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March 6, 2012

BC HYDRO - F2012-F2014
REVENUE REQUIREMENTS **EXHIBIT A-28**

Ms. Janet Fraser
Chief Regulatory Officer
British Columbia Hydro and Power Authority
333 Dunsmuir Street
Vancouver, BC V6B 5R3

Dear Ms. Fraser:

Re: British Columbia Hydro and Power Authority
Project No. 3698622/Order G-40-11
F2012 to F2014 Revenue Requirements Application

Further to Commission Order G-206-11, which established a Regulatory Timetable with respect to the above noted Application, enclosed please find Commission Information Request No. 2. In accordance with the Regulatory Timetable, please file your responses electronically with the Commission by Tuesday, March 27, 2012 in accordance with the Commission's Document Filing Protocols, effective May 16, 2005.

Yours truly,

Alanna Gillis

CM/cms
Enclosure
cc: Registered Interveners

BC Hydro and Power Authority
F2012 to F2014 Revenue Requirements Application

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A. RATE MANAGEMENT

1.0 Reference: Introduction
Exhibit B-1-3, Amended Append A
Exhibit B-16, BCOAPO IR 1.11.1
Regulatory Schedules and Tables

RESPONSE: BCOAPO IR 1.11.1

BC Hydro could restate the F2011 actual costs on a basis that is consistent with the presentation of the F2012 to F2014 revenue requirements, but BC Hydro does not believe the significant effort required to do this restatement would provide meaningful information. BC Hydro has restated the F2011 Plan as the F2011 NSA-12 to be comparable to the F2012 to F2014 revenue requirements.

1.1 Please update Amended Appendix A, NSA-12 balances to assume the integration of BCTC for 12 months based on ACTUAL F2011 results. Please provide detail explaining the calculation of each adjustment. Please explain if the resulting figures will equal the F2011 Actual column adjusted for BCTC actual costs to integration plus the Nature View adjustments.

2.0 Reference: Rate Management
Exhibit B-15, IR 1.2.1
Exhibit B-16: COPE IR 1.62.3, BCOAPO IR 1.82.1
Future Impacts of Rates

BCUC IR 1.2.1 asked BC Hydro to provide BC Hydro's 'best estimate' of the forecast rate increased in F2015, F2016 and F2017 which BC Hydro declined to answer to the reasons noted in its response. COPE IR 1.62.3 and BCOAPO IR 1.82.1 requested forecast rates for F2015-F2017 with variations to specific data.

Given the potential deferral nature of BC Hydro's proposed rates it is very important that the public know what the impact of the reduction in rates as proposed in New Table 1-A will have on future rates.

2.1 Please respond to BCUC IR 1.2.1 as requested in IR #1 using BC Hydro's 'best estimate' at this time. Please provide detail on the assumptions used to provide the response.

3.0 Reference: Rate Management
Exhibit B-1-3, Chapter 1, Section 1.1
Plans to Achieve Rate Decrease (Table 1-A)

3.1 In New Table 1-A, BC Hydro identifies 'Other' reduction of $10 million required to achieve the proposed rates. Please separate 'Other' between Government Review and Evidentiary update.

3.2 It is understood that the $10 million is made up of various items; however it is necessary to determine if the $10 million related to cuts in spending (real savings) or deferrals. Please

separate out 'Other' between real cuts in spending and amounts being deferred until a future period.

4.0 Reference: Rate Management
Exhibit B-1-3: Chapter 1, Sections 1.7.4-5; Chapter 7, Section 7.1.2
Exhibit B-15-1, IR 1.10.5
Amounts at Risk for BC Hydro

"With respect to the deferral of differences between forecast and actual costs, BC Hydro remains of the view that it should assume financial responsibility for controllable risks and create regulatory accounts for non-controllable risks. In the F05/F06 RRA, BC Hydro proposed the following criteria to be used to assess 17 whether a risk was controllable or non-controllable:

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

In the F05/F06 RRA Decision, the BCUC accepted BC Hydro's proposed criteria but concluded that risk/reward considerations were also a relevant criterion. The BCUC noted that even if some costs are non-controllable, the risk of variances from forecasts may be appropriately borne by the shareholder because of risk/reward considerations. BC Hydro is not proposing any changes to the criteria to be used to assess whether a risk is controllable or non-controllable." (Section 7.1.2, pp. 3-4)

RESPONSE: BCUC IR 1.10.5

Yes, BC Hydro is at risk for some of the forecast items presented in the Revenue Requirement Application.

Specifically, BC Hydro is at risk for variances from Plan on the following items:

Forecast Item	Amended Appendix A reference
Miscellaneous revenues	Schedule 15.0
Operating costs	Schedule 5.0, line 9 less lines 5 and 6
Provision and other costs	Schedule 5.0, lines 62 to 66 (1)
IFRS Mass Asset Harmonization costs and Amortization	Schedule 5.0, line 67; Schedule 7.0, line 26
Taxes	Schedule 6.0

Note 1 - lines 62 to 66 mainly includes Gains/losses on Asset Disposals and ARO Accretion.

BC Hydro included the following table identifying the variance that BC Hydro is at risk for in response to IR 1.10.5.

4.1 BC Hydro has identified Schedule 5.0 lines 62 to 66 as costs they are at risk for, however, line 67 Mass Asset Retirement of $19.9 million in F2013 and $20 million in F2014 were not included. Should it have been, and if not in which deferral account is the variance captured?

4.2 Is BC Hydro at risk for variance in the forecast ROE or certain components of the ROE? If not, please explain where the variances are captured?

4.3 Please confirm, or explain otherwise, that the table provided in response to BCUC IR 1.10.5 was prepared under the assumption that all of the variances that BC Hydro is proposing to be deferred in F2012-F2014 are approved.

4.4 Please update the table provided in BCUC IR 1.10.5 to include the forecast amounts (baseline) and calculate the percentage of the baseline to the total RRA. Please reference the amounts to Appendix A.

4.5 Please provide an additional table similar to the one provided in response to BCUC IR 1.10.5 to include the forecast amounts (baseline) included the percentage of the total RRA assuming that NONE of the requested variance deferral accounts are approved. Please reference the amounts to Appendix A.

4.6 Please provide a table, similar to the one provided in response to BCUC IR 1.10.5 identifying all the forecast items **and amounts (baselines)**, included the percentage of the total RRA, by year from F2007 to F2011. Please reference the amounts to Appendix A.

4.7 Please provide a table identifying all the forecast to actual variance for which BC Hydro is seeking approval for in this Application (only identify items which BC Hydro specifically requires BCUC approval for in this Application). Please distinguish between variances that were approved in F2011 but require further approval for the test period (ex: Load Variance) and variances that are new for the F2012-14 test period (ex: non-current OPEB) and identify the amounts (baselines) and the percentage of the total RRA. Please reference the amounts to Appendix A. Please also identify any forecast to actual variances items that are no longer being captured in a deferral or regulatory account that were captured in F2011.

B. AUDITOR GENERAL'S REPORT ON REGULATORY AND DEFERRAL ACCOUNTS

5.0 Reference: Deferral/Regulatory Accounts
Exhibit B-1-3, Appendix GG
Exhibit B-15, IR 1.4.1
Long Term Plan

In Response to IR 1.4.1 BC Hydro state that it is currently developing a more comprehensive and consolidated long-term plan to address the recovery of its regulatory accounts.

5.1 Does BC Hydro anticipate completing this plan and filing it prior to the commencement of the oral hearing in June 2012?

5.1.1 If no, when does it anticipate completing and filing the plan?

C. DEFERRAL ACCOUNTS & DARR

General

6.0 Reference: Heritage Deferral Account
Exhibit B-1-3, Amended Appendix A, Schedule 4.0, p. 23
Exhibit B-15, BCUC 1.14.1, BCUC 1.14.2
Cost of Energy
F2011 DARR Account variances

6.1 Please confirm that from F2011 onward, the Non-Heritage Sources of Supply in Schedule 4.0 of Amended Appendix A are required to be purchased by BC Hydro. Specifically for the "IPP's and Long-Term Commitments", is BC Hydro committed to purchase all energy that is offered, and if not, please identify which contracts allow BC Hydro to refuse energy that is offered or supplied.

6.2 Please identify which source of energy would have been reduced in F2011 if BC Hydro had chosen to generate Heritage Hydroelectric energy in the amount of 42,600 GWh.

6.3 Please identify the effect on the amount and the average cost of Market Electricity Purchases in F2011 if the actual generated Heritage Hydroelectric energy was 42,600 GWh instead of 39,303 GWh, and identify the cost of the associated with the incremental generated energy. In other words, what would have been the cost impact if the 3,297 GWh had been generated from Heritage hydroelectric resources instead of being purchased from the market?

7.0 Reference: Heritage Deferral Account
Exhibit B-15, BCUC 1.392.1; BCUC 1.392.7; BCUC 1.72.1
Cost of Energy - Williston Reservoir Operation
F2011 DARR Account variances

"BC Hydro also estimated that had Unit 3 been in service, about 360 GWh of additional energy would have drafted from Williston Reservoir by late spring 2008. With Unit 3 in service, BC Hydro would have bought additional market energy to refill at average price of about CAD $20/MWh across about June 29 to July 13, at rate of about 8 GWh per day in LLH. This low-priced energy was not purchased during the outage due to the risk of spill associated with higher reservoir elevations due to Unit 3 being out of service. This re-operation benefit is not captured in the detailed calculations implemented in the algorithm provided above, and thus was added as an extra offsetting line item with a value of $2.35 million." (BCUC 1.392.1)

"As can be seen in the following graph, the profile of Williston Reservoir is very similar in both the observed and calculated with Unit 3 in service traces. Under the case of Unit 3 in service, almost six feet of storage above 2,150 remained at the start of the 2009 freshet, demonstrating that this alternative operation is feasible from a reservoir operation perspective." (BCUC 1.392.7)

"Inflows to Williston Reservoir in the May 1 to October 1, 2010 period were approximately 4,400 GWh lower than normal for this period. In the May 1 to October 1, 2010 period, BC Hydro made net consolidated electricity market purchases of approximately 2,300 GWh into the system, of which approximately 2,100 GWh were net domestic electricity market purchases." (BCUC 1.72.1)

7.1 Given the multi-year nature of the Williston Reservoir, did the higher reservoir level at the end of the 2009 water year attributable to the GMS 3 failure benefit the situation of the low inflow

in the 2010 water year? If not, why not? If so, has the benefit been quantified? If quantified, please provide the amount.

8.0 Reference: Deferral Accounts
Exhibit B-16, AMPC IR 1.18.6
Interest and ROE

AMPC IR 1.18.6

Year	Year End Balance			Debt	Equity	Deemed Equity
	Total	Non-Cash	Net			
	($ million)	($ million)	($ million)	($ million)	($ million)	($ million)
F2007	449	90	360	303	56	85
F2008	572	319	253	191	62	93
F2009	1,016	326	690	617	72	109
F2010	1,713	629	1,084	996	89	133
F2011	2,161	533	1,628	1,527	101	152
F2012	2,768	482	2,287	2,157	130	195
F2013	4,158	1,200	2,958	2,799	159	238
F2014	4,696	1,156	3,540	3,347	193	289

8.1 BC Hydro provided the above table in response to AMPC IR 1.18.6 which identifies the amount of deferral subject to Debt and Deemed Equity. Leaving the data as provided, please update the table to include the dollar amount of Debt and Deemed Equity (recovered or compounded into the deferral account) in each of the years identified in the table.

9.0 Reference: Heritage Payment Obligation
Exhibit B-1-3: Chapter 1, Section 1.7.7, p. 1-45; Appendix A, Schedule 4.0
Baseline for HDA and NHDA

Cost of Energy (COE)
($ million)

			Reference	F2011 NSA-12	F2012 Update	F2013 Update	F2014 Update
				8	9	10	11
		Heritage Payment Obligation					
61		Heritage Energy	Line 8	499.7	402.2	393.8	371.2
62	A	Costs in Operating/Amortization		19.3	22.4	19.2	16.2
64	B	Notional Water Rentals		5.9	(9.0)	(1.3)	(5.0)
65	C	Skagit and Ancillary Revenue		(20.5)	(14.6)	(14.8)	(15.5)
69	D	Other		6.5	7.7	7.6	6.9
70		Total		510.9	408.7	404.5	373.7
71		**Total System Inflow (% of Normal)**		90%	100%	100%	100%

The above is an excerpt of Schedule 4.0 reflecting the details of the Heritage Payment Obligation specific forecast that BC Hydro is seeking BCUC approval for. (Exhibit B-1-3, p. 1-45)

9.1 Please provide references to where in the Amended Appendix A the costs associated with Cost in Operating/Amortization (line 62), Notional Water Rentals (line 64), Skagit and Ancillary Revenue (line 65) can be traced.

9.2 Why are the amounts hard coded and not coming from supporting Schedules within Appendix A?

Heritage Deferral Accounts

10.0 Reference: Heritage Deferral Account
Exhibit B-15, IR 1.8.1
Exhibit B-1-3, Chapter 7, Section 7.1.2
Deferral Account Components
Other

As provided by BCH - BCUC IR 1.8.1

Heritage Deferral Account													
	Opening Balance	Energy	Commodity Risk (gains/losses on derivatives)	Notional Water Rental	Skagit and Ancillary Revenue	Load Curtailment	Transfer to GMS 3	Other	total adjustments	Amortization	Interest	Ending Balance
F2005	$ -	$ 139.2	-$ 22.8	$ 10.7	$ 3.5	$ -	$ -	$ 0.3	$ 130.9	$ -	$ 7.0	$ 137.9
F2006	$ 137.9	$ 62.9	$ 29.7	-$ 0.2	$ -	$ -	$ -	$ -	$ 92.4	$ -	$ 10.4	$ 240.7
F2007	$ 240.7	-$ 34.6	$ 4.2	$ 4.9	$ 1.0	$ -	$ -	$ 1.1	-$ 23.4	-$ 53.3	$ 14.1	$ 178.1
F2008	$ 178.1	-$ 58.0	$ 1.9	-$ 2.9	$ 5.0	-$ 5.0	$ -	$ 2.8	-$ 56.2	-$ 50.2	$ 6.3	$ 78.0
F2009	$ 78.0	$ 192.6	$ 91.4	$ 0.7	-$ 5.4	$ -	-$ 21.2	$ 1.5	$ 259.6	-$ 22.6	$ 13.9	$ 328.9
F2010	$ 328.9	$ 8.2	-$ 10.7	$ 9.3	$ 3.2	$ -	-$ 8.3	$ 1.4	$ 3.1	-$ 29.3	$ 22.2	$ 324.9
F2011	$ 324.9	-$ 33.5	$ 1.1	$ 1.6	$ 3.4	$ -	$ -	-$ 0.5	-$ 27.9	-$ 62.7	$ 13.4	$ 247.7
TOTALS		*$ 276.8*	*$ 94.8*	*$ 24.1*	*$ 10.7*	*-$ 5.0*	*-$ 29.5*	*$ 6.6*	*$ 378.5*	*-$ 218.1*	*$ 87.3*	$ 247.7

10.1 Please confirm, or explain otherwise, that "**Other**" in the table above relates to the following items:

- Costs in Operating/Amortization
- Significant unplanned major maintenance costs
- Amortization and Finance costs on unplanned major capital expenditures
- Amortization of unplanned deferred capital costs
- Variable costs related to thermal generation

10.1.1 Please confirm, or explain otherwise, that since inception of the HDA total "Other" additions amount to $6.6 million representing less than 2 percent of total additions and therefore, for purposes of determining an appropriate DARR, are immaterial for consideration.

