bcuc
British Columbia
Utilities Commission

Patrick Wruck
Commission Secretary

Commission.Secretary@bcuc.com
bcuc.com

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

December 12, 2019

Sent via eFile

BC HYDRO F2020–F2021
REVENUE REQUIREMENTS EXHIBIT A-25

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

Re: British Columbia Hydro and Power Authority – F2020–F2021 Revenue Requirements Application – Project No. 1598990 – Panel Information Request No. 2

Dear Mr. James:

Please find attached Panel information requests pertaining to the above noted proceeding. Please file your responses to the BCUC by 12:00 pm on January 17, 2020.

Sincerely,

Original signed by:

Patrick Wruck
Commission Secretary

/jo
Enclosure

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British Columbia
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Vancouver, BC Canada V6Z 2N3
bcuc.com

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

PANEL INFORMATION REQUEST NO. 2 TO BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

Table of Contents **Page no.**

A. CHAPTER 4 – COST OF ENERGY

3.0 Reference: COST OF ENERGY
Exhibit B-1, Application, p. 2-9; Exhibit B-16, BCUC IR 304.5
Cost of IPP Energy – Exempt vs. Non-Exempt

Page 2-9 of the Application states:

> 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…energy supply contracts entered into before fiscal 2017…

British Columbia Hydro and Power Authority's (BC Hydro) response to British Columbia Utilities Commission (BCUC) Information Request (IR) 304.5 provides the below table that reflects forecast energy supply contracts entered into by BC Hydro from April 1, 2016 to June 1, 2019:

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

3.1 Please complete the below table showing the total forecast annual volume and cost for all energy supply contracts entered into by BC Hydro <u>before</u> April 1, 2016, that identifies all Electricity Purchase Agreements (EPAs) with Independent Power Producers (IPPs) contracts that were reviewed by the BCUC, and those EPAs that were exempt from BC Hydro review.

F2020	Exempt	Non-Exempt	Total
GWh			
Cost ($ million)			
Total			
F2021	**Exempt**	**Non-Exempt**	**Total**
GWh			
Cost ($ million)			
Total			

4.0 Reference: COST OF ENERGY
Exhibit B-1, Appendix DD, pp. 1, 8
Energy Studies Process Audit

Page 1 of Appendix DD identifies the following individuals who prepared the Q3 Fiscal 2019 (F2019) Energy Studies Process Audit (Audit):

Prepared By:

B. Mo (SINTEF)
A. Helseth (SINTEF)
J. Chong
R. Prinja
A. Lagnado

Page 8 describes both B. Mo and A. Helseth as research scientists employed by SINTEF.

Page 8 also states that B. Mo has "participated in previous BC Hydro reviews and consulting work related to the Peace model (1998) and Columbia modelling and coordination (1999 and 2008)."

4.1 Please confirm whether the individuals not identified as SINTEF employees are employees of BC Hydro. If not, please identify where they are employed and their expertise as it relates to the energy studies and / or audit process.

4.2 Please discuss the process used in awarding consulting work to SINTEF. Was this done through an RFP process? If not, why not?

5.0 Reference: COST OF ENERGY
Exhibit B-1, p. 1-15; Appendix DD, pp. 8, 9; Exhibit B-5; BCUC IR 15.3, 28.1, 29.1.1; Exhibit B-16, BCUC IR 309.1; BC Hydro Application for 2019 Letter Agreement with Powerex Corp. (2019 Powerex Letter Agreement Application), Exhibit B-5, BCOAPO IR 2.1; Exhibit B-7, BCUC IR 1.1; Exhibit B-8, BCUC IR 2.1.2
Energy Studies – Risk and Operations

On page 1-15 of the Application, BC Hydro states: "Our monthly Energy Studies optimize our operational management of all sources of energy supply on BC Hydro's integrated system".

On page 8 of Appendix DD to the Application, one of two objectives of the Energy Studies Process Audit is stated as "To evaluate whether the monthly Energy Studies process reliably supports operations, financial and strategic planning at BC Hydro."

On page 9 of Appendix DD, a key finding of the Energy Process Audit is that "Energy Study reports are prepared on time and contain an appropriate level of detail; however they do not serve short-term operational planning needs."

5.1 Please explain why the Energy Study reports do not serve short term operational planning needs. How does BC Hydro plan to address this key finding?

BC Hydro's response to BCUC IR 15.3 states:

> The Energy Studies model operations for the next five years (i.e., to the end of fiscal 2024 in the current studies). These results are used for operational decision making (e.g. setting the threshold sale price) and for near-term financial forecasts (e.g., the Cost of Energy forecast in the Application). However, operational forecasts are not used to determine the need for new resources.

BC Hydro's response to BCUC IR 28.1 states "In the month-to-year ahead time horizon, the Energy Study provides an appropriate level of guidance in terms of pricing, given that large storage reservoirs fill and draft on a seasonal time scale."

5.2 Please confirm, or otherwise explain, that "setting the threshold sale price" refers to the price used to determine how exports in the Transfer Pricing Agreement are allocated between BC Hydro and Powerex Corp. (Powerex).

5.2.1 Please explain why monthly Energy Studies use a five-year time horizon when an appropriate level of guidance in terms of pricing is provided for a time horizon up to a year only. In your response, please confirm whether pricing guidance provided by the Energy Study for the month-to-year time horizon resets every month, and whether threshold sale prices established in subsequent monthly Energy Studies are compared against threshold sale prices established in prior months as a way of validating monthly Energy Studies.

BC Hydro's response to BCUC IR 1.1 in the 2019 Powerex Letter Agreement Application states "Energy Studies are done monthly and look out five years for the reasons set out in BC Hydro's response to BCOAPO IR 1.2.1. BC Hydro confirms that the operating time horizon is not a rolling period up to three years."

BC Hydro's response to British Columbia Old Age Pensioners' Organization et al. (BCOAPO) 2.1 in the 2019 Powerex Letter Agreement Application states:

> The Energy Studies model the dispatch of the system five fiscal years into the future; running the model for the additional two years allows the forecast for the first three years to account for the impact of longer-term operational constraints (e.g., scheduled outages in the fourth and fifth years).

BC Hydro's response to BCUC IR 2.1.2 in the 2019 Powerex Letter Agreement Application provides the below table, that identifies the difference between the operating time horizon and the planning horizon:

Year	F20	F21	F22	F23	F24	[...]	F40+
Operating time horizon							
Planning time horizon							

5.3 Please confirm the date when the most recent three-year operating time horizon was set, given it is not a rolling period up to three years. As part of your response, please confirm when the next operating time horizon will be set.

5.4 Please confirm whether the planning horizon that follows the operating time horizon is a rolling period. As part of your response, please confirm when the next planning time horizon will be set.

