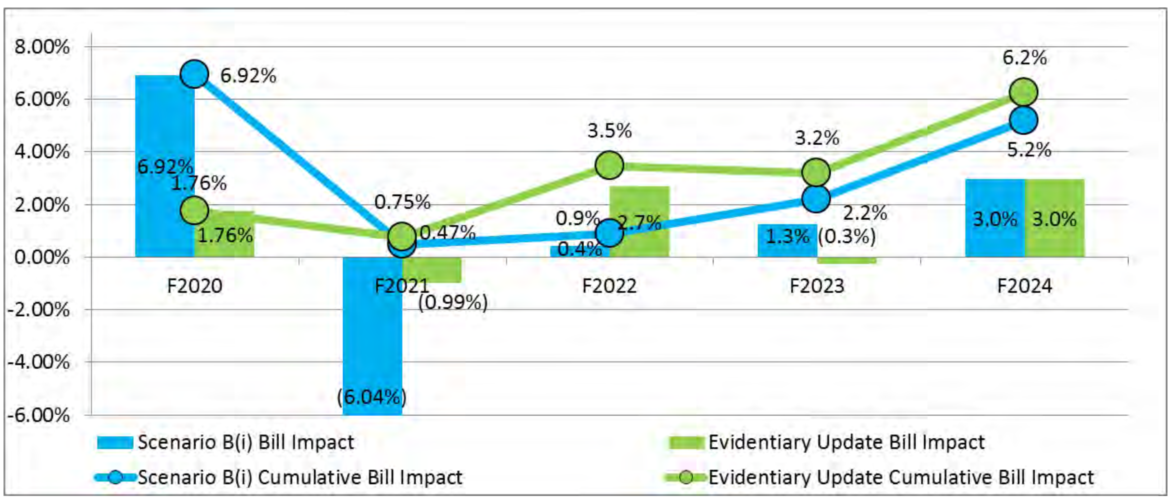
Please refer to the graphs and tables below for the results of this scenario.

BC Hydro notes that the use of the DARR mechanism from the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application in this scenario is forecast to leave a credit balance in the Cost of Energy Variance Accounts at the end of

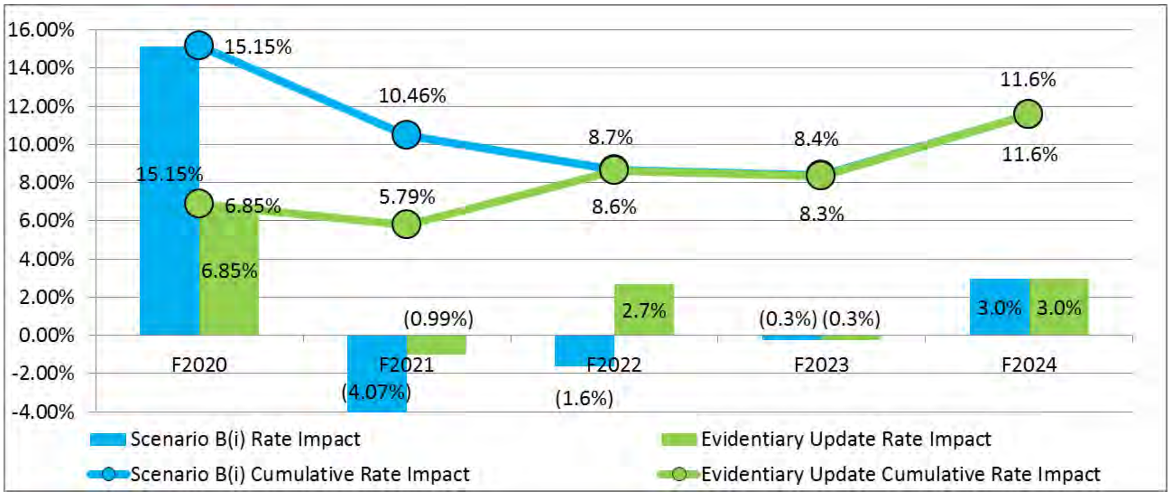
fiscal 2021 that would need to be refunded in future periods, subject to the BCUC's approval.

Similar to Scenario A, BC Hydro considers its proposed approach to be preferable to Scenario B(i) because BC Hydro's proposal better achieves Principle 2 in that it provides less rate volatility. Further, BC Hydro's proposal will not require a one-time true-up bill adjustment in respect of fiscal 2020. Scenario B(i) would require such an adjustment for fiscal 2020. The adjustment would be significant (5.16 per cent, which is equal to 6.92 per cent minus 1.76 per cent) and would therefore create hardship for some ratepayers, as BC Hydro assumes the adjustment would appear for customers on one bill sometime in fiscal 2021. Therefore, Scenario B(i) is also less desirable with respect to Principle 3.

Scenario B(i): Five-Year Net Bill Impact Forecast



Scenario B(i): Five-Year Rate Forecast



Scenario B(i): Rate Impacts, Deferral Account Rate Rider, Bill Impacts

Per Cent Increase / (Decrease)	F2020	F2021	F2022	F2023	F2024
Rate Impact	15.15	(4.07)	(1.63)	(0.27)	2.95
Cumulative Rate Impact	15.15	10.46	8.66	8.37	11.57
Deferral Account Rate Rider	(2.50)	(4.50)	(2.50)	(1.00)	(1.00)
Bill Impact	6.92	(6.04)	0.43	1.26	2.95
Cumulative Bill Impact	6.92	0.47	0.90	2.18	5.19

Scenario B(i): DARR Revenue and Revenue Shortfall

$ million	F2020	F2021	F2022	F2023	F2024
DARR Revenue - Collected / (Refunded)	(141)	(244)	(133)	(53)	(56)
Revenue Shortfall	741	514	425	413	581

Scenario B(i): Cost of Energy Variance Accounts Balance

$ million	F2020	F2021	F2022	F2023	F2024
Per Scenario	(488)	(261)	(150)	(107)	(55)
Per Evidentiary Update	(219)	(0)	(16)	(22)	(24)
Difference	(268)	(261)	(134)	(84)	(30)

<u>Scenario B(ii): BC Hydro's response to BCUC IR 3.296.4.ii and BCUC IR 3.296.5</u>

BCUC IR 3.296.4.ii contemplates a scenario where the DARR mechanism from the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application sets the DARR percentage over the Test Period using the actual net ending balances of the Cost of Energy Variance Accounts from the preceding fiscal year.

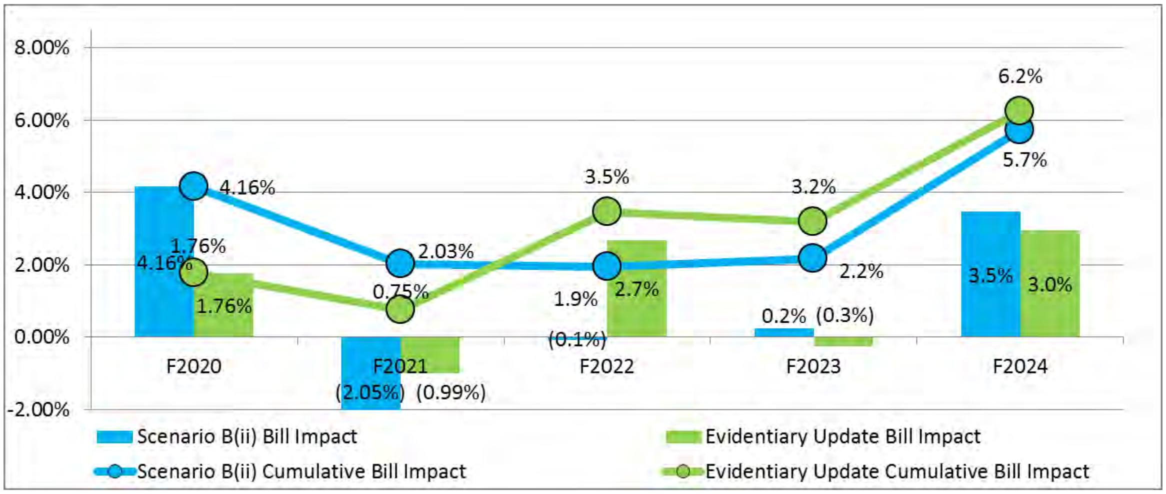
For the purpose of the five-year forecast requested by this scenario, BC Hydro uses the actual fiscal 2019 net ending balances of the Cost of Energy Variance Accounts to set the fiscal 2020 DARR percentage. The forecast Cost of Energy Variance Accounts from this scenario are then recast accordingly, so that the forecast net ending balances of Cost of Energy Variance Accounts from the preceding fiscal year are used to set the DARR percentage from fiscal 2021 to fiscal 2024.

Please refer to the graphs and tables below for the results of this scenario.

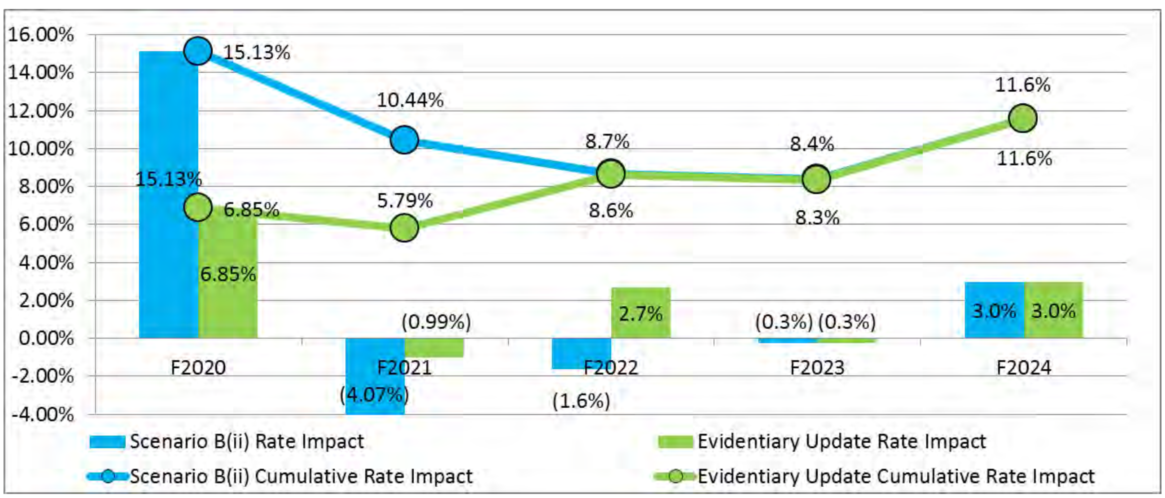
BC Hydro notes that the use of the DARR mechanism from the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application in this scenario is forecast to leave a credit balance in the Cost of Energy Variance Accounts at the end of fiscal 2021 that would need to be refunded in future periods, subject to the BCUC's approval.

Similar to the previous two scenarios, BC Hydro considers its proposed approach to be preferable to Scenario B(ii) because BC Hydro's proposal better achieves Principle 2 in that it provides less rate volatility. Further, BC Hydro's proposal will not require a one-time true-up bill adjustment in respect of fiscal 2020. Scenario B(ii) would require such an adjustment for fiscal 2020. The adjustment would still be significant (2.4 per cent, which is equal to 4.16 per cent minus 1.76 per cent) and would therefore create hardship for some ratepayers, as BC Hydro assumes the adjustment would appear for customers on one bill sometime in fiscal 2021. Therefore, Scenario B(ii) is also less desirable with respect to Principle 3.

Scenario B(ii): Five-Year Net Bill Impact Forecast



Scenario B(ii): Five-Year Rate Forecast



Scenario B(ii): Rate Impacts, Deferral Account Rate Rider, Bill Impacts

Per Cent Increase / (Decrease)	F2020	F2021	F2022	F2023	F2024
Rate Impact	15.13	(4.07)	(1.62)	(0.27)	2.95
Cumulative Rate Impact	15.13	10.44	8.66	8.36	11.56
Deferral Account Rate Rider	(5.00)	(3.00)	(1.50)	(1.00)	(0.50)
Bill Impact	4.16	(2.05)	(0.09)	0.24	3.47
Cumulative Bill Impact	4.16	2.03	1.93	2.17	5.72

Scenario B(ii): DARR Revenue and Revenue Shortfall

$ million	F2020	F2021	F2022	F2023	F2024
DARR Revenue - Collected / (Refunded)	(281)	(163)	(80)	(53)	(28)
Revenue Shortfall	740	513	425	413	581

Scenario B(ii): Cost of Energy Variance Accounts Balance

$ million	F2020	F2021	F2022	F2023	F2024
Per Scenario	(344)	(195)	(136)	(92)	(68)
Per Evidentiary Update	(219)	(0)	(16)	(22)	(24)
Difference	(125)	(195)	(120)	(70)	(44)

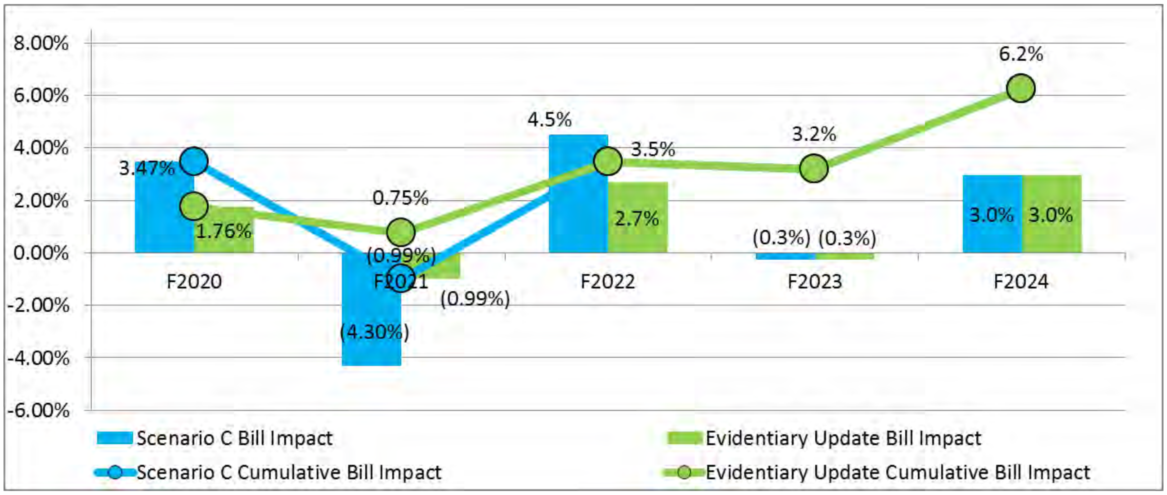
Scenario C: BC Hydro’s response to AMPC IR 3.12.1, BCOAPO IR 3.162.1, CEC IR 3.95.3, ZONE II RPG IR 3.60.2.i

These questions contemplate a scenario where the fiscal 2019 actual ending balance and forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the Cost of Energy Variance Accounts are refunded in equal amounts over fiscal 2020 and fiscal 2021.

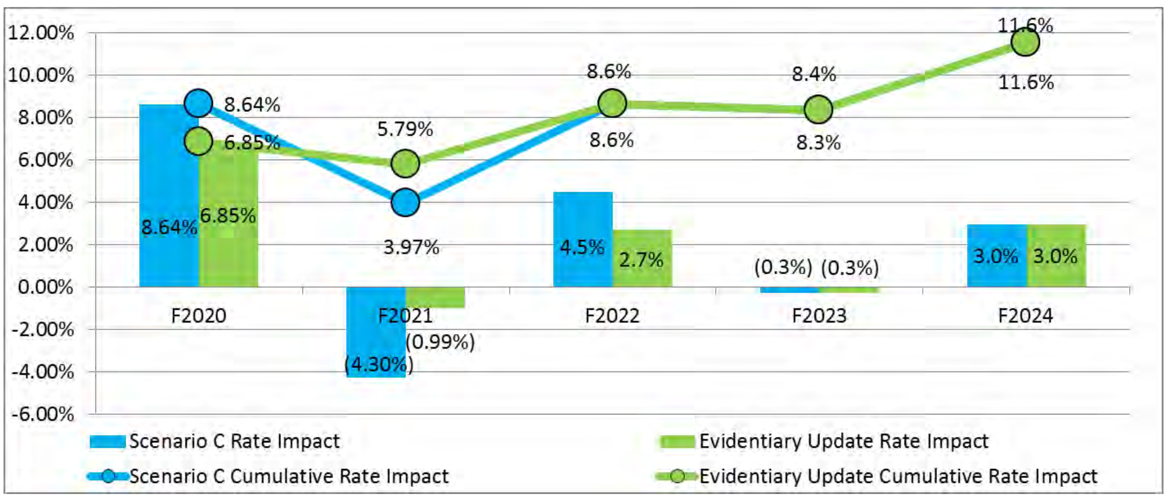
Please refer to the graphs and tables below for the results of this scenario.

Similar to the previous scenarios, BC Hydro considers its proposed approach to be preferable to Scenario C because BC Hydro’s proposal better achieves Principle 2 in that it provides less rate volatility. Further, BC Hydro’s proposal will not require a one-time true-up bill adjustment in respect of fiscal 2020. Scenario C would require such an adjustment for fiscal 2020. The adjustment would almost double the net bill increase (1.71 per cent, which is equal to 3.47 per cent minus 1.76 per cent) and would therefore create hardship for some ratepayers, as BC Hydro assumes the adjustment would appear for customers on one bill sometime in fiscal 2021. Therefore, Scenario C is also less desirable with respect to Principle 3.

Scenario C: Five-Year Net Bill Impact Forecast



Scenario C: Five-Year Rate Forecast



Scenario C: Rate Impacts, Deferral Account Rate Rider, Bill Impacts

Per Cent Increase / (Decrease)	F2020	F2021	F2022	F2023	F2024
Rate Impact	8.64	(4.30)	4.49	(0.26)	2.95
Cumulative Rate Impact	8.64	3.97	8.64	8.35	11.55
Deferral Account Rate Rider	0.00	0.00	0.00	0.00	0.00
Bill Impact	3.47	(4.30)	4.49	(0.26)	2.95
Cumulative Bill Impact	3.47	(0.99)	3.46	3.19	6.24

Scenario C: DARR Revenue and Revenue Shortfall

$ million	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**
DARR Revenue - Collected / (Refunded)	0	0	0	0	0
Revenue Shortfall	422	195	424	412	580

Scenario C: Cost of Energy Variance Accounts Balance

$ million	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**
Per Scenario	(308)	0	(16)	(22)	(24)
Per Evidentiary Update	(219)	(0)	(16)	(22)	(24)
Difference	(89)	0	0	0	0

Scenario D: BC Hydro’s response to BCSEA IRs 3.76.1 and 3.76.4, INCE IR 3.3

These questions contemplate a scenario where the fiscal 2020 interim rate and bill increases are approved as proposed and the fiscal 2021 rate and bill increases are set at zero per cent.

For the purpose of achieving the requested scenario, BC Hydro assumes that the Cost of Energy Variance Accounts amortization is the mechanism which would be adjusted to produce the fiscal 2021 bill impact of zero per cent.

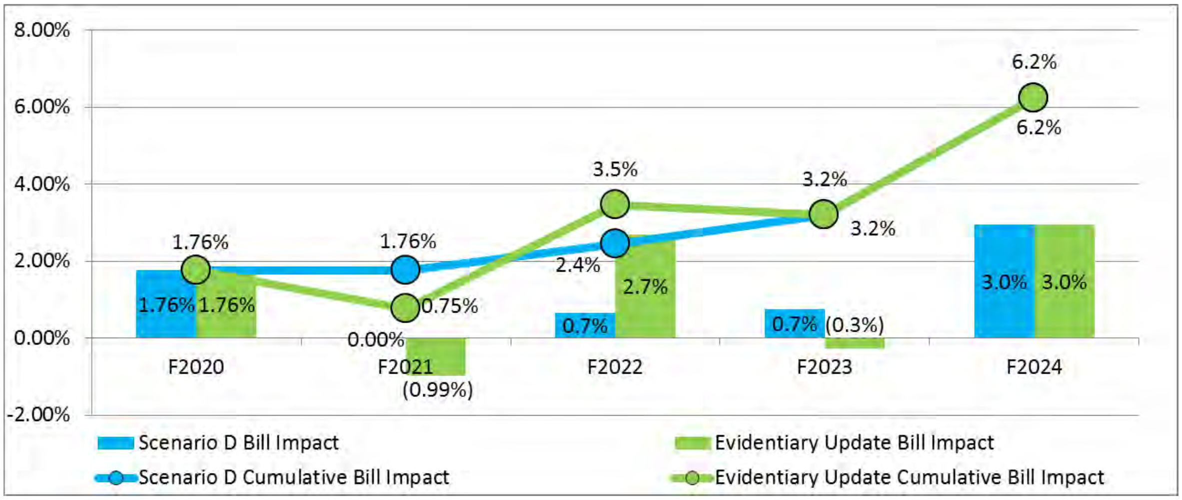
BC Hydro further assumes that the DARR mechanism from the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application, which uses the mid-year balances of the Cost of Energy Variance Accounts from the preceding fiscal year to set the DARR percentage, is used to amortize the Cost of Energy Variance Accounts in fiscal 2022 to fiscal 2024.

Please refer to the graphs and tables below for the results of this scenario.

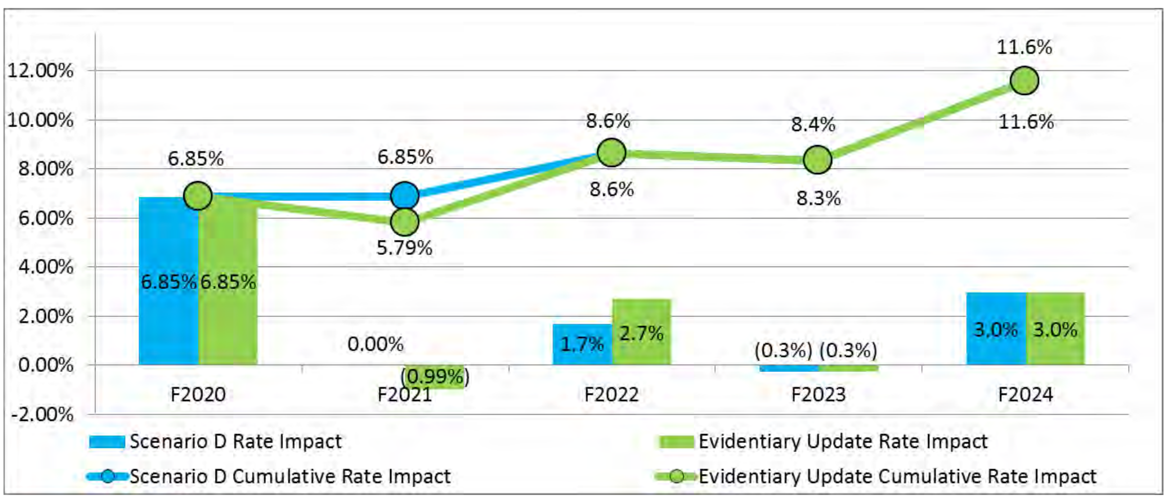
BC Hydro notes that this scenario is forecast to leave a credit balance in the Cost of Energy Variance Accounts at the end of fiscal 2021 that would need to be refunded in future periods, subject to the BCUC’s approval.

BC Hydro considers its proposed approach to be preferable to Scenario D because BC Hydro’s proposal better achieves Principle 1. More specifically, BC Hydro would recover more than its revenue requirement from ratepayers in the Test Period under Scenario D.

Scenario D: Five-Year Net Bill Impact Forecast



Scenario D: Five-Year Rate Forecast



Scenario D: Rate Impacts, Deferral Account Rate Rider, Bill Impacts

Per Cent Increase / (Decrease)	F2020	F2021	F2022	F2023	F2024
Rate Impact	6.85	0.00	1.68	(0.27)	2.95
Cumulative Rate Impact	6.85	6.85	8.64	8.35	11.55
Deferral Account Rate Rider	0.00	0.00	(1.00)	0.00	0.00
Bill Impact	1.76	0.00	0.66	0.74	2.95
Cumulative Bill Impact	1.76	1.76	2.43	3.19	6.24

Scenario D: DARR Revenue and Revenue Shortfall

$ million	F2020	F2021	F2022	F2023	F2024
DARR Revenue - Collected / (Refunded)	0	0	(53)	0	0
Revenue Shortfall	335	337	424	412	580

Scenario D: Cost of Energy Variance Accounts Balance

$ million	F2020	F2021	F2022	F2023	F2024
Per Scenario	(219)	(53)	(16)	(23)	(25)
Per Evidentiary Update	(219)	(0)	(16)	(22)	(24)
Difference	0	(53)	(0)	(0)	(0)

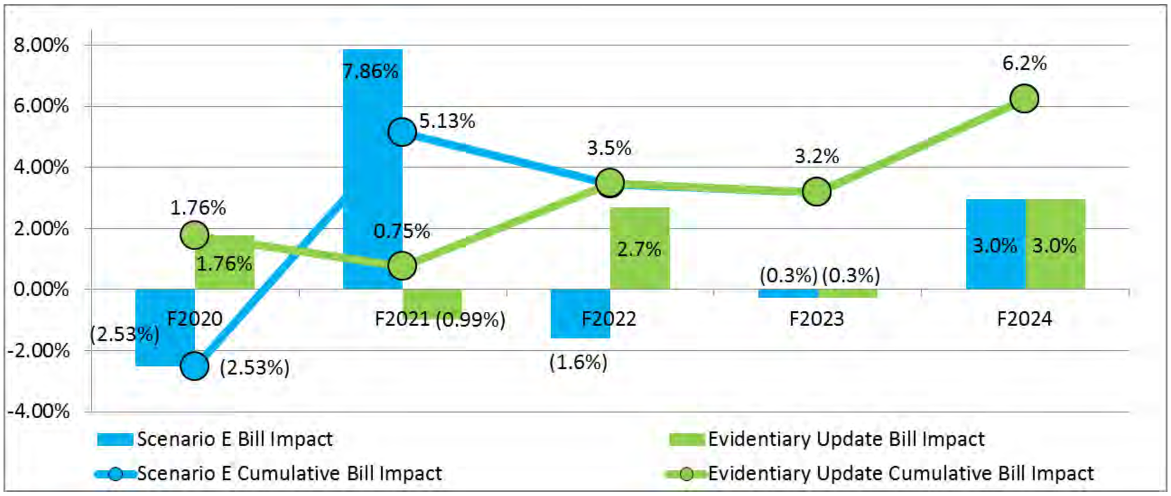
<u>**Scenario E: BC Hydro's response to CEC IR 3.95.4**</u>

This question contemplates a scenario where the fiscal 2019 actual ending balance and forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the Cost of Energy Variance Accounts are refunded in fiscal 2020.

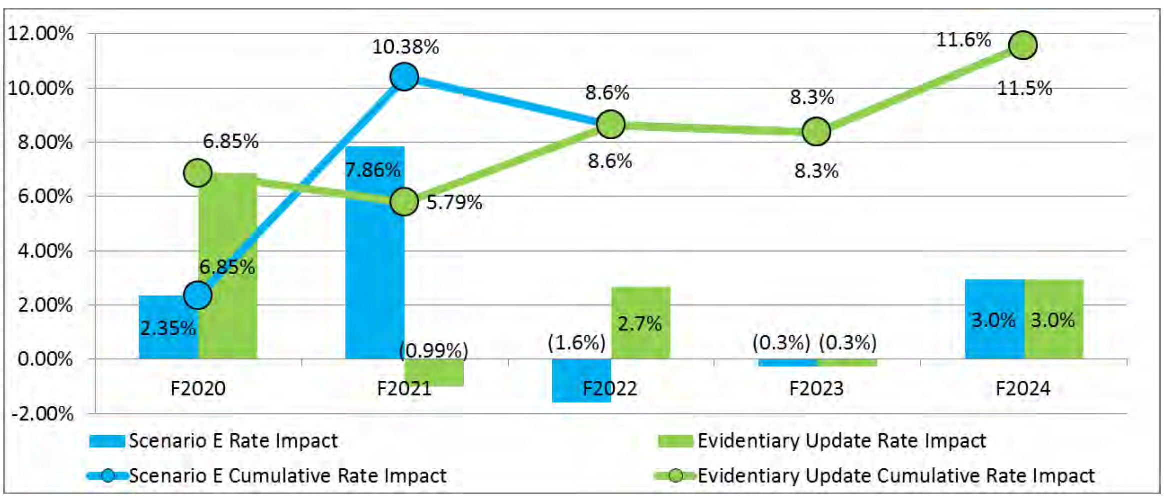
Please refer to the graphs and tables below for the results of this scenario.

BC Hydro considers its proposed approach to be preferable to Scenario E because BC Hydro's proposal better achieves Principle 2 in that it provides less rate volatility. Further, BC Hydro's proposal will not require a one-time true-up bill adjustment in respect of fiscal 2020. Scenario E would require such an adjustment for fiscal 2020. BC Hydro believes that this will cause confusion despite that there will be no hardship to ratepayers as the fiscal 2020 rates would decrease. Therefore, Scenario E is also less desirable with respect to Principle 3.

Scenario E: Five-Year Net Bill Impact Forecast



Scenario E: Five-Year Rate Forecast



Scenario E: Rate Impacts, Deferral Account Rate Rider, Bill Impacts

Per Cent Increase / (Decrease)	F2020	F2021	F2022	F2023	F2024
Rate Impact	2.35	7.86	(1.59)	(0.26)	2.96
Cumulative Rate Impact	2.35	10.38	8.63	8.35	11.55
Deferral Account Rate Rider	0.00	0.00	0.00	0.00	0.00
Bill Impact	(2.53)	7.86	(1.59)	(0.26)	2.96
Cumulative Bill Impact	(2.53)	5.13	3.46	3.19	6.24

Scenario E: DARR Revenue and Revenue Shortfall

$ million	F2020	F2021	F2022	F2023	F2024
DARR Revenue - Collected / (Refunded)	0	0	0	0	0
Revenue Shortfall	115	510	424	412	580

Scenario E: Cost of Energy Variance Accounts Balance

$ million	F2020	F2021	F2022	F2023	F2024
Per Scenario	3	(0)	(16)	(22)	(24)
Per Evidentiary Update	(219)	(0)	(16)	(22)	(24)
Difference	223	0	(0)	(0)	(0)

The unamortized $3 million balance in fiscal 2020 in the table above relates to capital additions in fiscal 2021 as part of the Waneta 2017 Transaction made by Teck during the lease term deferred to Non-Heritage Deferral account per the BCUC Order No. G-130-18.

Scenario F: BC Hydro's response to CEC IR 3.95.5

This question contemplates a scenario where customer bills are smoothed to the greatest extent over the fiscal 2020 to fiscal 2024 period.

For the purpose of the requested scenario, BC Hydro assumes that the Cost of Energy Variance Accounts amortization is the mechanism which would be adjusted to produce the smoothed bill impacts over the fiscal 2020 to fiscal 2024 period. BC Hydro does not believe it is advisable to use rate smoothing beyond the Test Period for reasons further explained below.

Under this scenario, bill increases are 1.01 per cent per year over the fiscal 2020 to fiscal 2024 period.

BC Hydro notes that the forecast period from fiscal 2022 to fiscal 2024 included in the Evidentiary Update is intended to show an estimate of future rates. Any revenue requirements or rate increases requested in this period, which is beyond the Test Period, should be determined based on a detailed assessment of BC Hydro's forecast revenues and costs at the time of its future revenue requirements filings, taking into account the conditions at that time.

Accordingly, BC Hydro considers that it is not advisable to smooth rates beyond the Test Period, or to use assumed future test period costs and revenues to determine a smoothed bill increase that impacts the Test Period.