10.1.2 In consideration of the materiality and frequency criteria to be used to assess whether a variance should be captured in a deferral account as outlined on p. 7-3 of the Application (Exhibit B-1-3), please explain why the variances represented in these "Other" items should continue to be eligible for deferral.

11.0 Reference: Heritage Deferral Account
Exhibit B-1-3, Appendix P, Schedule B, footnote 1
Deferral Account Components
Other - Costs Operating/Amortization

11.1 Please confirm, or explain otherwise, that "**Costs Operating/Amortization**" relate to costs associated with maintaining water licenses and water use plans, compensation and mitigation efforts of fund fish and wildlife programs and load curtailment efforts have been reclassified from cost of energy to other line items on the financial statements in preparation for the conversion to IFRS and in conjunction with BC Hydro's implementation of its new financial

system. Given that the nature of these costs has not changed, these costs continue to be treated as cost of energy for deferral accounting purposes.

11.1.1 Please explain how this differs from the capitalization of EPA and the impact on Cost of Energy.

11.1.2 Why has the same treatment not been proposed for the capitalization of EPA's?

12.0 Reference: Heritage Deferral Account
Exhibit B-15: IR 1.8.1; IR 1.348.2
Order G-94-04
Exhibit B-1-3, Chapter 7, Section 7.5.2
Deferral Account Components
Other – Significant Unplanned Major Maintenance Cost

12.1 Please provide the amount of "Significant unplanned major maintenance cost" additions to the Heritage Deferral Account between F2005 and F2011, excluding GMS 3, on a year by year basis.

12.2 Please confirm, or explain otherwise, that Order G-94-04 approved BC Hydro's request to include unplanned major maintenance expenditures greater than $1 million related to a single event equipment of infrastructure failure or weather related event.

12.3 Please confirm, or explain otherwise, that Distribution and Generation Operating and Maintenance costs have been over $400 million since F2007. (Exhibit B-15, IR 1.348.2, Attachment 1)

12.4 Please confirm that $1 million represents 0.25% of total Distribution and Generation Operating and Maintenance costs.

12.5 Would it not be more appropriate to have a $10 million base line representing 2.5% of costs? Please discuss.

12.6 Please confirm that in the event of an unusual expenditure during a test period BC Hydro has the ability to submit an Application to the Commission for recovery of those costs, similar to what occurred with Rock Bay (Exhibit B-1-3, p. 7-32).

13.0 Reference: Heritage Deferral Account
Orders: G-94-04; G-16-09
Exhibit B-1-3, Chapter 7, Section 7.3.15 & 7.3.16
Deferral Account Components
Other - Amortization and Finance costs on unplanned major capital expenditures

13.1 Please provide the amount of "Unplanned major capital expenditures" additions to the Heritage Deferral Account between F2005 and F2011 on a year by year basis.

13.2 Please confirm that Order G-94-04 approved BC Hydro's request to include any incremental annual impact where the sum of depreciation and finance charges is greater than $1 million caused by unplanned major capital expenditures related to single event equipment or infrastructure failure or weather related events.

13.3 Please confirm that on p. 7-20 of the Application (Exhibit B-1-3) BC Hydro is requesting to continue this regulatory account.

13.4 Please confirm that in the F09/F10 Decision the BCUC (Order G-16-09) directed BC Hydro to defer in a regulatory account any differences between forecast and actual finances charges.

13.5 Please confirm, or explain otherwise, that if approval is granted as requested, these variances (depreciation and finance) are no longer required to be captured in the HDA as they will be captured in other regulatory accounts.

14.0 Reference: Heritage Deferral Account
Orders: G-96-04; G-53-02; G-56-06
Deferral Account Components
Other - Amortization of unplanned deferred capital costs

F05/F06 RRA (Order G-96-04) P. 36, section 4.4.3 "Capital Costs Pursuant to BCUC Order No. G-53-02, Item 5" states the following:

> BC Hydro proposes that amounts amortized pursuant to BCUC Order No. G-53.02 be included in the HDA.
>
> Order No. G-53-02 allows for the amortization of First Nations negotiation and settlement costs. Negotiations costs are planned and forecast each year, but settlement costs are not forecast.

14.1 Please confirm, or explain otherwise, that the inclusion "Other-Amortization of unplanned deferred capital costs" was approved as part of the F05/F06 RRA (Order G-96-04).

14.2 For each year from F2005 to F2011, what have been the variances in the amortization of the First Nations Costs Regulatory Account that are included as additions to the HDA?

14.3 Please confirm that settlement costs included in the First Nations Costs Regulatory Account are not currently being amortized and BC Hydro is required to obtain approval from the BCUC for an appropriate amortization period pursuant to Order G-56-06.

14.4 Please explain why this variance should continue to be included in the HDA given the immaterial nature of the variance and the fact that Settlement costs are not currently being amortized.

15.0 Reference: Heritage Deferral Account
Exhibit B-15, IR 1.8.1
Deferral Account Components
General

As provided by BCH - BCUC IR 1.8.1

Heritage Deferral Account													
	Opening Balance	Energy	Commodity Risk (gains/losses on derivatives)	Notional Water Rental	Skagit and Ancillary Revenue	Load Curtailment	Transfer to GMS 3	Other	total adjustments	Amortization	Interest	Ending Balance
F2005	$ -	$ 139.2	-$ 22.8	$ 10.7	$ 3.5	$ -	$ -	$ 0.3	$ 130.9	$ -	$ 7.0	$ 137.9
F2006	$ 137.9	$ 62.9	$ 29.7	-$ 0.2	$ -	$ -	$ -	$ -	$ 92.4	$ -	$ 10.4	$ 240.7
F2007	$ 240.7	-$ 34.6	$ 4.2	$ 4.9	$ 1.0	$ -	$ -	$ 1.1	-$ 23.4	-$ 53.3	$ 14.1	$ 178.1
F2008	$ 178.1	-$ 58.0	$ 1.9	-$ 2.9	$ 5.0	-$ 5.0	$ -	$ 2.8	-$ 56.2	-$ 50.2	$ 6.3	$ 78.0
F2009	$ 78.0	$ 192.6	$ 91.4	$ 0.7	-$ 5.4	$ -	-$ 21.2	$ 1.5	$ 259.6	-$ 22.6	$ 13.9	$ 328.9
F2010	$ 328.9	$ 8.2	-$ 10.7	$ 9.3	$ 3.2	$ -	-$ 8.3	$ 1.4	$ 3.1	-$ 29.3	$ 22.2	$ 324.9
F2011	$ 324.9	-$ 33.5	$ 1.1	$ 1.6	$ 3.4	$ -	$ -	-$ 0.5	-$ 27.9	-$ 62.7	$ 13.4	$ 247.7
TOTALS		$ 276.8	$ 94.8	$ 24.1	$ 10.7	-$ 5.0	-$ 29.5	$ 6.6	$ 378.5	-$ 218.1	$ 87.3	$ 247.7

15.1 Please explain why there has not been any adjustment to "**Load Curtailment**" since F2008? If there has been an adjustment included in another component of the HDA, please identify the year and the amount of the adjustment relating to Load Curtailment and the component it is included in.

15.2 Please confirm, or explain otherwise, that "**Notional Water Rentals**" in the Heritage Deferral Account nets out against Notional Water Rentals in the Non-Heritage Deferral Account and therefore has a $0 impact on the combined HDA+NHDA+TIDA balance.

15.3 Please confirm, or explain otherwise, that the F2009 Transfer to GMS 3 of $21.2 million (as shown in the BCH table provided above) relates exclusively to an adjustment of the Heritage Cost of Energy and does not include any of the unplanned maintenance costs.

15.4 Please explain, and provide support, where the Commission approved variances related to Skagit Valley Treaty revenues and ancillary services revenues were recorded in the HDA.

15.5 For purposes of evaluating an appropriate DARR as it relates to the HDA please confirm, or explain otherwise, that excluding GMS 3 it appears that the only 'material' adjustment that impact the HDA relate to variance in Heritage Cost of Energy and Commodity Risks which make up over 98% of the total additions to the account.

16.0 Reference: Heritage Deferral Account
Exhibit B-15, IR 1.13
Exhibit B-1-3, Amended Appendix P
BC Hydro: F07/F08 RRA NSA; F11 RRA NSA
Deferral Account Components
Commodity Risk

Schedule G of Appendix P (Exhibit B-1-3) states that variances in gains/losses on energy derivatives and financial instruments used to minimize energy costs are included as part of total energy costs.

16.1 Please provide support of where the Commission explicitly approved the inclusion of this variance in the HDA.

Schedule F of Appendix P (Exhibit B-1-3) footnote 2 states "In order to mitigate some of the commodity risk on domestic energy costs, BC Hydro enters into various forward contracts with Powerex for the purchase of electricity. Powerex then chooses to match these forward contracts with a third party or can take on the risk/benefits of their own. The transactions between BC Hydro and Powerex are eliminated on consolidation. With respect to the deferral accounts, any gain or loss on the derivative instruments on the Powerex side would flow though the TIDA and the corresponding gain/loss on the BC Hydro side would flow through the HDA and NHDA. While the gain/losses on these derivative instruments are not shown as part of energy costs on the financial statements due to GAAP reporting requirements, these gains/losses are reclassified for the calculation of deferral account transfers as they are part of managing the energy purchase costs."

"In accordance with the terms of the F07/F08 RRA NSA and the F11 RRA NSA, BC Hydro will not energy into any forward electricity or natural gas purchase agreements (energy hedges) without the approval of the BCUC."

16.2 Based on the F07/F08 RRA NSA (natural gas hedges) and the F11 RRA NSA (electricity hedges), what variances are now captured in the HDA?

In response to BCUC IR 1.13.4 & 5 BC Hydro confirmed that the Commodity losses captured in the BC Hydro HDA in F2009 of $91.4 million were also reported as a gain of $91.4 million in Powerex's net income for regulatory purposes. In response to BCUC IR 1.13.4 & 5 BC Hydro confirmed that in F2009 Powerex net income was $243.9 million and included the a gain of $91.4 million. Because Powerex's net income was in excess of $200 million in that year the ratepayer absorbed the full loss of $91.4 million and only received the benefit of $47 million of the gain resulting in a net expense of $44 million to the ratepayer.

BC Hydro states that the gain/losses are eliminated upon consolidation and are not shown as part of cost of energy for financial reporting purposes.

16.3 Please explain why BC Hydro does not use Powerex's consolidated net income (i.e. removing all intercompany transactions) for regulatory purposes.

16.4 Please confirm, or fully explain otherwise, that the net dollar impact to BC Hydro's consolidated financial statement due to these intercompany gains/losses on energy derivatives and financial instruments is $0.

16.4.1 If yes, please explain why the ratepayer should be responsible for variances on intercompany transactions, when Powerex's net income is greater than $200 million that eliminate upon consolidation and have NO financial impact to BC Hydro.

17.0 Reference: Heritage Deferral Account
Exhibit B-1-3: Amended Appendix P; Amended Appendix A, Schedule 4.0
Order G-96-04
BC Hydro F05/F06 RRA, Chapter 2B
Heritage Special Direction #2, Appendix A
Deferral Account Components
Cost of Energy

17.1 Please confirm that Schedule G in Amended Appendix P lists all eligible Heritage Deferral Account transfers.

The inclusion of variances in Cost of Energy was approved by the Commission in Order G-96-04 in Directive 11 which states: The Commission Panel approves the HDA as proposed by BC Hydro.

In the F05/F06 RRA Application BC Hydro proposed on p. 2B-2 that HDA record variance between Cost of Energy including all costs in (a)(i) in schedule A to appendix A of HSD #2, except those arising from changes in customer load.

Clause (a)(i) of schedule A to appendix A of HSD #2 states: costs of energy such as the cost of water rentals and energy purchases of gas and electricity, required to supply heritage electricity.

Cost of Energy ($ million)	
Heritage Energy	
Hydroelectric (water rentals)	
Market electricity purchases	
Market Purchases to Non-Heritage	
Natural gas for thermal generation	
Domestic transmission	
Surplus Sales	
Other	
Total	

17.2 The table above from Amended Appendix A, Schedule 4.0 lists the components that make up the Cost of Heritage Energy that is recovered in rates. Please confirm, or explain otherwise, that Clause (a)(i) of schedule A to appendix A of HSD #2 was referring to variances in these components.

Schedule G in Amended Appendix P (Exhibit B-1-3) lists the rules that BC Hydro follows for deferral account transfers between the forecast and the actual cost relating to Cost of Energy that flow through the HDA as:

A. Gains/losses on energy derivatives and financial instruments used to minimize energy costs are included as part of total energy costs.

B. The total Heritage (including Skagit/Seattle City Light commitments) is limited to 49,000 GWh in terms of the Heritage contract. If the Heritage Energy including 100 per cent of market electricity purchases exceeds the Heritage Energy limit, the excess purchases are transferred to Non-Heritage Energy in order to reduce the Heritage Energy volumes to the Heritage Contract limit.

C. Cost of energy variances resulting from changes to compensation and mitigation costs, water rental remissions, or Skagit energy transportation contracts are eligible for deferral.

D. All load curtailment costs are to be included as part of the Heritage Payment Obligation and variances between Actual and Plan is to be included in the HDA (F09/F10 RRA Decision, Directive 30)

17.3 Please confirm, or explain otherwise, that the list provided in Schedule G of Appendix P is meant to reflect all Cost of Energy variances from Amended Appendix A, Schedule 4.0, lines 1-7 plus the items listed above? If not, please provide a complete list of variances captured in the HDA relating to Cost of Energy.

17.4 Please explain and provide support for where variances in items A, B, and C were approved for inclusion in the HDA.

Non - Heritage Deferral Accounts

18.0 Reference: Non-Heritage Deferral Account
Heritage Special Direction #2
Deferral Account Components
General

18.1 Please confirm that Section 7 of HSD #2 requires the Commission to allow BC Hydro to establish deferral account mechanisms for the purpose of recording differences between the forecasts of the Heritage Payment Obligation and Trade Income used to establish rates, and the actual, after-the-fact Heritage Payment Obligation and Trade Income but does not explicit require to Commission to have a Non-Heritage Deferral Account.

19.0 Reference: Non-Heritage Deferral Account
Exhibit B-1-3: Amended Appendix P; Chapter 1, Section 1.3.1.7
Exhibit B-15, IR 1.9
Order G-16-09
COE Evidentiary Update proposed addition to the NHDA

"In total, the additional amounts that BC Hydro is proposing to defer related to the increased in the forecast net Cost of Energy are $65.9 million in F2012, $103.2 million in F2013 and $46.2 million in F2014. As in previous years, BC Hydro is proposing that these additional deferrals be included in the Non-Heritage Deferral Account (NHDA)." (Exhibit B-1-3, Chapter 1, Section 1.3.1.7)

In BCUC IR 1.9.3 BC Hydro stated that if these costs were to be reflected in the test period "All else being equal, the requested rate increases would be 10.19 per cent in F2012, 4.73 per cent in F2013 and 2.35 per cent in F2014."