5.5 Please explain whether the statement that the Energy Study does not serve short-term operational planning needs relates to the planning time horizon.

BC Hydro's response to BCUC IR 29.1.1 states:

> 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. Long-term refers to the five-year time horizon over which the optimization is run.

5.6 Please explain how the maximum actual "risk-neutral long-term net revenue" earned is determined when measured against the relevant Energy Study, if Energy Studies are run monthly and the operating time horizon is fixed for a three-year period. In your response, please explain whether the results of this analysis inform the models used in the monthly Energy Studies.

6.0 Reference: COST OF ENERGY
Exhibit B-1, p. 4-17; Appendix DD, p. 9; Exhibit B-16, BCUC IR 309.1
Energy Study objectives

Page 4-17 of the Application states "The Energy Study optimizes the use of System Storage with imports and exports to meet load requirements."

Page 9 of Appendix DD to the Application states "BC Hydro has developed in-house models for long-term hydrothermal scheduling. These models are built to maximize risk neutral long-term net revenue."

6.1 Please define the phrase "long-term hydrothermal scheduling."

6.2 Please reconcile the objective of the Energy Study to optimize System Storage with imports and exports to meet load requirements, with the other objective that "these models are built to maximize risk neutral long-term net revenue."

BC Hydro's response to BCUC IR 309.1 states:

> 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.

6.3 Please expand on the statements that "there is no risk allocated to the shareholder" and that "BC Hydro manages trade-offs in short-term and long-term risks by modelling the system over a five-year time horizon" from the perspective of the ratepayer. In your response, please identify examples of trade offs to demonstrate: i) increases to short-term risks (and therefore decreases to long-term risks) faced by ratepayers: and ii) decreases to short-term risks (and therefore increases to long-term risks) faced by ratepayers as a result of maximizing risk-neutral long-term net revenue.

6.4 Please discuss any trade offs in short-term and long-term risks as they relate to long-term hydrothermal scheduling.

7.0 References: COST OF ENERGY

Exhibit B-1, Appendix DD, pp. 9–13; Exhibit B-5; BCUC IR 31.2, 31.3
Energy Studies – Backtesting

Page 9 of Appendix DD to the Application states "Effective governance is in place over the Energy Studies process."

Page 10 of Appendix DD states "Key areas for improvement include process automation, upgrading legacy software coding for the Peace River model, refining documentation, and periodically backtesting to gain more insights into model performance."

Page 11 of Appendix DD includes the following statements:

- The Market Model was last reviewed externally in 2005. The basic methodology behind the model has been more or less unchanged for many years, but model code was rewritten as part of the Comet Improvement Project implemented in 2016. Model parameters are updated yearly based on the availability of new observations.
- The Peace Model was implemented over 30 years ago and has been extensively tested through years of operational use.
- The current model [Peace Model] does not incorporate a snow state variable which could result in underestimating probabilities for prolonged wet or dry periods when computing water values.
- The methodology used to schedule the Columbia River system (COSTA and MUREO) is appropriate and considered best practice. However, given the complexities of the Columbia River system and the River Treaty, more effort should be put into verifying the results of the implemented models. Verification could be done by benchmarking against a second model which the team is currently developing with a university research group.

7.1 Please confirm, or otherwise explain, whether the Peace Model incorporates the impacts of the Site C dam.

7.2 Please explain the statement that "more effort should be put into verifying the results of the implemented models [COSTA and MUREO]." In your response, please address how the models are considered appropriate and best practice given the current effort put into verifying the results.

7.2.1 Please discuss the process used in selecting a university research group to develop a benchmarking model. Please discuss whether any other key models, or models used in the Energy Studies, use a benchmarking model in place to verify results.

7.3 Please discuss how BC Hydro has addressed the report's key area for improvement of "process automation."

Page 13 of Appendix DD states the following:

- No regular backtesting (or benchmarking) is performed in the current process. Typically, calculated marginal prices would be compared with market prices to assess model performance. Given there are no market prices for the BC Hydro system, this would not be possible. However, actual reservoir operation could be compared to model simulations.
- Backtesting could be easier to perform if the process is further automated as discussed previously.

BC Hydro's response to BCUC IR 31.2 includes the following statements:

- Back testing is not appropriate for the entire Energy Studies process. The BC Hydro system is constantly changing and there are many operational decisions that rely on human action. Therefore, back testing the Energy Study results would not provide useful insight into the quality of the models.
- Back testing has been done on several components of the Energy Studies process in order to calibrate sub-models. In addition, the simulated reservoir elevations are tracked against actual elevations each week. Deviations between the two are explained as part of the weekly operations update.

7.4 "The Market Model was last reviewed externally in 2005, however the model code was rewritten in 2016." Please clarify whether the Market Model has been externally reviewed since 2016. If so, please provide excerpts from the relevant external report. Alternatively, please identify any key areas of concern or improvement.

7.5 Please identify the most recent dates when reviews for those models where backtesting is considered appropriate were last performed, particularly with respect to each of the Peace Model and models for the Columbia River System (i.e. COSTA and MUREO). In your response, please identify whether each model was reviewed internally or externally.

7.6 Please discuss the frequency of backtesting, and what backtesting scheduling has been established for those models where backtesting is considered appropriate.

7.7 Please explain how a model can be relied on if it cannot be backtested or otherwise fully validated.

BC Hydro's response to BCUC IR 31.3 states:

> The major results of the Energy Studies are discussed each week within BC Hydro's Generation System Operations Group and with Powerex, and there are regular comparisons to previous results. A number of alternative models exist that are used as part of BC Hydro's daily and weekly analysis. The results of these alternative models are also used to verify that the Energy Studies models are working as intended.

7.8 Please explain why major results of Energy Studies, and comparisons to previous results, are discussed weekly if backtesting is not performed on a regular basis.

7.9 Please expand on what is meant by the statement "working as intended." In your response, please address whether this refers to meeting load requirements, or maximizing risk-neutral long-term net revenue.

7.10 Please discuss whether using the results of alternative models to the Energy Studies substitutes for back testing the models that comprise the monthly Energy Studies.

7.10.1 Please explain whether alternative models, which are used to verify that the Energy Studies models are working as intended, optimize the system in the short-run better than the monthly Energy Studies and if so, why.

B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

8.0 Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-1, pp. 9-1, 9-10; Exhibit B-5, BCUC IR 162.1; Exhibit B-12, BCUC IR 267.1; Exhibit B-19, p. 9; Appendix A, Schedule 3.4; Decision and Order G-40-19 to the FortisBC Inc. 2017 Cost of Service Analysis and Rate Design Application, dated

February 25, 2019 (FBC 2017 COSA and RDA Decision), pp. 87–88
Cost allocations to generation, transmission and distribution

Page 9-10 of the Application states "Consistent with past practice, current operating costs and provisions are directly assigned or allocated to the transmission function based on cost causation."