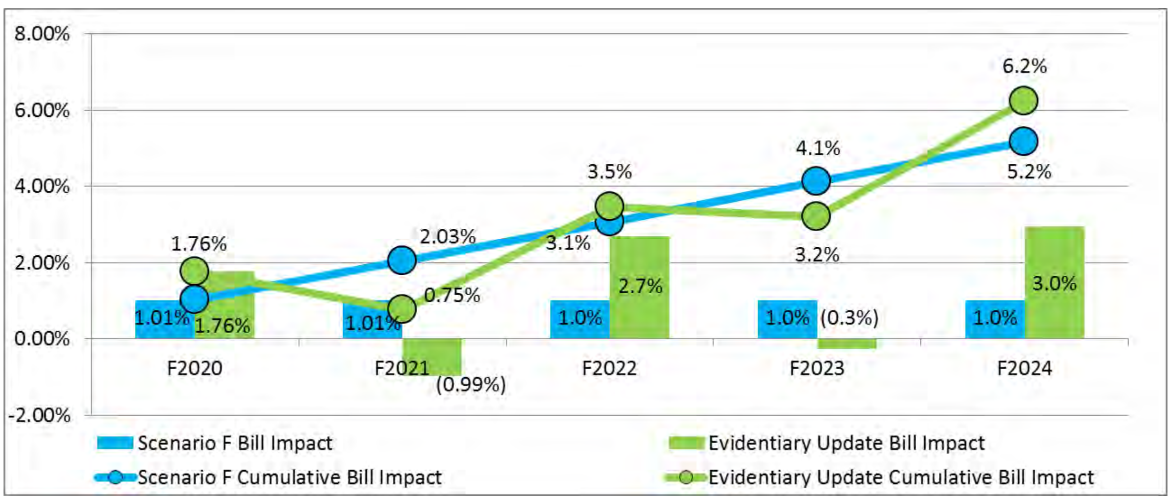
BC Hydro further notes that if bill impacts were smoothed beyond the Test Period, the fiscal 2022 to fiscal 2024 period could not be smoothed at the same bill impacts as in the Test Period unless a balance is allowed in a rate smoothing regulatory account at the end of fiscal 2024.

Therefore, BC Hydro considers its proposed approach to be preferable to Scenario F because BC Hydro's proposal better achieves Principle 4 in that it does not require rate smoothing that spans beyond the Test Period.

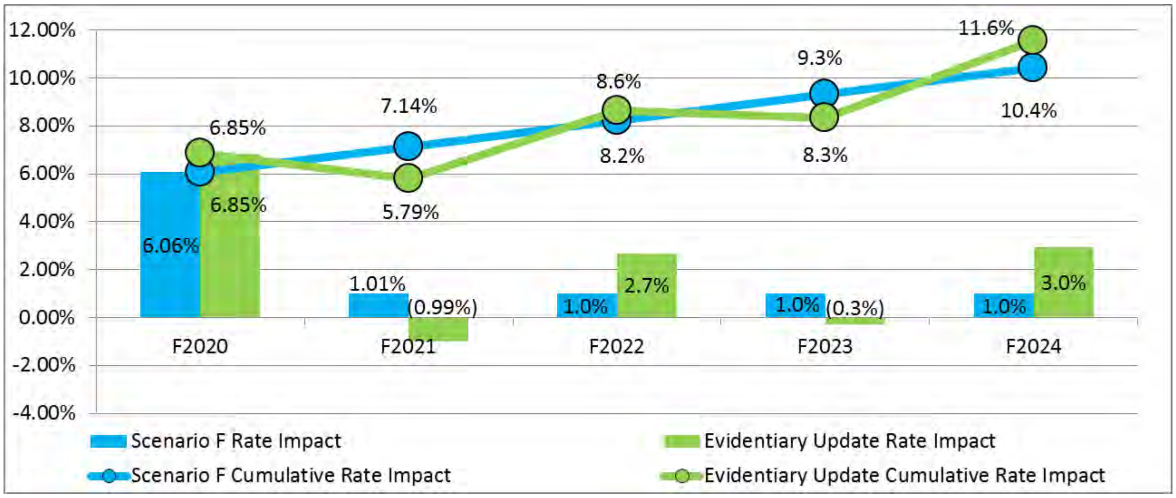
BC Hydro also notes that Scenario F will result in BC Hydro collecting more than its revenue requirements from ratepayers in the Test Period and thus BC Hydro's proposed approach also better achieves Principle 1.

Please refer to the graphs and tables below for the results of this scenario.

Scenario F: Five-Year Net Bill Impact Forecast



Scenario F: Five-Year Rate Forecast



Scenario F: Rate Impacts, Deferral Account Rate Rider, Bill Impacts

Per Cent Increase / (Decrease)	F2020	F2021	F2022	F2023	F2024
Rate Impact	6.06	1.01	1.01	1.01	1.01
Cumulative Rate Impact	6.06	7.14	8.22	9.32	10.42
Deferral Account Rate Rider	0.00	0.00	0.00	0.00	0.00
Bill Impact	1.01	1.01	1.01	1.01	1.01
Cumulative Bill Impact	1.01	2.03	3.07	4.11	5.16

Scenario F: DARR Revenue and Revenue Shortfall

$ million	F2020	F2021	F2022	F2023	F2024
DARR Revenue - Collected / (Refunded)	0	0	0	0	0
Revenue Shortfall	296	351	403	460	523

Scenario F: Cost of Energy Variance Accounts Balance

$ million	F2020	F2021	F2022	F2023	F2024
Per Scenario	(180)	(27)	(23)	(78)	(24)
Per Evidentiary Update	(219)	(0)	(16)	(22)	(24)
Difference	39	(27)	(7)	(56)	0

Scenario G: BC Hydro's response to INCE IR 3.1

This question contemplates a scenario where fiscal 2020 and fiscal 2021 rate and bill increases are approved as proposed per BC Hydro's original Application.

For the purpose of the requested scenario, BC Hydro assumes that the Cost of Energy Variance Accounts amortization is the mechanism which would be adjusted to produce the bill increases proposed per BC Hydro's original Application.

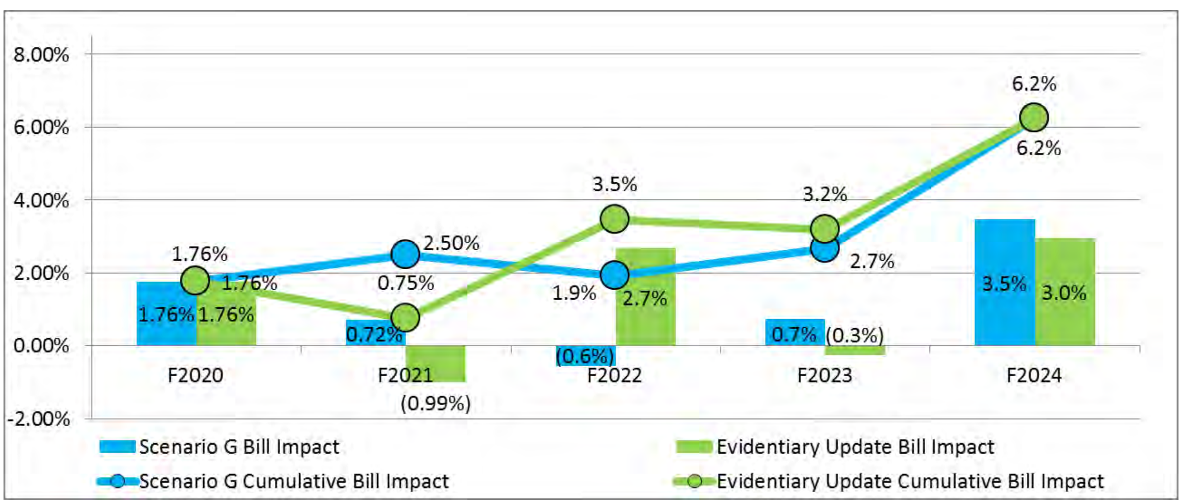
BC Hydro further assumes that the DARR mechanism from the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application, which uses the mid-year balances of the Cost of Energy Variance Accounts from the preceding fiscal year to set the DARR percentage, is used to amortize the Cost of Energy Variance Accounts in fiscal 2022 to fiscal 2024.

Please refer to the graphs and tables below for the results of this scenario.

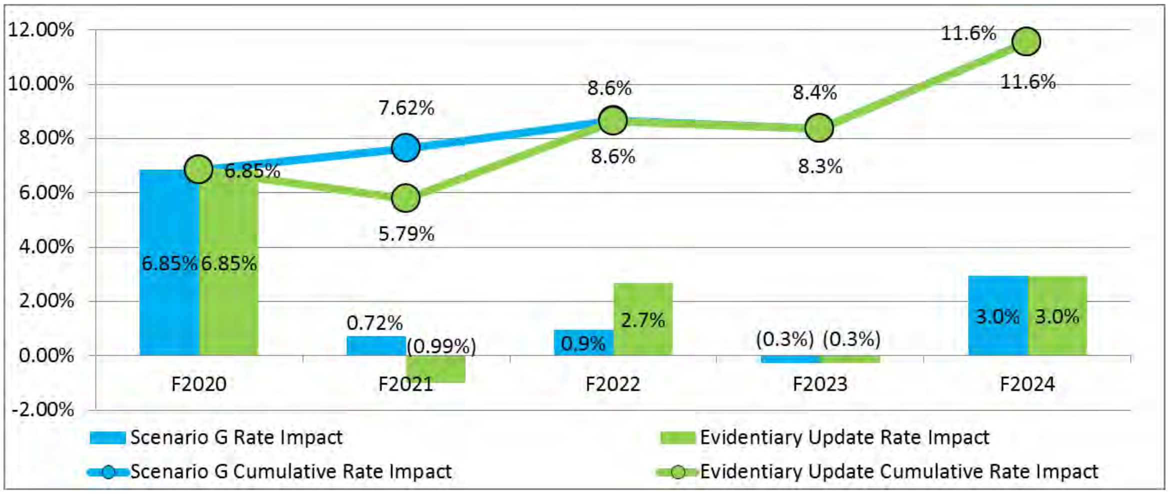
BC Hydro notes that this scenario is forecast to leave a credit balance in the Cost of Energy Variance Accounts at the end of fiscal 2021 that would need to be refunded in future periods, subject to the BCUC's approval.

BC Hydro considers its proposed approach to be preferable to Scenario G because BC Hydro's proposal better achieves Principle 1. More specifically, BC Hydro would recover more than its revenue requirement from ratepayers in the Test Period under Scenario G.

Scenario G: Five-Year Net Bill Impact Forecast



Scenario G: Five-Year Rate Forecast



Scenario G: Rate Impacts, Deferral Account Rate Rider, Bill Impacts

Per Cent Increase / (Decrease)	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**
Rate Impact	6.85	0.72	0.95	(0.27)	2.95
Cumulative Rate Impact	6.85	7.62	8.64	8.35	11.55
DARR %	0.00	0.00	(1.50)	(0.50)	0.00
Bill Impact	1.76	0.72	(0.57)	0.74	3.47
Cumulative Bill Impact	1.76	2.50	1.92	2.68	6.24

Scenario G: DARR Revenue and Revenue Shortfall

$ million	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**
DARR Revenue - Collected / (Refunded)	0	0	(80)	(27)	0
Revenue Shortfall	335	375	424	412	580

Scenario G: Cost of Energy Variance Accounts Balance

$ million	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**
Per Scenario	(219)	(91)	(29)	(9)	(10)
Per Evidentiary Update	(219)	(0)	(16)	(22)	(24)
Difference	0	(91)	(13)	14	14

Scenario H: BC Hydro's response to INCE IR 3.2

This question contemplates a scenario where fiscal 2020 interim rate increases are approved as proposed, and resulting bill increases are smoothed over the period from fiscal 2021 to fiscal 2024.

For the purpose of the requested scenario, BC Hydro assumes that the Cost of Energy Variance Accounts amortization is the mechanism which would be adjusted to produce the smoothed bill impacts over the fiscal 2021 to fiscal 2024 period. BC Hydro does not believe it is advisable to use rate smoothing beyond the Test Period for reasons further explained below.

Under this scenario, rate and bill increases are smoothed at 0.64 per cent per year over the fiscal 2021 to fiscal 2024 period.

BC Hydro notes that the forecast period from fiscal 2022 to fiscal 2024 included in the Evidentiary Update is intended to show an estimate of future rates. Any revenue requirements or rate increases requested in this period, which is beyond the Test Period, should be determined based on a detailed assessment of BC Hydro's forecast revenues and costs at the time of its future revenue requirements filings, taking into account the conditions at that time.

Accordingly, BC Hydro considers that it is not advisable to smooth rates beyond the Test Period, or to use assumed future test period costs and revenues to determine a smoothed bill increase that impacts the Test Period.

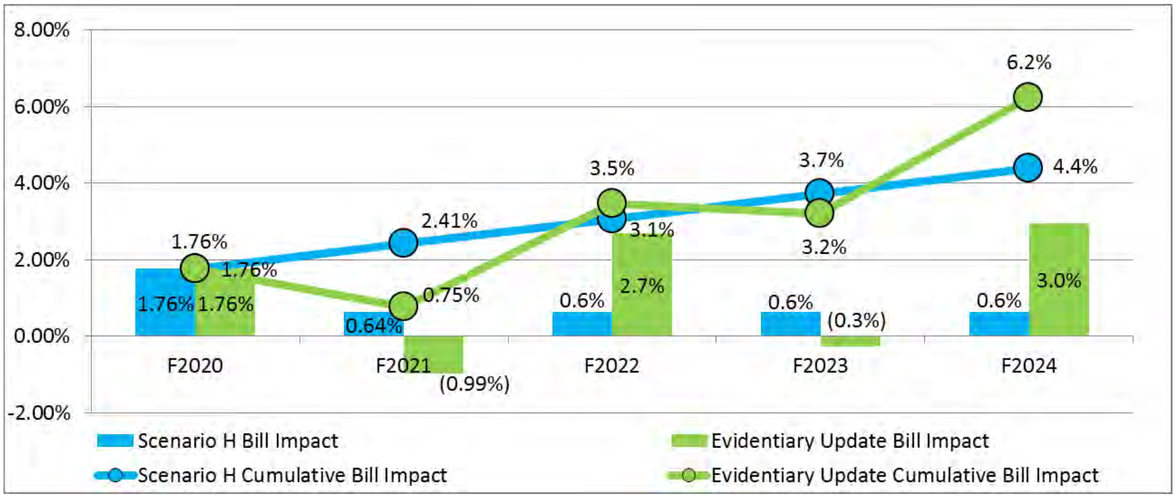
BC Hydro further notes that if bill impacts were smoothed beyond the Test Period, the fiscal 2022 to fiscal 2024 period could not be smoothed at the same bill impacts as in the Test Period unless a balance is allowed in a rate smoothing regulatory account at the end of fiscal 2024.

Therefore, BC Hydro considers its proposed approach to be preferable to Scenario H because BC Hydro's proposal better achieves Principle 4 in that it does not require rate smoothing that spans beyond the Test Period.

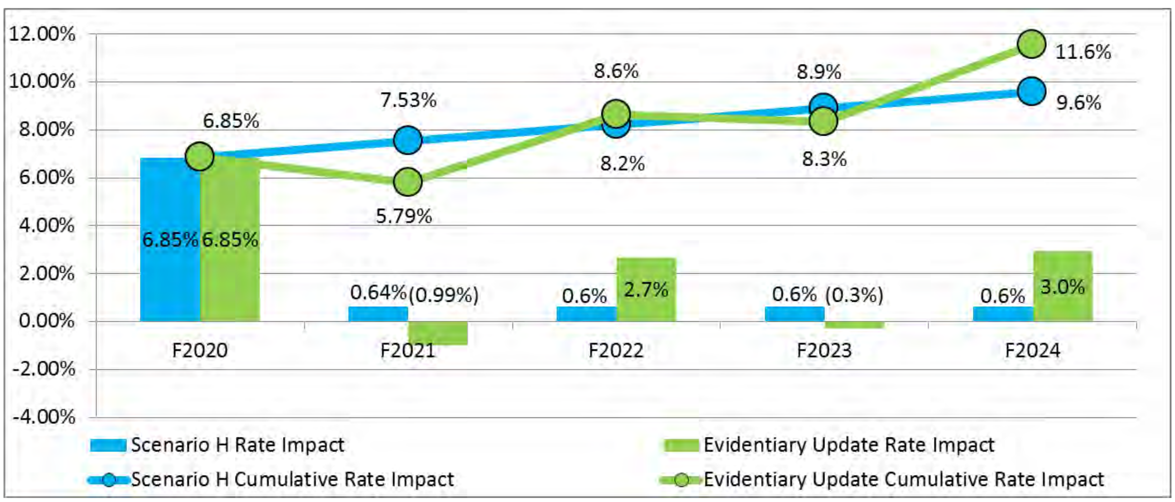
BC Hydro also notes that Scenario H will result in BC Hydro collecting more than its revenue requirements from ratepayers in the Test Period and thus BC Hydro's proposed approach also better achieves Principle 1.

Please refer to the graphs and tables below for the results of this scenario.

Scenario H: Five-Year Net Bill Impact Forecast



Scenario H: Five-Year Rate Forecast



Scenario H: Rate Impacts, Deferral Account Rate Rider, Bill Impacts

Per Cent Increase / (Decrease)	F2020	F2021	F2022	F2023	F2024
Rate Impact	6.85	0.64	0.64	0.64	0.64
Cumulative Rate Impact	6.85	7.53	8.21	8.90	9.59
Deferral Account Rate Rider	0.00	0.00	0.00	0.00	0.00
Bill Impact	1.76	0.64	0.64	0.64	0.64
Cumulative Bill Impact	1.76	2.41	3.06	3.71	4.37

Scenario H: DARR Revenue and Revenue Shortfall

$ million	F2020	F2021	F2022	F2023	F2024
DARR Revenue - Collected / (Refunded)	0	0	0	0	0
Revenue Shortfall	335	370	403	439	482

Scenario H: Cost of Energy Variance Accounts Balance

$ million	F2020	F2021	F2022	F2023	F2024
Per Scenario	(219)	(86)	(84)	(120)	(24)
Per Evidentiary Update	(219)	(0)	(16)	(22)	(24)
Difference	0	(86)	(68)	(97)	(0)

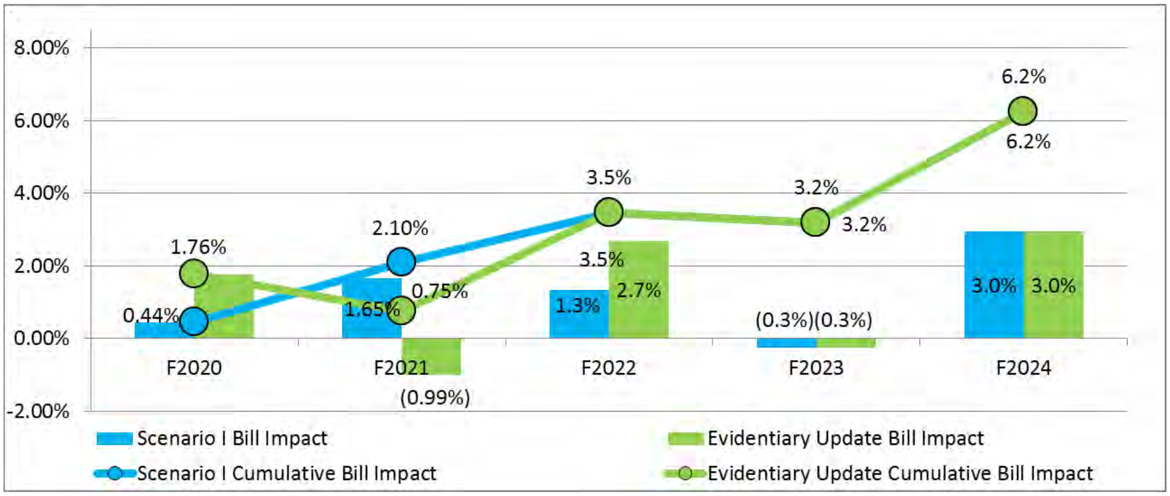
Scenario I: BC Hydro's response to ZONE II RPG IR 3.60.2.ii

This question contemplates a scenario where 75 per cent of the fiscal 2019 actual ending balance and forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the Cost of Energy Variance Accounts are refunded in fiscal 2020, and the remaining 25 per cent are refunded in fiscal 2021.

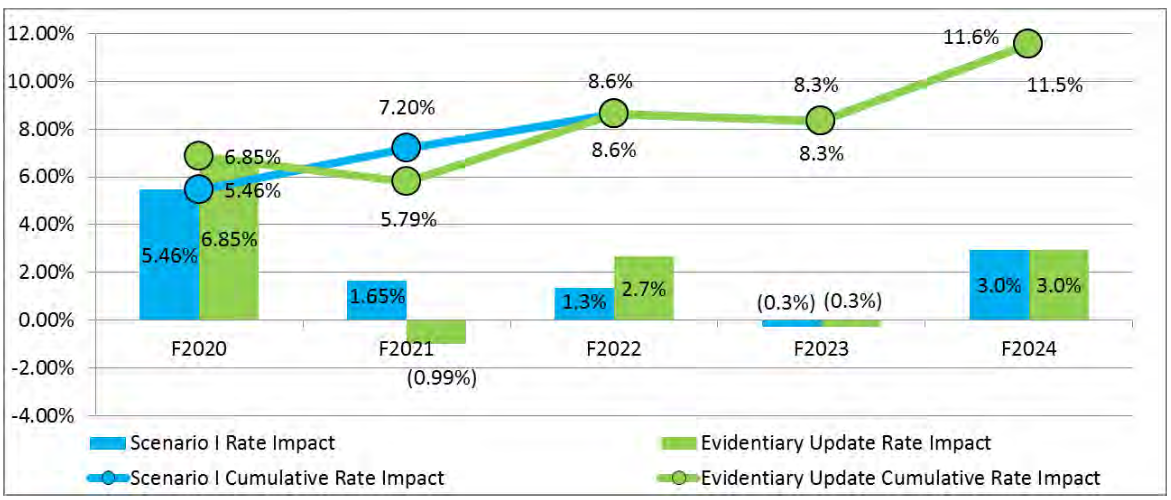
Please refer to the graphs and tables below for the results of this scenario.

BC Hydro considers its proposed approach to be preferable to Scenario I, as Scenario I involves an arbitrary allocation of DARR refund in the Test Period. Scenario I will also require a one-time true-up adjustment to customer bills. BC Hydro believes that this will cause confusion even if there will be no hardship to ratepayers as the fiscal 2020 rates would decrease. BC Hydro therefore considers its proposal to be clearer for ratepayers, less administratively burdensome for BC Hydro, while also achieving what BC Hydro considers to be stable and predictable rates.

Scenario I: Five-Year Net Bill Impact Forecast



Scenario I: Five-Year Rate Forecast



Scenario I: Rate Impacts, Deferral Account Rate Rider, Bill Impacts

Per Cent Increase / (Decrease)	F2020	F2021	F2022	F2023	F2024
Rate Impact	5.46	1.65	1.33	(0.26)	2.95
Cumulative Rate Impact	5.46	7.20	8.64	8.35	11.55
Deferral Account Rate Rider	0.00	0.00	0.00	0.00	0.00
Bill Impact	0.44	1.65	1.33	(0.26)	2.95
Cumulative Bill Impact	0.44	2.10	3.46	3.19	6.24

Scenario I: DARR Revenue and Revenue Shortfall

$ million	F2020	F2021	F2022	F2023	F2024
DARR Revenue - Collected / (Refunded)	0	0	0	0	0
Revenue Shortfall	267	354	424	412	580

Scenario I: Cost of Energy Variance Accounts Balance

$ million	F2020	F2021	F2022	F2023	F2024
Per Scenario	(151)	0	(16)	(22)	(24)
Per Evidentiary Update	(219)	(0)	(16)	(22)	(24)
Difference	69	0	(0)	(0)	(0)

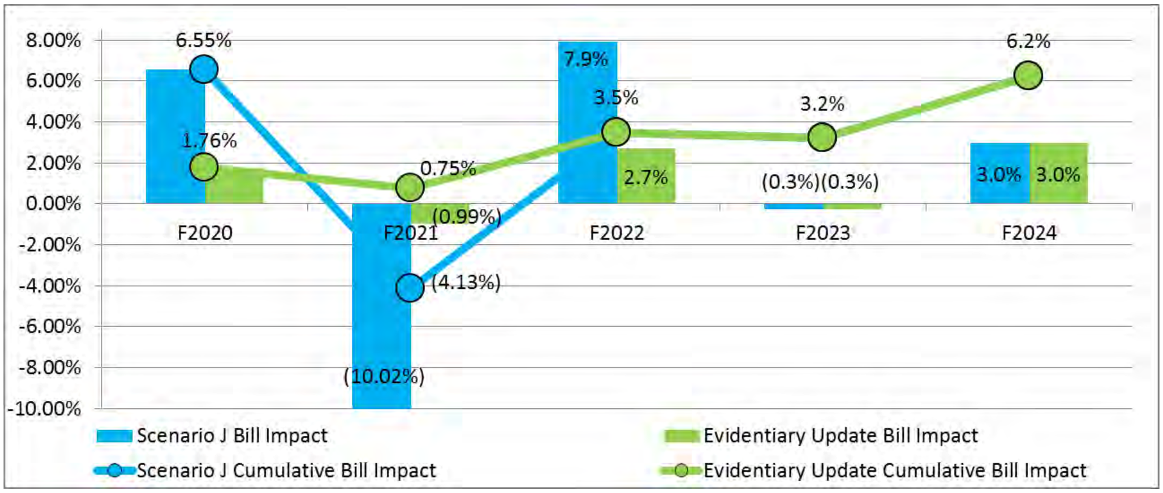
Scenario J: BC Hydro's response to ZONE II RPG IR 3.60.2.iii

This question contemplates a scenario where 25 per cent of the fiscal 2019 actual ending balance and forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the Cost of Energy Variance Accounts are refunded in fiscal 2020, and the remaining 75 per cent are refunded in fiscal 2021.

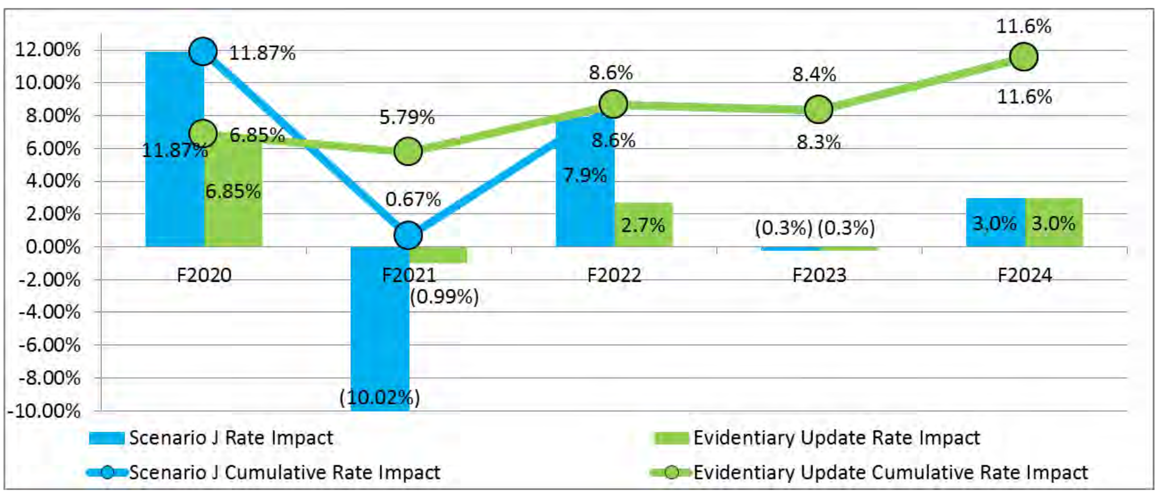
Please refer to the graphs and tables below for the results of this scenario.

BC Hydro considers its proposed approach to be preferable to Scenario J, as Scenario J involves an arbitrary allocation of DARR refund in the Test Period. BC Hydro's proposal also better achieves Principle 2 compared to Scenario J, in that it provides less rate volatility. Further, BC Hydro's proposal will not require a one-time true-up bill adjustment in respect of fiscal 2020. Scenario J would require such an adjustment for fiscal 2020. The adjustment would be significant (4.79 per cent, which is equal to 6.55 per cent minus 1.76 per cent) and would therefore create hardship for some ratepayers, as BC Hydro assumes the adjustment would appear for customers on one bill sometime in fiscal 2021. Therefore, Scenario J is also less desirable with respect to Principle 3.

Scenario J: Five-Year Net Bill Impact Forecast



Scenario J: Five-Year Rate Forecast



Scenario J: Rate Impacts, Deferral Account Rate Rider, Bill Impacts

Per Cent Increase / (Decrease)	F2020	F2021	F2022	F2023	F2024
Rate Impact	11.87	(10.02)	7.92	(0.26)	2.95
Cumulative Rate Impact	11.87	0.67	8.64	8.35	11.55
Deferral Account Rate Rider	0.00	0.00	0.00	0.00	0.00
Bill Impact	6.55	(10.02)	7.92	(0.26)	2.95
Cumulative Bill Impact	6.55	(4.13)	3.47	3.19	6.24

Scenario J: DARR Revenue and Revenue Shortfall

$ million	F2020	F2021	F2022	F2023	F2024
DARR Revenue - Collected / (Refunded)	0	0	0	0	0
Revenue Shortfall	581	33	424	412	580

Scenario J: Cost of Energy Variance Accounts Balance

$ million	F2020	F2021	F2022	F2023	F2024
Per Scenario	(468)	0	(16)	(22)	(24)
Per Evidentiary Update	(219)	(0)	(16)	(22)	(24)
Difference	(249)	0	0	0	0

<u>Other Scenarios Considered by BC Hydro</u>

In addition to Scenarios A and C presented above, BC Hydro also considered two additional scenarios when drafting its Evidentiary Update. These scenarios are described in BC Hydro's response to ZONE II RPG IR 3.57.2:

- **<u>Scenario K</u>, where the DARR mechanism from the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application, which uses the mid-year balances of the Cost of Energy Variance Accounts from the preceding fiscal year to set the DARR percentage, is modified to use the fiscal 2019 net ending balances of the Cost of Energy Variance Accounts to set the DARR percentage in fiscal 2020; and**

- **<u>Scenario L</u>, where the fiscal 2019 actual ending balance and forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the Cost of Energy Variance Accounts balances are refunded over fiscal 2020 and fiscal 2021 so that bill impacts are the same in both fiscal 2020 and fiscal 2021.**

Please refer to the graphs and tables below for the results of these scenarios.

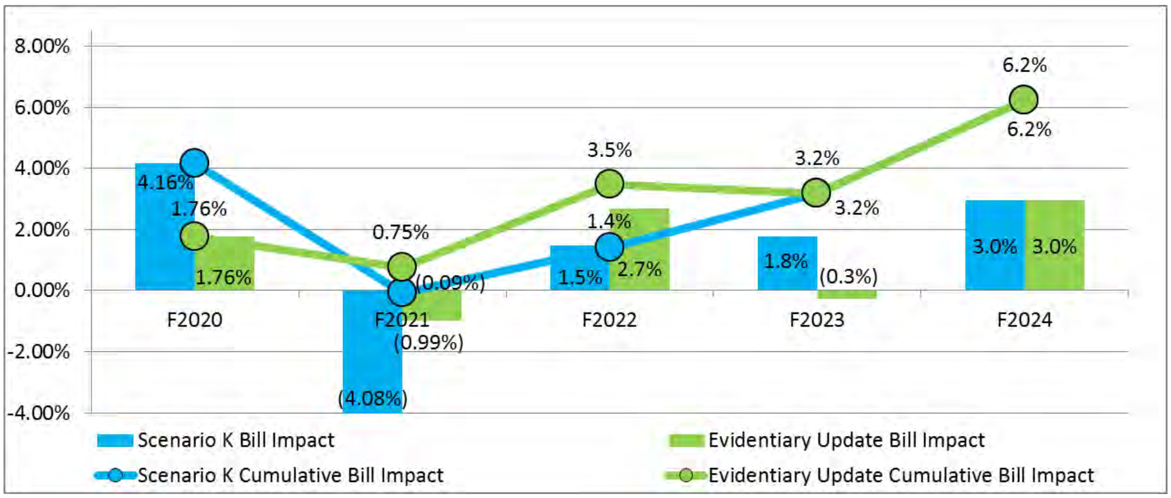
<u>Scenario K (as described in BC Hydro's Response to ZONE II RPG IR 3.57.2)</u>

Please refer to the graphs and tables below for the results of these scenarios.