19.1 Is this an incremental increase over what is already being proposed or would this be the total rate increase? Please explain.

19.2 If this is the total rate increase, please show how the rates of 10.19, 4.73 and 2.35 were derived and explain how the rate would be lower in F2013 and F2014 if an additional $103.2 million and $46.2 million were being recovered in rates in those years.

In response to IR 1.9.5 BC Hydro states: "In both the F09/F10 RRA and F11 RRA proceedings, BC Hydro's forecasts of cost of energy increased between the time of the original application and the subsequent filing of an evidentiary update. In neither evidentiary update did BC Hydro propose a higher rate increase, or propose to use the original forecast. Instead, in both cases BC Hydro proposed to defer the increased cost of energy in the NHDA, as it is currently proposing in this proceeding."

19.3 It is clear that this occurred as part of the F11 NSA as reflected in the $222.5 million addition to the NHDA; however, please provide further evidence, including references to the F09/F10 record, of this occurring in F09/F10.
Please provide the amount of the deferral in F09/F10.

19.4 Where in the table provided in response to BCUC IR 1.9.1 is the amount recorded?

19.5 Please confirm that Section 4.9 of Order G-16-09 Reasons for Decision (F09/F10 RRA) states "The Commission Panel does not accept that any transfers should be made to deferral accounts

for the sole purpose of affecting rates at this time. The BC Hydro proposal to credit the NHDA for $75.3 in order to achieve a final F2009 increase of 6.56 percent is denied."

19.5.1 Did this Commission Determination relate to the F09/F10 proposal to use the original forecast and not the evidentiary update forecast?

19.6 Please explain why BC Hydro thinks it is appropriate to use the evidentiary update forecasts for all balances other than the COE update. Other than the magnitude of its size, what make this forecast different from all the other forecasts?

20.0 Reference: Non- Heritage Deferral Account
Exhibit B-15, IR 1.9.1
Deferral Account Components
Other

As provided by BCH - BCUC IR 1.9.1

Non-Heritage Deferral Account	Opening Balance	Energy	Commodity Risk (gains/losses on derivatives)	Notional Water Rental	FX on Powerex trade account	Deferred Energy Costs	Other	Customer Load Cariance	ROE Adj	Mountain Pine Beatle	ABSU Founding Partners Benefits	F2007 Storm Restoration Regulatory Account	Transfer From BCTC Deferral Account	Total Adjustments	Amortization	Interest	Ending Balance
F2005	$ -	$ 154.5	-$ 5.3	-$ 10.7	-$ 10.6	$ -	$ -	$ -	$ -	$ -	$ -			$ 127.9	$ -	$ 3.0	$ 130.9
F2006	$ 130.9	$ 44.8	$ 19.8	$ 0.2	-$ 3.9	$ -	$ -	$ -	-$ 2.9	$ 7.3	-$ 0.6			$ 64.7	$ -	$ 9.0	$ 204.6
F2007	$ 204.6	$ 36.7	$ 3.3	-$ 4.9	$ 4.9	$ -	-$ 3.9	$ -	$ -	$ -	-$ 0.6			$ 35.5	-$ 45.3	$ 14.0	$ 208.8
F2008	$ 208.8	-$ 54.4	-$ 3.0	$ 2.9	-$ 18.6	$ -	$ 0.2	$ -	-$ 33.7	$ -	-$ 0.5			-$ 107.1	-$ 58.9	$ 8.8	$ 51.6
F2009	$ 51.6	-$ 39.5	$ 9.3	-$ 0.7	$ 9.7	$ -	$ 0.4	$ 8.4	$ -	$ -	-$ 0.5	$ 43.2		$ 30.3	-$ 14.9	$ 7.4	$ 74.4
F2010	$ 74.4	$ 124.0	$ 3.9	-$ 9.3	-$ 8.8	$ -	-$ 0.1	-$ 64.2	$ -	$ -	-$ 0.6			$ 44.9	-$ 6.6	$ 6.8	$ 119.5
F2011	$ 119.5	$ 18.6	-$ 12.1	-$ 1.6	-$ 4.0	$ 222.5	$ 16.0	-$ 20.7	$ -	$ -	-$ 0.2		$ 40.4	$ 258.9	-$ 23.5	$ 7.3	$ 362.2
TOTALS		$ 284.7	$ 15.9	-$ 24.1	-$ 31.3	$ 222.5	$ 12.6	-$ 76.5	-$ 36.6	$ 7.3	-$ 3.0	$ 43.2	$ 40.4	$ 262.5	-$ 149.2	$ 44.3	$ 362.2

20.1 Please provide a list of what is included in "Other".

20.2 Please provide the amount of **"Unplanned major capital expenditures"** additions to the Non-Heritage Deferral Account between F2005 and F2011 on a year by year basis.

20.3 Please provide the amount of **"Significant unplanned major maintenance cost**" additions to the Non-Heritage Deferral Account between F2005 and F2011 on a year by year basis.

21.0 Reference: Non- Heritage Deferral Account
Exhibit B-15, IR 1.9.1
Deferral Account Components
Cost of Energy

As provided by BCH - BCUC IR 1.9.1

Non-Heritage Deferral Account	Opening Balance	Energy	Commodity Risk (gains/losses on derivatives)	Notional Water Rental	FX on Powerex trade account	Deferred Energy Costs	Other	Customer Load Cariance	ROE Adj	Mountain Pine Beatle	ABSU Founding Partners Benefits	F2007 Storm Restoration Regulatory Account	Transfer From BCTC Deferral Account	Total Adjustments	Amortization	Interest	Ending Balance
F2005	$ -	$ 154.5	-$ 5.3	-$ 10.7	-$ 10.6	$ -	$ -	$ -	$ -	$ -	$ -			$ 127.9	$ -	$ 3.0	$ 130.9
F2006	$ 130.9	$ 44.8	$ 19.8	$ 0.2	-$ 3.9	$ -	$ -	$ -	-$ 2.9	$ 7.3	-$ 0.6			$ 64.7	$ -	$ 9.0	$ 204.6
F2007	$ 204.6	$ 36.7	$ 3.3	-$ 4.9	$ 4.9	$ -	-$ 3.9	$ -	$ -	$ -	-$ 0.6			$ 35.5	-$ 45.3	$ 14.0	$ 208.8
F2008	$ 208.8	-$ 54.4	-$ 3.0	$ 2.9	-$ 18.6	$ -	$ 0.2	$ -	-$ 33.7	$ -	-$ 0.5			-$ 107.1	-$ 58.9	$ 8.8	$ 51.6
F2009	$ 51.6	-$ 39.5	$ 9.3	-$ 0.7	$ 9.7	$ -	$ 0.4	$ 8.4	$ -	$ -	-$ 0.5	$ 43.2		$ 30.3	-$ 14.9	$ 7.4	$ 74.4
F2010	$ 74.4	$ 124.0	$ 3.9	-$ 9.3	-$ 8.8	$ -	-$ 0.1	-$ 64.2	$ -	$ -	-$ 0.6			$ 44.9	-$ 6.6	$ 6.8	$ 119.5
F2011	$ 119.5	$ 18.6	-$ 12.1	-$ 1.6	-$ 4.0	$ 222.5	$ 16.0	-$ 20.7	$ -	$ -	-$ 0.2		$ 40.4	$ 258.9	-$ 23.5	$ 7.3	$ 362.2
TOTALS		$ 284.7	$ 15.9	-$ 24.1	-$ 31.3	$ 222.5	$ 12.6	-$ 76.5	-$ 36.6	$ 7.3	-$ 3.0	$ 43.2	$ 40.4	$ 262.5	-$ 149.2	$ 44.3	$ 362.2

In the F05/F06 RRA Application BC Hydro proposed on p. 2B-3 that the NHDA record variance between the Cost of Energy and all non HPO energy costs except those arising from changes in customer load.

The inclusion of variances in Non-Heritage Cost of Energy was approved by the Commission in Order G-96-04 Directive 12 which states: The Commission Panel approves all elements of the NHDA, except the emergency restoration costs elements. (F05/F06 RRA Decision)

21.1 Please confirm that Schedule G in Amended Appendix P lists what BC Hydro considers to eligible Non-Heritage Deferral Account transfers.

Cost of Energy ($ million)	
	Non-Heritage Energy
	Mkt Purchases From Heritage
	Waneta (water rentals)
	IPPs and Long-Term Commitments
	New Capital Leases Under IFRS
	Non-Integrated Area
	Gas & Other Transportation
	Domestic Transmission
	Net Purchases (Sales) from Powerex
	Total

21.2 The table above from Amended Appendix A, Schedule 4.0 lists the components that make up the Cost of Non- Heritage Energy that is recovered in rates. Please confirm, or explain otherwise, these are the components that the F05/F06 decision was referring to when it stated all non HPO energy costs.

Schedule G in Amended Appendix P (Exhibit B-1-3) lists the rules that BC Hydro follows for deferral account transfers between the forecast and the actual costs relating to Cost of Energy that flow through the NHDA as:

A. Gains/losses on energy derivatives and financial instruments used to minimize energy costs are included as part of total energy costs.

B. Future Trade: when Powerex purchases energy for future trade the cost of the purchase from the external party and the sale to BC Hydro of this energy is recorded in Powerex and is included as part of Trade Income. The BC Hydro side of the entry is shown as part of domestic energy costs (on consolidation, the Powerex revenue from BC Hydro and the BC Hydro energy costs from Powerex are eliminated). The difference between Actual and Plan on the BC Hydro side to energy for future trade flows through the NHDA. The Powerex side of the transaction, which is part of Trade Income, flows through the Trade Income Deferral Account. Similar treatment is made when the energy is returned to Powerex.

21.3 Please confirm, or explain otherwise, the list provided in Schedule G of Appendix P is meant to reflect all Cost of Energy variances from Amended Appendix A, Schedule 4.0, lines 9-16, plus the items listed above. If not, please provide a complete list of variances captured in the NHDA relating to Cost of Energy.

21.4 Please explain and provide support where variances in items A & B were approved for inclusion in the NHDA.

22.0 Reference: Non- Heritage Deferral Account
Exhibit B-1-3, Appendix P
Exhibit B-15, IR 1.9.1
Deferral Account Components
Commodity Risks

As provided by BCH - BCUC IR 1.9.1

Non-Heritage Deferral Account																		
	Opening Balance	Energy	Commodity Risk (gains/losses on derivatives)	Notional Water Rental	FX on Powerex trade account	Deferred Energy Costs	Other	Customer Load Cariance	ROE Adj	Mountain Pine Beatle	ABSU Founding Partners Benefits	F2007 Storm Restoration Regulatory Account	Transfer From BCTC Deferral Account	Total Adjustments	Amortization	Interest	Ending Balance
F2005	$ -	$ 154.5	-$ 5.3	-$ 10.7	-$ 10.6	$ -	$ -	$ -	$ -	$ -	$ -			$ 127.9	$ -	$ 3.0	$ 130.9
F2006	$ 130.9	$ 44.8	$ 19.8	$ 0.2	-$ 3.9	$ -	$ -	$ -	-$ 2.9	$ 7.3	-$ 0.6			$ 64.7	$ -	$ 9.0	$ 204.6
F2007	$ 204.6	$ 36.7	$ 3.3	-$ 4.9	$ 4.9	$ -	-$ 3.9	$ -	$ -	$ -	-$ 0.6			$ 35.5	-$ 45.3	$ 14.0	$ 208.8
F2008	$ 208.8	-$ 54.4	-$ 3.0	$ 2.9	-$ 18.6	$ -	$ 0.2	$ -	-$ 33.7	$ -	-$ 0.5			-$ 107.1	-$ 58.9	$ 8.8	$ 51.6
F2009	$ 51.6	-$ 39.5	$ 9.3	-$ 0.7	$ 9.7	$ -	$ 0.4	$ 8.4	$ -	$ -	-$ 0.5	$ 43.2		$ 30.3	-$ 14.9	$ 7.4	$ 74.4
F2010	$ 74.4	$ 124.0	$ 3.9	-$ 9.3	-$ 8.8	$ -	-$ 0.1	-$ 64.2	$ -	$ -	-$ 0.6			$ 44.9	-$ 6.6	$ 6.8	$ 119.5
F2011	$ 119.5	$ 18.6	-$ 12.1	-$ 1.6	-$ 4.0	$ 222.5	$ 16.0	-$ 20.7	$ -	$ -	-$ 0.2		$ 40.4	$ 258.9	-$ 23.5	$ 7.3	$ 362.2
TOTALS		*$ 284.7*	*$ 15.9*	*-$ 24.1*	*-$ 31.3*	*$ 222.5*	*$ 12.6*	*-$ 76.5*	*-$ 36.6*	*$ 7.3*	*-$ 3.0*	*$ 43.2*	*$ 40.4*	$ 262.5	-$ 149.2	$ 44.3	$ 362.2

22.1 Please confirm, or explain otherwise, that **Commodity Risk** in the NHDA related to gains/(losses) on cash flow hedges with Powerex and Future Trades (embedded derivatives) with Powerex.

22.2 Please confirm that Commodity Risk between F2005 and F2011 has been $15.9 million to the expense (future) of ratepayers.

Footnote 6 in Schedule E of Appendix P (Ex. B-1-3) states these variances relate to "unrealized gains were recognized from the changes in the value of embedded derivatives components of future trades. These gains are eliminated against trade revenue on consolidation."

22.3 Please provide support of where the Commission explicitly approved the inclusion of these variances in the NHDA.

22.4 Would there be a net impact to the NHDA and the TIDA if Powerex's net income is greater than $200 million?

22.4.1 If yes, what was the net impact on the NHDA and TIDA in F05, F07 and F09 when Powerex's net income was in excess of $200 million?

22.5 Please confirm, or fully explain otherwise, that the net dollar impact to BC Hydro's consolidated financial statement due to the changes in the value of embedded derivatives components of future trades is $0.

22.5.1 If yes, please explain why the ratepayer should be responsible for variances on intercompany transactions, when Powerex's net income is greater than $200 million that eliminate upon consolidation and have NO financial impact to BC Hydro.

22.6 Please explain the difference between an embedded derivative of future trades and an energy hedge.

22.7 If there is no difference, why do the terms of the F07/F08 RRA NSA and F11RRA NSA which state that BC Hydro will not enter into any forward market electricity or natural gas purchase arrangements without the approval of the BCUC not apply to Non-Heritage energy?

22.8 Please confirm that **Foreign Exchange** with Powerex between F2005 and F2011 have been ($31.3) million to the expense (future) of ratepayers.

Schedule F to Appendix P (Ex B-1-3), footnote 3 states the following: This relates to the foreign exchange gain/loss on their receivable and this loss/gain would be part of Trade Income. Foreign exchange gains/losses arise as the Trade Account is recorded in $US. The gain/loss on the BC Hydro side is eliminated against the loss/gain on the Powerex side of consolidation within the finance charge components. As the mirror entry for Trade Income relating to F/X on the Trade Account is recorded on the Non-Heritage energy side, there is no net impact on the combined NHDA and TIDA due to these transactions. Net FX gains included losses related to internal cash flow hedges with Powerex.

