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VIA EFILE
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October 6, 2016

BC HYDRO F2017–F2019
REVENUE REQUIREMENTS EXHIBIT A-9

Mr. Tom Loski
Chief Regulatory Officer
Regulatory & Rates Group
British Columbia Hydro and Power Authority
16th Floor – 333 Dunsmuir Street
Vancouver, BC V6B 5R3

Dear Mr. Loski:

Re: British Columbia Hydro and Power Authority
Project No. 3698869 / Order G-40-16
F2017 to F2019 Revenue Requirements Application

Further to your July 28, 2016 filing regarding the above noted application, enclosed please find Commission Information Request No. 1. In accordance with the regulatory timetable set out in Order G-144-16, please file your responses no later than Monday, November 21, 2016.

Yours truly,

Original signed by:

Laurel Ross

kbb

BC Hydro and Power Authority
F2017–F2019 Revenue Requirements Application

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A. CHAPTER 1 – APPLICATION OVERVIEW

1.0 **Reference: APPLICATION OVERVIEW**
Exhibit B-1-1: p. 1-2; p. 1-17, Figure 1-1; p. 1-44
Impact on rates

1.1 Figure 1-1 shows that with or without the rate cap, the rate increase in F2019 would be 3 percent. Please explain why $299.4 million is necessary to be added to the Rate Smoothing regulatory account in F2019 if the rate increase would have been 3 percent irrespective of the cap?

1.2 On page 1-44 of the Application, BC Hydro requests approval to collect the difference between the final Open Access Transmission Tariff (OATT) rates approved and the interim refundable OATT rates approved through a one-time charge to OATT customers. Please confirm, or explain otherwise, that the rate cap increases, discussed on page 1-1 of the Application, do not apply to the OATT rates.

B. CHAPTER 3 – LOAD AND REVENUE FORECAST

2.0 **Reference: LOAD AND REVENUE FORECAST**
Exhibit B-1-1, p. 3-2 and 3-3
Load forecast methodology

BC Hydro states on page 3-3 of the Application that "Previous British Columbia Utilities Commission reviews of the Load Forecast, such as the review undertaken for BC Hydro's 2008 Long Term Acquisition Plan proceeding, concluded that BC Hydro's Load Forecast was acceptable. The Government's review of BC Hydro in 2011 indicated its forecasting process is well planned, and produces reliable results."

BC Hydro also states on page 3-2 of the Application that "The Load Forecast Methodology is generally consistent with the methodology used to prepare the December 2012 Load Forecast contained in the 2013 Integrated Resource Plan…"

2.1 Please provide a detailed description of the models and processes involved to produce BC Hydro's load forecast for the test period.

2.2 Please compare the methodology described above with the methodology reviewed by the Commission in its 2008 Long Term Acquisition Plan proceeding and by the Government in 2011 as described in the preamble. Where the methodology differs, please explain and provide justification for the changes made.

3.0 **Reference: COST OF ENERGY**
2013 Integrated Resource Plan (2013 IRP), p. 9-27; Application, pp. 2-7, 3-25
Independent Power Producers (IPP) portfolio

BC Hydro states on page 9-27 of its 2013 IRP that "BC Hydro anticipates that its management of the IPP EPA portfolio will be informed by the IRP review and approval process and through future RRA processes."

On page 2-7 of the Application, BC Hydro states that:

> the British Columbia Utilities Commission must not disallow the recovery in rates of the

> costs that have been incurred by BC Hydro or its subsidiary Powerex Corp. related to: …energy supply contracts entered into before fiscal 2017 (note that BC Hydro will be filing for review by the British Columbia Utilities Commission under section 71 of the Utilities Commission Act all renewals of energy purchase agreements and any new energy purchase agreements made during the test period)…

BC Hydro states on page 3-25 of the Application that:

> While the estimate of costs from IPP acquisitions inform the Cost of Energy calculation and are described in detail in Chapter 4 of this application, BC Hydro is not requesting as part of this application British Columbia Utilities Commission acceptance of any contract renewals. BC Hydro will be filing Electricity Purchase Agreements related to renewals separately from this application for review by the British Columbia Utilities Commission as required under section 71 of the Utilities Commission Act.

3.1 Please specify how this RRA process can inform BC Hydro's IPP EPA portfolio, as referenced in BC Hydro's 2013 IRP.

4.0 **Reference: LOAD AND REVENUE FORECAST**
Exhibit B-1-1, Section 3.2.1.1, p. 3-6, Section 3.2.2, p. 3-13 & Table 3-2, Appendix A, schedule 14
Actual sales from F2016 to be included

BC Hydro states on page 3-13 of the Application: "The final sales data for fiscal 2016 was not available at the time the Load Forecast was finalized. As such, the Load Forecasting models include sales data up to fiscal 2015. Table 3-2 includes the actual fiscal 2016 information that was available after the forecast was completed." Table 3-2 shows a decrease in F2016 actual load from the F2016 RRA forecast, particularly from the residential and large industrial customer classes.

BC Hydro presents the load and revenue forecast in schedule 14, Appendix A of the Application.

Schedule 14 in Appendix A of the Application shows the historical actual domestic energy sales from F2007 to F2016, and compares the historical forecast to actuals from F2009 to F2016. Line 10 shows that the actuals total domestic energy sales have consistently been below forecast from F2009 to F2016, as reproduced in table below.

GWh	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016
Forecast	52,702	52,622	51,794	52,919	53,527	54,356	53,130	53,760
Actual	52,316	50,233	50,607	51,487	50,992	52,010	51,199	51,023
Difference	-386	-2,389	-1,187	-1,431	-2,535	-2,346	-1,932	-2,737

BC Hydro states on page 3-6 of the Application that "The residential sales forecast is prepared on a temperature normalized basis; normal temperature is defined as a ten-year rolling average of monthly heating and cooling degree days."

4.1 Please explain how the input for F2016 demand is applied in BC Hydro's forecast for F2017 to F2019 in the absence of F2016 actual data at the time the forecast was produced.

4.2 Please expand Table 3-2 to provide the last five years of forecast and actual sales, the percentage difference between the forecast and actual sales for each year, and the average difference between forecast and actuals in the last five years.

4.3 The table in the preamble appears to suggest that there has been seven years of over-forecasted of domestic energy sales, averaging 3.87 percent higher forecast than actuals. Based on this observation, please comment on whether there is an indication of a statistical bias, accurate forecasting issues and/or a random occurrence.

4.3.1 Has BC Hydro considered the global temperature changes/trends over the last 10 years in its weather normalization period? Why or why not?

4.4 Please present the Use per Account (UPA) and customer count forecast for the test period, along with 10 years of historical actuals for the Residential and Light Industrial/Commercial customer classes in a data table and in a well-labeled graph.

4.5 In light of the F2016 actual data, please revisit the load forecast presented in the Application and advise of any changes that would be appropriate.

4.6 If the total electricity sales forecast were to be reduced by 3 percent for the F2017, F2018 and F2019 forecasted total volume, what would be the impact on the revenue deficiency as presented in line 22 in schedule 14 of Appendix A and the Load Resource Balance presented in Table 3-6 through Table 3-9 in the Application? Please repeat the analysis for a reduction in forecasted volume by 5 percent.

4.7 Please confirm, or explain otherwise, that the load forecast presented in the Application is prepared for the purpose of this RRA and no other purpose. If the load forecast presented in the Application and its subsequent Commission approval will be used for any purpose other than forecast rates for the test period, please explain.

5.0 **Reference: LOAD AND REVENUE FORECAST**
Exhibit B-1-1, Section 3.2.1.1, p. 3-9
Key drivers used in the F2017 to F2019 domestic sales forecast

On page 3-9 of the Application, BC Hydro states in footnotes 36 and 37 that housing starts projections, employment, retail sales and commercial output forecast growth rates are based on the Robert Fairholm Economic Consultant projection of March 2015.

5.1 Please provide a copy of the Robert Fairholm Economic Consultant projection report as referenced in the preamble.

5.2 Please explain the impact, if any, of using economic projections conducted in 2015 rather than in 2016 to produce the F2017 to F2019 demand forecast. In your response, please provide references to the difference between the economic projection for 2015 and 2016, if available.

5.3 Please provide a copy of the Robert Fairholm Economic Consultant projection report for 2016, if available. If not available, please explain how and how often BC Hydro monitors BC's economic outlook.

5.4 Please provide the source of the data that was relied upon to produce the key driver projections.

6.0 **Reference: LOAD AND REVENUE FORECAST**
Exhibit B-1-1, Section 3.2.1.4, p. 3-9
Large industrial sector

BC Hydro states on page 3-9 of the Application that "BC Hydro prepares the electricity sales forecast for the large industrial sector on an account-by-account basis. The forecast drivers include production forecasts, electric

intensity (i.e., kWh/unit of production), and probability weightings. The probability weightings represent the risk assessment of future expansion or contraction or the likelihood of previous trends in sales continuing."

6.1 Please explain how BC Hydro takes into account the forecasts of expected purchases provided from individual large industrial customers. If BC Hydro makes adjustments to the forecast reported by its large industrial customers, please explain how BC Hydro determines in what circumstance and by how much would an adjustment be made.

7.0 **Reference: LOAD AND REVENUE FORECAST**
Exhibit B-1-1, Section 3.2.1.1, pp. 3-5, 3-6
Liquefied natural gas (LNG)

BC Hydro explains on page 3-5 and 3-6 of the Application the LNG proponents that have requested electricity service from BC Hydro and are included in the Load Forecast are FortisBC Energy Inc. Tilbury Island LNG facility, LNG Canada to be located in Kitimat, and Woodfibre LNG to be located near Squamish. In particular, BC Hydro states that "FortisBC Energy Inc. is currently constructing an expansion of its all-electric Tilbury Island LNG facility," Woodfibre LNG is expected to make a final investment decision within the current fiscal year, and that LNG Canada announced that it would be delaying its final investment decision beyond December 2017.

BC Hydro also states on page 3-5 that "The LNG Load Forecast during the test period is relatively small compared to the longer-term outlook, ranging from 57 GWh in fiscal 2017 to 139 GWh in both fiscal 2018 and fiscal 2019."

7.1 Please provide a breakdown of LNG volume by LNG project as included in the load forecast for F2017 to F2019.

7.2 Please advise of any developments that have occurred for these projects (or other LNG projects) since the development of the load forecast.

7.3 Please provide an update on the status of the Electricity Supply Agreement with Woodfibre LNG, and explain whether there are any sales volumes expected in the test period.

7.4 Please explain whether there are any sales volumes included in the test period for LNG Canada. If yes, please explain the assumptions.

8.0 **Reference: LOAD AND REVENUE FORECAST**
Exhibit B-1-1, Section 3.2.2.2, pp. 3-16, 3-17 & Table 3-3
Oil and gas

BC Hydro states on page 3-17 of the Application: "Most of the growth in the sales to the large industrial sector over the test years stems from the oil and gas sector… This growth is primarily led by an expected increase in demand from gas producers in Northeast B.C." BC Hydro further states that "The projections in the oil and gas sector are highly uncertain because the magnitude of these loads vary dependent on factors including: increases in natural gas and natural gas liquids market prices (currently at low levels); <u>final investment decision and approvals on LNG projects</u>; and commitments to specific projects from gas producers that have requested electric service from BC Hydro." [emphasis added]

8.1 Please reconcile the growth projected for the oil and gas sector and BC Hydro's relatively small LNG volume anticipated in the large industrial forecast within the test period.

9.0 **Reference:** **LOAD AND REVENUE FORECAST**
Exhibit B-1-1, Section 3.2.2.1, pp. 3-15, 3-16
Impact of SMI on the Load Forecast

BC Hydro states on page 3-15 and 3-16 of the Application: "The estimated incremental effects of Smart Metering and Infrastructure [SMI] and Revenue Assurance Operations, relative to fiscal 2015 have also been included in the Load Forecast over the entire forecast period. These effects include: (i) incremental sales from entities (such as grow ops) previously diverting electricity which are switching to become paid revenues, and (ii) a reduction in losses from grow-ops leaving the system..."

9.1 Please quantify the incremental effects of SMI and Revenue Assurance Operations in terms of energy (kWh) and avoided cost ($) as included in the test year load forecast.

9.2 Please explain how BC Hydro observes and forecasts the amount of incremental volume from entities previously diverting electricity which are switching to become paid revenues, and gains in load from a reduction in losses from grow-ops leaving the system.

10.0 **Reference:** **LOAD AND REVENUE FORECAST**
Exhibit B-1-1, Section 3.2.2.2, p. 3-18
Mining

On page 3-18 of the Application, BC Hydro states that: "During the test years, sales to mining (metal and coal) are expected to be 3,804 GWh per year in fiscal 2017 and then decline by 76 GWh or 2.0 per cent to 3,728 GWh per year in fiscal 2018 and then increase by 106 GWh or 2.8 per cent to 3,834 GWh per year in fiscal 2019. Beyond the test years… the expected increase in sales from new mining loads will be offset by several mining projects reaching end of life."

10.1 Please explain whether there are any new mining load and mining projects reaching end of life within the test period. If yes, please elaborate on how they been accounted for in the forecast.

11.0 **Reference:** **LOAD AND REVENUE FORECAST**
Exhibit B-1-1, p. 3-32, Table 3-9, Appendix V, p. 35
Load resource balance

Table 3-9 on page 3-32 shows that, after considering planned resources, there is a peak capacity deficit of 96MW in F2023 and 236MW in F2024, a capacity surplus in F2025 to F2028, and a forecasted capacity deficit from F2029 onwards.

BC Hydro requests on Page 35 of Appendix V to the Application $38.6 million in funding for capacity focused pilots to understand the dependability of the capacity savings for inclusion in BC Hydro's planning.

11.1 Please explain BC Hydro's assumptions that result in a capacity deficit in F2023 and F2024.

11.2 Please explain BC Hydro's assumptions that result in a recovery to a capacity surplus situation from F2025 to F2028.

11.3 With reference to the timing of the anticipated resource availability and capacity demand, please comment on the likelihood of a capacity deficit occurring between F2017 to F2028.

12.0 **Reference:** **LOAD AND REVENUE FORECAST**
British Columbia's Climate Leadership Plan[1], p. 28
Load resource balance

The August 2016 British Columbia's Climate Leadership Plan (CLP) states on page 28 that "The [Climate Leadership Team] recommended that we increase the target to 100 per cent clean energy on the integrated grid by 2025, while allowing for the use of fossil fuels for reliability. BC Hydro will focus on acquiring firm electricity from clean sources."

12.1 Please explain how the target contained in the CLP to reach 100 percent clean energy on the integrated grid by 2025 impacts BC Hydro's resource stack, if at all, during the F2017–F2019 test period.

12.1.1 If there are changes to BC Hydro's resource stack, please explain how it impacts the load resource balance and COE during the test period and provide an update of the load resource balance and COE figures.

13.0 **Reference:** **LOAD AND REVENUE FORECAST**
Exhibit B-1-1, Section 3.3; F2005-F2016 Deferral Account Reports
Revenue Forecast – historic variance

The table below has been prepared on the basis of the information included in the BC Hydro Deferral Account Reports filed with the Commission for the fiscal years 2005–2016:

Non-Heritage Deferral Account
Annual Summary

Year	Reported Opening Balance	Cost of Energy	Commodity Risk	Notional Water Rental	FX Gains & Losses on Powerex Trade	Domestic Revenue Variance (2009)	ABSU Founding Partner Benefits	Deferred Operating Costs in NHDA	RRA Adjustments	PTP and NITS Variance	Capital Lease Adjustment	Burrard Costs	Other	Total Changes	Rounding	Amortization	Interest	Ending Balance
F2005	0.0	154.5	-5.3	-10.7	-10.6									127.9		0.0	3.0	130.9
F2006	130.9	44.8	19.8	0.2	-3.9		-0.6		-2.9					57.4		0.0	9.0	197.3
F2007	197.3	35.0	3.3	-4.9	8.9		-0.6	-2.7					7.3	46.3		-45.3	14.0	212.3
F2008	212.3	-58.7	-3.0	2.9	-52.2		-0.5		-33.7				-3.5	-148.7	0.1	-58.9	8.8	13.6
F2009	13.6	-51.5	9.3	-0.7	10.1	20.4	-0.6						38.0	25.0	0.1	-14.9	7.4	31.2
F2010	31.2	-22.8	-0.4	-9.3	-4.5	82.5	-0.6						43.2	88.1		-6.6	6.8	119.5
F2011	119.5	-44.5	-12.1	-1.6	-4.0	42.4	-0.2		222.5	16.0				218.5		-23.5	7.3	321.8
F2012	321.8	-147.0	12.9	18.9	2.4	62.8	0.6	11.2	65.9	0.2			40.4	68.3	-0.1	-39.8	16.8	367.0
F2013	367.0	-166.6		5.1	-3.9	176.1	0.4		103.2	-12.2				102.1	-0.1	-84.0	20.3	405.3
F2014	405.3	-195.5	15.2	-14.9		137.7		-0.9	49.8	5.3			62.2	58.9	0.0	-120.3	17.7	361.6
F2015	361.6	50.7	-4.8	-5.1		207.3				8.8	-22.8	4.1		238.2	0.1	-90.6	14.8	524.1
F2016	524.1	235.4	-0.5	1.9		268.9				-0.7	-31.0	9.0		483.0	-0.1	-117.7	27.5	916.8
Cummulative Total		-166.2	34.4	-18.2	-57.7	998.1	-2.1	7.6	404.8	17.4	-53.8	13.1	187.6	1,365.0	0.0	-601.6	153.4	

13.1 Please confirm, or explain otherwise, that any revenue forecast variance is currently being deferred to the Non Heritage Deferral Account (NHDA).

13.2 Please confirm, or explain otherwise, that additions to the NHDA relating to the Domestic Revenue Variance are $852.8 million in the five-year period between F2012 and F2016 as set out in the table above.

13.3 For each of F2014, F2015, F2016 please reconcile the addition to the NHDA for Domestic Revenue Variance set out in the table above to Appendix A, schedule 14 (specifically lines 22-24). By customer class, please explain the main drivers for the variance in each year addressing the forecast GWh as set out in Appendix A, schedule 14, lines 1–10 and the forecast Average Revenues as set out in lines 27–36.

[1] https://climate.gov.bc.ca/wp-content/uploads/sites/13/2016/06/4030_CLP_Booklet_web.pdf

14.0 **Reference:** **LOAD AND REVENUE FORECAST**
Exhibit B-1-1: Section 3.3, p. 3-24; Appendix A, schedule 14
Revenue Forecast – test period

On page 3-24 of the Application, BC Hydro states that the Revenue Forecast for F2017 and F2019 is based on F2016 rates approved by the Commission (Order G-48-14) and excludes the proposed rate increases sought in this application and the impact of any future rate structures changes.

14.1 Is there a potential for any significant impacts to the revenue forecast based on the outcome of the BC Hydro RDA proceeding? Please explain.

14.2 Please explain why LNG is shown as a separate line item in Appendix A, schedule 14, line 19.

C. CHAPTER 4 – COST OF ENERGY

15.0 **Reference:** **COST OF ENERGY**
Exhibit B-1-1, p. 4-5, 4-6
Minimize Cost of Energy

BC Hydro states on page 4-5 of the Application that "BC Hydro optimizes its supply portfolio, in particular its dispatchable resources, to maximize the consolidated net revenue over a five-year forecasting horizon while satisfying domestic integrated system requirements and contractual obligations."

BC Hydro further states on page 4-6 of the Application that "The Energy Study models are used by BC Hydro to inform operational decisions on system storage operations, thermal dispatch, and purchases and sales of market electricity. The same models are used for BC Hydro's ongoing financial forecasting of the Cost of Energy."

BC Hydro states on page 4-4 of the Application that: "The Cost of Heritage Energy is the cost that BC Hydro incurs to provide up to 49,000 GWh per year under the Heritage Contract to serve domestic load obligations." Line 8 in schedule 4 in Appendix A of the Application shows that the amount of Heritage Energy forecasted for F2017 to F2019 is 43,095 GWh, 41,473 GWh and 42,182 GWh, respectively.

15.1 Please explain in detail how BC Hydro models the hydro-electric system (e.g. snow pack, inflows, reservoir levels, generation availability, transmission constraints and load requirements).

15.1.1 Please elaborate on how BC Hydro uses these models to estimate unit costs of energy and unit values of energy to maximize the revenue from its dispatchable resources.

15.1.2 Please explain how BC Hydro optimizes the amount of Heritage Energy to be provided each year, including details on its hydroelectric generation capabilities, consideration for heritage hydroelectric generation in future fiscal years, market electricity purchases and thermal generation.

15.2 If BC Hydro forecasts that it will have excess energy in a test period, please explain how BC Hydro determines the amount, type or location of energy it will plan to procure from renewal of IPP contracts.

15.3 When there is a surplus of energy (e.g. during the freshet period), how does BC Hydro maximize the value of its exports? Please elaborate and provide illustrative operational examples and financial figures where appropriate.

15.4 Please elaborate, at a high-level, the inputs and processes involved in the Energy Study models that inform BC Hydro's financial forecasting of the COE.

16.0 **Reference: COST OF ENERGY**
2013 Integrated Resource Plan (2013 IRP), p. 9-27; Application, pp. 2-7, 3-25
Independent Power Producers (IPP) portfolio

BC Hydro states on page 9-27 of its 2013 IRP that "BC Hydro anticipates that its management of the IPP EPA portfolio will be informed by the IRP review and approval process and through future RRA processes."

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> the British Columbia Utilities Commission must not disallow the recovery in rates of the costs that have been incurred by BC Hydro or its subsidiary Powerex Corp. related to: …energy supply contracts entered into before fiscal 2017 (note that BC Hydro will be filing for review by the British Columbia Utilities Commission under section 71 of the Utilities Commission Act all renewals of energy purchase agreements and any new energy purchase agreements made during the test period)…

BC Hydro states on page 3-25 of the Application that

> While the estimate of costs from IPP acquisitions inform the Cost of Energy calculation and are described in detail in Chapter 4 of this application, BC Hydro is not requesting as part of this application British Columbia Utilities Commission acceptance of any contract renewals. BC Hydro will be filing Electricity Purchase Agreements related to renewals separately from this application for review by the British Columbia Utilities Commission as required under section 71 of the Utilities Commission Act.

16.1 Please specify how this RRA process can inform BC Hydro's IPP EPA portfolio, as referenced in BC Hydro's 2013 IRP.

17.0 **Reference: COST OF ENERGY**
Exhibit B-1-1, section 3.4.3.5, pp. 3-37, 3-42, section 4.3, p. 4-4
IPP cost

Section 3.4.3.5 of the Application explains the actions that BC Hydro has taken to implement "Recommended Action 4: Optimize existing portfolio of IPP resources" contained in the 2013 Integrated Resource Plan (2013 IRP). On page 3-42 of the Application, BC Hydro states that one of the actions includes a "One-time reductions in purchase commitments of approximately 2,050 GWh occurring between fiscal 2015 and fiscal 2018 through deferrals of commercial operations for Electricity Purchase Agreements [EPA]."

BC Hydro states on page 4-4 of the Application: "The primary component of the cost of Non-Heritage Energy are IPP costs which increase to $1,439 million in the fiscal 2019 plan from $1,229 million fiscal 2016 actual costs, as more IPP projects achieve commercial operation." In Appendix A, schedule 4 of the Application, Line 20 shows the unit cost of IPPs.

BC Hydro states on page 3-37 that "Prior to and during the initial years of operations, there is uncertainty on energy delivery to the BC Hydro system relative to the IPPs' initial estimates. This

uncertainty diminishes as BC Hydro gains operational information, and as new projects comprise a relatively small portion of the overall IPP portfolio…"

17.1 Please comment on whether the IPPs included in the test year forecasts are committed resources consistent with the amount approved by the 2013 IRP.

17.2 Please explain the increase in unit cost from IPPs over the test period.

17.3 Please elaborate on BC Hydro's ability, if any, to reduce its purchase commitment from existing EPAs.

17.4 Please specify the number of IPPs reaching commercial operation during the test period, the increase in volume that is anticipated from those IPPs for each of the years during the test period, and illustrate quantitatively how those IPPs contribute to the increase in IPP cost from $1,229 million in F2016 to $1,439 million in F2019.

17.5 Please explain how BC Hydro calculates the volume and cost forecast for new IPP projects that are about to reach or are in the early stages of its commercial operations.

17.5.1 Please explain how BC Hydro minimizes the uncertainties around the forecast for these new IPP projects.

18.0 **Reference: COST OF ENERGY**
Exhibit B-1-1, Section 3.4.3.5, pp. 3-42, 3-43, Appendix A, schedule 4; 2013 IRP, pp. 4-15, 4-16
IPP renewals

On page 3-43, BC Hydro states that it "continues to assume 50 percent of the energy and capacity contributions from biomass Electricity Purchase Agreements and 75 per cent from the run-of-river hydroelectric Electricity Purchase Agreements that are due to expire within the remaining years of the 2013 10 Year Rates Plan." BC Hydro also states for Electricity Purchase Agreement renewals, "BC Hydro expects to negotiate a lower energy price than the initial Electricity Purchase Agreement."

BC Hydro states on pp. 4-15 to 4-16 of its 2013 IRP that "For planning purposes, BC Hydro now estimates that about 50 per cent of the bioenergy EPAs will be renewed, about 75 per cent of the small hydroelectric EPAs that are up for the renewal in the next five years will be renewed, and all remaining EPAs will be renewed."

18.1 Please explain whether BC Hydro's assumption to renew 50 percent of bioenergy EPAs and 75 percent of run-of-river EPAs in the RRA refers to the number of contracts, capacity and/or energy contribution from those contracts, or any other determination.

18.1.1 Please explain whether this assumption is consistent with the 2013 IRP.

18.2 Please provide a breakdown of IPP renewals as a proportion of total IPP resources as included in the COE forecast for the test period by populating the table below. Existing IPPs are those entered into prior to F2017 and are active during the test period, IPP renewals are IPPs entered into prior to the test period that expire during the test period and are renewed during the test period. For contracts in the "Other" category, please explain:

		F2017	F2018	F2019	F2017-2019 Average
	Volume (GWh)				
1	Existing IPPs				
2	IPP Renewals				
3	Other				
4	Total IPP				
	Number of Contracts				
5	Existing IPPs				
6	IPP Renewals				
7	Other				
8	Total IPP				
	Cost ($/MWh)				
9	Existing IPPs				
10	IPP Renewals				
11	Other				
12	Total IPP				
	Cost ($ million)				
13	Existing IPPs				
14	IPP Renewals				
15	Other				
16	Total IPP				

18.3 If lines 4, 12 and 16 from the table above do not correspond with the numbers in lines 10, 20 and 37 in schedule 4 contained in Appendix A of the Application respectively, please explain.

18.4 For each year within the test period, please provide the number of contracts, total volume and average unit price of expiring IPP that are not renewed by populating the table below:

	F2016 Actual	F2017	F2018	F2019
Number of contracts				
Volume delivered if renewed (GWh)				
Average unit cost ($/MWh)				

18.5 In a table, please compare for each year the number of IPP contracts, total IPP volume (GWh) and IPP average unit cost ($/MWh) forecasted for years F2016 to F2019 in the 2013 IRP with the F2016 actual, F2017 forecast, F2018 forecast and F2019 forecast in the Application.

19.0 **Reference:** **COST OF ENERGY**
Exhibit B-1-1, Appendix A, schedule 4, section 8.11.1, p. 8-16
IPP capital leases

In schedule 4, Appendix A of the Application, BC Hydro shows the IPP capital leases in lines 93 through 105.

BC Hydro states on page 8-16 of the Application that "the IPP Cost of Energy in Appendix A, schedule 4.0, line 37 does not include all of the costs for the four Electricity Purchase Agreements that qualify as capital leases for the period fiscal 2017 to fiscal 2019."

19.1 In a table, please update the volume (GWh) and cost ($ million and $/MWh) of IPPs as set out in Appendix A, schedule 4, lines 10, 20 and 37 to, include IPP capital leases, for the test period and five years of historical actuals.

19.2 Please explain why the IPP capital leases are revenue rather that cost in years F2012 through F2014 as set out in Appendix A, schedule 4, line 99.

20.0 **Reference: COST OF ENERGY**
Exhibit B-1-1, section 4.3.2.2, p. 4-8
Electricity and gas prices

Figure 4-1 on page 4-8 of the Application shows the electricity and gas prices as of May 2, 2016.

20.1 Please provide the source of the data presented in Figure 4-1.

20.2 Please provide an updated Figure 4-1 as of November 1, 2016.

21.0 **Reference: COST OF ENERGY**
Exhibit B-1-1, Section 4.3.2.1, p. 4-9
End of period system storage

Table 4-2 on page 4-9 of the Application shows the end of period system storage at Williston and Kinbasket. In particular, F2015 Actual and F2016 Actual storage levels are both higher than the F2015 RRA and F2016 RRA forecast, respectively. BC Hydro states that "At the end of fiscal 2016, the system storage was 14,822 GWh, moving closer to BC Hydro's ten year average."

21.1 Please provide an update to Table 4-2 with information on current storage levels.

21.2 Please provide the actual and forecast storage levels in the past 10 years, along with the actual 10-year average.

21.2.1 If BC Hydro's storage levels were 10 percent lower than what is projected in the test years, please elaborate on its impact, if any, on BC Hydro's COE, annual energy production, capacity and imports/exports.

22.0 **Reference: COST OF ENERGY**
Exhibit B-1-1, Appendix A, schedule 4
Line losses

Schedule 4 in Appendix A to the Application shows the historical and forecasted volume from line losses and system use on line 15. Line 17 shows that actual line losses as a percentage of total load is 11.34 percent in 2014, 8.85 percent in 2015, 11.44 percent in 2016, and is forecasted to be 10.22 percent for F2017, 10.32 percent for F2018 and 10.30 percent for F2019.

22.1 Please explain BC Hydro's definition of line losses and system use as it pertains to its integrated system.

22.2 Please explain the reduction in line losses to 8.85 percent of total domestic load in F2015, and

whether the reduced amount of line losses experienced in F2015 can be expected in F2017 to F2019.

22.3 Please provide five years of historical and test period line losses separately for transmission and distribution, and also the aggregate for the system.

22.4 Please explain how BC Hydro produces its line losses forecast for the test period.

22.5 Please explain BC Hydro's efforts to monitor and minimize its line losses.

22.6 Please confirm, or explain otherwise, that any variance between forecast line losses and actual line losses are deferred to the HDA and NHDA.

23.0 **Reference: OTHER REVENUE REQUIREMENTS ITEMS**
Exhibit B-1-1, p. 8-17; Appendix A, schedule 4
Capital leases

23.1 Appendix A, schedule 4.0, line 99 shows the total actual expense for EPA capital leases for F2012 and F2016. For F2012–F2016, what would the actual COE have been had these EPAs been treated as operating leases for accounting purposes?

23.2 For each of F2017, F2018 and F2019 what would the COE expense be if the four capital leases identified in Table 8-14 were classified as operating leases?

23.3 Please confirm, or explain otherwise, that over the life of an EPA classified as a capital lease the amount recovered in the revenue requirement is the same as it would be if it was classified as an operating lease and the differences in any given year relate exclusively to timing differences.

23.3.1 If not, for each EPA classified as a capital lease in the test period, what is the forecast amount that will be recovered in the revenue requirements over the life of the lease and what would it be if it was classified as operating lease? Please explain where the variance is reported.

D. CHAPTER 5 – OPERATING COSTS – INITIATIVES TO IMPROVE OPERATIONS

24.0 **Reference: OPERATING COSTS – ORGANIZATION AND PLANNING**
Exhibit B-1-1, pp. 5-3 and 5-7; Appendices E, H
Organization changes and cost classifications

Section 5.2 and Appendix H of the Application respectively, describes changes to the BC Hydro organizational structure and the latest organizational chart. Section 5.2 also describes BC Hydro's focus on investments that align with its vision and Service Plan (Appendix E of the Application) and its focus on continuously seeking opportunities to reduce expenditures to keep within the 2013 10-Year Rates Plan. BC Hydro also explains that the planned operating expenditures proposed in this Application were approved at the executive team level.

24.1 Please quantify and explain the expected benefits and related costs as a result from each of the organizational changes.

24.1.1 How are the expected benefits and costs of each organizational change being tracked and monitored?

24.2 Any reduced maintenance projects in the current test period could result in longer-term increased maintenance expenditures. Please discuss how BC Hydro balances the competing interests of devising a suitable maintenance program with its goals to meet the objectives of the

10-Year Rates Plan.

25.0 **Reference: OPERATING COSTS – INITIATIVES TO IMPROVE OPERATIONS**
Exhibit B-1-1, Section 5.1, p. 5-1; Section 5.3.1.1, p. 5-12
SMI – Ongoing operating costs and savings assessment

On page 5-1, BC Hydro states:

> The ongoing costs (net of benefits) related to operationalizing the Smart Metering and Infrastructure Program are forecast to be $22.1 million in fiscal 2017, decreasing by $1.4 million in fiscal 2018 and decreasing by $0.1 million in fiscal 2019. These operating costs are a required element of achieving the net benefits of the Smart Metering and Infrastructure Program.

On page 5-12 of the Application BC Hydro discusses Technology Key Business Unit sustainment costs of $25.6 million in fiscal 2017 which includes Advanced Metering System applications, telecommunications network, Smart Metering and Infrastructure (SMI) related costs.

25.1 Please provide an assessment of ongoing SMI operating costs (including technology) and savings to demonstrate whether the SMI program will deliver the targeted net operating cost savings during the test period.

26.0 **Reference: OPERATING COSTS – INITIATIVES TO IMPROVE OPERATIONS**
Exhibit B-1-1, Section 5.3.1.1, p. 5-10
SMI – Technology key business unit operating costs in F2017

In Table 5-2 on page 5-10 of the Application, BC Hydro identifies an incremental operating cost of $25.6 million and an increase of 25 FTEs in F2017 for the Technology key business unit (within the Transmission, Distribution and Customer Service business group).

26.1 Please provide a breakdown of the $25.6 million incremental operating costs in the Technology key business unit in F2017. Specifically break the costs down between the components set out in Appendix A, schedule 5S, lines 1 to 9. For any components that relate to Services – Other, please provide a more detailed breakdown.

26.2 Please provide further clarification regarding the need for the incremental operating costs and FTE additions in the Technology key business unit.

27.0 **Reference: OPERATING COSTS – INITIATIVES TO IMPROVE OPERATIONS**
Exhibit B-1-1, Section 5.3.1.1, p. 5-10; Section 5.5.2, p. 5-65
SMI –Full time equivalents (FTEs)

In Table 5-2 on page 5-10 of the Application, BC Hydro states a total of 51 FTEs are required to perform SMI sustainment activities in F2017 to F2019, with 25 FTEs being under the Transmission Distribution and Customer Service business group.

Table 5-18 on page 5-65 of the Application shows that no FTEs are planned for F2017, F2018 or F2019 under the Transmission Distribution and Customer Service business group.

27.1 Please explain the discrepancy between Table 5-2 and Table 5-18 for FTEs required in F2017 to F2019.

27.2 Please confirm, or otherwise explain, that 26 FTEs (the difference between 51 FTEs and 25 FTEs) are from the Finance and Supply Chain key business unit within the Operations Support business group.

Table 5-18 further indicates that in F2016 RRA, BC Hydro had planned for no FTEs, however in F2016 Actual, BC Hydro employed 25 FTEs.

27.3 Please provide a rationale for why 25 FTEs were actually employed in F2016 and identify the tasks for which they were employed and why the need was not foreseen during planning of F2016.

28.0 **Reference: OPERATING COSTS – INITIATIVES TO IMPROVE OPERATIONS**
Exhibit B-1-1, p. 2-19; Section 5.3.1.1, pp. 5-10 to 5-11; Section 5.5.6.3, p. 5-92
SMI - meter choices program and manual meter reading

Page 5-92 of the Application states:

> Customer Service operating costs are planned to decrease by $0.6 million in fiscal 2017 compared to fiscal 2016 Plan. This is due to Smart Metering and Infrastructure savings related to reduced manual meter reading costs of $10.7 million…

Page 5-11 states "reduced meter reading costs of $19.7 million in fiscal 2017" is reflected as a F2017 operating cost savings in Table 5-2 on page 5-10.

28.1 Please confirm the amount of savings attributed to reduced meter reading costs and explain the difference between the $10.7 million and the $19.7 million in the above preambles.

BC Hydro's website indicates that there are three types of choices for meters under the Meter Choices Program[2]: Standard, Radio-off and Legacy. The Standard meter is said to be the smart meter which allows automatic meter reading. The Radio-off meter and Legacy meter do not provide automatic meter reading capability.

Page 2-19 of the Application indicates that "BC Hydro is currently in the process of a detailed review of the costs of the Meter Choices Program."

On page 5-11 of the Application, BC Hydro states that under the Customer Service and Distribution Design key business unit, a cost of $2 million in F2017 is related to customers who have chosen to participate in the Meter Choices Program. Page 5-11 also indicates that there is a manual meter reading costs in F2017 of $7 million related to meters that are unable to connect to the smart metering network.

28.2 Please explain the key cost drivers for each of the $2 million and $7 million proportion of costs relating to the Meter Choices Program. Please provide a breakdown of major cost items under each category.

28.3 How much does BC Hydro anticipate Meter Choices Program costs will be in F2018 and F2019? Specifically, does BC Hydro expect a decrease from the $2 million forecasted in F2017? Please explain.

[2] Meter Choices, BC Hydro website, https://www.bchydro.com/accounts-billing/rates-energy-use/electricity-meters/meter-choice.html?WT.mc_id=rd_meterchoices

29.0 **Reference: OPERATING COSTS – INITIATIVES TO IMPROVE OPERATIONS**
Exhibit B-1-1, Section 5.3.1.1, p. 5-13; Section 5.7.4.3, p. 5-143
SMI – Vehicle cost

On page 5-13 of the Application, BC Hydro states there are "net cost savings of $0.9 million related to vehicle cost savings due to the reduced requirement for meter readers and associated vehicles" under the Finance and Supply Chain key business unit within the Operations Support Business Group.

Page 5-143 of the Application states one of reasons for the increases in operating expenditures for Supply Chain is due to "an increase in Fleet costs of $3.8 million largely due to vehicle maintenance cost increases as a result of an aging fleet, changes in the size and mix of the fleet (more heavy and medium-sized work trucks)…"

29.1 Please discuss whether the $3.8 million increase in Fleet costs on page 5-143 is included in the net cost savings of $0.9 million on page 5-13.

30.0 **Reference: OPERATING COSTS – INITIATIVES TO IMPROVE OPERATIONS**
Exhibit B-1-1, Appendix A, p.7; Appendix K, Section 4, p.12
SMI – Distribution system metering device

Appendix K, page 12 of the Application indicates the following:

> An increase in the Smart Metering and Infrastructure Regulatory Account of $9.1 million is related to the Distribution System Metering Device write off of $19.1 million, offset by $10.0 million due to a settlement with a third party for liquidated damages resulting from non-delivery of certain aspects of the contract. The Distribution System Metering Device [DSMD] write off was due to the decision to move to a more optimal technology. This more optimal technology aids in the measurement and detection of electricity theft. Overall, these decisions lowered upfront costs and increased operating benefits, resulting in savings of $32.0 million to the Smart Metering and Infrastructure Program costs.

30.1 Does BC Hydro anticipate any capital additions or capital expenditures to the new technology in the F2017–F2019 test period?

30.2 What is the expected ongoing operating and maintenance/sustainment costs related to the new technology in F2017–F2019?

31.0 **Reference: OPERATING COSTS – INITIATIVES TO IMPROVE OPERATIONS**
Exhibit B-1, Appendix F
BC Hydro Workforce Plan

31.1 Please explain who prepared BC Hydro's Workforce Plan, what the key criteria and objectives were behind the design of the Workforce Plan and discuss the approval process.

31.2 Please clarify which business group and key business unit within BC Hydro is primarily responsible for managing and evaluating the progress and effectiveness of the Workforce Plan.

31.2.1 Is the Workforce Plan meant to be an updated living document? If so, please explain BC Hydro's process for updating and/or revising the Workforce Plan.

31.3 How are the outcomes measured? Please discuss whether BC Hydro has completed a cost benefit analysis on the Workforce Plan.

31.4 Please explain how the percentages in the second employee attrition table on page 20 of Appendix F of the Application are calculated. How does this table relate to the first employee attrition table on the same page?

32.0 **Reference: OPERATING COSTS – INITIATIVES TO IMPROVE OPERATIONS**
Exhibit B-1-1, Section 5.3.1.2, pp. 5-13–5-15
Work smart program

BC Hydro states on page 1-25 of the Application, "In addition to the hard savings noted above, BC Hydro implemented a Work Smart program that uses Lean methodology to examine internal processes for opportunities to make them more efficient."

On page 5-13 of the Application, BC Hydro states:

> The objectives of BC Hydro's Work Smart program include the following:
>
> - Assisting BC Hydro in achieving its strategic priorities including "Continue to improve the way we operate";
> - Improving employee engagement and empowerment by engaging employees throughout the process improvement cycle, from identifying process that can be improved right through to designing and implementing the future state processes; and
> - Reducing work effort on non-value added tasks enabling employees to focus on more critical, value added tasks.