However, BC Hydro's response to BCUC IR 267.1 states "Methodologies from the 2016 cost of service study [COSS] may not be directly applicable to the fiscal 2020 to fiscal 2021 Transmission Revenue Requirement given changes to BC Hydro's business and financial model (e.g., changes to regulatory accounts and cost definitions)."

8.1 Please reconcile the two statements above. Specifically, please explain how costs can be allocated consistent with past practice, yet the previous COSS may not be directly applicable in the test period.

8.2 Please clearly identify which 2016 COSS items are not directly applicable in this test period and how BC Hydro has allocated these costs in each of the fiscal 2020 and 2021 test periods for the Transmission Revenue Requirement (TRR).

Page 9 of Exhibit B-19 states "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."

Schedule 3.4 of Appendix A to Exhibit B-19 (Evidentiary Update) shows the following increases to the Transmission Revenue Requirement (TRR) in each of F2020 and F2021:

(In $ million)	F2020	F2021
Increase in Finance Charges Allocated to TRR (Line 4)	$20.7	$18.6
Increase in Total TRR (Line 28)	43.4	42.2

8.3 Please calculate the proportion of the increase in finance charges allocated to the TRR that are a result of costs that were previously classified as IPP Capital Lease costs under IFRS 16.

8.4 Please discuss how the application of IFRS 16 impacts BC Hydro's business and financial models as they relate to the TRR.

8.4.1 Please discuss what methodologies from the 2016 COSS, if any, may or may not be directly applicable to the fiscal 2020 to fiscal 2021 Transmission Revenue Requirement as a result of the application of IFRS 16.

Page 9-1 of the Application states:

> The rates charged under the OATT [Open Access Transmission Tariff] are designed to collect the TRR, which is the sum of BC Hydro's net transmission function costs, as calculated using a cost of service methodology... consistent with the method used by the British Columbia Transmission corporation (BCTC) and the method approved in the BCUC's 1998 Decision accompanying Order No. G-43-98 related to BC Hydro's Application for Approval of Wholesale Transmission Services.

BC Hydro's response to BCUC IR 162.1 states "There have also been multiple OATT amendments over the years that have addressed additional specific OATT rates and rate design issues."

Page 87 of the FBC 2017 COSA and RDA Decision states:

> The appropriateness of rate harmonization in British Columbia has not been revisited in

light of the fact that markets did not develop as expected as a result of deregulation of the industry around the time of Order No. G-12-99. These expected developments included significant retail access usage in B.C. and the formation of Regional Transmission Organizations (RTOs) within the Western Interconnection with centralized transmission planning and operations. These developments did not occur.

Page 88 of the FBC 2017 COSA and RDA Decision also states that "The Panel recommends that the BCUC establish a proceeding to inquire into the broader issues of transmission rate harmonization, with the involvement of transmission owners and transmission customers in the Province."

8.5 Please describe the general state of the BC energy industry and the North American market during 1998.

8.5.1 Please describe how each of the BC energy industry and the North American market has changed since that time. In your response, please discuss how the OATT amendments have addressed these changes, if any.

8.5.2 Please list the OATT amendments since 1998 and describe how they address which "specific OATT rates and rate design issues."

8.6 Please generally describe how BC Hydro's transmission system has changed since 1998. As part of your response, please address the following topics: reliability, capacity, number of customers.

8.7 Please explain the intent and purpose behind the harmonization tariff.

8.8 Please explain the difference between the OATT and the harmonization tariff.

9.0 Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-12, BCUC IR 266.2, 266.2.1 266.2.2, 266.5; Exhibit B-19, Appendix A, Schedule 3.4
Point-to-Point Transmission Service

Responses to BCUC IRs 266.2 and 266.2.1 identify that there are 22 external OATT customers that have executed Point-to-Point (PTP) Umbrella Agreements to use BC Hydro's PTP transmission service.

9.1 How many of the 22 external OATT customers with Umbrella Agreements are for short-term (ST) PTP transmission service, and how many are for Long-Term (LT) PTP transmission service?

BCUC IR 266.2.2 provides the table below that reflects the location of customers that use BC Hydro's PTP transmission service, excluding BC Hydro and Powerex:

Location	Number of OATT Customers
Within BC Hydro's service area	**0**
Outside of BC Hydro's service area, but within B.C.	**1**
Outside of BC Hydro's service area and outside of B.C.	**21**

9.2 Please discuss where (i.e. province / state) outside BC Hydro's service area these external OATT customers are based.

BC Hydro's response to BCUC IR 266.5 provides the below table and states the following:

Fiscal Year	Number of Umbrella Agreements from New Customers	Number of Signed Service Agreements from New Customers	Number of Signed Service Agreements from Existing Customers
F2017	0	0	3
F2018	1	0	2
F2019	0	0	4

9.3 Please confirm, or otherwise explain, that there are zero IPPs within BC Hydro's service area that are also OATT customers.

9.3.1 If confirmed, please clarify how IPP generation could be exported to the US or Alberta by either of BC Hydro or Powerex. In your response, please identify who pays for PTP transmission used in exporting electricity from the IPP.

9.4 Please clarify how many of the nine Service Agreements with existing customers signed since 2019 are with internal customers (BC Hydro and Powerex), and how many are with external OATT customers.

Schedule 3.4 of Appendix A to the Evidentiary Update shows forecast LT PTP Volumes for both Internal and External customers.

		F2019			F2020			F2021		
	Reference	RRA	Actual	Diff	Plan	Update	Diff	Plan	Update	Diff
Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
Long-Term PTP Volumes (GWh)										
Internal		8,042	8,609	568	8,567	8,567	0	8,567	8,567	0
External		1,314	876	(438)	1,314	1,314	0	1,314	1,314	0
Total		9,356	9,485	130	9,881	9,881	0	9,881	9,881	0

9.5 Please confirm, or otherwise explain, that forecast LT PTP Volumes with external customers during the F2020 and F2021 test periods reflect the four new Service Agreements for LT PTP transmission service signed by existing Transmission Customers in F2019.

9.6 Please discuss whether capacity constraints on BC Hydro's transmission system are a consideration for the provision of LT PTP transmission service.

9.7 Please identify the most recent year in which a new entity that applied to become a BC Hydro transmission customer executed a Service Agreement for LT PTP transmission service.

9.8 Please identify the most recent year in which BC Hydro exercised its right to rollover its service for LT PTP transmission.

9.9 Please discuss if a Service Agreement identifies the type of LT PTP transmission service(s) to be accommodated (i.e. firm or conditional firm service).

9.9.1 Please discuss how many of the nine signed Service Agreements from existing customers between F2017 and F2019 were for firm PTP transmission service or Conditional Firm Service.