22.9 Please provide support of where the Commission explicitly approved the inclusion of this variance in the NHDA.

22.10 Does the above quoted footnote still apply when Powerex's net income is greater than $200 million? Please explain.

23.0 Reference: Non Heritage Deferral Account
Order G-16-11
Exhibit B-1-3, Chapter 7, Section 7.1.2
Deferral Account Components
BCTC

In Order G-16-11 the Commission approved, among other things, that on a go-forward basis the NHDA will be allowed to capture difference between forecast and actual transmission service revenues and transmission maintenance expenditures over $1 million.

23.1 Based on the criteria provided on page 7-3 of the Application, please explain in detail why variance in this cost should be to the risk of ratepayers.

23.2 In order to determine an appropriate DARR would it not be simpler to have these variances captured in a separate regulatory account rather than the NHDA?

23.3 Do these costs have anything to do directly with the Non Heritage Cost of Energy calculation?

<u>Non - Heritage Deferral Accounts Load Variance</u>

24.0 Reference: Non-Heritage Deferral Account Components
Order G-16-09
Exhibit B-1-3, Appendix FF
Load Variance

Section 5.5.2 of Order G-16-09 Reasons for Decision (F09/F10 RRA) states "The JIESC, while philosophically opposed to the proposal because the utility should bear the forecasting risk, supports the proposal "at this time" due to economic factors, unproven DSM measures and new rate structures. The JUESC further submits that this deferral account should eliminate "as more normal conditions return."

24.1 Referring specifically to Appendix FF, please explain why BC Hydro still is of the opinion that normal conditions have not returned.

25.0 Reference: Non-Heritage Deferral Account Components
Exhibit B-1-3: Appendix A, Schedule 1; Appendix P
F07/F08 RRA NSA
F09/F10 RRA Order G-16-09
F11 RRA NSA
Exhibit B-15; IR.19.1, IR 1.10.2, IR 1.10.4
Load Variance

25.1 Please confirm that in F2005-F2008 variances related to cost of energy, except those arising from changes in customer load, were captured in the HDA and the NHDA.

25.2 Please confirm, or explain otherwise, that in the Quarterly Deferral Account reports submitted to the Commission between F2005 and F2008 BC Hydro reported the total Cost of Energy variance and then made an adjustment to remove the Cost of Energy related to Load.

25.3 If the load variance had not been approved in F2009, what would the "Remove Customer Load Variance" for the COE variance have been for F09, F10 and F11?

25.4 Please confirm, or explain otherwise, that in the F07/F08 RRA NSA BC Hydro's proposal that the cost of load variance net of incremental domestic revenue be transferred to the cost of energy Deferral Account was not agreed upon by the parties.

In the F09/F10 RRA Application BC Hydro requested and was granted approval (Order G-16-09) to record "Net Load" Variance in the NHDA. The calculation for the Net Load Variance is different from the calculation that was made to carve out the Customer Load Variance in F2005-F2008. The customer load variance that was carved out in F05-F08 related only to the variance in Cost of Energy relating to Load. In F09/F10 BC Hydro requested and was approved to capture BOTH the Cost of Energy and Revenue variances in the NHDA.

BC Hydro reported Non-Heritage Cost of Energy variances including Load in BCUC IR 1.9.1 as follows:

As reported by BC Hydro in the RRA Application			
	Cost of Energy	Customer Variance	Total
F2009	-$ 39.5	$ 8.4	**-$ 31.1**
F2010	$ 124.0	-$ 64.3	**$ 59.7**
F2011	$ 18.6	-$ 20.7	**-$ 2.1**
	$ 103.1	-$ 76.6	**$ 26.5**

However, in the Quarterly Deferral Account reports submitted to the Commission (Exhibit B-1-3, Appendix P) BC Hydro reports the Cost of Energy variance including load as follows:

As reported in the Quarterly Deferral Account Reports to the Commission			
	Cost of Energy	Customer Load Variance	Total
F2009	-$ 51.5	$ 20.4	-$ **31.1**
F2010	-$ 22.8	$ 82.5	$ **59.7**
F2011	-$ 44.5	$ 42.4	-$ **2.1**
	-$ 118.8	$ 145.3	$ **26.5**

According to BCUC IR 1.10.2 the Customer Load Variance reported in the Commission reports are Revenue Variances while the amounts reported in the Application are the Net Load Variances. In response to BCUC IR 1.10.4 BC Hydro states: "As shown in attachment K from the F09/F10 RRA, rather than first deducting the gross load variance (as had been done prior to F2009) and then adding the net load variance, mathematically the same result is obtained by adding the domestic revenue variance to the actual cost of energy. However, this is just a mathematical simplification, and the change in the transfer to the cost of energy Deferral Accounts arising from the deferral of the net load variance is still the **difference between the gross load variance and the revenue variance**." (emphasis added)

The difference between the gross load variance and the revenue variance is how BC Hydro reports to the Commission.

25.5 Please confirm that as a result of the F09/F10 decision and F11 RRA NSA BC Hydro is entitled to recover the variance in Cost of Energy due to Load and the variance in Revenue due to Load for F09, F10 and F11.

Revenue Requirements Summary ($ million)										
			F2009			F2010			F2011	
		RRA	Actual	Difference	RRA	Actual	Difference	NSA-9	Actual	Diff
Line	Column	1.1	2	2.1 = 2 - 1.1	2.2	3	3.1 = 3 - 2.2	4	5	6 = 5 - 4
20	**Less Other Utilities Revenue**	(15.2)	(22.0)	(6.9)	(16.6)	(16.3)	0.3	(17.6)	(16.3)	1.3
21	**Less Deferral Rider**	(14.1)	(14.0)	0.1	(15.3)	(29.7)	(14.4)	(113.9)	(112.9)	1.0
22	**Total Rate Revenue Requirement**	2,817.2	2,796.9	(20.3)	3,054.2	2,971.6	(82.5)	3,183.5	3,141.1	(42.4)
	Rate Revenue at Current Rates									
23	Total Domestic Revenue	2,846.4	2,833.0	(13.5)	3,086.0	3,017.6	(68.4)	3,315.0	3,270.3	(44.7)
24	Less Other Utilities	(15.2)	(22.0)	(6.9)	(16.6)	(16.3)	0.3	(17.6)	(16.3)	1.3
25	Less Deferral Rider	(14.1)	(14.0)	0.1	(15.3)	(29.7)	(14.4)	(113.9)	(112.9)	1.0
26	Revenue Subject to Rate Increase	2,817.2	2,796.9	(20.3)	3,054.1	2,971.6	(82.5)	3,183.6	3,141.1	(42.4)
27	**Revenue Shortfall**									
27.1	Revenue from 8% May 1 2011 Interi									
27.2	Remaining Shortfall									
28	**Rate Increases (May 1 for F2012)**		2.34%			8.74%		4.67%		
29	**Deferral Account Rate Rider**		0.50%			1.00%		3.53%		
30	**Net Bill Impact**		0.83%			9.28%		7.29%		

25.6 Please confirm that as reported in Amended Appendix A Schedule 1 the difference in the TOTAL Rate Revenue Requirement between forecast and actual is ($20.3) million in F2009, ($82.5) in F2010, and ($42.4) in F2011.

25.7 Please confirm that this variance is included in the NHDA as reported to the Commission in the year end Quarterly Deferral Account reports for F09, F10 and F11.

25.8 Do the F09, F10, and F11 Actuals reported in Amended Appendix A, Schedule 1 include variance from actual for items that BC Hydro has identified that it is at risk for in response to BCUC IR 1.10.5 (Miscellaneous revenues, Operating Costs, Provisions and other costs, IFRS Mass Asset Harmonized costs and Amortization and Taxes)?

25.8.1 If no, please explain.

25.8.2 If yes, please confirm, or explain otherwise, that under the current approved methodology BC Hydro is not at risk for any variance between forecast and actual.

25.9 Please explain how the revenue variance of ($20.3) million in F2009, ($82.5) in F2010, and ($42.4) in F2011 relates exclusively to Load and does not capture ALL revenue variance between the actual forecast Revenue Requirement and the Actual amounts incurred by BC Hydro.

26.0 Reference: Non-Heritage Deferral Account Components
Exhibit B-1-3: Appendix FF; Appendix A, Schedule 14.0
Load Variance

BC Hydro is requesting that load variances be included in the NHDA based on the uncertainty of key factors such as the economy, weather, and customer demand. The level of risk has been quantified in terms of confidence intervals in BC Hydro's 2010 Load Forecast (ref. Exhibit B-1-3, Appendix FF).

26.1 Please confirm that the load forecast data provided in Exhibit B-1-3, Appendix A, Schedule 14.0 is based on BC Hydro's 2010 Load Forecast as presented in Appendix FF. Please also confirm the date on which the 2010 Load Forecast was last updated to reflect the most current input variables.

26.2 Historically, there have always been risks associated with load forecasts. BC Hydro's request to have load variance deferred in the current test period is based on the belief that there are abnormally high levels of risk in the current test period in comparison to prior years. Please confirm whether this is correct.

26.2.1 BC Hydro has noted that the weather is a risk that is beyond their control. Is BC Hydro of the opinion that in general the weather has become more volatile, and therefore, less predictable when compared to pre-2009 test periods?

26.2.2 BC Hydro partially attributes an increase in risk to uncertainty of customer demand arising from changes in pricing. Traditionally, variations in demand due to fluctuations in price have been accounted for and modeled through the use of price-elasticity coefficients. Does price-elasticity remain a reliable method for forecasting the impact that price changes have on energy demand?

26.3 Please provide references to the relevant sections of Exhibit B-1-3 that provide evidence that economic, weather, and demand risks during the current test period are expected to be materially higher than in test periods prior to F2009.

TIDA

27.0 Reference: Trade Income Deferral Account
Exhibit B-15, IR 1.23.1
Deferral Account Components

Trade Income Deferral Account									
	Opening Balance	actual trade income	excess over cap	adjusted trade income	Forecast Trade Income	Total Adjustments	Amortization	Interest	Ending Balance
F2005	$ -	$ 256.0	$ 56.0	$ 200.0	$ 89.5	-$ 110.5	$ -	-$ 4.0	-$ 114.6
F2006	-$ 114.6	$ 179.4	$ -	$ 179.4	$ 91.0	-$ 88.4	$ -	$ 10.5	-$ 192.6
F2007	-$ 213.2	$ 259.1	$ 59.1	$ 200.0	$ 179.8	-$ 20.2	$ 47.2	-$ 15.9	-$ 202.2
F2008	-$ 202.2	$ 82.7	$ -	$ 82.7	$ 136.9	$ 54.2	$ 56.9	-$ 11.5	-$ 102.6
F2009	-$ 102.6	$ 243.9	$ 43.9	$ 200.0	$ 199.0	-$ 1.0	$ 29.6	-$ 5.9	-$ 79.9
F2010	-$ 79.9	$ 7.5	$ -	$ 7.5	$ 199.0	$ 191.5	$ 7.1	$ 3.0	$ 121.7
F2011	$ 121.7	$ 71.5	$ -	$ 71.5	$ 152.0	$ 80.5	-$ 23.5	$ 8.8	$ 187.5
TOTALS		*$ 664.7*	*$ 103.0*	*$ 561.7*	*$ 866.7*	***$ 305.0***	***$ 117.3***	***-$ 21.5***	$ 187.5

27.1 The updated table reflects changes as noted by BC Hydro in BCUC IR 1.23.1. Please confirm that the updated table is correct. If not confirmed please provide an updated table.

Deferral Account Rate Rider (DARR)

28.0 Reference: Deferral Accounts
Exhibit B-15, IR 1.5.4
Deferral Account Balance / Per Customer

In response to IR 1.5.4 BC Hydro states that "Dividing the total balance in the regulatory accounts by the total number of customers would not be meaningful, due to the wide variation in the size of the customers."

It is understood that there is a wide variation in the size of customers; however, the information still has relevance as the variation is customer size in likely consistent from year to year so the change in annual variation would be meaningful.

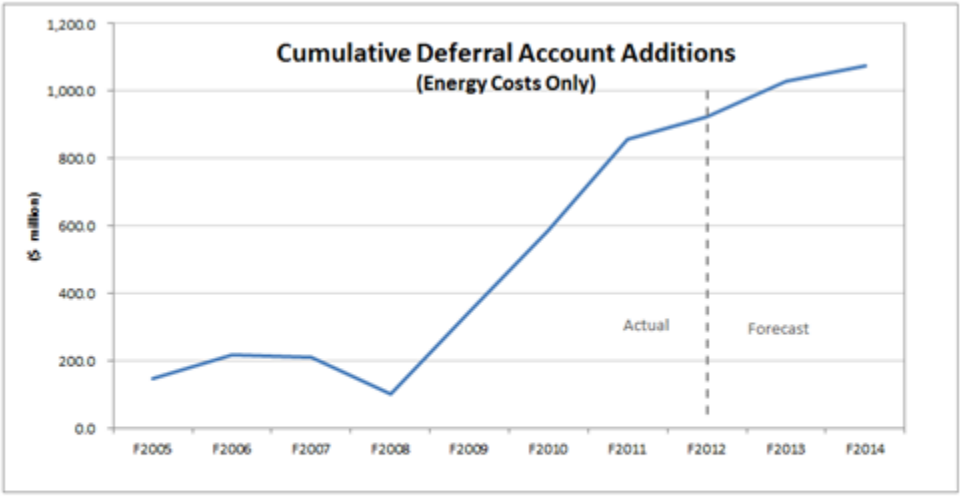
28.1 Please separate the amount of the DARR for each of the fiscal years from F2007 to F2014 in proportion to the annual energy consumption by Residential, Commercial, and Industrial customers, and provide the resulting DARR amount share per Residential, Commercial and Industrial customer.

29.0 Reference: Deferral Accounts
Exhibit B-1-3: Appendix C-2, Clause 7 (c)
Growing Balance in the Regulatory Accounts

HC2 clause 7(c) states: "When regulating and setting rates for the authority, the commission: must set or regulate the authority's rates in such a way as to allow the deferral accounts to be cleared from time to time within reasonable periods of time."

29.1 Would BC Hydro interpret this clause to refer exclusively to the Heritage, Non-Heritage and TIDA accounts and not BC Hydro's other Regulatory accounts? If not, please explain otherwise.

30.0 Reference: Deferral Accounts
Exhibit B-15, IR 1.19
Cost of Energy
Appropriate DARR



Cumulative Deferral Account Additions ($ million)	F2005 Actual	F2006 Actual	F2007 Actual	F2008 Actual	F2009 Actual	F2010 Actual	F2011 Actual	F2012 Forecast	F2013 Forecast	F2014 Forecast
Heritage Deferral Account	130.9	223.3	199.9	145.6	405.4	408.5	380.6	380.6	380.6	380.6
Non-Heritage Deferral Account	127.9	192.6	228.1	121.0	108.1	153.0	371.5	437.4	540.6	586.9
Trade Income Deferral Account	(110.5)	(198.8)	(219.0)	(164.8)	(165.8)	25.7	106.2	106.2	106.2	106.2
Deferral Account Balance	148.3	217.1	209.0	101.8	347.7	587.2	858.3	924.2	1,027.4	1,073.7

Source of data: F2012-F2014 Exhibit B-15, IR BCH Response 1.19.1

30.1 The above graph summarizes actual deferral account additions (energy costs only) for the period F2005 to F2011. Based on historical trends since 2005, please revise the graph to include a 90% confidence interval for the forecast period F2012 to F2014.