32.1 Please describe how BC Hydro has measured and plans to measure progress of and the outcomes of the Work Smart program against the objectives described on page 5-13 of the Application.

On page 5-14 of the Application, BC Hydro describes, "A typical Work Smart initiative will include many steps, from stakeholder interviews and data collection about the current state, to 'value stream mapping' where employees collaborate to create a visual representation and assess process steps, to developing and implement the future state process within 90 to 120 days."

Furthermore, on page 5-14, BC Hydro provides Table 5-3 which summarizes the Work Smart initiatives which have been completed to date and the benefits of these projects. On page 5-15, BC Hydro states, "Estimated capacity hours gained from Work Smart initiatives as at the end of fiscal 216 were 22,550 hours annually."

32.2 What was the development cost of the Work Smart program in F2015 and F2016?

32.3 Were the benefits in F2016 limited to the 22,550 labour hours? If yes, please quantify the savings. If not, what were the savings in F2016?

32.4 Please describe what areas of the business BC Hydro plans to focus on in F2017 to F2019 with respect to Work Smart initiatives and the expected benefits. Please elaborate on how the Work Smart program will be applied throughout the organization.

32.4.1 Please provide an estimate of the cost of Work Smart initiatives in F2017 to F2019 and the estimated capacity hour that are expected to be gain in each of those years.

32.4.2 Please provide an estimate of planned savings due to Work Smart initiatives in F2017 to F2019, if possible.

32.5 Please discuss if there is a cultural change necessary to achieve the desired benefits. If so, how is that cultural change being implemented and/or managed? How are front-line employees being engaged and how are their interests being aligned with this initiative? Please elaborate.

33.0 **Reference: OPERATING COSTS – INITIATIVES TO IMPROVE OPERATIONS**
Exhibit B-1, Section 5.3.1.3, pp. 5-15–5-16; Section 5.3.3, Table 5-8, p. 5-28
Workforce optimization program

On page 5-15 of the Application, BC Hydro states:

> In July 2015, BC Hydro launched the Workforce Optimization Program to examine BC Hydro's resourcing model to ensure that it has the right mix of internal and external resources… Pursuant to the Workforce Optimization Program, Business Groups identified areas where cost and/or risk could be reduced or outcomes improved by shifting work from external contractors to internal employees. The merits and cost savings of each of these opportunities were reviewed and approved by the executive team. At the end of October 2015, approximately 170 FTEs had been approved for hire through fiscal 2019 with offsetting reductions in the use of external resources.

On page 3 of Appendix F of the Application, BC Hydro states, "Approximately 200 FTEs have already been identified for conversion between fiscal years 2016-2019."

33.1 Please explain the difference between the 170 FTEs described on page 5-15 of the Application and the 200 FTEs described on page 3 of Appendix F of the Application. Is the difference of 30 FTEs due the conversion of external resources to internal employees in F2016 (actual)?

33.2 Please provide a breakdown of BC Hydro's workforce optimization plan into operating, capital and deferred hires in F2017, F2018 and F2019 by completing the table below and as attached.

	Reference	F2017 Plan	F2018 Plan	F2019 Plan	Total
Operating					
Capital					
Deferred					
Total	Table 5-8	110	49	11	170

BC Hydro states on page 5-16 of the Application, "The operating cost increase associated with these [170] FTEs is approximately $1.2 million per year."

33.3 As shown in Table 5-8 on page 5-28 of the Application, BC Hydro's plan is to hire 110 FTEs in F2017, 49 FTEs in F2018 and 11 FTEs in F2019. Please explain BC Hydro's forecast of $1.2 million per year in operating cost increases. Does this represent the average per year?

33.4 Is the plan for internal hires to replace external resources at a one-to-one ratio? Please clarify.

33.4.1 Please provide actual F2012–F2016 and forecast test period external resource headcount (e.g. contractor) in BC Hydro's workforce relating to capital, operating and deferred.

On page 5-16 of the Application, BC Hydro states:

> The financial benefits of the [workforce optimization] program are primarily capital savings as the majority of optimization opportunities pertain to resources executing capital work. Unlike contractors working on capital projects whose work for BC Hydro is solely related to the projects and thus whose costs can all be capitalized, BC Hydro

employees working on capital projects spend some of their time on internal, non-project related activities (e.g., general training) which cannot be capitalized. Thus, some new BC Hydro employees added as part of this program result in an increase to operating costs…

33.5 Please summarize, in table format, the gross capital and operating savings which have been achieved in F2016, and which BC Hydro forecasts to achieve, in each year of F2017–F2019 as a result of workforce optimization.

34.0 **Reference: OPERATING COSTS – INITIATIVES TO IMPROVE OPERATIONS**
July 2011 Government Review of BC Hydro (Report)
Recommendations

BC Hydro states on page 1-14 of the Application that, it "completed implementation of all of the [Government] panel's recommendations by March 2014."

Internal Controls

34.1 Page 37 of the Report summarizes BC Hydro's Internal Controls and Oversight in 2011. Have there been any changes since 2011 to BC Hydro's Internal Controls and Oversight? If so, please explain.

34.2 On page 121 of the report the Recommendations are summarized by topic area. Please explain how the results of the Recommendations regarding operating costs policies and processes (recommendations 5, 6, 17, 19, 20 and 21) have impacted the current revenue requirements application.

Operating Costs

On page 5 the Panel further states that "BC Hydro needs to make immediate changes. Specific areas to address include staffing levels, labour costs and travel and contracting policies."

34.3 Please provide a pie chart similar to the one set out on in Figure 2.2.1 on page 36 of the Report reflecting Total Expenditures by Resource for F2012–F2016 and for each year in the test period.

34.4 Please provide charts similar to Figure 2.2.3 on page 39, Figure 2.2.4 on page 41, and Figure 2.2.5 on page 41 of the Report, updated to include the test years forecast.

Labour Costs

On page 6 of the Report the Panel states:

> "For example, BC Hydro currently employees approximately 650 engineers, which is about six times more than the Ministry of Transportation and Infrastructure, with a similar-size capital program."
>
> "For example BC Hydro has 142 staff dedicated to external and internal communications for its 6,000 employees. This appears high compared to government's 187 communications staff for its 28,000 employees."
>
> On page 6 of the Report the Panel stated that "[it] believes that a more reasonable staffing level

would be in the order of 4,800 employees."

34.5 In each of the test periods, approximately how many engineers does BC Hydro employ? What percentage of those engineers work directly on capital projects and have their salaries capitalized?

34.6 In each of the test periods, approximately how many communications staff does BC Hydro employ? What percentage, if any, have part or all of their salaries capitalized?

On page 42 of the Report the Panel notes that "BC Hydro is reviewing the span of control (the ratio of staff to managers) in their organization to facilitate efficiencies. Currently there is a ratio of approximately one manager to every seven point five employees."

34.7 For each of the test years what is the forecast ratio of staff to managers?

34.8 Please explain what steps BC Hydro has taken to reduce the International Brotherhood of Electrical Workers overtime during the test period as discussed on pages 43 and 44 of the Report.

Recommendation 14 of the Report states "Adjust incentive plans under the Variable Pay program for Management and Professional staff to ensure targets for performance measures are set at a level that is not easily attained to prevent the incentive pay becoming part of base compensation."

34.9 Please explain how this recommendation is reflected in the forecast for incentive pay during the test period.

34.10 Please provide an updated table similar to Figure 2.2.8 on page 50 of the Report for F2012–F2016 to reflect the management and professional staff's performance rating –distribution by fiscal year.

Recommendation 15 of the Report states : "Reduce or eliminate the flex time sign up incentive and pay out options for hours worked beyond the 35 hour work week while maintaining the flex schedule option."

34.11 Please confirm, or explain otherwise, that the during the test period no cost relating to the pay out of flex time are included in the forecast revenue requirements.

E. CHAPTER 5 – OPERATING COSTS – GROSS AND BASE OPERATING COSTS

35.0 **Reference: OPERATING COSTS – GROSS OPERATING COSTS**
Exhibit B-1-1, Appendix A, schedules 5.0, 5S; BC Hydro F2012–2014 RRA, Exhibit B-15, BCUC IR 1.106.1
Services – ABSU, Services – Other, Materials, Building & Equipment

BC Hydro presents the following data in Appendix A, schedule 5S of the Application:

Operating Costs and Provisions - Total Company - Supplemental Schedule
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Gross Operating Costs Including Regulatory Account Additions										
1	Labour (excl Non-Current PEB)	L79 + L87	511.0	532.9	21.9	515.7	537.2	21.5	521.2	521.1	531.4
2	Services - ABSU	L80 + L88	48.5	52.2	3.7	47.7	60.7	13.1	49.1	48.4	49.6
3	Services - Other	L81 + L89	565.2	576.0	10.8	545.7	549.8	4.1	542.8	618.6	541.9
4	Materials	L82 + L90	40.4	44.6	4.1	40.1	49.5	9.4	41.1	41.0	40.9
5	Buildings & Equipment	L83 + L91	60.4	65.8	5.4	61.0	63.3	2.3	59.0	59.0	59.2
			1,225.5	1,271.5	46.0	1,210.1	1,260.5	50.4	1,213.3	1,288.1	1,223.0
	Less:										
6	Eligible Capital Overhead	L84 + L94	(65.4)	(66.7)	(1.3)	(65.4)	(68.9)	(3.4)	(68.2)	(69.0)	(69.7)
7	External Recoveries	L85 + L92	(27.7)	(35.0)	(7.3)	(27.8)	(27.1)	0.7	(26.2)	(29.2)	(21.5)
8	**Total Gross Operating Costs Including Regulatory Account Additions**	5.0 L65	**1,132.4**	**1,169.7**	**37.3**	**1,116.9**	**1,164.5**	**47.6**	**1,119.0**	**1,189.9**	**1,131.8**
9	**Total Gross Provision & Other Including Regulatory Account Additions**	5.0 L101	38.4	133.3	94.8	29.7	87.0	57.3	66.0	61.0	51.7
10	**Total Gross Operating Cost and Provision & Other Including Regulatory Account**	5.0 L124 (or 3.0 L17)	**1,170.8**	**1,303.0**	**132.2**	**1,146.6**	**1,251.5**	**104.9**	**1,185.0**	**1,250.9**	**1,183.4**

35.1 Please describe the costs which are included in each cost category in lines 2-5 of Appendix A, schedule 5S.

35.1.1 Within those line items, please explain where the following expenses are reported: capital project dispute resolution costs, capital project investigation costs, bad debts expense and non-current post-employment benefit costs.

<u>Services – ABSU</u>

As stated on page 59 of the 2011 Government Review Report, "ABSBC's [Accenture Business Services of BC] current scope of services includes: technology services, customer care services, meter reading, credit and collections, human resources, accounts payable, building management/maintenance and office services."

35.2 Have there been any changes since the 2011 Government Review to the current or forecast scope of services provided by ABSCBC? If yes, please discuss.

35.3 Are the variances between forecast and actual Services – ABSU captured in regulatory or deferral account? If yes, which one(s)?

35.4 Please explain the $11.6 million decrease between F2016 actual ($60.7 million) and F2017 forecast ($49.1 million) in Services – ABSU operating costs.

35.5 Please explain the reason for the variance (difference) in forecast versus actual Services – ABSU operating costs in F2015 and F2016.

<u>Services-Other</u>

35.6 In response to BCUC IR 1.106.1 in the BC Hydro F2012–2014 RRA, BC Hydro provided a breakdown of the cost items included in Services – Other. Please provide a similar table for

F2015 and F2016 planned and actual Services – Other and F2017 to F2019 planned Services – Other.

35.6.1 Are any of the variances between the forecast and actual Services – Other cost items captured in a regulatory or deferral account? If so, which components and in which account(s)?

35.7 Please explain the reason for the $75.8 million increase in F2018 to Services – Other and the reason the F2019 forecast is reduced to be more in line with the F2017 forecast.

<u>Building & Equipment</u>

35.8 Please explain why Building and Equipment operating costs are forecast to decrease by $5.5 million in F2017 compared to the F2015 and F2016 average actual cost.

35.9 Please explain how the test period forecasts were developed.

The following data is presented in Appendix A, schedule 5.0 of the Application:

Operating Costs and Provisions – Total Company ($ million)																								
			F2012			F2013			F2014			F2015			F2016		
		Reference	RRA	Actual	Diff	RRA	Actual	Diff	RRA	Actual	Diff	RRA	Actual	Diff	RRA	Actual	Diff
Line		Column		F			G			H		1	2	3 = 2 - 1	4	5	6 = 5 - 4
18	Buildings & Equipment		62.4	49.8	(12.6)	66.5	49.2	(17.3)	68.7	52.0	(16.7)	48.8	53.1	4.3	49.6	53.0	3.4

35.10 Please discuss the differences between forecast and actual Building and Equipment operating expenses from F2012–F2016. The data provided suggests that BC Hydro has been able to more accurately forecast these costs in recent years (F2015 and F2016). Please comment.

36.0 **Reference: OPERATING COSTS – GROSS OPERATING COSTS**
Exhibit B-1-1, Appendix A, schedule 5S; 2011 Government Review, p. 5-7
Labour costs

36.1 Please provide additional details for the labour costs as set out Appendix A, schedule 5S, line 1 with a breakdown of the balance into capital, deferred and total operating labour costs, and the details of operating labour costs into cost categories, for each staff affiliation by completing the tables below and as attached.

a) F2012 to F2016 forecast

		F2012 Actual					F2013 Actual					F2014 Actual					F2015 Actual					F2016 Actual				
Cost	Reference	MoveUP	IBEW	M and P	Executive	Total	MoveUP	IBEW	M and P	Executive	Total	MoveUP	IBEW	M and P	Executive	Total	MoveUP	IBEW	M and P	Executive	Total	MoveUP	IBEW	M and P	Executive	Total
Capital labour	A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred labour	B	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating labour																										
Base labour		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Current service - pension		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Current service - OPEB		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-current service - pension		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-current service - OPEB		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Overtime		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Annual performance pay		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Banked flex time payout		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Honorariums		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Operating labour	C	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Less: Non-current service costs - pension		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Less: Non-current service costs - OPEB		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating labour (excl Non-Current PEB)	Schedule 5S, L1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	532.9	-	-	-	-	537.2
Total Labour cost	D=A+B+C	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

b) F2012 to F2016 actual

		F2012 Plan					F2013 Plan					F2014 Plan					F2015 Plan					F2016 Plan				
Cost	Reference	MoveUP	IBEW	M and P	Executive	Total	MoveUP	IBEW	M and P	Executive	Total	MoveUP	IBEW	M and P	Executive	Total	MoveUP	IBEW	M and P	Executive	Total	MoveUP	IBEW	M and P	Executive	Total
Capital labour	A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred labour	B	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating labour																										
Base labour		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Current service - pension		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Current service - OPEB		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-current service - pension		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-current service - OPEB		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Overtime		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Annual performance pay		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Banked flex time payout		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Honorariums		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Operating labour	C	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Less: Non-current service costs - pension		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Less: Non-current service costs - OPEB		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating labour (excl Non-Current PEB)	Schedule 5S, L1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	511.0	-	-	-	-	515.7
Total Labour cost	D=A+B+C	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

c) F2017 to F2019 forecast

Cost	Reference	F2017 Plan					F2018 Plan					F2019 Plan				
		MoveUP	IBEW	M and P	Executive	Total	MoveUP	IBEW	M and P	Executive	Total	MoveUP	IBEW	M and P	Executive	Total
Capital labour	A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred labour	B	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating labour																
Base labour		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Current service - pension		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Current service - OPEB		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-current service - pension		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-current service - OPEB		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Overtime		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Annual performance pay		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Banked flex time payout		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Honorariums		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Operating labour	C	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Less: Non-current service costs - pension		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Less: Non-current service costs - OPEB		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating labour (excl Non-Current PEB)	Schedule 5S, L1	-	-	-	-	521.2	-	-	-	-	521.1	-	-	-	-	531.4
Total Labour cost	D=A+B+C	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

36.2 Is there a deferral or regulatory account that captures the difference between the forecast and actual costs with respect to base operating labour, operating overtime, annual performance pay, banked flex time payouts, honorariums or other. If yes, which account(s)?

37.0 **Reference: OPERATING COSTS – GROSS OPERATING COSTS**
Exhibit B-1-1, Appendix A, schedule 5S, p. 35; Section 5.3.2, Table 5-6, p. 5-24
Eligible capital overhead

BC Hydro presents the following data in Appendix A, schedule 5S of the Application:

Operating Costs and Provisions - Total Company - Supplemental Schedule
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Gross Operating Costs Including Regulatory Account Additions										
1	Labour (excl Non-Current PEB)	L79 + L87	511.0	532.9	21.9	515.7	537.2	21.5	521.2	521.1	531.4
2	Services - ABSU	L80 + L88	48.5	52.2	3.7	47.7	60.7	13.1	49.1	48.4	49.6
3	Services - Other	L81 + L89	565.2	576.0	10.8	545.7	549.8	4.1	542.8	618.6	541.9
4	Materials	L82 + L90	40.4	44.6	4.1	40.1	49.5	9.4	41.1	41.0	40.9
5	Buildings & Equipment	L83 + L91	60.4	65.8	5.4	61.0	63.3	2.3	59.0	59.0	59.2
			1,225.5	1,271.5	46.0	1,210.1	1,260.5	50.4	1,213.3	1,288.1	1,223.0
	Less:										
6	Eligible Capital Overhead	L84 + L94	(65.4)	(66.7)	(1.3)	(65.4)	(68.9)	(3.4)	(68.2)	(69.0)	(69.7)
7	External Recoveries	L85 + L92	(27.7)	(35.0)	(7.3)	(27.8)	(27.1)	0.7	(26.2)	(29.2)	(21.5)
8	**Total Gross Operating Costs Including Regulatory Account Additions**	5.0 L65	**1,132.4**	**1,169.7**	**37.3**	**1,116.9**	**1,164.5**	**47.6**	**1,119.0**	**1,189.9**	**1,131.8**
9	**Total Gross Provision & Other Including Regulatory Account Additions**	5.0 L101	38.4	133.3	94.8	29.7	87.0	57.3	66.0	61.0	51.7
10	**Total Gross Operating Cost and Provision & Other Including Regulatory Account Additions**	5.0 L124 (or 3.0 L17)	**1,170.8**	**1,303.0**	**132.2**	**1,146.6**	**1,251.5**	**104.9**	**1,185.0**	**1,250.9**	**1,183.4**

<u>Eligible Capital Overhead</u>

37.1 Please explain and provide BC Hydro's calculation for eligible capital overhead as seen on line 6 of Appendix A, schedule 5S of the Application. Please explain the impact of the ineligible capitalized overhead and the amortization of the IFRS Property, Plant & Equipment regulatory account on the calculation.

37.1.1 Please confirm, or otherwise explain, whether this is the same method of calculation used for financial reporting purposes.

37.2 Please provide F2012 to F2014 forecast and actual eligible capital overhead.

Line 42 of Appendix A, schedule 5S indicates the following forecast IFRS ineligible capital overhead amounts from F2017 to F2019 are $121 million, $89.6 million and $67.2 million respectively.

Line 3 of Table 5-6 on page 5-24 of the Application indicates the following IFRS ineligible capital overhead amounts from F2017 to F2019 are $877.6 million, $936.1 million and $961.1 million respectively.

37.3 Please confirm the correct forecast IFRS ineligible capital overhead amounts for F2017 to F2019.

External Recoveries

37.4 Please provide a breakdown of the external recoveries in line 7 of Appendix A, schedule 5S for forecast and actual in F2015 and F2016, and forecast for F2017 to F2019.

37.5 Please explain the variance between planned and actual external recoveries in F2015.

37.5.1 Please explain how the forecast was derived for F2017 to F2019.

38.0 **Reference: OPERATING COSTS**
Exhibit B-1-1, Section 5.3.2, Table 5-6, p. 5-24
Reconciliation of base operating costs to net operating costs

38.1 In the same format as in Table 5-6, please provide the previous three years' (F2014 to F2016) reconciliation of actual base operating costs to actual net operating costs.

39.0 **Reference: OPERATING COSTS – BASE OPERATING COSTS**
Exhibit B-1-1, Section 5.3.2, Table 5-5, p. 5-19
Table 5-5 – Base operating costs continuity schedule

39.1 In the same format as in Table 5-5, please restate the table using actuals and not forecast as the starting point for F2017. Also provide additional continuity data for the previous three years of costs starting with F2014 actuals.

39.2 Please provide a table similar to Table 5-5, using the same categories and layout, but presented on a gross basis rather than an incremental basis.

On lines 16, 17 and 26 of Table 5-5, BC Hydro provides forecasted increases/(decreases) in capital project dispute resolution, capital project investigation costs and bad debt, respectively, over the test period.

39.3 Please provide total forecast and actual costs for F2014 to F2016, and forecast costs for F2017 to F2019 for capital project dispute resolution, capital project investigation costs and bad debt.

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

> Pursuant to the Direction to the British Columbia Utilities Commission Respecting Mining Customers (Order in Council No. 123 approved and ordered on February 1 29, 2016), BC Hydro has set up a mechanism to allow certain mining customers in the province to temporarily defer payment of a portion of their BC Hydro electricity bills, to help those mines remain in operation while the prices for the commodities they produce are low.

39.4 Please clarify whether the planned $1.0 million increase in bad debts on line 26 of Table 5-5 on page 5-10 of the Application is related to the Mining Customer Payment Plan program described

above. If yes, please explain why it has not been included as an addition to the Mining Customers Payment Plan Regulatory Account.

On page 5-20 of the Application, BC Hydro states that it "sought significant savings and efficiencies to mitigate cost increases and looked at all areas of the organization… Cost increases during the test period are required to support key priorities, initiatives and ongoing operations."

39.5 Please elaborate on the process which BC Hydro undertook to challenge cost increases and seek savings and efficiencies, and the criteria considered. Who provides oversight of these savings and efficiencies initiatives?

BC Hydro states on page 5-20 of the Application that savings and efficiencies of $33.2 million are planned in fiscal 2017. Of this amount, $15.0 million is "from an initiative in the Transmission, Distribution and Customer Service Business Group… the key themes in this initiative include: inspections frequency optimization, technology functional reviews, work coordination and optimization, customer service cost savings improvements, vegetation management tools implementation and trouble response process improvements."

39.6 Please confirm, or otherwise explain, whether the initiatives described above will result in actual cost savings in the test period or whether some or all of the costs are being capitalized instead of expensed.

40.0 **Reference: OPERATING COSTS – BASE OPERATING COSTS**
Exhibit B-1-1, Section 5.3.2, p. 5-20
Table 5-5 - Canadian Electricity Association membership

On page 5-20 of the Application, BC Hydro explains that it is cancelling its membership in the Canadian Electricity Association in order to achieve savings in the test period.

40.1 What is the Canadian Electricity Association? Who are the members of the Canadian Electricity Association (e.g. Hydro Quebec, Hydro One, etc.)?

40.2 What is the cost of an annual Canadian Electricity Association membership and what benefits are derived by maintaining this membership?

40.3 What are the cost savings of cancelling the Canadian Electricity Association membership?

40.4 Why is BC Hydro cancelling its membership?

40.5 What information did BC Hydro receive from the Canadian Electricity Association? How is that information used by BC Hydro (e.g. the Performance Measures in Appendix N)? Without membership can this information still be obtained? Please elaborate.

40.6 What information does BC Hydro provide to the Canadian Electricity Association? Does BC Hydro plan on continuing to provide that information without membership? If not, is there any impact to the Canadian Electricity Association?

F. CHAPTER 5 – OPERATING COSTS – FULL TIME EQUIVALENTS AND STANDARD LABOUR RATES

41.0 **Reference: OPERATING COSTS – FULL TIME EQUIVALENTS**
Exhibit B-1-1, Section 5.3.3, pp. 5-24–5-29; BC Hydro F2012–2014 RRA, Exhibit B-1-3, Section 5.3, p. 5-28; Appendix F, Section 3, p. 12
Data

On page 5-25 of the Application, BC Hydro states:

> FTEs are calculated by taking the total number of hours (regular and overtime) worked in a given year divided by the average number of hours a full time employee would work per year. These averages differ by affiliation and, for the test period, are 1,621 hours for Management and Professional employees (including Executive), 1,535 hours for MoveUP employees and 1,461 hours for International Brotherhood for Electrical Workers employees.

On page 5-28 of Exhibit B-1-3 of the BC Hydro F2012–2014 RRA, BC Hydro states, "FTEs are calculated by taking the total number of hours worked in a given year divided by the average number of hours a full time employee would work per year (1,566 hours)."

In response to BCUC IR 1.95.5 in the BC Hydro F2012–2014 RRA, BC Hydro stated "positions that are included in the Executive SLR include CEO, Executive VPs, VPs, Senior VPs and Executive Directors."

41.1 Please explain why the calculation for an FTE has changed from the BC Hydro F2012–2014 RRA proceeding to the current Application. For clarity, please explain how the average number of hours a full time employee would work per year was determined in the current Application, and why it is appropriate in the current Application to use a different average for each affiliation (compared to using the same average for each affiliation as in the BC Hydro F2012-2014 RRA proceeding).

41.1.1 Please provide the total number of FTEs for F2012 calculated using the BC Hydro F2012–2014 RRA proceeding method and the current Application method.

41.2 For the purpose of the FTE calculation, please provide the average number of full time hours for Management and Professional employees (<u>excluding</u> Executive) and for Executive if the average number of full time hours for either affiliate alone is not 1,621 hours as set out on page 5-25 of the Application.

41.3 Please provide additional schedules of FTEs by completing the tables below and as attached. Please ensure FTEs for F2012 to F2016 are recast to the method used to calculate FTEs in the current Application in the completed tables, and separate Management and Professional employees from Executive.

a) A breakdown of operating FTEs (including FTEs added to regulatory or deferral accounts), capital FTEs and total FTEs, by business group and regular and overtime hour FTEs.

Full-Time Equivalents (FTEs)	OPERATING								CAPITAL								CONSOLIDATED							
Business Group	F2012 Actual	F2013 Actual	F2014 Actual	F2015 Actual	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan	F2012 Actual	F2013 Actual	F2014 Actual	F2015 Actual	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan	F2012 Actual	F2013 Actual	F2014 Actual	F2015 Actual	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
Training, Development and Generation																								
Regular Hour FTEs																								
Overtime Hour FTEs																								
Total training, development and generation FTEs	-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	-	-	-	-	-	1,010	1,010	1,010
Transmission, Distribution, and Customer Service																								
Regular Hour FTEs																								
Overtime Hour FTEs																								
Total transmision, distribution and customer service FTE	-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	-	-	-	-	-	2,922	2,941	2,952
Capital Infrastructure Project Delivery																								
Regular Hour FTEs																								
Overtime Hour FTEs																								
Total capital infrastructure project delivery FTEs	-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	-	-	-	-	-	1,243	1,275	1,285
Operations Support																								
Regular Hour FTEs																								
Overtime Hour FTEs																								
Total operations support FTEs	-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	-	-	-	-	-	1,121	1,119	1,119
TOTAL FTEs	-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	-	-	-	-	-	6,296	6,345	6,366

b) A breakdown of operating FTEs (including FTEs added to regulatory or deferral accounts), capital FTEs and total FTEs, by staff affiliation and regular and overtime hour FTEs.

Full-Time Equivalents (FTEs)	OPERATING								CAPITAL								CONSOLIDATED							
Staff Affiliation	F2012 Actual	F2013 Actual	F2014 Actual	F2015 Actual	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan	F2012 Actual	F2013 Actual	F2014 Actual	F2015 Actual	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan	F2012 Actual	F2013 Actual	F2014 Actual	F2015 Actual	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
Executive																								
Regular Hour FTEs																								
Overtime Hour FTEs																								
Total executive FTEs	-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Management and Professional (excluding Executive)																								
Regular Hour FTEs																								
Overtime Hour FTEs																								
Total management and professional FTEs	-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
MoveUP																								
Regular Hour FTEs																								
Overtime Hour FTEs																								
Total MoveUP FTEs	-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
International Brotherhood for Electrical Workers (IBEW)																								
Regular Hour FTEs																								
Overtime Hour FTEs																								
Total IBEW FTEs	-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL FTEs	-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-

In Table 5-7 on page 5-26 of the Application, BC Hydro provides the following regular hour and overtime hour FTE information:

FTEs (including Overtime)	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
Regular Hour FTEs	5,781	5,635	5,721	5,769	5,785
Overtime Hours FTEs	583	599	575	575	580
Total	6,365	6,234	6,296	6,344	6,365

41.4 Please provide the total associated dollar cost of the overtime hour FTEs described in Table 5-7 on page 5-26 of the Application for F2017 to F2019 forecast, and F2016 forecast and actual.

41.4.1 If these overtime hours were regular hours, what would the cost be?

41.5 Please explain the difference between the F2016 to F2019 internal FTE budgets shown on page 12 of Appendix F to the total forecast FTEs (including overtime) above. Is it because the internal FTE budgets on page 12 of Appendix F exclude overtime hour FTEs?

42.0 **Reference: OPERATING COSTS – STANDARD LABOUR RATES**
Exhibit B-1-1, Section 5.3.4, Tables 5-9, 5-10, pp.5-29–5-30

42.1 Please provide an alternative breakdown of standard labour rates by completing the table provided below and as attached, and include F2012 to F2016 actuals. Please provide breakdowns for Management and Professional employees and Executive.

($ per hour)	F2012 Actual				F2013 Actual				F2014 Actual				F2015 Actual				F2016 Plan				F2016 Actual				F2017 Plan				F2018 Plan				F2019 Plan			
	MoveUP	IBEW	M and P	Executive	MoveUP	IBEW	M and P	Executive	MoveUP	IBEW	M and P	Executive	MoveUP	IBEW	M and P	Executive	MoveUP	IBEW	M and P	Executive	MoveUP	IBEW	M and P	Executive	MoveUP	IBEW	M and P	Executive	MoveUP	IBEW	M and P	Executive	MoveUP	IBEW	M and P	Executive
Base pay																																				
Current service pension costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other benefit costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Premiums and allowances	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gainsharing/results pay	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard labour Rates	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	55.33	65.90	-	-	-	-	-	-	58.89	79.97	-	-	60.10	75.36	-	-	61.40	76.85	-	-

42.2 In the same format as provided in Table 5-10 on page 5-31 of the Application, please provide revised tables for Management and Professional employees, excluding Executive, and new tables for Executive employees for F2017 to F2019.

42.3 Please clarify whether the following costs are included in standard labour rates: annual performance pay, banked flex time payout, honorariums, first aid allowance and remote location incentive program. If so, which component(s)?

42.4 Please explain the forecast $1.53 premium and allowance increase for International Brotherhood for Electrical Workers (IBEW) employees for F2017.

42.4.1 Why is it significantly higher than the forecast $0.03 increase for MoveUP?

42.5 Please explain why there is a forecast $0.11 premium and allowances decrease for Management and Professional employees (including Executive) when there is a forecast increase for MoveUP and IBEW employees.

42.6 Please explain the forecast $0.23 gainsharing/results pay increase for Management and Professional employees (including Executive) for F2017.

42.6.1 Why is it significantly higher than the forecast $0.08 and $0.07 for Move UP and IBEW employees, respectively?

42.6.2 Why is the forecast increase gainsharing/results pay increase $0.00 for Management and Professional employees (including Executive) in F2018 and F2019?

Table 5-9 on page 5-29 of the Application shows planned increases in standard labour rates for all affiliations. In various places in Chapter 5 (e.g. on page 5-21), BC Hydro explains unavoidable labour cost increases are shown in the operating costs continuity schedules (e.g. on line 10 in Table 5-5).

42.7 By business group, please provide an analysis on gross labour cost showing how the increases in standard labour rates and resulting labour costs are being, or will be offset by, improvements in efficiency due to the work smart program and reductions in headcount due to the workforce optimization program. For clarity, please provide one analysis for each business group.

43.0 **Reference: OPERATING COSTS – BY BUSINESS GROUP**
Exhibit B-1-1, pp. 5-24, 5-63, 5-114 and 5-134
Data

43.1 Table 5-13 on page 5-45, Table 5-16 on page 5-63, Table 5-28 on page 5-114 and Table 5-31 on page 5-134 show the operating costs before regulatory transfers – net of recoveries for each of the business groups. Please provide each of these tables before regulatory transfers. For further clarity, please do not show net of recoveries.

43.2 Please expand Table 5-14 on page 5-36, Table 5-17 on page 5-64, Table 5-29 on page 5-114 and Table 5-32 on page 5-135, to include forecast and actual for F2014–F2016.

44.0 **Reference: OPERATING COSTS – GENERAL**
Exhibit B-1-1, Appendix L
Maintenance cost variances

44.1 In the F2016 Annual Deferral Account Report, BC Hydro states that all significant unplanned major maintenance costs greater than $1 million related to a single event equipment or infrastructure failure or caused by weather related events are deferred to the HDA and significant unplanned major maintenance costs greater than $1 million related to single even equipment of infrastructure failure are deferred to the NHDA.

44.2 If maintenance costs in the test period are less than forecast, will the variance be captured in either the HDA or NHDA for the benefit of ratepayers? If not, please explain.

45.0 **Reference: OPERATING COSTS - GENERAL**
Exhibit B-1-1, p. 2-11, 2-12, 5-40, 5-60; Appendices E, N, U
Reliability indices

On pages 2-11 and 2-12 of the Application, BC Hydro explains its first goal in its Service Plan is to set the standard for reliable and responsive service. BC Hydro explains that System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Key Generating Facility Forced Outage Factor (FOF) are important metrics to assess this performance. In Appendix E of the Application, BC Hydro provides its 2016/17 – 2018/19 Service Plan where it reports to the Province on these metrics. Page 7 of Appendix E shows for F2016, BC Hydro had forecast 3.06 and 1.46 for SAIDI and SAIFI, respectively. In Appendix N, Table N-1 of the Application, BC Hydro shows actual F2016 SAIDI and SAIFI results as 3.01 and 1.48, respectively, and notes that Key Generating Facility FOF replaces Winter Generation Availability. Appendix U is BC Hydro's annual report to the Commission on reliability indices where it reports on SAIDI, SAIFI and other reliability metrics. In this Appendix, BC Hydro reports three different SAIDI and SAIFI numbers for F2016: the SAIDIs reported are 10.69 (all, not normalized), 10.13 (distribution, not normalized) and 3.42 (overall, normalized); the SAIFIs reported are 2.29, 1.91 and 1.60. BC Hydro also trends SAIFI and SAIDI against industry averages since 1996.

45.1 Please reconcile the SAIDI and SAIFI metrics and results reported to the Commission in Appendix U with the SAIDI and SAIFI metrics and results reported in Appendices E and N.

45.2 Please confirm, or otherwise explain, that the SAIDI and SAIFI data provided in Appendix U suggests an upward trend in SAIDI and SAIFI and this in turn suggests a reduction in reliability over time.

On page 5-60 of the Application, BC Hydro explains:

> Aging infrastructure and prolonged use of the system at or near capacity have combined to put pressure on system reliability. Investments in system reliability often take a number of years to have an impact on performance. In recent years, BC Hydro has increased expenditures for reliability initiatives and such investments have had a demonstrated positive impact on current performance measures. Further information on performance measures is provided in Appendix N.

45.3 Please provide evidence that "…increased expenditures for reliability initiatives…have had a demonstrated positive impact on current performance measures."

45.4 Please confirm, or otherwise explain, that a reduction in investments (maintenance or capital) in system reliability often take a number of years to have an impact on performance.

Other metrics BC Hydro reports on in Appendix U are %ASAI (Average Service Availability Index), which is a measure of the percentage of time service is available in the year, average generator availability factor and average generator forced outage factor.

On page 5-40 of the Application, BC Hydro explains:

> The business group uses forced outage factor as a measure of reliability; a lower forced outage factor indicates a more reliable unit or facility. The forced outage factor results over the 11-year period from fiscal 2005 to fiscal 2016 reflect the Training, Development and Generation Business Group's investment strategy. The five year rolling forced outage factor for Key facilities has remained relatively constant. The five year rolling forced outage factor for Strategic facilities has also remained relatively constant over this period, excluding Alouette Generating Station which is at end-of-life and has not been redeveloped. However, the five year rolling forced outage factor for Available Energy facilities has increased from 5 per cent at the start of the period to slightly over 9 per cent as of end of fiscal 2015.

45.5 It appears that BC Hydro's F2016 %ASAI is lower than the industry average every year since 1996, except for F2004, and lower than its own %ASAI every year since 1996, except for 2007. Please comment on this observation, including the actions undertaken by BC Hydro to improve this metric.

45.6 Is the average generator availability factor for BC Hydro trending downwards? Using the data provided in Appendix U, please explain why or why not. Please explain the implications of the observed trend.

45.7 Is the average generator forced outage factor for BC Hydro trending upwards? Using the data provided in Appendix U, please explain why or why not. Please explain the implications of the observed trend.

45.8 Various utilities provide data to the Canadian Electricity Association to determine the industry averages. In BC Hydro's opinion, are these industry averages appropriate measures for comparisons to BC Hydro or are there specific utilities or industry group which would provide better comparisons? Please elaborate.

46.0 **Reference: OPERATING COSTS – GENERAL**
Exhibit B-1-1, Appendix N
Safety

In Appendix N of the Application, BC Hydro explains that its priority is workforce and public safety. In Table N-4 on page 9 of this Appendix, BC Hydro provides its lost time injury frequency safety metric results and targets.

46.1 Please provide and explain the industry average lost time injury frequency safety metric results and targets and compare it to BC Hydro's results and targets.

46.2 Please discuss the measures BC Hydro is taking to ensure and improve public safety.

46.3 Please provide and explain the metrics BC Hydro uses to monitor and evaluate BC Hydro's safety performance as it relates to the public. Please discuss BC Hydro's results, including any trends being observed.

G. CHAPTER 5 – OPERATING COSTS – TRAINING, DEVELOPMENT AND GENERATION BUSINESS GROUP

47.0 **Reference: OPERATING COSTS – TRAINING, DEVELOPMENT AND GENERATION**
Exhibit B-1-1, Section 5.4.2, Table 5-15, p. 5-46
FTEs

BC Hydro provides on page 5-46 of the Application the following information:

Table 5-15 Training, Development and Generation FTEs

	(FTEs)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	Training and Development	404	435	404	469	434	434	434

47.1 Please explain why the actual number of FTEs in F2016 exceeded the F2016 forecast by 65 FTEs in the Training and Development key business unit.

48.0 **Reference: OPERATING COSTS – TRAINING, DEVELOPMENT AND GENERATION**
Exhibit B-1-1, Section 5.4.1.2, pp. 5-36-5-40, 6-21; Appendixes N, R
Managing the life cycle of generation assets
Generation equipment maintenance

On pages 5-36 to 5-40 of the Application, BC Hydro explains that the Training, Development and Generation business group has a lifecycle asset management program aligned with PAS 55 and mostly aligned with ISO 55000. The program includes preventative (PM), condition based (CB), corrective (CO) and facility maintenance (FM). The PM activities are developed based on reliability centered maintenance (RCM) methodology failure mode and affects risk based analysis and set so that the total cost of maintenance is minimized while balancing reliability requirements. The business group periodically evaluates the condition of its major assets based on the latest available maintenance and inspection data and other items to develop an Equipment Health Rating (EHR). EHR for major Generation assets are provided in Appendix R.

48.1 Has BC Hydro's Generation lifecycle asset management program been externally audited? If so, please provide the results of the most recent audit. If not, please explain why not.

48.2 What is the target EHR distribution for each asset category (e.g. Should the distribution of turbines EHR be 10 percent unsatisfactory, 20 percent poor, 40 percent fair and 30 percent good, or something of the like)? Why? Please elaborate.

48.3 Please provide the total actual Generation maintenance costs (not for the business group, but for the activity, i.e. for work on Generation equipment and facilities) in F2015 and F2016 and the forecast maintenance costs for F2017, F2018 and F2019. Please separate the totals between PM, CB, CO and FM. Please comment on any trends observed.

48.4 Were there any major Generation equipment failures in F2015 or F2016? Please discuss.

48.5 Please explain to what extent the Available Energy Facility investment is a new strategy. Please comment on whether operating to failure is a possible scenario for a facility to be forced out of service. What are the risks involved?

48.5.1 Was the corporate risk matrix used to make this policy decision? If so, please provide those results. If not, please explain why not.

48.5.2 Please confirm that the Available Energy Facilities are being maintained with limited capital investment until being forced out of service are Elko, Falls River, Shuswap, Spillimacheen and Walter Hardman. If not confirmed, please provide the corrected list.

48.5.3 Please provide a description of each of these facilities and any issues they may have. For example, their nameplate capacities, typical inflow patterns, and historical and planned annual generation. Please compare this information to typical run-of-river IPPs.

48.5.4 Please provide the annual maintenance costs in PM, CB, CO and FM for each facility for F2015 and F2016, their 5 year average, and the forecast costs (expenditure caps?) to maintain these facilities for F2017, F2018 and F2019. Please comment on any trends observed.