10.0 Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-5, BCUC IR 165.1, 168.1; Exhibit B-13, AMPC IR 46.3, Attachment 1, p. 19;
Exhibit B-19, Appendix A, Schedule 3.4
PTP Transmission Service – Internal Customers

BC Hydro's response to BCUC IR 165.1 states:

> BC Hydro allocates a portion of its Point-To-Point costs to Powerex consistent with the Transfer Pricing Agreement. This allocation is performed monthly and does not separate Long-Term Point-To-Point charges from Short-Term Point-To-Point charges. The total monthly Point-To-Point costs are allocated based on each entity's activity within the month. Specifically, BC Hydro is the transmission customer under the OATT and reserves all Point-To-Point transmission required on its transmission system to meet its requirements.

BC Hydro's response to BCUC IR 168.1 states:

> BC Hydro is the entity that reserves both the Network Integration and the Point-To-Point transmission services as the customer under the OATT. BC Hydro, as customer, is then charged for these services, plus other required services such as scheduling and dispatch services, by BC Hydro as Transmission Provider, just as any other customer is charged for these services under the OATT.

10.1 Please clarify that BC Hydro, as a transmission customer, holds service agreements with BC Hydro in the same manner that external OATT customers hold service agreements for PTP transmission service.

Page 19 of Attachment 1 of BC Hydro's response to Association of Major Power Customers of British Columbia (AMPC) IR 46.3 states:

> B.C. Hydro shall pay for all transmission charges and shall self-supply all losses and ancillary services charges, on the Transmission System for electricity transactions under this Agreement [Transfer Pricing Agreement]. Unless otherwise determined by B.C. Hydro, acting reasonably, Powerex will pay to B.C. Hydro an amount equal to the parties' reasonable estimate of:
>
> > 9.2.1. the point-to-point transmission costs incurred by B.C. Hydro presently under Rate Schedule 3000 and 3001 in respect of transactions under this Agreement other than sales by B.C. Hydro to Powerex of Surplus Hydro Electricity under Section 5 .1, excluding
> >
> > 9.2.2. the point-to-point transmission costs incurred by B.C. Hydro in respect of transactions under any Interutility Agreements, to fulfill any of B.C. Hydro's treaty obligations and transactions in respect of the Canadian Entitlement,

Line 18 of Schedule 3.4 of Appendix A to the Evidentiary Update reflects Powerex PTP charges in each of fiscal 2020 and fiscal 2021 to be $41.5M and $34.0M, respectively.

10.2 Please explain any differences between the OATT and the Transfer Pricing Agreement, as they relate to energy, capacity, wheeling and other OATT related charges.

10.3 Please explain the process for how PTP transmission service is allocated by BC Hydro to Powerex under the TPA. As part of your response, please elaborate on how PTP transmission used to export electricity from each of an IPP or from BC Hydro's generation resources could be identified.

10.4 Please clarify whether Powerex holds any service agreements with BC Hydro in the same manner that external OATT customers hold service agreements for PTP transmission service. As part of your response, please identify the total PTP transmission capacity associated with those service agreements held by Powerex.

10.4.1 If confirmed, please discuss whether any of the OATT service agreements Powerex holds are outside the transmission charges payable to BC Hydro through the Transfer Pricing Agreement, as described in the preamble.

11.0 Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-1, pp. 4-23, 4-39; Exhibit B-12, BCUC IR 234.1; Exhibit B-19, Appendix A, Schedule 3.4, Schedule 4.0, Schedule 15.0
BC Hydro F2017 to F2019 Revenue Requirements Application (F2017-F2019 RRA), Exhibit B-14, BCUC IR 308.2
Internal and External OATT revenues

BC Hydro's response to BCUC IR 234.1 states:

> The table below lists the items that are not eligible for deferral to regulatory accounts:

Forecast Item	Appendix A Reference
Miscellaneous Revenues	Schedule 15.0, line 42 less lines 4 and 9
Operating costs	Schedule 5.0, line 15[(1)]
Provision and Other Costs	Schedule 5.0, lines 65 to 71[(2)]
Amortization (DSM and Existing Capital Assets) – Excludes Amortization on Capital Additions during the Test Period	Schedule 7.0, line 32 Less: Schedule 7.0, line 28 Schedule 7.0, line 30 Schedule 13.0, line 35
First Nations Negotiations Costs	Schedule 5.0, line 54[(3)]
Taxes	Schedule 6.0, line 24
Asset Retirement Obligation Accretion	Schedule 8.0, line 16
Powertech Net Income	Schedule 1.0, line 18

1. Except for the variances between forecast and actual Storm Restoration Costs and Current Service Costs.
2. Lines 65 to 71 include asset retirements and gains/losses on asset disposals.

Line 4 in Schedule 15.0 of Appendix A to the Evidentiary Update reflects External OATT revenues, which are included in the TRR.

			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
	Transmission										
4	External OATT	3.4 L73	14.0	15.4	1.4	15.4	15.9	0.5	15.4	15.9	0.5
5	FortisBC Wheeling Agreement		5.0	5.2	0.2	5.2	5.2	0.0	5.3	5.3	0.0
6	Secondary Revenue		5.0	8.7	3.6	6.0	6.0	0.0	6.2	6.2	0.0
7	Interconnections		1.9	4.9	3.0	2.2	2.2	0.0	2.2	2.2	0.0
8	Amortization of Contributions	11.0 L18:L19-L14	14.4	21.1	6.8	14.8	14.6	(0.3)	15.3	15.0	(0.3)
9	NTL Supplemental Charge		2.0	2.3	0.2	2.3	2.3	0.0	2.3	2.3	0.0
10	Total		42.4	57.6	15.3	45.9	46.1	0.2	46.6	46.8	0.2

11.1 Please explain why revenues from external OATT customers are eligible for deferral treatment. In your response, please explain the effect these variances have on both short-term (i.e. the next TRR) and long-term (i.e. beyond the next TRR) rates as paid by external OATT customers.

BC Hydro's response to BCUC IR 308.2 in the F2017-F2019 RRA states that:

> Variances between forecast and actual Point-to-Point charges (inter-segment revenues) are deferred to the Non-Heritage Deferral Account. Inter-segment revenues include charges to Powerex for Point-to-Point and charges to BC Hydro for BC Hydro's obligations under the Skagit Valley Treaty as well as charges associated with surplus sales.
>
> BC Hydro records the related costs for Point-to-Point charges in Heritage cost of energy (Appendix A, Schedule 4.0, line 30). Variances between forecast and actual amounts are deferred to the Heritage Deferral Account.

11.2 Please confirm that variances between forecast and actual PTP transmission allocated to the Cost of Heritage Energy are captured in the Heritage Deferral Account.