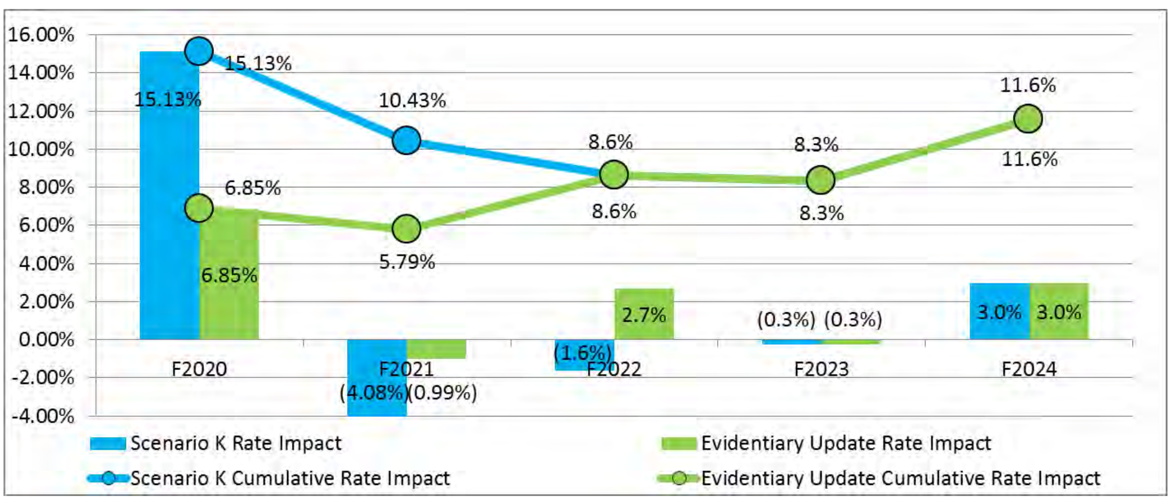
BC Hydro considers its proposed approach to be preferable to Scenario K because BC Hydro's proposal better achieves Principle 2 in that it provides less rate volatility. Further, BC Hydro's proposal will not require a one-time true-up bill adjustment in respect of fiscal 2020. Scenario K would require such an adjustment for fiscal 2020. The adjustment would more than double the net bill increase

(2.40 per cent, which is equal to 4.16 per cent minus 1.76 per cent) and would therefore create hardship for some ratepayers, as BC Hydro assumes the adjustment would appear for customers on one bill sometime in fiscal 2021. Therefore, Scenario K is also less desirable with respect to Principle 3.

Scenario K: Five-Year Net Bill Impact Forecast



Scenario K: Five-Year Rate Forecast



Scenario K: Rate Impacts, Deferral Account Rate Rider, Bill Impacts

Per Cent Increase / (Decrease)	F2020	F2021	F2022	F2023	F2024
Rate Impact	15.13	(4.08)	(1.62)	(0.27)	2.95
Cumulative Rate Impact	15.13	10.43	8.64	8.35	11.55
Deferral Account Rate Rider	(5.00)	(5.00)	(2.00)	0.00	0.00
Bill Impact	4.16	(4.08)	1.49	1.77	2.95
Cumulative Bill Impact	4.16	(0.09)	1.40	3.19	6.24

Scenario K: DARR Revenue and Revenue Shortfall

$ million	F2020	F2021	F2022	F2023	F2024
DARR Revenue - Collected / (Refunded)	(281)	(271)	(107)	0	0
Revenue Shortfall	740	513	424	412	580

Scenario K: Cost of Energy Variance Accounts Balance

$ million	F2020	F2021	F2022	F2023	F2024
Per Scenario	(344)	(84)	6	(0)	(1)
Per Evidentiary Update	(219)	(0)	(16)	(22)	(24)
Difference	(125)	(84)	21	22	23

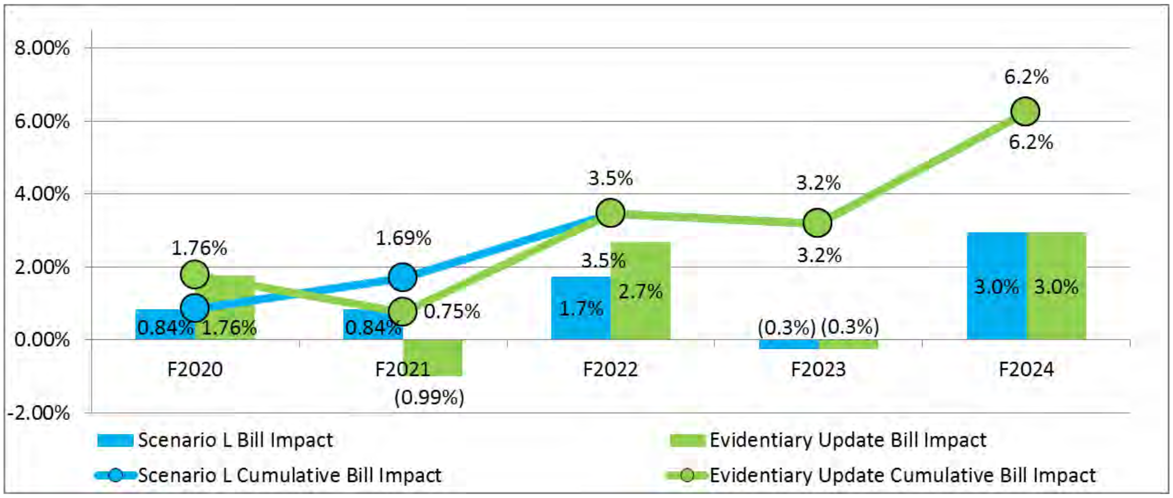
Scenario L (as described in BC Hydro's Response to ZONE II RPG IR 3.57.2)

Please refer to the graphs and tables below for the results of these scenarios.

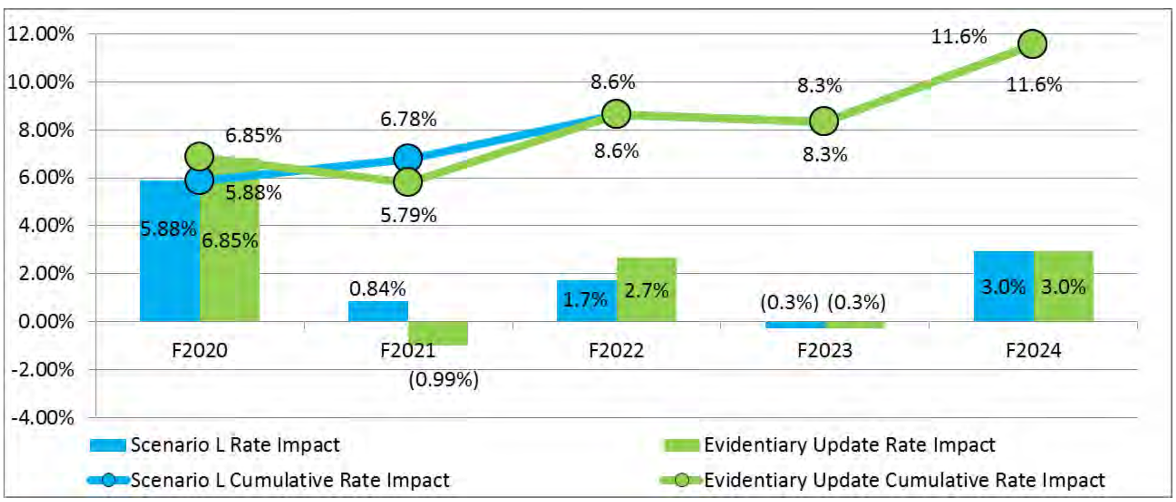
BC Hydro considered but did not propose this scenario. BC Hydro notes that this approach is fairly comparable to BC Hydro's proposal in terms of the principles outlined in page 2 of this response. However, BC Hydro considers the bill impacts from its proposal in the Evidentiary Update already sufficiently stable (i.e., the Evidentiary Update's cumulative bill impacts are 1.76 per cent and 0.75 per cent in fiscal 2020 and fiscal 2021 respectively, compared to Scenario L's 0.84 per cent and 1.69 per cent in fiscal 2020 and fiscal 2021, respectively).

Furthermore, BC Hydro views its proposal in the Evidentiary Update to be preferable with respect to Principle 3 compared to those in Scenario L, because BC Hydro's proposal does not require a one-time true-up bill adjustment in respect to fiscal 2020 customer bills.

Scenario L: Five-Year Net Bill Impact Forecast



Scenario L: Five-Year Rate Forecast



Scenario L: Rate Impacts, Deferral Account Rate Rider, Bill Impacts

Per Cent Increase / (Decrease)	F2020	F2021	F2022	F2023	F2024
Rate Impact	5.88	0.84	1.74	(0.26)	2.95
Cumulative Rate Impact	5.88	6.78	8.64	8.35	11.55
Deferral Account Rate Rider	0.00	0.00	0.00	0.00	0.00
Bill Impact	0.84	0.84	1.74	(0.26)	2.95
Cumulative Bill Impact	0.84	1.69	3.46	3.19	6.24

Scenario L: DARR Revenue and Revenue Shortfall

$ million	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**
DARR Revenue - Collected / (Refunded)	0	0	0	0	0
Revenue Shortfall	288	333	424	412	580

Scenario L: Cost of Energy Variance Accounts Balance

$ million	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**
Per Scenario	(172)	0	(16)	(22)	(24)
Per Evidentiary Update	(219)	(0)	(16)	(22)	(24)
Difference	48	0	(0)	(0)	(0)

296.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

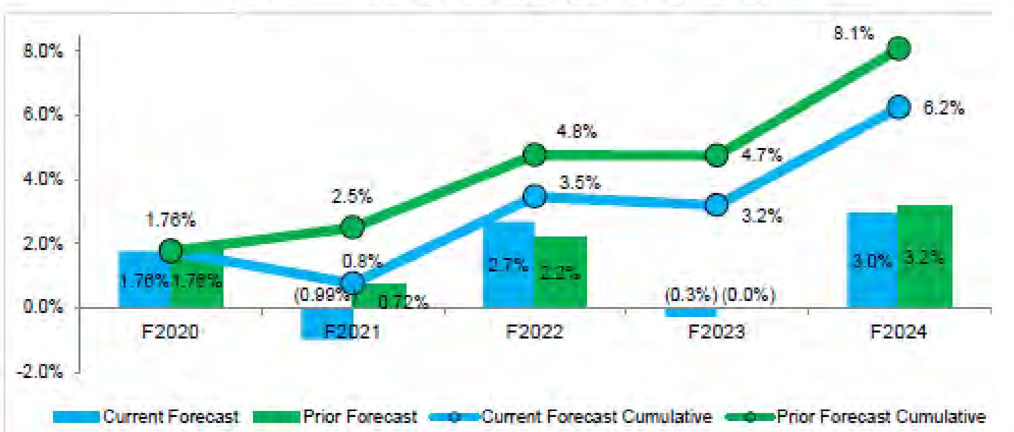
Reference: REGULATORY ACCOUNTS
Exhibit B-5, BCUC IR 148.1, 148.3, 148.4; Exhibit B-11, Figure 1, p. 1
Deferral Account Rate Rider (DARR)

In response to BCUC IR 148.3, 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



3.296.4 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.

RESPONSE:

Please refer to Scenarios B(i) and B(ii) of BC Hydro's response to BCUC IR 3.296.3 for the information requested in the question.

296.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

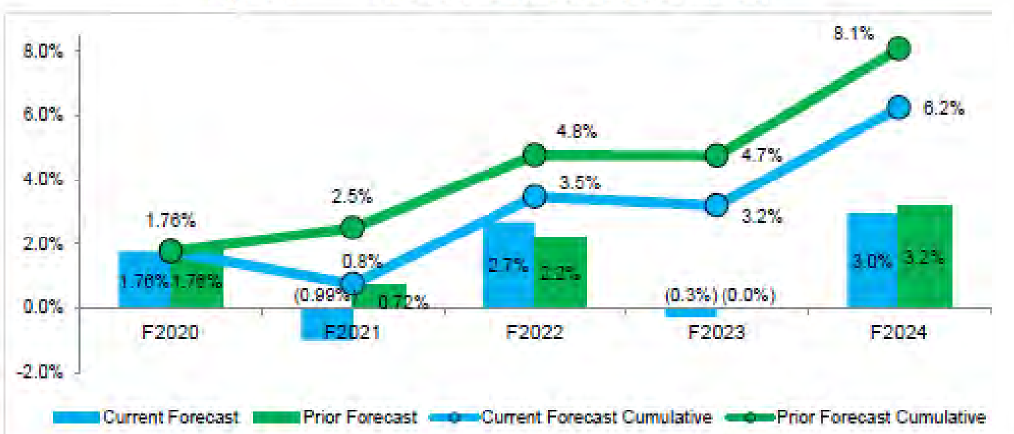
Reference: REGULATORY ACCOUNTS
Exhibit B-5, BCUC IR 148.1, 148.3, 148.4; Exhibit B-11, Figure 1, p. 1
Deferral Account Rate Rider (DARR)

In response to BCUC IR 148.3, 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



3.296.5 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.

RESPONSE:

Please refer to Scenarios A and B of BC Hydro's response to BCUC IR 3.296.3 for the information requested in the question.

296.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

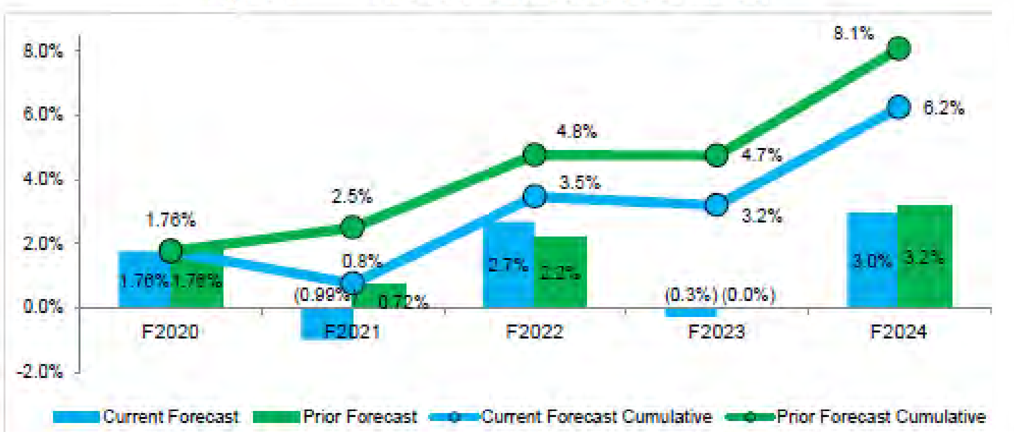
Reference: REGULATORY ACCOUNTS
Exhibit B-5, BCUC IR 148.1, 148.3, 148.4; Exhibit B-11, Figure 1, p. 1
Deferral Account Rate Rider (DARR)

In response to BCUC IR 148.3, 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



3.296.6 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.

RESPONSE:

The pros and cons of BC Hydro seeking a rate decrease in fiscal 2021 include:

Pros:

- **A 0.99 per cent rate decrease is based on the calculation of, and will result in the full recovery of, BC Hydro's revenue requirements in the Test Period.**
- **This approach fully amortizes the credit balance in the Cost of Energy Variance Accounts over the Test Period, which allows ratepayers to realize the benefit of this net credit balance more immediately than if the credit were to be refunded to ratepayers through a different amortization of the Cost of Energy Variance Accounts.**

Cons:

- **A rate decrease in fiscal 2021 will likely lead to a higher rate increase in fiscal 2022. While this results in some rate volatility, please refer to BC Hydro's response to BCUC IR 3.296.3 for a discussion of various other rate scenarios, most of which result in more volatility compared to BC Hydro's proposal.**

There are ways to avoid a rate decrease in fiscal 2021, which could include a scenario in which there is a zero per cent rate increase in fiscal 2021 and correspondingly smaller rate increases in fiscal 2022, fiscal 2023 and fiscal 2024 than those shown in the Evidentiary Update. BC Hydro considers that this would likely require the use of a rate smoothing regulatory account to capture the difference between the approved revenue requirement for fiscal 2021 and the amount to be recovered in that year. Alternatively, the credit balance in the Cost of Energy Variance Accounts could be refunded over a longer period of time.

BC Hydro has not proposed either of these alternative approaches in this case because the rates for fiscal 2022, fiscal 2023 and fiscal 2024 are not currently before the BCUC. Further, the forecast rate changes in fiscal 2022, fiscal 2023 and fiscal 2024 are likely to fluctuate before BC Hydro files its next revenue requirements application.

Accordingly, BC Hydro does not believe it would be advisable to establish a rate smoothing regulatory account that spans outside the Test Period in an attempt to smooth forecast rate changes in fiscal 2022, fiscal 2023 and fiscal 2024.

297.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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…

3.297.1 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.

RESPONSE:

The table included in BC Hydro's response to BCUC IR 1.149.1, updated for the fiscal 2019 actual results, is provided below. The aggregate variance for the period from fiscal 2012 to fiscal 2019, excluding the fiscal 2018 variance, is (2.3) million as shown in the last column in the schedule.

($ million)	**F2012**	**F2013**	**F2014**	**F2015**	**F2016**	**F2017**	**F2018**	**F2019**	**Total**
Actual	20.2	16.4	32.2	22.4	24.2	42.4	67.5	42.0	267.3
RRA Plan	34.3	20.9	21.0	24.6	31.2	39.5	35.7	30.6	237.8
Variance from Plan	(14.1)	(4.5)	11.2	(2.2)	(7.0)	2.9	31.8	11.3	29.5
% Variance from Plan	(41.1)	(21.5)	53.3	(8.9)	(22.4)	7.3	89.1	37.0	
Exclude F2018							(31.8)		
Variance excluding F2018	(14.1)	(4.5)	11.2	(2.2)	(7.0)	2.9	-	11.3	(2.3)
Variance from Prior Year	1.1	(3.8)	15.8	(9.8)	1.8	18.2	25.1	(25.5)	
% Variance from Prior Year	5.9	(19.0)	96.5	(30.4)	8.0	75.2	59.2	(37.8)	

297.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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…

3.297.1 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.

3.297.1.1 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.

RESPONSE:

BC Hydro believes that it is the magnitude of the <u>annual</u> variances that is a relevant factor for assessing whether deferral is appropriate, not the magnitude of the aggregate variance over an extended period of time.

In the absence of a regulatory account, ratepayers would not pay aggregate costs over an extended period of time or have rates set based on aggregate results over time. Rather, rates must be set based on forecast costs in a particular test period.

Moreover, aggregated variances over a period of time are not indicative of future volatility in a particular test period. However, annual variances, positive or negative, would suggest that variances can continue to be expected in future years.

As shown in BC Hydro's response to BCUC IR 3.297.1, over the past seven years (excluding fiscal 2018), actual annual variances have ranged from $14 million

below plan to $11 million above plan, including 41 per cent below plan to 53 per cent above plan over the same period.

BC Hydro's response to BCUC IR 1.149.1 stated the following:

> **"BC Hydro considers the variances experienced with respect to dismantling costs in recent years (as shown in the table above) to be material, and that such variances are possible in the future."**

The inclusion of the fiscal 2019 actual results further illustrates the continuing variability in these expenditures.

BC Hydro considers the assessment of the deferral treatment of dismantling costs on the basis of the aggregate variance over the seven year period (excluding fiscal 2018) to be inappropriate for the following reasons:

- **The period of time is arbitrary and given the variations in the annual variances it is only a coincidence that the aggregate variance is low. There is no basis to support that the aggregate variance will offset evenly in future periods; and**
- **There is no basis to exclude the fiscal 2018 variance from the cumulative variance. When the fiscal 2018 variance is included, the cumulative variance is $29.5 million which is significant.**

297.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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…

3.297.2 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.

RESPONSE:

BC Hydro requested deferral treatment specific to the Salmon River decommissioning and dismantling in the Salmon River Diversion Ceasing of Operations Application filed with the BCUC on March 7, 2017. The BCUC rejected this approach in its decision, preferring to address all dismantling cost variances in a consistent manner in a revenue requirements application proceeding. BCUC Order No. G-96-17 regarding BC Hydro's Salmon River Diversion Ceasing of Operations Application stated the following on page 20:

> **"At this time, the Panel does not consider there to be anything special or unique about the costs to Cease Operation and Decommission the Diversion that would warrant alternate treatment from the general dismantling costs treatment that will be determined in the RRA. The Panel considers that treatment of the costs to Cease Operations and Decommission the Diversion should be consistent with the general treatment of BC Hydro's other dismantling costs".**

BC Hydro does not consider there to be any pros associated with discontinuing the Dismantling Cost Regulatory Account and instead having BC Hydro apply for variance treatment on a case-by-case basis. The cons of such an approach are provided below.

- **Approval on a case by case basis would lead to regulatory inefficiency due to the high volume of requests that would require review and would result in higher costs for both BC Hydro and BCUC. For example, although the fiscal 2018 variance was mainly due to the Salmon River Diversion, it only accounted for 57 per cent of the fiscal 2018 variance. The Salmon River Diversion dismantling cost was $18.1 million and the fiscal 2018 variance was $31.8 million. In fiscal 2018, BC Hydro had in excess of 300 projects with dismantling costs. The majority of these related to dismantling costs of less than $0.1 million each. The table below shows the details for projects with dismantling costs in excess of $0.1 million for fiscal 2018.**

Category	Number of Projects	Total Dismantling Cost ($ million)
Greater than $1 million	10	46.4
Between $0.5 million and $1 million	10	6.6
Between $0.1 million and $0.5 million	53	10.6

As shown in the table above, there would be a large number of regulatory filings required to approve dismantling deferrals on a case by case basis.

- **The time required to receive approval and uncertainty regarding receiving approval under a case-by-case approach would lead to project scheduling and timing delays to dismantling work that would also impact capital projects as many capital projects involve dismantling of existing assets. In short, such a process would increase costs and schedules for these projects.**

- **If dismantling costs are approved for deferral on a project-by-project basis, the portion of forecast dismantling costs to include in rates for a test period could not be accurately determined unless all dismantling project deferral applications and decisions were completed in advance of the test period.**

298.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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.

3.298.1 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.

RESPONSE:

Confirmed.

298.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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 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.

3.298.2 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.

RESPONSE:

Confirmed. BC Hydro's accounting treatment of DSM expenditures in the current test period is consistent with the approach of not capitalizing or deferring DSM expenditures that are considered in the concept development phase and the approach of writing off cancelled programs in the year in which the program is cancelled. Further explanation is provided below.

Concept Development:

Concept development phase costs are defined as early program research activities. This includes activities such as searching for new research findings, and the conceptual formulation of possible program alternatives. The level of activity categorized as concept phase development has gradually dropped over time.

DSM program concepts have been extensively investigated and developed within the industry over the past decade, and BC Hydro takes advantage of those learnings. As a result, concept development expenditures would only be measured in hours of effort, and are subsequently not tracked as a discrete component. The labour allocation assigned to operating expenditures is intended to include the concept development activities. These costs are expensed.

The concept development (or research) phase is also distinct from the program development phase. Program development activities include the design, testing and assessment of programs and their components through pilots and demonstration projects. These costs are deferred.

Cancelled Programs:

During the test period, there are no programs expected to be cancelled. If a program is cancelled during the test period and BC Hydro has not received or does not expect to receive future benefits, the associated expenditures would be written off.

298.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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

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> 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.

3.298.2 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.

3.298.2.1 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.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.298.2 where BC Hydro confirms that its accounting treatment of DSM expenditures in the Test Period is consistent with the approach of not capitalizing or deferring DSM expenditures that are considered in the concept development phase and the approach of writing off cancelled programs in the year in which the program is cancelled.

298.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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 150.2, 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.'

3.298.3 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.

RESPONSE:

The methodology used for calculating the energy-weighted and cost-weighted average measures lives of BC Hydro's low-carbon electrification expenditures is the same as the methodology used for BC Hydro's demand-side measures expenditures.

298.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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

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.

3.298.4 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.

RESPONSE:

In order to match costs with benefits, it is appropriate to amortize DSM expenditures over the period during which the benefits of those DSM expenditures will be realized by customers (i.e., average measure life of DSM measures). Amortizing the balance in the DSM Regulatory Account over 10 years would result in over-collecting on costs during the 10-year period relative to the period of time the benefits will be realized by customers, since the weighted average measure life of DSM measures at the end of fiscal 2021 is close to 15 years. As discussed in section 10.5.6 of Chapter 10 of the Application, the measure life assumptions used by BC Hydro are considered to be conservative estimates. The current amortization period of 15 years supports intergenerational equity between current ratepayers and future ratepayers and maintains rate stability.

Please refer to BC Hydro's response to BCUC IR 1.150.6.1 for further information on the benefits of the current 15-year amortization period compared to a 10-year amortization period.

298.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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

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.

3.298.5 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.

RESPONSE:

Confirmed. The 11-year average persistence of energy savings from DSM program activity in fiscal 2009 to fiscal 2011, based on the DSM Plan in the 2008 Long Term Acquisition Plan (LTAP), is an energy-weighted average. The same methodology was used to calculate both the 11-year average from the 2008 LTAP and the energy-weighted averages shown in Table 10-14 of Chapter 10 of the Application.

298.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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

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> 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.

3.298.5 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.

3.298.5.1 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.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.298.5 where we confirm that the methodology used to calculate the weighted average measure life of DSM expenditures during the Test Period is the same as the methodology that was used in the 2008 Long Term Acquisition Plan.

298.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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
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> 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.

3.298.5 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.

3.298.5.2 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.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.298.5 where we confirm that the methodology used to calculate the weighted average measure life of DSM expenditures during the Test Period is the same as the methodology that was used in the 2008 Long Term Acquisition Plan.

298.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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

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.

3.298.6 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.

RESPONSE:

The incremental rate impact in the Test Period from reducing the 15-year amortization period for the DSM Regulatory Account to a 10-year amortization period would depend on whether the change in amortization period was applied on a prospective basis or not.

Descriptions of two scenarios are shown below, as well as tables showing the estimated incremental rate impact forecast balance of the DSM Regulatory Account at the end of fiscal 2020 to fiscal 2024.

For the purpose of this rate impact analysis (specifically, to be able to show estimated rate impacts for the Test Period), BC Hydro did not assume that the fiscal 2020 rate increase is kept the same as in the Application (1.76 per cent).

Scenario 1 - Assumptions

- **Amounts in the DSM Regulatory Account relating to expenditures up to and including fiscal 2018 continue to be amortized over the remaining years of their original 15-year amortization period**
- **Amounts in the DSM Regulatory Account relating to fiscal 2019 and future expenditures are amortized over 10 years**

Estimated Incremental Revenue Requirement and Rate Impact

10-Year Amortization Period	F2020	F2021
Revenue Requirement impact ($ million)	$3.7	$7.1
Rate impact (annual)	0.1%	0.1%
Rate impact (cumulative)	0.1%	0.1%

The cumulative rate impact figures in the table above are the same due to rounding.

10-Year Amortization Period	F2020	F2021	F2022	F2023	F2024
DSM Regulatory Account Forecast closing balance ($ million)	$916.6	$900.6	$874.4	$833.6	$788.7

15-Year Amortization Period (current)	F2020	F2021	F2022	F2023	F2024
DSM Regulatory Account Forecast closing balance ($ million)	$920.3	$911.7	$896.2	$869.1	$840.8

Scenario 2 - Assumptions:

- **Amounts in DSM Regulatory Account relating to expenditures with less than 10 years remaining (under their original 15-year amortization period) are amortized over their remaining life**
- **Amounts in DSM Regulatory Account relating to expenditures with more than 10 years remaining (under their original 15-year amortization period) are amortized over 10 years**
- **Amounts in DSM Regulatory Account relating to fiscal 2019 and future expenditures are amortized over 10 years**

Estimated Incremental Revenue Requirement and Rate Impact

10-Year Amortization Period	F2020	F2021
Revenue Requirement impact ($ million)	$10.5	$13.7
Rate impact (annual)	0.2%	0.1%
Rate impact (cumulative)	0.2%	0.3%

10 Year Amortization Period	F2020	F2021	F2022	F2023	F2024
DSM Regulatory Account Forecast closing balance ($ million)	$909.7	$886.8	$853.7	$805.9	$754.1

15-Year Amortization Period (current)	F2020	F2021	F2022	F2023	F2024
DSM Regulatory Account Forecast closing balance ($ million)	$920.3	$911.7	$896.2	$869.1	$840.8

298.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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

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.

3.298.7 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.

RESPONSE:

There is no 'rule-of-thumb' to estimate the magnitude of the rate impact for every one-year change to the amortization period for the DSM Regulatory Account.

Please refer to BC Hydro's response to BCUC IR 3.298.6 for a discussion of various scenarios of the amortization period adjustment.

Although it is obvious that the rate impact will be larger if the amortization period is shortened by five years (from 15 years to 10 years) compared with shortening the amortization period by, say, one year (from 15 years to 14 years), there is no linear relationship between the reduction in the amortization period and the rate impact (i.e., the rate impact is not five times larger).

The same holds true for rate impacts related to the shortening of the amortization period on a prospective basis. In other words, there is also no simple linear relationship between the magnitude of the reduction in the amortization period and the magnitude of the revenue requirement (and rate) impact, as demonstrated in the example below.

The tables below show estimated DSM amortization amounts (in $ million) for the period from fiscal 2020 to fiscal 2024 for the two scenarios provided in BC Hydro's response to BCUC IR 3.298.6.

Scenario 1

DSM Amortization ($million)

Amortization Period	F2020	F2021	F2022	F2023	F2024
10 Years	107.0	114.8	120.2	127.0	131.8
11 Years	106.0	112.8	117.3	123.3	127.3
12 Years	105.2	111.1	114.8	120.1	123.5
13 Years	104.5	109.7	112.8	117.5	120.3
14 Years	103.8	108.5	111.0	115.2	117.6
15 Years	103.3	107.4	109.5	113.2	115.2

Scenario 2

DSM Amortization ($million)

Amortization Period	F2020	F2021	F2022	F2023	F2024
10 Years	113.9	121.7	127.1	133.9	138.7
11 Years	109.6	116.3	120.8	126.8	130.8
12 Years	106.6	112.5	116.3	121.6	125.0
13 Years	104.9	110.1	113.2	117.9	120.7
14 Years	103.8	108.5	111.0	115.2	117.6
15 Years	103.3	107.4	109.5	113.2	115.2

BC Hydro notes that the incremental rate impact of a prospective change in the amortization period also increases over time. If the amortization period of the DSM Regulatory Account were shortened on a prospective basis, the incremental rate impact in fiscal 2020 would be limited only to the incremental amortization related to fiscal 2019 DSM expenditures. However, the incremental rate impact in fiscal 2021 would include the incremental amortization related to fiscal 2019 DSM expenditures plus the incremental amortization related to fiscal 2020 DSM expenditure. This growth will continue in each subsequent year.