48.5.5 Please provide the annual reliability, availability and productivity performance indices for F2015, and F2016 and the 5 year averages for these indices for these facilities. Please compare to industry averages for these types of facilities and comment on any trends observed and note any decisions that may affect the results.

48.5.6 Please compare the costs to maintain and invest capital at these facilities to achieve industry average reliability, availability and productivity levels for these types of facilities to the costs of procuring equivalent energy and capacity through the standing offer program, new IPP contracts, IPP renewals and/or DSM activities.

48.5.7 Please provide any relevant business cases or analysis which informed management's decision to maintain these facilities with limited capital investment until being forced out and then to investigate refurbishment, redevelopment or decommissioning.

On page 5-40 of the Application, BC Hydro explains that it:

> has prioritized capital investment in Key facilities, with a lower level of investment in the Strategic facilities. With the exception of Whatshan Generating Station and Aberfeldie Generating Station, the business group will continue to operate and maintain Available Energy facilities with limited proactive and minimal reactive capital investment until all units at a facility are forced out of service indefinitely. Investment at any facility will be limited to a multi-year expenditure cap that results in a positive net present value until redevelopment. When a facility is forced out of service, and on an individual basis, plans will be developed for the economic refurbishment or redevelopment of the facility or decommissioning.

On page 6-21 of the Application, BC Hydro explains that "… Alouette and Elko generating stations and Shuswap Unit 1 have been forced out of service due to unsatisfactory equipment conditions and will remain out of service for an extended period."

48.6 Please elaborate on BC Hydro's investment strategy of a lower level of investment for Strategic Facilities. Is BC Hydro's plan for Strategic Facilities similar to that of Available Energy Facilities, in that they will be limited to a multi-year expenditure cap, maintained until forced out of service and then reviewed for refurbishment, redevelopment or decommissioning? For example, Alouette, a Strategic Facility, is currently forced out and will remain out of service for an extended period. Please elaborate.

49.0 **Reference: OPERATING COSTS – TRAINING, DEVELOPMENT AND GENERATION**
Exhibit B-1-1, Section 5.4.1.2, p. 5-41; Section 5.7.6.2, p. 5-165
Managing the life cycle of generation assets

Mandatory reliability standards

On page 5-41 of the Application, BC Hydro states:

> Under the *Utilities Commission Act*, BC Hydro must annually determine cost impacts of new or revised standards. On May 15, 2015, BC Hydro filed Mandatory Reliability Standards Assessment Report No. 8 summarizing the cost impacts of 37 new and revised reliability standards.

Below is a summary of the Mandatory Reliability Standards (MRS) related costs to BC Hydro as estimated in BC Hydro's Assessment Report No. 7, No. 8 and No. 9 prepared by the Commission:

Table 1: MRS Cost Estimates from BC Hydro Assessment Reports No. 7–9

	ADOPT STANDARDS		ADOPT REVISED TERMS		NOTES
	Incremental One-Time Cost	Annual Ongoing Cost	Incremental One-Time Cost	Annual Ongoing Cost	
MRS Assessment Report #9[3]	At least $1,369,000	At least $132,000	$0	$0	1. Adopt 15 revised standards 2. Adopt 10 new/revised terms
MRS Assessment Report #8[4]	At least $33,910,670	At least $7,757,100	$60,000	$0	1. Adopt 34 revised standards 2. Adopt 45 revised terms
MRS Assessment Report #7[5]	$24,000	$0	$1000	$0	1. Adopt 22 revised standards 2. Adopt 6 new/revised terms

49.1 Please repopulate the table above to show actual incremental one-time costs and actual annual ongoing costs. Please explain any variance in costs.

The Critical Infrastructure Protection (CIP) Version 5 standards will be effective in BC on October 1, 2018.

On page 5-165 of the Application, BC Hydro indicates that the Security department's "Priorities in fiscal 2017 that must be sustained through fiscal 2017 to fiscal 2019 and beyond include: Design and implementation of security solutions and systems as required by the North American Electric Reliability Corporation, Critical Infrastructure Protection…"

49.2 Please provide F2015 and F2016 forecast and actual operating costs for any work completed for MRS overall and discuss any variances. Please specifically discuss how much of the cost can be attributed to CIP overall.

[3] 2016 Assessment Report #9, p.33 and p.43, http://www.bcuc.com/Documents/Proceedings/2016/DOC_46199_B-1_BCH_MRS-Report-No9.pdf
[4] 2015 Assessment Report #8, p.55 and p.78, http://www.bcuc.com/Documents/Proceedings/2015/DOC_43998_B-1-1_BCH-Errata-No1.pdf
[5] 2014 Assessment Report #7, p.25 and p.41, http://www.bcuc.com/Documents/Proceedings/2014/DOC_41400_B-1-1_05-02-2014_BCH-MRS-AssessmentReportNo7-ERATTA.pdf

49.3 Please provide a breakdown of forecasted operating costs for F2017, F2018 and F2019 driven by MRS overall. Please specifically show how much of the cost can be attributed to CIP overall as well as CIP Version 5 standards coming into effect on October 1, 2018.

H. CHAPTER 5 – OPERATING COSTS – TRANSMISSION, DISTRIBUTION AND CUSTOMER SERVICE BUSINESS GROUP

50.0 **Reference: OPERATING COSTS – TRANSMISSION, DISTRIBUTION AND CUSTOMER**
Exhibit B-1-1, Section 5.5.2, Table 5-16, p. 5-63
Operating costs

Table 5-16 on page 5-63 of the Application shows actual and planned operating costs for the transmission, distribution and customer service business group as follows:

Table 5-16 Transmission, Distribution and Customer Service Operating Costs Before Regulatory Account Transfers, Net of Recoveries – By Key Business Unit

	($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	Field and Grid Operations	138.0	138.9	137.7	140.1	146.4	147.9	149.6
2	Asset Management and Distribution Engineering	152.8	162.3	151.7	155.1	158.1	158.6	158.1
3	Program and Contract Management	12.2	11.8	12.2	10.9	12.9	13.1	13.3
4	Customer Service and Distribution Design	90.1	92.9	90.1	94.5	88.0	85.7	86.2
5	Technology	108.4	108.9	110.1	107.2	139.5	139.7	138.9
6	Business Unit Support	11.9	2.9	9.0	5.8	(8.9)	(8.9)	(8.9)
7	Total (5.4 L18)	513.4	517.6	510.9	513.6	536.0	536.0	537.2

50.1 Please explain the increase in technology costs of $31.7 million on line 5 of Table 5-16 between F2016 actual and F2017 forecast.

On page 5-97, BC Hydro explains that: Technology operating cost increases are "partially offset by savings through the Workforce Optimization Program and a budget transfer post re-organization."

50.2 Please elaborate on the above statement and provide the Workforce Optimization and budget transfer savings which are expected.

On page 5-98, BC Hydro states:

> The business group costs that are budgeted in Business Unit Support include First Nations community payment in lieu of taxation, exempt materials, as well as business group initiatives such as business process reviews and efficiency projects. These costs are offset in the test period by savings to be realized through the Transmission, Distribution and Customer Service Efficiency Initiative which currently are not allocated to individual Key Business Units.

50.3 Please recast the information presented in Table 5-16 before regulatory transfers (i.e. not net of recoveries) and after allocating the test period savings to be realized through the Transmission, Distribution and Customer Service Efficiency initiative to individual key business units.

50.3.1 Please provide a breakdown of the Business Unit Support costs in the revised table for planned and actual Business Unit Support costs in F2015 and 2016, and planned Business Unit Support costs for F2017 to F2019.

51.0 **Reference: OPERATING COSTS – TRANSMISSION, DISTRIBUTION AND CUSTOMER**
Exhibit B-1-1, Section 5.5.2, pp. 5-61–5-62
Operating costs continuity schedule

On pages 5-61 and 5-62 of the Application, BC Hydro explains its past efforts to find operation efficiencies and savings in the Transmission, Distribution and Customer Service group by engaging its employees to provide input. It notes that it is still developing project plans for finding operational efficiencies in the test period and that it is forecasting $15 million of sustainable savings. Table 5-17 on page 5-64 shows the anticipated savings on line 11.

51.1 Please clarify whether the total sustainable savings are $15 million per year for each year of the test period or whether it is $15 million in total for the 3 year period.

51.2 Considering these plans are still being developed, please explain how BC Hydro determined that it would achieve $15 million in sustainable savings. For example, is this a target or goal, or is it an analytical forecast based on past experience? Please elaborate.

51.3 How is performance being measured as it pertains to the sustainable savings? Please explain.

51.4 Please explain why this initiative is only planned for the Transmission, Distribution and Customer Service groups as opposed to the entire organization.

52.0 **Reference: OPERATING COSTS – TRANSMISSION, DISTRIBUTION AND CUSTOMER**
Exhibit B-1-1, Section 5.2, Table 5-18, pp. 5-65, 5-86
FTEs

On page 5-86 of the Application, BC Hydro states:

> FTEs in the Program and Contract Management Key Business Unit are increasing by 22 in fiscal 2017 from fiscal 2016 actual FTEs, and a further four in fiscal 2018. The increases relate to Workforce Optimization as contractors are being replaced with employees to manage work programs and reduce overall capital costs.

52.1 Please elaborate on the forecast increase in Program and Contract Management FTEs from F2016 actual to F2017 forecast, and F2017 forecast to F2018 forecast.

52.2 Please provide the expected operating and capital savings from this workforce optimization activity.

Relating to the Technology key business unit, BC Hydro states on page 5-97 of the Application that "FTEs increase by four across the group from fiscal 2016 actual FTEs compared to fiscal 2017 plan and increase by 15 in fiscal 2018 and 11 in fiscal 2019. These changes relate to the Workforce Optimization Program and will reduce overall capital costs as well as decrease our dependence on contractors to manage capital projects and maintain and support BC Hydro systems."

52.3 Please elaborate on the changes described in the above statement and show how overall capital costs will be reduced even though FTEs are increasing.

53.0 **Reference: OPERATING COSTS – TRANSMISSION, DISTRIBUTION AND CUSTOMER**
Exhibit B-1-1, pp. 5-59, 5-77, 5-98-5-107; Appendix S
Transmission and distribution equipment maintenance

On page 5-59 of the Application, BC Hydro explains that it evaluates the condition of the transmission and distribution assets based primarily on the latest available maintenance data and assigns an Asset Health Index (AHI). It elaborates that AHI is a recently developed methodology that assigns ratings of Very Good, Good, Fair, Poor or Very Poor, which in turn can be grouped and analyzed by asset class and/or criticality. Appendix S provides the AHI ratings for transmission and distribution asset groups. On page 5-77 of the Application, BC Hydro explains that an external review of its asset management practices was conducted in 2013 and concluded that practices were forward looking and among the leaders in the industry.

On pages 5-98 to 5-107, BC Hydro provides a description of its transmission and distribution maintenance program and explains that the activities are developed using an RCM (reliability centered maintenance) methodology to optimize equipment reliability, maintenance cost and outages. It notes the main types of maintenance programs are PM, CO and CB maintenance.

53.1 Please compare the AHI to the previous methodology employed and further explain the differences in the methods. Is the AHI methodology expected to lead to higher or lower costs to maintain transmission and distribution assets in the test period and in the long term? Please elaborate.

53.2 What was the cost to implement AHI? What are the expected benefits? How are these benefits being tracked? Please elaborate.

53.3 Is the transmission and distribution lifecycle asset management program aligned with PAS 55, ISO 55000, or some other industry standard? Please elaborate.

53.4 Please provide the key findings and recommendations of the 2013 external review.

53.5 How does AHI compare to EHR? Why is AHI used for transmission and distribution assets and EHR is used for generation assets? Please elaborate.

53.6 Is AHI used elsewhere? Please explain.

53.7 What is the target AHI distribution for each asset category? Why?

53.8 Please provide the AHI for each asset category from the first year of implementation to today. Please comment on any trends observed. For example, are certain asset categories improving their AHI distribution, or is their AHI distribution deteriorating? Please elaborate.

53.9 Were there any major transmission and distribution equipment failures in F2015 or F2016? Please discuss.

53.10 On a whole, has moving to AHI increased or decreased expected PM, CO or CB maintenance and/or capital investment requirements? Please elaborate.

54.0 **Reference: OPERATING COSTS – TRANSMISSION, DISTRIBUTION AND CUSTOMER**
Exhibit B-1-1, Section 5.5.3.4, pp. 5-68, 5-71, 5-76
Construction services

On page 5-71 of the Application, BC Hydro discusses the Construction Services (CS) key business unit and explains that it is made up of up full time-managers and International Brotherhood of Electrical Workers (IBEW) crew leaders supporting a scalable workforce of approximately 300 IBEW full time temporary

trade employees. In Table 5-20 on page 5-68 of the Application, BC Hydro shows there were 521 FTEs in F2015 and 454 FTEs in F2016 in this business unit. The table also shows BC Hydro's forecast is for 404 FTEs in this business unit each year of the test period. On page 5-76 of the Application, BC Hydro explains that the increase in Regional Operations FTEs of 46 is due to the return of employees that worked on the Interior to Lower Mainland (ILM) Project from Construction Services and vacancies.

54.1 Please provide the breakdown of full-time permanent and full-time temporary employees in CS for the three years leading up to CS' work on the ILM project, for the period of support during the ILM project, after the ILM project, and forecast for the test period. Please also provide this breakdown by full-time managers, IBEW crew leaders and staff. Please discuss any observations.

54.2 Please explain why the group has a considerable size of full time temporary employees.

54.3 Does having these employees as full time temporary affect BC Hydro's ability to attract and retain employees for this group? Please elaborate.

54.4 When the employees were initially moved from Regional Operations to CS to support the ILM project, how did Regional Operations manage with the reduced workforce? Please elaborate.

54.5 Will the reduction in CS FTEs from 521 FTEs in F2015 to 404 FTEs in the test period affect this business unit's ability to execute its responsibilities effectively? For example, to quickly deploy resources in response to urgent and emergent work such as transformer oiling and reactive equipment winding repairs. Please elaborate.

I. CHAPTER 5 – OPERATING COSTS – CAPITAL INFRASTRUCTURE PROJECT DELIVERY BUSINESS GROUP

55.0 **Reference: OPERATING COSTS – CAPITAL INFRASTRUCTURE PROJECT DELIVERY**
Exhibit B-1-1, Appendix N; Exhibit B-6, Supplemental Appendix I-B
Budget to actual costs

In Table N-2 of Appendix N of the Application, BC Hydro explains that it is 0.18 percent below budget on $6.49 billion in project spending. On page 6 of this Appendix, BC Hydro also explains that over the past five years BC Hydro has delivered 563 capital projects at a total cost of $3.94 billion, and notes that this is 1.8 per cent under budget in aggregate. BC Hydro explains it is reporting based on the original approved full scope implementation budgets excluding project reserve funds.

55.1 Please elaborate on how the $3.94 billion and the $6.49 billion were calculated.

55.2 Please discuss how the budget and actuals provided in the Supplemental Appendix I-B reconcile to the $3.94 billion and $6.49 billion.

55.3 Does BC Hydro make use of any analytical tools such as efficiency ratios or industry comparators to determine if historical or future capital or operating cost levels are reasonable? Has the finance department completed any such analysis or have there been any internal or external audit reports dealing with capital or operating cost levels? Please elaborate.

56.0 **Reference: OPERATING COSTS – CAPITAL INFRASTRUCTURE PROJECT DELIVERY**
Exhibit B-1-1, Table 5-28, p. 5-114; Section 5.6.10, p. 5-1316
Business unit support costs

Table 5-28 on page 5-115 of the Application shows total planned and actual business unit support costs in F2015 and 2016, and planned business unit support costs in the test period in line 7 as follows:

Table 5-28 Capital Infrastructure Project Delivery Operating Costs Before Regulatory Account Transfers, Net of Recoveries, by Key Business Unit

	($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	Project Delivery	12.7	12.1	12.7	12.0	13.4	14.2	14.3
2	Generation and Transmission Engineering	12.3	13.3	12.4	12.3	14.0	14.2	14.4
3	Aboriginal Relations	5.0	5.5	5.1	6.2	6.1	6.1	6.1
4	Environmental Risk Management	25.6	26.8	25.6	26.4	27.2	27.5	27.8
5	Dam Safety	9.5	9.4	9.5	9.7	8.8	8.9	9.0
6	Properties	33.2	32.9	33.0	32.9	32.2	32.5	32.8
7	Business Unit Support	(49.6)	(47.4)	(49.6)	(38.6)	(45.3)	(51.6)	(52.3)
8	Total (5.5 L9)	48.7	52.7	48.7	61.0	56.3	51.8	52.1

On page 5-131 of the Application, BC Hydro states:

> The Capital Infrastructure Project Delivery Business Unit Support Key Business Unit hold the budget for the Office of the Deputy Chief Executive Officer and for the business group costs that are not specifically related to any single Key Business Unit… The business group costs that are budgeted in Business Unit Support include capital project investigation costs, capital project dispute resolution costs, First Nations community payment in lieu of taxation, dam safety investigation costs and capital overhead.

56.1 Please provide a breakdown as described on page 5-131 of the Application of the business unit support costs in line 7 of Table 5-28 which is before regulatory transfers (i.e. not net of recoveries) for forecast and actual business unit support costs in F2015 and 2016, and forecast business unit support costs in the test period.

57.0 **Reference: OPERATING COSTS – CAPITAL INFRASTRUCTURE PROJECT DELIVERY**
Exhibit B-1-1, Table 5-30, pp. 5-115, 5-119, 5-121, 5-130
FTEs

In table 5-30 on page 5-115 of the Application, BC Hydro shows that it had expected 1,157 and 1,196 FTEs in Capital Infrastructure Project Delivery business group in F2015 and F2016, respectively. However, F2015 and F2016 actual FTEs were 1,088 and 1,099, respectively.

57.1 Please explain the reasons for the unfilled positions in the Capital Infrastructure Project Delivery business group in F2015 and F2016.

57.2 Would this level of job vacancies be expected through the test period? Why or why not? Please explain.

On page 5-119 of the Application, BC Hydro states for the Project Delivery key business unit, "Compared to the fiscal 2016 Actual FTEs the fiscal 2017 FTEs are expected to increase by 54 with a further increase of 28 in fiscal 2018 due to Workforce Optimization. From fiscal 2018 to fiscal 2019 Plan FTEs will remain constant."

On page 5-121 of the Application, BC Hydro states that for the Generation and Transmission Engineering key business unit, "FTEs are planned to increase by 15 in fiscal 2017 from fiscal 2016 actual FTEs. The increase in fiscal 2017 relates to Workforce Optimization. FTEs are planned to remain constant for fiscal 2018 and fiscal 2019."

57.3 Please further explain the increase in FTEs in the Project Delivery and Generation and Transmission Engineering key business groups due to Workforce Optimization and demonstrate the savings that are expected.

57.4 Are any of these positions similar to ones that were eliminated in 2011 or later? If so, why are they being recreated? Please elaborate.

On page 5-130 of the Application BC Hydro states,

> Planned FTEs for Site C Clean Energy Project Key Business Unit will increase by 77 in fiscal 2017 from fiscal 2016 actual FTEs as the project staffs up to a full complement of resources to manage and administer the project. In fiscal 2018 an increase of three and in fiscal 2019 an increase of 10 FTEs primarily related to increases for overtime as the project team takes on all implementation activities. All Site C Clean Energy Project FTEs are charged to capital.

57.5 Please explain, with examples, why BC Hydro will need 199 FTEs to oversee the capital work for the Site C project.

58.0 **Reference: OPERATING COSTS – CAPITAL INFRASTRUCTURE PROJECT DELIVERY**
Exhibit B-1-1, Section 5.6.7, pp. 5-127, 5-128
Dam safety

On page 5-127 of the Application, BC Hydro discusses the Dam Safety key business unit and explains that BC Hydro is accountable to the Government of BC and to the Comptroller of Water Rights, for ensuring the safety of its dams in accordance with Dam Safety Regulation. BC Hydro explains that "BC Hydro has a comprehensive dam safety program, which has been compared favorably to the leading programs around the world… BC Hydro develops and maintains world-class capability in risk assessment and dam safety engineering, and is committed to providing the resources to meet or exceed dam safety guidelines." On page 6-22 of the Application, BC Hydro mentions the 2007 Canadian Dam Association Guidelines.

58.1 Please discuss Dam Safety Regulations and the 2007 Canadian Dam Association Guidelines. Have there been changes to either of these that would be expected to drive additional maintenance or capital investments at BC Hydro dams? Were these changes accounted for in this Application? Please elaborate.

58.2 How is BC Hydro's Dam Safety program being reviewed by internal or external groups? Who provides the oversight and governance of Dam Safety at BC Hydro? How is it being compared to other leading programs around the world? Please provide the latest results.

58.3 Please explain how BC Hydro determined that it develops and maintains world-class capability in risk assessment and dam safety engineering.

59.0 **Reference: OPERATING COSTS – CAPITAL INFRASTRUCTURE PROJECT DELIVERY**
Exhibit B-1-1, Section 5.5.7.3, p. 5-95; Section 5.7.6.2, p. 5-165
Physical and cyber security

On page 5-95 of the Application, BC Hydro discusses cyber security. On page 5-165 of the Application, BC Hydro discusses the Security department and explains that the department is responsible for the protection and security of people, infrastructure, assets and operations. BC Hydro explains that approximately 1,700 incidents are received each year by Security Command Center and reviewed by the investigation team.

59.1 Please confirm that no major physical or cyber security incidents occurred at BC Hydro in F2015 or F2016. If not confirmed, at a high level, please discuss those major incidents and the measures BC Hydro is taking to ensure they do not reoccur.

59.2 Has BC Hydro noticed any trends in the number or severity of physical or cyber security incidents? Please elaborate and provide data.

59.3 Without consideration of BC Hydro's 10 Year Rate Plan, would BC Hydro be spending more on physical and cyber security? Please elaborate.

J. CHAPTER 5 – OPERATING COSTS – OPERATIONS SUPPORT BUSINESS GROUP

60.0 **Reference: OPERATING COSTS-OPERATIONS SUPPORT**
Exhibit B-1-1, Section 5.7, Table 5-31, pp. 5-134, 5-143, 5-170
Operating costs

Table 5-31 on page 5-134 of the Application shows total planned and actual operating costs for the operations support business group as follows:

Table 5-31 Operations Support Operating Costs Before Regulatory Account Transfers, Net of Recoveries – By Key Business Unit

	($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	Executive	0.7	0.8	0.7	0.8	0.9	1.0	1.0
2	Finance and Supply Chain	108.2	104.5	108.1	112.6	119.4	120.2	121.6
3	Corporate Affairs	53.7	50.4	53.8	51.1	53.1	53.3	53.9
4	Safety, Security, Emergency Management	25.6	24.4	25.7	29.2	30.0	30.0	30.0
5	General Counsel	12.2	11.6	12.2	11.0	12.2	12.3	12.3
6	IPP Capital Lease Operating Costs	29.4	29.4	33.8	34.2	28.2	63.6	54.3
7	Corporate Costs	(131.6)	(127.9)	(98.3)	(120.6)	(94.8)	(71.2)	(47.5)
8	Total (5.1 L19)	98.2	93.3	136.0	118.4	148.9	209.1	225.6

60.1 Please further explain the reasons for the increases in Supply Chain operating costs from $79.5 million in F2016 RRA to forecast $91.8 million in F2017. For example on page 5-143 of the Application, BC Hydro identifies expenditure increases of $3.8 million, $1.7 million and $3.3 million, which leaves $3.3 million unaccounted for – is that remaining amount due to standard labour increases? Please elaborate.

60.2 Please confirm, or otherwise explain, that the impact of the low Canadian dollar would be reflected in Supply Chain capital costs and not in operating costs.

60.3 Please provide the average and median maintenance cost per vehicle in F2015 and F2016 and the forecast maintenance cost per vehicle for each year of the test period. Please discuss any trends observed.

On page 5-170 of the Application, BC Hydro states, "Corporate Costs is a category of general expenses that are not specifically related to any single Business Group or Key Business Unit and are managed centrally under the Operations Support Business Group. The primary costs in this category include insurance costs, corporate membership dues and fees, and IFRS ineligible capital overhead."

60.4 Please provide a breakdown as described on page 5-170 of the Application of the corporate costs in line 7 of Table 5-31 which is before regulatory transfers (i.e. not net of recoveries) for forecast and actual corporate costs in F2015 and 2016, and forecast corporate costs in the test period.

On page 5-172 of the Application, BC Hydro states, "Non-current service costs [for post-employment

benefits] are charged to operating expenses of the Operations Support Business Group."

60.5 Please clarify the key business unit within the Operations Support business group which holds non-current service post-employment benefit costs.

60.6 Please confirm, or explain otherwise, that the non-current service post-employment benefit costs are ($9.6) million in F2017, ($12.1) million in F2018 and ($14.6) million in F2019 as set out in Table 5-39.

61.0 **Reference: OPERATING COSTS – OPERATIONS SUPPORT**
Exhibit B-1-1, pp. 5-23, 5-156–5-168; Appendix FF
Safety initiatives

On page 5-23 of the Application, BC Hydro explains that it is investing in safety initiatives to target high priority areas to improve its safety record. In Appendix FF, BC Hydro provides various safety related documents, including its 5-year Safety Plan and Measures of Success. Pages 5-156 to 5-165 discuss the safety aspects of BC Hydro's Safety, Security and Emergency Management key business unit. Table 5-31 on page 5-134 shows the operating costs for this key business unit.

On page 5-162 of the Application, BC Hydro states "17 of the 21 Safety Taskforce recommendations have been implemented and transferred to sustainment. The four remaining recommendations to be implemented have been incorporated into the Five-Year Safety Plan."

And on page 5-168, BC Hydro explains:

> Safety Operating costs will increase by a $4.3 million in fiscal 2017 and remain at that level for fiscal 2018 and fiscal 2019. This increase relates to $5.0 million of additional funding to implement Safety Improvement Projects that address the four remaining BC Hydro Safety Taskforce recommendations, comply with regulatory arc flash and confined space requirements set out for us by WorkSafe BC and build corporate systems and tools supporting excellence in Safety (e.g., Field Access to Safety Information).
>
> Safety, Security, and Emergency Management will increase by seven FTEs in fiscal 2017 compared to fiscal 2016 actual FTEs with a further two in fiscal 2018. These additions are related to the Workforce Optimization Program and will replace contractors supporting Capital work.

61.1 Please provide the total actual operating costs for all safety activities for F2014, F2015 and F2016 across all key business units and please provide the total forecast operating costs for all safety activities planned for all business groups for F2017, F2018 and F2019. Please discuss any trends observed.

61.2 Please compare the safety spending trend to the results of the Measures of Success and any other metrics BC Hydro finds appropriate. Is the safety spending achieving the desired results? Please elaborate.

61.3 Please discuss the "New West incident" noted in the 5-year Safety Plan and the fatality or serious injury noted in the Measures of Success, if different.

61.4 If there are only 4 Task Force Recommendations left, why is the Safety budget increasing? Please elaborate.

61.5 Please demonstrate the Workforce Optimization benefits that will come from the 7 new hires.

61.6 Are any of these positions similar to positions that were eliminated since F2011? Please discuss.

62.0 **Reference: OPERATING COSTS – OPERATIONS SUPPORT**
Exhibit B-1-1, Section 5.7.6, p. 5-160
Asbestos management

On page 5-160 of the Application, BC Hydro states:

> WorkSafe BC regulations require that an asbestos management plan be in place for all workplaces that have asbestos containing materials… BC Hydro's Asbestos Management Program will be updated to improve governance and standardization, and asbestos management activities will be embedded in asset management and work issuance processes to ensure inventories and labels are sustained and asbestos containing materials hazards are consistently identified for workers.

62.1 Please discuss the work that will be required over the test period related to asbestos management, and when BC Hydro expects to complete all asbestos management activities.

62.2 Please provide actual asbestos management activity costs over the past five years and planned asbestos management activity costs for the test period.

K. CHAPTER 5 – OPERATING COSTS – POST EMPLOYMENT BENEFIT COSTS

63.0 **Reference: OPERATING COSTS – POST EMPLOYMENT BENEFIT COSTS**
Exhibit B-1-1, pp. 5-7, 5-30, 5-171–5-174; July 2011 Government Review of BC Hydro
Pension costs

On page 5-30 of the Application BC Hydro states that "Effective January 2016, BC Hydro changed the cost sharing model related to its registered defined benefits pension plan such that employees and BC Hydro each contribute fifty percent of the annual cost contributions. Previously, BC Hydro's portion was higher."

63.1 What was BC Hydro's portion previously?

63.2 What are the forecast savings in the test period relating to this change?

63.3 Please show where on Tables 5-38 and 5-39 these saving s are reflected.

63.4 Please explain why these savings were not reflected in Table 5-5.

Recommendation 16 of the 2011 Government Review of BC Hydro (Report) states: "Revisit the current post-retirement benefit coverage for extended health and life insurance benefits provided to reduce the impact to ratepayers."

63.5 Please explain the changes that have occurred to the Other PEB benefit coverage including extended health and life insurance benefits as a result of this recommendation.

<u>Current Service Costs</u>

63.6 Please expand Table 5-38 to include forecast and actual data for F2012 to F2014. For F2012–F2016, please explain the reason for any variance between forecast and actual. Please report the Pension Benefit and the OPEB on separate lines.

63.7 Please further break down the forecast current OPEB expense in each of the test years by medical, extended health and dental benefits, Canadian Pension Plan, Employment Insurance, workers compensation premiums and supplemental pension.

63.8 Is BC Hydro requesting that the variance between the amount forecast in Table 5-28 and the actual costs be deferred to the Non-Current Pension Cost regulatory account? Specifically do the values in Table 5-28 set the baseline? If yes, please explain what the values on line 11 of Table 7-3 on page 7-8 relate to.

Non-Current Service Costs

63.9 Please expand Table 5-39 to include forecast and actuals for F2012 to F2014.

63.10 Please confirm, or explain otherwise, that the variance between forecast and actual Plan Income and Interest Expense for both Pension Benefit and OPEB are deferred to the Non-Current Pension Cost regulatory account.

63.11 Do the totals set out in Table 5-39 set the baselines for the variance calculation for deferral to the regulatory account in each of the test year? If yes, please explain what the values on line 5 of Table 7-3 on page 7-8 relate to. If not, what is the variance baseline?

63.12 Please provide a table that shows the actual number of employees who received benefits in F2012 to F2016 and the forecast for the test period (i.e. head count).

Actuarial Valuation

63.13 On page 5-171 of the Application, BC Hydro states that an actuarial valuation is currently being performed as at December 31, 2015, which will be completed by September 2016.

63.14 Has the actuarial valuation been completed, and if so, please file a summary.

63.15 Please explain how, if at all, the results of the valuation impact the current and non-current PEB forecasts.

63.16 If available, please file BC Hydro's most recent financial statement pension note.

L. CHAPTER 6 – CAPITAL EXPENDITURES AND ADDITIONS

64.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, pp. 6-12–6-14; Appendices G, R, S
Enterprise-wide framework for capital prioritization

On pages 6-12 to 6-14, BC Hydro explains how it ranks capital investments and notes that in the F2012-F2014 RRA it informed the Commission that it was developing an enterprise-wide framework for capital prioritization. BC Hydro refers to Appendix G which is a briefing note updating the BC Hydro Board on its 10 Year Capital Forecast. On page 13 of that briefing note, BC Hydro provides a summary of the prioritization framework it uses for risk and value dimensions and on page 17 it provides its corporate risk matrix. Appendix R of the Application provides Equipment Health Ratings (EHR) for Generation assets and Appendix S provides Asset Health Index (AHI) ratings for transmission and distribution assets.

64.1 Is the enterprise-wide framework for capital prioritization a combination of the corporate risk matrix and the risk and value dimension summaries? If not, please provide the documented policies that form the basis of the enterprise-wide framework for capital prioritization.

64.2 In terms of the corporate risk matrix, has a risk threshold been established? If so, how was it determined?

64.3 In terms of the value dimension, please elaborate on how BC Hydro determines if there is value to pursuing a project. For example, what time period is used for the Net Present Value (NPV) analysis or what is the required internal rate of return?

64.4 How is the enterprise-wide framework for capital prioritization related to EHR and AHI ratings? Please elaborate.

64.5 Please explain how other costs such as operations and maintenance costs are incorporated into the enterprise-wide framework for capital project prioritization.

64.6 For assets that do not have EHR or AHI ratings (e.g. penstocks, dams, gates, IT, etc.) how are these projects prioritized? Are there plans to implement rating systems for these assets? Please elaborate.

64.7 Please discuss the policies that BC Hydro follows to review and prioritize ex-plan projects (i.e. projects that BC Hydro is not aware of when initially prioritizing/preparing the plan). Would other projects be deferred or cancelled to accommodate the ex-plan project? Or, would the project be added to the plan? What risk do ex-plan projects pose on the revenue requirement in the test period? What is BC Hydro's past experience with ex-plan projects? Please elaborate.

65.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Chapter 6, p. 6-54; BC Hydro Inquiry of Expenditures to the Adoption of the SAP Platform proceeding (SAP proceeding), Exhibit B-3, Section 4.2 Financial Oversight; Section 4.4 Internal Audit; Attachments 11–23
Financial oversight and expenditure authorization policies for capital projects

In Section 4.2 of Exhibit B-3 of the BC Hydro Inquiry of Expenditures to the adoption of the SAP proceeding BC Hydro describes its financial oversight and governance including financial authority approval limits. Attachments 11 to 19 are the specific policy documents, including Project Management Guidelines and Delivery Practices and Attachments 20 to 23 relate to internal audits on BC Hydro's Information Technology & Telecommunications (IT&T).

On page 6-54 of the Application describes the Capital Projects Committee of the Board of Directors.

65.1 Please confirm, otherwise explain, that the financial oversight and governance described in Section 4.2 and Attachments 11-19 of the SAP proceeding continue to apply. If there are differences, please explain those differences. Please bring these financial oversight and governance documents listed above into this proceeding.

65.2 Please provide any other Capital Projects Committee governance related documents or policies that relate to its mandate, and the review and approval processes it uses for capital projects.

65.3 Please provide the documents that are equivalent to the Project Management Guidelines and Delivery Standard Practices (e.g. Project and Portfolio Management Practices) for Generation, Transmission, Distribution, Properties and Fleet projects.

65.4 Please discuss BC Hydro's internal audit processes and results as they relate to Generation, Transmission, Distribution, Properties and Fleet capital project initiating, planning, executing, monitoring and controlling, and closing processes. Please provide the findings and recommendations of the most recent audit.

66.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Chapter 6, Appendices I, J
BC Hydro 2010 Capital Project Filing Guidelines

On July 23, 2010 BC Hydro filed with the Commission Capital Project Filing Guidelines (Guidelines).

66.1 Please confirm, otherwise explain, that BC Hydro continues to follow the Guidelines filed with the Commission on July 23, 2010.

66.1.1 If confirmed, please add these Guidelines to the record of this proceeding. If not confirmed, please provide and explain any new filing guidelines/policies that BC Hydro now follows.

66.2 What are BC Hydro's capital project filing guidelines for Dam Safety, gates and spillway projects?

67.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-2, Table 6-4, p. 6-7
Capital Additions Forecast

Table 6-4 shows that for F2015, BC Hydro was forecasting $2.3 billion in capital additions and had $1.8 billion in actual additions. BC Hydro is forecasting $1.6 billion, $1.4 billion and $2.3 billion in capital additions for F2017, F2018 and F2019, respectively.

67.1 What are the consequences in the near and long term to deferral accounts and ultimately rates if BC Hydro were to have capital additions 20 percent higher or 20 percent lower than forecast in the test period? Similarly, what is the probability of such a difference in capital additions occurring? Please elaborate.

68.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, pp. 6-60, 6-61; Appendix J; Exhibit B-6, Supplemental Appendix I-A
Definitions – costs and accuracy

On pages 6-60 to 6-61, BC Hydro explains that in the project identification stage a preferred alternative is identified and the expected estimate accuracy at the end of feasibility studies is +50/-15 percent, nine times out of ten. It also explains that in the project definition stage, regulatory applications are produced on the basis of the preliminary designs and the expected estimate accuracy is +15/-10 percent, nine times out of ten.

68.1 Please confirm, otherwise explain, that all dollar amounts provided in Chapter 6, Supplemental Appendix I-A and Appendix J are in as spent dollars.

68.2 Should the upper bound of an estimate's accuracy range (including contingency but excluding management reserves) be the criteria for which the Commission should use to determine whether or not section 45 (2) of the UCA applies?

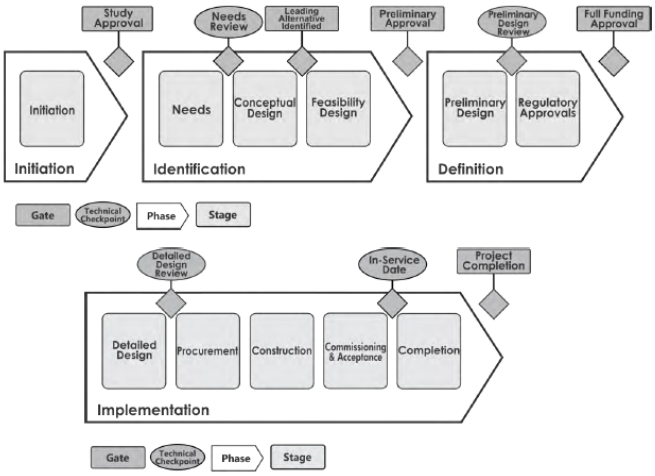
69.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, p. 6-60; Exhibit B-6, Supplemental Appendix I-A, I-B
Definitions – Start of construction and in-service dates

Supplemental Appendix I-A includes columns for the current start date of construction and the current forecast in service date (ISD). The footnotes explain that the current start date of construction is the implementation approval date and the current forecast ISD is the expected in service date when the

project goes into service. Supplemental Appendix I-B includes a column for ISD per SAP and a column for Implementation Approval ISD. Footnote 4 explains that ISD in this case is the in-service date per SAP financial system when the project goes into service, including month and fiscal year. Footnote 7 explains that Implementation Approval ISD refers to the ISD date identified when the project was first approved by BC Hydro for implementation.

In Figure 6-3 on page 6-60, BC Hydro provides the project lifecycle sequence from project initiation to construction to completion and identifies full-funding approval and in-service date milestones.

Figure 6-3 Project Lifecycle Sequence from Project Initiation to Completion



UCA refers to extensions, expenditures and expenditure schedules. Section 45(5) of the UCA reads:

> If it appears to the commission that a public utility should, before constructing or operating an extension to a utility plant or system, apply for a separate certificate of public convenience and necessity, the commission may, not later than 30 days after construction of the extension is begun, order that subsection (2) does not apply in respect of the construction or operation of the extension. (Emphasis added)

Direction 7 (11) (a) refers to allowance of costs for extensions that come into service before F2017.

69.1 Please explain the policies, processes and criteria BC Hydro uses to determine the actual ISD for each type of project (i.e. generation, transmission, distribution, technology, properties and other capital). How is acceptance defined?

69.2 Please confirm, otherwise explain, that BC Hydro's policies, processes and criteria for determining the actual ISD have been applied consistently across all the projects listed in Supplemental Appendices I-A and I-B and are consistent with Figure 6-3. If there are exceptions, please list those exceptions and explain why.

69.3 Please confirm, otherwise explain, that the "Full Funding Approval" milestone provided in Figure 6-3 is what BC Hydro considers the implementation approval date.

69.4 Please confirm, otherwise explain, that in Figure 6-3, and generally in BC Hydro construction projects for extensions, the detailed design stage, the detailed design review milestone and procurement stage come before the construction stage.

69.5 For the purposes of section 45(5) of the UCA, when does BCH consider construction of a project to begin?

70.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Chapter 6; Exhibit B-6, Supplemental Appendix I-B
Definitions – sustainment, growth, dam safety, redevelopment, technology and extension

Direction 7 (11) (a) refers to the allowance of costs for extensions that come into service before F2017.

In Exhibit B-6, Supplemental Appendix I-B, BC Hydro provides a column titled exempt from BCUC review per section 11 of Direction 7 and explains in footnote 9 that based on the meaning of "extension" used in BC Hydro's existing Capital Project Filing Guidelines, this column indicates if the project is an extension and is therefore considered to be exempt from BCUC review pursuant to section 11 of Direction 7.

In BC Hydro's 2010 Capital Project Filing Guidelines BC Hydro explains that the term extension is not defined in the UCA but provides its approach to CPCN and expenditure schedule applications that it will with the Commission.

70.1 Please provide BC Hydro's definitions for sustainment, growth, dam safety and redevelopment.

70.2 Please provide further information regarding BC Hydro's interpretation of the term extension to help the Commission better understand how BC Hydro determined whether or not a project was exempt pursuant to Direction No. 7 (11)(a) in Appendix I-B.

70.3 Please add a column to Appendix I-A indicating whether or not BC Hydro considers the project an extension.

70.4 Please explain BC Hydro's policies, processes and/or criteria that it follows to support, oversee and control categorization of capital expenditures and additions as sustainment, growth, dam safety, redevelopment and extension.

70.5 Can sustainment, growth, dam safety or redevelopment projects be categorized as extensions? Please explain which can be categorized as extensions and which cannot, and why this is the case.