Page 4-23 of the Application states "The costs included under Domestic Transmission – Other…include approximately $16 million per year for wholesale transmission in British Columbia, to deliver energy to the B.C./US. Border."

Page 4-39 of the Application states the following:

- The use of BC Hydro's transmission system for export related to Surplus Sales pursuant to the OATT is referred to as Domestic Transmission – Export.
- Domestic Transmission – Export costs are expected to be $17.4 million in fiscal 2020 and $21.0 in fiscal 2021.

11.3 Please confirm that variances between forecast and actual PTP transmission used for exporting surplus sales are captured in the Non-Heritage Deferral Account.

Schedule 3.4 of Appendix A to the Evidentiary Update reflects the following Inter-segment revenues for PTP transmission allocated between BC Hydro and Powerex:

			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
	Inter-Segment Revenue										
18	Powerex PTP Charges		(16.6)	(26.4)	(9.8)	(32.5)	(41.5)	(9.0)	(32.5)	(34.0)	(1.5)
19	BC Hydro PTP Charges		(45.9)	(34.3)	11.6	(33.6)	(19.1)	14.5	(37.2)	(35.0)	2.2
20	Total		(62.5)	(60.7)	1.8	(66.1)	(60.6)	5.5	(69.7)	(69.0)	0.7
21	Total Current Costs		828.3	824.5	(3.8)	931.9	971.6	39.7	930.3	969.0	38.7

Schedule 4.0 of Appendix A to the Evidentiary Update reflects the following allocations of PTP transmission to the Cost of Energy:

		F2019			F2020			F2021		
		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
	Cost of Energy ($ million)									
	Heritage Energy									
23	Water Rentals	356.4	363.1	6.7	343.1	329.3	(13.8)	349.1	323.2	(25.9)
24	Natural Gas for Thermal Generation	10.7	7.6	(3.1)	8.1	7.5	(0.6)	8.5	8.5	(0.0)
25	Domestic Transmission - Other	22.1	22.3	0.2	22.5	24.5	2.0	22.4	24.4	2.0
26	Non-Treaty Storage and Libby Coordination Ag	(7.2)	(181.9)	(174.7)	3.3	15.0	11.7	(2.5)	(11.7)	(9.3)
27	Remissions and Other	(33.1)	(33.9)	(0.8)	(26.1)	(25.2)	0.9	(26.8)	(26.7)	0.1
28	Total	349.0	177.2	(171.8)	350.9	351.2	0.3	350.8	317.7	(33.1)
	Market Energy									
34	Market Electricity Purchases	35.9	125.0	89.1	40.0	211.6	171.5	18.2	43.7	25.4
35	Surplus Sales	(129.2)	(115.0)	14.2	(97.1)	(0.4)	96.7	(111.4)	(97.0)	14.4
36	Net Purchases (Sales) from Powerex	0.7	25.0	24.3	(0.5)	33.1	33.6	0.5	6.1	5.6
37	Domestic Transmission - Export	29.9	18.5	(11.4)	17.4	1.1	(16.3)	21.0	17.0	(4.0)
38	Total	(62.6)	53.5	116.1	(40.2)	245.3	285.5	(71.7)	(30.3)	41.4

11.4 Please explain why BC Hydro PTP charges in Line 19 of Schedule 3.4 do not reconcile to allocations of domestic transmission as reflected in Schedule 4.0, and as provided in the Evidentiary Update and summarized in the below BCUC staff table:

(in $ million)	F2020		F2021	
	Plan	Update	Plan	Update
Schedule 3.4				
BC Hydro PTP Charges (Line 19)	$33.6	$19.1	$37.2	$35.0
Schedule 4.0				
Domestic Transmission – Other* (Line 25)	$16.0	$16.0	$16.0	$16.0
Domestic Transmission – Export (Line 37)	$17.4	$1.1	$21.0	$17.0
Total	$33.4	$17.1	$37.0	$33.0
Difference	$0.2	$2.0	$0.2	$2.0

**~$16.0 million is described in the preamble as wholesale transmission in B.C. to deliver energy to the B.C. U.S. border, and comprises part of the total reflected in Line 25 of Schedule 4.0.*

12.0 Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-5, BCUC IR 163.1, 163.5.1, 164.1, 164.1.1
NITS and PTP Allocation to Distribution

In Exhibit B-5, BC Hydro's response to BCUC IR 163.1 states:

> BC Hydro notes that Network Load in BC Hydro's service area would not be served using PTP but instead is served by BC Hydro as the Network Customer using Network Integration Transmission Service in accordance with Part I (Common Service Provisions) and Part III (Network Integration Transmission Service) of the OATT.

BC Hydro's response to BCUC IR 164.1 states:

> Point-To-Point Allocation to Distribution on Appendix A, schedule 3.4, line 12 represents the cost to use Point-To-Point transmission service to serve domestic load customers. It is a cost borne by BC Hydro domestic load customers and is recovered through BC Hydro's bundled sales rates.

BC Hydro's response to BCUC IR 164.1.1 states:

> …Point-To-Point transmission costs are allocated to domestic load customers as they benefit from the use of the transmission system to move energy from generation facilities to their point of interconnection (e.g. on the distribution system).

12.1 Please explain the difference between "Point-to-Point Allocation to Distribution" and Network Integrated Transmission Service as it relates to providing service to domestic load customers.

12.1.1 Please provide an example of how Network Integration Transmission Service (NITS) is used to serve domestic load.

12.2 Please confirm, or otherwise explain, whether domestic load customers pay for both NITS <u>and</u> PTP transmission allocated to Distribution through bundled sales rates.

BC Hydro's response to BCUC IR 163.5.1 states:

> Delivering energy from a non-designated resource on an as-available basis means transmitting energy to serve Network Load from a generation resource that has not been designated as being fully committed to serve Network Load per section 30 of the OATT. For example, imports from resources in the U.S. that are not owned or controlled by BC Hydro would constitute the delivery of energy from a non-designated generation resource on an as-available basis.

The Transmission Customer must reserve Short-Term (including Network Economy) or Long-Term Transmission Service before it can schedule (deliver) energy from non-designated resources.

12.3 Please clarify whether PTP transmission service or Network Integration Transmission service is used when imports of (energy / capacity) are used to serve domestic load customers.

13.0 Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-1, p. 9-27; Exhibit B-5; Exhibit B-19, Appendix A, Schedule 3.4; Rate Schedule 1 of BC Hydro's OATT
LT PTP Transmission Rates

Page 9-27 of the Application states "The long-term PTP revenue is derived from the forecast long-term PTP volumes and the proposed long-term PTP rates. The forecasts of long-term PTP volumes are based on committed long-term transmission contracts."

Line 41 in Schedule 3.4 of Appendix A to the Evidentiary Update states that proposed rates for LT PTP transmission service in fiscal 2020 and fiscal 2021 are $81,695/MW/year and $81,546/MW/year, respectively.