Eventually, there will be an incremental decrease in revenue requirements and rates once the expenditure is fully amortized under the shorter amortization period compared to the original 15-year period.

298.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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

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.”

3.298.8 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.

RESPONSE:

Section 3 of Direction No. 8 prescribes BC Hydro’s fair and reasonable return, including the requirements under section 60(1)(b)(ii) of the *Utilities Commission Act,* to be a return on equity of $712 million in each of fiscal 2020 and fiscal 2021. In other words, the fair and reasonable return requirements are applicable and are satisfied if BC Hydro’s allowed return on equity is $712 million in each of fiscal 2020 and fiscal 2021.

299.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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.

3.299.1 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.

RESPONSE:

This answer also responds to AMPC IR 3.16.1 and CEC IR 3.102.1.

BC Hydro remains committed to achieving the $100 million net gain target and recognizes that initial sales completions have been slower than expected. However, we are making progress and expect to deliver on the $100 million net gains target by the end of fiscal 2024.

The lower than planned gains from real property sales from fiscal 2015 to fiscal 2019 are due to the following contributing factors which have delayed sale completions:

- **Progress of consultations with First Nations on property dispositions;**
- **Required subdivision, re-zoning and environmental remediation prior to sale;**
- **Fluctuating market interest in the properties; and**
- **The time for buyers' due diligence and processes to complete a purchase.**

Regardless of the timing of sale completions, ratepayers will receive the benefit of these net gains through the annual amount of $10 million included in BC Hydro's revenue requirements over the 10-year period (i.e., fiscal 2015 to fiscal 2024) and the use of Real Property Sales Regulatory Account.

299.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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

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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.

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

RESPONSE:

BC Hydro believes that the variances experienced from fiscal 2015 to fiscal 2019 will not be experienced during fiscal 2020 to fiscal 2024 for the following reasons:

- **Property sales have already been completed in fiscal 2020 with additional sales scheduled to complete in fiscal 2021; and**

- **Activities required to prepare properties for sale including consultation with First Nations, completion of subdivision, re-zoning, and environmental remediation prior to sale are expected to be completed to allow for the sale of further surplus properties before the end of fiscal 2024.**

As discussed in BC Hydro's response to BCUC IR 3.299.7, some combination of properties will be sold to achieve the target of $100 million in net gains by the end of fiscal 2024.

299.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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 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.

3.299.3 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.

RESPONSE:

This answer also responds to BCUC IRs 3.299.4, 3.299.5, 3.299.6, 3.299.8 and 3.299.8.1.

The following information regarding the Real Property Sales Regulatory Account is from section 7.8.7, page 7-41 and 7-42 of the Application:

> **"BC Hydro has increased our net gains target from $50 million to $100 million and extended the timeframe to**

> **achieve this target to the end of fiscal 2024. This means that the Real Property Sales Regulatory Account is expected to self-clear based on the forecast gains and losses experienced from fiscal 2020 to fiscal 2024 and is forecast to have a zero balance by the end of fiscal 2024, subject to potential interest charges.**
>
> **Consistent with this revised target, BC Hydro has included $10 million in forecast net gains from real property sales in both fiscal 2020 and fiscal 2021, in this application".**

Prior to this Application, BC Hydro had included $50 million ($10 million per year for five years) in its revenue requirements over the fiscal 2015 to fiscal 2019 period. BC Hydro has increased its net gains from real property sales target from $50 million to $100 million.

As shown in BC Hydro's response to BCUC IR 3.301.1, BC Hydro had recognized actual cumulative gains of $4.4 million prior to fiscal 2020. As BC Hydro's net gains target is $100 million, BC Hydro is forecasting gains of $95.6 million (i.e., targeted gains of $100 million less actual gains realized to-date of $4.4 million) from fiscal 2020 to fiscal 2024, which will self-clear the balance in the Real Property Sales Regulatory Account (subject to interest charges).

BC Hydro remains committed to achieving the $100 million net gains target and providing this benefit to ratepayers. BC Hydro recognizes that initial sales completions have been slower than expected; however, we are making progress and plan to deliver on the $100 million net gains target by the end of fiscal 2024. Specific details are provided in BC Hydro's confidential response to BCUC IR 3.299.7.

As stated in section 7.8.7 of Chapter 7 of the Application, the timing of completion of real estate transactions is difficult to forecast accurately. This is because the timing and amount of net sales proceeds can be impacted by potential issues that can be encountered with environmental remediation and certification, subdivision requirements, consultation with First Nations, negotiating purchase and sales agreements with potential buyers, and changes in market prices. For further information, please refer to BC Hydro's responses to BCUC IR 1.151.4 and BCUC IR 3.299.1.

Therefore, BC Hydro has forecast the net gains evenly over the remaining five years of the program from fiscal 2020 to fiscal 2024. Annual forecast net gains on real property sales of $19.1 million (i.e., $95.6 million divided by five) are included in the Evidentiary Update.

The annual forecast net gain of $19.1 million impacts the Evidentiary Update as shown in Table 1 below. The annual incremental forecast gain (reference B in

Table 1), not included in a previous revenue requirement, of $10 million (i.e., $50 million incremental gain divided evenly over five years) reduces the revenue requirement to the benefit of ratepayers. The excess annual forecast gain of $9.1 million (reference C in Table 1) reduces the balance in the Real Property Sales Regulatory Account.

BC Hydro did not consider alternative approaches for forecasting real property sales gains as there is no accurate way to forecast these gains by year due to the factors noted previously in this response.

BC Hydro's approach ensures that ratepayers receive the benefits from the net gains on sale of real property on a smoothed basis. BC Hydro does not consider the period between fiscal 2020 and fiscal 2024, over which time the account is expected to self-clear (subject to interest charges) to create material intergenerational equity issues.

In the absence of the account, the net gains would be to the account of the shareholder.

Table 1

($ Million)	Appendix A Reference	Ref	F2020	F2021	
Total forecast net real property gain		A	19.1	19.1	
Included in Test Period Revenue Requirement					
Real Property Sales	5.0 line 76	B	(10.0)	(10.0)	Base line
Forecast net gain in excess of $10 million base line		C=A-B	9.1	9.1	
Excess over baseline transferred to regulatory account					
Real Property Sales	5.0 line 107	C	(9.1)	(9.1)	Forecast regulatory transfer
Real Property Sales Regulatory Account					
Beginning of Year	2.2 line 138		49.2	41.7	
Adjustment to Opening Balance	2.2 line 139		-	-	
Additions	2.2 line 140	C	(9.1)	(9.1)	
Interest	2.2 line 141		1.7	1.4	
Recovery	2.2 line 142		-	-	
End of Year			41.7	34.0	

Notwithstanding that BC Hydro did not consider alternative methods of forecasting real property sales gains as discussed above, BC Hydro provides the pros and cons of the following two alternative methods of forecasting the gains:

- **Forecasting zero gains; and**
- **Forecasting based on expected sales.**

Forecasting zero gains

The pros of this approach are as follows:

- **More accurate reflection of BC Hydro's experience for the period from fiscal 2015 to fiscal 2019; and**
- **The regulatory account balance would not increase if BC Hydro does not realize the expected gains included in the Evidentiary Update which would result in lower carrying charges applied to the regulatory account.**

The cons associated with this approach are as follows:

- **Rates will be higher in the test period; and**
- **The benefits to ratepayers will be delayed until a test period after actual sales are recognized.**

Forecasting based on expected sales

Due to the high likelihood of forecasting inaccuracies (as a result of the factors described above impacting the timing of sales), BC Hydro does not consider there to be any pros associated with this approach.

The con of forecasting on this basis is as follows:

- **The annual impact on rates will vary and will not be as smooth and stable as the existing approach.**

299.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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 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.

3.299.4 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.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.299.3, where we explain that we do not consider the period between fiscal 2020 and fiscal 2024, over which time the account is expected to self-clear (subject to interest charges) to create material intergenerational equity issues.

299.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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 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.

3.299.5 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.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.299.3 where we explain that BC Hydro did not consider alternative approaches for forecasting real property sales gains as there is no accurate way to forecast these gains by fiscal year due to various factors noted in that response. In that response, we also discuss alternative methods and why the selected method is preferred.

299.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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

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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.

3.299.6 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.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.299.3, where we provide the pros and cons of forecasting zero net gains/losses from real property sales in the Test Period.

299.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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 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.

3.299.7 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.

RESPONSE:

Attachment 1 to this response provides details regarding the surplus properties that have sold since fiscal 2015 and the properties that are being prepared for sale, based on the information BC Hydro has as of September 26, 2019. This attachment is being filed confidentiality with the BCUC only as it contains commercially sensitive information. Public disclosure of the information would harm our negotiating position and ultimately harm our customers.

The attachment provides a current list of surplus properties (i.e., properties that BC Hydro does not require for operational purposes). Some combination of these properties will be sold to achieve the $100 million in net gains target by the end of fiscal 2024.

The majority of the value of BC Hydro's surplus properties is located in the Lower Mainland area. BC Hydro is working with the province to coordinate its engagements with Musqueam, Squamish and Tsleil-Waututh Nations regarding the potential disposition of surplus lands in the Lower Mainland area.

Several factors could impact the timing of property sales and the amount of net proceeds that will be achieved. For details on these factors, please refer to BC Hydro's response to BCUC IR 1.151.4.

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(Accessible by opening the Attachments Tab in Adobe)

299.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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 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.

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

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.299.3, where we explain that forecast net gains included in the Evidentiary Update are $19.1 million including the $10 million baseline included in the revenue requirement.

299.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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

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> 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.

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

3.299.8.1 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.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.299.3, where we provide the pros and cons of forecasting the net gains and losses from real property sales for the Test Period based on the properties that BC Hydro plans to sell in the Test Period.

300.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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).1

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."

3.300.1 Please elaborate on the difference between "the actual experience gains or losses related to BC Hydro's pension and other post

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[1] Emphasis added.

employment benefit plans" and "the variances between actual and forecast non-current pension costs."

RESPONSE:

Actual experience gains and losses are adjustments to the net pension plan liability and the other post-employment benefit plan liabilities due to changes in discount rates, rates of return on pension plan assets, and any experience gains or losses or changes in assumptions.

Variances between actual and forecast non-current pension costs are the differences in net interest expense of the retirement benefit plans.

300.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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);
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> 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).[1]

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."

3.300.2 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

[1] Emphasis added.

other post employment benefit plans" and "the variances between actual and forecast non-current pension costs."

RESPONSE:

Confirmed.

300.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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).1

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."

3.300.2 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

[1] Emphasis added.

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."

3.300.2.1 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.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.300.2.

300.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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).1

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."

3.300.3 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

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[1] Emphasis added.

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.

RESPONSE:

This response provides a discussion on the impact to the Test Period revenue requirements and rates if the following items were not deferred to the Non-Current Pension Costs Regulatory Account.

Experience Gains or Losses

In general, if experience gains or losses related to BC Hydro's pension and other post-employment benefit plans were not eligible for deferral to the Non-Current Pension Costs Regulatory Account, any such gains or losses would to the account of the shareholder and would mean that ratepayers would not pay the actual costs.

With respect to the Test Period, BC Hydro included an experience gain of $70.0 million related to the elimination of Medical Services Plan premiums in fiscal 2020 in the Evidentiary Update (Appendix A, Schedule 2.2, line 79, column 5). This experience gain will reduce revenue requirements and rates in the test period beginning in fiscal 2022 in accordance with BCUC Order No. G-47-18, which approved the amortization of transfers to the Non-Current Pension Costs Regulatory Account, at the start of the next test period. Therefore, there will be no impact to the current Test Period revenue requirements or rates if experience gains or losses were not given deferral treatment to the Non-Current Pension Costs Regulatory Account. However, in the subsequent test period beginning fiscal 2022, ratepayers would not receive the benefit of this experience gain.

There were no other experience gains or losses related to BC Hydro's pension and other post-employment benefit plans included in the Test Period in the Evidentiary Update.

Variances Between Actual And Forecast Non-Current Pension Costs

If the variances between actual and forecast non-current pension costs were not deferred to the Non-Current Pension Costs Regulatory Account, any such variances would be deferred to the Total Finance Charges Regulatory Account. That is because non-current pension costs are part of BC Hydro's finance charges and any variances between plan and actual finance charges are deferred to the

Total Finance Charges Regulatory Account. These variances would be recovered over the next test period per the recovery mechanism of the Total Finance Charges Regulatory Account, in accordance with BCUC Order No. G-47-18.

There were no variances between actual and forecast non-current pension costs included in the Test Period in the Evidentiary Update as actual results for the Test Period are not yet available.

300.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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).1

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."

3.300.4 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

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1 Emphasis added.

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.

RESPONSE:

The table below provides the requested amounts deferred to the Non-Current Pension Costs Regulatory Account. Please refer to BC Hydro's response to BCUC IR 3.300.1 for a discussion of what is included in non-current service pension costs variance, and experience gains and losses.

	(Gain)/Loss - $million						
	F2015	F2016	F2017	F2018	F2019	F2020[3]	F2021[3]
Non-Current Pension Costs Variance[1]	52	57	72	71	67	-	-
Experience (Gains)/Losses [2]	265	69	(203)	(194)	173	(70)	-
Total Deferred to Non-Current Pension Costs Regulatory Account	317	125	(131)	(123)	240	(70)	-

1. **As per the Evidentiary Update, Appendix A, Schedule 8.0, Line 17.**
2. **As per the Evidentiary Update, Appendix A, Schedule 9.0, Line 8.**
3. **Fiscal 2020 and fiscal 2021 actuals will be finalized at their respective year-ends.**

The variances deferred were due to the following:

- **The fiscal 2015 deferred amount was primarily due to experience losses on pension liabilities as a result of a decrease in the discount rate, partially offset by experience gains on the pension plan assets due to a higher rate of return;**
- **The fiscal 2016 deferred amount was primarily due to experience losses on the pension plan assets due to a lower rate of return and changes to BC Hydro's mortality assumption, partially offset by experience gains on pension liabilities due to an increase in the discount rate;**
- **The fiscal 2017 deferred amount was primarily due to experience gains on pension plan assets due to a higher rate of return and changes to actuarial assumptions recommended by BC Hydro's external actuary, partially offset by experience losses on pension liabilities due to a decrease in the discount rate;**
- **The fiscal 2018 deferred amount was primarily due to the reduction of Medical Services Plan premiums by the Government of B.C. and experience gains on pension plan assets due to a higher rate of return, partially offset by experience losses on pension liabilities due to a decrease in the discount rate;**

- **The fiscal 2019 deferred amount was primarily due to experience losses on pension liabilities due to a decrease in the discount rate and changes in actuarial assumptions recommended by BC Hydro's external actuary, partially offset by experience gains on pension plan assets due to a higher rate of return; and**

- **The fiscal 2020 deferred amount relates to the elimination of Medical Services Plan premiums recorded in May 2019 when the legislation was passed.**

300.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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

3.300.5 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.

RESPONSE:

As confirmed in BC Hydro's response to BCUC IR 3.300.2, the only items that can be deferred to the Non-Current Pension Costs Regulatory Account are as follows:

- **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.**

BC Hydro provides the analysis requested in the question in relation to the five criteria stated in section 7.5.1 of the Application:

1. **BC Hydro's ability to directly or indirectly influence the cost category;**
2. **The volatility of the cost category;**
3. **The predictability of the cost category;**
4. **The materiality of the cost category to the revenue requirement; and**
5. **The frequency of major exceptions within the cost category.**

Criteria two, three and five relate to volatility. The table below provides the actual experience gains/losses and the non-current pension cost variances deferred to the Non-Current Pension Cost Regulatory Account for the past five years.

($ Million)		**Appendix A Reference**		**F2015**	**F2016**	**F2017**	**F2018**	**F2019**
Non-Current Pension costs								
	Actual	8.0L17		55.0	56.9	66.0	62.0	55.9
	Plan	8.0L17		2.9	0.1	(6.1)	(8.5)	(10.9)
	Variance from plan		**A**	52.1	56.8	72.1	70.5	66.8
	Inter-year difference					0.5	(0.5)	
	Adjusted variance	2.2L82		52.1	56.8	72.6	70.0	66.8
Experience gains/losses	Actual	2.2L79	**B**	264.5	68.5	(203.2)	(193.6)	173.1
Net addition to Non-Current Pension Account			**A+B**	316.6	125.3	(130.6)	(123.6)	239.9
Variance from Prior Year								
Non-current pension Actuals					1.9	9.1	(4.0)	(6.1)
Experience gains/losses					(196.0)	(271.7)	9.6	366.7
% Variance from Prior Year								
Non-current pension					3.5	16.0	(6.1)	(9.8)
Experience gains/losses					(74.1)	(396.6)	(4.7)	(189.4)

As shown in the table above, these amounts vary significantly from year-to-year.

With respect to non-current pension cost variances, the table above shows significant annual variances between actual and plan amounts and significant variances between years. The large variances in Non-Current Pension Costs are due to the difference in the rate (i.e., rate of return versus liability discount rate) used to determine the return on plan assets between the Application and actual results as described on pages 5G-15 and 5G-16 of section 5G.9 of Chapter 5G of the Application:

> **"This section has been prepared under International Accounting Standard 19, Employee Benefits (IAS 19), with the exception of the return (investment income) on pension plan assets which is determined and based on the expected long-term rate of return rather than the liability discount rate as specified by IAS 19. The expected long-term rate of return reflects BC Hydro's expected earnings on pension plan assets. This forecast methodology is consistent with the methodology used in previous revenue requirement applications".**

With respect to experience gains/losses, the annual amounts are significant and vary significantly from year-to-year. Experience gains/losses vary due to factors such as changes in discount rates, rates of return on plan assets and changes in experience and actuarial assumption. Most of the changes in the factors impacting both of these items are beyond BC Hydro's control as they are largely market driven.

Criteria one relates to controllability and is applicable because experience gains/ losses and non-current pension cost variances are not controllable, for the reasons discussed above.

Criteria four relates to materiality. There is no clear way to define materiality for this purpose. In section 7.6 of the Application, BC Hydro notes that "expenditures of greater than $10 million in a fiscal year would be considered material".

However, this section relates to the establishment of new regulatory accounts. It also assumed the continuation of existing regulatory accounts – which capture the variances which entail the most risk, and the sum of which is very significant. If this were not the case, the $10 million figure proposed in respect of proposed new regulatory accounts would need to be revisited (and lowered).

Notwithstanding that BC Hydro considers that the materiality criterion does not apply to individual accounts or their components, the additions to the Non-Current Pension Costs Regulatory Account shown in the table above are material.

301.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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.

3.301.1 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

RESPONSE:

BC Hydro provides the analysis requested in the question in relation to the five criteria from section 7.5.1 of the Application:

1. **BC Hydro's ability to directly or indirectly influence the cost category;**
2. **The volatility of the cost category;**
3. **The predictability of the cost category;**
4. **The materiality of the cost category to the revenue requirement; and**
5. **The frequency of major exceptions within the cost category.**

Real Property Sales Regulatory Account

Criteria two, three and five all relate to variances. The table below provides the actual, plan and variance amounts related to real property sales net gains over the past five years. Real property net actual gains variances are shown as compared to the following amounts in the table:

- **Annual baseline net gains (see item B in the table) of $10 million included in the revenue requirements; and**

- **Total net gains included in the respective applications which consists of the annual baseline net gains plus planned transfers to the Real Property Sales Regulatory Account (see item D in the table).**

($ million)	Appendix A Reference	IR Reference	F2015	F2016	F2017	F2018	F2019
Actual		A	(2.1)	(0.5)	(0.2)	(1.6)	(0.0)
Plan - baseline	Sch. 5.0, Line 76	B	(10.0)	(10.0)	(10.0)	(10.0)	(10.0)
Plan - regulatory transfer	Sch. 5.0, Line 107	C			6.5	(10.0)	(14.0)
Total plan net gains included in Application		D=B+C	(10.0)	(10.0)	(3.5)	(20.0)	(24.0)
Variance from plan	Sch. 2.2, Line 140	A-B	7.9	9.5	9.8	8.4	10.0
Variance from net gain on sales		A-D	7.9	9.5	3.3	18.4	24.0
% Variance from plan			78.7	95.3	94.3	92.0	100.0

The table above shows significant variances between actual and plan amounts (in both dollar and percentage terms), and significant variances between years. Property sales are frequently volatile and unpredictable due to activities required to prepare properties for sale including consultation with First Nations and completion of subdivision, re-zoning, and environmental remediation which can lead to shifts in timing that cause an expected sale to move from one year to another. The impact of these shifts can significantly exceed $10 million due to the value of many of BC Hydro's surplus properties.

Remediation Regulatory Account

Criteria two, three and five all relate to variances. The table below provides actual, plan and variance amounts related to asbestos and polychlorinated biphenyl (PCB) expenditures over the past five years. These asbestos and PCB expenditures have been deferred to the Remediation Regulatory Account as additions for the past five and three years respectively.

($ million)	**Appendix A Reference**	**F2015**	**F2016**	**F2017**	**F2018**	**F2019**
Actual						
Asbestos	Sch. 2.2, Line 128	4.3	5.6	7.9	9.0	11.0
PCB	Sch. 2.2 Line 96	9.2	13.9			
PCB	Sch. 2.2 Line 129			14.2	14.3	18.6
Total Actual		13.5	19.5	22.1	23.3	29.6
Plan						
Asbestos	Sch. 2.2, Line 128	1.8	0.9	22.6	14.8	13.6
PCB	Sch. 2.2 Line 96	13.6	13.3			
PCB	Sch. 2.2 Line 129			18.3	18.9	15.3
Total Plan		15.5	14.2	40.9	33.6	28.9
Variance from Plan		(2.0)	5.3	(18.8)	(10.3)	0.7
% Variance from Plan		(13.0)	37.2	(46.0)	(30.6)	2.4

The table above shows significant variances between actual and plan amounts (in both dollar and percentage terms). Variances in asbestos and PCB expenditures between actual and planned amounts arise from the timing and scope of work undertaken.

Criteria one can be broadly considered to be related to variances as well, as variances are indicative of BC Hydro's ability to influence the costs related to the account.

Criteria four relates to materiality. There is no clear way to define materiality for this purpose. In section 7.6 of the Application, BC Hydro notes that:

> **"expenditures of greater than $10 million in a fiscal year would be considered material".**

However, this section relates to the establishment of new regulatory accounts. It also assumed the continuation of existing regulatory accounts – which capture the variances which entail the most risk, and the sum of which is very significant. If this were not the case, the $10 million figure proposed in respect of proposed new regulatory accounts would need to be revisited (and lowered).

Notwithstanding that BC Hydro does not consider the $10 million to be relevant in respect of existing regulatory accounts, the tables above show that variances have exceeded $10 million in a number of recent years.

301.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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.

3.301.2 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.

RESPONSE:

The tables below provide the variance and variance explanations for each fiscal year since fiscal 2015 between:

(i) The forecast and actual asbestos remediation costs (Table 1); and

(ii) The forecast actual polychlorinated biphenyl regulations compliance costs (Table 2).

Table 1: Asbestos remediation costs

$ million	a	b	b-a	
Fiscal Year	RRA Plan	Actual	Variance	Variance Explanation
2015	1.8	4.3	2.5	Higher spend mainly due to: - $2.4M - Unplanned Distribution underground asbestos work.
2016	0.9	5.6	4.6	Higher spend mainly due to: - $3.6M - Unplanned Distribution underground asbestos work; and - $0.9M - Costs were included in the properties capital forecast that were later determined to be asbestos remediation costs when the actuals were recorded.
2017	22.6	7.9	(14.6)	Lower spend mainly due to: - $(15.5)M - Slower than anticipated start of work than anticipated for the Transmission and Stations underground work, slower than anticipated start on the Stations Inventory Program which resulted in fewer remediation items in the reactive abatement program, and efficiencies gained through bundling of work for Distribution Underground. Partially offset by: - $1.2M - Higher spend primarily due to scope advancement for the Burrard Asbestos Management Program and Burrard's change to a synchronous condense only facility.
2018	14.8	9.0	(5.8)	Lower spend mainly due to: - $(5.3)M - Slower than anticipated start of Stations Underground work as scope shifted to future fiscal years, and lower than anticipated remediation items identified from the Stations Inventory Program.
2019	13.6	11.0	(2.6)	Lower spend mainly due to: - $(2.1)M - A number of capital projects and the associated remediation costs were delayed to future

Table 2: Polychlorinated biphenyl regulations compliance costs

$ million	a	b	b-a	
Fiscal Year	RRA Plan	Actual	Variance	Variance Explanation
2015	13.6	9.2	(4.5)	Lower spend mainly due to: - $(4.7)M - Program delays related to bushing replacements, leak mitigation and oil replacements resulting in delays of work and delays in the initiation of sampling and verification of PCB content in BC Hydro's overhead distribution transformers, an activity which informs BC Hydro's Replacement Program for PCB oil phase-out in distribution assets.
2016	13.3	13.9	0.6	Higher spend mainly due to: - $1.1M - Completion of prior year delayed work related to leak repairs and leak mitigation activities.
2017	18.3	14.2	(4.2)	Lower spend mainly due to: - $(2.8)M - Reclassification of costs relating to a new Materials Classification Facility and the Oil Management Department Tank Farm Upgrade project that were forecast as being PCB remediation costs but the actual costs were capitalized; and concentration of sampling and verification work on lower cost simple sites and deferral of work on complex sites to future fiscal years. - $(0.8)M - Cost savings from disposing of four of six transformers at Bridge River, with low PCB levels, within BC.
2018	18.9	14.3	(4.5)	Lower spend mainly due to: - $(2.1)M - Cost savings from disposing of four of six transformers at Bridge River, with low PCB levels, within BC. - $(2.1)M - Lower than planned Transmission transformer leak repair work which was subsequently delayed to a future fiscal period and the delay of the distribution overhead sampling and verification work, due to vendor default on the sampling contract, which also resulted in a deferral of sampling work to the future fiscal years.
2019	15.3	18.6	3.3	Higher spend mainly due to: - $3.5M - Prioritization of the station transformer bushing replacements due to increased risk for regulatory non-compliance resulted in an increase in the number of bushing replacements; and completion of the delayed leak repairs and distribution sampling activities from prior fiscal year.

301.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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

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.

3.301.3 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.

RESPONSE:

Confirmed.

301.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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

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

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>
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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.

3.301.3 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.

3.301.3.1 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.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.301.3.

301.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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

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).

3.301.4 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.

RESPONSE:

The variances between actual and forecast cost of energy arising from differences between forecast and actual domestic customer load are also referred to as ‘net load variance’ or ‘net cost of energy deferred’.

BCUC Order No. G-16-09 approved the deferral treatment of load variances. The net load variance has since been captured in the Cost of Energy variance accounts as the gross cost of energy deferral less the domestic revenue variance. Please refer to the attached BCUC IR 1.129.3 from the Previous Application for further details.

The net load variance / net cost of energy deferred for fiscal 2015 to fiscal 2019 is shown in line 3 of the table below.

	($ millions)	Schedule Reference	F2015 Diff	F2016 Diff	F2017 Diff	F2018 Diff	F2019 Diff
1	Gross Cost of Energy variance	4.0 L39	128.0	83.9	(43.8)	(119.2)	(244.2)
2	Domestic Revenue Variance	14.0 L20 - L18	(207.3)	(268.8)	(1.3)	13.6	(50.7)
3	Net Cost of Energy Deferred	L1 - L2	335.4	352.7	(42.5)	(132.8)	(193.5)

The reasons for the variances are as follows:

Fiscal 2015:

Gross cost of energy was $128.0 million higher than approved primarily due to lower surplus sales, higher net purchases from Powerex, higher energy costs associated with the Non-Treaty Storage Agreement and higher costs of energy purchases from Independent Power Producers due to a change in accounting treatment for one of the Electricity Purchase Agreements. This was partially offset by lower water rentals and lower market electricity purchases.

Domestic revenues were $207.3 million lower than approved due to lower residential revenues and lower large industrial revenues.

Further explanations can be found in Appendix K of the Previous Application.

Fiscal 2016:

Gross cost of energy was $83.9 million higher than plan primarily due to higher costs of energy purchases from Independent Power Producers partially offset by higher revenue from surplus sales. In addition, market electricity purchases and water rental costs were lower than approved.

Domestic revenues were $268.8 million lower than plan due to lower residential revenues and lower large industrial revenues.

Further explanations can be found in Appendix K of the Previous Application.

Fiscal 2017:

Gross cost of energy was $43.8 million lower than approved primarily due to lower costs of energy purchases from Independent Power Producers and higher surplus sales.

Domestic revenues were $1.3 million lower than plan largely due to slightly lower large industrial revenues partially offset by higher light industrial and commercial load.

Further explanations can be found in Appendix G of the Application.

Fiscal 2018:

Gross cost of energy was $119.2 million lower than approved primarily due to lower costs from Independent Power Producers and lower market electricity purchases.

Domestic revenues were $13.6 million higher than approved largely driven by higher light industrial and commercial load.

Further explanations can be found in Appendix G of the Application.

Fiscal 2019:

Gross cost of energy was $244.2 million lower than plan primarily due to higher recoveries from water transactions associated with Non-Treaty Storage and Libby Coordination Agreements and lower costs of energy purchases from Independent Power Producers, partially offset by higher market electricity purchases required to meet domestic load requirements.

Domestic revenues were $50.7 million lower than approved primarily due to lower residential revenues and slightly lower large industrial revenues, partially offset by higher light industrial and commercial revenues.

Further explanations can be found in Appendix G of the Evidentiary Update.

British Columbia Utilities Commission Information Request No. **1.129.3** Dated: **October 6, 2016** British Columbia Hydro & Power Authority Response issued **November 21, 2016**	Page 1 of 2
British Columbia Hydro & Power Authority **Fiscal 2017 – Fiscal 2019 Revenue Requirements Application**	**Exhibit:** **B-9**

129.0 Topic: **Chapter 7 – Deferral and Other Regulatory Accounts – Deferral Accounts**

Reference: **DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Order G-94-06, BC Hydro F2007–F2008 RRA NSA; Order G-16-09: BC Hydro F2011 RRA NSA; Order G-77-12A, Order G-47-14; Directive No. 7
NHDA – Cost of Energy Deferral Accounts
Load forecast variance

Order G-94-06 in the BC Hydro F2005–F2006 RRA approved the variance for cost of energy – except those arising from changes in customer load – to be captured in the HDA and the NHDA.

In the F2007–F2008 RRA, BC Hydro proposed that the cost of load variances net of incremental domestic revenues be transferred to the cost of energy deferral accounts. However, section 27 of the F2007–F2008 RRA negotiated settlement agreement (NSA) found that they would continue to be excluded.

Order G-16-09 of the BCH F2009–F2009 RRA approved the inclusion of the net impact of load variances in the cost of energy deferral accounts for F2009 and F2010, stating: “in light of recent volatility in BC Hydro’s load forecast, the uncertain economic outlook, the recent introduction of the RIB and the uncertain impact of future DSM programs, BC Hydro’s proposed deferral treatment for load variances is approved for the test period.”

The F2011 RRA NSA approved the inclusion of the net impact of load variance in the cost of energy deferral account for F2011.

On page 7-8 of the BC Hydro Amended F2012–F2014 RRA BC Hydro proposed that the net impact of load variance continue to be included in the Cost of Energy Deferral Account for F2012 to F2014. Order G-77-12A approved the following:

> The continuation of the deferral of the difference between forecast and actual cost of energy arising from differences between forecast and actual domestic customer load through the NHDA for F2012-F2014.

Order G-47-14 of the F2015–F2016 RRA approved the continuation of the treatment approved by Order G-77-12A for F2015–F2016 and Direction No. 7, section 7 (c)(ii) directed the continuation indefinitely.