70.6 Can dam safety or redevelopment projects be categorized as sustainment or growth? Please explain.

70.7 Please explain why all the technology, properties and other capital projects are defined as sustainment. Can they be defined as growth or extensions? Please explain.

71.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Chapter 6
Definitions – expenditure and expenditure schedule

Section 44.2 of the UCA refers to expenditure schedules. Chapter 6 is titled Capital Expenditures and Additions.

71.1 Please confirm, otherwise explain, that in this Application and pursuant to section 44.2(3) of the UCA, BC Hydro is only requesting acceptance of a DSM expenditure schedule and is not requesting acceptance of any other expenditure schedule (if any) provided in the Application.

72.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, p. 6-81
Generation, transmission, distribution, technology and other capital projects

On page 6-81 of the Application BC Hydro explains that "Transmission capital expenditures and additions include Substation Distribution Asset expenditures and additions. The Substation Distribution Asset costs are tracked separately, enabling the determination of transmission function costs for rate design and other purposes."

BC Hydro's 2010 Capital Project Filing Guidelines state: "[Substation Distribution Asset] projects will not typically be filed as stand-alone applications; rather, the SDA expenditures will be included as part of a transmission project."

72.1 Please provide and explain any policies, processes or criteria for how BC Hydro defines projects as either generation, transmission, distribution, technology, properties or other capital in particular where a project might include more than one of these elements (for example a project that has elements of transmission, distribution and property). Please confirm that the policies and processes are applied consistently. If not, please identify and explain any variances.

72.2 Please explain how BC Hydro defines or delineates between distribution assets and transmission assets. For instance, is a 138kV to 25kV step-down transformer a distribution asset or a transmission asset? Please elaborate.

72.3 Please confirm, otherwise explain, that if a project has a transmission asset, no matter what the percentage of the project scope or cost that transmission asset makes up, the project defaults to be considered a transmission project for the purposes of BC Hydro's current Capital Project Filing Guidelines.

73.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, pp. 6-15–6-17; Appendix G
Deferred projects

On pages 6-15 to 6-17 of the Application, BC Hydro explains that over the F2017 to F2019 period, planned capital expenditures were reduced by $381.2 million and planned capital additions were reduced by $392.5 million from initial plans.

BC Hydro explains that for Generation the majority of changes were associated with delaying projects in the sustaining capital portfolio resulting in a decrease in capital additions of $17.3 million. For Transmission and Distribution (T&D), BC Hydro explains that planned reductions of $167.2 million in capital additions will not materially impact customer reliability during the rate period, but will have some impact on Asset Health. For Technology, the $25.8 million in reductions include delay or cancellation of asset refresh or enhancement programs, and reprioritization of system resilience programs to an as-needed basis. Property reductions of $177 million were achieved due to delay or reduction in scope of building development projects at support facilities.

73.1 Please provide a list of all projects greater than $20 million (or $5 million for IT projects) that were part of the initial plan but were deferred or cancelled to achieve the $381.2 million / $392.5 million reductions in the test period.

73.1.1 Please explain why each of these projects was deferred and/or cancelled.

73.1.2 Please provide the risk and value dimension evaluations for these projects, including the

evaluated corporate risk matrices.

73.1.3 Will delaying any of these projects beyond F2019 begin to materially impact customer reliability after F2019? Please explain why or why not.

73.1.4 Will these reductions result in higher capital costs in the future? Please explain.

73.2 Is deferring the Generation sustaining capital portfolio projects expected to increase each of preventative, condition based or corrective maintenance? Please explain.

73.3 Other than SAIDI, SAIFI and generator forced outages, are there any other key performance indicators that may be affected by the decision to defer these sustaining capital projects? Please elaborate.

73.4 For the T&D projects, please quantify the expected impact on Asset Health of the reductions.

73.5 Considering Asset Health is being impacted, please elaborate on why this is not expected to impact reliability in the rate period.

73.6 Are BC Hydro's T&D assets in a better portfolio condition (i.e. higher Asset Health) than what is necessary to achieve the reliability levels its customers expect? Please explain.

73.7 How does the fleet condition of BC Hydro's T&D assets compare to other utilities? Please elaborate.

73.8 Please discuss the impacts of the delay or cancellation of asset refresh and enhancement programs and reprioritization of system resilience programs.

73.8.1 Does delay or cancellation of asset refresh and enhancement programs result in delaying benefit from improvements/efficiencies in operation, maintenance and / or additional costs or administrative activities? Please explain.

73.9 Are there projects proceeding in the test period which ranked lower on risk and value dimensions than any of the deferred projects? If so, please list those projects and explain the reasons for these exceptions.

74.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, p. 6-21; Appendix I, line 11
Out of service generating stations

On page 6-21 BC Hydro explains that "…Alouette and Elko generating stations and Shuswap Unit 1 have been forced out of service due to unsatisfactory equipment conditions and will remain out of service for an extended period."

Appendix I shows an Alouette dam safety project for $10 million.

74.1 Please provide the up to date Facility Asset Plans for Alouette, Elko and Shuswap.

74.2 Please describe BC Hydro's plans for these facilities.

74.3 Are these facilities being used and are they useful? Please elaborate. For regulatory purposes, should those assets be removed from rate base?

74.4 How are these facilities currently being accounted for? Please explain.

74.5 Have these facilities effectively been decommissioned?

74.6 How do the costs of redevelopment, refurbishment or repair of these facilities compare to the

costs of purchasing power from others, or DSM activities? Please elaborate.

74.7 Please elaborate on the Alouette dam safety project.

75.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, p. 6-24–6-26
Facility asset plans and 10 year capital forecast

On page 6-24 of the Application, BC Hydro explains it develops facility asset plans for its hydroelectric generating facilities. These plans are presented to the Generation Asset and Risk Planning Committee for agreement in principle and endorsement. This committee is made up of the Training, Development and Generation Leadership Team. On pages 6-24 and 6-25 BC Hydro explains the 10 year capital forecast business group review process, including a review by the Training, Development and Generation Leadership Team, the BC Hydro executive team and the BC Hydro Board of Directors.

75.1 Are the facility asset plans submitted to the Board of Directors for information, review and/or for approval? Please elaborate. Who is the business owner of the facility asset plans and why?

75.2 Is the 10 year capital forecast submitted to the Board for information, review and/or for approval? Please elaborate. Who is the business owner of the 10 year capital forecast and why?

75.3 Is there a guiding document or policy for preparation, review and approval of facility asset plans and 10 year capital plans? Please elaborate.

76.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, pp. 6-29, 6-30, 6-34; Appendix S
Asset Health Index – aging asset demographic

On page 6-29 of the Application BC Hydro explains that its level of sustainment expenditures on T&D of $1.1 billion in the test period is below the rate of replacements needed to maintain the condition and average age of these assets. On pages 6-30, 6-34 and Appendix S BC Hydro explains its Asset Health Index methodology.

76.1 Please confirm, otherwise explain, that all other things equal, this proposed level of sustainment expenditures on T&D will result in higher levels of sustainment expenditures on T&D assets in the future. Please elaborate.

76.2 Ignoring the rate plan, would BC Hydro recommend increasing T&D sustainment expenditures? Why or why not? Please elaborate.

76.3 For assets common to both Generation and T&D (e.g. power transformers and gas insulated circuit breakers), how does BC Hydro's new AHI methodology, the equipment ratings, maintenance, repair, refurbishment, replacement criteria/decisions compare to Generation and its EHR methodology? Are there key differences? If so, why? Please elaborate.

76.4 Is BC Hydro planning to move to a single consistent asset/equipment health rating methodology? If so, when? If not, why not.

77.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, pp. 6-30, 6-31
Customer reliability and safety s pending

On pages 6-30 and 6-31 of the Application BC Hydro explains that expenditures totaling approximately $125 million and $140 million over the test period are planned to address reliability and employee and

public safety concerns not related to aging assets.

77.1 Please confirm, otherwise explain, that the $125 million and $140 million in expenditures in the test period are for capital in the test period. If so, are these capital additions? Please elaborate.

77.2 Please provide a list and brief descriptions of the five largest reliability and five largest safety programs included in the $125 million and $140 million spending plans.

77.3 Please explain the benefits BC Hydro expects to achieve as a result of this spending and please explain how these expected benefits are being tracked and measured.

77.4 Please provide the comparable reliability and safety spending for F2012, F2013, F2014, F2015 and F2016.

77.5 Has BC Hydro noted improvements in reliability and safety as a result of its prior capital spending? Please elaborate.

78.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, pp. 6-36, 6-43-6-45; Appendix K, O
T&D and technology asset capital planning processes

On page 6-36 of the Application BC Hydro explains that at step 4 it looked at resource availability, and is mainly constrained by Communications, Protection and Control Technologists, and notes that $1 billion in lower risk capital investments were delayed outside the rate plan as a result of resource constraints.

On pages 6-43 and 6-44 of the Application BC Hydro explains that at step 2 of the technology capital planning process it looks at resource constraints. Projects are selected until the annual capital funding constraint is reached. Appendix O is BC Hydro's Technology Group 5-year Strategic Plan.

On page 6-45, BC Hydro explains that its technology capital plans and actual expenditures are dynamic and are expected to differ from that presented in the revenue requirements application for a number of reasons.

In Appendix K, Tables K-19 to K-22 show large changes and variances from year to year in planned and actual expenditures as well as in planned and actual additions for Technology.

78.1 Please confirm, otherwise explain, that there are projects with a positive NPV that were deferred due to resource constraints.

78.2 Considering BC Hydro suggests its technology capital plans are dynamic and subject to change, how will BC Hydro keep the Commission aware of any major changes to its plan? What risk could changing technology plans pose to the company and ratepayers?

78.3 Please explain how the expected benefits of technology projects are being tracked and measured.

78.4 Are there any major strategy shifts identified in BC Hydro's Technology Group 5-year Strategic Plan that could result in significant changes to BC Hydro's long-term IT&T spending and/or constrain future major decision making? For example, strategic decisions similar to moving to SAP as an ERP, contracting services with ABSU and TELUS, or organizational structure changes. Please elaborate.

79.0 **Reference:** **CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, pp. 6-54, 6-69, 6-70
Capital project and program delivery – Customer Services and Distribution Design and Generation Operations

In note 1 on page 6-54 of the Application BC Hydro explains that "Generation Operations delivers a portion of the generation sustain work (generally projects less than $1 million)." On page 6-70 BC Hydro explains that Generation Operations will deliver approximately $54 million over the test period. On page 6-69 BC Hydro explains that Customer Services and Distribution Design will deliver close to $440 million over the test period.

79.1 What project delivery processes and practices do these groups follow for their capital projects? Are there specific policies or documents? Please elaborate.

80.0 **Reference:** **CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, p. 6-66
First Nations, environment and communities

On page 6-66 and 6-67 of the Application BC Hydro explains its aboriginal consultation and engagement in delivery of capital projects and T&D capital programs. On pages 6-67 to 6-68 BC Hydro explains its environmental approach for capital projects. On page 6-68 BC Hydro explains its community engagement activities for capital projects.

80.1 Please provide the total annual environmental program capital spending for F2012 through to F2016 and forecast for F2017, F2018 and F2019. Please comment on any trends observed.

80.2 Please provide the total annual capacity funding and annual cost of impact benefit agreements related to capital projects for F2012 through to F2016 and forecast for F2017, F2018 and F2019. Please comment on any trends observed.

80.3 Please provide the total annual community engagement program capital spending for F2012 through to F2016 and forecast for F2017, F2018 and F2019. Please comment on any trends observed.

81.0 **Reference:** **CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, pp. 2-3, 6-19, 6-23; Appendix J, p. 1; Exhibit B-6, Supplemental Appendix I-A – Generation, line 1; BC Hydro 2015 Rate Design Application proceeding, Exhibit B-37
Revelstoke Install Unit 6

On page 6-19 of the Application BC Hydro explains that Revelstoke Unit 6 is required during the test period to meet BC Hydro's expected load. On page 6-23 BC Hydro explains that given the long lead time associated with new generation, work on preparing for the installation of Revelstoke Unit 6 is needed in the test period in order to meet a required in-service date.

The *Clean Energy Act* provides an exemption for: "Revelstoke Unit 6, a project to install an additional turbine and related works and equipment at Revelstoke."

Appendix J shows a forecast capital cost of $328 million to $591 million and describes the Revelstoke Install Unit 6 project as follows:

> The scope of the Revelstoke Unit 6 project is to install a 500 MW unit in the existing empty Unit 6 bay. In addition, there is a transmission requirement for an additional series capacitor station on the transmission line from Vaseux to Nicola and some enhancements within existing substations… the approved 2013 Integrated Resource Plan identifies Revelstoke Unit 6 as a contingency resource and recommends advancing Revelstoke Unit 6 through Definition phase to preserve a fiscal 2021 earliest in-service date…the project would be needed on an expected basis in fiscal 2026; this timing is driven by long term maintenance outages planned for Mica Units 1-4.

In Exhibit B-37 of the 2015 BC Hydro Rate Design Application (2015 RDA) shows Revelstoke Unit 6 in-service in F2027 on a planned basis at a unit capacity cost of $57/MW.yr (2013$).

On page 2-3 BC Hydro explains that it is currently undertaking work to advance this project to the environmental assessment stage.

81.1 Please explain what BC Hydro means by Revelstoke Unit 6 is required during the test period to meet BC Hydro's expected load.

81.2 Please elaborate on the work BC Hydro is performing on preparing for the installation of Revelstoke Unit 6 in the test period.

81.3 What is the required in-service date?

81.4 What is the lead time associated with Revelstoke Unit 6?

81.5 From this stage in the Revelstoke Unit 5 project, or this stage in the Mica 5 and 6 project, to their respective in-service dates, how long did it take? Please explain.

81.6 Has BC Hydro advanced Revelstoke Unit 6 through the Definition phase? What would constitute BC Hydro completing advancement of this project through the Definition phase? Please elaborate.

81.7 Assuming Revelstoke Unit 6 were needed at the next opportunity, when could it be reasonably be completed by? For example, in three years?

81.8 Considering BC Hydro's recent load resource balance update provided in the 2015 RDA, does BC Hydro anticipate needing Revelstoke Unit 6 before fiscal 2027?

81.9 Assuming Revelstoke Unit 6 is not needed until F2027, has BC Hydro considered delaying expenditures to a point where it could still meet the ISD? Please elaborate.

81.10 Are the additional series capacitor station and the enhancements within existing substations included in the CEA exemption? Please explain.

81.11 What is the estimated cost of the additional series capacitor station and the enhancements within existing substations?

81.12 How does the cost estimate for the Revelstoke Install Unit 6 project compare to the actual cost of the Revelstoke Unit 5 project? Are there differences in scope beyond the additional series capacitor station and enhancements within existing substations? Please elaborate.

81.13 Please confirm, otherwise explain, that the costs of the additional series capacitor station and the enhancements within existing substations are included within the unit capacity cost of $57/MW.yr (2013$)?

81.14 How does BC Hydro's position on the inclusion/exclusion of the additional series capacitor station and the enhancements within existing substations in the Revelstoke Unit 6 project

compare to its position on the projects related to Site C (i.e. Peace to Kelly Lake and Fort St. John to Taylor)? Please elaborate.

82.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Appendix J, pp. 13-14; Exhibit B-6, Supplemental Appendix I-A – Generation, line 13; F2016 Annual Report to the Commission, p. 13
John Hart Dam Seismic Upgrade

On page 13 of the F2016 Annual Report to the Commission (F2016 Annual Report), BC Hydro explains that the John Hart Dam Seismic Upgrade is anticipated to be a Section 44.2 filing as it is "Anticipated to exceed $100 million threshold for Generation projects but is not considered an extension to the BC Hydro system because this project is not designed to serve incremental load and there is no increase in generating capability." In Supplemental Appendix I-A of the Application, this project is listed at a project cost of $408.2 million, with capital expenditures of $3.9 million, $9.0 million and $11.0 million in F2017, F2018 and F2019, respectively.

82.1 Please confirm, otherwise explain, that the reasons BC Hydro provided in the F2016 Annual Report for anticipating to file this project under section 44.2 rather than as a CPCN, are consistent with BC Hydro's current interpretation of the term extension.

82.2 Please confirm, otherwise explain, that if BC Hydro intends to proceed with this project that BC Hydro will file an expenditure schedule for acceptance under Section 44.2 of the UCA.

82.3 Please elaborate on what the $23.9 million in expenditures in the test period are planned to be spent on.

82.4 If the Commission finds that the definition of extension includes this project, would BC Hydro be amenable to the Commission requiring a CPCN by ordering in this proceeding that section 45(2) does not apply?

82.5 Please confirm, otherwise explain, that BC Hydro is of the opinion that there are likely to be significant public interest issues with this project that would benefit from public review, for example need, timing, access, safety downstream of the dam or large capital additions. If confirmed, please summarize some of those potential issues and BC Hydro will address public participation in a public review.

82.6 When was BC Hydro first aware that John Hart would require some form of major seismic upgrade and that it would cost hundreds of millions of dollars? Please explain and provide supporting documentation.

82.7 When did BC Hydro first inform the Commission that major seismic work would be required and that it would be expected to cost hundreds of millions of dollars? Please explain and provide supporting documentation.

82.8 Is there dam seismic work taking place as part of the John Hart Generating Station Replacement project? If so, would that work reduce the $408 million estimate for this project? Please elaborate.

82.9 Please provide the approximate unit cost of energy ($/MWh) from the John Hart Generating Station to its transmission point of interconnection if it factors in the costs of both this seismic upgrade project (i.e. approximately $408.2 million) and the costs of generating station replacement project (assume $1,019.9 million)?

83.0 **Reference:** **CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Appendix J, pp. 4-5; Exhibit B-6, Supplemental Appendix I-A – Generation, line 3; Ruskin Dam and Powerhouse Upgrade Project Semi-Annual Progress Report No. 8, pp. 3-4, 7-8;
Ruskin Dam Safety and Powerhouse Upgrade

On pages 7 and 8 of this project's eighth semi-annual progress report filed on May 16, 2016, BC Hydro provides the following project milestone table for project components:

Table 1 Project Milestones

No.	Description/Status	Original Plan Date	Forecast Date	Actual Date	Variance (Months)[1]
1	BC Hydro Board of Directors Approval	February 2011		February 2011	0
2	BCUC CPCN Decision	January 2012		March 2012	2
3	Right Abutment In-Service	July 2013		July 2013	0
4	Spillway Gates 1 & 2 In-Service	February 2015		November 2015	9
5	Spillway Gates 3 & 4 In-Service	June 2016	November 2016		5
6	Spillway Gate 5 In-Service	May 2017	June 2017		1
7	1st Unit In-Service	November 2015	June 2016		7
8	2nd Unit In-Service	September 2016	November 2016		2
9	3rd Unit In-Service	June 2017	June 2017		0
10	Switchyard In-Service	June 2017	June 2017		0
11	Project Complete	March 2018	March 2018		0

On pages 3 and 4 of this report, BC Hydro also explains that the Dam Crest Block seismic capacity is deficient and that the current project scope will not be delayed due to this deficiency. BC Hydro explains that if the scope for the crest block is approved, the scope of work may be initiated under a separate project.

83.1 Please provide the scope of the Ruskin Dam Safety and Powerhouse project that is covered by the $126.2 million in prior capital additions.

83.1.1 Please split that scope between Direction No. 7 exempt additions (i.e. extensions) and non-exempt additions and explain why and how the split has been made.

83.2 Please provide the CPCN forecast cost estimates of the non-exempt pre-F2017 scope and compare to the actual costs to complete. Please explain any material variances.

83.3 Similarly, please compare the CPCN forecast in-service dates of the non-exempt pre-F2017 scope to the actual in-service dates for this work. Please explain any material variances.

83.4 Please provide an order of magnitude of the potential cost of the Dam Crest Block seismic remediation project (e.g. under $5 million, $5-$20 million, $20-$100 million, over $100 million) and a ballpark estimate of a potential construction start date (e.g. F2018, F2019, F2020, beyond F2020).

83.5 Would this project be expected to be a section 44.2 filing? Why or why not? Please explain.

84.0 **Reference:** **CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1,Appendix J, p. 7; Exhibit B-6, Supplemental Appendix I-A - Generation, line 4
Clowhom Rehabilitate Generating Station

In Supplemental Appendix I-A and Appendix J, BC Hydro lists this project as a redevelopment project for a strategic facility at a cost of $90.9 million and notes that the capital additions are expected outside of the test period. The project has forecast capital expenditures of $0.3 million, $1.1 million, and $1.2 million in F2017, F2018 and F2019 and a current start date of construction left blank.

84.1 Would this project be considered a refurbishment project that is not undertaken to serve incremental load growth, but through efficiencies may result in additional MWs and/or GWhs/year on a planning basis? Please elaborate.

84.2 Please provide the accuracy range of the $90.9 million estimate.

84.3 If BC Hydro plans to proceed with this project, please provide an approximate time frame for the start of construction (e.g. F2017, F2018, F2019 or beyond F2019). Based on the expenditure forecast it appears to be forecast to start construction beyond F2019.

84.4 If BC Hydro intends to proceed with this project, will it file a section 44.2 or CPCN application? Please elaborate provide the rationale.

85.0 **Reference:** **CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Appendix J, p. 12; Exhibit B-6, Supplemental Appendix I-A – Generation, lines 10, 23
W.A.C. Bennett Spillway Gate Upgrade and Recommission /Seal Spillway Sluice Gates

The W.A.C. Bennett Spillway Gate Upgrade is listed as a $20.3 million to $35.9 million project starting construction in November 2016, but with only $1.7 million forecast capital expenditures in F2017. The W.A.C. Bennett Dam Recommission / Seal Spillway Sluice Gates project is listed at $12.4 million but does not have a construction start date, a cost estimate range or capital expenditures listed in the test period. BC Hydro explains that for projects under $20 million expenditures are not provided.

85.1 Please confirm, otherwise explain, that both of these projects are for work on the same spillway gates (e.g. one project is on the electrical, mechanical and protection and control equipment that operates the spillway gates and the other project is on the physical gates themselves).

85.1.1 If so, are there any advantages, such as efficiencies in project management, or spillway gate outage times that could be found by grouping these two projects together? Are there any risks of doing so? Please elaborate.

85.2 If available, please provide the approximate accuracy range of the $12.4 million estimate.

85.3 Please explain why BC Hydro forecast only $1.7 million in expenditures in F2017 if it is forecasting a start of construction date of November 2016.

85.4 Please discuss why the Spillway Gate Upgrade project is forecast to start construction in the late fall (i.e. November 2016). Are there any advantages to performing this work at this or another time of year? Please elaborate.

85.5 If available, please provide the approximate construction start date of the Recommission / Seal Spillway Sluice Gates project and the expenditure forecast in the test period.

85.6 Assuming it is appropriate to combine the two projects, would BC Hydro expect this project to

exceed $50 million? Please elaborate.

85.7 Considering the spillway gate upgrade project is expected to start construction in November 2016, should the Commission prioritize and expedite determining an expenditure threshold for dam safety, including spillway, projects? Please explain.

86.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Appendix J, p. 15; Exhibit B-6, Supplemental Appendix I-A – Generation, line 14
Ladore Spillway Seismic Upgrade

The project cost estimate shown in Supplemental Appendix I-A is $52.9 million. The current start date of construction is TBD, but expenditures are shown as $0.3 million, $2.5 million and $10.4 million in F2017, F2018 and F2019, respectively. The project name is Ladore Spillway Seismic Upgrade and the description in Appendix J explains that a Dam Safety Investigation is in progress to evaluate the seismic performance of the dam, including the spillway.

86.1 Please confirm, otherwise explain, that based on the expenditure forecast, BC Hydro is anticipating construction for this project to start in F2019.

86.2 Please confirm, otherwise explain, that the project cost estimate provided in Supplemental Appendix I-A is for work only associated with the spillway gates and hoist structure and does include any costs associated with potential seismic work on the dam.

86.3 Is BC Hydro considering filing the spillway project as a section 44.2 filing along with a potential dam seismic project, or separately? Please explain.

86.4 Please explain the longer term strategy for Ladore. Is BC Hydro considering a full redevelopment similar to John Hart and Strathcona? Please explain.

86.4.1 If confirmed, is BC Hydro considering filing the spillway project with the potential dam seismic project and a potential redevelopment project all as one application, or separately? Please explain. Would that be under section 44.2 or as a CPCN application?

86.5 Please confirm, otherwise explain, that BC Hydro is of the opinion that there are likely to be significant public interest issues with this project, the dam seismic project, or a potential redevelopment project, that would benefit from public review, for example need, timing, public access and safety or large capital additions. If confirmed, please summarize some of those potential issues.

86.6 Please provide the facility asset plan for this facility.

87.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Appendix J, p. 17; Exhibit B-6, Supplemental Appendix I-A – Generation, line 17
Strathcona Upgrade Discharge

The project cost estimate shown in Supplemental Appendix I-A is $220.2 million. The current start date of construction is listed as TBD and the project has forecast capital expenditures of $0 million, $1.5 million, and $4.5 million, in F2017, F2018 and F2019, respectively. The description in Appendix J explains that the Strathcona Dam is known to be seismically deficient and this is one of the first steps in resolving this major deficiency. BC Hydro elaborates that this project is:

> …one of a series of seismic upgrade projects at Strathcona. The full risk reduction

> strategy is to construct a new low-level outlet (this project), upgrade the spillway, decommission the existing intake tower and power conduit beneath the embankment, relocate the powerhouse and finally, to rebuild the embankment dam. The work will be carried out in a staged manner over two or perhaps three decades.

BC Hydro also states:

> Although powerhouse relocation is not part of this project, planning on where to construct a new power tunnel and a new powerhouse is included in the scope, to ensure that the layout will be compatible with the potential footprint for the future upgrade to the embankment dam in the final step of the seismic upgrades.

87.1 Please confirm, otherwise explain, that the project cost estimate provided in Supplemental Appendix I-A is for work only associated with the first step.

87.2 Please confirm, otherwise explain, that based on the expenditure forecast, BC Hydro is anticipating construction for this project to start in F2019 or later.

87.3 Please confirm, otherwise explain, that BC Hydro is expecting to file this project as a section 44.2 filing. If so, approximately when?

87.4 Is BC Hydro considering filing the low-level outlet project (i.e. this project), the spillway project, the decommissioning project, the new powerhouse project and the rebuild project all as one application, each separately, or some other combination? Please elaborate. Please provide the breakdown of how these projects would be filed with the Commission (i.e. under section 44.2 or as CPCN applications).

87.5 Please confirm, otherwise explain, that BC Hydro is of the opinion that there are likely to be significant public interest issues with this project, the spillway project, the decommissioning project, the new powerhouse project and the rebuild project, that would benefit from public review, for example need, timing, public access and safety or large capital additions. If confirmed, please summarize some of those potential issues.

87.6 Please provide the facility asset plan for this facility.

88.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Appendix J, pp. 22, 29; Supplemental Appendix I-A – Generation, lines 34, 43; Appendix R
Bridge River 2 – Upgrade Units 5, 6, 7 and 8

In Supplemental Appendix I-A the project cost estimate for Bridge River 2 Upgrade Units 5 and 6 is listed as $83.3 million to $52.5 million, with a construction start date of F2018, a current forecast ISD of F2019, and capital expenditures of $4.6 million, $29.9 million and $15.8 million, in F2017, F2018 and F2019, respectively. In Appendix J, BC Hydro explains that this project is to restore reliability to the generators and ancillary systems and presents an opportunity to uprate the generators to achieve incremental dependable capacity and energy. Generators 5 and 6 are rated unsatisfactory. The governors, exciters and circuit breakers are rated poor.

Also in Supplemental Appendix I-A, the project cost estimate for Bridge River 2 Upgrade Units 7 and 8 is listed as $53.7 million, with a construction start date TBD and capital expenditures of $0 million, $0.9 million and $6.4 million in F2017, F2018, and F2019. In Appendix J, BC Hydro explains that this project is to restore reliability to the generators and ancillary systems and presents an opportunity to uprate the generators to achieve incremental dependable capacity and energy. Generators 7 and 8 are

rated poor. The circuit breakers are rated poor.

In Appendix R, BC Hydro explains that capital investment or replacement of assets in unsatisfactory condition are generally recommended for capital investment or replacement within the next five to seven years, whereas investments in assets assessed as poor are generally considered with the next 10 to 12 years.

88.1 Please confirm, otherwise explain, that the Bridge River 2 facility has only 4 generating units: Units 5, 6, 7 and 8, and that these two projects described are in effect replacing all generating units at this facility.

88.2 Please confirm, otherwise explain, that based on the expenditure forecasts, units 7 and 8 are to be replaced immediately following the replacements of units 5 and 6.

88.3 Please confirm, otherwise explain, that both of these projects are refurbishment projects that are not undertaken to serve incremental load growth, but through efficiencies may result in additional MWs and/or GWhs/year on a planning basis. Is there a need for the additional MWs and/or GWhs? Please confirm that the need for the project is due to asset health and not achieving additional efficiency or MWs and/or GWhs.

88.4 Please explain the BC Hydro Board approval process that has been undertaken to date for these two projects and please provide any supporting documentation.

88.5 Are there efficiencies or cost savings that can be achieved by combining these two projects into one project with two phases? For example, in scheduling or contracting work, or in procuring and maintaining similar systems (e.g. the same manufacture and design for the generators and circuit breakers)? Please elaborate and provide the Bridge River 2 one-lines in your explanation.

88.6 Please provide the facility asset plan for this facility.

88.7 Please compare the separation of this work into two projects with the combining of the replacement of five turbines on the GMS Units 1 to 5 turbine replacement project into one project.

88.8 Please explain why the two Bridge River projects are listed as separate projects.

88.9 Please explain why some of the Bridge River 1 and 2 systems up for replacement in these projects that are rated poor are being considered for replacement at this time. For example, have they been in poor condition for some time and are on the verge of unsatisfactory? Please elaborate.

88.10 How does BC Hydro prioritize assets for replacement that are not in unsatisfactory condition? For example, the Bridge River projects are planning to replace some assets that are in poor condition earlier than 10 to 12 years.

89.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Appendix J, pp. 20–21; Exhibit B-6, Supplemental Appendix I-A – Generation, lines 28, 29
Cheakamus projects

Supplemental Appendix I-A lists the Cheakamus Units 1 and 2 Generator Replacement project and the Cheakamus Upgrade Fire Protection project with current authorized amounts of $73.4 million and $7.6 million, respectively. The current start date of construction for the Cheakamus Units 1 and 2 Generator Replacement project is listed as F2015. It shows capital expenditures of $11.3 million, $18.0 million and $13.0 million, in F2017, F2018 and F2019, respectively.

Appendix F, pages 20 and 21 read: "The purpose of this project is to replace the Cheakamus generators which are in Poor condition. There is also an opportunity to uprate the generators to achieve increased dependable capacity and energy" and "In addition to the need to address the Poor condition of the generators to maintain reliability of supply, there is an opportunity to increase the rated capacity of the Cheakamus generating units to 90 MW each. All other equipment required to support the increase to 90 MW per unit is already in service."

89.1 Please elaborate on what construction has started on the replacement projects. For example, is one generator currently out of service and being dismantled and/or the new generator being constructed, while the other one continues to be in service?

89.2 Is the Upgrade Fire Protection project for the generator fire protection system or the powerhouse? Are there any linkages to the requirements or benefits of the Unit 1 and 2 replacement projects to this project? Please explain.

89.3 Please provide a list of recent Cheakamus projects that were necessary to be completed to support the increase to 90 MW and their costs. For example, were there any transformer, bus, circuit breaker, exciter, governor or turbine related projects that were required to be completed to achieve the 90 MW up-rating? Please provide the station one-line to support your answer.

89.4 Please provide the facility asset plan for Cheakamus.

90.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Appendix J, p. 24; Appendix R; Exhibit B-6, Supplemental Appendix I-A – Generation, line 35
GM Shrum 1–10 Control System Upgrade

Supplemental Appendix I-A lists this project as having the current pre-implementation cost estimate of $58.4 million to $77.2 million. It also shows capital expenditures of $11.4 million, $11.9 million and $8.9 million, in F2017, F2018 and F2019, respectively. Appendix J explains that various Fair and Poor rated equipment is planned to be replaced.

Appendix R explains the following Equipment Health Ratings for Fair and Poor are as follows:

> Fair: There is some normal deterioration of the asset with one or more minor defects; function is not affected
> Poor: There is serious deterioration of the asset or serious defects in at least some portions of the asset; function is affected.

Appendix R also explains: "Investments in assets assessed as poor are generally considered with the next ten to 12 years."

90.1 Please explain when or under what conditions assets in Fair condition are considered for replacement?

90.2 Please explain and justify why Fair and Poor rated equipment is being replaced at this time.

90.3 Could any or some of these replacements be deferred outside of the test period with little risk? Please elaborate.

90.4 Please explain and provide supporting documentation for the portions of this project that have already started construction and those that have not. Please link this to the test period

expenditure forecast provide in the preamble.

90.5 Would BC Hydro consider any of these works extensions? Are they necessary upgrades, along with other upgrades, such as turbine or generator upgrades, to achieve the increased capacity or additional energy output? Please explain why or why not.

91.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Appendix J, p. 31; Appendix R; Exhibit B-6, Supplemental Appendix I-A – Generation, line 52
Mica Modernize Controls

Supplemental Appendix I of the Application lists this project as having a pre-engineering estimate of $40.5 million and a current start date of construction as TBD. It also shows capital expenditures of $0 million, $0.2 million and $3.2 million, in F2017, F2018 and F2019, respectively.

Appendix R shows Mica units 1, 2, 3 and 4 have exciters in Fair condition. It also shows that governors for units 1, 2 and 3 are in Fair condition. Appendix R does not list conditions for control room equipment or unit protection and control equipment directly.

Appendix J explains that for the exciters limited availability of spare parts is a concern and that "Due to the lack of readily available spare parts and technical expertise, a major failure of either the governor or exciter could result in a generator forced outage of the affected unit for up to 12 months."

91.1 Please confirm, otherwise explain, that BC Hydro has a process for rating control room equipment and unit protection and control equipment. If confirmed, please explain what that process is and provide the ratings for these components. If not, please explain why not.

91.2 Please confirm, otherwise explain, there are spare parts available, just not readily. For example, do other stations across the province have similar equipment installed and are spare parts available from those plants? Please elaborate.

91.3 Please confirm, otherwise explain, that BC Hydro has a training program and manuals for these types of exciters, governors, protection and controls.

91.4 Please confirm, otherwise explain, that construction for this project is expected to begin outside of the test period (i.e. expenditures in the test period are very low) and provide an estimated start date of construction. If not confirmed, could these replacement projects be deferred outside of the test period with little risk? Please elaborate.

92.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1,; Appendix J, p. 34; Exhibit B-6, Supplemental Appendix I-A – Generation, line 67
Mica Replace Units 1 to 4 Generator Transformers

Supplemental Appendix I-A lists this project as having a pre-engineering estimate of $61.8 million and a current start date of construction as TBD. It also shows capital expenditures of $0.0 million, $0.6 million and $1.2 million, in F2017, F2018, and F2019, respectively. Appendix J explains that this project is to replace twelve single-phase generating unit transformers. It also explains that the Equipment Health Rating of eight transformers is Poor, while the other four are rated as Fair. It also explains that as the Mica transformers are located in an underground powerhouse, a failure presents a life safety risk for people working in the underground powerhouse in addition to resulting in a forced outage. Appendix R explains that for a Fair EHR there is some normal deterioration of the asset with one or more minor

defects; function is not affected.

92.1 Please explain the current measures BC Hydro is taking to mitigate the life safety risk.

92.2 Please explain why the Fair assets are being planned to be replaced at this time. What are the minor defects and is BC Hydro planning to address them in the interim? If they are addressed, would these assets be considered in acceptable condition to sufficiently mitigate risk and defer replacement? Please elaborate.

92.3 Please confirm, otherwise explain, that construction for this project is expected to begin outside of the test period (i.e. expenditures are very low in the test period). If not confirmed, could this replacement project be deferred outside of the test period with little risk? Please elaborate.

93.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Appendix J, p. 35; Exhibit B-6, Supplemental Appendix I-A – Generation, line 69
Seven Mile Overhaul Units 1 to 3 Turbines

Supplemental Appendix I-A lists this project as having a pre-engineering estimate of $83.0 million and a current start date of construction as TBD. It also shows capital expenditures of $0.0 million, $0.0 million and $0.9 million, in F2017, F2018 and F2019, respectively. Appendix J explains that the Equipment Health Rating is fair for all four Seven Mile turbines. It also explains that cavitation has been an issue since the original installation, and significant weld repairs are undertaken at two-year intervals, with a significant maintenance cost.

Appendix R explains that for a Fair EHR there is some normal deterioration of the asset with one or more minor defects; function is not affected.

93.1 Please explain the difference between an overhaul of unit 1 to 3 turbines versus bi-annual weld repairs (i.e. does overhaul mean runner replacement?).

93.2 Please confirm, otherwise explain, that the $83.0 million dollar estimate is for the runner replacement option.

93.3 Please explain why these Fair assets are planned to be replaced at this time.

93.4 What are the maintenance costs of the bi-annual weld repairs?

93.4.1 Is each unit repaired every two years or is a single runner repaired every two years?

93.4.2 What is the expected life of a new runner?

93.4.3 What is the expected remaining life of the existing runner if weld repairs continue?

93.5 Please relate this project's drivers and expected outcomes to the drivers and actual outcomes of the GM Shrum Units 1 to 5 Turbine Replacement project.

93.6 Please confirm, otherwise explain, that construction for this project is expected to begin outside of the test period (i.e. expenditures are very low in the test period). If not confirmed, could this project be deferred outside of the test period with little risk? Please elaborate.

94.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, p. 6-79; Exhibit B-6, Supplemental Appendix I-A – Generation, line 74
Burrard

In Supplemental Appendix I-A, BC Hydro lists the authorized costs of $7.3 million to convert Burrard to

synchronous condense only.

On page 6-79 BC Hydro explains that "there is limited capital investment at Burrard in fiscal 2017 to fiscal 2019, while plans are developed for the investment required to convert Burrard from a generating station to a synchronous condenser station."

Table 4-5 on page 4-14 shows that in F2017 Burrard Thermal having $0 forecast for natural gas purchases but $5.9 million in natural gas purchases inclusive of Transportation and Taxes.

94.1 Please provide the current Burrard operating order and the operating order before it was restricted from operating as a generating facility.

94.2 Can a change in the Burrard operating order result in Burrard operating only as a synchronous condenser on a permanent basis? Please elaborate.

94.3 Please describe the capital work included in the $7.3 million cost to convert Burrard to a synchronous condense only facility.

94.4 Please explain what capital work beyond the $7.3 million capital work is required to convert Burrard to a synchronous condense only facility. What is the approximate cost of that work?

94.5 How does Burrard provide voltage support today? How did it do so in the past? How will it do so after conversion to a synchronous condense only facility? Is natural gas used? Please elaborate.

94.6 If Burrard Thermal is not using natural gas for synchronous condense operation and is not generating, please explain the $5.9 million in Transportation and Taxes for natural gas for Burrard Thermal.

95.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-6, Supplemental Appendix I-A – Generation
Capital addition actuals in prior years, projects less than $5 million or in-service - Generation

Supplemental Appendix I-A lists capital additions in prior years for projects less than $5 million dollars or in-service. It lists growth capital additions in prior years as $848.8 million, dam safety as $326.6 million, and sustaining as $542.0 million. It also provides capital additions for these projects for F2017, F2018, F2019 and beyond F2019.

95.1 Please split these total capital additions between projects less than $5 million and projects that are already in service that have capital additions in the test period.

95.2 How were the capital addition forecasts for these small projects developed? Please elaborate.

95.3 For projects less than $5 million: please provide the sum of capital additions for F2015 and F2016 separately. Please comment on any trends observed from F2015 through F2019. For example, is growth and dam safety spending decreasing? Is sustaining spending increasing or flat? Why or why not? Please elaborate.

95.4 Considering Direction No. 7, how should the commission treat trailing costs for extensions that came in to service before F2017? Would BC Hydro consider these trailing costs exempt too? Please elaborate. Please provide an estimate (order of magnitude) of the total trailing costs for the list of Direction No. 7 exempt projects (i.e. under$5million, $5–20 million, $20–50 million).

96.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-6, Supplemental Appendix I-A – Transmission, lines 1, 3; Appendix J, pp. 36, 38
Courtenay Area Substation and Wellington Substation

Appendix J of the Application explains that both the Courtenay Area substation and the Wellington substation projects received Commission approval for definition stage funding in 2009 and 2010 when these projects were overseen by the British Columbia Transmission Corporation (BCTC).

96.1 Please confirm, otherwise explain, that BC Hydro did not seek nor did it receive Commission approval to proceed with these projects.

96.2 Please confirm, otherwise explain, that BC Hydro sought and received BC Hydro Board approval to proceed with these projects (i.e. implementation stage funding).

96.3 Please confirm, otherwise explain, that BC Hydro's approach to definition stage funding approvals for projects differ from BCTC's approach when it was a separate organization. If confirmed, please explain those differences and why the change in approach.