Lines 55–57 of Schedule 3.4 state that the average price for LT PTP transmission service in fiscal 2020 and fiscal 2021 are $9.33/MWh and $9.31/MWh.

Rate Schedule 1 of BC Hydro's OATT states "The Reserved Capacity Charge for the Long-Term Firm Service Rate will be up to a maximum price as set out below except where the POD is a point of interconnection between the Transmission System and the transmission system of Fortis BC, Inc., in which case the rate shall be zero ($0.00)."

13.1 Please clarify that the proposed OATT rates for LT PTP transmission are "maximum prices" i.e. the rate agreed upon between BC Hydro and an OATT customer could be lower than the proposed rates of $81,695/MW/year and $81,546/MW/year in fiscal 2020 and fiscal 2021, respectively.

13.1.1 Please clarify why the hourly equivalent price for LT PTP transmission, as stated on lines 55–57 of Schedule 3.4 is considered an "average price" when Rate Schedule 1 states that "The Reserved Capacity Charge…will be up to a maximum…".

13.2 Please explain how long-term rates on point to point contracts are established, i.e. could OATT customers negotiate an LT rate that was less than the maximum price as set out in Rate Schedule 1 at that time?

13.2.1 Please discuss whether service agreements for LT PTP transmission service set a fixed price for the term of each agreement, or if the price changes over the term of each contract.

14.0 Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-1, pp. 9-23, 9-24; Decision and Order G-43-98 to BC Hydro's Application for Wholesale Transmission Services, dated April 23, 1998 (BC Hydro WTS Decision), p. 31
NITS and PTP Transmission Service – Calculations

Page 9-23 of the Application states:

The NITS charge is designed to recover the TRR, less any revenues from PTP and Ancillary services, as illustrated in the following equation:

$$\text{Monthly NITS Charge} = \frac{\text{TRR} - (\text{PTP Revenue} + \text{Ancillary Services Revenue})}{\text{12 months}}$$

Page 31 of the BC Hydro WTS Decision states:

> The Network Transmission Revenue Requirement is equal to BC Hydro's total Transmission Revenue Requirement less forecast revenues from Point-to-Point Transmission Service, grandfathered contracts and certain other small adjustments (Exhibit 2, BCUC IR 1, Question 35). Accordingly, it is the residual Transmission Revenue Requirement.

Page 9-24 of the Application states:

> PTP service is the reservation and transmission of capacity and energy, on a firm or non-firm basis, from point A to point B, on the transmission system.
>
> The PTP service rate is designed to recover the cost of the TRR if PTP transmission service were used to transfer the maximum capacity supply on the system. In theory, if there were no NITS customer, the PTP charge would recover the TRR, less ancillary service revenue. Specifically, based on the approved rate design, the PTP Transmission Service rate is based on the following:
>
> $$\text{PTP Rate} = \frac{(\text{TRR - Ancillary Services Revenue})}{(\text{Maximum Capacity Supply})}$$

14.1 Please clarify whether PTP transmission service involves the reservation of capacity <u>and</u> energy, as stated in the preamble, and if so, why the formula to calculate the PTP rate is only based on capacity.

14.2 For the equation on page 9-24, please clarify whether the "PTP Rate" is for long term or short term PTP service.

14.3 Please reconcile the two equations as stated in the preamble, which appear to be circular. Specifically, please address the assumption that "if there were no NITS customer, the PTP charge would recover the TRR, less ancillary service revenue," however, the NITS charge is a residual calculation that recovers the TRR, "less any revenues from PTP and Ancillary Services".

15.0 Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-5, BCUC IR 163.1, Attachment 6, p. 2
Allocation of long-term firm Available Transfer Capability (ATC)

Page 2 of Attachment 6 to BC Hydro's response to BCUC IR 163.1 states:

> If long-term firm ATC becomes available from constructing Network Upgrades in response to long-term transmission service request with the Transmission Customer subsequently executed a Service Agreement, the ATC associated with those Network Upgrades will be awarded to that Transmission Customer first.

15.1 Please discuss how OATT customers would be notified when long-term firm ATC along any transmission line is increased or becomes available. As part of the response, please indicate when OATT customers can begin submitting bids for LT firm ATC along any transmission path where construction projects increase ATC (i.e. are requests made during the planning phase, during construction, once construction is complete, etc.).

16.0 Reference: TRANSMISSION REVENUE REQUIREMENT

Exhibit B-1, p. 9-27; Exhibit B-5, BCUC IR 166.6
ST PTP Transmission Service

Page 9-27 of the Application states:

> The short-term PTP (including non-firm PTP) revenue forecast reflects the discounting of short-term PTP rates on export and wheel-through transactions. The applicable rates are $3.00/MWh during High (Heavy) Load Hours and $1.00/MWh during Low (Light) Load Hours, Sundays and North American Electricity Reliability Corporation (NERC) holidays.

BC Hydro's response to BCUC IR 166.6 states:

> In its September 10, 2009 Decision on the 2008 Application, issued with BCUC Order G-102-09, the BCUC approved the Short-Term rate design proposal as filed.
>
> BC Hydro believes that the rationale provided for the Short-Term rate design in the 2008 Application remains valid.

16.1 Please explain whether the ST PTP rates, as established in Order G-102-09 were discounted based on LT PTP transmission rates at that time. If not, please explain how ST PTP rates were established and why.

16.1.1 Please explain why ST PTP rates as established in Order G-102-09 remain valid. As part of your response, please discuss the conditions under which the ST PTP rates were established, and why the ST PTP rates and rate design continue to be valid in the test period.

C. DEBT MANAGEMENT REGULATORY ACCOUNT

17.0 Reference: Debt Management Regulatory Account
Exhibit B-11, Appendix D, p. 2; Table D-2, p. 4; Exhibit B-17, AMPC IR 3.14.4, Attachment 1 to AMPC IR 3.14.2, 3.14.6, 3.14.7.2; BC Hydro 2019/2020 Second Quarter Report, Note 9 to the unaudited condensed consolidated interim financial statements for the three and six months ended September 30, 2019[1]
Forecast account balances

Table D-2 in Appendix D to the Evidentiary Update provides the historical actual and forecast balances of the Debt Management Regulatory Account for F2017 to F2024. For the actual F2019 balance and the F2020 forecast balance, they are shown as $163 million and $276 million, respectively.

BC Hydro's F2020 second quarter financial statements show the September 30, 2019 balance of the Debt Management Regulatory Account as $592 million.

17.1 Please explain the $429 million[2] change in the Debt Management Regulatory Account from the end of F2019 to September 30, 2019.