1.129.3 In the F2012 Annual Deferral Account Report, schedule F, note 3, BC Hydro states that Order G-77-12A allows BC Hydro to continue to defer the net load variances. Please explain the relationship between a net load variance and a variance between the forecast and actual cost of energy arising from differences between forecast and actual domestic customer load. It appears that the latter relates to the energy variance only while the former includes the revenue variance as well. Please discuss.

RESPONSE:

The terms 'net load variance' and 'variance between the forecast and actual cost of energy arising from differences between forecast and actual domestic customer load' have the same effective meaning.

In the Fiscal 2009 - Fiscal 2010 Revenue Requirements Application, BC Hydro proposed that the net impact of load variance be included in the Cost of Energy variance accounts. This was further explained in BC Hydro's Undertaking No. 76 of the Fiscal 2009 – Fiscal 2010 Revenue Requirements Application which described that "differences between actual and forecast cost of energy arising from differences between actual and forecast load be captured in the Cost of Energy variance accounts (they are not currently captured in any deferral account mechanism). This would have the effect, if accepted, of deferring all cost and revenue implications of actual load being different from forecast load." The mechanics of this calculation were also illustrated in the attached Appendix K of the Fiscal 2009 - Fiscal 2010 Revenue Requirements Application, which demonstrates how the inclusion of the net load variances in the Cost of Energy variance accounts would simplify the calculation of the net cost of energy deferral to be equal to the gross cost of energy deferral less the domestic revenue variance.

British Columbia Utilities Commission Order No. G-16-09 approved the deferral treatment of load variances, and the net load variance has since been captured in the cost of energy deferral accounts as the gross cost of energy deferral less the domestic revenue variance.

301.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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:

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).

3.301.5 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.

RESPONSE:

Variances between the actual and forecast cost of energy arising from differences between actual and forecast domestic customer load are beyond BC Hydro's control and are frequently volatile and unpredictable due to uncontrollable factors such as weather and economic conditions.

For example, if British Columbia experiences a cold winter, actual load may be higher than forecast, which would mean that BC Hydro would collect more revenue than forecast. If this variance was not deferred, this would result in an increase in BC Hydro's net income, which would be to the account of the shareholder, rather than to the benefit of ratepayers.

Similarly, uncontrollable events could result in actual load being lower than forecast. A specific and notable example is the July 2015 closure of the Howe Sound Pulp and Paper facility due to low water levels. This closure was unexpected and represented approximately $40 million in reduced annual revenue to BC Hydro. If this variance was not deferred, it would have resulted in a significant impact to BC Hydro's net income in that fiscal year.

From fiscal 2015 to fiscal 2019 variances between the actual and forecast cost of energy arising from differences between actual and forecast domestic customer load ranged from ($193.5) million to $352.7 million.

Overall, the deferral of variances between actual and forecast load to the Non-Heritage Deferral Account ensures that customer rates reflect actual revenues and costs.

Please refer to BC Hydro's response to BCUC IR 3.301.4 for further information.

301.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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

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).

3.301.5 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.

3.301.5.1 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.

RESPONSE:

BC Hydro provides the analysis requested in the question in relation to the five criteria from section 7.5.1 of the Application:

1. **BC Hydro's ability to directly or indirectly influence the cost category;**
2. **The volatility of the cost category;**
3. **The predictability of the cost category;**
4. **The materiality of the cost category to the revenue requirement; and**
5. **The frequency of major exceptions within the cost category.**

Part A

The cost of energy variances referred to in the question includes components that are deferred to the Heritage Deferral Account and components deferred to the Non-Heritage Deferral Account. BC Hydro considers the assessment of individual deferral accounts more appropriate than assessing individual components. BC Hydro provides the assessment of the Heritage Deferral Account and its components in BC Hydro's response to BCUC IR 3.294.3.

Non-Heritage costs vary due to uncontrollable factors that are difficult to predict or control including water inflows, surplus sales, electricity and gas market prices and load. From fiscal 2015 to fiscal 2019 variances deferred to the Non-Heritage Deferral Account have ranged from ($170.3) million to $482.9 million.

Part B

Notwithstanding the response in Part A of the response to this question regarding variances between the actual and forecast cost of energy arising from differences between actual and forecast domestic customer load, BC Hydro provides the analysis requested in the question in relation to the five criteria from section 7.5.1 of the Application.

Criteria two, three and five all relate to variances.

Please see BC Hydro's response to BCUC IR 3.301.5 where BC Hydro explains that variances between the actual and forecast cost of energy arising from differences between actual and forecast domestic customer load are beyond BC Hydro's control and are frequently volatile and unpredictable due to uncontrollable factors such as weather and economic conditions. From fiscal 2015 to fiscal 2019 variances between the actual and forecast cost of energy arising from differences between actual and forecast domestic customer load ranged from ($193.5) million to $352.7 million, as shown in BC Hydro's response to BCUC IR 3.301.4.

Criteria one can be broadly considered to be related to variances as well, as variances are indicative of BC Hydro's ability to influence the costs related to the account. As identified above, variances in cost of energy arising from differences between actual and forecast domestic customer load occur due to a number of factors beyond BC Hydro's control.

Criteria four relates to materiality. There is no clear way to define materiality for this purpose. In section 7.6 of the Application, BC Hydro notes that:

> **"expenditures of greater than $10 million in a fiscal year would be considered material".**

However, this section relates to the establishment of new regulatory accounts. It also assumed the continuation of existing regulatory accounts – which capture the variances which entail the most risk, and the sum of which is very significant – if this were not the case, the $10 million figure proposed in respect of proposed new regulatory accounts would need to be revisited (and lowered).

Notwithstanding that BC Hydro considers that the materiality threshold does not apply to existing regulatory accounts or their components, the variances between the actual and forecast cost of energy arising from differences between actual and forecast domestic customer load that ranged from ($193.5) million to $352.7 million are material.

301.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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

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).

3.301.5 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.

3.301.5.2 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.

RESPONSE:

There would be no impact to the Test Period revenue requirement or rates.

If the variance treatment for cost of energy arising from differences between actual and forecast load is disallowed beginning in the current Test Period, then any variances between forecast and actual amounts for fiscal 2020 and fiscal 2021 related to this component of cost of energy would not be eligible for deferral to the Non-Heritage Deferral Account, and would be the account of the shareholder. Any such variances would impact BC Hydro's actual net income (as opposed to being recovered from ratepayers through rates).

It is not possible to quantify the impact of such a scenario in the Test Period because actual results for fiscal 2020 and fiscal 2021 are not yet known.

Please refer to BC Hydro's response to BCUC IR 3.301.4, which shows the magnitude of the variances between actual and planned cost of energy arising from the difference between actual and forecast domestic customer load for the fiscal 2015 to fiscal 2019 period.

301.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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

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).

3.301.5 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.

3.301.5.3 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.

RESPONSE:

There would be no impact to the revenue requirement or rates in subsequent test periods.

If the variance treatment for cost of energy arising from differences between actual and forecast load is disallowed beginning in the current Test Period, then any variances between actual and planned amounts in subsequent test periods related to this component of cost of energy would not be eligible for deferral to the Non-Heritage Deferral Account, and would be to the account of the shareholder. Any such variances would impact BC Hydro's actual net income (as opposed to being recovered from ratepayers through rates in future years).

It is not possible to quantify the impact of such a scenario in future test periods because actual results for those future fiscal years are not yet known. Please refer to BC Hydro's response to BCUC IR 3.301.4, which shows the magnitude of the

variances between actual and planned cost of energy arising from the difference between actual and forecast domestic customer load for the fiscal 2015 to fiscal 2019 period.

301.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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

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).

3.301.6 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.

RESPONSE:

This answer also responds to BCUC IR 3.301.6.1.

The response provides a high level description of the Directions noted in the question and the regulatory accounts impacted as a result.

Direction No. 1

Direction No. 1 resulted in the establishment of the Home Purchase Option Plan Regulatory Account, which was approved by BCUC Order No. G-55-09. The balance in this account was fully recovered in fiscal 2016 and the account is now closed.

Direction No. 6

Direction No. 6 relates to the Fiscal 2015 to Fiscal 2016 Revenue Requirements Application and did not direct the BCUC to approve the establishment or ongoing use of any regulatory accounts.

Direction No. 6 specified certain costs and specific dollar amounts to be deferred to, and amortized from, a number of BC Hydro's regulatory accounts for the fiscal 2015 to fiscal 2016 test period only and its directives are no longer applicable.

Direction Nos. 3 and 7

Direction No. 3 relates to the Fiscal 2012 to Fiscal 2014 Revenue Requirements Application and most of its directives are no longer applicable. However, as shown in the table below, this direction resulted in the establishment of the IFRS transition regulatory accounts and the approval of the recovery amounts related to those accounts, as well as the recovery of the Capital Projects Investigation Costs Regulatory Account.

The following regulatory accounts were continued by BCUC Order No. G-48-14 pursuant to Direction No. 7 with no changes to scope, recovery period, recovery mechanism, or application of carrying costs:

- **Heritage Deferral Account;**
- **Trade Income Deferral Account;**
- **Rock Bay Remediation Regulatory Account;**
- **Asbestos Remediation Regulatory Account (renamed Remediation Regulatory Account by BCUC Order No. G-47-18); and**
- **Non-Current Pension Costs Regulatory Account.**

The following regulatory accounts were established by BCUC Order No. G-48-14 pursuant to Direction No. 7:

- **Rate Smoothing Regulatory Account; and**
- **Real Property Sales Regulatory Account.**

As noted in section 7.7.6 of Chapter 7 of the Application, BC Hydro wrote-off the balance in the Rate Smoothing Regulatory Account in the third quarter of fiscal 2019 and is seeking approval to close this regulatory account. As a result,

there is a zero balance in this account at the beginning of the test period and BC Hydro is seeking approval to close this account in this Application.

Direction No. 7 also set the Deferral Account Rate Rider (DARR) for fiscal 2015 and future fiscal years at 5 per cent. As discussed in section 7.7.1 of Chapter 7 of the Application, BC Hydro is seeking approval to reduce the DARR from 5 per cent to 0 per cent, effective April 1, 2019.

Direction No. 8

None of regulatory accounts established or continued by Direction Nos. 3 or 7 are continued by Direction No. 8.

With the repeal of Directions No. 3 and No. 7, the BCUC has enhanced oversight over BC Hydro's regulatory accounts. Section 4(1) of Direction No. 8 specifies that the BCUC must not disallow for any reason the recovery in rates of the balance of BC Hydro's regulatory accounts as at March 31, 2019; however, it does not preclude the BCUC from determining if those regulatory accounts should continue past March 31, 2019.

The table below provides the regulatory accounts where changes in scope, recovery period, recovery mechanism, or application of carrying costs were directed by Directions Nos. 3 and 7 and provides the corresponding BCUC order number approving these changes with respect to BC Hydro's existing regulatory accounts that continue to be impacted by these changes.

Regulatory Account	Approval for:	Direction to BCUC	BCUC Order	BCUC Directive/ Section
IFRS Property, Plant and Equipment	Establishment of Account, Recovery Period: 40 years[1]	Direction No. 3	G-77-12A	Section 1 (xxi)
IFRS Pension	Establishment of Account, Recovery Period: 20 years[1]	Direction No. 3	G-77-12A	Section 1 (xxii)
Capital Project Investigation Costs	Recovery Period: 10 years	Direction No. 3	G-77-12A	Section 1 (xvi)
Non-Current Pension Costs	Scope change to include experience gains or losses	Direction No. 3	G-77-12A	Section 1 (xiv)
DSM	Recovery Period: 15 years	Direction No. 3	G-77-12A	Section 1 (vi)

Regulatory Account	Approval for:	Direction to BCUC	BCUC Order	BCUC Directive/ Section
Non-Heritage Deferral Account	**Scope change to include deferral of Burrard costs**	**Direction No. 7**	**G-48-14**	**Item 6**
Real Property Sales	**Establishment of Account, Application of carrying costs**	**Direction No. 7**	**G-48-14**	**Item 30**
First Nations Costs	**Application of carrying costs**	**Direction No. 7**	**G-48-14**	**Item 20**

1. **Please refer to BC Hydro's response to BCUC IR 1.154.1, where BC Hydro explains how the amortization periods were determined.**

For the changes identified in the table above, BC Hydro considers that the changes in scope, recovery period, and application of carrying costs continue to be appropriate for the current and future test periods for the reasons noted below.

IFRS Transition Accounts - IFRS Property, Plant and Equipment and IFRS Pension

The two IFRS transition accounts were established as a result of BC Hydro's transition to IFRS (as part of the Prescribed Standards) in fiscal 2013.

There will be no further additions to the IFRS Property, Plant and Equipment Regulatory Account after the end of the Test Period and there are no further additions to the IFRS Pension Regulatory Account.

Please refer to BC Hydro's response to BCUC IR 3.301.6.2, where we describe how the IFRS Property, Plant and Equipment and IFRS Pension regulatory accounts meet BC Hydro's criteria set out in section 7.5.1 of Chapter 7 of the Application.

BC Hydro considers that the recovery periods for these regulatory accounts continue to be appropriate as they result in approximately the same revenue requirement impact as under the previous CGAAP rules.

Non-Current Pension Costs Regulatory Account

As discussed in section 7.8.11 of Chapter 7 of the Application and in BC Hydro's response to BCUC IR 3.300.5, experience gains and losses are sensitive to changes in market discount rates, rates of return on pension plan assets and changes in actuarial assumptions. This means that annual actuarial gains and losses are subject to large positive and negative fluctuations that are not within BC Hydro's control. For example, the elimination of Medical Services Plan

Premiums resulted in significant actuarial gains in fiscal 2019 and fiscal 2020. In the absence of regulatory approval to defer these gains and losses to the Non-Current Pension Costs Regulatory Account, this actuarial gain would have been to the account of the shareholder and ratepayers would not receive the benefit of this actuarial gain. Accordingly, BC Hydro believes it is appropriate to continue to defer the variances between actual and forecast non-current pension costs to the Non-Current Pension Costs Regulatory Account.

Please refer to BC Hydro's response to BCUC IR 3.300.5, where we describe how the Non-Current Pension Costs Regulatory Account meets BC Hydro's criteria set out in section 7.5.1 of Chapter 7 of the Application.

Capital Project Investigation Costs Regulatory Account

As discussed in section 7.7.5 of Chapter 7 of the Application, the Capital Project Investigation Costs Regulatory Account will be fully amortized by the end of the Test Period and BC Hydro is seeking BCUC approval to close this account at the end of fiscal 2021.

DSM Regulatory Account

BC Hydro considers that the current DSM amortization period appropriately matches the time over which the benefits will be received by ratepayers and supports intergenerational equity. Please refer to BC Hydro's response to BCUC IR 3.298.4 where BC Hydro explains that the current amortization period of 15 years supports intergenerational equity between current ratepayers and future ratepayers and maintains rate stability. In addition, please refer to BC Hydro's response to BCUC IR 1.150.6.1 for further information on the benefits of the current 15 year amortization period compared to a 10 year amortization period.

Non-Heritage Deferral Account – deferral of Burrard costs

Costs related to the decommissioning of those portions of Burrard Thermal that are not required for transmission support services are deferred to the Non-Heritage Deferral Account. At present, BC Hydro is not aware of any future costs for Burrard that meet the definition of "Burrard costs" stated in Direction No. 7.

Real Property Sales Regulatory Account

As discussed in BC Hydro's response to BCUC IR 3.299.3, BC Hydro has a net gain on real property sales target of $100 million. BC Hydro remains committed to achieving the $100 million target and providing this benefit to ratepayers. BC Hydro recognizes that initial sales completions have been slower than expected; however, BC Hydro is making progress towards this target and plans to deliver on the $100 million net gains target by fiscal 2024.

Pursuant to section 4 of Direction No. 8, the existing balance in this regulatory account as at March 31, 2019 is recoverable from ratepayers. Maintaining the Real Property Sales Regulatory Account means that the existing account balance as at March 31, 2019 will not be borne by ratepayers when future property sales occur.

Please refer to BC Hydro's response to BCUC IR 3.301.6.2 where we describe how the how the Real Property Sales Regulatory Account meets BC Hydro's criteria set out in section 7.5.1 of Chapter 7 of the Application.

As discussed in section 7.9 of Chapter 7 of the Application, BC Hydro incurs finance charges related to the balances for a number of its regulatory accounts. Accordingly, it is appropriate that interest should be applied to this regulatory account, consistent with the application of interest to other cash variance accounts.

First Nations Costs Regulatory Account

As discussed in section 7.9 of Chapter 7 of the Application, BC Hydro incurs finance charges related to the balances in its regulatory accounts. Balances in this account represent settlement payments that have been paid (i.e., a cash outlay has been made) and are being amortized in rates over a longer period of time. Accordingly, it is appropriate that interest should be applied to this regulatory account, consistent with the application of interest to other regulatory accounts.

301.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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

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).

3.301.6.1 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.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.301.6 where we discuss why the changes in scope, recovery period, or application of carrying costs should be continued for the regulatory accounts identified in the table in that response.

301.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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

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).

3.301.6.2 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.

RESPONSE:

Scope changes identified in BC Hydro's response to BCUC IR 3.301.6 are as follows:

- **IFRS Property, Plant and Equipment;**
- **IFRS Pension;**
- **Non-Current Pension – Actuarial gains/losses;**
- **Non-Heritage Deferral Account – Burrard costs; and**
- **Real Property Sales.**

BC Hydro provides the analysis requested in the question in relation to the five criteria from section 7.5.1 of the Application:

1. **BC Hydro's ability to directly or indirectly influence the cost category;**
2. **The volatility of the cost category;**
3. **The predictability of the cost category;**

4. **The materiality of the cost category to the revenue requirement; and**

5. **The frequency of major exceptions within the cost category.**

Please refer to BC Hydro's response to BCUC IR 3.301.1 for the assessment of the Real Property Sales Regulatory Account. Please also refer to BC Hydro's response to BCUC IR 3.300.5 for the assessment of the actuarial gains/loss component of the Non-Current Pension Costs Regulatory Account.

The IFRS Property, Plant and Equipment and the IFRS Pension regulatory accounts meet criterion one as they were the result of a change in accounting standards that was beyond BC Hydro's control.

Criteria four relates to materiality. There is no clear way to define materiality for this purpose. In section 7.6 of Chapter 7 of the Application, BC Hydro notes that:

> **"expenditures of greater than $10 million in a fiscal year would be considered material".**

However, this section relates to the establishment of new regulatory accounts. It also assumed the continuation of existing regulatory accounts – which capture the variances which entail the most risk, and the sum of which is very significant. If this were not the case, the $10 million figure proposed in respect of proposed new regulatory accounts would need to be revisited (and lowered).

Notwithstanding that BC Hydro considers that the materiality threshold does not apply to existing regulatory accounts or their components, these accounts also meet criterion four as each of these accounting changes was in excess of $200 million which significantly exceeds the $10 million figure stated in section 7.6 of Chapter 7 of the Application.

Criteria two, three and five are applicable to variance accounts. As these two accounts are not variance accounts, these criteria do not apply.

At present, BC Hydro is not aware of any future costs for Burrard that meet the definition of "Burrard costs" stated in Direction No. 7; therefore, BC Hydro is not providing an assessment of the five criteria for these costs.

302.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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.

3.302.1 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.

RESPONSE:

The differences between the Evidentiary Update and the Application forecast are attributable to the following:

- **Two additional Electricity Purchase Agreements were determined to be leases under IFRS 16. These Electricity Purchase Agreements differ from most other Electricity Purchase Agreements due to related coordination agreements. The agreements required significant judgement to determine the appropriate application of IFRS 16 for the effects of the combined agreements:**
  - **The Electricity Purchase Agreements, in conjunction with the coordination agreements, provide BC Hydro dispatch rights for the facilities. BC Hydro's dispatch rights provide BC Hydro control of the assets; therefore, the Electricity Purchase Agreements meet the definition of a lease under IFRS 16;**
  - **In addition, unlike most other Electricity Purchase Agreements, BC Hydro pays for deemed electricity output (based on entitlement agreements), not the actual output of the facilities. The payments based on deemed output**

were determined to be fixed payments required to be recognized on the balance sheet under IFRS 16; and

- **The addition of the two leases increased the adoption adjustment by $86 million; and**

- **The measurement of the Electricity Purchase Agreement included in the Application as a lease under IFRS 16 was adjusted due to refinements in the present value calculation that result in a $3 million reduction in the adoption adjustment.**

Please refer to BC Hydro’s response to BCUC IR 3.302.7.1 where BC Hydro explains that the Auditor General of B.C. (BC Hydro’s external financial statement auditor) agreed with BC Hydro’s impact assessment subject to completion of its audit of BC Hydro’s annual fiscal 2020 financial statements.

302.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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)

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.

3.302.2 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.

RESPONSE:

Not confirmed. BC Hydro is requesting to defer to the Non-Heritage Deferral Account a one-time debit adjustment of $64.8 million related to the initial adoption of IFRS 16; however, BC Hydro does expect future variances related to existing Electricity Purchase Agreements that are considered leases as discussed in the paragraphs below.

For existing Electricity Purchase Agreements that are considered leases, variances will arise due to the need to adjust the measurement of the right-of-use

asset balance and the lease obligation for actual inflationary increases which may differ from the inflation assumptions used in the forecast. Although the changes in the measurement of the asset and the obligation could be significant, the annual impact will be much less significant as the measurement adjustment is spread over the remaining term of the lease through changes in depreciation and finance charges.

In addition, if a new Electricity Purchase Agreement lease was recognized during a test period there could be variances due to the timing of the commencement of recognition, or amount of the depreciation and interest expenses. At this time, BC Hydro is not anticipating any new Electricity Purchase Agreement leases.

Also, please refer to BC Hydro’s response to BCUC IR 3.302.7.1 where BC Hydro explains that the Auditor General of B.C. agreed with BC Hydro’s impact assessment as reflected in the Quarter 1 financial statements, subject to completion of its audit. In BC Hydro’s response to BCUC IR 3.302.7.2, BC Hydro explains that in the audit of BC Hydro, if the Auditor General of B.C. does not agree with BC Hydro’s implementation of IFRS 16 for Electricity Purchase Agreement leases, BC Hydro would adjust its financial statements. Any variance related to adoption impacts would be deferred to the Non-Heritage Deferral Account.

302.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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
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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.

3.302.3 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.

RESPONSE:

Confirmed, the variances related to Electricity Purchase Agreement leases are now negative and will not provide the same benefit to ratepayers as a positive variance deferred to the Non-Heritage Deferral Account.

Although there is a negative variance on adoption of IFRS 16, costs associated with these Electricity Purchase Agreements are lower in future periods by the amount of the variance on adoption. Therefore, ratepayers will pay for the actual costs over the life of these Electricity Purchase Agreements, which includes the adoption variance in the Non-Heritage Deferral Account.

302.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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)

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.

3.302.3 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.

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

RESPONSE:

The rationale for deferring the $64.8 million variance to the Non-Heritage Deferral Account is that ratepayers should pay the actual costs incurred for the acquisition of electricity under Electricity Purchase Agreements. The $64.8 million are actual costs incurred for these Electricity Purchase Agreements that have been

attributed to a prior period as a result of a change in an accounting standard. If the $64.8 million is not permitted to be deferred and recovered in future rates, ratepayers will not pay the actual costs incurred under these agreements. The change in the accounting standard has not changed the total costs of these agreements, only the timing of recognition of the costs.

BC Hydro requested this deferral treatment in section 8.13.3 of Chapter 8 of the Application as shown below:

> **"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".**

BC Hydro recognized that the impact of IFRS 16 could vary from the amounts originally included in the Application and stated this potential in section 8.13.3 of Chapter 8 of the Application as follows:

> **"[T]he actual impacts of the new standard may vary from these estimates as BC Hydro completes its assessment, including as a result of clarifications and interpretive guidance that may be developed by the International Accounting Standards Board, accounting firms and industry groups to assist in the implementation of the new standard. BC Hydro anticipates that material variances are possible when we complete our assessment of EPAs, including the review by our external auditors".**

The IFRS 16 adoption impacts reflect a change in the timing of expenses associated with these Electricity Purchase Agreements as a result of a change in an accounting standard. In the absence of the accounting change, these costs would have been borne by ratepayers in future periods. The change in timing should not affect BC Hydro's ability to collect the costs.

302.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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)

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.

3.302.4 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.

RESPONSE:

The pros and cons of deferring the interest expense variances for Electricity Purchase Agreement leases separately to the Total Finance Charges Regulatory Account are as follows:

Pros

- **The default deferral account for finance charge variances is the Total Finance Charges Regulatory Account unless there is a specific order requiring deviation from the default. For compliance with the existing orders, the interest expense variance should be deferred to the Total Finance Charges Regulatory Account.**

- **Consistency with the treatment of most finance charge variances, which are deferred to the Total Finance Charges Regulatory Account. A consistent treatment is more transparent and administratively efficient.**

Cons

- **Inconsistent treatment compared with variances for all other Electricity Purchase Agreement variances which are deferred to the Non-Heritage Deferral Regulatory Account.**
- **Potential differences in the recovery period for the variance associated with the Electricity Purchase Agreement lease as the Total Finance Charges Regulatory Account recovery period is the following test period whereas the recovery period for the Non-Heritage Deferral Account has not been determined for the next test period. While the recovery periods for the two regulatory accounts are the same for this test period, as noted in section 7.7.1.1 of Chapter 7 of Application, BC Hydro expects to propose to return to the DARR table mechanism approved by the BCUC in the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application in the subsequent test period starting in fiscal 2022.**

Please refer to BC Hydro's response to BCUC IR 3.302.2, where BC Hydro identifies the reasons for future variances and its expectations regarding the significance of the potential variances.

302.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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)

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.

3.302.5 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.

RESPONSE:

BC Hydro provided its assessment of the Electricity Purchase Agreement lease amortization scope eligibility for the Amortization of Capital Additions Regulatory Account in its response to BCUC IR 1.15.1 in the Fiscal 2012 to Fiscal 2014 Amended Revenue Requirements proceeding. For reference, BCUC IR 1.15.1 from that proceeding asked:

> **"How will variances between actual and forecast cost under IPP contracts that are subjected to capital lease accounting treatment impact additions to the Non Heritage Deferral Account and the Amortization of Capital Additions and Total Finance Charges regulatory accounts? Please comment on whether current definitions under these deferral and regulatory accounts specifically allow for variances from EPA contracts under capital leases."**

BC Hydro does not consider Electricity Purchase Agreement capital lease amortization variances to be in scope as the current definitions of deferral and regulatory accounts do not specifically mention treatment of IPP contracts that are subject to capital lease accounting treatment. As stated in BC Hydro's response to BCUC IR 1.15.1 in the Fiscal 2012 to Fiscal 2014 Amended Revenue Requirements proceeding:

> **"For post-COD EPAs, capital leases are booked to plan for amortization, finance charges, operating costs, and property taxes. These values are established at COD and do not vary thereafter, except for a pre-determined allowance for inflation in operating costs and property taxes. Variance in delivered volumes and pricing (e.g., CPI or time of delivery variances) are accounted for through the Non-Heritage Deferral Account, consistent with EPAs not subject to capital lease accounting.**
>
> **The cost of pre-COD EPAs subject to capital lease accounting can vary from plan for two key reasons. First, a change in the in-service date will cause costs to be incurred earlier or later than plan. Second, because the capital lease obligation is established at COD, there may be differences in the valuation or breakdown of costs as compared to the plan, for reasons such as differences in CPI or discount rates, as well as updates to the EPAs delivery forecast.**
>
> **In the cases of pre-COD EPAs subject to capital lease accounting, variances in the cost components are treated commensurate with the cost components classification. Variances in cost of energy and finance charges are subject to deferral or regulatory account treatment. Variances in amortization, operating costs, and property taxes are not subject to deferral or regulatory account treatment.**
>
> **The current definitions of deferral and regulatory accounts do not specifically mention treatment of IPP contracts that are subject to capital lease accounting treatment, however, the cost of energy Deferral Accounts and Total Finance Charges Regulatory Account capture all differences between plan and actual in their respective categories."**

Consistent with this assessment regarding the ineligibility of these variances, BC Hydro has not included amortization variances on IPP contracts subject to capital lease accounting in the Amortization of Capital Additions.

BC Hydro would not be opposed to a directive requiring these depreciation variances on leased asset additions to be deferred to the Amortization of Capital

Additions Regulatory Account (instead of the Total Finance Charges Regulatory Account). As stated in BC Hydro's response to BCUC IR 1.146.1:

> **"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."**

302.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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)

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.

3.302.6 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.

RESPONSE:

The proposed opening balance adjustment of $64.8 million to the Non-Heritage Deferral Account (NHDA) is the net impact of the initial adoption of IFRS 16. As the result of adopting IFRS 16, the accounting treatment for a number of energy purchase agreements changed. As BC Hydro adopted IFRS 16 retrospectively, the estimated financial impact if BC Hydro was always following IFRS 16 is

summarized in the table below which totals the $64.8 million net opening balance adjustment ($ million):

Finance charges	**$136.3**
Amortization	**$446.6**
Cost of energy	**($382.8)**
Operating expenses	**($135.4)**
Net Opening Balance Adjustment	**$64.8**

For the purpose of estimating the bill impacts in this response, BC Hydro assumes that the requested rate increase for fiscal 2020 remains the same, as per BC Hydro's proposal outlined on page 10 of the Evidentiary Update, and therefore the entire two year impact is reflected in fiscal 2021.

Scenario A

If the BCUC does not approve the deferral treatment of the $64.8 million opening balance adjustment to NHDA and instead provides a directive requiring the depreciation variances attributable to EPA leases to be deferred to the Amortization of Capital Additions Regulatory Account:

- **The $64.8 million debit adjustment will be removed from NHDA in fiscal 2020 and not collected from ratepayers in the Test Period as currently proposed in the Evidentiary Update;**
- **The estimated unfavourable variance in finance charges of $136.6 million will be deferred to the Total Finance Charges Regulatory Account and recovered from ratepayers in the next test period;**
- **The estimated unfavourable variance in amortization of $446.6 million will be deferred to Amortization of Capital Additions Regulatory Account and recovered from ratepayers in the next test period;**
- **The estimated favourable variance in cost of energy of $382.8 million will be deferred to NHDA and refunded in the current Test Period based on our proposal in the Evidentiary Update to refund the Cost of Energy Variance Accounts to ratepayers in the Test Period;**
- **The estimated favourable variance of $135.4 million in operating costs is not eligible to be deferred to any existing regulatory account and therefore would be to the account of the Shareholder through an adjustment to opening retained earnings. As a result, ratepayers would not get the benefit of the favourable variance;**

- **The Test Period revenue requirements are reduced by an estimated $473.1 million (i.e., $382.8 million + $64.8 million + $25.5 million in interest); and**

- **The fiscal 2021 bill decrease of 0.99 per cent in the Evidentiary Update will change to an estimated bill decrease of 10.0 per cent.**

BC Hydro notes that the estimated fiscal 2021 bill decrease in this scenario is due to the removal of the increase to the NHDA and the refund of the favourable variances in cost of energy in the Test Period, while the unfavourable variances deferred to the Total Finance Charges Regulatory Account and the Amortization of Capital Additions Regulatory Account will cause large bill increases after the Test Period. Assuming a two year test period beginning in fiscal 2022, and assuming that the forecast which BC Hydro presented in the Evidentiary Updates holds true, BC Hydro estimates the required bill increase in fiscal 2022 to be approximately 19 per cent.