96.4 Are there any differences between BC Hydro's definitions and policies for extension, start of construction, in-service date or authorized amount between when it was the two organizations and today? Please elaborate.

97.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Appendix J, pp. 40-41; F2012–F2014 RRA, Appendix I, lines 27, 56;
Exhibit B-6, Supplemental Appendix I-A – Transmission, line 5
Horne Payne Substation Upgrade

Supplemental Appendix I-A shows that this project has a current authorized amount of $92.6 million and a current start date of construction of F2016. It also shows capital expenditures of $18.6 million, $29.0 million and $21.9 million, in F2017, F2018 and F2019, respectively. Appendix J explains that this project is replacing two projects that were listed in the F2012-F2014 Amended RRA: Horne Payne Substation Expansion ($14.4 million, forecast ISD Oct-2013) and Horne Payne Substation – add feeder section and feeder positions ($10 million, forecast ISD Oct-2013).

The project description in Appendix J is as follows:

> The North Burnaby Area study developed a 30-year plan for the Horne Payne, Lougheed and Barnard substations and service areas. The first resulting project from the study is the Horne Payne Substation Upgrade, which includes the addition of two 230/25 kV, 150 MVA transformers and three 25 kV, 50 MVA indoor gas-insulated feeder sections. A new control building will also be added, and the existing main control building will be decommissioned.
>
> The project as currently described will also add two 230/25 kV 150 MVA transformers, in addition to:
>
> - Three 50 MVA gas insulated feeder sections with 18 feeder positions and three transfer ties;
> - One gas insulated building; and
> - One control building.

97.1 Please confirm, otherwise explain, that the North Burnaby Area Study outlines options for long-term strategies for BC Hydro in this area and depending on the strategy BC Hydro selects, there could be significant differences in costs, benefits and/or risks to future BC Hydro ratepayers.

97.1.1 If confirmed, please elaborate and provide the up-to-date study and if selected, the strategy.

97.2 Would BC Hydro consider the conversion of equipment in this area from 12kV to 25kV a decision with significant public interest or cost implications? Why or why not?

97.3 Please provide a complete regulatory history of this project and all prior related projects (e.g. the F2012-F2014 RRA projects, and any projects described in the F2014, F2015 and F2016 annual report projects). Please include all forecast costs and in-service dates.

97.3.1 Is this the first time the Commission has been provided a total forecast cost of $92.6 million for this project? What is the accuracy range? Please elaborate.

97.4 For what reason(s) has BC Hydro not sought CPCN approval for this project.

97.5 Please provide a breakdown of this project's total forecast costs between transmission, distribution and properties.

97.6 Please provide the construction start date for each major part of the project. Which parts of the project have begun construction and which parts of the project not started construction yet? Please elaborate.

97.7 Is this project or the future Lougheed and Barnard projects connected to, contingent on or required for the Metro North project? Please elaborate.

98.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Appendix J, p. 42; Exhibit B-6, Supplemental Appendix I-A – Transmission, line 6
Kamloops Substation

Supplemental Appendix I-A shows that this project has a current authorized amount of $48.9 million and a current start date of construction of F2016. It also shows capital expenditures of $11.4 million, $16.9 million and $9.7 million, in F2017, F2018 and F2019, respectively. Appendix J explains that this project is to accommodate load growth. It describes the project as constructing a new 138/25 kV distribution substation.

98.1 Is this the first time the Commission has been provided a total forecast cost of $48.9 million for this project? What is the accuracy range? Please elaborate.

98.2 Please provide the construction start date for each part of the project. Have parts of the project not started construction yet? Please elaborate.

98.3 Please explain why this project is categorized as a transmission project considering it is described as being a new distribution substation.

98.4 For what reason(s) has BC Hydro not sought CPCN approval for this project?

99.0 **Reference:** **CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, p. 6-120; Appendix J, p. 43; Exhibit B-6, Supplemental Appendix I-A – Transmission, line 7
Fort St. John and Taylor Electric Supply

Supplemental Appendix I-A shows that this project has a current authorized amount of $53.1 million and a current start date of construction of F2016. It also shows capital expenditures of only $2.2 million in F2017 and note C shows that definition work for this project was complete under the Site C Clean Energy Project. Appendix J explains that Site C recommends removal of two transmission lines that feed the Fort St. John and Taylor area and to maintain adequate supply capability the construction of a 138 kV switchyard at Site C Substation with two three-phase 300 MVA 500/138 kV transformers, and re-terminating the two transmission lines at the Site C Substation will be required. Page 6-120 of the Application explains that the Provincial Treasury Board holds a $440 million project reserve.

99.1 Please confirm, otherwise explain, that this project would not be necessary if Site C were not being constructed.

99.1.1 If confirmed, please explain why this project is not part of the Site C project.

99.2 For what reasons has BC Hydro not sought a CPCN approval for this project? Could project management reserves or the Provincial Treasury Board's $440 million project reserve be used to cover this cost? Please explain.

99.3 Please confirm the actual start date of construction and provide evidence. Please explain how only $2.2 million is being spent in F2017 but construction began in F2016.

99.4 Does this project meet BC Hydro's definition of an extension? Please explain why or why not?

99.5 Please confirm, otherwise explain, that BC Hydro is of the opinion that there are likely to be significant public interest issues with this project that deserve consideration, for example need, timing and route selection. If confirmed, please summarize some of those potential issues.

100.0 **Reference:** **CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Appendix J, p. 44; F2015 Annual Report, p. 12; F2016 Annual Report, p. 13; Exhibit B-6, Supplemental Appendix I-A – Transmission, line 8
Metro North Transmission

Supplemental Appendix I-A shows that this project has an approximate cost of $216.6 million with a current construction start date of TBD. It also shows capital expenditures of $2.5 million, $4.2 million and $9.9 million, in F2017, F2018 and F2019, respectively. Appendix J explains "An interim operational solution has been identified to temporarily resolve these constraints by reconfiguring the system with real-time switching operation, such that no load curtailment will be required until winter 2020, after which time this project is expected to resolve the constraints." In the F2015 and F2016 Annual Reports BC Hydro lists Metro North as an anticipated CPCN filing.

100.1 Please confirm, otherwise explain, that construction of this project is expected to start late in this test period (i.e. F2019) in order to meet the required F2020 need.

100.2 Please confirm, otherwise explain, that BC Hydro is of the opinion that there are likely to be significant public interest issues with this project, for example route selection, that would benefit from public review. If confirmed, please summarize some of those potential issues.

100.3 Will BC Hydro file for CPCN approval for this project? Why or why not?

101.0 **Reference:** **CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Appendix J, pp. 46, 62; Exhibit B-6, Supplemental Appendix I-A – Transmission, lines 9, 35; BC Hydro 2010 Capital Project Filing Guidelines, cover letter, p. 1
West Kelowna Transmission Project and Westbank Substation Upgrade

Supplemental Appendix I-A shows that the West Kelowna Transmission Project has an approximate cost of $77.6 million with a current construction start date TBD. It also shows capital expenditures of $1.1 million, $3.6 million and $12.6 million, in F2017, F2018 and F2019, respectively. Appendix J explains "This project is driven by reliability concerns associated with the single circuit radial transmission system that currently supplies the West Kelowna area. The West Kelowna area is supplied by a single substation, Westbank Substation, which in turn is supplied radially by a single 138 kV transmission line from Nicola Substation." In the cover letter accompanying BC Hydro's 2010 Capital Project Filing Guidelines BC Hydro anticipated it would file an application for this project with the Commission.

Supplemental Appendix I-A shows that the Westbank Substation Upgrade has an approximate cost of $24.0 million with a current construction start date of TBD but with capital additions in the test period. It also shows capital expenditures of only $0.5 million in F2017, but $10.0 million in F2018 and $12.5 million in F2019. Appendix J explains: "The Westbank Substation Upgrade project will increase the substation summer firm capacity to address the current capacity deficit and future load growth. The project will also add a second 138 kV line position to connect a new transmission line to be built under a separate project."

101.1 Please confirm, otherwise explain, that construction of the West Kelowna Transmission Project and the Westbank Substation Upgrade are both expected to start in the test period. Based on the expenditure forecast it appears that the substation project is forecast to start construction in about F2018 and the transmission project in about F2019. Please confirm or otherwise provide the expected start of construction dates.

101.2 Please confirm, otherwise explain, that BC Hydro is of the opinion that there are likely to be significant public interest issues with the West Kelowna Transmission Project that would benefit from public review, for example route selection. If confirmed, please summarize some of those potential issues.

101.3 Are there benefits such as schedule efficiencies or cost savings that can be achieved by combining these two projects into one project? Please elaborate and provide the one-lines in your explanation.

101.4 Please explain why these two projects are listed as separate projects. In the past, were they one project? Please elaborate.

101.5 Please provide the accuracy ranges of the two project estimates.

101.6 Will BC Hydro be filing for a CPCN approval for either or both of these projects? Why or why not?

102.0 **Reference:** **CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Appendix J, p. 47; BC Hydro Annual Reports, F2014, p. 1; F2015, p. 12; F2016, p. 13; Exhibit B-6, Supplemental Appendix I – Transmission, line 10
Peace Region Electric Supply (PRES)

Supplemental Appendix I-A shows that the PRES project has an approximate cost of $162.9 million with a current construction start date TBD. It also shows capital expenditures of only $1.5 million, $2.0 million

and $6.0 million in F2017, F2018 and F2019, respectively. Appendix J explains:

> A long lead time will be required to implement capacity additions on both the transmission and the distribution systems in the area. BC Hydro is making its best effort to meet its obligation to supply new industrial customers, without putting its existing customers at risk of interruption due to the increased load. BC Hydro is already restricting service to new industrial customers. It is important to proceed with Peace Region Electricity Supply so that as early an in service date as possible can be attained to meet the forecasted load in the area.

In BC Hydro's F2014 and F2015 Annual Reports this project was an anticipated CPCN filing as BC Hydro noted it exceeds the $100 million threshold for Transmission projects and considered it an extension to the BC Hydro system. In the F2016 Annual Report, BC Hydro still anticipates this project to exceed the $100 million threshold for Transmission projects and considers it an extension to the BC Hydro system. However, BC Hydro now states it is uncertain at this time under which section of the UCA this project will be filed.

102.1 Please explain what commitment from what customer is necessary prior to starting construction on this project.

102.2 Please explain how BC Hydro is restricting service to new industrial customers in this area. Is this restriction consistent with BC Hydro's transmission extension policy? Please elaborate.

102.3 Have any potential new customers voiced concerns about being restricted? If so, what are those concerns and how is BC Hydro addressing them?

102.4 Please confirm, otherwise explain, that construction of this project is expected to start in test period. Based on the expenditure forecast it appears that this project is forecast to start construction in F2019 or later.

102.5 Please discuss BC Hydro's recent load forecast reductions and the relationship to the need and timing of this project.

102.6 Please confirm, otherwise explain, that BC Hydro is of the opinion that there are likely to be significant public interest issues with this project that would benefit from public review, for example route selection and stranded asset risk. If confirmed, please summarize some of those potential issues.

102.7 Please elaborate on why BC Hydro is now uncertain under which section of the UCA this project will be filed.

102.8 Would BC Hydro be opposed to the Commission requiring a CPCN by ordering in this proceeding that section 45(2) does not apply for this project? Please explain.

103.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1-1, cover letter, p. 1; Exhibit B-6, Supplemental Appendix I-A – Transmission, lines 11, 12
Projects A and B

Supplemental Appendix I-A shows that Projects A and B have approximate costs of $130 million and $25 million, respectively, with current construction start dates TBD, and both are capital expenditures and additions in F2017. The cover letter for Exhibit B-1-1-1 explains "These two [projects] address the potential acquisition of land and development of new facilities".

103.1 Is BC Hydro seeking approval for these land acquisitions? If not, why not? If so, under what section (i.e. section 44.2, CPCN or other)?

103.2 Has BC Hydro already purchased the land? If so, what consultation was complete? If not, what consultation is expected prior to purchase? Please discuss.

103.3 Does BC Hydro consider land acquisition commencement of construction? Please explain.

103.4 Does BC Hydro consider land acquisition for an extension, an extension? Please explain.

103.5 Please explain the regulatory accounting for land acquisitions. For example, how are the carrying costs treated? When does the land become a capital addition and included in rate base? Please explain why. What happens if the land is sold at a later date at a profit? How about at a loss? Who is at risk and who benefits from these gains or losses?

104.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Appendix J, p. 51; Exhibit B-6, Supplemental Appendix I-A – Transmission, lines 11, 12, 14
West End Substation Construction Project

Supplemental Appendix I-A shows the West End Substation Construction Project has a pre-engineering cost of $331 million dollars with a current construction start date TBD. It also shows no capital expenditures in F2017, and only $1.0 million and $3.0 million in F2018 and F2019, respectively. Appendix J explains that this project is for a new station in the West End neighbourhood of Downtown Vancouver in the first stage of a 30-year Downtown Vancouver Electricity Supply Plan. However, it also notes that the 30-year Vancouver Downtown Electricity Supply Plan is still being prepared.

104.1 Please confirm, otherwise explain, that construction of the West End Substation Construction project is not expected to start in test period. Based on the expenditure forecast it appears that this project is forecast to start construction beyond F2019.

104.2 Is the 30-year Downtown Vancouver Electricity Supply Plan complete? If so, please provide a summary of the plan. If not, when will it be complete?

104.3 What is or was the review and approval process of the 30-year Downtown Vancouver Electricity Supply Plan? Please elaborate.

105.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Appendix J, p. 53; Exhibit B-6, Supplemental Appendix I-A – Transmission, lines 16, 18–21
Northwest Substation Upgrades Project (NSUP) and Customer Requested Projects

Supplemental Appendix I-A shows that NSUP has an approximate cost of $64 million to $113 million with current construction start date of F2018. Appendix J of the Application explains:

> future load growth associated with LNG and other industrial load interconnections will exceed the capacity of local generation meaning BC Hydro will be unable to meet normal reliability standards and customers' requirements. Additionally, the proposed interconnection of LNG Canada requires additional line positions at Minette substation and will cause voltage issues in the area… Progression into Implementation will be dependent on customers making positive final investment decisions, which is expected to occur by late fiscal 2017.

105.1 Please confirm, otherwise explain, that BC Hydro's transmission extension policy is being applied to this project.

105.1.1 If confirmed, please explain how costs are being allocated and how risks are being mitigated.

105.2 Are any of the customer requested projects in lines 18 to 21 related to and in addition to the NSUP project? Please explain.

105.3 Please explain which customers are required to make a positive final investment decision prior to proceeding into Implementation.

105.4 Considering this project's cost estimate range exceeds $100 million, does BC Hydro consider this project exceeds the $100 million threshold for transmission projects in BC Hydro's 2010 Capital Project Filing Guidelines and will it file for CPCN approval for this project? Please discuss.

106.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, p. 6-120; Appendix J, p. 54; Exhibit B-6, Appendix I-A – Transmission, line 17
Peace Region to Kelly Lake 500kV Transmission Reinforcement

Appendix I-A shows this project has a pre-engineering estimate of $268 million with a current construction start date of TBD and only $1.0 million in capital expenditures forecast for F2019. Appendix J of the Application explains:

> The transfer capacity of Peace Region to Kelly Lake 500 kV transmission lines is limited by thermal, voltage and transient stability. Additional generation will be added in the Peace Region in the next 20 years including the Site C Clean Energy Project and IPPs. The additional generation will require increased transfer capability of the Peace Region to Williston section to supply the growing system load south of the Peace region and of the Williston to Kelly Lake section to supply the growing load in the Lower Mainland.

Page 6-120 of the Application explains that the Provincial Treasury Board holds a $440 million project reserve.

106.1 Please confirm, otherwise explain, that this project is not expected to start construction in the test period. Please provide the expected start of construction date.

106.2 Is the transfer capacity of the Peace Region to Kelly Lake transmission system capable of transferring Site C's energy to Kelly Lake in the absence of this project (i.e. assuming no additional transfer capacity is needed for IPPs)? Please explain.

106.3 Please provide the forecast for IPPs and their additional generation that will be added in this area.

106.4 To get power transfer from Site C to the southern load center (i.e. past Kelly Lake), are there any additional transmission or substation upgrades necessary? Please explain.

106.5 Please confirm, otherwise explain, that BC Hydro is of the opinion that there are likely to be significant public interest issues with this project, for example route selection, that would benefit from public review. If confirmed, please summarize some of those potential issues.

106.6 Please confirm, otherwise explain, that BC Hydro considers this project an extension.

106.7 Will BC Hydro be filing for a CPCN approval or section 44.2 approval for this project? Why or why not? If so, when?

107.0 **Reference:** **CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, pp. 6-32, 6-85–6-87; Appendix J, pp. 55–64; Exhibit B-6, Supplemental Appendix I-A – Transmission, lines 22–38
Station expansion and modification projects and generator interconnections

On pages 6-85 to 6-87 BC Hydro discusses station expansion and modification projects as well as generator interconnections. On page 6-32 of the Application BC Hydro explains that some growth investments in the test period are based on the 2015 Substation Load Forecast.

107.1 Please further describe the 2015 Substation Load Forecast.

107.2 What criteria or guidelines does BC Hydro use to prioritize and initiate station expansions and modifications? For example, does BC Hydro initiate substation expansion projects when load is forecast to reach a certain percentage of substation capacity in a certain amount of time? Please elaborate.

107.3 Does BC Hydro have Facility Asset Plans for substations similar to Generation stations? Please explain.

107.4 What is BC Hydro doing to keep the costs for these types of projects down? For instance, has BC Hydro considered using containerized GIS substations, rather than building/expanding using traditional substations? How about using containerized GIS substations or unique protection plans for generator interconnections? Please elaborate.

108.0 **Reference:** **CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Appendix J, p. 57; F2012–F2014 Amended RRA, Appendix J, p. 117; Exhibit B-6, Appendix I-A – Transmission, line 29
Bid Bend Substation

Appendix I-A shows this project as having an implementation approval of $56.4 million but a current authorized amount of $67 million. It also shows an implementation approval in service date of F2016 but a current forecast in service date of F2018. Appendix J explains: "This project involves construction of a new 60/12 kV, 67 MVA substation in the Big Bend area of South Burnaby to address the load growth of the area." In the F2012–F2014 RRA this project was listed as $33.0 million (+100 percent/-50 percent).

108.1 Please explain why this project is delayed and what caused this project to go over budget.

109.0 **Reference:** **CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Appendix J, p. 67; Ministerial Order M073 – Transmission Upgrade Exemption Regulation; Exhibit B-6, Appendix I-A – Transmission, line 41
Terrace to Kitimat Transmission

Appendix I-A shows this project as having an estimated cost of $100 million to $177 million and a current start date of construction of January F2017. Appendix J explains this project is the "Replacement of the 59 km transmission line 2L99 between Skeena Substation and Minette substation and the 2.5 km transmission line 2L103 between Minette Substation and the Rio Tinto Alcan owned Kitimat substation."

109.1 Please explain differences between this project and the Transmission Upgrade Exemption Regulation, if any.

110.0 **Reference:** **CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Appendix J, p. 69; Exhibit B-6, Appendix I-A – Transmission, line 43
Mainwairing Substation Upgrade

Appendix I-A shows this project as having a cost estimate of $92.9 million and a current start date of construction of TBD. It also shows only $1.4 million in capital expenditures in F2017, but $31.3 million in F2018 and $40.8 million in F2019. Appendix J explains "This project is to replace the power transformers T1 and T3, the two 12 kV feeder sections and the control building that have reached end of life at Mainwaring Substation."

110.1 Based on the expenditure forecast, it appears that this project is forecast to start construction in F2018. Please confirm this is the expected construction start date. If not confirmed, please provide the expected start of construction.

110.2 What is the accuracy range of this project cost estimate?

110.3 Does BC Hydro consider this project to be an extension? Will this project provide for additional capacity? Please elaborate.

110.4 Please provide a breakdown of this project's total forecast costs between transmission, distribution and properties.

110.5 Does this project have any relationship to future or recent past projects (e.g. Horne Payne, Big Bend, and Newell)? If so, please describe the relationship.

110.6 What criteria does BC Hydro use to define control building and feeder end-of-life? Please explain.

111.0 **Reference:** **CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, pp. 6-40, 6-90; Supplemental Appendix I-A – Transmission, line 47
Mandatory Reliability Standards – Critical Infrastructure Protection Version 5 (CIP V5)

On page 6-40 under foundational IT expenditures, BC Hydro explains it has foundation cyber security investments planned for F2017 to F2019 that include CIP.

On page 6-90, BC Hydro explains that the increase in protection and control expenditures for transmission in F2018 and F2019 over prior years is due to the CIP V5 Compliance at Medium Impact Transmission and Distribution Stations Project.

On page 4 of Appendix I, BC Hydro provides the following capital additions for the North American Electric Reliability Corporation (NERC) CIP V5 Compliance at Medium Impact T&D Stations (CIP V5 Compliance) project:

	Capital Additions Actuals Prior Years	Capital Additions Forecast F17	Capital Additions Forecast F18	Capital Additions Forecast F19	Capital Additions Forecast >F19	Total Capital Additions
NERC CIP V5 Compliance at Medium Impact T&D Stations	-	1.9	12.2	9.1	1.6	24.8

111.1 Are the investment costs for NERC CIP in the foundation-cyber security technology area accounted for in the NERC CIP V5 Compliance project? If not, please provide these investments costs for F2017 to F2019.

111.2 Please provide the F2015 and F2016 forecast and actual capital additions driven by adoption of Mandatory Reliability standards. Please discuss any variances.

111.3 Please provide a breakdown of forecasted capital additions for F2017, F2018 and F2019 driven by adoption of Mandatory Reliability Standards. Please provide a high-level explanation of these costs.

112.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-6, Appendix I-A – Transmission
Capital additions for projects less than $5 million – Transmission

Appendix I-A shows the capital addition forecast for growth transmission projects less than $5 million for F2017, F2018 and F2019 as $96.2 million, $27.4 million and $6.6 million, respectively. For sustaining projects less than $5 million for F2017, F2018 and F2019 it shows $223.1 million, $202.4 million and $221.7 million, respectively. Note 2 explains: "Some projects in service at the end of F2016 have trailing expenditures that result in capital additions in the test period. These expenditures have been aggregated and included in the line item "Projects less than $5 million."

112.1 Please split these capital additions between the total capital additions for projects less than $5 million and the total capital additions for projects that are already in service with trailing costs.

112.2 How were the capital addition forecasts for the less than $5 million projects developed? Please elaborate.

112.3 Please provide the actual capital additions for F2015 and F2016 projects less than $5 million for both growth and sustaining. Please comment on any trends observed from F2015 through F2019. For example, is growth spending decreasing? Is sustaining spending increasing or flat? Why or why not? Please elaborate.

112.4 Please provide an estimate (order of magnitude) of the total trailing costs for the list of transmission Direction No. 7 exempt projects less than $5 million (i.e. <$5million, $5 – 20 million, $20 – 50 million).

113.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Appendix I – Distribution
Capital additions for projects less than $5 million – Distribution

Appendix I of the Application shows the capital addition forecast for customer driven growth distribution projects less than $5 million as $151.6 million, $159.9 million and $161.8 million, for F2017, F2018 and F2019, respectively. For system expansion and improvement projects less than $5 million, it shows $27.9 million, $36.9 million and $41.2 million, for F2017, F2018 and F2019, respectively. For sustaining projects less than $5 million it shows $41.5 million, $23.7 million and $51.9 million. Note 2 explains that trailing costs are also included in these amounts.

113.1 Please split these capital additions between the total capital additions for projects less than $5 million and the total capital additions for projects that are already in service with trailing costs.

113.2 How were the capital addition forecasts for the less than $5 million projects developed? Please elaborate.

113.3 Please provide the actual capital additions for projects less than $5 million for each of the three categories for F2015 and F2016. Please comment on any trends observed from F2015 through F2019. For example, is growth spending increasing? Is system expansion and improvement spending flat-lining? Is sustaining spending increasing? Why or why not? Please elaborate.

113.4 Please provide an estimate (order of magnitude) of the total trailing costs for the list of Direction No. 7 exempt projects less than $5 million (i.e. <$5million, $5 – 20 million, $20 – 50 million).

114.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, p. 6-110; Exhibit B-6, Supplemental Appendix I-A – Technology, lines 5, 6 Projects over $2 million, Enterprise Billing Infrastructure and Graphic Work Design Tool projects

Supplemental Appendix I-A shows the capital addition forecast for IT projects greater than $2 million as $96.7 million, $100 million and $122.2 million with portfolio adjustments of $17.6 million, $9.9 million and $12.2 million, respectively.

Supplemental Appendix I-A also shows the Enterprise Billing Infrastructure (Billing) project has a pre-engineering cost estimate of $16.2 million in F2018, capital additions of $16.2 million in F2018, but expenditures of only $8.8 million and $2.1 million in F2017 and F2018. The Graphic Design Tool (Graphic) project has a current pre-implementation cost estimate of $12.9 million to $23.0 million with capital additions of $15.0 million in F2018, but expenditures of only $6.3 million in F2017 and $4.3 million in F2018. The current start date of construction of both projects is TBD.

Page 6-110 of the application explains that an area of IT focus is providing energy conservation tools.

114.1 Is BC Hydro requesting approval for any IT project in this proceeding?

114.2 Please provide the forecast and actual capital additions totals for IT projects greater than $2 million for F2015 and F2016. Please comment on any trends observed from F2015 through F2019.

114.3 Please explain how the portfolio adjustments were determined.

114.4 Please further describe the Billing and Graphic projects.

114.5 Please reconcile the capital expenditure and addition forecasts for both the Billing project and the Graphic project.

114.6 Does the Billing project or the Graphic project meet BC Hydro's 2010 Capital Project Filing Guideline threshold for IT&T projects? Please explain.

114.7 Does the Billing project or the Graphic project have linkages to SAP? Please explain.

114.8 Are the energy conservation tools included in the F2017-F2019 DSM expenditure plan? Why or why not?

114.9 Please discuss the implications of deferring each of the IT&T projects listed in Appendix I out of the test period.

115.0 **Reference:** **CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, p. 6-39, 6-96, 6-104, 6-106-6-108, 6-112, 6-117; Exhibit B-6, p. 5; Exhibit B-6, Supplemental Appendix I-A – Technology, lines 36, 48
Smart Metering and Infrastructure Technology Capital Additions and Expenditures

Page 6-104 of the Application states "The Smart Metering and Infrastructure Program [SMI] completed in fiscal 2016 and as such there are neither capital expenditures nor additions in the fiscal 2017 to fiscal 2019 test period."

The following tables show no capital additions or expenditures forecast for SMI in F2017 to F2019: Table 6-13 on page 6-96 (Distribution Capital Expenditures), Table 6-17 on page 106 (Technology Group Actual and Plan Capital Expenditures), Table 6-18 on page 106 (Technology Group Actual and Plan Capital Additions) and Table 6-22 on page 6-117 (Properties Plan and Actual Capital Additions).

For Technology Capital Investment Planning on Page 6-39 of the Application, BC Hydro discusses the following Foundational IT Expenditures related to Smart Metering:

> Foundation-Application expenditures implement and sustain the enterprise-class application platforms, including… Smart Metering.
>
> Foundation-Infrastructure… Investments planned for fiscal 2017 to fiscal 2019 include… Smart Metering and Infrastructure Renewal.
>
> Foundation-Telecommunications expenditures implement and sustain a portion of BC Hydro's telecommunications systems consisting of…smart meter field area network… Investments planned for fiscal 2017 to fiscal 2019 include… Smart Metering and Infrastructure Field Area Network Sustainment…

Further, Supplemental Appendix I-A on page 5 shows Technology Projects Capital Additions in F2017–F2019 as follows:

Table 2: Technology Projects Capital Additions

Capital Additions	F17 Forecast	F18 Forecast	F19 Forecast
SMI Field Area Network Sustainment	4.2	4.5	4.5
SMI Infrastructure Renewal	0.5	0.5	0.5

Table 6-19 on page 6-107 and Table 6-20 on page 6-108 of the Application shows Technology IT Plan Capital Expenditures and Additions, specifically the Foundation IT capital additions and expenditures for Infrastructure, Telecommunications and Applications in F2017–F2019 as follows:

Table 3: Technology IT Planned Capital Additions and Expenditures

Foundational IT	Capital Additions			Capital Expenditures		
	F17 Plan	F18 Plan	F19 Plan	F17 Plan	F18 Plan	F19 Plan
Infrastructure	16.6	15.7	15.5	16.3	14.5	15.5
Telecommunications	13.8	12.8	11.9	10.8	13.1	11.2
Applications	13.3	4.4	4.3	9.6	3.7	4.3

115.1 Please reconcile why BC Hydro states that no capital expenditures or additions are expected in the test period for the SMI program, however, it lists SMI work elsewhere in the Application that will incur expenditures and cause additions.

115.2 Please confirm, or otherwise explain, that the SMI Field Area Network Sustainment and SMI Infrastructure Renewal capital additions are included in the Infrastructure and Telecommunications capital additions provided in Table 6-20.

115.3 How much does BC Hydro expect to spend in the test period on expenditures (i) to implement and sustain the Smart Metering enterprise-class application platforms and (ii) to implement and sustain a portion of BC Hydro's telecommunications systems for the smart meter field area network?

115.3.1 Please confirm, or otherwise explain, that the forecast Smart Metering enterprise-class application platforms expenditures and additions are included in the Applications capital expenditures and additions in Table 6-19.

115.3.2 Please confirm, or otherwise explain, that the forecast smart meter field area network expenditures and additions are included in the Telecommunications capital expenditures in Table 6-19.

115.4 Please provide a breakdown of all SMI related expenditures and additions that are in the Infrastructure, Telecommunications and Applications line items in tables 6-19 and 6-20. Please also describe the work associated with these expenditures and additions.

116.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, pp. 6-47–6-49; Appendix J, pp. 76–79, 84; Exhibit B-6, Appendix I-A – Other, lines 5, 6, 15
Chilliwack, Vernon and Victoria Field Buildings

Appendix I-A shows current authorized amounts of $46.3 million for the Vernon Field Building (Vernon) project and $41.6 million for the Victoria Field Building (Victoria) project. It also shows an estimated cost of $29.3 million for a Chilliwack Field Building (Chilliwack) project with a construction start date TBD, but with capital expenditures of $4.7 million, $2.4 million and $10.2 million, in F2017, F2018, and F2019, respectively. On pages 6-47 to 6-49 of the Application BC Hydro explains the properties capital planning process including the use of health assessments.

116.1 What is the likelihood of either the Vernon project or the Victoria project exceeding $50 million? Please elaborate.

116.2 Is construction expected to start on the Chilliwack project in the test period? Based on the expenditure forecast, it appears that this project is forecast to start construction as early as F2017. Please explain.

116.3 What is the leading alternative for the Chilliwack project?

116.4 What is included in the Chilliwack project cost estimate and what is its accuracy range? Why is the estimated cost of the Chilliwack so much less than the other two projects listed above? Please elaborate.

116.5 Please provide the health assessment for the Atchelitz field building associated with the Chilliwack project.

117.0 **Reference:** **CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Appendix J, pp. 80–83; Exhibit B-6, Supplemental Appendix I-A – Other, lines 9, 11
Construction Services/Lower Mainland Transmission Building and Material Classification Facility

Supplemental Appendix I-A shows project cost estimates of $36.5 million for the Construction Services/Lower Mainland Transmission Building (CS/LMT) project with a construction start date of F2018 and $40.5 million for the Material Classification Facility (Classification) project with a construction start date TBD, but with forecast expenditures of $1.6 million, $6.9 million and $15.8 million, in F2017, F2018, and F2019, respectively. Appendix J explains that one option would require the two facilities to swap locations, in which one project cannot advance without the other and together would have an expected capital cost in excess of $50 million. In this case, BC Hydro would plan to submit a joint application for both the Material Classification Facility and Construction Services/Lower Mainland Transmission projects to the Commission. Appendix I-A also list a project for a Materials Management Facility (Management) for $10 million with a construction start date TBD.

117.1 Please describe the Management project. Is this project in any way linked to the CS/LMT or Classification projects? Please elaborate.

117.2 Is the swapping option the leading alternative for the CS/LMT and Classification projects? Please elaborate.

117.3 Considering the close proximity of these CS/LMT and Classification planned projects (i.e. one is across the street from the other), would one anticipate savings/efficiencies if both projects were managed as one (e.g. construction contracts, project management, labour, materials, scheduling) irrespective of whether the locations were swapped? Please elaborate.

117.4 Is construction expected to start on the Management project in the test period? How about the Classification project? Based on the expenditure forecast it appears that this project is forecast to start construction in F2018. Please elaborate.

117.5 Please describe what is included in each project cost estimate and provide the accuracy ranges of each project. Independently, does either the CS/LMT or the Classification project's upper cost estimate range exceed $50 million?

117.6 Please confirm, otherwise explain, that BC Hydro is of the opinion that there are likely to be significant public interest issues with this project that deserve consideration, for example hazardous materials handling and storage. If confirmed, please summarize some of those potential issues.

118.0 **Reference:** **CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, pp. 6-49–6-51, 6-118, 6-119; Exhibit B-6, Appendix I-A – Other, line 18
Fleet/Vehicles/Materials Management

Appendix I-A shows cost estimates of $40.3 million, $32.4 million and $30.2 million for Fleet/Vehicles/Materials Management for F2017, F2018 and F2019. Similarly, pages 6-118 and 6-119 show that fleet capital additions actuals were $16.1 million and $21.2 million in F2015 and F2016 and are forecast to be $40.3 million, $32.4 million, and $30.2 million for F2017, F2018 and F2019, respectively. Pages 6-49 to 6-51 of the Application explain the fleet capital planning process.

118.1 Please confirm that the cost estimates provided in Appendix J are for fleet capital additions only. Otherwise, please split these capital additions between Fleet, Vehicles and Materials

Management as applicable.

118.2 Please comment on any trends observed in capital additions for fleet from F2015 through F2019.

118.3 Please discuss the effect of SMI on the number of vehicles.

118.4 Please provide the age distribution of vehicles and the condition distribution of vehicles for F2015 and F2016 and the forecasts for F2017, F2018 and F2019.

118.5 What is the target fleet age and vehicle condition? Why did BC Hydro select these targets? How does that compare to the actual fleet age and condition at the beginning and end of the test period? Please elaborate.

118.6 How does BC Hydro determine when an employee gets a vehicle? How does BC Hydro determine how many vehicles a department is allocated?

118.7 How many vehicles were there in each of F2012–F2016 and what is the forecast for the test period? Please comment on any trends observed.

118.8 How many vehicles per employee were there in each of F2012-F2016 and what is the forecast for the test period. Please comment on any trends observed.

118.9 Please further describe the overall guiding documents that show how BC Hydro is following fleet industry principles and practices.

118.10 Please compare BC Hydro's policies and practices to FortisBC's policies and practices regarding fleet management.

118.11 Please explain how BC Hydro applies its corporate prioritization framework to fleet management.

119.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Appendix K, Section 5
F2015 and F2016 capital expenditure and addition variances

Section 5 in Appendix K of the Application discusses BC Hydro's capital expenditure and addition variances for F2015 and F2016. BC Hydro explains that variances may be caused by changes to the plan, phasing, timing, scope, market conditions or other factors. Tables K-11 and K-12 both show that BC Hydro is spending less (expenditures) and adding less (additions) than forecast in the F2015–F2016 RRA.

119.1 Please explain earned value management principles.

119.2 On a portfolio basis, please elaborate on BC Hydro's scope, schedule and cost performance for F2015 and F2016. On aggregate, is BC Hydro completing the original scope of work on time and on budget? Please elaborate (use earned value management principles where possible).

119.3 Does BC Hydro track its project portfolio performance using earned value management principles? Why or why not? If not, does BC Hydro think there would be value in devising a method to do so? Please explain.

119.4 Over time has BC Hydro been getting better at planning, executing, monitoring and controlling capital? Please explain.

120.0 **Reference:** **CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-6, Supplemental Appendix I-B
F2015 and F2016 capital additions – Scope, Schedule and Budget

Footnote 6 in Supplemental Appendix I-B explains "Implementation Approval $ refers to the 'authorized' total capital cost of the project when it was first approved by BC Hydro for implementation." Similarly, footnote 7 explains "Implementation Approval ISD refers to the ISD date identified when the project was first approved by BC Hydro for implementation." [Emphasis added]

120.1 Please confirm, otherwise explain, that the Implementation Approval ISD and the Implementation Approval $ are the same forecast in-service dates and project cost point estimates BC Hydro provided to the Commission in CPCN, section 44.2, RRA, or Annual Report filings (and where applicable, approved or accepted by the Commission).

120.1.1 If not confirmed, for non-exempt projects, please include those dates and project cost estimates as new columns to Supplemental Appendix I-B.

120.2 For non-exempt projects in Supplemental Appendix I-B with total capital additions (column O) exceeding 10 percent or $10 million of the original project cost point estimates as identified to the Commission in CPCN, section 44.2, RRA or Annual Report filings (and where applicable, approved or accepted by the Commission), please explain the variances. Please draw from project reports where applicable.

120.2.1 Please also detail any changes in the project expected amounts and project authorized amounts due to accounting changes associated with adopting IFRS.

120.3 For non-exempt projects in Supplemental Appendix I-B with actual in-service dates 6 months past the Commission reviewed forecast ISD, please explain the schedule variances. Please draw from project reports where applicable.

120.4 For non-exempt projects in Supplemental Appendix I-B, please confirm, otherwise explain, that the original scope of these projects, as identified to the Commission in CPCN, section 44.2, RRA or Annual Report filings (and where applicable, approved or accepted by the Commission) were complete.

120.4.1 If not confirmed, please list these projects; provide a description of the original scope, the scope that was complete and a detailed comparison of between the two. Please refer to compliance fillings where applicable (e.g. Hugh Keenleyside Report 4 – Appendix C).

121.0 **Reference:** **CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-6, Supplemental Appendix I-B – Generation, lines 1, 4; Exhibit B-1-1, Appendix K
GM Shrum (GMS) Units 1 to 5 Turbine and Unit 1 to 4 Generator Rotor Pole Replacements

Supplemental Appendix I-B lists GM Shrum Units 1 to 5 Turbine Replacement (GMS Turbine) and Unit 1 to 4 Generator Rotor Pole Replacements (GMS Rotor) as separate projects.

121.1 For the GMS Turbine project, were the expected benefits as laid out in the application realized? Please elaborate. Please refer to compliance filings where appropriate.

121.2 For the GMS Turbine project, please provide a detailed comparison of the accelerated schedule and costs with those presented in the section 44.2 application. Please refer to compliance filings

where appropriate.

121.3 Also for GMS Turbine project, please provide the forecasted total costs of the project including any on-going incremental forecasted capital or maintenance costs related to cavitation. Please refer to compliance filings where appropriate.

121.4 Please explain why the GMS Turbine and Rotor projects were not combined into one project.

121.4.1 Are both projects necessary to achieve a common goal? For example, an eventual increase in capacity or additional energy from GMS. Please elaborate.

121.4.1.1 If so, are there any other projects or work that are or were required to achieve that common goal? For example, stator, iso-phase bus, governor, exciter, circuit breaker or transformer work. Please elaborate.

121.4.2 Were both projects planned and executed in the same period?

121.5 Please provide the GMS Facility Asset Plan.

122.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-6, Appendix I-B – Generation, line 5
Mica SF6 Gas-insulated Switchgear Replacement (Mica GIS Project)

In G-38-10, the Commission found that the Mica GIS Project is not in the public interest and orders that the capital expenditure schedule having an expected cost estimate of $180.6 million is not accepted.

122.1 Please explain the above decision and justify why this project should now be accepted into rates (i.e. in the public interest). Please refer to submissions in compliance filings where appropriate.

123.0 **Reference: CAPITAL EXPENDITURES AND ADDITIONS**
Exhibit B-1-1, Appendix K, pp. 42, 44; Exhibit B-6, Supplemental Appendix I-B – Other, line 1
Smart Metering and Infrastructure Technology Capital Addition Variances

In regard to the SMI Program, under Appendix K of the Application, BC Hydro states on page 44 that "in the Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application the program was forecast for completion at the end of fiscal 2015."

Further on page 44 in Appendix K, BC Hydro states "the fiscal 2016 capital additions are $56.5 million greater than plan, due primarily to the change in the project completion date to fiscal 2016. This resulted in certain project assets with capital expenditures prior to fiscal 2015 entering service in fiscal 2016." Table K-22 on page 42 shows the Technology Sub-Categories -–Capital Additions F2015 and F2016 Actual to Forecast:

Table 4 SMI Technology Capital Addition Variances F2015–F2016

($ millions)	F2015			F2016		
	RRA	Actual	Variance	RRA	Actual	Variance
Smart Metering and Infrastructure	26.1	22.5	3.6	11.3	67.8	(56.5)

123.1 Please explain why the F2015 SMI technology actual additions ($22.5 million) closely match the F2015 forecast additions ($26.1 million), but the F2016 actual additions ($67.8 million) are much greater than the F2016 forecast additions ($11.3 million) even though the SMI program completion date was delayed to F2016. Were there additions or changes to the project scope

that may have contributed to the increase in technology capital additions? Please elaborate.