30.2 Please provide an electronic spreadsheet that makes it possible to trace how BC Hydro has calculated the 80% confidence interval.

30.3 Based on historical results, please provide an estimate of the maximum and minimum cumulative deferral account additions for HDA, NHDA, and TIDA for F2012, F2013, and F2014. Please assume a 90% confidence interval.

Actual Energy Costs Only ($ million)	F2005 Actual	F2006 Actual	F2007 Actual	F2008 Actual	F2009 Actual	F2010 Actual	F2011 Actual	Average
Heritage Deferral Account								
Forecast Cost	486.0	425.9	463.7	388.1	406.4	432.2	510.9	
Actual Cost	616.9	518.3	440.3	331.9	666.0	435.3	483.0	
Difference	130.9	92.4	(23.4)	(56.2)	259.6	3.1	(27.9)	54.1
Per Cent Difference	26.9%	21.7%	-5.0%	-14.5%	63.9%	0.7%	-5.5%	12.6%
Absolute Difference	130.9	92.4	23.4	56.2	259.6	3.1	27.9	84.8
Per Cent Absolute Difference	26.9%	21.7%	5.0%	14.5%	63.9%	0.7%	5.5%	20%
Non-Heritage Deferral Account								
Forecast Cost	354.9	379.8	569.9	632.3	628.0	688.5	794.8	
Actual Cost	482.8	440.7	606.1	559.4	564.0	798.2	771.4	
Difference	127.9	60.9	36.2	(72.9)	(64.0)	109.7	(23.5)	24.9
Per Cent Difference	36.0%	16.0%	6.4%	-11.5%	-10.2%	15.9%	-3.0%	7.1%
Absolute Difference	127.9	60.9	36.2	72.9	64.0	109.7	23.5	70.7
Per Cent Absolute Difference	36.0%	16.0%	6.4%	11.5%	10.2%	15.9%	3.0%	14.1%
Trade Income Deferral Account								
Forecast Trade Income	(89.5)	(91.0)	(179.8)	(136.9)	(199.0)	(199.0)	(152.0)	
Actual Trade Income	(200.0)	(179.4)	(200.0)	(82.7)	(200.0)	(7.5)	(71.5)	
Difference	(110.5)	(88.4)	(20.2)	54.2	(1.0)	191.5	80.5	15.2
Per Cent Difference	123.5%	97.1%	11.2%	-39.6%	0.5%	-96.2%	-53.0%	6.2%
Absolute Difference	110.5	88.4	20.2	54.2	1.0	191.5	80.5	78.0
Per Cent Absolute Difference	123.5%	97.1%	11.2%	39.6%	0.5%	96.2%	53.0%	60.2%

Data Source: F2012-F2014 RRA, Exhibit B-15, IR 1.19.2

30.4 The table above summarizes the mean absolute percent error (MAPE) of BC Hydro's cost of energy forecasts for the period F2005 to F2011. The data indicates that there are years in which BC Hydro has under forecast and conversely years in which BC Hydro has over forecast cost of energy. On average, it appears that the forecasts for Heritage and Non-Heritage cost of energy have a bias of under forecasting the actual cost of energy by 12.6% and 7.1% respectively. Similarly, the table indicates that trade income forecasts have an over-forecast bias of 6.2%. To what extent, if any, does BC Hydro use historical trends to adjust or "over-ride" its forecast models?

31.0 Reference: Deferral Accounts
Exhibit B-15, IR 1.21 & 22
Appropriate DARR

In response to BCUC IR 1.21.2, BC Hydro has provided a 90% confidence interval for the Deferral Account balances at the end of F2014.

$ million	5th Percentile	Mean	95th Percentile
HDA+NHDA Balance	508	739	886
TIDA Balance	34	163	287
Combined Balance[1]	658	903[2]	1,102

BC Hydro has also provided a table that summarizes the key assumptions ("Key Assumptions Table") used in deriving the confidence intervals that are summarized in the above table (BCUC IR 1.21.2 Attachment 1). The Key Assumptions Table suggests that BC Hydro has not included the impact of economic uncertainty on the load revenue or cost of energy used in deriving confidence intervals. Moreover, uncertainty surrounding IPP forecasts appears not to have been taken into account.

31.1 An assessment of risk that excludes the impact of economic uncertainty and IPP forecast would likely understate the level of risk. Please confirm the extent to which this is correct.

31.2 Based on a 90% confidence interval, please confirm what percentile BC Hydro has based their forecast of combined deferral account balances for F2012, F2013, and F2014.

32.0 Reference: Deferral Accounts
F09/F10 BCH RRA, Exhibit 1, Chapter 6
Exhibit B-1-3, Chapter 7, Table 7-3, p. 7-9
Exhibit B-15, IR 1.17.2
Exhibit B-16, BCSEA IR 1.28.1; BCSEA IR 1.33.1; COPE IR 1.37.1
Appropriate DARR
Table DARR Mechanism

In the F09/F10 RRA Application (Ex B-1, p. 6-8) BC Hydro stated that it recognized the permanent nature of the Deferral Accounts, and that there may be significant volatility in the net balance from year to year, and proposes that it would be appropriate to adjust the level of the DARR each year in a manner that would meet the following objectives:

- minimize intergenerational inequity by being responsive to the changing net balance in the Deferral Accounts (recovery of the net balance of approximately four to six years);
- maintain rate stability for customers to the extent practicable; and
- be administratively simple and transparent.

BC Hydro proposed the Table DARR Mechanism as recreated in the current Application on p. 7-9 (Exhibit B-1-3) which the Commission approved pursuant to Order G-16-09.

However, the approved table is capped out at a 5% DARR when the balance in the deferral accounts is greater than $500 million. (Exhibit B-16, COPE IR 1.37.1)

In response to BCUC IR 1.17.2 BC Hydro expanded the table to reach a net balance of $1 billion as BC Hydro has forecast that the balance at the end of the test period is expected to be just under $900 million.

32.1 If it is determined that the Table DARR Mechanism should continue to be utilized does BC Hydro have any objections to adopting the updated Table DARR Mechanism in BCUC IR 1.17.2 response which provided a DARR greater than 5% when the balance is in excess of $500 million?

32.1.1 If not, please fully explain BC Hydro's position.

32.2 Does the updated Table DARR Mechanism as provided in BCUC IR 1.17.2 meet the objective that BC Hydro proposed in the F09/F10 RRA Application?

32.2.1 If not, please fully explain.

In response to BCSEA IR 1.28.1 BC Hydro states that it continues to believe that the DARR mechanism as previously approved and shown in Table 7-3 is appropriate but has sought a deviation from the formula as part of a plan to achieve particular rate increases.

32.3 Without regard to BC Hydro's plan to achieve particular rate increases, does BC Hydro believe that the Update DARR mechanism as provided in response to BCUC IR 1.17.2 is appropriate?

In response to BCSEA IR 1.33.1 BC Hydro states that in addition to clearing the total balance in the Deferral Accounts in a reasonable period of time, minimizing intergenerational inequities would also require that the average total balance in the Deferral Accounts be close to zero over a reasonable amount of time.

32.4 When balances in the Deferral Accounts are in excess of $500 million does BC Hydro believe that the criteria as provided in the F09/F10 RRA and the criteria noted in response to BCSEA IR 1.33.1 are achieved with the original Table DARR mechanism as presented in Table 7-3 of the Application (Exhibit B-1-3)? With the Table DARR mechanism as presented in response to BCUC IR 1.17.2? If not, please explain otherwise.

33.0 Reference: Deferral Accounts
Exhibit B-15, IR 1.17.2
Appropriate DARR
Table DARR Mechanism

In IR 1.17.9 the BCUC asked the following: Based on the DARR as determined in response to IR 1.17.2 (updated to $1 billion) with interest based on the current WACD and additions of $130 million (historical average), when would the Deferral Accounts be cleared to a $0 balance? BC Hydro responded by stating that by F2022 the balance would be approximately $230 million however the accounts would never clear under these assumptions.

33.1 Please provide an updated Table DARR Mechanism that allows the accounts to clear in four to six year assuming WACD at the current level and average additions of $130 million.

33.2 Please provide an updated Table DARR Mechanism that allows the accounts to clear in four to six year assuming WACD at the current level and average additions of $65 million.

33.3 Does BC Hydro believe that the criteria as outlined in the F09/F10 RRA (Exhibit 1, p. 6-8) and the criteria noted in response to BCSEA IR 1.33.1 are achieved with either of the tables provided in response to this IR? If not, please provide the relevant information.

34.0 Reference: Deferral Accounts
Exhibit B-15, IR 1.17.1
Appropriate DARR

34.1 Please calculate the rate rider (DARR) required to recover deferral accounts at least once in the next 6 years based on the following simultaneous assumptions: (1) a 90% probability of a zero balance at least once in 6 years; (2) Heritage, Non-Heritage, and TIDA additions are included in the calculation; (3) current deferral account balances are taken into consideration; (4) future deferral account additions (based on historical average) are included in the calculation; (5) interest on the balances in the Deferral Accounts are taken into consideration. Please provide an electronic copy of your calculation.

D. REGULATORY ACCOUNTS

General

35.0 Reference: Regulatory Accounts
Exhibit B-1-3, Amended Appendix A, Schedule 1
Exhibit B-16, AMPC IR 1.14.1
Regulatory Schedules and Tables

In IR 1.14.1 AMPC prepared a very useful table that it asked BC Hydro to confirm. Unfortunately the table was not correct therefore BC Hydro could not confirm it but instead references some examples of why the table was incorrect.

35.1 The table format is very useful as it easily shows the costs proposed to be deferred in the test period by grouping. Please prepare a table exactly like the sample provided in IR 1.14.1 with the correct data.

35.2 If there were no deferrals in the test period so that lines 9 and 13 in Amended Appendix A, Schedule 1.0 were both $0 what would the revenue shortfall on line 27 and the rate increase on line 28 be in each of the test years (F2012-F2014)?

Demand Side Management

SEE SECTION X DEMAND SIDE MANAGEMENT

First Nations Negotiations and Settlement Costs & First Nations Provision

36.0 Reference: First Nations Negotiations and Settlement Costs
First Nations Provision
Exhibit B-1-3: Chapter 7, Section 7.3.2; Amended Appendix X, Schedule 2.2
Exhibit B-15: IR 1.24, IR 1.25
Order G-53-02; Order G-56-06; Order G-11-08

BC hydro has confirmed that there is no interest accumulated in the First Nations Negotiations and Settlement Costs account because Order G-53-02 did not provide for it. (Exhibit B-16: IR 1.24.1, IR 1.24.4.1)

36.1 Please confirm, or explain otherwise, that the First Nations Negotiation and Settlement Costs regulatory account attracts **financing costs** which are recovered in the test period rather than being added to the regulatory account.

36.2 If yes, please quantify any financing costs recovered in the test period relating to this provision.

BC Hydro has stated that F2011 actual additions to the First Nation Negotiations and Settlement Costs regulatory accounts includes a $2.1 million **'provision'** for implementation costs related to a settlement. (Exhibit B-16, IR 1.24.2)

36.3 Is the $2.1 million provision related to a F2011 cash transaction or rather a provision for a future cash transaction?

36.3.1 If it relates to a future cash transaction why is it included in the regulatory account?

36.3.2 If it relates to a future cash transaction when is the transaction expected to be completed?

36.4 Exhibit B-15, IR 1.25.8 shows the amortization of additions to the regulatory account. The $2.1 provision is not included in the balances being amortized over the test period. Please explain why not.

Exhibit B-15, IR 1.24.3 details all the forecast **'additions'** to the First Nations Negotiations and Settlement Costs regulatory account from Amended Appendix X, Schedule 2.2 line 10.

36.5 Please confirm that no settlement costs are included in this line item and that all settlement costs additions are included on line 11 "transfers from provision".

The **forecast ending F2014 balance** in the First Nations Litigation and Settlement Costs Regulatory Account is $180.1 million. (Amended Appendix A, Schedule 2.2, line 13)

36.6 Please confirm that the forecast ending balance is made up of the following (in millions):

Negotiation and Settlement Costs (subject to amortization)	$ 32.4
F2011 Provision	$ 2.1
Settlement Costs (Exhibit B-15, IR 1.24.3.1)	$145.6

Order G-53-02 approved the capitalization of ongoing negotiations and litigations with First Nations, the costs of settlements arising from those negotiations and the amortization of those costs over a ten-year period in the First Nations Litigation and Settlement Costs Regulatory Account.

Order G-56-06 allowed BC Hydro to establish a regulatory asset (First Nations Settlement Provision Regulatory Account) in the amount of a loss provision it recognizes (as required by GAAP) in respect to two claims made against it by First Nations and carry forward the regulatory asset until:

a) Settlement with the First Nation is completed and the actual amount is known;

b) BC Hydro has filed an application providing for the accounting treatment for the final settlement amount and the manner in which, if any, that amount may be recovered in rates;

36.7 Please confirm that no amendments were made to the First Nations Litigation and Settlement Costs Regulatory Account amortization period as established in BCUC Order G-53-02 as a result of Order G-56-06. If not, please describe in detail what the legal changes were.

36.8 Please confirm that nowhere in Order G-56-06 does it allow for BC Hydro to transfer settlement amounts from the First Nations Settlement Provision Regulatory Account into the First Nations Litigation and Settlement Costs Regulatory Account without filing an Application with the Commission.

36.9 Does the First Nations Settlement Provision Regulatory Account include any Settlements with First Nations that are complete and the actual amount of the settlement is known?

36.9.1 If yes, why has BC Hydro not filed an Application with the Commission for the accounting treatment of the final settlement amount?

36.10 Please explain if a settlement is complete for the three Grievances identified in Exhibit B-15, IR 1.25.4 totaling $318.3 million. If not complete, please explain the difference between Ratified and Completed.

Order G-11-08 was issued to allow BC Hydro to record all claims in the regulatory account and not just the two claims previously identified in Order G-56-06. Further the Order directed the following:

> With respect to the First Nations Loss Provision Regulatory account, BC Hydro is to file an application, when a settlement is completed, for the final amount for the aggregate loss provision in respect of any settlement claim and the manner in which, if any, that amount may be recovered in rates.

BC Hydro states that BCUC Order G-11-08 amends Order G-53-02 such that settlement costs transferred to the First Nations Negotiation and Settlement Costs Regulatory Account are not amortized or recovered in rates until the BCUC grants approval to do so.

36.11 Please show exactly where in Oder G-11-08 or G-06-06 it states that settlements transferred into the First Nations Litigation and Settlement Cost are not amortized over ten years.