Scenario B

If BCUC does not approve the deferral treatment of $64.8 million opening balance adjustment to NHDA and does not provide a directive requiring the depreciation variances attributable to EPA leases to be deferred to the Amortization of Capital Additions Regulatory Account:

- **The $64.8 million debit adjustment will be removed from NHDA in fiscal 2020 and not collected from ratepayers in the Test Period as currently proposed in the Evidentiary Update;**

- **The estimated unfavourable variance in finance charges of $136.6 million will be deferred to the Total Finance Charges Regulatory Account and recovered from ratepayers in the next test period;**

- **The estimated unfavourable variance in amortization of $446.6 million is not eligible to be deferred to any existing regulatory account and therefore would be to the account of the Shareholder through an adjustment to opening retained earnings. As a result, ratepayers would not pay the actual costs incurred;**

- **The estimated favourable variance of $135.4 million in operating costs is not eligible to be deferred to any existing regulatory account and therefore would be to the account of the Shareholder through an adjustment to opening retained earnings. As a result, ratepayers would not get the benefit of the favourable variance and would not be paying the actual costs incurred;**

- **As in Scenario A, the Test Period revenue requirements are reduced by an estimated $473.1 million (i.e. $382.8 million + $64.8 million + $25.5 million in interest); and**
- **The fiscal 2021 bill decrease of 0.99 per cent in the Evidentiary Update will change to an estimated bill decrease of 10.0 per cent.**

BC Hydro notes that the estimated fiscal 2020 bill decrease in this scenario is due to the refund of the favourable variances in cost of energy in the Test Period while the unfavourable finance charge variance, deferred to the Total Finance Charges Regulatory Account, will cause large bill increases after the Test Period. Assuming a two year test period beginning in fiscal 2022, and assuming that the forecast which BC Hydro presented in the Evidentiary Updates holds true, BC Hydro estimates the required bill increase in fiscal 2022 to be approximately 15 per cent.

302.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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, 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.

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

RESPONSE:

BC Hydro has discussed its implementation of IFRS 16 with the Auditor General of B.C. as reflected in the Quarter 1 financial statements, which has also been reflected in the Evidentiary Update.

302.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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, 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.

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

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

RESPONSE:

The Auditor General of B.C. agreed with BC Hydro's impact assessment as reflected in the Quarter 1 financial statements, subject to completion of its audit of BC Hydro's annual fiscal 2020 financial statements.

302.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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, 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.

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

3.302.7.2 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.

RESPONSE:

If the Auditor General of B.C. does not agree with BC Hydro's implementation of IFRS 16 for Electricity Purchase Agreement leases, BC Hydro would adjust its financial statements. Any variance related to adoption impacts would be deferred to the Non-Heritage Deferral Account, which is consistent with the treatment of the $64.8 million. This will ensure that ratepayers pay the actual costs incurred.

This treatment assumes that the BCUC approves BC Hydro's request to defer variances related to the accounting for Electricity Purchase Agreements determined to be leases under IFRS 16 to the Non-Heritage Deferral Account. If the BCUC does not approve BC Hydro's request to defer these variances, the impact at adoption, including the variances (whether positive or negative), would be to the account of the shareholder, recorded to retained earnings and ratepayers would not pay the actual costs incurred.

302.0 D. CHAPTER 7 – REGULATORY ACCOUNTS

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)

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.

3.302.8 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.

RESPONSE:

An updated version of Table 8-18 from the Application is included below and it shows the amounts forecast in the Application and the revised forecast amounts.

Table 8-18 (Updated)

	IFRS 16 Adjustment at April 1, 2019 ($ million)	
Financial Statement Item (Debit/(Credit)	As Stated in Application	Revised Forecast
Right-of-use asset	16.8	24.1
Lease obligation	(17.6)	(24.8)
Net Change	0.8	0.7

In addition, an updated version of Table 8-19 is included below which shows the amounts forecast in the Application and the revised forecast based on the actual adoption impacts.

Table 8-19 (Updated)

($ million)	Fiscal 2020 As Stated in Application	Fiscal 2020 Revised Forecast	Fiscal 2021 As Stated in Application	Fiscal 2021 Revised Forecast	Test Period Total As Stated in Application	Test Period Total Revised Forecast
IAS 17						
Operating expenses	3.9	4.0	3.9	4.0	7.8	8.0
IFRS 16						
Depreciation	3.1	3.1	3.2	3.1	6.3	6.2
Finance charges	1.0	1.3	1.0	1.2	2.0	2.5
Total	4.2	4.4	4.2	4.3	8.4	8.7
Net Change	**0.3**	**0.4**	**0.3**	**0.3**	**0.6**	**0.7**

The fiscal 2020 and fiscal 2021 amounts included in the Application were not revised in the Evidentiary Update to reflect the revised forecast as the impact to the revenue requirement (as shown in the table above) was only $0.1 million.

303.0 E. CHAPTER 4 – COST OF ENERGY

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.

3.303.1 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 per cent and 75 per cent, respectively.

RESPONSE:

To clarify, the 100 per cent referred to in BC Hydro's response to BCUC IR 1.15.1.1 provides the actual renewal values for those EPAs that were renewed between May 1, 2016 and October 1, 2018. In the fiscal 2019 RRA Plan (which was based on the IPP forecast as of May 1, 2016), in aggregate, these EPAs were forecast to be renewed at 75 per cent of their historical energy volumes. As of October 1, 2018, these EPAs were renewed and are forecast to contribute 100 per cent of their historical EPA energy volumes.

The 75 per cent renewal value set out in BC Hydro's response to BCUC IR 1.15.2 is a forecast that refers to expiring EPA volumes which are assumed to be renewed after October 1, 2018. If one of these expiring EPAs were subsequently to be renewed, then 100 per cent of that EPA's actual associated volume would be then included in the forecast.

303.0 E. CHAPTER 4 – COST OF ENERGY

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.

3.303.2 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.

RESPONSE:

With respect to the EPA renewal assumptions applied to fiscal 2020 and fiscal 2021 for the IPP forecast, the 2013 Integrated Resource Plan (IRP) is not a material factor because:

1. **For biomass EPAs expiring during the test period, the 2013 IRP renewal assumption of 50 per cent has been superseded by the assumptions used for the Biomass Energy Program;**

2. **For hydro run of river EPAs expiring during the Test Period, the 2013 IRP renewal assumption of 75 per cent continues to apply (as discussed in BC Hydro's response to BCUC IR 3.303.1), but there are only two run-of-river EPAs expiring during the test period and their volumes are small (i.e., combined capacity of these two facilities is less than 4 MW); and**

3. **There are no other EPAs expiring during the Test Period that are part of the integrated system's resource plan.**

303.0 E. CHAPTER 4 – COST OF ENERGY

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

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 4 MW 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.

3.303.3 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.

RESPONSE:

As discussed in BC Hydro's response to BCOAPO IR 2.155.3, prior to the recent adoption of market price, we generally used market prices in periods of surplus and the Long Run Marginal Cost in periods of deficit to determine BC Hydro's opportunity cost for an EPA on the integrated system.

BC Hydro also considered, and continues to consider, cost benchmarks when evaluating the cost effectiveness of an EPA. These benchmarks include an estimate of the IPP's cost of service (including a rate of return), as well as the IPP's opportunity cost, the impact to BC Hydro rates and system benefits and support characteristics (if applicable).

303.0 E. CHAPTER 4 – COST OF ENERGY

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

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 4 MW 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.

3.303.4 Please clarify what it meant by the statement: "we do not have certainty as to whether the 75 per cent 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 per cent relates to the 75 per cent renewal assumption.

RESPONSE:

During the Test Period, there are two run of river hydro EPA renewals that are included in the forecast. BC Hydro is uncertain whether the 75 per cent, in aggregate, renewal assumption which is used for run-of-river projects can reasonably be achieved. This is because BC Hydro is uncertain whether it will be successful in negotiating agreements for the projects at the market price, given that the price may be below the IPP's cost of service or the IPPs may seek

alternatives to an EPA renewal with BC Hydro. As noted in the preamble to the question, this change in approach for run-of-river hydro EPA renewals would not have a material impact on the Cost of Energy during the Test Period.

304.0 E. CHAPTER 4 – COST OF ENERGY

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

3.304.1 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.

RESPONSE:

BC Hydro anticipates that it will be scheduling network upgrade work for the seven run of river IPP projects whose EPAs have been renewed. These IPP projects are: Akolkolex, Soo River, Boston Bar, Doran Taylor, Brown Lake, Sechelt Creek, and Walden North. The total dollar amount of these costs is estimated to be $400,000 in fiscal 2020 and $360,000 in fiscal 2021.

In each case, the network upgrades on BC Hydro's system is triggered by the renewal of the IPP's EPA. However, if the IPP chooses to remain connected to the BC Hydro system in order to transmit electricity, these network upgrades would still be required in the absence of an EPA renewal.

304.0 E. CHAPTER 4 – COST OF ENERGY

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
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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

3.304.1.1 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.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.304.1.

304.0 E. CHAPTER 4 – COST OF ENERGY

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

3.304.2 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.

RESPONSE:

Network upgrade costs are not included in Line 5 of Schedule 4.0 in Appendix A (i.e., not included as part of Cost of Energy). Network upgrades costs are not Cost of Energy costs, but are capital and operating costs accounted for in Schedule 13.0 and Schedule 5.0 of Appendix A. BC Hydro notes, however, that Network Upgrade Costs are taken into consideration when determining the cost-effectiveness of an EPA.

304.0 E. CHAPTER 4 – COST OF ENERGY

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

3.304.3 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.).

RESPONSE:

The nature of the network upgrades referred to in BC Hydro's EPA Renewals Application vary depending on the project but such upgrades may include a review of protection settings, Supervisory Control and Data Acquisition (SCADA) implementation (including telecom), control centre integration and installation of surge arrestors. The benefits to ratepayers from these upgrades once completed are the safe and reliable operations of the BC Hydro transmission and distribution system.

304.0 E. CHAPTER 4 – COST OF ENERGY

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
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> 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].

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	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

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

RESPONSE:

BC Hydro understands the question to be asking how often network upgrades are implemented for IPP projects. These network upgrades are “Network Upgrades” as defined in BC Hydro’s Standard Generator Interconnection Agreement under the OATT, and are driven by specific events, such as a new or renewed EPA for the project or a material modification made either by the customer or BC Hydro. Network Upgrades are not scheduled on a recurring basis.

304.0 E. CHAPTER 4 – COST OF ENERGY

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

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."

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

	F2020 RRA	**F2021 RRA**
GWh		
Total Cost ($ millions)		

RESPONSE:

Two tables are provided below. The first table is based on the forecast in the Application (as of October 1, 2018) and the second table is based on the forecast in the Evidentiary Update (as of June 1, 2019).

The information provided reflects the forecast for energy supply contracts entered into by BC Hydro from April 1, 2016 (i.e., the values include contracts signed during fiscal 2017 and after fiscal 2017) to the respective forecast dates set out above.

	F2020 RRA	F2021 RRA
GWh	383	435
Total Cost ($ millions)	22.6	27.4

	F2020 EU	F2021 EU
GWh	346	434
Total Cost ($ millions)	19.4	27.4

304.0 E. CHAPTER 4 – COST OF ENERGY

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

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.

3.304.6 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.

RESPONSE:

There are five IPP facilities within B.C. that are eligible for California's Renewable Portfolio Standard (RPS). All five of these facilities are wind facilities that have EPAs with BC Hydro. For four of these facilities, BC Hydro has EPAs for the combined energy and environmental attributes associated with each of the facilities.

In the case of the four facilities from which BC Hydro acquires both the energy and environmental attributes, Powerex works with the facility owners to qualify the facilities with the California Energy Commission (CEC) as eligible for California's RPS. To the extent that there are costs associated with certification, audit and licensing fees associated with establishing or maintaining eligibility for California's RPS, Powerex is responsible for these costs. Powerex recovers these costs through its marketing activity and returns the overall benefit of the activity back to BC Hydro via Trade Income.

Accordingly, no reimbursements by BC Hydro associated with registration and ongoing qualification with the CEC are forecast for fiscal 2020 or fiscal 2021.

304.0 E. CHAPTER 4 – COST OF ENERGY

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

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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.

3.304.6 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.

3.304.6.1 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.

RESPONSE:

As noted in BC Hydro's response to BCUC IR 3.304.6, Powerex, as the California market participant, generally pays all costs associated with registration and ongoing qualification and there are no forecast costs for reimbursements by BC Hydro in fiscal 2020 or fiscal 2021.

Five B.C. wind facilities have approval for California RPS and are registered to create RECs in WREGIS. Additionally, three B.C. wind facilities are currently pending approval for California Energy Commission registration and certification. These applications are expected to be finalized in 2020.

304.0 E. CHAPTER 4 – COST OF ENERGY

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
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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.

3.304.6 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.

3.304.6.2 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.

RESPONSE:

Not confirmed. For further discussion, please refer to BC Hydro's response to BCUC IR 3.304.6.

304.0 E. CHAPTER 4 – COST OF ENERGY

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

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- 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.

3.304.7 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.

RESPONSE:

Eligible facilities (presently, limited to wind facilities in B.C.) are registered with the California Energy Commission (CEC) for approval in California's Renewable Portfolio Standard (RPS) in accordance with requirements set out in the California Energy Commission's California Renewable Energy Guidebook.[1] Powerex, as the California market participant, leads the application process and pays all associated registration costs. Only facilities approved and certified by the CEC are eligible for the California RPS.

As part of the CEC's registration and approval process, eligible facilities must be registered in the Western Electricity Coordinating Council's (WECC's) Western Renewable Energy Generation Information System (WREGIS), a renewable energy certificate (REC) accounting system. WREGIS tracks renewable energy generation from units that register in the system by using verifiable data and creating RECs for this generation. Specifically, monthly generation data from eligible facilities is sent to WREGIS, and RECs are created in the WREGIS system. When energy from eligible facilities is delivered to California, the eligible energy is tracked through a CEC facility ID on the NERC e-tag from the source facility in BC to the ultimate delivery point in California. WREGIS matches the unique facility ID on the NERC e-tag to the associated RECs in the system, and then retires these RECs in WREGIS.

1 https://efiling.energy.ca.gov/getdocument.aspx?tn=217317

305.0 E. CHAPTER 4 – COST OF ENERGY

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.

3.305.1 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.

RESPONSE:

Attachment 1 to this response provides the updated Market Electricity Purchases, Surplus Sales and Net Purchases (Sales) from Powerex on a monthly and annual basis for fiscal 2019 through fiscal 2021.

The information in this attachment has been redacted in accordance with BCUC Order G-146-19. BC Hydro will file an un-redacted version of this attachment on October 18, 2019.

CONFIDENTIAL ATTACHMENT

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306.0 E. CHAPTER 4 – COST OF ENERGY

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).

3.306.1 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.

RESPONSE:

Not confirmed. There are situations in which imports and exports do not have an impact on System Storage. For example, during the spring freshet, exports can occur while the two major reservoirs are at minimum generation.

307.0 E. CHAPTER 4 – COST OF ENERGY

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.

3.307.1 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.

RESPONSE:

Other parameters that have changed between the June 2019 and October 2018 Energy Studies include:

- **Forward market prices for natural gas and electricity;**
- **US$/C$ exchange rate;**
- **Outages on generating units in the BC Hydro system;**

- **The addition of one more year of historic weather (2018) in the ensembles;**
- **Historic data for the October through early June period (primarily captured in starting system storage); and**
- **Confirmed Energy Supply Contract purchases.**

307.0 E. CHAPTER 4 – COST OF ENERGY

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."

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> - 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.

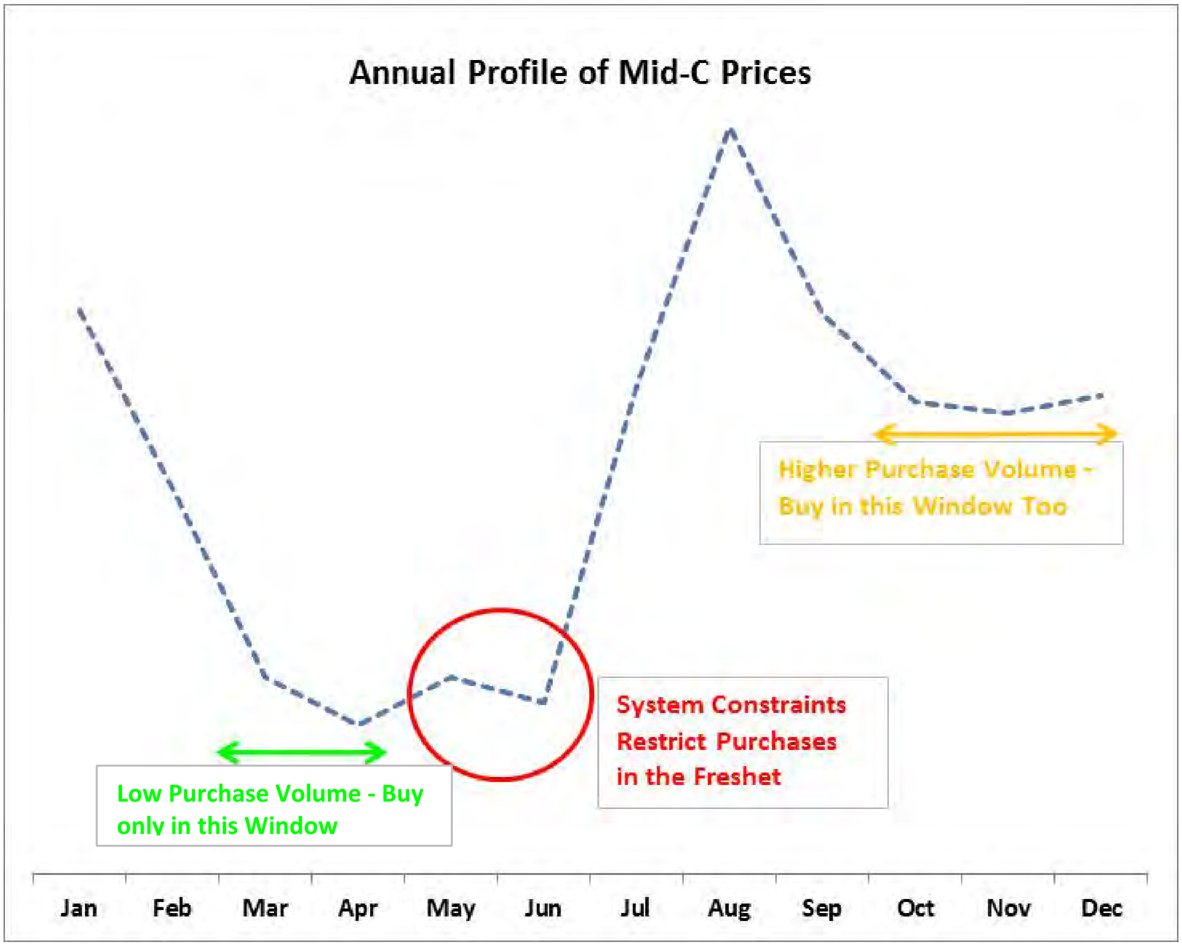
3.307.2 Please discuss whether the changes due to dry conditions and lower water inflows, delayed IPP commercial operation dates, and if lower forecast IPP deliveries had any impacts on the prices at which the lower planned surplus sales and higher planned market electricity purchases transactions are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

RESPONSE:

The volume of expected Market Electricity Purchases and Surplus Sales does impact the average price that BC Hydro pays for energy, all else being equal, because by using BC Hydro's system storage the energy imports can occur in lower priced periods and exports of surplus energy can occur in higher priced

periods. As the volume of imports or exports increases, so does the time period over which the transactions must take place.

To illustrate, if only a small volume of purchases is required, BC Hydro would set a low Threshold Purchase Price, and energy would come into the system at only the lowest priced times. As the deficit increases, BC Hydro must increase its Threshold Purchase Price to take more energy at times of incrementally higher prices, resulting in an overall higher average purchase price. This is illustrated by the graphic below.



Notwithstanding the above, the average price paid for Market Electricity Purchases is expected to be lower than the average price of energy that would have otherwise been purchased from IPPs had it been available. Consequently, BC Hydro has a forecasted lower Cost of Energy for the Test Period.

308.0 E. CHAPTER 4 – COST OF ENERGY

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.

3.308.1 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.

RESPONSE:

As referenced in the preamble to the question, there are many factors that can affect future natural gas and electricity supply and prices. The impact (if any) of constrained natural gas supply on forward Sumas prices would be reflected in the June 2019 Energy Study, as this study incorporates forward prices as of June 6, 2019.

Enbridge has announced that the Enbridge T-South pipeline will be restored to 90 to 95 per cent capacity by November 1, 2019, and full capacity by mid to late November 2019. For further information, please refer to: https://noms.wei-pipeline.com/notices/ci_notice.show?id=52563.

308.0 E. CHAPTER 4 – COST OF ENERGY

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

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> 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.

3.308.1 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.

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

RESPONSE:

Please refer to BC Hydro’s response to BCUC IR 3.308.1.

309.0 E. CHAPTER 4 – COST OF ENERGY

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."

3.309.1 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.

RESPONSE:

This answer also responds to BCUC IR 3.309.2.

There is no risk allocated to the shareholder. Through the Cost of Energy Variance accounts, the costs and benefits from the consolidated net revenue from operations are allocated to ratepayers.

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

If BC Hydro were to optimize to a different objective such as maximizing total generation or minimizing costs from operations, it is not certain whether the risk, in terms of variance in the Cost of Energy, would increase or decrease. In general, however, the expected long-term benefit to ratepayers would be less than the expected benefit obtained from maximizing expected consolidated net revenue from operations. If the optimization objective were changed to minimize the variance in the Cost of Energy, then the expected consolidated net revenue would be lower. For more information about maximizing consolidated net revenue, please see section 4.3.3 of Chapter 4 of the Application.

309.0 E. CHAPTER 4 – COST OF ENERGY

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."

3.309.2 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.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.309.1.

309.0 E. CHAPTER 4 – COST OF ENERGY

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

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.

3.309.3 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?

RESPONSE:

BC Hydro assumes that 'external market risks' in the question relates to the risk of market prices being higher or lower than forecast, which would affect the Cost of Energy.

Yes, there are external market risks that BC Hydro is exposed to because the price that BC Hydro pays to or receives from Powerex for its purchases or sales is based on a market index price at Mid-C. Consequently, BC Hydro considers the Mid-C price in its Energy Studies.

The Energy Study would 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, only to the extent such changes impact the Mid-C price (due to the integrated nature of western energy markets). As with any commodity, forward market prices already factor in risks in remote markets to the extent that they impact prices in the local market.

309.0 E. CHAPTER 4 – COST OF ENERGY

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

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3.309.4 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.

RESPONSE:

BC Hydro operates its System Storage to help protect ratepayers from changes in market prices because storage provides some flexibility to time Market Purchases and Surplus Sales.

BC Hydro also incorporates market price variability into its optimization of net revenue from operations in the Energy Study. As described in BC Hydro's response to BCUC IR 1.31.1, variability in market prices is only one component of the overall variability considered in the Energy Study and is addressed by considering a range of possible Mid-C prices over the five-year horizon of the Energy Study.

Variances between forecast and actual Cost of Energy are deferred to the Cost of Energy variance accounts for future recovery from or refund to ratepayers.

309.0 E. CHAPTER 4 – COST OF ENERGY

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

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.

3.309.5 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.

RESPONSE:

As noted on page 4-15 of the Application, "At the beginning of each Energy Study, Powerex provides BC Hydro with forward market price curves for electricity at Mid-C and gas prices at Sumas. The Energy Study uses these forward curves as a starting point and then adds variability to these prices to capture an expected range of price uncertainty."

Henry Hub is the most liquid forward natural gas trading market in North America with a long history of spot and forward trading prices. In the forward markets, Sumas Gas prices trade as a basis to the Henry Hub price. BC Hydro thus uses the Henry Hub Price to help forecast potential variability in gas prices at Sumas. California and Desert Southwest forward market prices do not provide any incremental benefit for forecasting Mid-C forward prices because Mid-C forward prices are similarly liquid to California or the Desert Southwest and Mid-C prices are not defined as a spread to California or the Desert Southwest. The Energy Studies market model uses the historic spot and forward prices as part of the process that develops the range of price uncertainty.

309.0 E. CHAPTER 4 – COST OF ENERGY

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
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3.309.6 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.

RESPONSE:

The requested chart has not been provided. BC Hydro has received this data pursuant to subscription services with Platts and ICE Data, LP, both of which are subject to confidentiality restrictions. BC Hydro is therefore not authorized to disclose the data unless consent is obtained. BC Hydro will seek to obtain consent from Platts and ICE Data, LP and, if obtained, BC Hydro will provide the data to the BCUC as part of its response to the fourth round of Information Requests. Any such disclosure by BC Hydro would need to be subject to the BCUC confirming that the information would remain confidential to the BCUC only.

Henry Hub prices have historically been driven by North American natural gas supply and demand fundamentals. Sumas gas prices are often correlated to Henry Hub gas prices, but can become separated as a result of local conditions.

Mid-C prices are generally correlated with Sumas gas prices because natural gas fired generation in the Pacific Northwest is often the marginal source of energy. However, there are times when Mid-C prices disconnect from the Sumas gas

price. One example of this occurs during the freshet, when most of the Pacific Northwest gas-fired generation is shutdown. Another example when a disconnect can occur is when there are generation capacity constraints.

310.0 E. CHAPTER 4 – COST OF ENERGY

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.

3.310.1 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.

RESPONSE:

Attachment 1 to this response provides eTag examples reflecting the export of electricity from BC Hydro's system to the U.S. for the following export transmission paths:

1. **W/BCHA/BCHA-BPAT/KI-BC.US.BORDER;**
2. **W/BCHA/BCHA-BPAT/GMS.MCA.REV-BC.US.BORDER;**
3. **W/BCHA/BCHA-BPAT/BCHA.INT.SYS -BC.US.BORDER; and**
4. **W/BCHA/BCHA-BPAT/BCHA.LM.SYS-BC.US.BORDER.**

This attachment is being filed in confidence with the BCUC only. The eTags included in this attachment represent confidential customer business information and the eTag print-out format is proprietary to BC Hydro's webSmartTag supplier.

BC Hydro does not have a recent transmission reservation on the path W/BCHA/BCHA-BPAT/ POWELL.RIVER-BC.US.BORDER. Accordingly, no eTag example is available for this path.

Please also refer to BC Hydro's *Submitting Energy Schedules Business Practice*, previously provided as Attachment 7 to BC Hydro's response to BCUC IR 1.163.1, for additional discussion of scheduling on BC Hydro's transmission system.

The following table provides the definitions of abbreviations used in eTags.

Abbreviation	Definition
GCA	Generation Control Area
PSE	Purchasing Selling Entity
LCA	Load Control Area
CA	Control Area
TP	Transmission Provider
MO	Market Operator
Sched Entities	Scheduling Entities
Product: 1-NS	Non-Firm Service over secondary receipt and delivery points
Product: 2-NH	Non-Firm Hourly Service
Product: 3-ND	Non-Firm Daily Service
Product: 4-NW	Non-Firm Weekly Service
Product: 5-NM	Non-Firm Monthly Service
Product: 6-NN	Network Integration Transmission Service from sources not designated as network resources
Product: 7-F	Firm Point-to-Point Transmission
Product: 7-FN	Network Integration Transmission Service from Designated Resources

Attachment 2 to this response summarizes the information and terms contained within eTags. This attachment is being filed in confidence with the BCUC only as it is proprietary to BC Hydro's webSmartTag supplier.

For additional information on eTags, please refer to the section "Parts of an e-Tag", beginning on page 12 of the Interchange Reference Guidelines published by the North American Electric Reliability Corporation and included as Attachment 3 to this response.

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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Interchange Reference Guidelines

Version 2

RELIABILITY | ACCOUNTABILITY



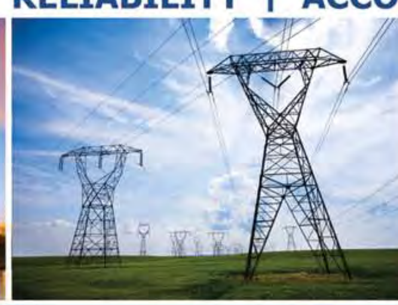


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Table of Contents

Revision Log

Revision Number	Description of changes
1	• Original document
2	• Added *Table of Contents* section • Added *Revision Log* section • Added *Introduction* section • Added *Interchange Terms* section • Notated all NERC Glossary terms within the document • Added *Interchange Coordinator* section • Updated previous section "The Relationship between Interchange Transactions and Interchange Schedules" section into new *Interchange Fundamentals* section • Added *Implementing Interchange* section • Added *Practical Guide to Interchange Implementation* section including references to the e-Tag specifications and schema • Moved and updated previous "Implementing Interchanges Schedules" section to *Other Interchange Schedule Concepts* subsection • Added *A Note on Dynamic Transfers* section • Added *Consideration for Interchange Involving DC Tie Operator* section • Removed previous section "Interchange Schedules within a Multi-Party Regional Agreement or Transmission Tariff"

Introduction

The Interchange Reference Guidelines address and explain the process to implement Interchange. This document is intended to address the following:

1. Defines Interchange terms,
2. Reviews Interchange Transaction and Interchange Schedule concepts,
3. Reviews the theory of implementing Interchange,
4. Reviews the practical processes used to implement Interchange via e-Tag, and
5. Discusses Dynamic Schedules and DC Ties as related to Interchange.

Interchange Terms

NOTE: In this document, the use of the terms are intended to be identical with the NERC "**Glossary of Terms Used in Reliability Standards"** and the NAESB Business Practice Standard WEQ-000 titled **"Abbreviations, Acronyms, and Definition of Terms".** The definitions listed in the two documents above should prevail if there are any discrepancies. The NERC **"Glossary of Terms Used in Reliability Standards"** is posted at the NERC website in the same location as the Reliability Standards under the link name **"Glossary of Terms"**.

The following terms are used in this document and not defined in standardized industry *Business Practices*:

Market Assessment – The evaluation and verification of the commercial details of *Interchange.*
Market Operator – An entity that is responsible for the implementation of an organized market and submits market adjustments based on market outcomes. A Market Operator must be registered in the Electric Industry Registry (EIR) in order to submit market adjustments.

Wide Area Reliability Tool — This generic term is intended to reflect in a "tool neutral" manner those wide-area reliability assessment tools (such as the *Interchange Distribution Calculator (IDC)* for the Eastern *Interconnection*) acknowledged by NERC as a decision making tool among various reliability entities.

Reliability Assessment – The evaluation and verification of the reliability details of *Interchange*

All terms from the NERC Glossary and defined above are capitalized and italicized in this document. Certain other terms from other locations, such as the e-Tag specification, may be capitalized as well.

Interchange Coordinator

The NERC Functional Model lists the Interchange Coordinator (IC) as the function responsible for communicating *Arranged Interchange* for reliability evaluation and for communicating *Confirmed Interchange* to be implemented between *Balancing Authorities (BAs)*. However, NERC reliability standards refer to the *Interchange Authority (IA)*. These guidelines do not make reference to the *IA* or the IC, but instead refers to the *Sink Balancing Authority* as the responsible entity.

Interchange Fundamentals

The Relationship between Interchange Transactions and Interchange Schedules

Purchasing-Selling Entities (PSEs) and in some instances *BAs* "arrange" *Interchange Transactions* by buying and selling energy and capacity and arranging for *Transmission Services*. A compilation of these arranged *Transactions* are forwarded by the *PSE* to the *Sink Balancing Authority*. Reliability entities assess and "approve" or "deny" *Interchange Transactions* based on reliability criteria, arrangements for *Interconnected Operations Services*, and *Transmission* rights. To "implement" the *Interchange Transaction*, all affected reliability entities incorporate the *Interchange Transaction* into their *Interchange Schedules* as explained on the following pages.