Supplemental Appendix I-B on page 4 also shows actual SMI program capital additions in F2015 and F2016. It shows $31.5 million was incurred in F2015 and $155.5 million was incurred in F2016.

123.2 Please confirm, or otherwise explain, that the technology related actual capital additions ($22.5 million in F2015 and $67.8 million in F2016) are included in the capital additions shown in Supplemental Appendix I-B.

123.3 Please provide the F2015–F2016 RRA forecast capital additions for the SMI program and compare to the actual additions in Supplemental Appendix I-B. Please provide a high level breakdown of each. Please discuss any variances.

M. CHAPTER 7 – DEFERRAL AND OTHER REGULATORY ACCOUNTS – DEFERRAL ACCOUNTS

124.0 **Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Exhibit B-1-1, p. 7-4, Table 7-1, p. 7-6, Table 7-2; Direction No. 7
Fiscal 2024 forecast

Direction No. 7 states that the Commission "must set rates in such a way as to allow the regulatory accounts to be cleared from time to time within a reasonable period taking into consideration the rate caps."

Table 7-2 on page 7-4 of the Application shows that the total regulatory accounts balance is forecast to decrease by $2.3 billion, or approximately 40 percent, between F2016 to F2024 resulting in an ending balance of $3.6 billion.

124.1 Please explain in detail BC Hydro's specific plan to reduce the balance to $3.6 billion by F2024 and who is accountable to ensure the plan is achieved.

124.2 Please expand Table 7-2 to included five years of comparative data (F2012–F2016) and also include (i) the total annual percent increase by year and (ii) the total interest expense by year.

124.3 What is the forecast WACD rate in F2020–F2024 used to prepare Table 7-2?

124.3.1 What would the total balance be in each of F2020–F2024 if the WACD was to increase by 0.1 percent per year, 0.3 percent per year or 0.5 percent per year?

The F2016 ending balance in the Cost of Energy Variance Accounts is $1.143 billion. BC Hydro forecast the ending balance to be $42 million in F2024 which accounts for $1.101 billion of the decrease.

124.4 For F2017–F2024 please provide a table that shows the opening balance, forecast additions, interest and recoveries for each of the Cost of Energy Variance Accounts. Please include an explanation for the assumptions that were used to determine the forecast additions and recoveries.

124.5 For the years F2020–F2024 is it assumed that 100 percent of the DARR has been applied to the Cost of Energy Variance Accounts? If not, please explain with reference to Direction No. 7.

124.6 Please calculate the average additions (excluding interest) to the HDA, the NHDA and the TIDA during the past 5 years.

124.7 Please confirm, or explain otherwise, that since F2009 the average annual addition to the NHDA relating to the Domestic Revenue Variance has been $125 million and the average five year addition has been $171 million. Please explain what changes, especially regarding the load

forecast, are anticipated that could result in this variance being eliminated or significantly reduced in order to achieve the forecast ending balance of $33 million in F2024.

124.8 For the Cost of Energy Variance Accounts, please provide a table that shows the opening balance, the forecast additions, interest and recoveries for F2017–F2024 under the assumption that forecast additions are equal to the five year average additions. Please discuss whether or not this is a reasonable assumption.

124.9 Please calculate the total average additions (excluding interest) for the Other Cash Variance Accounts set out in Table 7-2 during the past 5 years.

124.10 For each of the Other Cash Variance Accounts, please provide a table that shows the opening balance, the forecast additions, interest and recoveries for F2017–F2024 under the assumption that the forecast additions are equal to the five year average additions. Please discuss whether or not this is a reasonable assumption.

124.11 For the Benefit Matching Accounts, the Rate Smoothing Account and the IFRS Transitions Accounts set out in Table 7-2, please provide a table that shows the opening balance, the forecast additions, interest and recoveries for F2017–F2024. Please include an explanation for each of the assumptions considered in determining the forecast additions and the forecast recoveries.

125.0 **Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Exhibit B-1-1, pp. 7-8 to 7-16
Threshold for establishing new regulatory accounts

In sections 7.3 and 7.4 of the Application, BC Hydro has included a discussion on its types of regulatory accounts and it position on amortization and thresholds for establishing new regulatory accounts.

125.1 Is BC Hydro requesting the Commission to approve BC Hydro's positions as put forward in sections 7.3 and 7.4 or has the information been provided for information purposes only? Please discuss fully.

125.2 In BC Hydro's view, would it be appropriate to have a term established by the Commission for any new regulatory account approvals? Specifically, does BC Hydro think it is reasonable for the Commission to require BC Hydro to reapply and make its case again, perhaps every 5 years? Please discuss fully.

126.0 **Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Exhibit B-1-1, Appendix L; F2005–F2015 Annual Deferral Account Reports Summary

126.1 On the basis of the F2005–F2016 Annual Deferral Account Reports filed with the Commission, staff compiled the following summary tables relating to the HDA NHDA. Please confirm the accuracy of the table, or update as necessary.

Table 5: HDA Staff Summary

Heritage Deferral Account Annual Summary																
Year	Opening Balance	Cost of Energy (Heritage)	Pre F2012 Commodity Risk	Notional Water Rental	Skagit Valley Treaty & Ancillary Revenue	Costs in Operating / Amortization	Amortization of Unplanned Deferred Capital Cost (G-53-02)	Variable Cost Related to Thermal Generation	Deferred Operating Costs in HDA	Other	Total Changes	Rounding	Amortization	Interest	Transfer to GMS 3	Ending Balance
F2005	0.0	139.3	-22.8	10.7	3.5						130.7	0.4		6.9		138.0
F2006	138.0	62.9	29.7	-0.2							92.4	-0.1		10.4		240.7
F2007	240.7	-35.0	4.2	4.9	1.0		-0.3	0.7	1.1		-23.4		-53.3	14.1		178.1
F2008	178.1	-58.0	1.9	-2.9	5.0		-1.6	0.3	6.0	-7.0	-56.3		-50.2	6.3		77.9
F2009	77.9	192.6	91.4	0.7	-5.4			0.1	21.4		300.8		-22.6	13.9	-41.1	328.9
F2010	328.9	8.2	-10.6	9.3	3.2		-1.0	0.2	2.1	0.1	11.5	-0.1	-29.3	22.2	-8.3	324.9
F2011	324.9	-33.0	1.1	1.6	3.4	-0.5	-1.1	-0.1	0.7		-27.9		-62.7	13.4		247.7
F2012	247.7	-13.2		-18.9	-0.3	-0.1	-0.6	-0.3	1.5		-31.9		-27.2	12.0	43.2	243.8
F2013	243.8	-124.4		-5.1		-0.2	-0.8	-0.2	7.0		-123.7		-55.8	5.6		69.9
F2014	69.9	35.2		14.9	-0.9	0.2	-1.0	-0.6	2.5		50.3		-18.0	2.6		104.8
F2015	104.8	77.3		5.1	-2.4	-0.2			1.9		81.7	-0.1	-26.2	4.5		164.7
F2016	164.7	-151.5		-1.9	-1.7	-1.0	0.6	0.3	2.5		-152.7	-0.3	-37.0	0.3		-23.9
Cummulative Total		100.4	94.9	18.2	5.4	-1.8	-5.8	0.4	46.7	-6.9	251.5	-0.2	-382.3	112.2	-6.2	

Table 6: NHDA Staff Summary

Non-Heritage Deferral Account Annual Summary																			
Year	Reported Opening Balance	Cost of Energy	Commodity Risk	Notional Water Rental	FX Gains & Losses on Powerex Trade	Domestic Revenue Variance (2009)	ABSU Founding Partner Benefits	Deferred Operating Costs in NHDA	RRA Adjustments	PTP and NITS Variance	Capital Lease Adjustment	Burrard Decommissioning Costs	Other	Total Changes	Rounding	Amortization	Interest	Ending Balance
F2005	0.0	154.5	-5.3	-10.7	-10.6									127.9		0.0	3.0	130.9
F2006	130.9	44.8	19.8	0.2	-3.9		-0.6		-2.9					57.4		0.0	9.0	197.3
F2007	197.3	35.0	3.3	-4.9	8.9		-0.6	-2.7					7.3	46.3		-45.3	14.0	212.3
F2008	212.3	-58.7	-3.0	2.9	-52.2		-0.5		-33.7				-3.5	-148.7	0.1	-58.9	8.8	13.6
F2009	13.6	-51.5	9.3	-0.7	10.1	20.4	-0.6						38.0	25.0	0.1	-14.9	7.4	31.2
F2010	31.2	-22.8	-0.4	-9.3	-4.5	82.5	-0.6						43.2	88.1		-6.6	6.8	119.5
F2011	119.5	-44.5	-12.1	-1.6	-4.0	42.4	-0.2		222.5	16.0				218.5		-23.5	7.3	321.8
F2012	321.8	-147.0	12.9	18.9	2.4	62.8	0.6	11.2	65.9	0.2			40.4	68.3	-0.1	-39.8	16.8	367.0
F2013	367.0	-166.6		5.1	-3.9	176.1	0.4		103.2	-12.2				102.1	-0.1	-84.0	20.3	405.3
F2014	405.3	-195.5	15.2	-14.9		137.7		-0.9	49.8	5.3			62.2	58.9	0.0	-120.3	17.7	361.6
F2015	361.6	50.7	-4.8	-5.1		207.3				8.8	-22.8	4.1		238.2	0.1	-90.6	14.8	524.1
F2016	524.1	235.4	-0.5	1.9		268.9				-0.7	-31.0	9.0		483.0	-0.1	-117.7	27.5	916.8
Cummulative Total		-166.2	34.4	-18.2	-57.7	998.1	-2.1	7.6	404.8	17.4	-53.8	13.1	187.6	1,365.0	0.0	-601.6	153.4	

127.0 **Reference:** **DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Exhibit B-1-1: pp. 7-17 and 7-18, Appendix A, schedule 4; Direction No. 7, Appendix C
HDA – Cost of Energy Deferral Accounts
Heritage Payment Obligation (HPO)

The following table below is an excerpt of Appendix A (regulatory model), schedule 4, reflecting details of the Heritage Payment Obligation for the test periods and three comparative years:

		Heritage Payment Obligation												
67	A	Heritage Energy	Line 34	371.2	406.4	35.2	311.6	388.9	77.3	357.6	206.1	(151.5)	279.3	250.2	279.3
68		Costs in Operating/Amortization		16.2	16.4	0.2	15.7	15.5	(0.2)	13.0	12.9	(0.1)	12.3	12.4	12.9
69		Commodity Risk		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
70		Notional Water Rentals		(5.0)	9.9	14.9	(1.4)	3.7	5.1	1.9	(0.0)	(1.9)	(1.9)	(1.7)	0.7
71	B	Skagit and Ancillary Revenue	14.0 L18	(15.5)	(16.4)	(0.9)	(16.2)	(18.6)	(2.4)	(16.5)	(18.2)	(1.7)	(12.6)	(12.0)	(12.1)
72		Load Curtailment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
73		Water License Variances	5.0 L43	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
74		Deferred Operating HDA	5.0 L48	0.0	2.5	2.5	0.0	1.9	1.9	0.0	2.5	2.5	0.0	0.0	0.0
75		Transfer to GMS 3 Reg Account		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
76	C	Other		6.9	5.2	(1.6)	43.5	43.5	0.0	43.2	44.1	0.9	28.2	36.5	36.2
77		Total		373.7	423.9	50.2	353.2	434.9	81.7	399.2	247.3	(151.9)	305.3	285.4	317.1

127.1 Annual variance between the actual and forecast HPO are deferred to the HDA in accordance with Direction No. 7. Please confirm, or explain otherwise, that BC Hydro requires Commission approval of the HPO in each of the test years.

<u>Heritage Energy</u>

On page 7-17 of the Application, BC Hydro states that "[t]he Heritage Deferral account captures variances between actual and forecast energy costs associated with BC Hydro's Heritage Resources that

are incurred to supply Heritage Electricity. Heritage Energy is defined as 49,000 GWh per year less the energy generated for delivery under the Skagit Valley Treaty…"

127.2 Please explain why the forecast for Heritage Energy in the HPO is based on 43,095 GWh, 41,473 GWh and 42,182 GWh (Appendix A, schedule 4, line 8) in test years F2016, F2017 and F2018 respectively and not 49,000 GWh less energy generated for delivery under the Skagit Valley Treaty.

BC Hydro states on page 7-18 of the Application "[w]hile rates are set assuming average water inflow levels, the lower cost hydro generation levels can fluctuate by +/- 5,000 GWh between low and high years, resulting in the need to sell surplus power or purchase energy from the market."

127.3 Please explain the applicability, if any, of this statement on the forecast for Heritage Energy in the HPO.

Skagit and Ancillary Revenue

127.4 The F2017–2019 forecast for Skagit and Ancillary Revenue in the HPO can be traced to schedule 14, line 27 in Appendix A; however, that line is title Seattle City and Light. Please confirm that the Seattle City and Light is the same as the Skagit Valley Treaty.

127.5 The F2017–2019 forecast for Skagit and Ancillary Revenue in the HPO appears to include the forecast for Skagit but not Ancillary Revenue. Given that Direction No. 7, Appendix C states that "revenues from the provision of ancillary services to the transmission operator in respect of third party use of the transmission system" are to be subtracted in the calculation of the HPO, please explain why an adjustment for Ancillary Revenues does not appear to have been made in the determination of the HPO.

Other

127.6 In the years prior to F2017 please confirm, or explain otherwise, that Other items in the HPO relate to the forecast of (i) the Unamortized Deferred Capital Costs from Order G-53-02 (First Nations) and (ii) the variance related to thermal generation.

127.6.1 Has this changed in the test period? If yes, please explain.

127.7 Please provide a further breakdown of the F2017–F2019 forecast for Other.

127.8 Prior to F2015 the forecast for Other was less than $10 million. Please explain why starting in F2015 it has increased significantly.

128.0 **Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Exhibit B-1-1: pp. 7-8, 7-19; Appendix A, schedule 4; Order G-53-02
HDA – Cost of Energy Deferral Accounts
Change request

On page 7-19 of the Application, BC Hydro requests the following change to the HDA:

> Effective starting fiscal 2017, annual negotiations costs related to First Nations be excluded from the calculation of the heritage payment obligation [HPO] for the purposes of deferring variances to the Heritage Deferral Account [HDA]. BC Hydro believes it should bear the risk associated with the variance in annual negotiation costs.

128.1 Have the impacts of this request been incorporated into the HPO forecast set out in Appendix A, schedule 4? If not, please explain.

128.2 What specific First Nation variance costs relating to Order G-53-02 were included in the NHDA between F2007 and F2016? Specifically, were the variances restricted to negotiation and litigation cost or were the variances relating to the costs of settlements arising from those negotiations included as well?

128.3 As summarized in Table 5: HDA Staff Summary under the column Amortization of Unplanned Deferred Capital Cost please confirm, or explain otherwise, that the between F2007 and F2016 the variance related to this item was $5.8 million to the benefit of ratepayers.

128.4 Given that the variance has been to the benefit to ratepayers please explain why this variance should not continue to be captured in either the NHDA or the First Nations Regulatory Account.

129.0 **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.

129.1 Please explain how the net impact of load variance is calculated, particularly in reference to the F2009, F2010 and F2011 Annual Deferral Account Reports, schedule F, note 4.

129.2 In response to BCUC IR 1.10.3 in the F2012–F2014 RRA, BC Hydro stated that the $42.4 million in F2011 that is added to the NHDA is a revenue variance and not a net load variance. Please explain the difference between a net load variance and a revenue variance.

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.

129.4 As summarized in Table 6: NHDA Staff Summary, please confirm, or explain otherwise, that since F2009 BC Hydro has been recording the Domestic Revenue Variance in the NHDA resulting in a total deferral of $998.1 million. Please show the variance relating exclusively to (i) the cost of energy due to load and (ii) variance due to revenue. Please reconcile total numbers in Table 6: NHDA Staff Summary.

129.5 Starting in F2009, it appears that the addition to the NHDA relating to the Domestic Revenue Variance ties directly to Appendix A, schedule 1, line 23, Total Revenue Requirement Variance, which is the variance between the forecast total revenue requirement and the actual revenue requirement. Please explain fully how the Cost of Energy Variance Related to Load equals the Total Revenue Requirement Variance.

129.6 Are there any forecasts in the F2017–F2019 RRA that do not have variance protection through one of the Cost of Energy deferral accounts or a regulatory account? If yes, please specially identify each forecast including a reference to the regulatory model (Appendix A). Please ensure the response is in the same format as BCUC IR 1.10.5 in the F2012–F2014 BC Hydro RRA.

130.0 **Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Exhibit B-1-3, BC Hydro Amended F2012–F2014 RRA, pp. 7-6 and 7-8
Exhibit B-1-1, Appendix A, schedule 1
Deferral Account
NHDA – Cost of energy and load variances

130.1 In the same format as provided in Amended Table 7-1 titled "Net Impact of Load Variance Summary" on page 7-6 of the BC Hydro F2012-F2014 RRA Amended Application, please provide the data for years F2014, F2015 and F2016.

130.2 In the same format as provided in Amended Table 7-2 titled "Net Impact of Load Variance F2010-F2011" on page 7-8 of the BC Hydro F2012-F2014 RRA Amended Application, please provide the data for years F2014, F2015 and F2016. Please ensure that line 14 Total of Amended Table 7-2 agrees to the difference shown in Appendix A, schedule 1, line 23, of the current Application for each years.

130.2.1 In F2014, F2015 and F2016, does the calculation of Gross load variance assume that the change in energy supplied arising from the variance in domestic sales is priced at the average market price? If yes, please explain why this is appropriate. If not, please explain.

130.2.1.1 Does BC Hydro intend on calculating the gross load variance during the test period in the same manner? If not, how will the calculation be performed?

130.3 For each of the test years, please calculate the Domestic Revenue Variance assuming that the load forecast as set out in Appendix A, schedule is 14, lines 1-10, is 3 percent lower or 3 percent

higher.

130.3.1 Please discuss the resulting impact on the Rate Smoothing Account, if any.

131.0 **Reference:** **DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Exhibit B-1-1, p. 1-15, 8-5; Direction No. 7
NHDA – Other

131.1 Direction No. 7 (7)(c) prescribes what the Commission must allow regarding the NHDA. The direction is limited to Burrard costs and the COE variance arising from actual and forecast domestic customer load. With regard to the other variance captured in the NHDA as set out in Table 6: NHDA Staff Summary, please discuss if further or renewed approval to capture these variances are required. If not, please explain.

131.2 Please explain why costs related to Burrard Thermal are included in the NHDA and recovered through the DARR rather than being placed in a separate regulatory account? Please explain the relationship between Non Heritage Energy and Burrard Thermal.

On page 8-15 of the Application, BC Hydro states that in F2015 and F2016 BC Hydro included the deferral of $22.8 million and $31.0 million respectively into the NHDA for the benefit of ratepayers that was not required under existing regulatory orders. BC Hydro explains that the variance was due to a classification change for EPAs from capital to operating.

131.3 Please explain why BC Hydro has not requested a directive to require such treatment for EPA accounting classification variances to be deferred to the NHDA on a go forward basis?

132.0 **Reference:** **DEFERRAL AND OTHER REGULATORY ACCOUNTS**
F2011–F2016 Annual Deferral Account Reports; Exhibit B-1-1, p. 8-12, Appendix A, schedule 1
TIDA – Cost of Energy Deferral Account

132.1 On the basis of the F2011–F2016 Annual Deferral Account Reports filed with the Commission, staff compiled the following summary table relating to the TIDA. Please confirm the accuracy of the table, or update as necessary.

Table 7: TIDA Staff Summary

Trade Income Deferral Account By Reporting Period									
Year	Reported Opening Balance	Adj IFRS Conversion	Powerex Net Income (Actual)	Trade Income (Forecast)	Variance	*rounding*	Amortization	Interest	Ending Balance
F2011	121.7		71.5	152.0	80.5		-23.5	8.8	187.5
F2012	187.5		142.0	142.0	0.0	-0.1	-20.6	7.9	174.7
F2013	174.7	30.0	98.2	113.0	14.8	0.2	-40.0	10.5	190.2
F2014	190.2		-58.4	113.0	171.4	0.0	-48.9	12.0	324.7
F2015	324.7		120.1	110.0	-10.1	0.0	-81.3	11.3	244.6
F2016	244.6		58.7	110.0	51.3		-54.9	9.1	250.1
TOTAL		30.0	360.6	588.0	227.4	0.1	-245.7	50.8	
5 year average excluding F2014			98.1	125.4	27.3				

In Table 7-3 of the Application, BC Hydro show a forecast Trade Income of $115.2 million in F2017 and F2018 and $115.1 million in F2019 with any difference being deferred to the TIDA in accordance with Direction No. 7, 7(b). On page 8-12, BC Hydro states that: "Using a five-year average as the basis of

forecasting Powerex net income is consistent with prior revenue requirement applications and is reasonable given the year-to-year volatility in market conditions."

132.2 Please confirm, or explain otherwise that in F2014, the Powerex Income included losses from the California legal settlement[6] and as set out in Direction No. 7.

132.3 Given that losses are not included in the TIDA transfer calculation before or after F2014, please explain fully why it should be included in the five year average.

132.3.1 Given that the five year average excluding F2014 is $98.1 million, please explain why a $100 million forecast for Trade Income in each of F2017–F2019 would not be more appropriate.

132.4 Please provide Powerex's average net income over the past 10 years including and excluding F2014.

133.0 **Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Exhibit B-1-1, p. 7-6, 7-20; Appendix L; Directive No. 7
Deferral Account Rate Rider (DARR)

Direction No. 7 10 (3)(iii) states:

> (iii) the portion of forecast revenue from the deferral account rate rider in the applicable fiscal year of the authority that is amortized from the net balance of the heritage deferral account, the non-heritage deferral account and the trade income deferral account at the end of the immediately preceding fiscal year must be amortized from the respective balances of those accounts in proportion to the ratios of the balances of those accounts to the net balance of all 3.

133.1 Please fully explain how this allocation is performed and provide any assumptions.

133.2 In a similar format as Table 7-5 on page 7-20, please show how the forecast Deferral Account Rater Rider (DARR) of $223.5 million, $231.3 million and $248.1 million in test years F2017-F2019 have been applied to each of the three Cost of Energy Deferral Accounts.

133.3 Appendix L to the Application includes the Fiscal 2016 Deferral Account Report. The balance in the HDA at the beginning of F2016 was $164.7 million. During the year, amortization of $37 million collected through the DARR and was applied to the HDA resulting in a credit balance of $23.9 million at the end of F2016. Please explain why the DARR is applied to the HDA in excess of drawing the balance down to $0.

133.4 Please explain why the HDA is forecast to remain in a credit position throughout the period.

[6] In accordance with Direction No. 7 the "California Settlement" means the settlement of litigation between Powerex Corp. and various California parties arising from events and transactions in the California power market during 2000 and 2001, as approved by the Federal Energy Regulatory Commission (US) on October 4, 2013.

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134.0 **Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Exhibit B-1-1, p. 7-21; Appendix A, schedule 2.2; BC Hydro F2012-F2014 RRA
Amortization of Capital Additions regulatory account

In response to BCUC IR 2.13.5 in the F2012–F2014 RRA BC Hydro stated "If the Amortization of Capital Additions Regulatory Account and the Total Finance Charges regulatory account are continued as proposed, then it is not necessary to capture the variances in depreciation and finance charges in the HDA for unplanned capital expenditures."

134.1 Please confirm, or explain otherwise, that if approval for the continuation of the Amortization of Capital Additions regulatory account is not provided, then any variance between forecast and actual capital additions related to the heritage assets would be eligible for inclusion in the HDA under the terms of the HPO.

134.2 Please confirm, or explain otherwise, that if approval for the continuation of the Amortization of Capital Additions regulatory account is not provided, then any variance between forecast and actual amortization costs related to IPP Capital Leases would be eligible for inclusion in the NHDA.

134.3 Please discuss fully how BC Hydro's request for continued approval of the Amortization of Capital Expenditures regulatory account meets BC Hydro's criteria as set out on page 7-10 of the Application. Please ensure you address each of the five items listed as well as the risk/reward consideration.

134.4 Please fully explain which variance related to the amortization of property, plant and equipment as set out in schedule 7 of Appendix A is BC Hydro requested be captured in the Amortization of Capital Additions regulatory account. Specifically, is the variance related exclusively to the amortization of additions or does it apply to the amortization of existing asset as well.

134.5 Please explain why Appendix A, schedule 2.2, does not show any actual additions to this regulatory account between F2012 and F2016.

134.6 Please provide a table that includes forecast and actual amortization expense between F2012 and F2016 and provide an explanation for each variance. Please show amortization on existing assets and amortization on additions separately and tie the variance to schedule 2.2.

135.0 **Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Exhibit B-1-1, p. 7-22; Direction No. 7; BC Hydro F2012–F2014 RRA
Total finance charges regulatory account

135.1 Please explain how BC Hydro interprets Direction No. 7 (4)(b) which states that the Commission must ensure that rates allow the authority to collect sufficient revenues to enable the authority to meet all its debt service and other financial obligations.

135.1.1 Specifically, does Direction No. 7 require the Commission to allow BC Hydro to have a Total Finance Charge regulatory account for variances to allow the authority to collect sufficient revenues to meet all its debt service and other financial obligations when they vary from forecast? Please fully explain.

Direction No. 7, Appendix A, defines the HPO to included, among other things, the following: All costs of owning the heritage resources, including, without limitations depreciation, interest, <u>finance charges</u> and other asset related expenses. [Emphasis added]

In response to BCUC IR 2.13.5 in the F2012–F2014 RRA BC Hydro stated "If the Amortization of Capital Additions Regulatory Account and the Total Finance Charges regulatory account are continued as proposed, then it is not necessary to capture the variances in depreciation and finance charges in the HDA for unplanned capital expenditures."

135.2 Please confirm, or explain otherwise, that if approval for the continuation of the Total Finance Charge regulatory account is not provided, then any variance between forecast and actual finance costs related to the heritage assets would be eligible for inclusion in the HDA under the terms of HPO.

135.3 Please confirm, or explain otherwise, that if approval for the continuation of the Total Finance Charge regularly account is not provided, then any variance between forecast and actual finance charges related to the EPAs classified as capital leases would be eligible for inclusion in the NHDA.

135.4 Please discuss fully how BC Hydro's request for continued approval of the Total Finance Charges regulatory account meets BC Hydro's criteria as set out on page 7-10 of the Application. Please ensure you address each of the five items listed as well as the risk/reward consideration.

135.5 Please explain why Appendix A, schedule 2.2, line 91 does not show any actual additions to this regulatory account between F2012 and F2016.

135.6 Please provide a table that includes forecast and actual finance charges between F2012 and F2016 and provide an explanation for each variance.

136.0 **Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Exhibit B-1-1, p. 7-22; Direction No. 7
Rock Bay Remediation regulatory account

136.1 Is BC Hydro proposing that the actual costs related to Rock Bay Remediation are recorded directly as additions to the regulatory account and not included in operating costs on an annual basis? If yes, please discuss why it would be appropriate for the full costs to be recorded in the regulatory account and not just the variance between forecast and actual.

136.2 Please discuss whether the treatment that BC Hydro is requesting is consistent with Direction No. 7.

137.0 **Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Exhibit B-1-1, pp. 7-25, 7-26, 7-43 and 7-10; Appendix A, schedule 2.2; Direction No. 7
Asbestos Remediation regulatory account

On pages 7-26 of the Application, BC Hydro requests approval for actual costs associated with polychlorinated biphenyl (Poly) regulation compliance and asbestos remediation to be deferred to the Asbestos Remediation account.

137.1 Is BC Hydro proposing that the actual costs to comply with the Poly regulations and asbestos remediation are to be recorded directly as additions to the regulatory account and not included in operating costs on an annual basis? If yes, please discuss why it would be appropriate for the full costs to be recorded in the regulatory account and not just the variance between forecast and actual.

137.2 What are the forecast costs for compliance with the Poly Regulation and asbestos remediation

for each year of the test period?

137.3 Direction No. 7 (7)(h) prescribes that the Commission must allow the authority to defer the variance between forecast and actual asbestos remediation costs into the asbestos remediation regulatory account. Please confirm, or explain otherwise, that this is the treatment that BC Hydro is requesting approval for. If not, please explain.

137.4 Please discuss fully how BC Hydro's request, as it relates to the treatment of Poly compliance costs, meets BC Hydro's criteria as set out on page 7-10 of the Application. Please ensure each of the five items listed as well as the risk/reward consideration is addressed.

138.0 **Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Exhibit B-1-1, pp. 7-24, 7-42 and 7-43; Appendix A, schedule 2.2
Environmental Provisions regulatory account

138.1 For each of F2017–F2019 please provide a breakdown of the Beginning of Year balance set out on line 124 of schedule 2.2 between the Rock Bay, asbestos remediation and Poly provision.

138.2 For financial reporting purposes, is BC Hydro still required to set up a loss provision liability for Rock Bay, asbestos remediation and Poly compliance? If not, please explain.

On page 7-24, BC Hydro states that as it makes actual expenditures related to Poly compliance the balance in the Environmental Provisions account is drawn down. On page 7-43, BC Hydro states that in the case of Poly compliance the cost were expensed as incurred and the Environmental Provisions account was reduced by an equal amount.

138.3 Please reference where on lines 124 to 132 of schedule 2.2 the expenditures related to Poly compliance have reduced the Environmental Provision account. Were these costs included with the Rock Bay or the asbestos transfers? If yes, please provide a breakdown.

138.4 Please explain what the deferred additions on line 126 of schedule 2.2 relate to.

138.5 Please explain why the Environmental Provisions regulatory account is being amortized into rates (recovery) as set out on line 131 of schedule 2.2.

139.0 **Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Exhibit B-1-1, p. 7-36 to 38; Appendix A, schedule 2.2
Future Removal and Site Restoration (FRSR) regulatory account

On page 7-37 of the Application, BC Hydro states that the FRSR account is being drawn down as actual expenditure are made.

139.1 Please confirm, or explain otherwise, that as the expenditures are made and the costs are drawn down they are not recorded as an operating costs expense.

139.2 Historically, has BC Hydro been approved to recovered actual dismantling costs through the FRSR? Please discuss.

139.3 Please confirm or explain otherwise that if the Commission approves BC Hydro's request for the account to defer, on an annual basis, any variance between planned and actual dismantling costs, the account will be a "Cash Variance Account" and not a "Benefits Matching Account".

139.3.1 Please discuss fully how this request meets BC Hydro's criteria as set out on page 7-10 of the Application. Please ensure you address each of the five items listed as well as risk/reward consideration.

139.4 Please confirm, or explain otherwise, that once the account is drawn down to $0 at the end of F2017, any further dismantling costs will be included in operating cost, unless there is a separate approval for BC Hydro to capture the variance between actual and forecast in the regulatory account

140.0 **Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Exhibit B-1-1, pp. 7-9, 7-28 to 31; Appendix A, schedule 2.2, 5 and 5S; Order G-148-15
Non-Current Pension Costs regulatory account

Baselines and Operating Expense

On Table 7-3 BC Hydro sets out the regulatory account baselines for Non-Current Post-Employment Benefits (PEB)-Pension and Current PEB – Operating.

140.1 Are the forecast Current and Non-Current PEB costs included in forecast operating costs during the test period? If not, please explain why not. If yes, what line items on schedule 5 and 5S are included?

140.2 Please explain why the baseline for Non-Current PEB as set out in Table 7-3 is a negative.

140.3 For each component currently approved to be captured in the Non-Current Pension Costs regulatory account please provide a table that reports the forecast and actual expense for F2012–F2016 and for forecast expense for F2017–F2019. Please ensure the table distinguishes between Pension and Other PEB.

140.4 Is the amount shown in Table 7-3 the total forecast Current PEB expense for the test period? If not, please provide the total forecast Current PEB expense for each of F2017–F2019. Please distinguish between Pension PEB and Other PEB.

Current Service Cost Variance

BC Hydro is requesting that the Pension regulatory account be approved to capture the variance between the forecast costs and the actual costs related to the operating portion of the post-employment benefits current pension costs.

140.5 Please confirm, or explain otherwise, that BC Hydro is requesting to capture the variance between forecast and actual Current Service Costs for Pension PEB in the Pension Regulatory Account.

140.5.1 How is BC Hydro proposing the variance between forecast and actual Current Service Costs for Other PEB be treated?

140.6 Please discuss fully how this request meets BC Hydro's criteria as set out on page 7-10 of the Application. Please ensure each of the five items listed as well as the risk/reward consideration is addressed.

140.7 Please confirm, or explain otherwise, that upon approval BC Hydro will be entitled to recover the actual pension expense relating to all the components in the Pension PEB and the Other PEB expense.

140.8 What is the proposed amortization period for the variance related to the current service costs? If not one year, please explain fully why a variance relating to a current period operating expense should be amortized over a period greater than one year.

140.9 Please explain the advantages and disadvantages of having a separate regulatory account to

record the non-current PEB variances and the current PEB variances.

Change in forecast methodology

On page 7-30 of the Application, BC Hydro is requesting approval to a change the forecast methodology for the current service costs effective F2017 and ongoing.

140.10 Please confirm, or explain otherwise, that the forecast Current PEB reported in Table 7-3 is calculated under the proposed change. What would the balance be without reflecting the change in the forecast methodology?

140.11 Please confirm, or explain otherwise, that the proposed change will impact regulatory accounting only and not financial reporting.

140.11.1 If not confirmed, please explain what accounting standard allows this treatment.

140.11.2 If confirmed, please discuss if any complications may arise in tracking the variance between forecast and actual Current PEB if BC Hydro is using a different forecast for regulatory purposes.

140.12 If the Commission does not approve BC Hydro's request to defer the variance between forecast and actual current service costs to the regulatory account, will this have any impact on BC Hydro's request to change the forecast methodology for the current service cost?

Recovery of Actuarial Gain

On page 7-31 of the Application, BC Hydro requests approval for the actuarial gain (which is forecast to be transferred to the Pension Costs regulatory account in F2017 as a result of using the forecast discount rate of 4.38 percent) to be amortized, beginning in F2018, over a 12-year period.

140.13 What is the amount of the actuarial gain that is forecast to be transferred to the Pension Cost regulatory account in F2017? Please reference the line in Appendix A, schedule 2.2.

140.14 Is the gain a result of the new forecast methodology being requested for the current service costs?

140.15 Will this actuarial gain be reported for financial reporting purposes or is it only for regulatory accounting purposes?

140.16 Please explain the Other Comprehensive Income (OCI) adjustment of $335.7 million in F2017 on line 115 of schedule 2.2.

140.17 Please explain the $10 million addition in F2017 on line 116 of schedule 2.2.

140.18 Please provide a continuity schedule showing the detailed amortization (recovery) calculations for $59.3 million in F2017 and $31.3 million in both F2018 and F2019.

140.18.1 For each of the requests on page 7-31, bullet points 1, 3 and 4, relating to approval for amortization periods, please reference the related amortization expense in the continuity schedules.

140.19 For F2017, F2018 and F2019, please identify the portion of the Beginning of the Year balance on line 113, schedule 2.2 that relates to each of the items in bullet points 1, 3 and 4 as set out on page 7-31.

Compliance with Order G-148-15

On page 7-29 of the Application, BC Hydro states that "By Order No. G-148-15 the British Columbia Utilities Commission approved the deferral of the fiscal 2016 variance [relating to the current pension costs] to the Non-Current Pension Cost Regulatory Account for future recovery, with the disposition of the variance to be addressed by BC Hydro in its next revenue requirements application."

140.20 Please explain specifically where in the Application the amortization of the $17.2 million is addressed. If not specifically addressed, please explain.

141.0 **Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Exhibit B-1-1, p. 7-32; Direction No. 7; Order G-53-02
First Nations Costs regulatory account

Order G-53-02 approved the capitalization (deferral) of ongoing negotiation and litigation costs for First Nations, the costs of settlements arising from those negotiations and the amortization of those cost over a ten-year period.

On page 7-32 of the Application, BC Hydro states "Settlement payments transferred to the First Nation Costs Regulatory Account from the First Nations Provision Regulatory Account are not amortized or recovered, pending British Columbia Utilities Commission approval to do so."

Pursuant to Order G-11-08, BC Hydro must submit an application when a settlement is complete, for the accounting treatment of the final amount of the aggregate loss provision in respect of any settled claim and the manner in which, if any, the amounts may be recovered in rates.

Direction No. 7 (11)(d) prescribes that the Commission must not disallow for any reason recovery in rates that costs incurred with respect to the First Nations settlements.

Direction No. 7 defines "First Nations Settlements" to mean the settlement of litigation between the authority and the Tsay Ken Dene and Kwadacha First Nations, and the settlement of damages and claims by the St'at'imc First Nations against the authority as agree to between the authority and the First Nation on August 31, 2009, November 27, 2008, and May 10, 2001, respectively.

Negotiation Costs

BC Hydro request that starting in F2017, and on an ongoing basis, actual negotiations cost will be deferred to this account each year, and actual negotiation costs will be recovered from this account.

141.1 Please confirm, or explain otherwise, that BC Hydro is proposing that negotiation costs are directly added to the regulatory account and are not included operating costs. If confirmed please explain why this is appropriate. Is this treatment consistent with the historic treatment of negotiations cost?

141.1.1 Are any of the forecast First Nations negotiation costs in the test period included in operating costs? If yes, please reference the line in schedule 5, Appendix A, where they have been included.

141.1.2 Please provide a table that shows the forecast and actual First Nations negotiation costs for F2012–F2016 and the forecast costs for each of F2017 through F2019. Please ensure that the variance between forecast and actual for F2012–F2016 agrees to the additions

in the NHDA and if not, please explain the reason for the variance.

BC Hydro further states that: as a result, variances between forecast and actual negotiation costs will not be deferred to the First Nations Cost Regularly Account or the NHDA as BC Hydro believes that it should bear the risk.

141.2 Given that BC Hydro is requesting that the actual negotiation costs be added First Nations Cost Regulatory Account, please confirm that the actual cost will then be recovered from ratepayers. If not, please explain.

Recovery of Settlements

141.3 BC Hydro states on page 7-33 of the Application that Order G-48-14 directed that amortization of specific amount in F2015 and F2016. Did this amortization include the amortization of any settlements not included in the definition of "First Nations Settlements" as set out in Direction No. 7?

BC Hydro requests approval for the actual F2016 closing balance related to settlement payments and negotiation costs incurred prior to F2015 to be recovered in rates over an eight-year amortization period commencing in F2017.

141.4 Which part of the F2016 $132.8 million ending balance relates to pre F2016 costs? Please breakout the amount relating to (i) negotiation costs and (ii) settlement costs. For the proportion relating to settlement costs, please disclose which settlement it relates to and which First Nations the settlement is for.

141.4.1 For any settlement not included in the definition of "First Nations Settlements" as set out in Direction No. 7, is BC Hydro requesting specific approval to recover that settlement as required by Order G-11-08?

BC Hydro requests approval for the actual F2016 closing balance related to lump settlement payments incurred in F2016 to be recovered in rates over a 9 years amortization period commencing in F2017.

141.5 Which part of the F2016 $132.8 million ending balance relates to costs incurred during F2016?

141.6 Please break out the F2016 settlement costs by settlement and explain if the settlement is a lump sum settlement or an annual payment settlement and which First Nation the settlement is for.

141.7 For any settlements made in F2016 not included in the definition of "First Nations Settlements" as set out in Direction No. 7, is BC Hydro requesting specific approval to recover that settlement as required by Order G-11-08?

BC Hydro requests approval for actual lump sum settlement payments and annual settlement payments to be deferred to the First Nations Costs regulatory account effective F2017, and on an ongoing basis.

141.8 To date, have all the settlement costs included in the definition of First Nations Settlements been recorded in the First Nations Costs regulatory account?

141.9 In BC Hydro's view, does Directive No. 7 require the Commission to allow BC Hydro to recover all First Nations Settlement Costs or just those included in the definition?

141.10 Please clarify whether BC Hydro is requesting a blanket approval to recover all current and future lump sum and annual First Nations settlement costs that are not otherwise identified in the definition of First Nations Settlements as set out in Directive No. 7 with no further process?

141.11 If approval for this request is granted, what amortization period is BC Hydro proposing for any new lump sum and annual settlements?

142.0 **Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Exhibit B-1-1, p. 7-32; Appendix A, schedule 2.2
First Nations Provision regulatory account

142.1 For each of F2017–F2019, please provide a breakdown of the Provision balance set out on line 15 of schedule 2.2 for each First Nations claim and identify if they relate to a lump sum payment or an annual payment.

142.1.1 For lump sum payments please disclose when the payment is expected to be made. For annual payments please indicate whether the payments have commenced and when they are expected to be completed.

142.2 For financial reporting purposes, is BC Hydro still required to record a loss provision for First Nation's claims? If yes, is the forecast balance in the provision account equal to the forecast provision for financial reporting? If not, please explain.

142.3 There is a $5.3 million reduction to the First Nations Provision account on line 16 of schedule 2.2 in F2017. This same amount can be traced to schedule 5, line 93. Please explain what the $5.3 million relates to why it is removed from operating costs and deferred to the First Nations Provision. Please explain why there is no such adjustment in F2018 or F2019.