36.12 Please comment on BC Hydro's position of the following interpretation of Order G-56-06: Order G-56-06 did not change the directives of Order G-53-02 at all rather it allowed BC Hydro to set up a regulatory asset to offset a loss provision that CGAPP required for financial reporting. The impact to Order G-53-02 was that all settlements added to the First Nations Litigation and Settlements Costs first needed approval by the Commission to determine the amount and amortization period. Order G-56-06 put further restrictions on Order G-53-02 and did not eliminate the need to amortize settlement additions over ten years. Further Order G-11-08 simply extended the claims that were allowed to be included in the First Nations Provision account as set out in Order G-53-02 to include all claims and not restrict the account to the two previously identified.

36.13 Please confirm, or explain otherwise, that no amendments were made to the First Nations Litigation and Settlement Costs regulatory account amortization period as established in BCUC Order G-53-02 as a result of Order G-11-08.

36.14 Please confirm that nowhere in Order G-11-08 does it allow for BC Hydro to transfer settlement amounts from the First Nations Settlement Provision Regulatory Account into the First Nations Litigation and Settlement Costs Regulatory Account without filing an Application with the Commission.

36.15 Please confirm that BC Hydro has transferred $145.6 million from the Provision account into the Settlement account (Exhibit B-15, IR 1.24.3.1) which is not being amortized into rates. (Exhibit B-15, IR 1.24.12)

36.15.1 Please confirm, or explain otherwise, that under both CGAPP and IFRS settlement payments cannot remain in the Provision Account (First Nations Settlement Provision Regulatory Account) and have to be either expensed or transferred into some other regulatory account.

36.16 Please confirm, or explain otherwise, that the forecast balance in the First Nations Settlement Provision Regulatory Account in each of the test periods is the balance forecast to be required as a loss provision under CGAPP/IFRS. In other words, even though these claims have been ratified they are still considered contingent liabilities under GAAP and are not required to be expensed. (Exhibit B-15: IR 1.25.4, IR 1.25.5.2)

36.17 If the Settlement Costs in the First Nations Negotiation and Settlement Costs regulatory account were to be amortized over a ten year period starting in F2012 what would the incremental rate impact (in $ and %) be in each of the three test periods?

First Nations costs (Excluding Settlement Costs, i.e. the costs that are currently being amortized into rates) captured in the First Nations Litigations and Settlement regulatory account average about $5.5 million between F2005 and F2014 and the variance between actual and forecast was on average only $1.3 million in the F2009/F2010/F2011 period.

36.18 Based on the **regulatory account criteria** as outlined on page 7-3 of Exhibit B-1-3 please assess why BC Hydro thinks a regulatory account is still required to capture First Nations costs (other than settlement costs as listed in IR 1.24.6) in the test period.

36.19 Other than to keep rates low, please explain why expensing these costs would not be appropriate on a go forward basis.

Site C

37.0 Reference: Site C
Exhibit B-1-3, Chapter 7, Section 7.3.5; Chapter 5, Section 5.7.8
Exhibit B-15, IR 1.27

37.1 BC Hydro has confirmed that $41.7 million dollars in interest will accumulate in the test period in addition to the capitalized expenditures as shown in Exhibit B-1-3, Table 5-54, p. 5-232. Please confirm, or explain otherwise, that if the $41.7 million in interest was not added to the regulatory account it would have been recovered in rates in the test period as part of financing costs.

37.2 In response to BCUC IR 1.27.7 BC Hydro states that in addition to IDC (Interest of $41.6 million) BC Hydro is also requesting to add to the regulatory account (for recovery in a future period) financing costs of $32.6 million relating to project contingencies. Please show the details of the calculation for the financing costs including disclosing the amount of the contingency and what specifically it relates to.

37.2.1 Does the IDC calculation reported in Amended Table 5-54 include IDC on the Contingency?

37.3 Are the contingency amounts included in the forecast additions (Project Definition, Consultation, and Project Management) reported in Amended Table 5-54?

37.4 Please explain why financing costs on a contingency should be approved for deferral in the Site C Project Costs.

Storm Restoration Costs

38.0 Reference: Storm Restoration Costs
Exhibit B-1-3, Chapter 7, Section 7.3.9
Exhibit B-15, IR 1.31.4.1

38.1 Please update the table provided in Exhibit B-15, IR 1.31.4.1 to show forecast Storm Expenditures in F2007, F2008, F2009 and F2010, and the F2011 Actual.

Capital Project Investigation Costs

39.0 Reference: Capital Project Investigation Costs
Exhibit B-1-3, Chapter 7, Section 7.3.11

39.1 If the CPI regulatory account were to be amortized over ten years (based on the current WACD) what is the total amount of finance charges that would be recovered in rates during this period?

39.2 If the CPI regulatory account were to be amortized over five years (based on the current WACD) what is the total amount of finance charges that would be recovered in rate during this period?

GM Shrum 3

40.0 Reference: GM Shrum 3
Exhibit B-1-3, Chapter 7, Section 7.3.12
Exhibit B-15, IR 1.34.2

In response BCUC IR 1.34.2 BC Hydro states that BC Hydro has never before sought to recover expressly net opportunity costs attributable to outage; the HDA deferral has captured variance between forecast and actual cost of energy, even to the extent that the variances were caused by a unit outage.

40.1 Please explain if the "net opportunity cost" relates to an actual difference in the dollar value of the forecast Cost of Energy or is it a notional amount.

Amortization of Capital Additions

41.0 Reference: Amortization of Capital Additions
Exhibit B-1-3: Chapter 7, Section 7.3.15; Appendix A, Schedule 2.2
Exhibit B-15, IR 1.36.2

In response to BCUC IR 1.36.2 BC Hydro states that on Schedule 2.2, the variance captured in the Amortization of Capital Additions Regulatory Account is shown as a Recovery, whether the variance is positive or negative.

41.1 It would seem logical that Additions relate to variances, and Recoveries relate to amortization. If this assumption is not correct, please explain what the Additions and Recoveries to regulatory accounts on Schedule 2.2 relate to.

41.2 For transparency purposes would it not be better to show the additions and recoveries as separate line items in Schedule 2.2?

41.2.1 Please explain why the additions to the regulatory account are combined with recoveries rather than showing them separately.

Total Finance Charges

42.0 Reference: Total Finance Charges
Exhibit B-1-3, Chapter 7, Section 7.3.16
Exhibit B-15, IR 1.37.2

In response to BCUC IR 1.37.2 BC Hydro states that the variance in the Total Finances Charges Regulatory Account is shown as a Recovery, whether the variance is positive or negative.

42.1 For transparency purposes would it not be better to show the additions and recoveries as separate line items in Schedule 2.2?

42.1.1 Please explain why the additions to the regulatory account are combined with recoveries rather than showing them separately.

SMI Regulatory Account
SEE SECTION J SMART METERING AND INFRASTRUCTURE PROGRAM

Home Purchas Option Plan

43.0 Reference: Home Purchase Option Plan
Exhibit B-1-3, Chapter 7, Section 7.3.18
Exhibit B-15, IR 1.38.8

In response to BCUC IR 1.38.8 BC Hydro states that as part of the plan to achieve the applied for rate increases BC Hydro in not proposing to amortize this regulatory account until after the test period.

43.1 Irrespective of the target rate increase, what amortization does BC Hydro suggest would be an appropriate period to amortize this regulatory account?

Non-Current Pension Cost Regulatory Account
SEE SECTION H PENSION AND OTHER POST RETIREMENT BENEFITS

Environmental Provision

44.0 Reference: Environmental Provision
Exhibit B-1-3: Chapter 7, Section 7.3.21; Appendix HH
BC Hydro F2011 RRA, Exhibit B-1, p. 7-24
Order G-88-10, G-180-10

BCH F2011 RRA p. 7-24 states: "Due to the unforeseeable nature of environmental remediation costs, and due to the increasing standards and requirements being set by regulatory bodies, BC Hydro plans to apply to the BCUC before the end of F2010 for approval to establish a regulatory account to capture any environmental liability provision required under GAAP."

BCUC issued Order G-88-10 approving the regulatory account but BC Hydro was not seeking any pre-approval from the Commission with respect to the ultimate recovery in rates of the loss provision liability or related regulatory asset. BC Hydro stated if and when actual costs are incurred by BC Hydro, it would seek recovery of the actual costs at a future proceeding.

In the F2011 RRA evidentiary update BC Hydro states on p. 33: "The BCUC approved the establishment of the Environmental Provisions Regulatory Account in Order G-88-10. As shown in Table 12 above, the costs of removing and disposing of contaminants in F2011 is forecast to be $14.6 million."

As a result of this forecast, the BC Hydro NSA F2011 approved the forecast $14.6 million of costs relating to removing and disposing of contaminants in F2011.

In Exhibit B-1-3 (F2012-F2014 ARRA) Appendix HH, p. 2 BC Hydro stated that the APPROVED amortization period is a 'draw down based on forecast operating costs' and references Order G-180-10. Order G-180-10 was the F2011 RRA NSA final Order.

44.1 Please confirm, or explain otherwise, that there is no approved amortization period for this regulatory account pursuant to Order G-88-10 rather only approval for expenditures to be recovered in F2011.

44.2 Please confirm, or explain otherwise, that BC Hydro is required to seek approval for recovery of the actual costs and therefore in the Application before the Commission BC Hydro is seeking recovery of the forecast cost in F2012-F2014.

Rock Bay Remediation

45.0 Reference: Rock Bay Remediation
Exhibit B-1-3, Chapter 7, Section 7.5.2
Exhibit B-15, 1.40, 1.41

In BCUC IR 1.41.1.2 staff asked if a one year amortization period would be appropriate for this account and BC Hydro responded by referencing IR 1.41.1.1 which does not answer the IR.

45.1 Given that the costs were incurred in F2011 and the amounts are known would it be appropriate to fully amortize this balance in the test period and if not why not?

45.2 Please confirm, or explain otherwise that the environmental provision required under GAAP for the Rock Bay Remediation is reflected in the Environmental Provision Regulatory Account.

45.3 Please confirm that the GAAP Handbook section that requires BC Hydro to report an environmental liability provision is Section 3290 Contingencies.

45.4 Please confirm that the HB 3290 states the following:

- *The amount of a contingent loss should be accrued in the financial statements by a charge to income when both of the following conditions are met:*

  (a) it is likely that a future event will confirm that an asset had been impaired or a liability incurred at the date of the financial statements; and

  (b) the amount of the loss can be reasonably estimated.

In response to BCUC IR 1.40.3 BC Hydro states that BC Hydro is unable to provide a reasonable estimate of remediation costs in F2012-F2014.

45.5 If a reasonable estimate cannot be made for expected costs in F2012-F2014 please explain how the provision as required under HB 3290 was calculated.

In BCUC IR 1.40.6 staff asked BC Hydro to explain why it is deferring the F2012-F2014 Rock Bay remediation cost to a time outside of the test period, BC Hydro responded that it believes that a better approach is to exclude forecast costs related to the Rock Bay environmental remediation from the F12-F14 RRA and, instead, recover only actual costs incurred and expects to address recovery of these costs in its F2015 RRA.

45.6 Given that rates are set based on forecasting future costs please explain why BC Hydro thinks it would be appropriate to wait and see what the actual costs are before requesting recovery of these costs?

45.7 Given that these costs are forecast to be incurred in F2012-F2014 please explain why ratepayers in a period after F2014 should be responsible for paying for them? Please discuss in your response how BC Hydro's proposed treatment impacts intergeneration equity concerns.

In response to BCUC IR 1.40.6 BC Hydro states: "The costs in any given fiscal period related to the Rock Bay environmental remediation cannot be accurately planned because both the amount and timing of expenditures depends in part on further analysis and testing …"

45.8 It is understood that making a forecast includes a certain amount of risk but if BC Hydro knows it is going to incur costs in F2012-F2014 please explain why it would be appropriate not to make some reasonable forecast and request that the variance be captured in the Rock Bay regulatory account.

PROPOSED REGULATORY ACCOUNTS

IFRS PP&E Regulatory Account
SEE SECTION R INTERNATIONAL FINANCIAL REPORTING (IFRS)

IFRS Pension and Other Post-employment Benefits
SEE SECTION H PENSION AND OTHER POST RETIREMENT BENEFITS

Outsourcing Implementation Costs Regularly Account

46.0 Reference: Outsourcing Implementation Costs Regulatory Account
Exhibit B-1-3, Chapter 7, Section 7.4.4
Exhibit B-15, IR 1.41

In Exhibit B-1-3 (Chapter 5, Section 5.2.2.1) (ARRA Application) BC Hydro states:

> Through these new agreements, BC Hydro will be able to obtain incremental cost savings for BPO, data centre operation, and facilities management services, and expects that savings will be achieved for the balance of IT services that are being taken to market. Gross cost savings for the F12-F14 period are forecast to be **$35 to $40** million relative to the previous agreement with ABS. The operating cost savings are reflected in the Amended F12-F14 RRA in Corporate Costs, Section 5.7.9. BC Hydro expects gross cost savings of $119 million over the life of the three new agreements and the contemplated agreements for the balance of the IT services being taken to market.

The original ABS agreement expired March 31, 2013. The new contracts were effective September 1, 2011.

Implementing the new service arrangements involves significant one-time transition costs, including: wind-down and start-up costs charged by the previous and new service provider related to the transition of services (approximately $26 million); and outsourcing and advisory services (approximately $5 million) for a total of approximately $31 million."

BC Hydro is proposing that no amortization on the Outsourcing Implementation Cost Regulatory Account is to be taken in the test period and therefore no costs related to the revised outsourcing arrangement are to be recovered in rates in the test period. Rather an additional $2.8 million in interest will accumulate in the account for recovery from ratepayers in a future period.

In response to BCUC IR 1.41.1 BC Hydro states that it believes that these costs should be deferred and amortized over the term of the new outsourcing arrangements in order to better match the costs and benefits.

46.1 Given that 33 percent of the benefits are being realized in the test period ($40 million of the $119 million) and approximately 40 percent of the contract will be realized in the test period please explain how the 'matching' principal applies with no amortization being taken in the test period.

46.2 Please update the table provided in response to BCUC IR 1.41.4 to reflect the percentage of the contract duration that occurs in the test period.

Arrow Water Systems Divestiture Costs

47.0 Reference: Arrow Water System Divesture Costs
Exhibit B-1-3, Chapter 7, Section 7.5.1

47.1 If BC Hydro was not trying to constrain rate increases what would they propose an appropriate amortization period would be for this account given the costs were incurred in F2011 and would have been expensed in the absence of this regulatory account?

47.2 Given that theses costs were incurred in F2011 please explain why ratepayer in a period after F2014 should be responsible for paying for them. Please discuss in your response how BC Hydro's proposed treatment impacts intergeneration equity concerns.