In this example, there are three *Interchange Transactions* (IT1, IT2, and IT3) that result in a number of *Interchange Schedules* between *BAs* A, B, C, and D. (Refer to Figure A on the right and Table 1 below. For simplicity, we are ignoring losses.)

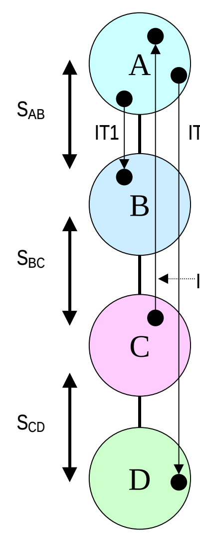

Figure A - Interchange Transactions and Schedules

Interchange Transaction 1 (IT1)

BA A is the *Source Balancing Authority* for *Interchange Transaction* 1 (IT1), and *BA* B is the *Sink Balancing Authority*. To make IT1 occur, *BA* A implements an *Interchange Schedule* with *BA* B ($S_{AB\text{-}IT1}$). In this case, the *Source Balancing Authority* A is the *Sending Balancing Authority*, and the *Sink Balancing Authority* B is the *Receiving Balancing Authority*.

Interchange Transaction 2 (IT2)

BA A is also the *Source Balancing Authority* for *Interchange Transaction* 2 (IT2). *BA* D is the *Sink Balancing Authority* for this *Interchange Transaction*. B and C are *Intermediate Balancing Authorities*. The resulting *Interchange Schedules* are from *Sending Balancing Authority* A to *Receiving Balancing Authority* B ($S_{AB\text{-}IT2}$), *Sending Balancing Authority* B to *Receiving Balancing Authority* C ($S_{BC\text{-}IT2}$), and *Sending Balancing Authority* C to *Receiving Balancing Authority* D ($S_{CD\text{-}IT2}$).

Interchange Transaction 3 (IT3)

BA C is the *Source Balancing Authority* for *Interchange Transaction* 3 (IT3), and *BA* A is the *Sink Balancing Authority*. B is the *Intermediary Balancing Authority*. To make IT3 occur, *Sending Balancing Authority* C implements an *Interchange Schedule* with *Receiving Balancing Authority* B ($S_{CB\text{-}IT3}$), and *Sending Balancing Authority* B implements an *Interchange Schedule* with *Receiving Balancing Authority* A ($S_{BA\text{-}IT3}$).

Net Schedules

BAs A and B can calculate a *Net Interchange Schedule* between these two *BAs* by adding $S_{AB\text{-}IT1}$ and $S_{AB\text{-}IT2}$ and $S_{BA\text{-}IT3}$. *BAs* B and C can calculate a *Net Interchange Schedule* between these two *BAs* by adding $S_{BC\text{-}IT2}$ and $S_{CB\text{-}IT3}$.

The *Net Scheduled Interchange* for A is $S_{AB\text{-}IT1} + S_{AB\text{-}IT2} + S_{BA\text{-}IT3}$. The *Net Scheduled Interchange* for B is $S_{AB\text{-}IT1} + S_{AB\text{-}IT2} + S_{BA\text{-}IT3} + S_{BC\text{-}IT2} + S_{CB\text{-}IT3}$.

Balancing Authority	Sink Balancing Authority for:	Source Balancing Authority for:	Sending Balancing Authority for:	Receiving Balancing Authority for:	Net Interchange Schedules	
A	IT3	IT1, IT2	IT1, IT2	IT3	$S_{AB\text{-}IT1} + S_{AB\text{-}IT2} + S_{BA\text{-}IT3}$	Match
B	IT1		IT2, IT3	IT1, IT2, IT3	$S_{AB\text{-}IT1} + S_{AB\text{-}IT2} + S_{BA\text{-}IT3}$ $S_{BC\text{-}IT2} + S_{CB\text{-}IT3}$	 Match
C		IT3	IT2, IT3	IT2	$S_{BC\text{-}IT2} + S_{CB\text{-}IT3}$ $S_{CD\text{-}IT2}$	 Match
D	IT2			IT2	$S_{CD\text{-}IT2}$	

Table 1 - Relationship Between Balancing Authorities, Interchange Schedules, and Interchange Transactions

Implementing Interchange

Interchange Transactions are the representation of a *PSE* or *BA* arranging for energy and capacity transfers between different parties. From a real-world perspective, these compiled arrangements are known as a *Request for Interchange (RFI)*. The *RFI* goes through two types of assessment: *Market Assessment* and *Reliability Assessment*.

Prior to the assessment stages, the *PSE* puts together the business arrangements for the *Interchange* with *Transmission Service Providers (TSPs)*, *Generation Providing Entities(GPEs)*, and *Load-Serving Entities (LSEs)* and may obtain preliminary reliability approvals from *BAs*, *TSPs*, and *Reliability Coordinators (RCs)* where required. At this stage, *Agreements* (including *Transmission Service* reservations) are aggregated into a single request. This aggregated information, the *RFI*, is sent to the *BAs*, *PSEs*, and *TSPs* and begins both the *Market Assessment* and *Reliability Assessment*.

During the *Market Assessment* and *Reliability Assessment*, the *RFI* proposed by the *PSE* is evaluated by the approval entities to ensure all the proper information has been given for both commercial and reliability issues and that system conditions allow for approval. Note that the actual *RFI* submission can be assessed and approved or denied by both market and reliability entities.

In both the NERC Standards and NAESB Business Practice Standards, *RFIs* go through several transitions as they are evaluated. Prior to either assessment period, any compiled arrangements are known only as *RFI*. Once the *RFI* is passed to the reliability and market entities to begin evaluation during the *Reliability Assessment* and *Market Assessment*, respectively, then the *RFI* becomes known as *Arranged Interchange*. If approvals are obtained from all entities with approval rights during the *Reliability Assessment* and *Market Assessment*, then the *Arranged Interchange* transitions to *Confirmed Interchange*. *Confirmed Interchange* has obtained all necessary approvals and is ready to be implemented in the *Net Scheduled Interchange* portion of all impacted *BAs*. Once the *Ramp* start time is reached, *Confirmed Interchange* transitions to *Implemented Interchange*. At that point in time, each impacted *BA* will implement the *Implemented Interchange* value into their *Area Control Error (ACE)* equation as part of the *Net Scheduled Interchange*.

The "Normal" Process of Coordinating Interchange

Figure B below shows the normal, reliability-related steps in coordinating *Interchange*. When the *RFI* is submitted to the *Sink Balancing Authority*, it is processed through the *Market Assessment* and *Reliability Assessment*. Once approved during the assessments, the *Sink Balancing Authority* electronically distributes the *Interchange* status, and the *Interchange* information is entered into the *Wide Area Reliability Tool* and into the *ACE* equations of the applicable *BAs*. Note that the NERC INT Standards require coordination of any *Interchange* with any DC tie operating *BA* on the *Scheduling Path*.

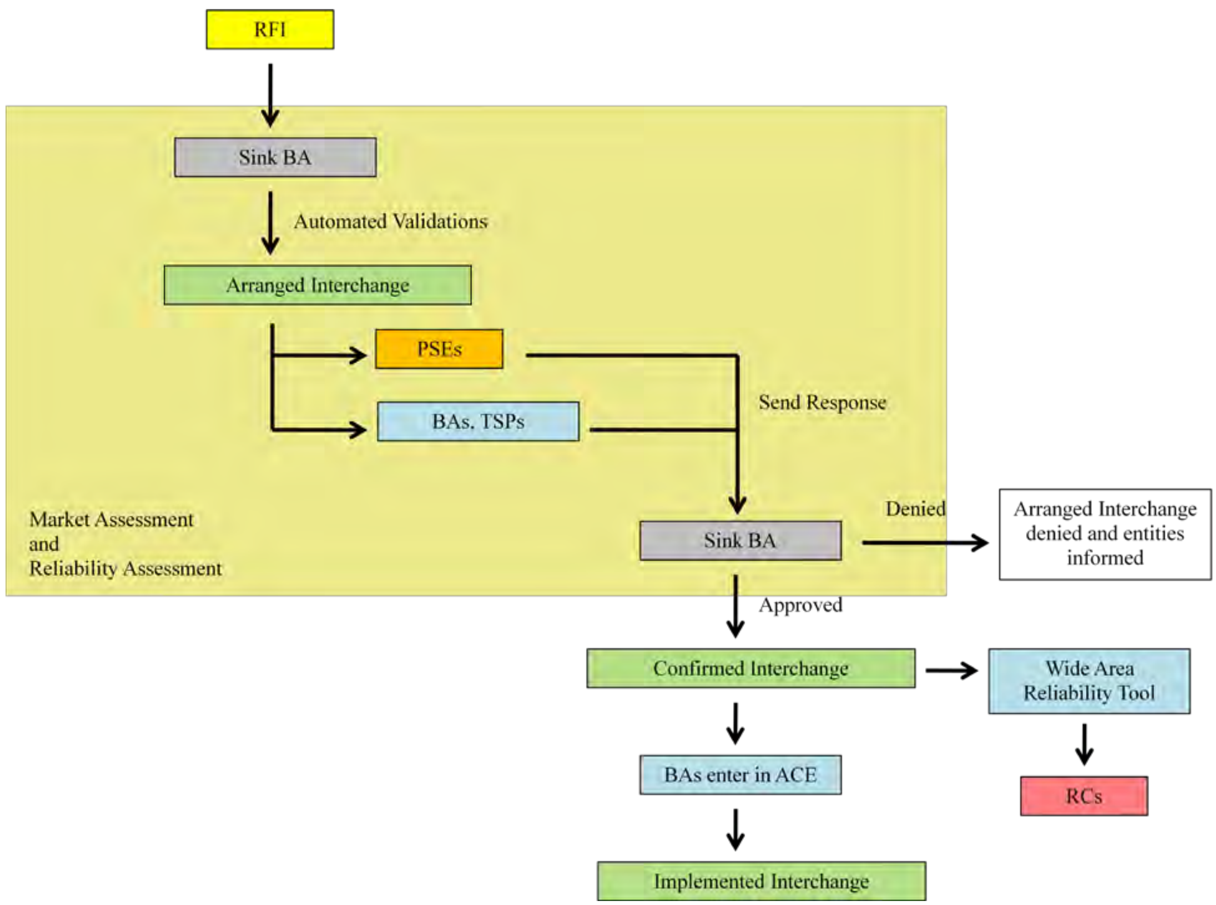

Figure B - Processing on Initial RFI Submission

Interchange Changes for Reliability Reasons

Once *Arranged Interchange* has transitioned to the *Confirmed Interchange* or *Implemented Interchange*, it is entirely possible that the *Interchange* parameters (i.e., MW, *Ramp* start and stop, duration, etc.) may need to change for reliability reasons. The change to *Confirmed Interchange* or *Implemented Interchange* does not eliminate the necessity for coordination. While Figure B shows the coordination that takes place when an *RFI* is initially submitted, Figure C shows coordination steps to effect a change to *Confirmed Interchange* or *Implemented Interchange*.

Interchange created to address an actual or anticipated reliability-related risk or as part of an energy sharing *Agreement* is implemented first without submitting an *RFI* and then follows the submission and transition steps shown in Figure B. *Interchange* modified to address an actual or anticipated reliability-related risk, known as *Reliability Adjustment RFI*, is implemented first and then follows the submission and transition steps shown in Figure C. Note that when submitting *Reliability Adjustment RFI*, only a *Reliability Assessment* occurs since approval rights are only granted to the *Source Balancing Authority* and *Sink Balancing Authority*.

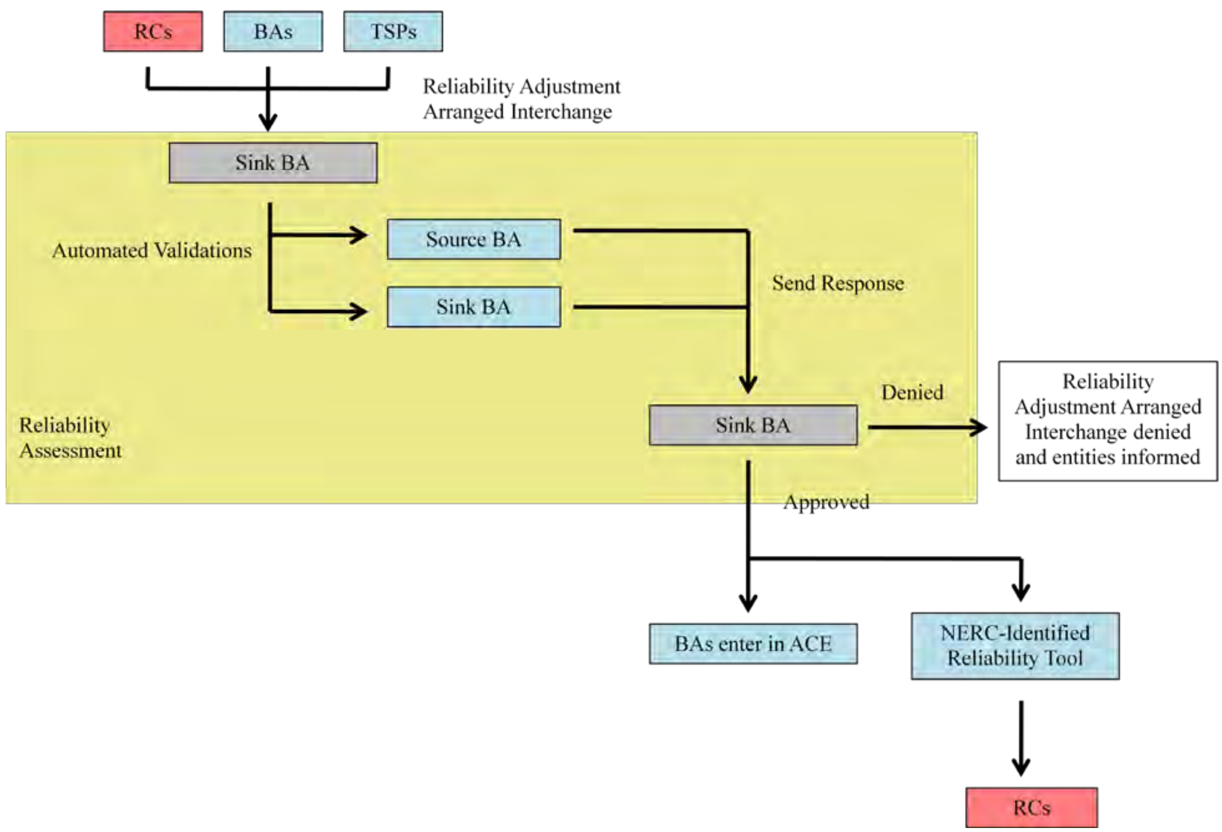

Figure C – Processing of Reliability Adjustment RFI Request

Interchange Changes for Market Reasons

Figure D shows a change (e.g., cancel, increase MW, decrease MW, change *Ramp* or duration info, etc.) initiated by the *PSE*, *BA*, or *Market Operator* for non-reliability reasons once the *Arranged Interchange* has transitioned to *Confirmed Interchange* or *Implemented Interchange*. In this case, the *Confirmed Interchange* or *Implemented Interchange* will undergo the same *Market Assessment* and *Reliability Assessment* as performed when submitting the initial *RFI*. Subsequent steps also follow the same process.

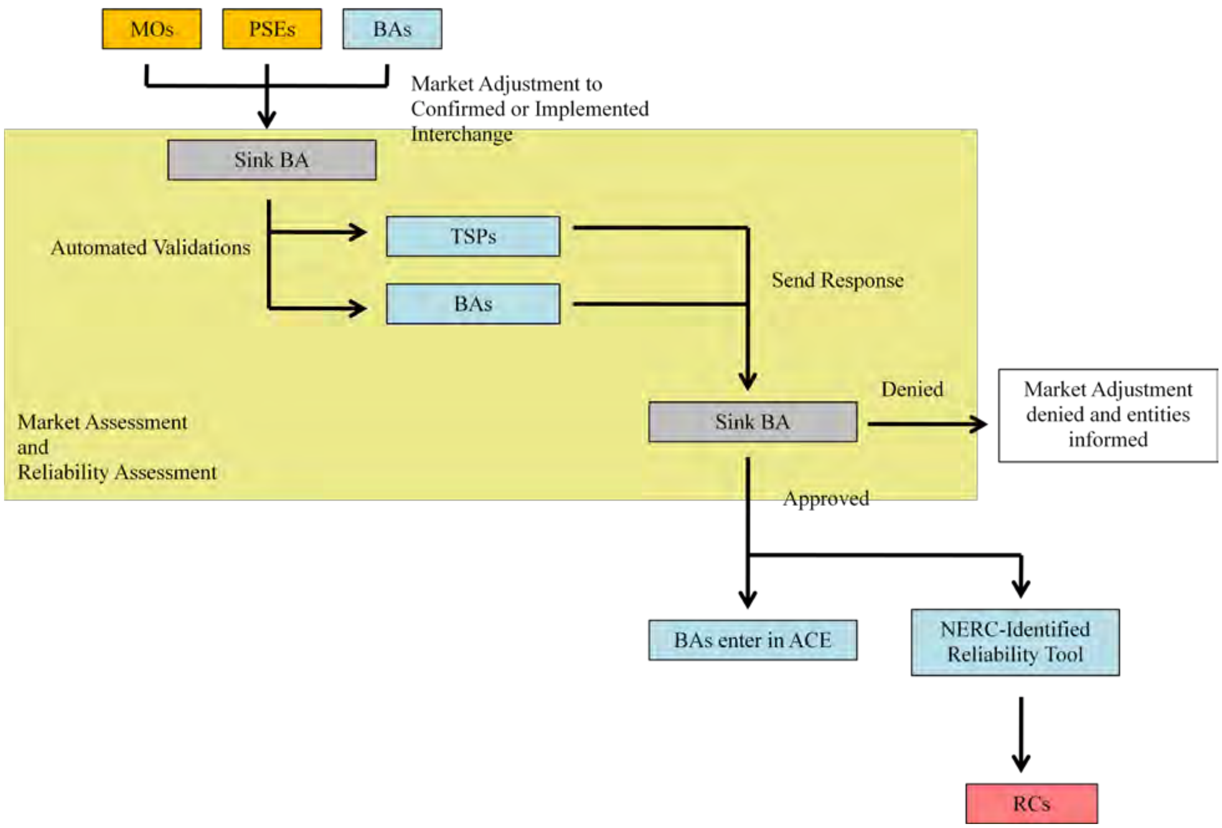

Figure D – Processing of Market Adjustment Request

Practical Guide to Interchange Implementation

The previous sections of this document detail some of the concept behind accomplishing *Interchange*. The first section discussed *Interchange* in terms of how it is transferred between different entities. The second section discussed the way *Interchange* is processed from a theoretical perspective and using terms that are not used during the daily processing of *Interchange*. This section will describe how *Interchange* is practically accomplished on a daily basis.

Interchange is a coordinated process. This process involves arranging for transferring power from a source to a sink point and arranging for the *Transmission* rights across all impacted entities. As this practice grew in volume, the industry moved to adopt technology that would facilitate the business and allow *RCs* to manage *Transmission* congestion. The systems that facilitate the business are based on the e-Tag specifications and schema. Systems implementing the e-Tag specifications allow for entities involved in *Interchange* to assemble an *RFI* into an e-Tag and then send it out for the required approvals before implementation. Any entity that has registered a Tag Agent Service in the EIR can assemble and submit an e-Tag. Typically an entity related to the *Sink Balancing Authority* is responsible for gathering the power deals and *Transmission* rights for submission.

The e-Tag Specifications and Schema are maintained by NAESB and assist in providing the processes required by the NERC and NAESB standards related to *Interchange*. The Joint Electric Scheduling Subcommittee has the primary obligation of monitoring and modifying the e-Tag Specifications and Schema and also has reporting obligations to both the NAESB Executive Committee and the NERC Interchange Subcommittee.

A Note on Wide Area Reliability Tools

In order to maintain reliability, *Interchange* must be coordinated with several entities other than those involved in the transaction. One type of monitoring is accomplished by *Wide Area Reliability Tools*; examples of such tools include the IDC in the Eastern *Interconnection* and webSAS in the Western *Interconnection*. These tools are used for managing congestion when *RCs* (Eastern *Interconnection*) or *BAs* (Western *Interconnection*) issue adjustments to *Interchange* to relieve congested paths in real-time, Each *Wide Area Reliability Tool* has a specific set of rules on how *Interchange* is adjusted.

Functions Detailed in the e-Tag Specifications

The e-Tag Specifications and Schema discuss the practices and technical details needed in the systems that drive e-Tag. Systems implementing the e-Tag specifications are based on transferring data over the Internet to gather and distribute approvals. Most entities implement the e-Tag specifications by contracting with vendors that have developed these systems. The e-Tag Specifications details three main functions that are needed, and all three functions are accomplished by most vendors with their software:

1. Tag Agent - Software component used to generate and submit new e-Tags, Corrections, and Profile Changes to an Authority and to receive State information for these requests.

2. Tag Approval - Software component used to indicate individual approval entity responses when requested by Authority Service as well as submit Profile Changes.
3. Tag Authority - Software component that receives Agent and Approval Requests and Responses and forwards them to the appropriate Approval Services. Also maintains master copy of an e-Tag (all associated Requests), the Composite State of the e-Tag, etc. and responds to queries regarding the e-Tags in its possession.

These different functions ensure that e-Tag submission, approval, and coordination are all handled properly.

Parts of an e-Tag

An e-Tag has several required components in order to be valid. Without these components, the necessary information would not be conveyed to the approving entities. Most software has checks in place to ensure the proper information is supplied. The required parts of an e-Tag include:

1. e-Tag ID – Each e-Tag has a unique e-Tag identifier based on four key attributes:
   a. Source Balancing Authority Code
   b. PSE Code (Tag Author PSE)
   c. Unique transaction identifier
   d. Sink Balancing Authority Code

   The codes specified above for *BAs* and *PSEs* come from the EIR which will be detailed below.

2. Transaction Types – There are several variations in the transaction type that can be chosen for an e-Tag. Transaction types assist in noting the purpose and implementation of a particular e-Tag. Specific *Transmission* tariffs and *Business Practices* should be referenced to determine which of the following transaction types should be selected. e-Tag recognizes the following transaction types:
   a. Normal: These are the normal energy *Schedules* and should represent the largest number of e-Tags. They will include *Schedules* that use *Point to Point Transmission Service*, *Network Integration Transmission Service*, or grand-fathered service under a regional tariff.
   b. Dynamic: A *Dynamic Schedule* is scheduled using an expected value but the actual energy transfer is determined in *Real-time* by separate communications external to the e-Tag system. Also included in this type will be regulation energy *Schedules* and energy imbalance *Schedules*. The e-Tag should contain the expected average energy in the energy profile and contain the maximum expected energy in the Transmission Allocation. Dynamic e-Tags may be adjusted by the *Source Balancing Authority*, *Sink Balancing Authority*, or e-Tag author up to 168 hours in the past using a market adjust to set the actual *Interchange Schedule* value. For additional information related to implementation of *Dynamic Schedules,* please see the Dynamic Transfer Reference Guidelines.

c. Emergency: *Emergency Schedules*, including reserve sharing, *Spinning Reserve*, and supplemental reserve may be scheduled as *Emergency Schedule* Type. For additional detail of when to use Emergency type, see the NERC Glossary of Terms for *Emergency RFI* as well as *Emergency* and *Energy Emergency.*

d. Loss Supply: Loss Supply type is used for customers to self-supply losses. This type is used to differentiate between a loss *Schedule* and a normal *Schedule*. Some tariffs presently require that *Schedules* for losses require different treatment than *Schedules* for the associated energy.

e. Capacity: Capacity type is typically used for entities to import *Operating Reserves* from outside their *Reserve Sharing Group* but may also be used to arrange for purchases or sales of *Spinning Reserve* and supplemental reserve between other entities. This type of e-Tag may be activated upon contingency with zero *Ramp* durations.

f. Pseudo-Tie: A *Dynamic Transfer* implemented as a *Pseudo-Tie* rather than a *Dynamic Schedule*. This type is used in the same way as a Dynamic e-Tag. These e-Tags may be adjusted in the same manner as Dynamic transaction type e-Tags. For additional information related to implementation of *Pseudo Ties,* please see the Dynamic Transfer Reference Guidelines.

g. Recallable: A WECC-only transaction type typically used for “interruptible” or “non-firm” transactions. Adjustments to this transaction type only require *Source Balancing Authority* & *Sink Balancing Authority* approval..

3. Market Segments – Each e-Tag has a section to identify those portions of the path that are associated with the tracking of title and responsibility. Market Segments contain information that describes the market information, such as the identity of the market participant, the firmness of energy the market participant is delivering, and the physical segments the entity is responsible for providing. Market Segments must be listed in order from the *PSE* responsible for generation to the *PSE* responsible for *Load*. There will only be one market segment for generation and one segment for *Load*, but there can be multiple intermediate market segments. Market Segments can describe the responsibility for scheduling actual power delivery, or it can describe non-physical title transfers. These are seen when a market participant takes financial possession for the energy commodity but does not physically move that energy before transferring possession to another financially responsible party. When this occurs, the market segment will not contain any physical segments.

4. Physical Segments – e-Tags also have a section to represent those portions of the path that are physical in nature and represent a movement of energy. There are three types of Physical Segment:

   a. Generation - Generation Segments contain information that describes a generation resource, such as the location of the generation, the firmness of the energy supplied by the resource, and contract references that identify the resource commitment.

b. Transmission – Transmission Segments contain identification that describes a *Transmission Service*, such as the identity of the provider, the *Point of Receipt (POR)* and *Point of Delivery (POD)* of the service, the firmness of the service, simple loss information, and contract references that identify the service commitment.

   Load - Load Segments contain information that describes a *Load*, such as the location of the *Load*, the interruptability of the *Load*, and contract references that identify the *Load* obligation. All definitions for information in the segments above must be valid in the EIR which will be described below. Physical Segments must be listed in order from Generation to *Load*. Generation Segments must always be listed first, while Load Segments must be listed last. e-Tags may only have one Generation Segment and one Load Segment. All physical segments must reference a parent market segment, identifying the market entity responsible for the physical segment. These references must also be in an order that matches that described by the market segments. An optional field in the Physical Segments is Scheduling Entities. Many *TSPs* require that e-Tags illustrate not only the contractual relationship between the *TSP* and the *Transmission Customer* but also the internal scheduling information to implement the *Transmission Service* sold under their *TSP's Transmission* tariff. To this end, Scheduling Entities may be defined for a particular Transmission segment.

5. Profile Set – The Profile Sets, commonly referred to as the Energy Profile, section of an e-Tag defines the level at which transactions should run as well as the factors that set those levels. Profiles are specified as a series of time-ordered segments of duration associated with a particular profile. Profiles may optionally contain *Ramp* duration (in minutes) associated with both start time and stop time. The *Ramp* stop time is not needed (and is ignored) in any profile except for the last profile. The *Ramp* duration specifies the number of minutes over which the generator will change from the previous block level to the current block level. *Interchange Schedule* ramping is executed between *BAs* using straddle *Ramp* methods as defined below in "Other Interchange Schedule Concepts".. The *Ramp* duration exists in the e-Tag in order to provide a vehicle by which *Ramp* duration may be exchanged between entities. The Profile Set of an e-Tag is influenced by two different profiles:

   a. Market Limit - The Market Limit defines the level at which the e-Tag author wishes the transaction to run. This level can be used to specify an initial value for a *Dynamic Schedule* as well as a simple level at which the transaction is to be run.

   b. Reliability Limit – The Reliability Limit defines the maximum allowable level at which a transaction may run when that transaction has been identified by a *RC* or other reliability entity as being limited by some *Constrained Facility*. This limit is typically used to indicate *Curtailments*.

      The lower of the most recent approved Market Limit and most recent approved Reliability Limit sets the Current Level on an e-Tag. The Current Level contains the level at which the transaction should be running based on all approved Requests processed by the Authority.

6. Transmission Allocation - Transmission Allocations are a type of e-Tag profile set that defines the way in which market participants will fill their capacity commitments with *Transmission Service* reservations. Transmission Allocations specify a particular reservation, the provider associated with the reservation, and profiles associated with that reservation that describe how the reservation should be consumed. Transmission Allocations must always be associated with Transmission Physical Segments; association with other segments (such as Generation or Load) is not allowed. The Maximum Reservation Capacity associated with each physicalsegment should be greater than or equal to the energy profile. The Transmission Allocation for all Transmission segments must be greater than or equal to the minimum of the *POR* profile and *POD* profile for that segment. One or more *Transmission Service* reservations may be utilized together in what is known as stacking. There are two types of stacking:

   a. Vertical Stacking – A market participant may have two or more *Transmission Service* reservations flowing from the same source to the same sink for the same time period. In this case, Vertical Stacking can be used to tag a Profile Set equal to the combined capacity of the two *Transmission Service* reservations. For example, an e-Tag author can use two 50 MW *Transmission Service* reservations on the same e-Tag to cover 100 MW on the Energy Profile. Figure E shows an example of how Vertical Stacking appears on an e-Tag.

Start	Stop	Energy Profile	Transmission Allocation	
Time	Time	MW	Reservation 1	Reservation 2
12:00	13:00	100	50	50

Figure E – Vertical Stacking

   b. Horizontal Stacking – A market participant may have two or more reservations flowing from the same source to the same sink for different hours. In this case, Horizontal Stacking can be used to tag a Profile Set for the entire time range as long as the capacity of the *Transmission Service reservation* for each hour is not exceeded. For example, an e-Tag author can use two 100 MW *Transmission Service* reservations in subsequent hours to cover 100 MW on the Energy Profile for both hours. Figure F shows an example of how Horizontal Stacking appears on an e-Tag.

Start	Stop	Energy Profile	Transmission Allocation	
Time	Time	MW	Reservation 1	Reservation 2
12:00	13:00	100	100	
13:00	14:00	100		100

Figure F – Horizontal Stacking

7. Loss Accounting – The Loss Accounting section of an e-Tag specifies the manner in which losses should be accounted for over a specified period of time. Over time, an e-Tag Author may elect to specify different choices for how losses will be provided. Usually each *Transmission Operator* across which an e-Tag flows will have specified transactions which require losses and also usually detail what type of losses are required. The two main types of losses in the industry today are Financial Losses and In-Kind Losses. The type of losses provided is dependent upon each Transmisson Provider's tariff / contract.

A Note on the Electric Industry Registry

Several sections detailing the required parts of an e-Tag make reference to the EIR. The EIR is a database where participants in the e-Tagging process register information involved in the process. This registration includes entity names and codes, such as *PSEs*, *BAs*, and *TSPs*. Other pieces of information that are registered include Source and Sink names used on e-Tags, authorized *PSEs* for specific sources and sinks, and valid products for use on e-Tags. The EIR is managed by NAESB.

E-Tag Approval and Timing Process

Once an e-Tag is submitted by an author, it is distributed by the Tag Authority to the appropriate approval entities. For new e-Tag submissions and modifications to e-Tags made by *PSEs*, the *PSEs*, *BAs*, *TSPs* specified on the e-Tag have approval rights. For e-Tag modifications requested for reliability reasons (*Curtailments* and reloads), only the *Source Balancing Authority* and *Sink Balancing Authority* have approval rights. All reliability entities must provide their approval for an e-Tag or modification to an e-Tag to be implemented.

In order to manage this approval process, the industry has developed guidelines around the timing of submitting and processing the approvals. These timing rules are part of the NERC Interchange Standards as well as the NAESB Wholesale Electric Quadrant Business Practice Standards. There are differences in the timing tables between the Eastern *Interconnection* and ERCOT *Interconnection* versus the Western *Interconnection*. Therefore, two different tables are used to show these timing differences.