142.4 Do any of the Transfers to Negotiating Costs set out on line 18 of schedule 2.2 between F2009 and F2019 relate to any lump sum payments or annual payments for First Nations settlements that are not otherwise identified in the definition of First Nations Settlements as set out in Direction No. 7? If yes, please explain where approval for their recovery was obtained.

143.0 **Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Exhibit B-1-1, p. 7-41; Appendix A, schedule 2.2
Rate Smoothing regulatory account

Directive No. 7 (7)(h)(i) states that when regulating and setting rates for the authority, the Commission must allow the authority to establish an account for recovery in rates in future fiscal years of the authority those portions of the authority's allowed revenue requirements in a particular year that were not or are not to be recovered in rate in that particular year.

143.1 Please confirm, or explain otherwise, that this clause is referring the Rate Smoothing regulatory account approved in the F2015–F2016 RRA.

143.2 Please confirm, or explain otherwise, that the Rate Smoothing regulatory account will only capture the variance between the forecast revenue requirement and the revenue requirements required to achieve the rate caps as set out in Direction No. 7(9)(2) and no additions will be made to the account relating to the variance between the forecast and actual revenue requirements.

143.3 Please explain why Appendix A, schedule 2.2 shows the additions to the Rate Smoothing account in each year of the test period as an offset to amortization (recovery) and not as an addition? Specifically, please explain why the Rate Smoothing additions are treated as negative recoveries.

143.3.1 For F2012–F2019 please recalculate schedule 2.2 lines 217 to 224 accounting for the Rate Smoothing additions to be treated as Regulatory Account Additions and not

Regulatory Account Recoveries.

143.3.2 In BC Hydro's view, how does this treatment impact the information provided in Appendix 1, schedule 1, lines 13 to 16.

144.0 **Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Exhibit B-1-1, p. 7-26; Appendix A, schedule 5 and 2.2
Real Property Sales regulatory account

144.1 Please explain why there are forecast additions to this regulatory account on line 175 of schedule 2.2 in Appendix A when the forecast on schedule 5, line 91 also includes a forecast for the provision**.**

144.1.1 It appears that the actual forecast is the sum of the forecast in schedule 5, line 91 and schedule 2.2, line 175. If this is correct, please explain why the forecast has not been updated in schedule 5 and the forecast additions in schedule 2.2 eliminated.

145.0 **Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Exhibit B-1-1, pp. 1-9, 7-27
Mining Customer Payment Plan regulatory account

On February 5, 2016, the Province announced a five-year Mining Customer Payment Plan program, under which major mines would be allowed to defer payment of up to 75 percent of two years' worth of their electricity bills, with repayment plus interest as commodity prices recover.

145.1 Please explain why the Mining Customers Payment Plan regulatory account is not included in Appendix A, schedule 2.2. Please confirm, or explain otherwise, that there is no forecast activity in this account during the test period.

145.2 Please confirm, or explain otherwise, that the interest to carry the unpaid electricity bills is included in finance charges and recovered from ratepayers in the test period. If not, please explain. If yes, please quantify for each year.

145.3 Please confirm, or explain otherwise, that the interest rate charged to the mining customer on the unpaid electricity bill is a higher rate than BC Hydro's cost to finance the unpaid balance.

145.4 Please confirm, or explain otherwise, that eventually the interest collected on the unpaid bills will be reflected in the revenue requirements calculation through amortization of the regulatory account.

145.5 To date what is the balance of amount payable to BC Hydro by mining customers under this program?

145.5.1 Has BC Hydro made any assessment for financial reporting purposes (impairment reserve) of what the impairment, if any, may be?

146.0 **Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Exhibit B-1-1, p. 7-40
Smart Metering and Infrastructure regulatory account

146.1 Please confirm, or explain otherwise, that no further additions are expected to be added to the SMI regulatory account given that the program is complete and operational.

146.1.1 If yes, would it be reasonable that the Commission determine this account to be closed upon recovery of the balance? Why or why not?

147.0 **Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Exhibit B-1-1, p. 7-23 and 7-41; Appendix A, schedules 2.2 and 5
Arrow Water System and Provision regulatory account

147.1 When the actual expenditures are incurred and transferred from the provision account to the divesture account, do these costs flow through operating costs and provisions as part of schedule 5 in Appendix A lines 79–84, or anywhere else on schedule 5? If yes, please trace where in schedule 5 the forecast is included. If not included, please explain why not.

On page 7-24 of the Application, BC Hydro states that the cost is estimated at $0.3 million per year and is requesting approval to continue to recover, on an ongoing basis, the annual charges to the regulatory account.

147.2 Please explain how the continuation of the Arrow Water System regulatory variance account meets BC Hydro's criteria set out on page 7-10 of the Application.

147.3 Given that the initial divesture costs have been recovered through the regulatory account and the annual costs are only forecast to be $0.3 million per year, please fully explain why BC Hydro considers it necessary to maintain this regulatory account rather than forecasting the divesture costs as part of operating costs.

147.4 For financial reporting purposes, will BC Hydro be required to record a loss provision liability with regard to the divestiture of the Arrow Water System in F2017–F2019? If yes, is the forecast balance in the provision account equal to the forecast provision for financial reporting? If not, please explain.

148.0 **Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Exhibit B-1-1, p. 7-20
Storm Restoration Costs regulatory account

148.1 Table 7-8 sets out the baseline for Storm Restoration Costs at $6.7 million in each of F2017–F2019. Please provide a table that shows the forecast and actual Storm Restoration Costs for F2011–F2016.

149.0 **Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Exhibit B-1-1, p. 7-28; Appendix A, schedule 2.2
Foreign Exchange Gains/Losses regulatory account

149.1 Please explain why there are forecast additions to the account in F2017, F2018 and F2019.

149.2 Please provide an explanation for the forecast additions and the forecast recovery calculation.

149.3 BC Hydro has classified this regulatory account as a non-cash variance account. If the account is non-cash, please explain why the balance is amortized into rates and recovered as part of the revenue requirements.

149.4 How are these foreign exchange gains and losses treated for financial reporting purposes?

150.0 **Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Exhibit B-1-1, p. 7-36; Appendix A, schedule 2.2
Site C regulatory account

On page 7-36 of the Application BC Hydro states "Notwithstanding that BC Hydro has commenced capitalization of costs, certain costs related to the project may not be eligible for capitalization under

the Prescribed Standards. For example, some legal costs are eligible for capitalization under the Prescribed Standards, but some are not."

150.1 Please confirm, or explain otherwise, that for the purposes of the revenue requirement calculation in each year of the test period, BC Hydro has assumed all costs related to Site C will be capitalized and has not forecast any additions to the Site C regulatory account.

150.2 It appears that BC Hydro anticipates some costs may not be eligible for capitalization; however there are no forecast additions in the Site C regulatory account in the test period. Please explain.

150.2.1 For each of F2017 to F2019, please estimate to the best of your ability what costs may not be eligible for capitalization.

150.3 If the requested change to the scope of the account as set out in Table 7-9 is not approved, how will any costs related to Site C that are not eligible for capitalization be treated and how, if at all, will this affect any other regulatory or deferral account additions and or the actual ROE?

151.0 **Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS**
Exhibit B-1-1, p. 7-40; Appendix A, schedule 2.2
Regulatory account
Capital Project Investigation Costs

151.1 For F2011 to F2016, please provide a table that shows the forecast and actual Capital Project Investigation (CPI) costs.

151.2 For each of F2017 to F2019, where are the CPI costs recorded in Appendix A to the Application?

O. CHAPTER 8 – OTHER REVENUE REQUIREMENTS ITEMS

152.0 **Reference: OTHER REVENUE REQUIREMENTS ITEMS**
Exhibit B-1-1: pp. 8-1 to 8-5; Appendix A, schedules 7, 12 and 13
Direction No. 7
Amortization

On pages 8-1 and 8-2 of the Application, BC Hydro states that the depreciation rates used in this Application are the same as those approved by the Commission with the exception of certain property, plant and equipment (PP&E) at the Burrard synchronous condense facility (Burrard Facility).

152.1 When was last time BC Hydro performed a depreciation study?

152.2 Does BC Hydro plan on performing and filing an updated depreciation study with the Commission prior to, or as part of, the next RRA? If not, please explain.

On page 8-1 of the Application BC Hydro states that PP&E in service is amortized on an individual component-by-component basis over the expected useful lives of the assets using the straight-line method.

152.3 Has BC Hydro considered whether the Equivalent Life Group (ELG) method would better reflect depreciation costs? Will BC Hydro be considering alternate depreciation methods such as the ELG when conducting its next depreciation study?

152.4 Are the depreciation rates and policies used for regulatory accounting purposes the same as those used for financial reporting? For any deviations please identify the difference and explain

why it is appropriate.

152.5 Schedule 12 of Appendix A to the Application shows the calculation for Accumulated Amortization on lines 6 to 16. Please confirm, or explain otherwise, that this relates exclusively to Amortization of Capital Assets as set out on lines 1 to 5 of schedule 7. If not, please explain the relationship between the two schedules.

152.5.1 For F2013 through F2019, please break out the Amortization of Capital Assets total on line 6 of schedule 7 by the same classifications as provided in schedule 12, lines 7 to 15. Please ensure the baseline for Amortization of Capital Additions agrees to schedule 13, line 93 and if not, please reconcile.

152.6 Please provide a table that shows forecast and actual Total Gross Amortization for F2012 through F2016 and forecast for F2017 to F2109. Please indicate the portion of the variance that was recorded in the Amortization of Capital Additions regulatory account for F2012 through F2016. For any variances not recorded in a regulatory account please explain the reason for the variance.

Burrard Facility

BC Hydro is seeking approval for certain depreciation rates at the Burrard Facility as the rates prescribed by Direction No. 7 only applied to F2015 and F2016.

152.7 Please provide a PP&E continuity schedule for the Burrard Facility for F2015 and F2016 and forecast F2017, F2018 and F2019. Specifically, for each of the classes of PP&E assets set out in Direction No. 7, Appendix B and Table 8-1 of the Application, please identify the following: (i) cost, (ii) additions, (iii) retirements, (iv) opening accumulated depreciation, (v) depreciation expense and (vi) the net value. Please ensure that the columns are totaled and include a value for the total depreciation expense for each year relating to these assets.

152.8 Please explain why the depreciation rates set out in Table 8-1 are different from those prescribed in Direction No. 7, Appendix B for F2015 and F2016.

152.9 Please expand Table 8-1 to include the depreciation rates for F2012 to F2015.

152.10 At a high level please explain why the depreciation rates set out in Table 8-1 were selected for F2017–F2019.

152.11 Prior to F2015, were there any other changes to the depreciation rates approved by the Commission as part of the last depreciation study, relating to the Burrard Facility? If yes, please explain.

152.12 For the years F2012 to F2019, please confirm, or explain otherwise, that the depreciation expense Total Gross Amortization set out on line 31 or schedule 7 includes the depreciation expense for the Burrard Facility.

Dismantling Costs

152.13 Please explain the reason for the large variance between forecast and actual dismantling costs over the past five years as set out on line 16 of schedule 7.0.

152.13.1 Were any of these variances captured in a regulatory account? If yes, which one(s)?

153.0 **Reference: OTHER REVENUE REQUIREMENTS ITEMS**
Exhibit B-1-1, pp. 8-6, 8-7; OIC 590
Return on equity

153.1 Order in Council (OIC) 590 approved on July 28, 2016, prescribed the distributed surplus (ROE) dollar amounts for F2017-F2019. In each of the test years what is the annual rate of return on deemed equity that is required in order to achieve the distributed surplus as prescribed in OIC 590?

153.2 Please confirm, or explain otherwise, that the actual ROE will likely be different than the ROE as prescribed in OIC 590. At the end of the test year if the actual ROE is lower or higher than prescribed in OCI 590, please explain how BC Hydro will treat the difference.

153.3 Please update Table 8-5 to reflect the changes prescribed in OIC 590.

154.0 **Reference: OTHER REVENUE REQUIREMENTS ITEMS**
Exhibit B-1-1, pp. 8-7, 8-8 and 8-9; Appendix A, schedules 1 and 8; Direction No. 7
Finance charges

154.1 Please confirm, or explain otherwise, that Gross Finance Charges as set out in in the revenue requirements calculation in Appendix A, schedule 1 is made up of the sum of schedule 8 lines 2-9 and line 12-24.

154.2 Please confirm, or explain otherwise, that the recovery of accretions costs added to the First Nations Settlement Provision, Environmental Provision and Arrow Water Provision are included in Gross Finance Charges.

154.2.1 Given that the accretion is added to the regulatory account and recovered through amortization expense, please explain why it is included in the Gross Finance Charges used to calculate the revenue requirement.

154.3 Are there any non-cash items which attract finance charges that are recovered in the revenue requirements during the test period? If yes, please identify them by reference to the line item on schedule 8 and explain the rationale for their inclusion.

154.4 Please explain why the calculation for Debt Costs-Excluding Planned on line 91 of schedule 8 is a hard coded number? Please show the detailed calculation for the $735.1 million expense in F2017 as well as the calculation for F2018 and F2019.

154.5 Please explain how BC Hydro derived the Weighted Average Cost of Debt (WACD) as set out on line 106 of schedule 8 for each of three test years.

154.5.1 What would the Gross Finance Charges be in each of F2017–F2019 if the WACD decreased by 1 percent, or increase by (i) 0.5 percent, (ii) 1.0 percent or (iii) 1.5 percent?

154.6 Please explain how BC Hydro derived the short term interest rate set out on line 99 of schedule 8 for each of the three test years.

154.7 For F2012–F2016 please provide a table that show forecast and actual finance charges.

154.8 Please expand Table 8-6 to include the planned and actual interest and exchange rates for F2012–F2016.

154.9 Line 61 on schedule 8 shows the dividend paid to the government. Is 100 percent of the dividend paid to the government added to the short term debt calculation in each of the three test periods? If not, please explain.

155.0 **Reference: OTHER REVENUE REQUIREMENTS ITEMS**
Exhibit B-1-1: pp. 8-10 and 8-11; Appendix A, schedules 1 and 6; Direction No. 7
Taxes

155.1 Please confirm, or explain otherwise, that there is no regulatory account that captures the variance between forecast and actual tax expense.

155.2 Please expand Table 8-8 to include forecast and actual data for F2012–F2016 for each of the components that make up the tax expense.

155.3 For F2015 and F2016, please provide a detailed calculation for actual Grants in Lieu and School Taxes and for F2017 to F2019, please provide a more detailed calculation for the forecast as set out in Table 8-8.

155.4 Please explain how BC Hydro interprets Direction No. 7 (4)(b), which states that the Commission must ensure that rates allow the authority to collect sufficient revenues to enable the authority to meet all its tax obligations.

155.4.1 Specifically, does Direction No. 7 require the Commission to establish a regulatory account for tax variances to allow the authority to collect sufficient revenues to meet all its tax obligations if the actuals differ from the forecast?

156.0 **Reference: OTHER REVENUE REQUIREMENTS ITEMS**
Exhibit B-1-1: pp. 1-42, and 8-11; Appendix A, schedule 15
Non-Tariff Revenues

156.1 Is there a deferral or regulatory account that captures the variance between forecast and actual costs for each of the various components included in the Non-Tariff Revenues as set out in schedule 15? If yes, please identify the deferral or regulatory account(s).

156.2 For F2012–F2019, please summarize the Non-Tariff Revenues set out in schedule 15 by: Amortization of CIAC, Secondary Revenues, External OATT, Corporate General Rent, Power Factor Surcharges, Late Charges and Other. Please include both the forecast and actuals for F2012 through F2016.

156.3 Please explain what Smart Metering & Infrastructure Impact set out on line 19 and Other Operating Recoveries set out on line 22 of schedule 15 relate to and explain why the forecast in each of the test periods is less than the actual in F2015 and F2016.

156.4 Please explain why the forecast Interconnection Charges on line 9 of schedule 15 are significantly lower than in the previous five years.

156.5 Page 1-42 of the Application states that the increase in Non-Tariff Revenues is partially due to an increase in forecast liquid natural gas (LNG) revenues of approximately $11 million. Please explain why LNG revenues are considered Non-Tariff Revenues and explain why LNG is shown as a separate line item (line 21) in Appendix A, schedule 1.

157.0 **Reference: OTHER REVENUE REQUIREMENTS ITEMS**
Exhibit B-1-1: pp. 8-11, 8-12, and 8-14; Appendix A, schedule 3
Inter-Segment revenues

157.1 Is there a deferral or regulatory account that captures the variance between forecast and actual for each of the three components included in Inter-Segment Revenues as set out in Table 8-10? If yes, which account(s)?

157.2 Please expand Table 8-10 to include forecast and actuals for F2012–F2016.

157.3 On page 8-14 of the Application, BC Hydro states that it has allocated business support costs to Powerex for F2017–F2019 in accordance with the F2009–F2010 RRA. Has the allocation for the test period been performed in accordance with the F2009–F2010 RRA approved allocation? If not, please explain.

157.4 Please explain why the allocation to Powerex is lower in the test period than the actual allocation was in both F2015 and F2016.

157.4.1 Is the variance between the forecast and the actual Powerex-Corporate Allocation captured in the Trade Income Deferral Account (TIDA) or any other regulatory account? If yes, which account?

157.5 Please explain why the forecast for Powerex PTP Charges in F2017 as set out in Table 8-10 are forecast to be almost $20 million less than in F2016.

157.6 Please explain how the forecast for the BC Hydro PTP Charges, as set out in Table 8-10, of $47.8 million in F2017, $51.4 in F2018 and $45.9 million in F2019 were determined, considering that the previous two year average is $23.75 million?

157.7 Please explain the reason for the variability in the forecast PTP charges during the test period for both Powerex and BC Hydro.

157.8 What is the average OATT rate increase, specifically relating to PTP charges, in each of F2017 through F2019?

158.0 **Reference: OTHER REVENUE REQUIREMENTS ITEMS**
Exhibit B-1-1, p. 8-12; Appendix A, schedule 1
Subsidiary Net Income – Powertech Net Income

158.1 For the each of F2017–F2019, please explain how the forecast for Powertech Net Income, as set out in Appendix A, schedule 1, line 18 is derived.

159.0 **Reference: OTHER REVENUE REQUIREMENTS ITEMS**
Exhibit B-1-1, p. 8-14; Appendix A, schedule 5
Provisions and Other

The Application on page 8-14 states: "'Provisions and Other' refers to gains and losses on tangible and intangible assets, non-cash provisions expenses and other cost that are not within the scope of other Nature View expense items on BC Hydro's financial statements."

159.1 Please explain what is meant by a non-cash provision expense.

In Appendix A, schedule 5, BC Hydro includes $66 million, $61 million and $57.1 million in provisions in F2017 through F2019, respectively, which are included in the Gross Operating Costs and are recovered in the revenue requirements.

159.2 Please include a detailed explanation for each of the provision listed on lines 79, 80, 81 and 84 of schedule 5 and a rationale for the forecast in each of the test years.

159.2.1 On a line-by-line basis, are any of the variances between forecast and actual for these provisions captured in a deferral or regulatory account? If yes, which one(s)?

159.2.2 It appears that on average over the past five years BC Hydro has under forecast these

provisions by approximately $15 million. Please explain the reasons for the variance.

159.3 Lines 87 to 90 relate to forecast dismantling costs. Please confirm, or explain otherwise, that the forecast F2017 dismantling costs also include $8.6 million (ending balance of the FRSR deferral account).

159.3.1 Please provide explanations for the forecast dismantling costs of $30.6 million plus $8.6 million in F2017, $35.7 million in F2018, and $30.7 million in F2019.

159.4 What were the actual dismantling costs in F2012–F2016 and were they recorded in operating costs or as an adjustment to the Future Removal and Site Restorations regulatory account?

On page 8-14, BC Hydro states that for external reporting purposes, transfers to the Rate Smoothing Account are included in Domestic Revenue.

159.5 Given that the amounts transferred to the Rate Smoothing Account in a given year will not be recovered in rates in that particular year and therefore do not result in actual revenues, please explain how the Prescribed Standard allow for the transfers to the Rate Smoothing Account to be reported as revenue in F2017, F2018 and F2019. Please reference the applicable accounting standard that allows for this treatment.

159.5.1 In future years when the Rate Smoothing Account is amortized into rates and recovered as revenue please explain how that revenue will be treated for financial reporting purposes.

159.6 Will any other regulatory account additions be treated as Domestic Revenue for financial reporting purposes in the test period? If yes, please identify which additions and quantify the total in each test year.

160.0 **Reference: OTHER REVENUE REQUIREMENTS ITEMS**
Exhibit B-1-1, Appendix A, schedule 1; Direction No. 7
Schedule 1

160.1 Line 20 of schedule 1 sets out Other Utility Revenues. Please confirm, or explain otherwise, that these revenues relate to Seattle City Lights and the Skagit Valley Treaty.

160.1.1 Please confirm, or explain otherwise that any variance between forecast and actual is deferred to the NHDA.

160.1.2 Please explain why this is shown as a separate line item on schedule 1.

160.1.3 Please explain why the forecast Other Utility Revenues in F2017–F2019 of approximately $12.2 million (set out on line 20 of schedule 1) is considerably lower than the previous five year actual average of $16.6 million.

160.2 Without consideration of the rate cap set by Direction No. 7, in each of the test years what change in (i) an expense item and (ii) a capital addition, would result in a 1 percent change in the rate?

160.3 Please confirm, or explain otherwise, that without consideration of the Rate Smoothing regulatory account the revenue deficiency would be $381.9 million in F2017, $614.3 million in F2018 and $773.6 million in F2019 (line 29 plus line 34 of schedule 1).

P. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENTS

161.0 **Reference: CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENTS**
Exhibit B-1-1, Section 9.1, p. 9-1; BC Hydro 2015 Rate Design Application – F2016 Cost of Service Study and Rate Class Segmentation Negotiated Settlement Agreement, Order Number G-47-16
Transmission Revenue Requirements (RR) – Methodology

On page 9-1 of the Application, BC Hydro states:

> The Transmission Revenue Requirement is the sum of BC Hydro's net transmission function costs as calculated using a cost of service methodology that is consistent with the method used in BC Hydro's previous revenue requirement applications as well as the method previously used by the British Columbia Transmission Corporation. The calculation of the Transmission Revenue Requirement remains consistent with the British Columbia Utilities Commission's 1998 Decision accompanying Order No. G-43-98 related to BC Hydro's Application for Approval of Wholesale Transmission Services.

161.1 Please confirm, or explain otherwise, that the methodology used to calculate the Transmission RR for F2017-F2019 is consistent with methodology approved for F2012–F2014 pursuant to Order G-77-12A and F2015–F2016 pursuant to Order G-48-14.

161.1.1 If not, please explain, and provide a rationale, for the difference between the methodology put forward in this Application and the methodologies approved for F2012-F2016.

161.2 BC Hydro's current cost of service study was approved in a negotiated settlement agreement as part of the ongoing Rate Design Application (Order G-47-16). Please confirm that the results of that cost of service study (COSS) are reflected in the Transmission RR calculation for F2017-F2019.

162.0 **Reference: CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENTS**
Exhibit B-1-1, pp. 9-5, 9-8, 9-9, 9-10, Table 9-1; Order G-47-16
Transmission RR – Amortization (DSM), Technology and Customer Service, Generation Related Transmission Assets

<u>Amortization</u>

Line 3 of Table 9-1 shows the Amortization allocated to the Transmission RR. BC Hydro states on page 9-9 of the Application, "The amortization assigned to gross transmission includes amortization related …. to 10 per cent of demand-side management [DSM] amortization [as directed by Order No. G-43-98m]."

Order G-47-16, Appendix A, page 14 of the BC Hydro 2015 Rated Design proceeding states, "Parties support the BC Hydro proposal (90% generation/5% transmission/5% distribution), subject to BC Hydro revisiting the functionalization between generation, transmission, and distribution in the F2019 COSS [Cost of Service Study] and RDA [Rate Design Application]."

162.1 To what extent does the recent COSS impact the calculation of the Transmission RR relating to DSM amortization in the test period? Please explain.

Technology and Customer Service

Line 18 of Table 9-1 shows the internal allocations adjustment from transmission relating to technology and customer service costs. The table shows an increase in this allocation from $185.1 million in fiscal 2016 (actual) to $214.7 million in fiscal 2017 (plan).

162.2 Is the increase due to a change in the percentage allocated to the Transmission RR or have the base technology and customer service costs increased? If the increase is due to either of these factors please quantify. If not, please explain the reason for the increase.

Generation Related Transmission Asset

Line 13 of Table 9-1 shows the internal allocations adjustment from transmission relating to Generation Related Transmission Assets. On page 9-10 of the Application, BC Hydro states: "By Letter No. L-92-07 the British Columbia Utilities Commission accepted that a fixed charge of $43.3 million was appropriate for Generation Related Transmission Asset costs, and that re-evaluations of Generation Related Transmission Asset costs were not required."

162.3 Have any additional generation related transmission assets been created since 2007? If yes, please explain why this allocated remains appropriate.

163.0 **Reference: CHAPTER 9 – TRANSMISSION REVENUE REQUIREMEN*T*S**
Exhibit B-1-1, Section 9.3.2, Table 9-4, p. 9-16
Network integration transmission service (NITS)

163.1 Please expand Table 9-4, which sets out the calculation of the monthly NITS charges to include F2012, F2013 and F2014.

164.0 **Reference: CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENTS**
Exhibit B-1-1, Section 9.5, p. 9-20
Proposed OATT Rates

164.1 Is the calculation of the OATT rates set out in Table 9-8 (which recovers the Transmission RR) consistent with the most recent Commission order(s) approving the calculation of the OATT rates?

165.0 **Reference: CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENTS**
Exhibit B-1-1, Section 9.4, p. 9-19, Table 9-7
External PTP revenues forecast

On page 9-1 of the Application, BC Hydro states, "[a]s the main users of the transmission system, BC Hydro and Powerex account for approximately 98.5 per cent of the revenue collected through the OATT. External transmission customers account for the remaining approximately 1.5 per cent of revenue."

On page 9-19, BC Hydro states, "The forecast of external short-term Point-To-Point volumes are based on fiscal 2016 actual volumes. The internal short term Point-To-Point volumes are based on the energy studies model."

165.1 Please explain the appropriateness of the assumption that external short term point-to-point volumes will remain at actual fiscal 2016 levels.

165.2 Please explain, in reference to Table 9-7, how external transmission customers' percentage share of the recovery of the Transmission RR is expected to change, if at all, throughout the test period.

165.3 In forecasting the total external PTP revenues, was consideration given to a potential increase due to any BC based Independent Power Producers that do not have their contracts renewed with BC Hydro during the test period who may want to sell into the market?

165.3.1 If not, please explain why not. If yes, please explain the impact on the forecast.

166.0 **Reference: CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENTS**
Exhibit B-1-1, Section 9.3.2, Table 9-4, p. 9-16
Impact on the Total Revenue Requirements

On page 9-15 BC Hydro states that the Transmission RR is collected through BC Hydro's OATT rate schedules for the following services: Network Integration Transmission Services (NITS), Point-to-Point Transmission Services (PTP) and Ancillary Services (AS).

Tables 9-4, shows that for F2017 the Transmission RR is $926.7 million, NITS are $825.1M, PTP $93.3 million and AS is $5.4 million.

In Appendix A of the Application (regulatory schedules) the Non-Tariff Revenues in F2017 includes $14.1 million collected from External OATT and F2017 Inter-Segment Revenues includes $11.8 million for PTP charges recovered from Powerex and $47.8 million for PTP charges recovered from BC Hydro largely related to Skagit Valley Treaty obligation.

166.1 Please confirm that in F2017 the Transmission RR credited to the calculation of the Total Revenue Requirements as set out in Appendix A, schedule 1, is $85.3 million.

166.1.1 If not, please identify the line items and the corresponding dollar values in Appendix A schedule 1 (and any supporting schedules) where any additional OATT revenues impact the calculation of the Total Revenue Requirement.

166.2 Please confirm, or explain otherwise, that the remaining portion of the Transmission RR ($841million in F2017) is recovered through the Total Revenue Requirements because that portion is used to deliver electricity to BC Hydro customers.

166.3 Please confirm, or explain otherwise, that the variance between the forecast and actual Powerex and BC Hydro Skagit Valley Treaty PTP charges are deferred to the NHDA.

166.4 Is the variance between forecast and actual Non-Tariff Revenues collected from the External OATT deferred to any deferral or regulatory account? If yes, which one?

Q. CHAPTER 10 – DEMAND SIDE MANAGEMENT EXPENDITURES

167.0 **Reference: DEMAND SIDE MANAGEMENT EXPENDITURES**
Exhibit B-1-1, p. 10-1, Appendix BB, p. 2; FortisBC Energy Utilities (FEU) 2014 Long Term Resource Plan (LTRP) Decision (FEU 2014 LTRP Decision), p. 25; UCA, s. 44.1, 44.2
Legislative framework

On page 10-1 of the Application, BC Hydro requests acceptance of the F2017–F2019 demand side measures (DSM) expenditure schedule under section 44.2 of the UCA. Section 44.1 of the UCA addresses long-term resource and conservation planning.

The Minister's Letter of Support on DSM (Appendix BB to the Application) states on page 2: "… [the] government supports the proposed DSM expenditures for the Fiscal 2017 to Fiscal 2019 period as a prudent and responsible evolution of the DSM plan approved by government as part of the 2013 IRP. I also expect BC Hydro to consult on a new long-term conservation target, beyond 2020, through the 2018 [Integrated Resource Plan (IRP)] process."

On page 25 of the FEU 2014 LTRP Decision (G-189-14) the Commission states: "Ideally, the utility should first file an LTRP and then file a DSM expenditure schedule under section 44.2 of the UCA. This allows the utility to receive guidance regarding the overall size and approach of the DSM funding proposal prior to filing the detailed DSM expenditure schedule."

167.1 For DSM, please explain the interaction between section 44.1 and 44.2 of the UCA. Specifically, which areas of DSM are typically addressed under section 44.1, and which are addressed under section 44.2?

167.1.1 Please discuss the timing of the next BC Hydro IRP and the consultative process BC Hydro plans to follow related to DSM.

167.2 Please discuss what level of weight BC Hydro considers the Commission should give to the government letter attached at Appendix BB to the Application when considering alignment of the DSM expenditure schedule with BC Hydro's IRP.

Section 44.2 (1) of the UCA states that a public utility <u>may</u> file with the Commission an expenditure schedule, and section 44.2 (3) and (4) states that, after its review, the Commission must accept the schedule, reject the schedule or accept or reject part of a schedule. (Emphasis added)

167.3 Please explain whether, under section 44.2 of the UCA, the Commission can direct BC Hydro to: (i) file a DSM expenditure schedule; (ii) make additions to a DSM schedule (such as add or expand DSM programs); and/or (iii) change the design of a particular DSM program (for example, the incentive level or eligibility criteria) without rejecting the budget of that program.

167.4 Please discuss the practical effect on BC Hydro's proposed DSM spend if the DSM expenditure schedule was rejected, in whole or in part, on the basis that spending levels were too low. Specifically, (i) what ability would BC Hydro have to increase the spending (in terms of timing or other constraints), and (ii) could DSM spending levels over F2017–F2019 actually decrease as a result of rejection of the expenditure schedule?

167.5 Does BC Hydro consider that a two year DSM expenditure request (F2017–F2018) would result in better alignment with the updated conservation potential review going forward? Please explain.

167.6 Is BC Hydro requesting approval to transfer DSM funds between categories or between years? If not, why not? If yes, please describe and justify the funding transfer rules requested.

168.0 **Reference: DEMAND SIDE MANAGEMENT EXPENDITURES**
Exhibit B-1-1, p. 10-33; BC Hydro 2013 IRP, pp. 3-24 – 3-38, 6-25, 6-26, 9-10, 9-16, 9-17
Consistency with the IRP – data review

On pages 9-16 and 9-17 of the BC Hydro 2013 IRP, BC Hydro recommended DSM Option 2 and described the principles employed to adjust expenditures for DSM programs over the next three years while maintaining the potential to achieve higher DSM savings in the long term.

On page 9-10 of the BC Hydro November 2013 IRP, BC Hydro included F2014–F2016 and F2014–F2021 target DSM spend. On pages 3-24 to 3-28 of the 2013 IRP, BC Hydro compares energy and capacity DSM options and on table 6-5 (p. 6-25) shows Mid savings level for DSM options and percentage of load growth. Figures 6-3 and 6-4 (p. 6-26) of the Application show energy and capacity gaps.

168.1 Please update figures 3-1, 3-2, 3-3, 3-4, 3-5 (pages 3-5 to 3-6), figures 6-3 and 6-4 and Table 6-5 (pages 6-25, 6-26) in the F2013 IRP to show: (i) DSM Option 2 results as included in the 2013 IRP compared to (ii) updated DSM results (actual to F2016 and as requested for F2017 onwards).

168.2 In table form, consistent with Table 10-7 of the Application (p. 10-33), please compare DSM spending and GWh energy savings for the following periods: (i) F2014 to F2016 as included in the 2013 IRP with (ii) actual F2014 to F2016 results. Please also show percentage differences.

168.2.1 Where BC Hydro has fallen short of its DSM energy savings target or spend by 20 percent or more in any of the categories, please explain why it occurred (quantitatively and qualitatively) and what action BC Hydro plans to take to address the shortfall.

168.3 In table form, consistent with Table 10-7 of the Application, please compare DSM spending and GWh energy savings for: (ii) F2017 to F2019 as anticipated in the 2013 IRP; and (ii) F2017 to F2019 as proposed in this Application. Please also show percentage differences.

168.3.1 Where percentage funding changes for any DSM category is significantly different from the average percentage change for the total DSM spend, please explain why.

169.0 **Reference: DEMAND SIDE MANAGEMENT EXPENDITURES**
Exhibit B-1-1, pp. 1-6, 10-16, 10-22, 10-23; BC Hydro 2013 IRP, p. 3-19, 3-20; CEA, s. 2
Consistency with the IRP – rationale for change

On Table 3-4 in the 2013 IRP (pp. 3-19, 3-10) BC Hydro describes the near-term program adjustments for DSM Option 2 (for example, for the Smart Meter program to defer in-home display but to continue to support the web portal). BC Hydro compares the 2013 IRP DSM Plan to the proposed DSM Plan in Table 10-5 (p. 10-22) of the Application.

Table 10-6 on page 10-23 of the Application shows the percentage of load growth at F2021 be met by DSM under the high load forecast. The result is 59 percent (proposed DSM plan, high load forecast with LNG) compared to the *Clean Energy Act* (CEA) objective target of 66 percent.

On page 10-16 of the Application, BC Hydro states that it has made changes to its DSM plan to "align with this expanded energy management scope and company-wide priorities, as well as the 2013 10 Year Rate Plan and our changing customer system needs." On page 1-6 of the Application, BC Hydro includes as a key goal: "Rates will continue to be affordable."

169.1 Please explain how (i) expanded energy management scope; (ii) company-wide priorities; (iii) the 2013 rates plan and (iv) changing customer system needs contributed to the changed F2017–F2019 DSM plan.

169.2 Please describe the DSM principles/approach employed in the 2013 IRP to adjust DSM expenditures over the F2014 to F2016 period, and explain whether they have changed for this Application. Specifically, is it only the inputs into the IRP that have changed for this Application (and if so, which ones), or has BC Hydro changed the DSM principles/weightings used to develop its 2017–2019 DSM plan (if so, please describe).

169.2.1 Please update Table 3-4 in the BC Hydro 2013 IRP to include two additional columns showing (i) actual program results/adjustments made for F2014–F2016 and (ii) adjustments proposed for F2017–F2019.

169.3 Please explain why (i) BC Hydro includes as one of its four goals a focus on affordable rates rather than affordable bills and (ii) whether the emphasis placed on affordable rates versus affordable bills has changed in this Application compared to the 2013 IRP.

169.3.1 Has BC Hydro given a reduced weight to (i) providing broad access for customers to participate in DSM programs, and (ii) minimizing missed DSM project opportunities, in this Application compared to the F2013 IRP? If yes, please explain why.

169.3.2 Is BC Hydro confident that it would still be able to meet the CEA '66 percent reduction in demand target by the year 2020' target with the proposed DSM expenditure schedule if the 'high load forecast with LNG load growth occurred'? Please explain.

169.4 For each rate class, please provide and explain the marginal revenue assumption (in ¢/kWh) used to estimate the directional rate impact of the alternative DSM portfolios in Table 10-5 of the Application.

169.5 Please estimate the overall rate change that would result if BC Hydro's F2017–F2019 DSM spend equaled that proposed in the 2013 IRP. Please also provide a breakdown of the total rate affect showing the effect of (i) the increased DSM amortization and (ii) the reduction in energy sold by customer class.

170.0 **Reference: DEMAND SIDE MANAGEMENT EXPENDITURES**
Exhibit B-1-1, pp. 3-31, 10-19
Consistency with the IRP – reference price

BC Hydro uses $36 per MWh as the avoided energy cost stream for the Utility Cost Test (UCT) screening filter on page 10-19 of the Application. Table 3-8 of the Application (p. 3-31) shows that BC Hydro expects to be in energy surplus until F2032.

170.1 Please estimate the average persistence of savings (in years) of BC Hydro's F2017–F2019 DSM proposal.

170.2 Please provide further information to support the $36 per MWh avoided energy cost estimate used by BC Hydro for the UCT screening filter and describe the key assumptions.

170.2.1 Does the $36/MWh avoided cost estimate assume BC Hydro is in an energy surplus position over the time period when BC Hydro is achieving energy savings from the DSM program? Please explain.

170.2.2 Please explain whether the $36/MWh estimate assumes surplus energy is short-term, non-firm, non-clean energy, and whether a higher price could be achieved if the surplus energy was sold as a clean, longer-term firm product (for example, to FortisBC).

170.3 Please estimate, in $/MWh for each year over the next 15 years, BC Hydro's avoided energy cost (i.e. the $ effect on BC Hydro's cost of energy of a DSM program delivering energy savings). Please also provide the levelized avoided energy cost over the next 15 years.

170.3.1 Please explain whether there has been any material change in the estimated levelized avoided energy cost from 2013 to 2016 (if there has been, please explain).

170.4 Please estimate a capacity screening filter in $-kW-year using a methodology consistent with that used to develop the $36/MWh estimate used for DSM energy savings (i.e., based on the

market value of surplus capacity). Please describe supporting assumptions.

171.0 **Reference:** **DEMAND SIDE MANAGEMENT EXPENDITURES**
Exhibit B-1, p. 3-46, Appendix X, p. 2; Exhibit B-2, Attachment 3, p. 4; DSM Regulations, s. 4
Long run marginal cost (LRMC) – energy

BC Hydro provides its avoided energy cost (electricity and natural gas) assumptions in Appendix X to the Application, and estimates avoided electric energy costs at $85 per MWh (F2013 $) for F2015–F2033. BC Hydro states on page 3-46 of the Application that the avoided cost of greenfield clean or renewable IPPs is $100/MWh (F2015).

Section 4 (1.1)(b)(ii) of the DSM Regulations requires that, in applying the total resource cost test (TRC), the avoided electricity cost, in addition to the avoided capacity cost, is "an amount that the commission is satisfied represents the authority's long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia."

Table 1 (page 4) of BC Hydro's F2016 DSM Annual Report (Exhibit B-2, Attachment 3), show expenditures and incremental energy electricity savings for F2016.

171.1 Please describe the portfolio of energy resources used to arrive at the avoided electric energy ($85/MWh) estimate, and demonstrate that it represents (i) long-term energy supply (please explain the time period used) and (ii) BC clean energy supply. If the portfolio includes DSM, please (i) explain whether the DSM cost included is the total resource cost or the utility cost and justify the approach used and (ii) explain how the cost of DSM can be used as an input in evaluating the cost-effectiveness of DSM.

171.1.1 Please explain whether the methodology used to calculate the energy LRMC is consistent with the approach used in the 2013 IRP. If the methodology has changed, please describe. If the inputs have instead changed (for example, the weighting or values used in the avoided cost portfolio) please describe the change.

171.1.2 Please explain whether (and if so, how) the energy LRMC estimate includes the benefit of avoided: transmission losses, distribution losses and/or ancillary services.

171.2 In a format consistent with Table 1 in the BC Hydro's F2016 DSM annual report, please provide the TRC result (in $/MWh) for each DSM expenditure category for the period F2013 to F2016, and the period F2017–F2019.

171.3 Please explain whether an increase in the LRMC estimate would have any material effect on BC Hydro's proposed DSM portfolio. Specifically, is the reduction in the DSM portfolio primarily due to TRC (LRMC), UCT (LRMC), UCT (Market Price) or rate impact considerations?

171.4 Please provide and support the LRMC of gas estimate described on page 10 of Appendix W to the Application.

172.0 **Reference:** **DEMAND SIDE MANAGEMENT EXPENDITURES**
Exhibit B-1, Appendix X, p. 2; Exhibit B-1-2, Attachment 3, p. 9; Exhibit B-2, Attachment 3, p. 9; FortisBC Inc. (FBC) 2017 DSM Expenditure Application dated August 8, 2016 (FBC 2017 DSM Application), Appendix C
LRMC – capacity

BC Hydro provides its avoided capacity costs and generation system reserve margin in Appendix X to the

Application. FBC included a 2016 Deferred Capacity Expenditure Study (FBC 2016 capacity study) at Appendix C to its 2017 DSM Expenditure Application.