17.2 Given that the balance in the Debt Management Regulatory Account has increased to $592 million as at the end of the second quarter of F2020, please discuss whether BC Hydro's current forecast ending balances for F2020 to F2024 are different from the balances provided in the

[1] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/quarterly-reports/F20-Q2-Report.pdf
[2]$429 million = $592 million - $163 million

Evidentiary Update.

17.2.1 If so, please provide the updated forecast ending balances of the Debt Management Regulatory Account for each of F2020 to F2024.

17.2.2 If not, please explain why not.

In response to AMPC IR 3.14.4, BC Hydro provided an Excel worksheet labelled "FDH EU," which shows the details by individual hedge that make up the additions to the Debt Management Regulatory Account fiscal 2020 in the Evidentiary Update.

As part of the response, BC Hydro stated that the forecast F2020 balance of the Debt Management Regulatory Account is based on the realized and unrealized hedge values as of May 31, 2019.

Note 9 to BC Hydro's F2020 second quarter financial statements show $423 million of additions to the Debt Management Regulatory Account from the end of F2019 to September 30, 2019.

17.3 Please update the "FDH EU" worksheet to show the calculation of the $423 million addition to the Debt Management Regulatory Account for the six-month period ending in September 30, 2019.

17.3.1 For the Evidentiary Update, BC Hydro used the hedge values as at May 31, 2019. Please identify the date that the realized and unrealized hedge values were based on to produce the financial statements for the six months ended September 30, 2019.

17.3.2 Of the $592 million ending balance in the Debt Management Regulatory Account, please identify the hedges that have been realized.

17.3.3 If applicable, please provide an updated "FDH EU" worksheet with the most current realized and unrealized hedge values to show the current forecast F2020 additions to the Debt Management Regulatory Account.

On page 2 of Appendix D to the Evidentiary Update, BC Hydro states the following regarding the forecast F2020 and F2021 balance in the Debt Management Regulatory Account:

> The increase is mostly non-cash (only a small portion relates to hedges that have realized and were settled in cash) and will be offset by lower finance charges when the hedged future debt is issued at lower interest rates.

In response to AMPC IR 3.14.7.2, BC Hydro states:

> Over the life of hedged bond issuances (10-years and 30-years), the gains or losses on hedging and the related higher or lower interest rates on the associated debt issuances largely offset. Therefore, although the decrease to long-term and short-term debt costs in the test years appears to be small relative to the additions to the DMRA, if the comparison is made over the entire term of the associated debt issuances, increases to the DMRA will be largely offset by lower interest costs on the associated debt issuances.

17.4 Please clarify how the gains or losses on hedging and the related higher or lower interest rates on the associated debt issuances largely offset. Please provide an illustrative example as part of the explanation.

In response to AMPC IR 3.14.6, BC Hydro describes its current hedging strategy and states:

> BC Hydro reviews and updates its debt management strategy on an annual basis as part

of the formulation of the upcoming year's Liability Risk Management Annual Strategic Plan. BC Hydro monitors the strategy on an ongoing basis, updating it when and as appropriate.

17.5 Please discuss whether the balance in the Debt Management Regulatory Account impacts BC Hydro's debt management strategy. If so, please explain how the debt management strategy has been updated as a result of the increase in the Debt Management Regulatory Account balance in F2020.

D. PRESCRIBED UNDERTAKINGS UNDER THE CLEAN ENERGY ACT AND GREENHOUSE GAS REDUCTION (CLEAN ENERGY) REGULATION

18.0 Reference: CHAPTER 10 – DEMAND SIDE MANAGEMENT
Exhibit B-1, Appendix Y, pp. 3, 8, 10–11; Exhibit B-1, Appendix BB, pp. 1–4, 10, 16
Prescribed undertakings

Page 3 of Appendix Y to BC Hydro's Application states:

> **…** the Low Carbon Electrification (LCE) Demand-Side Management (DSM) Projects/Programs that we have undertaken and plan to undertake over fiscal 2019, fiscal 2020 and fiscal 2021. All of our LCE DSM Projects/Programs are within one or more class of undertakings prescribed under the Greenhouse Gas Reduction (Clean Energy) Regulation, issued under section 18 of the Clean Energy Act.

Table 2-1 on page 8 of Appendix Y outlines BC Hydro's expenditures for the Initial LCE Projects for 2018 – 2022, at a total cost of $29.71M.

Table 3-2 on page 11 of Appendix Y outlines BC Hydro Funded Low Carbon Electrification Program Expenditures for 2018 – 2022, at a total cost of $16.65M.

Pages 1–4 of Appendix BB, Attachment 2 - Fiscal 2018 Annual Report No. 1 state:

> The GGRR Reporting Requirements also requests a report by a Fairness Advisor on the competitiveness of any call process held during the reporting period. BC Hydro confirms that in Fiscal 2018 it did not hold any call processes in regard to its LCE DSM Project/Programs or its LCE Infrastructure Projects.

Table 2 in Appendix BB sets out Electrification Information for LCE DSM Projects/Programs for Year Ending March 31, 2018 and shows the actual cost at $0.22M. Table 5 in Appendix BB sets out the LCE Infrastructure Projects Results as of March 31, 2018.

18.1 Has BC Hydro prepared a Fiscal 2019 GGRR Annual Report?

18.1.1 If so, please provide a copy of this report.

18.2 Is the list, description and cost of prescribed undertakings outlined at Appendices Y and BB still accurate and up to date?

18.2.1 If not, please update Appendices Y and BB to include all prescribed undertakings up to December 31, 2019.

18.2.2 Does BC Hydro have any projects or programs under the Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR) in addition to the programs and projects described in Appendices Y and BB?

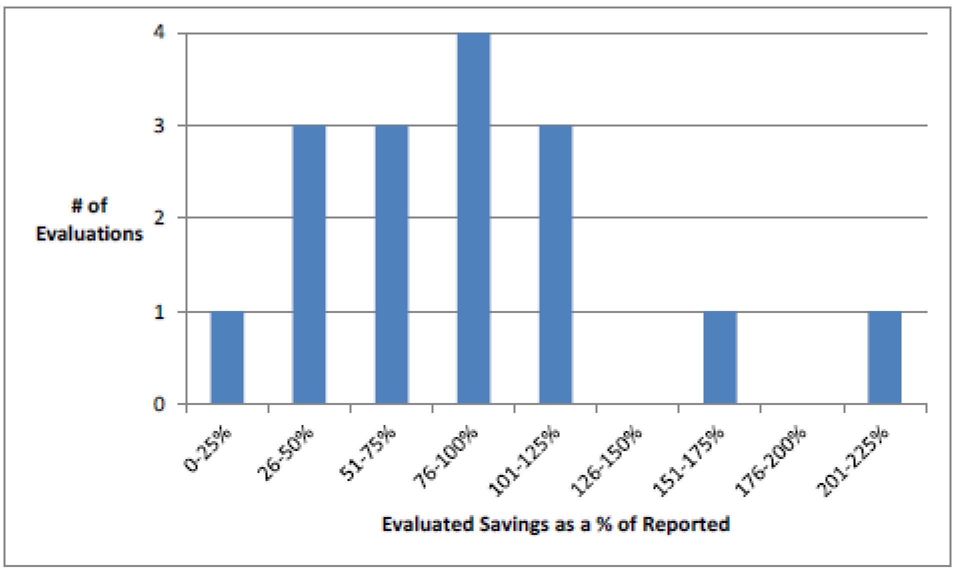
18.3 Please provide a high level rate impact estimate of BC Hydro's prescribed undertakings as a result of the programs and projects outlined in Appendices Y and BB. If there are any updates please also provide any updated rate impact estimate.