E. LOAD REVENUE AND FORECAST

48.0 Reference: Cost of Energy
Exhibit B-1-3, Chapter 4, Section 4.1.3
Forecast Uncertainty

"Due to the uncertainties associated with changes in inflows, market prices and loads, the 95 per cent confidence interval for the F2012 forecast Cost of Energy is approximately +$73 million and -$188 million. The corresponding 95 per cent confidence intervals for the Cost of Energy for F2013 and F2014 are expected to widen relative to F2012 due to the greater uncertainty in the forecast of market prices further into the future." (p. 4-4)

48.1 An "uncertainty" is only genuine in situations in which it is not possible to reasonably determine the probably of the event occurring. In all other circumstances, an event is said to have an associated "risk" because probabilities can reasonably be calculated and verified. For example, the variation in weather is a risk given the extensive weather data available. On the other hand, an unexpected mechanical failure at a generating station (e.g. GM Shrum) is an event arising from uncertainty. Does BC Hydro agree with this perspective? If not, please discuss why.

48.2 What level of risk does BC Hydro believe is prudent for ratepayers to assume in its load and cost of energy forecasts for the test period? Please express the risk level as a probability.

49.0 Reference: Load Revenue and Forecast
Exhibit B-15: IR 1.46.1, 1.46.3, 1.46.6, 1.46.8
Load Forecast
Forecast Uncertainty

49.1 Please provide an updated version of the graph in Exhibit B-15, IR 46.1 with an 80% confidence interval based on the methodology employed by BC Hydro. Please also include a fully functional electronic version of the graph and the method used to calculate associated confidence interval.

49.2 In several IRs, including BCUC IR 1.46.3, BC Hydro has directed the Commission to forecast data provided in Exhibit B-1-3, Appendix FF, which contains the BC Hydro 2010 Load Forecast. The 2010 Load Forecast is not directly comparable to the forecast provided in BC Hydro's F2012-

F2014 Amended RRA since it is based on "Before DSM and Rate Impacts." Please provide an updated version of BC Hydro's 2010 Load Forecast that permits data to be directly compared the Revenue Requirement Model in Appendix A of Exhibit B-1-3.

49.3 In response to BCUC IR 1.46.6, BC Hydro has provided a table that shows the 80% confidence interval for the main user groups. Please provide an electronic copy of the following table that includes formulas and assumptions necessary to become familiar with BC Hydro's methodology for calculating confidence intervals.

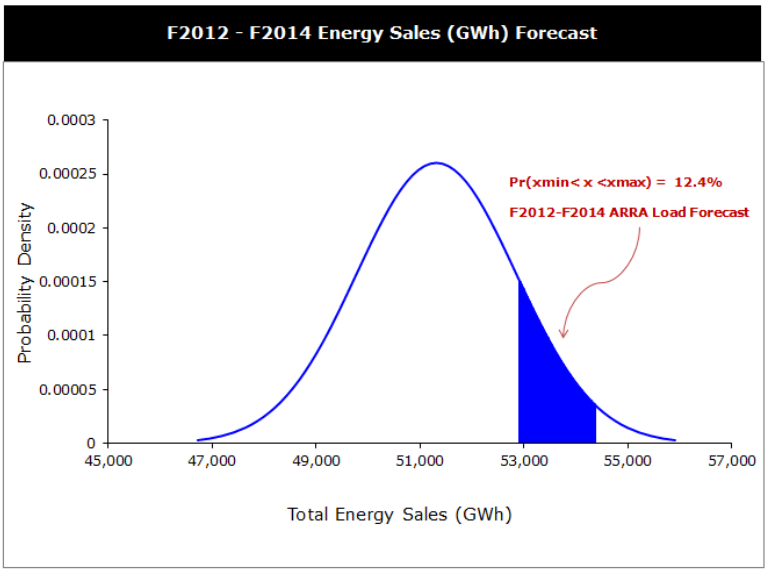
Domestic Energy Sales	F2012		F2013		F2014	
GWh	Low	High	Low	High	Low	High
Residential	18,015	19,474	18,385	19,930	18,738	20,420
Ligth Industrial and Commercial	18,425	19,403	18,692	19,840	19,002	20,328
Large Transmission	14,364	14,969	15,357	16,143	16,729	17,732
Other	2,077	2,077	2,116	2,116	2,142	2,142
Total Domestic Energy Sales Range	**52,881**	**55,923**	**54,549**	**58,028**	**56,612**	**60,622**

49.4 The following table summarizes the probabilities associated with BC Hydro's F2012, F2013 and F2014 forecast based on actual energy sales (GWh) for the past nine years. The probabilities have been calculated using normal distribution for the specified mean and standard deviation in order to assess the level of risk associated with BC Hydro's load forecast. For example, the table suggests that based on historical results there is a 95.8% probability total energy sales in the test period would be equal to or exceed 48,677 GWh. Likewise, that there is a 14.8% probability that total energy sales will be equal to or exceed forecasted 54,356 GWh in F2014. Please discuss why this is, or is not, a good indicator of forecast risk.

Year	Total Energy Sales (GWh)		Probability P ≥ Energy Sales
F2003	48,677	Actual	95.8%
F2004	50,151	Actual	77.7%
F2005	51,205	Actual	52.9%
F2006	52,440	Actual	23.1%
F2007	52,911	Actual	14.9%
F2008	53,299	Actual	9.8%
F2009	52,316	Actual	25.7%
F2010	50,233	Actual	76.0%
F2011	50,607	Actual	67.8%
F2012	52,919	Forecast	14.8%
F2013	53,527	Forecast	7.4%
F2014	54,356	Forecast	2.4%
	Mean = 51,315		Std Dev.= 1,531

49.4.1 Please include any additional statistical data not already provided in Exhibit B-1-3 that BC Hydro deems helpful in assessing the level of risk associated with the load forecast for F2012, F2013, and F2014.

49.5 The below graph suggests that BC Hydro's load forecast has over-estimated energy sales during the F2012-F2014 test period as indicated by the low probability of achieving forecasted levels of energy sales. Please confirm whether this graph is accurate and provide an updated version if otherwise.



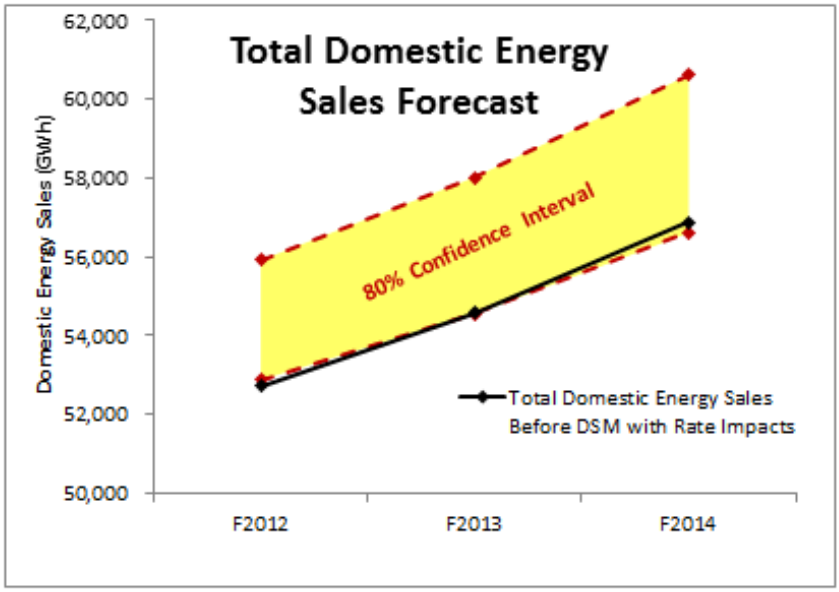
Year	Total Energy Sales (GWh)	Probability P ≥ Energy Sales	Z-Score
F2012	52,919	14.8%	1.0
F2013	53,527	7.4%	1.4
F2014	54,356	2.4%	2.0

49.5.1 A load forecast that is higher than actual will result in an understated Rate Revenue Requirement (ref. Exhibit B-1-3, Appendix A, Schedule 1.0, line 22) and lower customer rates than are otherwise warranted. This in turn leads to increases in deferral account balances (ref. BC Hydro's Commission filed Deferral Accounts Report F2008 to F2011). Please confirm whether this generally reflects that nature of BC Hydro's load forecasts for the period F2008, F2009, F2010, and F2011. Please provide commentary if otherwise.

49.6 What impact would there be on the F2012-F2014 Rate Revenue Requirement and proposed rate increases if BC Hydro's load forecast was required to fall within one standard deviation of the F2003 to F2011 mean.

49.6.1 Please discuss why a Commission directive of this nature would or would not be prudent from the perspective of reducing ratepayer risk, reducing deferral account balances, reducing interest charges, and reducing inter-generational inequity.

49.7 The following graph summarizes the confidence level for forecasted total domestic energy sales for the test period. Please confirm whether this information is correct and provide a restated version if necessary.



Year	Low	High	Total Domestic Sales
F2012	52,881	55,923	52,726
F2013	54,549	58,028	54,583
F2014	56,612	60,622	56,888

Source of Data: Exhibit B-15, IR 1.46.6 and Exhibit B-1-3, Appendix FF, p. 134

49.7.1 Using the most recently available data, please provide a restated version of the above graph for total domestic energy sales net of DSM with rate impacts.

50.0 Reference: Load Revenue and Forecast
Exhibit B-15, IR 1.46.8
DCAT - Domestic Energy Sales

50.1 In response to IR 1.46.8 BC Hydro indicates that the Revenue Requirement Model provided in Exhibit B-1-3, Appendix A has not been adjusted to account for the November 30, 2011 suspension of the DCAT project. Please confirm whether BC Hydro plans on providing an update to their Revenue Requirement Model that takes into account reduced energy demand associated with the suspension of the DCAT project.

50.1.1 What impact will the suspension of the DCAT project have on Rate Revenue Requirement and proposed rate increases during the test period?

51.0 Reference: Load Revenue and Forecast
Exhibit B-15, IR 1.45.1
Domestic Energy Sales

Comparison of RRA Forecast (Original Application) and Actual								
	Domestic Energy Sales				Domestic Energy Revenue			
Year	Forecast (GWh) 1	Actual (GWh) 2	Difference (GWh) 3 = 2 - 1	% Difference 4 = 3/2	Forecast ($ Million) 5	Actual ($ Million) 6	Difference ($ Million) 7 = 6 - 5	% Difference 8 = 7/6
F2005	49,287	51,205	1,918	3.7%	2,583	2,643	61	2.3%
F2006	49,604	52,440	2,836	5.4%	2,603	2,710	107	3.9%
F2007	53,142	52,911	(231)	-0.4%	2,789	2,739	(50)	-1.8%
F2008	53,842	53,299	(543)	-1.0%	2,838	2,801	(37)	-1.3%
F2009	54,791	52,316	(2,475)	-4.7%	2,944	2,819	(125)	-4.4%
F2010	55,594	50,233	(5,361)	-10.7%	3,248	2,988	(260)	-8.7%
F2011	51,550	50,607	(943)	-1.9%	3,166	3,157	(9)	-0.3%
			Bias = (686)	MAPE = 4.0%			Bias = (45)	MAPE = 3.3%

Data source: Exhibit B-15, IR 1.45.1

51.1 Historical results from F2005 to F2011 suggest that there is a bias towards over-forecasting domestic sales and energy revenue by the amounts shown in the above table. There has been an over-forecast bias of 686 GWh in energy sales and $45 million in domestic revenue. Please discuss why BC Hydro may or may not agree that the above table illustrates a forecast bias.

F. COST OF ENERGY

Change in the definition of Self Sufficiency

52.0 Reference: Load Resource Balance
Exhibit B-15, IR 1.53.1
Cost of Energy - Canadian Entitlement
Self-Sufficiency

"The reliance on 400 MW of market purchases is eliminated in response to the Clean Energy Act requirement in section 6(2) to achieve electricity self-sufficiency 'solely from electricity generating facilities within the Province'. This elimination is not related to the Canadian Entitlement."

52.1 Please provide the energy and capacity associated with the Canadian Entitlement for the period F2012 to F2017.

52.2 Please explain how BC Hydro, its ratepayers, and Powerex receive any benefit from the Canadian Entitlement.

Cost of Energy

53.0 Reference: Cost of Energy
Exhibit B-15, IR 1.58.2, 1.58.2.1, and 1.59.4

BC Hydro has provided an updated version Amended Figure 4-1 Electricity and Gas Prices. Please provide a tabular summary that indicates how the price forecasts have changed between September 7, 2010 and December 6, 2011.

53.1 Please confirm whether BC Hydro's Revenue Requirement Model (ref. Exhibit B-1-3, Appendix A) relies upon the September 7, 2010 or the December 6, 2011 price forward curves for electricity and gas.

53.2 Please confirm what price forward curves were used in deriving the table provided in response to IR 1.58.2.1.

54.0 Reference: Cost of Energy
Exhibit B-15, IR 1.66.2
Total Gross Cost of Energy

54.1 Please provide an electronic version of the graph provided in response to IR 1.66.2 together with a fully functional spreadsheet showing how the Adjusted Gross Cost of Energy was calculated.

55.0 Reference: Cost of Energy
Exhibit B-15, IR 1.60.6
Source of Supply - System Optimization Overview

"The Alcan 2007 EPA is not a take-or-pay contract in that there are no situations where BC Hydro must pay for energy that is not delivered. The Alcan EPA requires BC Hydro to pay for all electricity scheduled and delivered to the point of interconnection."

55.1 Please confirm whether BC Hydro has any contractual ability to set or modify the amount or timing of the electricity scheduled and delivered to the point of interconnection. If "yes", please provide details.

56.0 Reference: Cost of Energy
Exhibit B-16, CEBC IR 1.5.7
Source of Supply - Surplus Sales

"The probability underlying the mean values given on line 24 of Schedule 4.0 of the Amended Application, that BC Hydro will make domestic surplus sales, is 30 per cent, 50 per cent and 70 per cent for F2012, F2013 and F2014 respectively."

56.1 Please discuss the rational for a surplus sales forecast based on a 30% probability for F2012. Similarly, please discuss the 50% probability and 70% probability used to forecast surplus sales in F2013 and F2014 respectively.

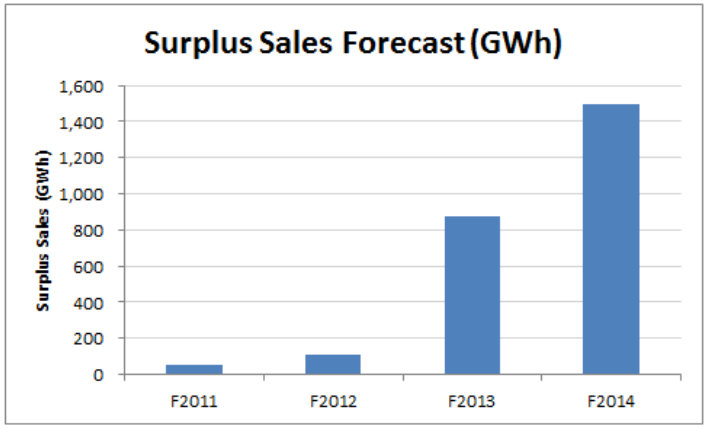
56.2 Please restate Schedule 4.0 of Exhibit B-1-3, Appendix A by assuming a 90% probability for surplus sales in the test period (line 24 of Schedule 4.0).

56.2.1 Please also calculate what impact this would have on Total Rate Revenue Requirement (Exhibit B-1-3, Appendix A, Schedule 1, line22) for F2012, F2013, and F2014.