Any e-Tag that is submitted or modified "On-Time" as defined in the NERC INT standards timing tables, as well as any modification to an e-Tag submitted for reliability reasons, must be evaluated. All Late or *After the Fact (ATF)* e-Tag submissions should be evaluated as time permits.

Other Interchange Schedule Concepts

1. **Ramp duration**. When the *Sending Balancing Authority* and *Receiving Balancing Authority* implement an e-Tag between each other in their respective *ACE* equations, the *BAs* must begin their generation adjustments at the same time using the same *Ramp* durations. A mismatch of these parameters will cause a *Frequency Error* in the *Interconnection*. The standard *Ramp* for e-Tags in the Eastern and ERCOT *Interconnections* is 10 minutes across the e-Tag start time (straddle), and the standard *Ramp* for e-Tags in the Western *Interconnection* is 20 minutes across the tag start time (straddle). Non-standard *Ramps* may be used as long as all *BAs* involved in the *Transaction* agree to the *Ramp* stated on the e-Tag. Figure G shows standard *Ramps*.

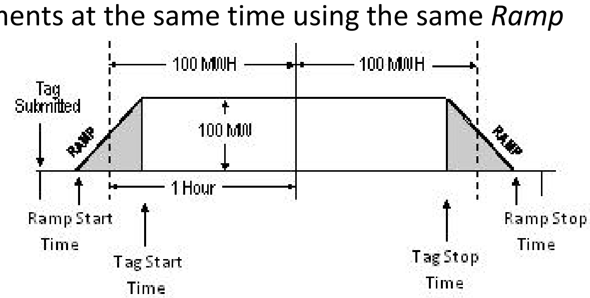

Figure G - Interchange Schedule resulting from 100 MW Interchange Transaction for two hours showing ramps, energy profiles, and energy accounting for each hour.

2. **Starting and ending times**. Most e-Tags generally start and end on the *Clock Hour*. However, *PSEs* may submit e-Tags that start and/or stop at other times beside the *Clock Hour*. *BAs* and *TSPs* should try to accommodate these intra-hour e-Tags. Figure G shows a two hour *Interchange Schedule* starting and stopping at the top of the hour.

3. **Interchange accounting**. All *BAs* must account for their *Interchange Schedules* the same way to enable them to confirm their *Net Interchange Schedules* each day with their *Adjacent Balancing Authorities* as required in NERC BAL Standard **BAL-006 (Inadvertent Interchange)**. *BAs* traditionally use "block" *Interchange Schedule* accounting. This accounting method ignores straddle *Ramp* times and instead uses the *Transaction* start and stop times. This, in effect, moves the energy associated with the starting and ending *Ramps* into their adjacent starting and ending *Clock Hours* of the *Interchange Schedule*. Figure H illustrates the block accounting principle.

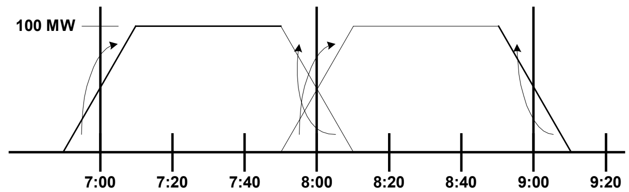

Figure H - Block accounting moves the ramp energy into the adjacent Clock Hours.

A Note on Dynamic Transfers

Dynamic Schedules and *Pseudo-Ties are special Transactions* that rely on time-varying energy tra*nsfers. While e-Tag prov*ides for both transac*tion types, many tagging requi*rements for both types are addressed in regional criteria and *Transmission Operator Business Practices. For more detai*l on these types of *Transactions*, see the NERC Dynamic *Tra*nsfer Guidelines document.

Consideration for Interchange Involving DC Tie Operators

Per the NERC INT Standards, the *Sending Balancing Authorities* and *Receiving Balancing Authorities will co*ordinate *Interchange with an*y DC tie operating *BA*. Note that DC tie operators that are *Intermediate Balancing Authorities* would receive the *Interchange Schedule* information and be subject to the applicable INT standards. The DC Tie operator also would be responsible for notifying the *Sink Balancing Authority* of a DC tie trip and the associated Interchange modification

310.0 E. CHAPTER 4 – COST OF ENERGY

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.

3.310.2 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.

RESPONSE:

Attachment 1 to this response provides eTag examples reflecting the export of electricity from BC Hydro's system to Alberta for the following export transmission paths:

1. **W/BCHA/BCHA-AESO/GMS.MCA.REV-AB.BC; and**
2. **W/BCHA/BCHA-AESO/BCHA.INT.SYS-AB.BC.**

This attachment is being filed in confidence with the BCUC only. The eTags included in this attachment represent confidential customer business information and the eTag print-out format is proprietary to BC Hydro's webSmartTag supplier.

BC Hydro does not have a recent transmission reservation on the paths W/BCHA/BCHA-AESO/KI-AB.BC, W/BCHA/BCHA-AESO/BCHA.LM.SYS-AB.BC or W/BCHA/BCHA-AESO/ POWELL.RIVER-AB.BC. Accordingly, no eTag examples are available for these paths.

CONFIDENTIAL ATTACHMENT

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311.0 E. CHAPTER 4 – COST OF ENERGY

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

3.311.1 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.

RESPONSE:

BC Hydro is providing two eTag examples in BCUC Confidential Attachment 1 reflecting the import of electricity that was used to supply domestic load.
BC Hydro notes that deliveries from Powerex to BC Hydro at the border in any given hour could include purchases under numerous agreements, such as under the 2018 Letter Agreement, the Transfer Pricing Agreement, the Skagit Treaty, etc. There is not necessarily a one-to-one correspondence between specific eTags and specific agreements or transactions.

The eTags included in Attachment 1 to this response represent confidential customer business information and the eTag print-out format is proprietary to BC Hydro's webSmartTag supplier.

Please refer to BC Hydro's response to BCUC IR 3.310.1, including its attachments, for additional description of information contained on eTags. Please also refer to BC Hydro's *Submitting Energy Schedules Business Practice*, previously provided as Attachment 7 to BC Hydro's response to BCUC IR 1.163.1, for additional discussion of scheduling on BC Hydro's transmission system.

CONFIDENTIAL ATTACHMENT

FILED WITH BCUC ONLY

312.0 E. CHAPTER 4 – COST OF ENERGY

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%

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

RESPONSE:

Confirmed. Distribution losses are included in line 13 of Schedule 4.0 of Appendix A of the Evidentiary Update. BC Hydro calculates line losses and system use as the difference between total domestic sales and total sources of supply. Total sources of supply includes sales to all of BC Hydro's customers and distribution and transmission line losses.

British Columbia Utilities Commission Information Request No. **3.312.2** Dated: **September 19, 2019** British Columbia Hydro & Power Authority Response issued **October 10, 2019**	Page 1 of 1
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit:** **B-16**

312.0 E. CHAPTER 4 – COST OF ENERGY

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%

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

RESPONSE:

Line 15 does not represent average or peak period losses. Rather, it represents the ratio of the difference between total sources of supply and total domestic sales, as a percentage of total domestic sales. On a forecast basis, total sources of supply incorporate an estimate of losses which is based on historical averages.

On an actual basis, line 15 represents the ratio of the difference between total actual sources of supply and total actual domestic sales, as a percentage of total actual domestic sales. Actual losses reflect actual temperatures and system operating conditions which vary from year to year.

For further information on the calculation of line losses please refer to our response to BCUC IR 3.312.10.

312.0 E. CHAPTER 4 – COST OF ENERGY

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

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.”

3.312.3 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.

RESPONSE:

This response also provides the answer to BCUC IR 3.312.4.

The forecast line losses are included in BC Hydro’s forecast of total sources of supply (i.e., system gross requirements), and are shown on line 12 of schedule 4.0 of Appendix A of the Evidentiary Update.

Actual line losses are primarily due to a combination of losses on the high voltage transmission network and losses on the lower voltage distribution network. A variance in the losses on the lower voltage distribution network is driven mainly by variances between forecast and actual billed sales to residential and commercial customers.

In contrast, actual line losses on the high voltage transmission network are impacted by within-province generation patterns. Much of the hydro generation in the province (in the Peace and Columbia regions) is relatively distant from the load centres in the Lower Mainland and Vancouver Island, resulting in transmission losses that are approximately 7 per cent of generation. In contrast, supply from the U.S. tends to have lower losses because it is delivered at the B.C. border, and the largest delivery point (the west side tie line) is at the Lower Mainland. Losses due to IPP and Long-Term Commitments depend on where the generation occurs and the voltage of the associated lines.

The fiscal 2019 difference in hydro generation (line 1, column 3 of schedule 4) plus IPPs and Long-Term Commitments (line 5, column 3 of schedule 4) totals approximately 5,000 GWh. Assuming a 7 per cent loss factor for hydro generation, and IPPs and long-term commitments, then the difference in generation accounts for approximately 350 GWh of the 657 GWh variance in line losses and own use for fiscal 2019, reported on line 13, column 3 of schedule 4.

With respect to the difference between fiscal 2019 actuals and fiscal 2020 forecast, the forecast of line losses for fiscal 2020 reflected in the total source of supply is based on historical averages, and is not impacted by fiscal 2019 actuals. As such, it does not include any adjustments for generation and import patterns, and therefore the forecast of losses for fiscal 2020 is similar to the fiscal 2019 RRA forecast.

312.0 E. CHAPTER 4 – COST OF ENERGY

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

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."

3.312.4 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

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.312.3.

312.0 E. CHAPTER 4 – COST OF ENERGY

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

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."

3.312.5 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.

RESPONSE:

There are many factors that impact actual losses, including how the various sources of generation (i.e. Heritage hydro, IPPs, surplus sales and market purchases) are optimized to meet domestic load. Other factors such as transmission operations and temperature also impact the actual losses. These factors are not used to develop the forecast line losses, which are included in BC Hydro's forecast of total sources of supply (i.e., system gross requirements) which is shown in line 12 on schedule 4.0. Rather, forecast line losses are based on historical averages.

On a plan basis, between fiscal 2020 and fiscal 2021 there is a 0.5 per cent decrease in total domestic sales and 0.6 per cent decrease in total sources of supply. As such, line losses and own use over the test period are approximately the same percentage of total domestic sales as shown on line 15. For the Evidentiary Update (EU), the decrease in total domestic sales and total sources of supply is less than 1 per cent. Therefore, line losses and own use is relatively flat between the Application and the EU for fiscal 2020 and fiscal 2021.

312.0 E. CHAPTER 4 – COST OF ENERGY

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

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)."

3.312.6 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 per cent loss percentage used in wheeling energy from Mid-C to the BC border.

RESPONSE:

BC Hydro's estimated line losses accrue from losses in the over 18,000 km of transmission lines at voltages between 69 kV and 500 kV within B.C., sending power from as far away as the North Coast and Peace regions to the Lower Mainland, as well as on over 60,000 km of lower voltage distribution lines serving residential and commercial customers.

In contrast, the 1.9 per cent losses on the wheel from Mid-C to the B.C. border are per Bonneville Power Authority Transmission Tariff schedule 9, and are related to losses on just the high voltage lines connecting the U.S. to B.C, over much shorter distances.

A link to the schedule is provided here: Bonneville Power Authority Transmission Tariff, Schedule 9.

312.0 E. CHAPTER 4 – COST OF ENERGY

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

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)."

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

RESPONSE:

For the purpose of this analysis, a 1 per cent change in line loss as a percentage of sales (which is assumed to occur in fiscal 2020 and persists into fiscal 2021) is calculated as 533 GWh in each of fiscal 2020 and fiscal 2021. This is calculated by applying 1 per cent to the fiscal 2020 and fiscal 2021 forecast domestic sales volume on line 1 of Schedule 14.0 of Appendix A (53,296 GWh and 53,253 GWh respectively). An impact to finance charges as a result of the change to cost of energy due to the line loss percentage change is assumed to be immaterial and excluded from this analysis.

For fiscal 2020, the impact of a 1 per cent change to the line loss percentage is estimated to result in a change to domestic purchases as almost no surplus sales are forecast in fiscal 2020. Surplus sales volumes of 84 GWh (or $0.4 million) in fiscal 2020 forecast update (lines 9 and 35 of Schedule 4.0 of Appendix A) reflect actual surplus sales recorded for May 2019 during the freshet season when forced exports and low market prices occurred. This gave rise to a skewed average unit cost for surplus sales in fiscal 2020 (line 21 of Schedule 4.0 of Appendix A) at $5.0/MWh due to low volumes at low prices, making surplus sales an unfitting estimate for the purpose of this analysis. Assuming the line loss impact will increase or decrease market purchases in fiscal 2020 by 533 GWh at an average unit cost of $41.5/MWh (line 20 of Schedule 4 of Appendix A), the rate impact is estimated at $22.1 million, or 0.45 per cent in fiscal 2020.

For fiscal 2021, the impact in the 1 per cent change to the line loss percentage that was assumed to occur in fiscal 2020 and persists into fiscal 2021 is estimated to result in a change to surplus sales at an average unit cost of $47.0/MWh (line 21, Schedule 4.0, Appendix A) for 533 GWh. The rate impact is estimated to be

approximately $25.0 million, or 0.50 per cent on a cumulative basis. Assuming a rate increase of 0.45 per cent in fiscal 2020, the required net rate increase in fiscal 2021 is only 0.06 per cent as most of the increase is covered by the fiscal 2020 increase.

312.0 E. CHAPTER 4 – COST OF ENERGY

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

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)."

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

RESPONSE:

As discussed further in BC Hydro's response to BCUC IR 3.312.9, BC Hydro considers transmission line losses when evaluating equipment selection and design.

In addition, BC Hydro operates its system to minimize transmission line losses. For example:

- **System operators manage the electrical grid so that transmission lines are kept in service whenever possible. This reduces the overall impedance of the grid and lowers transmission losses;**
- **Operators take action to maintain a voltage profile within normal operating range across the system to minimize the transfer of reactive power, thereby reducing losses; and**
- **Our Energy Management System is used to calculate real time losses so that operators can see the impact of network topology changes on line losses.**

312.0 E. CHAPTER 4 – COST OF ENERGY

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

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)."

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

RESPONSE:

BC Hydro's incentive to minimize transmission and distribution line losses is realized in increased revenue opportunities through energy sales both inside and outside of B.C. Line loss is one of the major factors that BC Hydro considers in equipment selection and design evaluation. For example:

- **Selection of conductors for use on the system is based on the Life-Cycle Cost assessment and considers purchase, installation, operation, and sustainment, including the impact of line losses across a range of loading conditions (e.g., low and high);**
- **Selection of transformers is based on the total cost of ownership, including capital cost and losses over the lifetime of the transformer; and**
- **System improvements such as phase balancing, three-phasing of single phase lines, conductor upgrades, feeder reconfiguration, voltage management, voltage conversion from 12 kV to 25 kV, etc., are typically performed due to other drivers (i.e., load management) but will have the additional benefit of loss reduction.**

BC Hydro does not have any direct customer incentive programs to reduce transmission and distribution line losses. However, section 7.2.2 of the BC Hydro Electric Tariff (Requirements for Lagging Power Factor) allows for penalties to distribution customers that have a low power factor. This incents distribution customers to improve their power factor, thereby reducing line losses.

Similarly, BC Hydro's Electric Tariff Supplement No. 5 (TS 5) and associated default rate schedules for transmission voltage service use kVA demand for the purpose of calculating Billing Demand. This provides customers with a direct

financial incentive in their demand charge to improve power factor to unity (which will reduce transmission system line losses).

For customers billed under Rate Schedule 1823 (Stepped Rate) and Tariff Supplement 74 (TS 74), BC Hydro treats customer investments to reduce losses in their private transmission line and substation transformer equipment as customer-funded demand side management. These projects are eligible to be recognized as an Energy CBL (Customer Baseline Load) adjustment under TS 74, reducing the marginal rate that the customer pays for energy.

Further, under TS 5, transmission customers are required to maintain a specific minimum power factor at each site (typically 95 per cent lagging). Where a customer's failure to maintain this minimum power factor causes operational problems to BC Hydro's system, BC Hydro has the right to pursue remedies from the customer, including the cost of any necessary system alterations.

312.0 E. CHAPTER 4 – COST OF ENERGY

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

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.

3.312.10 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.

RESPONSE:

The methodology used for forecasting line losses for fiscal 2020 and fiscal 2021 reflected in the total sources of supply (i.e., total system gross requirements) in the Application and the Evidentiary Update is consistent with that used in previous revenue requirement applications.

312.0 E. CHAPTER 4 – COST OF ENERGY

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

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.

3.312.11 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.

RESPONSE:

The losses used in the DSM Plan represent losses between the customer meter and the Lower Mainland. The losses in the Load Forecast, as reflected on line 15 of Schedule 4.0, represent losses between the customer meter and BC Hydro's generation resources.

Losses between the customer meter and the Lower Mainland are lower than losses between the customer meter and generation resources because BC Hydro's main customer load centres are geographically closer to the Lower Mainland than they are to generation resources.

BC Hydro's DSM Plan uses energy savings at the Lower Mainland for the purposes of cost-effectiveness testing. This reflects appropriate valuation of energy benefits because the avoided costs used within these calculations reflect unit energy costs which have been adjusted for delivery to the Lower Mainland.

313.0 E. CHAPTER 4 – COST OF ENERGY

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).

3.313.1 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."

RESPONSE:

It is a coincidence that the variance between plan and actual Cost of Energy in fiscal 2019 of $244.2 million is equal to the $244.2 million increase in the recovery of the Trade Income Deferral Account over the Test Period in the Evidentiary Update compared with the Application.

Both Cost of Energy and Powerex Corp's net income include intercompany transactions that are eliminated upon consolidation. For example, Cost of Energy includes "Net Purchases (Sales) from Powerex" shown on Schedule 4.0, line 36 which is considered part of Trade Income.

Similarly, Powerex net income represents its trade revenue net of the business expenses which include payments to BC Hydro such as "Powerex - Business Support Allocation" and "Powerex PTP Charges" shown on Schedule 3.0, lines 47 and 49 respectively. These costs are grouped under Inter-Segment Revenue on Schedule 1.0, line 8 to reduce BC Hydro revenue requirements.

313.0 E. CHAPTER 4 – COST OF ENERGY

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
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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).

3.313.2 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.

RESPONSE:

This answer also responds to BCUC IRs 3.289.1, 3.313.2.1 and 3.313.2.2, AMPC IR 3.11.1, BCOAPO IR 3.168.4, and CEABC IR 3.49.2.

BC Hydro did not update the forecast Trade Income (line 17 on Schedule 1.0 of the Appendix A) for the Test Period in the Evidentiary Update for fiscal 2019 actual results.

BC Hydro considered the scope of the Evidentiary Update to be limited to targeted adjustments, primarily related to fiscal 2019 actuals and the new Cost of Energy forecast as discussed on page 2 of the Evidentiary Update. Therefore, we did not consider the updating of forecasts in the Test Period based on five-year averages for Trade Income and storm restoration costs to fall into the scope of the Evidentiary Update.

The forecast Trade Income and storm restoration costs for the Test Period in the Evidentiary Update are based on the five-year average of historical actual amounts for the period from fiscal 2014 to fiscal 2018.

As discussed in BC Hydro's response to AMPC IR 3.3.2, the specific conditions that led to the exceptional Trade Income in fiscal 2019 are unlikely to reoccur to the same extent going forward. Trade Income has historically been highly variable and has ranged from $59 million to $436 million over the previous five years (i.e., fiscal 2015 to fiscal 2019) and has averaged approximately $125 million per year over fiscal 2007 to fiscal 2018. The variability in Trade Income from fiscal 2010 to fiscal 2019 can also be seen in BC Hydro's response to INCE IR 3.14.0. Accordingly, BC Hydro's considers that its forecast Trade Income in the Test Period is reasonable.

Furthermore, any variances between forecast and actual Trade Income during the Test Period will be deferred to the Trade Income Deferral Account.

313.0 E. CHAPTER 4 – COST OF ENERGY

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).

3.313.2 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.

3.313.2.1 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.

RESPONSE:

Please refer to BC Hydro’s response to BCUC IR 3.313.2, where we explain why we did not update the forecast Trade Income for the Test Period based on a five-year average of the actual results from fiscal 2015 to fiscal 2019.

313.0 E. CHAPTER 4 – COST OF ENERGY

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;
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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).

3.313.2 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.

3.313.2.2 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.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.313.2, where we explain why we did not update the forecast Trade Income based on a five-year average of actual results from fiscal 2015 to fiscal 2019.

As noted in that response, and in BC Hydro's response to AMPC IR 3.3.2, the specific conditions that led to the exceptional Trade Income in fiscal 2019 are unlikely to reoccur to the same extent going forward. As shown in the table below, Trade Income has historically been highly variable and has ranged from $59 million to $436 million over the previous five years and has averaged approximately $125 million per year over fiscal 2007 to fiscal 2018. The variability in Trade Income from fiscal 2010 to fiscal 2019 can also be seen in BC Hydro's response to INCE IR 3.14.0. Accordingly, BC Hydro's considers that its forecast Trade Income in the Test Period is reasonable.

The table below provides the calculation of the five-year average for Trade Income based on actual Trade Income for fiscal 2015 through fiscal 2019.

$ million	**F2015 Actual**	**F2016 Actual**	**F2017 Actual**	**F2018 Actual**	**F2019 Actual**	**F2015 - F2019 Average**
Trade Income (Appendix A, Sch 1.0, Ln 17)	(120.1)	(58.7)	(130.2)	(136.6)	(435.7)	(176.3)

The tables below provide the impact to Test Period revenue requirements, rates, and bills, assuming fiscal 2019 actual Trade income is included in the five-year average used to forecast fiscal 2020 and fiscal 2021Trade Income.

$ million	F2020	F2021
Forecast Trade Income with F2019 actual Trade Income	(176.3)	(176.3)
Forecast Trade Income, Evidentiary Update (Appendix A, Sch 1.0, Ln 17)	(120.6)	(120.6)
Impact to revenue requirements	(55.7)	(55.7)

% Rate Impact	F2020	F2021
Forecast rates if forecast Trade Income incorporates F2019 actual Trade Income	6.85	(3.13)
Forecast rates, Evidentiary Update (Appendix A, Sch 1.0, Ln 30)	6.85	(0.99)
Rate Impact	0.00	(2.15)

% Bill Impact	F2020	F2021
Forecast bills if forecast Trade Income incorporates F2019 actual Trade Income	1.76	(3.13)
Forecast bills, Evidentiary Update (Appendix A, Sch 1.0, Ln 32)	1.76	(0.99)
Bill Impact	0.00	(2.15)

For the purpose of forecasting the rate and bill impacts above, BC Hydro assumes that the requested rate increase for fiscal 2020 remains the same, as per BC Hydro's proposal outlined on page 10 of the Evidentiary Update, and therefore the entire two-year impact of higher Trade Income is refunded to ratepayers in fiscal 2021.

Please note that the tables above may not add due to minor rounding differences.

313.0 E. CHAPTER 4 – COST OF ENERGY

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 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."

3.313.3 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.

RESPONSE:

The Powerex net income of $120.6 million included in the Application is based on the five-year average of actual results over the fiscal 2014 to fiscal 2018 period.

The Powerex net income of $125 million included in BC Hydro's 2019/20 – 2021/22 Service Plan represents an approximate average amount of the three years covered by the Service Plan period (fiscal 2020, fiscal 2021 and fiscal 2022).

In the 2019/20 – 2021/22 Service Plan, fiscal 2020 and fiscal 2021 are based on the five-year average over the fiscal 2014 to fiscal 2018 period while fiscal 2022 is based on the five-year average over the fiscal 2015 to fiscal 2019 period, using actuals for fiscal 2015 to fiscal 2018 and the fiscal 2019 RRA forecast amount for fiscal 2019.

314.0 E. CHAPTER 4 – COST OF ENERGY

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

3.314.1 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.

RESPONSE:

BC Hydro entered the 2018 Letter Agreement as a prudent risk management decision, regardless of whether BC Hydro system conditions improved or worsened and/or market prices increased or decreased over the balance of the winter. Accordingly, the primary purpose and success of the agreement is in its risk reduction.

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1 https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.

2 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.

It is difficult to accurately estimate what the costs would have been had BC Hydro used spot market purchases or Island Generation as the timing and availability of purchases absent the 2018 Letter Agreement cannot be known. Absent the certainty of supply to import a specified volume of firm imports, provided by the 2018 Letter Agreement, BC Hydro would have set a higher Threshold Purchase Price and would have purchased more energy as the shortfall position worsened.

The following tables compare the cost of the Energy Supply Contract (US$91.3 million) to the hypothetical cost of alternative sources of energy from Island Generation and the Spot Market (totaling US$189.5 million).

	Energy (GWh)	Average Price (US$/MWh)	Cost (US$ millions)
Energy Supply Contract (as of March 1)	2,428	37.59[3]	91.3

Hypothetical Cost of Alternative Sources of Energy	Energy (GWh)	Average Price (US$/MWh)	Cost (US$ millions)
Island Generation (February to April)[4]	528	126.29	66.7
Spot Market (January to April)[5]	1,900	64.61	122.8
Total	2,428	78.04	189.5

[3] This is the weighted average price BC Hydro paid to Powerex under the Agreement.

[4] ICG generation costs based on assumed 90 per cent availability, using actual Sumas gas prices to March 7 and forward prices for the balance of the forecast horizon (including gas transportation and carbon tax costs).

[5] Spot market costs based on average monthly prices and assume imports at levels that result in 660 MW across the January to April period, using actual Mid-C prices to March 7 and forward prices for the balance of the forecast horizon (including wheeling costs).

314.0 E. CHAPTER 4 – COST OF ENERGY

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

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.

3.314.2 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.

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1 https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.

2 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.

RESPONSE:

BC Hydro has not attached the excel data as requested. BC Hydro has received this data pursuant to a subscription service with ICE Data, LP subject to confidentiality restrictions and is therefore not authorized to disclose the data unless consent is obtained. BC Hydro will seek to obtain consent from ICE Data, LP and, if obtained, BC Hydro will provide the data to the BCUC as part of its response to the fourth round of Information Requests. Any such disclosure by BC Hydro would need to be subject to the BCUC confirming that the information would remain confidential to the BCUC only.

In general, changes in the heavy load and light load Mid-C forward prices reflect broad supply and demand fundamentals and materialize via a multitude of individual decisions by many market participants that are not known by BC Hydro. Factors may include changes to market participants' expectations of, but not limited to, demand, generation supply, transmission constraints, natural gas prices, economic activity, etc.

314.0 E. CHAPTER 4 – COST OF ENERGY

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

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> 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.

3.314.3 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.

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1 https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.

2 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.

RESPONSE:

BC Hydro is filing part of this response in confidence with the BCUC, as the information remains confidential up to October 18, 2019, when the Cost of Energy Evidentiary Update will be publicly released.

The Amended 2018 Letter Agreement was based on results from the November 2018 Energy Study. At that time, snowpack had yet to be built across winter 2018 to 2019, and fiscal 2020 forecast precipitation was not yet known. Therefore, average System Inflow from the November 2018 Energy Study was forecast to be 100 per cent of Normal. Fiscal 2020 System Inflow is forecast to be [redacted] of Normal in the June 2019 Energy Study. This reduction is due to drier than average weather during the first part of fiscal 2019, and below average snowpack during winter 2018 to 2019, especially in the Williston basin.

314.0 E. CHAPTER 4 – COST OF ENERGY

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

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.

3.314.4 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.

[1] https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.

[2] 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.

RESPONSE:

Not confirmed. No particular Energy Study was used as the basis for the BC Hydro 2019 Letter Agreement Application. The 2019 Letter Agreement was entered into proactively so that measures are in place to respond to physical supply issues that may arise. It provides an additional tool for BC Hydro to employ to address short-term operational requirements. As noted on page 4 of the 2019 Letter Agreement, there is no other mechanism currently in place that allows BC Hydro to purchase physical wholesale electricity on a forward basis.

Confirmed volumes and prices of the forward purchase would be included in the following month's Energy Study. Transactions made under the 2019 Letter Agreement will be filed publicly at the end of a 90-day period following the calendar quarter in which any deliveries of electricity are made pursuant to the 2019 Letter Agreement.

The June 2019 Energy Study includes volumes and costs for transactions associated with the 2019 Letter Agreement Application in fiscal 2020.

314.0 E. CHAPTER 4 – COST OF ENERGY

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

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.

3.314.5 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.

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[1] https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.

[2] 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.

RESPONSE:

BC Hydro entered the 2019 Letter Agreement proactively to ensure appropriate measures were in place to respond to future physical supply issues. The ability to acquire wholesale electricity from Powerex on a forward basis remains a valuable tool for BC Hydro to have available to address short-term operational requirements. The primary purpose and expected success of the agreement is in its risk reduction.

The Cost of Energy estimate from Evidentiary Update includes all costs and energy deliveries under the 2019 Letter Agreement that were confirmed as of June 20, 2019.

Trade Income for fiscal 2020 and fiscal 2021 is based on the five-year average from fiscal 2014 to fiscal 2018. It does not include any forecast of transactions under the 2019 Letter Agreement.

314.0 E. CHAPTER 4 – COST OF ENERGY

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

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.

3.314.6 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.

RESPONSE:

BC Hydro understands that the Western Energy Imbalance Market (EIM) benefits as published by the California Independent System Operator (CAISO) are only gross benefits based on displaced generation and do not account for all costs nor benefits accruing to individual participants in the market.

As explained in BC Hydro's response to BCUC IR 1.143.1, Powerex Corp. transacts a broad range of standard and custom products and services in the wholesale energy and renewable markets across the Western Electricity Coordinating Council (WECC), and these markets are inherently dynamic and volatile. Each of the elements of Powerex's portfolio exhibits volatility, as does the portfolio as a whole. Including estimated financial implications of isolated elements of Powerex's overall activities, such as the benefits of Powerex participation in the EIM, when forecasting Trade Income, would not be any more accurate than the current five-year average methodology. Such an approach may in fact prove to be less reliable and objective than the current methodology.

1 https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.

2 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.

Consequently, BC Hydro believes the use of a five-year average for rate setting in the test year period, coupled with a Trade Income Deferral Account to capture variances, remains the most reasonable and appropriate methodology for forecasting Trade Income. This approach ensures that ratepayers receive all of the benefits of Trade Income.

315.0 E. CHAPTER 4 – COST OF ENERGY

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.'

3.315.1 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.

RESPONSE:

Confirmed.

315.0 E. CHAPTER 4 – COST OF ENERGY

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.'

3.315.2 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.

RESPONSE:

From time to time, BC Hydro will enter into a stand-alone commercial arrangement whereby BC Hydro agrees to exercise (or not exercise) its rights under the EPA in a certain way, and in consideration the IPP will make a payment to BC Hydro. As these arrangements are outside of the EPA, and represent a time limited agreement between the parties, the costs may not necessarily be included within our forecast Cost of Energy.

However, payments related to such commercial arrangements are generally applied against BC Hydro's Cost of Energy. Accordingly, ratepayers would benefit as any variance between forecast and actual would be deferred. The payments to BC Hydro related to these types of commercial arrangements are currently estimated at $2 million for the Test Period.

316.0 E. CHAPTER 4 – COST OF ENERGY

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."

3.316.1 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.

RESPONSE:

Confirmed.

316.0 E. CHAPTER 4 – COST OF ENERGY

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."

3.316.1 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.

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

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.316.1.

316.0 E. CHAPTER 4 – COST OF ENERGY

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."

3.316.2 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.

RESPONSE:

Natural gas is not sold by BC Hydro to the Island Generation facility but is a cost borne by BC Hydro in accordance with the terms of the Electricity Purchase Agreement. The costs for these natural gas purchases are part of IPPs and Long-Term Commitments and are included within Line 29 of Schedule 4.0 of Appendix A.