18.4 Please provide a copy of any reports that have been prepared by a Fairness Advisor on the competitiveness of any call process held in relation to BC Hydro's LCE DSM Project/Programs or its LCE Infrastructure Projects.

E. DEMAND SIDE MANAGEMENT

19.0 Reference: DEMAND SIDE MANAGEMENT
Exhibit B-1, Appendix AA, p. 9
Evaluation results

On page 9 of Appendix AA of the Application BC Hydro provides a histogram summarizing the results of 16 DSM impact evaluations conducted by BC Hydro over a five-year period from fiscal 2014 through fiscal 2018. Eleven of the 16 evaluations found electricity savings to be less than reported while five evaluations found electricity savings to be more than reported.



19.1 Please provide the following data for the 16 DSM impact evaluations referenced above:

- The names of the programs, specifying the market segment if applicable.
- The estimated projected energy savings and expenditure for each of the 16 evaluated programs as accepted in the applicable expenditure schedules, and the total energy savings and expenditures for all 16 evaluated programs;
- The evaluated net impact savings and actual expenditures for each of the 16 evaluated programs, separately and cumulatively. In cases where the required level of granularity is not available, please include supporting explanations clarifying why this information is not available.

19.2 Please explain in detail the meaning of "reported" in the graph above versus planned or evaluated savings, including identifying the type of party reporting if necessary. The response should contextualise the meaning of "reported" within the full DSM project cycle.

19.3 Please explain if and how these evaluation results are used by BC Hydro to adjust both DSM plans and energy forecasts, providing examples of where this has occurred.

20.0 Reference: DEMAND SIDE MANAGEMENT
Exhibit B-12, BCUC IR 271.2

Historical evaluation of DSM initiatives

In response to BCUC IR 271.2 requesting copies of the last three completed evaluation reports, BC Hydro provided copies of the following:

- Television Market Evaluation: Fiscal 2015 to Fiscal 2018;
- Leaders in Energy Management – Commercial: Fiscal 2013 to Fiscal 2017; and
- Commercial Building Code Evaluation Report: September 2009 to December 2014.

Page v of the Television Market Evaluation states:

> This is a market evaluation that examines changes in the market for new televisions in B.C. in the context of 2013 and 2015 provincial regulations for TV energy efficiency…. BC Hydro demand side management programs targeting the TV market were available from F2009 to F2014, which is prior to the evaluation period.

Page 12 of the Television Market Evaluation BC Hydro states:

> BC Hydro forecasts and reports gross electricity savings associated with energy efficient product regulations in its demand-side management (DSM) plan and uses these estimates in its load forecast. BC Hydro supports the development and introduction of energy efficient product standards and regulations by funding market and technical research, and delivering DSM programs to ready the market for changes to regulations. During the four year period covered in the gross savings calculation, there were no DSM programs or offers in place targeting the TV market. This evaluation estimates the electricity savings in BC Hydro's service territory due to changes in the efficiency of TVs sold in B.C., which includes the influence of provincial TV regulations operating in the context of external drivers and the evolving global TV market. The evaluation does not attempt to determine the share of savings directly attributable to changes in regulation or other specific actions.

Page 24 of the Television Market Evaluation states:

> 9. Gross evaluated savings in the new TV market were 50, 45, 42 and 33 GWh/yr, respectively, for each year from F2015 to F2018. In contrast, the reported savings for each year over the same period ranged from 64 GWh/yr to 69 GWh/yr.
>
> 11. The evaluated gross savings (in the new TV market) were consistently lower than the reported savings, and the gap increased in each year….

Page xii of the Leaders in Energy Management – Commercial (LEM-C) Evaluation states that BC Hydro's LEM-C program achieved 11 percent more savings during fiscal years F2013 to F2017 than was expected.

20.1 As BC Hydro did not provide any DSM programs in the TV market segment over the four year period covered by the gross savings calculation, please clarify the intent of the TV market evaluation, and similar evaluations.

20.2 Please confirm in what year BCUC acceptance of the DSM expenditures on the LEM-C program were granted and provide the planned expenditures and forecast savings at the time the application was filed.

20.2.1 Please provide a table comparing planned to actual expenditures and evaluated net savings for this program.

20.3 Please provide the estimated cost of both evaluations, including a breakdown by internal and external resources.

20.4 In cases where evaluated DSM savings are found to be lower, or higher, than originally anticipated, please discuss how these results are used by BC Hydro to adjust forecast DSM savings, making reference to both DSM plans, and load forecast processes.

21.0 Reference: DEMAND SIDE MANAGEMENT
Exhibit B-12, BCUC IR 271.1.1
Selection of external DSM advisors

In response to BCUC IR 271.1.1 regarding the criteria for selecting external DSM advisors to assist with DSM evaluations, BC Hydro states:

> As indicated in BC Hydro's response to BCUC IR 2.271.1, BC Hydro has had long-term relationships with its external advisors. There have been two changes with external advisors since fiscal 2009. These are:
> - David Sumi was replaced by Rafael Friedmann in fiscal 2011 because he changed consulting firms and his new firm could have been in a conflict of interest for other potential work on DSM for BC Hydro; and
> - Ed Vine was replaced by Econoler in fiscal 2018 because of Ed Vine's retirement.
>
> …
> Criteria used by BC Hydro to select the external advisor include:
> - Free from conflict of interest, meaning that they were not currently (and had not been in the past) providing services to BC Hydro related to DSM program design or implementation;
> - Extensive experience conducting and overseeing Demand-Side Management (DSM) evaluation work;
> - Extensive and current knowledge of DSM evaluation methodologies; Subject matter expertise in the disciplines of statistics, engineering, social sciences, and/or economics; and
> - Record of work with other utilities.

21.1 Please provide copies of the resumes for the Evaluation Advisors referenced in the table provided in response to BCUC 271.1, confidentially if necessary.

21.2 Please discuss BC Hydro's views on the risks and benefits of using the same External Advisors for long periods of time, and how BC Hydro ensures that the External Advisors remain neutral.