On page 9 of the BC Hydro F2016 DSM Annual Report (Exhibit B-2, Attachment 3) BC Hydro states: "Net levelized utility cost is calculated by subtracting capacity benefits from gross utility costs and then dividing the resulting net utility costs by electricity savings." On the same page, BC Hydro shows codes and standards and rate structures with a negative net levelized cost.

BC Hydro estimates TRC and UCT ratios for its F2017–F2019 proposed programs in Appendix W, page 9 of the Application.

172.1 Please explain whether it is considered industry best practice to treat capacity benefits as a reduction of utility costs in calculating the total utility cost ($/MWh) of DSM programs (which can result in a negative utility DSM cost). Please also provide $/MWh net levelized utility costs for each program (excluding capacity benefits) for (i) F2013 to F2016, and (ii) F2017 to F2019.

172.1.1 Please explain whether network and generation capacity benefits associated with DSM programs are reflected in the program TRC and UCT ratios included in Appendix W, page 9 of the Application. If not, please comment on whether this is consistent with the DSM Regulations and update the ratios to include capacity benefits for BC Hydro DSM programs (including the portfolio total) for (i) F2013 to F2016, and (ii) F2017 to F2019.

172.2 Please (i) describe the methodology used by BC Hydro to estimate avoided network costs (including whether it is consistent with one of the four approaches described on pages 4 to 6 of the FBC 2016 capacity study) and (ii) estimate BC Hydro's avoided network costs using the same methodology recommended for FBC on pages 21 through 23. Please provide input assumptions and supporting calculations.

172.2.1 Using the average load factor of BC Hydro's domestic energy sales, please translate the total capacity LRMC estimate (generation, transmission, distribution) into ¢/kWh.

172.3 Please explain how the generation system reserve margin affects DSM cost effectiveness ratios.

173.0 **Reference: DEMAND SIDE MANAGEMENT EXPENDITURES**
Exhibit B-1-1, p. 10-29; Exhibit B-1-2, Appendix W, p. 10; Guide to the Demand-Side Measures Regulation[7] (DSM Guide), pp. 7–8
Non-Electricity Benefits

BC Hydro states on page 10-29 of the Application that "The [TRC] Test results reported in Appendix W have been calculated using BC Hydro's long-run marginal cost and the total avoided cost benefits have been increased by 15 per cent (the 15 per cent increase is labelled non-electricity benefits in Appendix W, Table 10). Results show that the demand-side measures are cost-effective."

Table 10 in Appendix W to the Application shows that non-electricity benefits (NEB) is $0 under the Total Resource Cost Test (TRC) for all programs except for the Low Income and New Construction programs. NEB is included in the modified TRC for all programs.

The DSM Guide states on page 7 that "The value of the NEB adder must be such that expenditure

[7] http://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/energy-efficiency/guide_to_the_dsm_regulation_july_2014_c2.pdf

portfolio's benefits (after the application of the ZEEA in s. 4(1.1) (a) and (b)) increase by 15%." Page 8 of the DSM Guide includes illustrative examples of how the 15 percent NEB adder can be applied.

173.1 Based on the information presented in Table 10, please reconcile BC Hydro's statement that "total avoided cost benefits have been increased by 15 per cent" in the TRC results.

173.2 Please explain whether a 15 percent increase in total avoided cost benefits is the same magnitude as a 15 percent increase in overall benefits as stated in the DSM Guide. If they are different, please quantify the difference and the impact on TRC and UCT results (in terms of benefit/cost ratio) for each program listed in Table 3 on page 3 of Appendix W to the Application.

174.0 **Reference: DEMAND SIDE MANAGEMENT EXPENDITURES**
Exhibit B-1-1, p. 10-5
Portfolio level review – general

BC Hydro provides F2014 to F2016 actual and forecast DSM results on page 10-5 of the Application.

174.1 Please complete the following table for each sector/component (residential, commercial, etc.) and for the total DSM portfolio. For the cost-effectiveness measures (TRC etc.) please show (i) the portfolio total and (ii) the portfolio total excluding codes and standards and rates.

	F2012	**F2013**	**F2014**	**F2015**	**F2016**
Approved	$xm	$xm	$xm	$xm	$xm
Spent	$xm	$xm	$xm	$xm	$xm
Spent as a % of Approved	x%	x%	x%	x%	x%
Actual Energy Savings	xMWh	xMWh	xMWh	xMWh	xMWh
Forecast Energy Savings	xMWh	xMWh	xMWh	xMWh	xMWh
Actual as a % of Forecast	x%	x%	x%	x%	x%
TRC/mTRC					
UCT					
Ratepayer Impact Measure (RIM)					

174.2 Has BC Hydro proposed any new DSM programs or measures for F2017–F2019? If yes, please explain.

175.0 **Reference:** **DEMAND SIDE MANAGEMENT EXPENDITURES**
Exhibit B-1-1, p. 10-33, Appendix V; BC Hydro F2012–F2014 Revenue Requirements Application (RRA), Exhibit B-1-3B, pp. 63, 64; FBC PBR 2014–2018 Application, Exhibit B-24, BCUC IR, 2.108.8, 2.108.8.1; Lawrence Berkeley National Laboratory report, "The Program Administrator Cost of Saved Energy for Utility Customer-Funded Energy Efficiency Programs", 2014, (Lawrence Berkeley 2014 Report)[8]
Portfolio level review: effectiveness

BC Hydro stated in the F2012–F2014 RRA (Appendix II, pp. 63, 64 of 271): "An analysis … indicates that DSM will reduce energy and capacity costs for BC Hydro ratepayers by approximately $16.4 billion in present value terms (F2011 $) over the F2012 – F2036 time period, relative to a supply-only scenario."

The Lawrence Berkeley 2014 Report provides benchmarking data on the utility cost and total resource cost of DSM programs.

BC Hydro includes F2017–F2019 program level benefit cost ratios in Appendix V of the Application.

175.1 Using the same row headings shown in Table 10-7 of the Application (p. 10-33), please include three columns that show the F2017–F2019 total dollar benefit for each of the following scenarios: (i) long-run BC benefit (TRC benefit-cost ratio vs. LRMC); (ii) long-run utility benefit (utility cost (UC) benefit-cost ratio vs. LRMC);and (iii) short-run utility benefit (UC benefit-cost ratio vs. Market Price). For each column please also show the total benefit and net benefit (benefit less costs).

175.1.1 Please also break down the F2017–F2019 total estimated benefit in each scenario above into its component benefits (electric energy, generation capacity, customer non-energy benefits etc.) and show each component benefit as a percentage of the total benefit.

175.2 Assuming cost-effectiveness is determined on a program by program basis, for each DSM program (such as the residential retail program), under the DSM Regulations please identify whether (i) the program is required to pass TRC/mTRC (please specify which one) in order to be considered cost-effective, and (ii) could be determined to not be cost-effective if it does not pass the UCT. Please present the results in table form, including the program TRC/mTRC and UCT results for the F2017–F2019 period.

175.2.1 Please undertake the same analysis, assuming cost-effectiveness is determined (i) on the portfolio as a whole, and (ii) on an individual program basis for rate structures and codes & standards, using a portfolio basis for the rest.

175.2.2 Please identify any measures included within the DSM portfolio that (i) do not pass the TRC and/or (ii) do not pass the mTRC. For any measures identified not passing the TRC/mTRC, please identify which programs they are included in, the DSM budget requested over the F2017–F2019 period related to this measure, and explain why BC Hydro is including these measures.

175.3 Please explain whether BC Hydro considers cost-effectiveness evaluation should be undertaken on a measure, program or portfolio basis.

175.4 Please reproduce the following figures/tables from the Lawrence Berkeley 2014 report: Figure 2-3; Figure 3-16; Table 3-4 (levelized cost only); Figure 3-10; Figure 3-11; Figure 3-12; Figure 3-13;

[8] https://emp.lbl.gov/sites/all/files/lbnl-6595e.pdf

Figure 3-14; Figure 3-21. For each table/figure, please provide comparable BC Hydro total DSM results (excluding rates, codes and standards, and capacity focused DSM) for (i) F2014-F2016, and (ii) F2017-F2019 and comment on any significant differences.

175.4.1 Please map BC Hydro's DSM programs to Figure 2-2. If BC Hydro does not have any DSM programs in any of the areas, please explain why.

175.4.2 Please reproduce the pie charts on Figure 3-1 (expenditures and lifetime gross savings) and Figure 3-2 of the report and produce similar pie charts for BC Hydro for F2014–F2016 and F2017–F2019. Please explain any significant differences.

175.4.3 Please reproduce Figure 3-18 and Figure 3-19 and update them to include BC Hydro results for F2014–F2016 and F2017–F2019. Please explain where BC building costs would align with the IEEC/ASHRAE categories provided, and explain any significant differences.

In the FBC PBR 2014–2018 Application, FBC provided a comparison of incentives as a percentage of program spend over time and to an ACEEE 2009 report results (BCUC 2.108.8, 2.108.8.1).

175.5 Please provide total DSM incentives paid as a percentage of total BC Hydro DSM costs for each year from F2013 to F2019 and compare them to the FBC and ACEEE results in BCUC 2.108.8 and 2.108.8.1 IR referenced above. Please explain any significant differences.

176.0 **Reference: DEMAND SIDE MANAGEMENT EXPENDITURES**
BC Hydro 2013 IRP, p. 9-18, Appendix 4D, p. 10 of 13; Ministerial Order M233; FBC 2017 DSM Application, Exhibit B-1, Appendix B, pp. 10, 11, Appendix A/B to Appendix B
Portfolio level review: balance

On page 9-18 of the 2013 IRP, BC Hydro compared in Tables 9-8 and 9-9 DSM spend/savings by sector, and Table 3 of Appendix 4D to the IRP shows energy savings as a percentage of retail sales.

The DSM Regulations were modified by Ministerial Order M233 dated June 4, 2014, which amended the DSM Regulation in a number of areas and included an expanded definition of 'low-income' household.

FBC includes on pages 10 and 11 of Appendix B to 2017 Application for Acceptance of DSM Expenditures Application a description of the low-income program it offers, and at Appendix A and B to Appendix B actual annual data for 2010 to 2015.

176.1 Please provide, for each customer class, total DSM dollar spend over the F2017–F2019 period as a percentage of F2016 revenues received. Please explain how BC Hydro has mapped DSM program spend to revenues received from those customer categories. Please explain any significant variation in these percentages between customer classes.

176.1.1 Please update Table 9-8 and 9-9 in the 2013 IRP to compare (i) F2014–F2016 forecast, (ii) F2014–F2016 actual and (iii) F2017–F2019 plan. Please explain any significant differences in funding allocation over time.

176.2 Please reproduce Table 3 of Appendix 4D to the 2013 IRP and show BC Hydro's average energy savings (i) in total and (ii) excluding codes and standards and rates, as a percentage of retail sales for F2016–F2016 (actual) and F2017–F2109 (forecast). Please discuss whether BC Hydro DSM savings as a percentage of sales are in line with industry average.

176.3 Please identify the F2014–F2016 (forecast), F2014–F2016 (actual) and F2017–F2019 DSM funding request specifically targeted at: (i) low-income households, (ii) rental accommodation, (iii) schools and (iv) post-secondary institutions. Please explain any significant difference in the programs offered or funding allocated between these two periods.

176.4 Please describe the consultative approach BC Hydro undertook in developing its low-income DSM program and budget.

176.4.1 Please provide, in table form, (i) BC Hydro and (ii) FBC low income DSM actual/forecast funding as a percentage of the DSM portfolio total for each year from F2011 (FBC 2010) to F2016 (FBC 2015). Please comment on any significant differences in DSM funding allocation between the two utilities or over time.

176.4.2 Please identify any low-income DSM programs offered by FBC that are not offered by BC Hydro, and explain why BC Hydro does not offer similar programs to its customers.

176.4.3 Please identify the changes BC Hydro has made to its low-income programs in light of the DSM Regulations expanded low-income household definition.

176.5 Does BC Hydro consider that all customers have a reasonable opportunity to participate in at least one DSM program offered? Please explain why or why not.

176.5.1 Please explain whether (and if so, how) BC Hydro has given specific consideration to other potentially 'hard to reach' customers or those who could be disproportionality adversely affected by conservation rate designs in developing its DSM portfolio. Please specifically address: First Nation communities, rural communities without access to natural gas, low-income/high use residential customers and high use customers in rental accommodation who are direct customers of BC Hydro.

177.0 **Reference: DEMAND SIDE MANAGEMENT EXPENDITURES**
Exhibit B-1-1, p. 3-41, 3-42; CEA, s. 2
BC Clean Energy Objectives

Section 2 of the CEA describes BC's Energy objectives, which include encouraging switching to lower emission fuels and reducing GHGs. BC Hydro states on page 3-41 and 3-42 of the Application that Recommended Action 10 from the 2013 IRP is "… advancing electrification with a focus on industrial, transportation and other sectors" and that BC Hydro has positioned itself to respond through DSM.

177.1 Has BC Hydro explored low-carbon electrification DSM programs (for example, electric vehicles and other fuel switching programs)? If yes, please explain the results and whether these DSM programs could reduce the BC Hydro revenue requirement and rates. If no, please explain why not.

177.2 Does BC Hydro exclude customers from eligibility for DSM incentives where they are fuel switching from gas to electricity? If yes, please describe and explain why.

177.3 Please describe the DSM programs BC Hydro has for the conversion from propane or oil to electricity. Please also compare the incentives available from FEI/BC Hydro/LiveSmart to an illustrative residential BC Hydro customer with propane appliances in an area where natural gas is available wanting to (i) switch to natural gas or (ii) switch to electricity.

178.0 **Reference: DEMAND SIDE MANAGEMENT EXPENDITURES**
Exhibit B-1-1, p. 10-29, Appendix V, pp. 2, 3, 7, 8; CEA, s. 2
Codes and standards/rates: evaluation approach

BC Hydro refers to First Nation Strategies on page 3 of Appendix V to the Application and on page 2 states that "only a small portion of the identified [Codes and Standards development] savings need to be attributed to BC Hydro activities for the Codes and Standards initiative to be cost-effective."

In Appendix V (pages 2, 7 and 8) BC Hydro estimates for the F2017–F2019 codes and standards program a TRC result of 6.4 and a UCT result of 149, residential inclining block (RIB) rate a TRC of 19.91 and UCT of 19.9 and the transmission service stepped rate a TRC of 3.1 and UCT of 21.5. BC Hydro states on p. 10-29 of the Application that it has not included the attribution of savings from codes and standards to DSM programs that increase the use of the regulated item.

178.1 Please explain the process BC Hydro uses to calculate the TRC/mTRC and UCT result for (i) codes and standards (including the methodology used to attribute energy savings) and (ii) rates.

178.1.1 Please explain why the TRC and UCT for the RIB rate are the same and – if it is because energy savings are assumed to result from behavioural changes only – whether this assumption is supported by evidence.

178.2 Please describe the level of accuracy required in determining the (a) attribution of codes and standards energy saving and (b) energy savings from rate design, specifically with regard to determining if each program will (i) pass the TRC (i.e., is in the public interest), (ii) pass the UCT (i.e., is cost effective to the utility) and (iii) materially affect the ability of BC Hydro to support the "66 percent reduction in demand by the year 2020" BC energy objective.

178.3 Please explain why BC Hydro has not included the attribution of savings from codes and standards to DSM programs that increase the use of the regulated item. If BC Hydro used this approach, would it change the cost effectiveness result of any DSM program? If so, how?

178.4 Please explain why BC Hydro has included First Nation Strategies (other than support for housing policy and community energy plans) as a code and standard rather than a DSM program.

178.5 Please describe the process BC Hydro has to identify areas where it can (i) identify codes and standards opportunities and (ii) assist in their development. Please also describe the consultation process BC Hydro undertook with third parties (including various levels of government and other utilities) in establishing the F2017–F2019 codes and standards budget.

179.0 **Reference: DEMAND SIDE MANAGEMENT EXPENDITURES**
Exhibit B-1-1, p. 10-5, Appendix V, pp. 1-3, 6-8, Appendix Y, Attachment 1, p. 4, Attachment 2, p. 4; Exhibit B-2, Attachment 3, p. 4;
Codes and standards/rates – historical and projected savings

BC Hydro describes the F2017–F019 Codes and Standards budget on pages 1 to 3 of Appendix V to the Application, and F2014 to F2016 actual results on Table 1 of the F2014–F2016 DSM annual reports. BC Hydro requests $3.5 million for F2017–2019 for completion of the 2015 rate design application (RDA) and ongoing maintenance of the RS 1823 stepped rate (Appendix V pp. 6-8).

179.1 Please provide a breakdown of the $3.5 million requested rate design cost, showing the cost of activities related to the 2014 RDA, ongoing maintenance of existing conservation rates and the budget to consider new rate designs that conserve energy or promote energy efficiency.

179.2 Please provide a table of the Codes and Standards for which BC Hydro is claiming/expects to claim savings in F2014–F2019.

179.2.1 For each of the Codes and Standards for which BC Hydro is claiming/expects to claim savings, please discuss and quantify (in actual direct funding or person-hours) BC Hydro's direct involvement in the creation or compliance of the Code or Standard including:

i. Preparation of market research;

ii. Preparation of cost benefit analyses;

iii. Funding of code or standard development;

iv. Aiding in market transformation including: increasing availability in rural areas and niche markets; upstream involvement in technology development (e.g. LED lighting); market stimulus; helping to increase competition to lower consumer costs; provision of incentives; educating industry and consumers on merits of new technologies; and retail promotion; and

v. Compliance Enhancement including: measures to inform industry and customers about an upcoming regulation; industry training and capacity-building related to an upcoming regulation; advising government on expected compliance issues for upcoming regulation; and partnering with utilities and Ministry on an integrated compliance strategy with shared resourcing and funding.

179.2.2 Please discuss other British Columbia utilities' involvement in the creation or compliance of these same Codes and Standards, and explain how the utilities attribute savings from Codes and Standards they have jointly helped develop.

179.3 Please provide any impact or process evaluation or other market studies that directly link BC Hydro codes and standard activities (and thus expenditures) to increases in product/service compliance over the last 10 years.

180.0 **Reference: DEMAND SIDE MANAGEMENT EXPENDITURES**
Exhibit B-1-1, pp. 10-34, 10-50, 10-51
Codes and standards – targets and key performance indicators (KPIs)

Under Table 10-12 of the Application, BC Hydro summarizes the key DSM KPIs for Codes and Standards.

180.1 Please provide details on how success in each Key Performance Indicator for Codes and Standards is measured. Does BC Hydro consider that a survey of governments to determine how satisfied they are with BC Hydro's level of assistance could also be a useful KPI? Please explain.

180.2 Please provide a breakdown of the targets/forecasts set for each Codes and Standards Key Performance Indicator for F2017–F2019.

181.0 **Reference:** **DEMAND SIDE MANAGEMENT EXPENDITURES**
Exhibit B-1-1, Appendix D, p.2, Appendix V, pp. 34, 35; BC Hydro 2013 IRP, p. 9-12; Navigant, Assessing Demand Response (DR) Program Potential (Navigant Report), 2014[9]
Capacity focused DSM – approach

BC Hydro requests on pages 34 and 35 of Appendix V to the Application $38.6 million in funding for capacity focused pilots to understand the dependability of the capacity savings for inclusion in BC Hydro's planning. On page 9-12 of the BC Hydro 2013 IRP, BC Hydro states: "Activities should be cost-effective to ensure BC Hydro's investments in DSM will generally be lower than the LRMC …"

The Shareholder's Letter of Expectations attached at Appendix D to the Application states on page 2: "… BC Hydro is directed to take the following strategic actions: … Improve customer satisfaction by providing timely and responsive service and exploring innovative energy conservation solutions such as load curtailment rates."

Navigant Consulting prepared for the Northwest Power and Conservation Council a 2014 report titled 'Assessing Demand Response (DR) Program Potential for the Seventh Power Plan' (Navigant DR Report).

181.1 Please describe the high level objectives of the F2017–F2019 capacity focused DSM funding request. Please specifically address whether it is for: (i) information gathering on the cost to customers of providing capacity; volume of capacity available in BC; and/or dependability of capacity; (ii) to obtain capacity for resale or to meet BC Hydro F2017–F2019 capacity needs and/or (iii) customer satisfaction (if so, which customer(s)). For each objective identified, please explain how performance will be measured and reported.

181.1.1 For each objective, please describe alternative approaches considered to meet that objective (such as benchmarking, survey, customer education, etc.) and explain why BC Hydro considers the $38.5 million proposal put forward to be the preferred option.

181.2 Please explain how BC Hydro interprets the Shareholder Letter of Expectations direction to improve customer satisfaction by exploring innovative energy conservation solutions such as load curtailment rates. Specifically, is the customer satisfaction improvement directed at a particular customer segment (and if so, which), and what level of exploration would be required to meet this directive (would analysis similar to the Navigant DR report be sufficient)?

181.3 Does BC Hydro consider that, to provide a net BC benefit, the TRC cost of the capacity focused DSM program should be less than the LRMC of capacity ($50 to $55/kW-year)? Please explain.

181.3.1 Does BC Hydro consider that the UCT of obtaining capacity from customers should also be less than the LRMC of capacity ($50 to $55/kW-year)? Please explain.

182.0 **Reference:** **DEMAND SIDE MANAGEMENT EXPENDITURES**
Exhibit B-1-1, p. 3-32
Capacity focused DSM – need

BC Hydro provides its peak capacity load resource balance on page 3-32 of the Application.

[9] https://www.nwcouncil.org/media/7148943/npcc_assessing-dr-potential-for-seventh-power-plan_updated-report_1-19-15.pdf

182.1 Using BC Hydro's capacity LRMC estimate, please estimate the total dollar cost to BC Hydro of meeting annual forecast capacity gaps for each year as identified on page 3-32 of the Application. Please also calculate (a) the dollar net present value (NPV) of meeting this gap over the next (i) 10 years and (ii) 15 years, and (b) BC Hydro's $38.6 million funding request as a percentage of the NPV estimate.

182.1.1 Please discuss whether the estimate has changed significantly from the 2013 IRP (and if so how) and whether, based on past experience, BC Hydro tends to over or under forecast capacity gaps.

182.2 For F2017–F2036, please indicate how much of sub-total (h) on page 3-32 of the Application can be attributed to capacity (MW) savings as a result of capacity focused DSM programs.

183.0 **Reference: DEMAND SIDE MANAGEMENT EXPENDITURES**
BC Hydro 2013 IRP, pp. 3-28, 9-21; Commission Order G-115-99 dated October 28, 1999, Rate Schedule 1849 (Price Dispatched Curtailment Program)
Capacity focused DSM – request

The BC Hydro 2013 IRP includes on page 3-28 of the 2013 IRP the estimated TRC and utility cost (UC) for capacity focused DSM, and on page 9-21 forecasts F2015-F2016 capacity focused DSM of $0.75 million for industrial load curtailment and $5 million for capacity focused programs.

Commission Order G-115-99 approved the Price Dispatched Curtailment program.

183.1 Please describe how the capacity focused DSM funding from F2015 to F2016 was spent, explain variances from the 2013 IRP budgeted amounts and describe the results achieved.

183.2 Please reproduce Table 3-6 in the 2013 IRP showing the TRC and UCT estimates for capacity-focused DSM, discuss how BC Hydro arrived at these estimates and provide updated estimates.

183.3 Please provide a breakdown of the capacity focused DSM spend/request for each year from F2014 to F2019 to show (a) an activity view of where the funding dollars were/plan to be spent, and (b) a resource view (e.g., internal labour, incentives, consultants, overhead). Please explain any significant change over time. Please also include a breakdown of capacity DSM incentives by customer class for each year.

183.4 Please explain why BC Hydro has included the 'capacity DSM incentive' as a DSM cost (as opposed to an adjustment to forecast revenue). Please include in your response how BC Hydro accounted for: (i) payments made to customers under BC Hydro's 1999 Price Dispatch Curtailment program and (ii) changes in expected revenues received from different customer segments resulting from the introduction of a conservation rate.

183.4.1 Please describe the effect on rates (assuming no rate cap), if the design/administration/ evaluation of the DSM capacity pilots were treated as DSM, but customer incentives were treated as a reduction in expected revenues.

183.5 Does BC Hydro consider there would be a net benefit from an accelerated regulatory review (within this proceeding) of the $38.6 million capacity focused DSM request? Please explain why or why not.

184.0 **Reference:** **DEMAND SIDE MANAGEMENT EXPENDITURES**
Exhibit B-1-2, Appendix W, Table 3; Exhibit B-2, Attachment 3, p. 4
DSM program level data

BC Hydro provides 10 data tables in Appendix W of the Application showing the details of each program from F2016 to F2024.

BC Hydro presents its Report on Demand-Side Management Activities for Fiscal 2016 (2016 Annual Report) in Attachment 3 of its Evidentiary Update filed as Exhibit B-2. In Table 1 on page 4 of BC Hydro's 2016 Annual Report, BC Hydro presents the expenditures and incremental electricity savings for F2016.

184.1 Please provide a summary table showing the expenditure, energy savings and cost-benefit test results for each program in the following format for all of the programs included in Table 3 of Appendix W. Please also provide the program sector subtotal and total portfolio weighted TRC result which includes up to 10 percent of the total expenditure on programs that are cost-effective under the modified TRC (mTRC).

Program	Utility Expenditures		Energy Savings		Cost-Benefit Test							Levelized cost ($/MWh)
	2017-2019	% of total	2017-2019	% of total	TRC (using LRMC)	TRC (using $36/MWh	mTRC	UCT (ratio)	UCT ($/MWh)	PCT	RIM	
Codes and Standards												
…												
Portfolio total*		100%		100%								
Portfolio Weighted TRC:_____												

* Cost-benefit test on a portfolio basis reflects the weighted average based on proportion of total expenditure

184.2 Please identify the DSM programs or measures considered by BC Hydro for F2017-F2019 that passed the TRC using BC Hydro's LRMC of energy but failed BC Hydro's $36/MWh screening filter. Please include the utility cost (in $/MWh) of those programs/measures.

184.3 Please provide a summary table and in a working excel spreadsheet in the format presented below showing the incentive spending, non-incentive spending, energy savings, number of participants, and input assumptions for all of the DSM programs included in Table 3 in Appendix W of the Application. For programs with multiple measures, please include each individual measure as an additional line item.

Program	Utility Expenditures (2017-2019) ($ and % of total expenditure for the measure)		Energy Savings		number of program participants	Input Assumptions						
	Incentive expenditure	Non-incentive expenditure	2017-2019	Projected lifetime savings		Measure life (years)	Savings persistence (years)	Free rider rate (%)	Spillover rate (%)	Market effects rate (%)	Rebound effects rate (%)	Cross effects rate (%)
Residential Sector	$ (%)											
…												
Portfolio total												

184.3.1 For each number reported in the table above, please provide justification and references to supporting documentation.

184.4 For Table 1 through Table 8 presented in Appendix W, please expand the tables to include historical actual and forecast for F2013 to F2016, and variance between actual and forecast for each year from F2013 to F2016. For the expanded Table 4, please replicate the table to express incentive cost as a percentage of total spend for each program, and a table for incentive cost per program participant. Please provide all of the expanded tables in a working excel spreadsheet, including formulas and all supporting details available.

184.4.1 For each program where the incentive percentage or incentive/participant has changed by more than +/- 25 percent between forecast F2014 and forecast F2017, please explain.

184.5 In a format consistent with Table 7 in Appendix W of the Application, please provide a table with historical actual and forecast for F2013 to F2016, variance between actual and forecast for each year from F2013 to F2016, and forecast for F2017 to F2019 for i) TRC ratio and ii) UCT ratio, respectively.

184.5.1 For each program where the TRC and/or UCT differs by more than +/- 25 percent between forecast 2016 and actual 2016, please explain.

184.6 In a format consistent with Table 1 in the BC Hydro F2016 DSM Annual Report, please include the following columns: F2013 to F2016 TRC; F2013–F2016 net levelized utility cost ($/MWh); forecast DSM expenditures for total F2014–F2016; forecast DSM expenditures for total F2017–F2019; and percentage change in forecast DSM from F2014–F2016 to F2017–F2019.

184.6.1 For each DSM program when funding has been changed from plan F2014–F2016 to forecast F2017 by 25 percent or more, please explain the reason for the change in funding.

185.0 **Reference: DEMAND SIDE MANAGEMENT EXPENDITURES**
Exhibit B-1-1, pp. 10-35, 10-36
Program level economic benefits

On page 10-35 to page 10-36 of the Application, BC Hydro explains that there are economic development benefits, environmental benefits and additional customer benefits.

185.1 Please elaborate on how each proposed program produces the benefits described by BC Hydro.

185.2 Please explain and quantify how the TRC and UCT reported for each program have reflected the benefits explained above. In particular, are these benefits reflected as non-energy benefits?

186.0 **Reference: DEMAND SIDE MANAGEMENT EXPENDITURES**
FBC 2017 DSM Application, Appendix B, sub Appendix A, p. 1;
Program comparison

In the FBC 2017 DSM Application, it presents its 2015 Year-end DSM Report in Appendix B. Page 1 of Appendix A to the 2015 Year-end DSM Report shows FBC's DSM program results for 2015.

186.1 Using FBC's 2015 Year-end Annual Report DSM results (Table A-1) for residential, low-income, commercial and industrial sector DSM results, please provide a comparison of similar programs offered by FBC in F2015 and by BC Hydro in 2017–2019 in a table set up below.

	BC Hydro				FBC			
Program	TRC	UCT	UCT ($/MWh)	Levelized cost ($/MWh)	TRC	UCT	UCT ($/MWh)	Levelized cost ($/MWh)
…								

186.1.1 Please comment on the potential reason for any significant differences between BC Hydro and FBC's TRC, UCT and levelized cost.

186.2 Please identify any programs offered by FBC but not BC Hydro (excluding low income programs addressed previously) and explain why BC Hydro is not proposing to offer these programs. In your response, please include FBC's TRC and UCT results.

187.0 **Reference: DEMAND SIDE MANAGEMENT EXPENDITURES**
Exhibit B-1-1, Appendix V, pp. 26, 30; BC Hydro PowerSmart website titled "Distribution Project Initiative" [10]; BC Hydro PowerSmart website titled "Transmission Incentive Program"[11]
Industrial programs – leaders in energy management program

On page 26 of Appendix V to the Application, BC Hydro states that the Leaders in Energy Management – Transmission program "addresses the market barriers that prevent the adoption of more energy efficient projects by encouraging and assisting these customers in integrating energy efficiency into their ongoing business practices and corporate culture."

BC Hydro states on its Transmission Project Incentives website: "Get up to 75% funding for your energy efficiency upgrade projects and improve the payback on your investment."

On page 30 of Appendix V to the Application, BC Hydro states that the Leaders in Energy Management – Distribution program "seeks to address the access to capital, lack of internal and external resources, and knowledge of energy-efficiency market barriers that are holding back the adoption of more energy efficient projects and behaviours and to transform the market to higher levels of energy efficiency by encouraging and assisting customers in integrating energy efficiency into their ongoing business practices and corporate culture."

BC Hydro states on its Distribution Project Incentive website: "Get up to 75% funding (to a maximum of $500,000) for your energy efficiency upgrade projects and improve the payback on your investment to as little as one year."

187.1 Please confirm, or explain otherwise, that the transmission project incentives are offered under the Leaders in Energy Management – Transmission program, and the distribution project incentives are offered under the Leaders in Energy Management – Distribution as proposed in the Application. If not confirmed, please explain whether the incentive promoted on BC Hydro's website will be continued for F2017 to F2019. And if so, under which program are they offered?

187.2 Please explain how BC Hydro determines that an incentive offering of up to 75 percent for energy efficiency upgrade projects, in addition to BC Hydro's other strategies and resources available under the programs, is necessary to promote energy efficiency uptake.

187.2.1 Please comment on the performance of the programs if the incentives offered is up to

[10] https://www.bchydro.com/powersmart/business/programs/project-incentives/distribution.html
[11] https://www.bchydro.com/powersmart/business/programs/project-incentives/transmission.html

50 percent of the cost of the energy efficiency update projects.

187.3 Please comment on the impact to the performance of the industrial distribution program if the payback period is increased to 2 years from the current 1 year.

187.4 For both Leaders in Energy Management programs please provide the number and percentage of eligible customer who received a financial incentive in the past three years and anticipate participating in F2017 to 2019.

188.0 **Reference: DEMAND SIDE MANAGEMENT EXPENDITURES**
Exhibit B-1-1, Appendix V, pp. 38-39
Public awareness

On page 38 of Appendix V to the Application, BC Hydro states that "over the next three years, paid, owned and earned strategies are expected to maintain conservation awareness at current levels. BC Hydro states that "activities will become more prominent in the digital space…" On page 39 of Appendix V to the Application, BC Hydro explains its community outreach and school education initiatives.

188.1 Please elaborate on the "paid, owned and earned strategies," and provide a breakdown of planned activities under Public Awareness. For each activity described above, please provide a breakdown of cost for F2013 to F2016 actuals and F2017 to F2019 forecast.

189.0 **Reference: DEMAND SIDE MANAGEMENT EXPENDITURES**
Exhibit B-1-1, Appendix V, p. 40
Indirect and Portfolio Enabling

On page 40 of Appendix V to the Application, BC Hydro provides under section 18.4 a breakdown and description of its indirect and portfolio enabling supporting initiative.

189.1 For each of the seven items included in the table provided under section 18.4, please provide the breakdown of cost for F2013 to F2016 actuals and F2017 to F2019 forecast.

190.0 **Reference: DEMAND SIDE MANAGEMENT EXPENDITURES**
Exhibit B-2, Attachment 3, p. 12; BC Hydro F2012-F2014 RRA, Exhibit B-15, BCUC IR 1.446.6
BCH Operational DSM Costs

BC Hydro includes operational expenditures in Table 6 (p. 12) of the F2016 Annual DSM Report.

190.1 Please provide an employee organizational chart for the BC Hydro DSM department.

190.2 Please provide, in table form consistent with Table 6 of the F2016 BC Hydro DSM Annual Report, annual operating expenditures for each year from F2012 to F2016 (actual) and forecast for F2017 to F2019. Please also include a description of 'other' costs and (to the extent practicable) a break-down of this category into major sub-components. Please explain only significant changes.

190.3 Please provide in a table form, annual data from F2012 to F2016 (including totals for each year) for: (i) the number of full-time equivalent (FTE) employees working on DSM related projects at BC Hydro; and (ii) total operating costs as a percentage of total DSM spend. Please explain any significant changes over time.

190.4 Please explain how BC Hydro allocates overhead costs to programs, and provide a table showing

the breakdown of allocated F2017 to F2019 DSM overhead costs by program. Please include a column showing overhead costs as a percentage of total program costs.

190.5 Please explain how BC Hydro, in the development and implementation of its DSM programs, ensures that it actively coordinates with LiveSmart, FBC and FortisBC Energy Inc. (FEI).

190.6 Please discuss the BC Hydro Electricity Conservation and Efficiency Advisory Committee's role in DSM Performance Management. Specifically, please discuss the committee's role in: (i) identifying DSM opportunities; (ii) planning, designing, or adjusting programs; (iii) auditing or confirming electricity savings; (iv) approving program funding; and (v) approving transfers or funding among programs.

190.7 Do BC Hydro DSM costs include an allocation of costs from BC Hydro customer service departments? If yes, please explain, quantify and justify their inclusion as a DSM cost.

BC Hydro provided in the F2012–F2014 RRA (Exhibit B-15, IR BCUC 1.446.6) a table comparing BC Hydro's DSM spending and average utility cost to other utilities.

190.8 Please update the data provided in the response above to reflect current estimates.

191.0 **Reference: DEMAND SIDE MANAGEMENT EXPENDITURES**
Exhibit B-1-1, p. 10-50, Appendix Z, pp. 10, 11; California Evaluation Framework[12], 2004, pp. 21, 27; California Energy Efficiency Evaluation Protocols, 2006, p. 31[13]
Evaluation, Measurement & Valuation (EM&V) Independence

BC Hydro states on page 10-50 of the Application that "… BC Hydro is guided by the California Evaluation Framework and Protocols and the U.S. Department of Energy Uniform Methods Project Protocols."

The California Evaluation Framework states:

> The Framework also stipulates that program evaluations will be conducted by firms, organizations, or groups that are independent of the implementation administrator or contractor and that the evaluation teams will maintain an arm's-length relationship with implementation administrators and contractors in order to help assure objective and reliable evaluation efforts. (p. 21)
>
> When distilled to its most basic level, the essential over-arching purpose of evaluation is to help ensure that good decisions are made regarding the investment of energy program resources by providing rigorous, independent evaluation studies and study results. (p. 27)

The California Energy Efficiency Evaluation Protocols: Technical, Methodological and Reporting Requirements for Evaluation Professionals (2006) states on page 31: "All impact evaluations must meet the requirements of the Sampling and Uncertainty Protocol. … Bias is the greatest threat to the reliability of savings estimates."

On page 10 to 11 of Appendix Z, BC Hydro elaborates on its EM&V independence and oversight. Page 11 states "draft evaluation reports are reviewed by two external evaluation advisors… Final evaluation reports are reviewed and subject to approval by an Evaluation Oversight committee made up of BC

[12] http://www.calmac.org/publications/California_Evaluation_Framework_June_2004.pdf
[13] http://www.calmac.org/publications/EvaluatorsProtocols_Final_AdoptedviaRuling_06-19-2006.pdf

Hydro staff representing business units with an interest in demand-side management and chaired by a staff person from outside the Conservation and Energy Management business unit."

191.1 Please explain how BC Hydro follows the California Evaluation Framework principle that program evaluations be conducted by firms, organizations or groups that are independent of the implementation administrator. Please provide specific protocols or written process to support the answer.

191.2 Please describe the sampling approaches BC Hydro plans to use and explain whether they meet the requirements of the California Sampling and Uncertainty Protocol.

191.3 Please elaborate on the review and approval process of the evaluation reports, and the review criteria/benchmark used by the Evaluation Oversight committee.

191.4 Please describe the services included in the DSM EM&V F2017–2019 budget.

191.5 Please comment on the additional cost involved if BC Hydro's finalized EM&V reports are reviewed and audited by a third party, particularly on its input assumptions to calculate cost effectiveness, prior to being filed with the Commission.

191.5.1 Please comment on whether this practice would improve independence, oversight on compliance with industry standards, and regulatory efficiency.

192.0 **Reference: DEMAND SIDE MANAGEMENT EXPENDITURES**
Exhibit B-1-1, Appendix Z, pp. 6-7, Attachment 1, Attachment 2, Attachment 3
EM&V plan

BC Hydro provides an Evaluation Work Plan for its impact evaluations on page 6-7 of Appendix Z of the Application.

BC Hydro presents the Demand-Side Management Milestone Evaluation Summary Reports for F2013, (F2013 EM&V Report) F2014 (F2014 EM&V Report), and F2015 (F2015 EM&V Report)in Appendix Z of the Application in Attachment 1, Attachment 2, and Attachment 3, respectively.

192.1 In a table, please provide the historical actual and planned EM&V spend for F2013 through F2016, and the EM&V budget proposed for F2017 to F2019. Please also show the EM&V budget as a percentage of total spend for each year from F2013 to F2019 (both planned and actual for F2013 to F2016).

192.2 In a table, for each DSM program listed in Table 3 of Appendix W, please present the type of EM&V that BC Hydro plans to perform in F2017–F2019, the timing, and the associated budget.

Program	EM&V Scheduled			Type of Evaluation (reference objective and methodology from previous EM&V report, if appropriate)	EM&V Budget		
	2017	2018	2019		2017	2018	2019
Hypothetical example: Residential Behaviour Program	x			Process Evaluation (see F2013 EM&V Report, section 2.4)	$3000		
…							
				Total Budget:			

The F2013 EM&V Report contains six studies on DSM programs, none of which contain recommendations.

In the F2014 EM&V Report, recommendations are provided in the studies on the following DSM initiatives: RIB Rate: F2009–F2012, large general service (LGS) and medium general service (MGS) Conservation Rates: Calendar Years 2011–2012, Commercial product incentive program (PIP): F2011–F2013, and workplace conservation awareness (WCA) initiative: F2011–F2012.

In the F2015 EM&V Report, recommendations are provided in the studies on the following DSM initiatives: LGS and MGS Conservation Rates: F2014, and Power Smart Partners Commercial Program: F2011-F2012.

192.3 Please confirm that out of the studies containing a recommendation, the Commercial PIP, WCA initiative and Power Smart Partners Commercial Program are DSM programs. The rest are rate structures. If not confirmed, please explain.

192.4 Please explain how the recommendations contained in the past three EM&V reports have been adapted in the proposed program offerings for F2017 to F2019.

192.5 Please explain in detail BC Hydro's feedback loop (including timing and process) to use EM&V results to inform DSM program offerings and implementation.

192.6 Please explain whether recommendations can be provided in more EM&V studies on DSM programs, such as those included in the F2013 EM&V report.