57.0 Reference: Cost of Energy (CONFIDENTIAL)
Exhibit B-15, IR 1.63.1
Source of Supply - Market Surplus Sales

57.1 Please confirm that each of the 38 weather sequences is assumed to have an equal probability (i.e. 0.0263).

57.2 The surplus sales (GWh) forecasted for F2012-F2014 were derived by taking the mean of the 38 weather sequences (ref. Exhibit B-1-3, Appendix A, Schedule 4, line 24). As illustrated in the following graph, BC Hydro's weather sequences give rise to large year-over-year increases in surplus sales. Please confirm that the increase in surplus sales have no significant relation to weather sequences per se, but rather to the Alcan 2007 EPA. (Exhibit B-1-3, Chapter 4, Amended Table 4-6)



Source of data: Exhibit B-15, IR 1.63.1

57.3 What probability does BC Hydro ascribe to the Alcan 2007 EPA energy volumes of 1,084 GWh in F2012, 1,616 GWh in F2013, and 1,703 GWh in F2014?

58.0 Reference: Cost of Energy
Exhibit B-15, IR 1.64.3
Forecast Uncertainty

58.1 Longer test periods (e.g. 3 years) have the benefit of reducing the number of regulatory filings and associated costs. However, one of the trade-offs is that longer-term forecasts and higher forecast risk must be accommodated. This in-turn increases ratepayer risk and may lead to increased deferrals and ratepayer costs. Please provide an economic assessment of the optimum length of a test period based the associated costs and benefits for test periods that range from one year to 5 years including an electronic copy of calculations and key assumptions.

58.2 BC Hydro has indicated that they do not have ready access to information on the duration of test periods used by other peer utilities. Please provide an estimate of the FTE requirement (hours or days) required to compile this information from publicly available documents.

59.0 Reference: Cost of Energy
Exhibit B-1-3, Amended Appendix A, Schedule 4.0, p. 23
Cost of Energy - Mix
Source of Supply - Heritage Generation

59.1 BC Hydro's forecast for Heritage Energy supply is based on the long-term optimization of integrated system constraints and contractual obligations. Furthermore, the forecast for Heritage Energy supply is optimized to maximize net revenue over a three to five year operating horizon. Please confirm, or explain otherwise.

59.1.1 Please describe the specific constraints or assumptions that prevent BC Hydro from forecasting 49,000 GW.h of Heritage Energy supply in F2012, F2013 and F2014.

59.1.2 Please describe the amount of hydroelectric Heritage Energy under average water conditions.

59.1.3 Please explain the reservoir inflow assumptions BC Hydro has used to yield annual hydroelectric Heritage Energy of less than 46,000 GW.h. for F2012, F2013 and F2014.

59.2 Please provide a revised Schedule 4.0 of Amended Appendix A assuming hydroelectric Heritage Energy based on average water conditions for F2012, F2013 and F2014.

59.3 Please provide the background and components of the Heritage Energy amount of 49,000 GW.h and explain why this value is not attainted throughout the test period.

59.3.1 Please describe if and how the energy capability of Heritage resources under average water conditions have changed since 2007 and if any changes are anticipated in the test period.

60.0 Reference: Cost of Energy
Exhibit B-1-3: Chapter 4, Section 4.4.4.3; Chapter 6, Section 6.5, Amended Table 6-4
Exhibit B-15-1, BCUC IR 1.65.1
Heritage Resource Smart Projects

60.1 Please explain why BC Hydro is not developing its own Heritage capacity resource smart projects ahead, of or instead of, EPAs where it is financially advantageous. For greater clarity, why would BC Hydro enter into market EPAs if it has a suite of its own resource smart projects that could be developed at lower costs?

60.2 Please identify, in a table format, the specific Generation resource smart projects forecasted to go into service during the test period, the associated increase in energy and capacity, cost per MW of energy, and the cost per MW of the additional capacity.

60.3 Please identify, in a table format, the specific Generation resource smart projects that will incur capital expenditures in the test period, the associated increase in energy and capacity, cost per MW of energy, cost per MW of the additional capacity and the forecasted in service date.

60.4 Please identify, in a table format, the remaining specific Generation resource smart projects that are planned for the future and the estimated/best guess increase in energy and capacity, cost per MW of energy, cost per MW of the additional capacity and projected in service date (in 2011 dollars).

60.5 Please state (in 2011 dollars) the marginal cost of energy and capacity that BC Hydro uses for planning purposes and confirm, or explain otherwise, that these figures are based on the most recent call for power.

60.6 Please state (in 2011 dollars) the range of prices for energy and capacity acquired from the most recent EPA contracts.

60.7 Please confirm that BC Hydro will be entering into EPAs during the test period, and explain the range of prices for energy and capacity.

<u>Load Resource Balance</u>

61.0 Reference: Load Resource Balance
Exhibit B-1-3B, Amended Figure II-1-1, Page 17 of 271
Energy LRB after DSM
Operating versus Planning Firm Energy Capability

61.1 Please provide the detailed water inflow forecasts and operating factors that contribute to the lower Firm Energy Capability in the Operating horizon as compared to the Planning horizon as shown in Amended Figure II-1-1.

62.0 Reference: Load Resource Balance
Exhibit B-1-3B, Amended Figure II-1-1, Page 34 of 271
Exhibit B-1-3B, Amended Table 1, Page 114 of 271
Heritage non-firm energy/market allowance
Interpretation of OIC Nos. 35 and 36

'With the move from critical to average water, the 2,500 GWh/year of Heritage non-firm energy/market allowance becomes 4,200 GWh/year in F2015 and 4,500 GWh/year in F2016 and beyond." (page 34 of 271)

62.1 Please explain the background of the 4,200 GWh/year and the 4,500 GWh/year of "Heritage non-firm energy/market allowance" in the reference.

62.2 Please explain why Amended Table 1 has no "Heritage non-firm energy/market allowance" for F2012 through F2014.

62.3 Please explain BC Hydro's reliance upon "market allowance" in F2015 and beyond, and how this complies with self-sufficiency.

62.4 Please explain the decrease in the "Waneta Transaction" amount after F2016 in Amended Table 1.

62.5 Please provide the details for the "AltaGas Power (NTL) (signed EPAs)" in Amended Table 1 including the resource type, the monthly energy and capacity, and the effective price.

62.6 Please explain why Amended Table 1 has no "SM Theft Reduction" until F2017.

Line Losses and System Use

63.0 Reference: Load Revenue and Forecast
Exhibit B-15, IR 1.45.1
Line Loss and System Use

63.1 BC Hydro has provided a list of initiatives undertaken to reduce line losses in response to IR 1.59.4. Please provide a tabular summary of the capital and operational costs associated with each initiative during the test period and the associated cost-benefit in terms of reduced line losses.

63.2 BC Hydro has stated that "electricity theft costs BC Hydro customers more than $100 million each year" (ref. http://www.bchydro.com/news/articles/conservation/2011/smart_meter_facts.html). Please discuss how the implementation of smart meters during the test period is reflected in a reduction in Line Loss and System Use as forecasted in Exhibit B-15, Appendix A, Schedule 4.0, line 33.

63.2.1 For F2012, F2013 and F2014, please provide a tabular summary that segments Line Loss and System Use in terms of the key factors contributing to energy losses, including but not limited to: actual line losses, system use, and theft. Please express the energy losses in terms of lost energy sales (GWh) and lost revenue ($ million).

63.2.2 As it relates to the test period, BC Hydro has used a five-year rolling average of historical total system losses as the basis for forecasting line losses (Schedule 4.0, line 33). Given that smart meters were not implemented prior to the current test period, please discuss why BC Hydro deems it appropriate to use a historical five-year rolling average to forecast energy losses.

63.2.3 In response to COPE IR 1.17.1 (ref. Exhibit B-16), BC Hydro has assumed an average revenue of $100 /MWh in F2012, $108 / MWh in F2013, and $118 / MWh in F2014. Please reconcile these numbers with the forecasted average revenue provided in Exhibit B-1-3, Appendix A, Schedule 14, line 33.

63.3 Please explain why BC Hydro does not account for the cost of line losses and system use in Exhibit B-1-3, Appendix A, Schedule 4.0. Where does BC Hydro account for the cost of line losses?

64.0 Reference: Cost of Energy
Exhibit B-15, IR 1.59.3
Line Loss and System Use

64.1 System Use is understood to be BC Hydro's own use, which includes station service and electricity used in BC Hydro's office buildings and other BC Hydro facilities. Are there any System Uses that are not metered? If yes, please provide a schedule that itemizes the unmetered uses and a description of how energy consumption is determined, recorded and verified.

64.2 Please provide an estimate of the cost and time required for BC Hydro to undertake: (a) line loss and system use audit, (b) a benchmark comparison of line loss and system use with other peer group utilities that have a similar customer density (# of customers / circuit km) to BC Hydro.

65.0 Reference: Cost of Energy
Exhibit B-15, BCUC 1.59.2, Attachment 1, page 39 0f 141,
Use Comparison of actual values with system models
Line Losses and System

"At the beginning of this study, discussion with BC Hydro engineers was undertaken to obtain data and information for losses in generation and distribution subsystems. BC Hydro prepares a report entitled "Comparative Statement of Electrical Production" (CESP) annually. In this report, estimated loss in various parts of the system is included. It was stated that the most applicable CESP is for the year 2006 in which the total loss in the BC Hydro integrated system is about 9.13% of generation16 or 10.05% of the total load." (p. 39 of 141)

65.1 Please provide copies of the last three annual CESP reports.

65.2 Please explain if the calculated losses were compared with actual system losses as part of the BCTC Transmission System Losses Study (Attachment 1 to BCUC 1.59.2), and if not, why not. For the study year considered in the BCTC Transmission System Losses Study, please provide a summary of the actual system losses against the calculated system losses.

65.3 Please confirm whether the BCTC Transmission System Losses Study (Attachment 1 to BCUC 1.59.2) provided any estimate of distribution losses, and if not, why not.

65.4 Please explain the timing and effect, if any, of the ILM transmission line on transmission system losses.

Capital Leases

SEE SECTION R. IFRS

BCTC Integration

66.0 Reference: Transmission Revenue Requirement, Intersegment Revenue & Cost of Energy
Exhibit B-15: IR 1.327.1, IR 1.74.1, 1.74.2, IR 1.327.1, IR 1.327.1.3, IR 1.328.2.1, IR 1.328.3, IR 1.328.4
Exhibit B-1, BCTC F2011 RRA
Order G-16-11
BCTC Integration
TRR and BCTC integration impact on the Cost of Energy

In response to IR 1.327.1 BC Hydro prepared a reconciliation to show how the TRR impacts the COE for the pre-BCTC integration (F2007-F2010), the BCTC integration in F2011 and the post-BCTC integration (F2011-F2014).

In BC Hydro's response to BCUC IR 1.328.4.1.2, BC Hydro reconciliation takes the information from IR 1.327.1 and shows where the BC Hydro's portion of the transmission costs are recorded in its ARRA from F08 to F14:

66.1 To clarify our understanding of the impact of the TRR and the BCTC integration on the Cost of Energy and BC Hydro's ARRA, please confirm, or explain otherwise, the following:

a. Prior to integration, the TRR was recovered from customers through blended OATT rates that reflected the costs of BC Hydro and BCTC. BC Hydro, in its capacity as a transmission

customer under the OATT, incurs the majority of TRR primarily through its NITS and PTP charges.

b. For years prior to the BCTC integration and up to F2011, the TRR application was comprised of the following three components: BC Hydro's Owner's Revenue Requirement (BCH ORR), Asset Management and Maintenance Revenue Requirement (AMM RR) and the BCTC Revenue Requirement (BCTC RR).

   i. The BCH ORR reflected net costs related to BC Hydro's ownership of the transmission system and management of transmission property rights. These net costs were classified in the BC Hydro's RR based on their nature (e.g. Allowed Net Income, Finance Charges, OMA, Amortization, Taxes, Non-Tariff Revenue, Recoveries). These costs were not included in the Cost of Energy.

   ii. The AMM RR related to costs for the maintenance work performed on the transmission assets by BCTC in accordance with the Asset Management and Maintenance Agreement. BC Hydro paid and expensed these cost as part of its OMA. These costs were not included in the Cost of Energy.

   iii. The BCTC RR reflected costs for the provision of the transmission services under the OATT. BC Hydro's portion of these cost were included as part of its Domestic Transmission Cost of Energy. The PTP charges relating to BC Hydro's obligation under the Skagit Valley Treaty were included in the Heritage Cost of Energy. BC Hydro's PTP charges relating to Distribution and its NITS charges for Distribution were included in Non-Heritage Cost of Energy. The PTP charges relating to Powerex were reflected in Intersegment Revenues and were not included in the Cost of Energy.

c. "Prior to integration, the approved TRR was guaranteed under the terms of the Master Agreement between BC Hydro and BCTC and any differences in amounts collected (relative to approved amounts) were reflected in the BCTC Revenue Deferral Account. The approved TRR includes an amount for return on equity. Differences from the approved return on equity and the actual return on equity were borne by the individual companies, and these differences were not collected through the BCTC Revenue Deferral Account… Also, under the terms of BCTC's Revenue Deferral Account, any differences in actual PTP revenue compared to the approved PTP revenue were borne by BC Hydro in its capacity as a (NITS) customer" (BCUC IR 1.328.4). These differences were charged to the Non-Heritage Cost of Energy.

d. For fiscal years post BCTC integration, the total Transmission Revenue Requirement is included as part of the BCH ARRA. The BCTC costs are now reflected based on their nature (i.e. Operating costs, finance charges and amortization). The Cost of Energy only includes the PTP charges for Powerex and BC Hydro's Skagit obligation. The PTP charges for Distribution are now internal allocations and have been eliminated from domestic transmission cost of energy and intersegment revenues. In addition, the BCTC Revenue Deferral Account has been disposed and variances between the forecast and actual transmission service PTP revenue are captured in the NHDA in accordance with BCUC Order No. G-16-11.

e. Prior to the BCTC integration, the Intersegment Revenues included the following: PTP charges for BC Hydro's Skagit obligation, PTP charges for Distribution, variances in the PTP charges between forecasted and actual, and PTP charges for Powerex. In F2011, the

Intersegment Revenues included nine months of NITS Distribution charges that was intended to offset the full twelve months NITS Distribution charges included in the domestic transmission Cost of Energy. Post BCTC integration, the Intersegment Revenues included the PTP charges for BC Hydro's Skagit obligation and the PTP charges for Powerex.

f. "Prior to the integration of BCTC, all PTP charges and NITS charges under the OATT were paid to BCTC. BC Hydro, as the transmission owner, received revenues back from BCTC as part of the Transmission Revenue Requirement. These revenues, referred to as "inter-segment revenues" on lines 18 to 19 of Schedule 3.4, were accounted for as Powerex, Generation, and Distribution revenues, prorated based on allocated PTP charges as discussed in BCUC IR 1.331.2, to effect the consolidation of all cross-company charges. There was no allocation of actual PTP revenues to Powerex, Generation or Distribution. Since the BCTC integration, BC Hydro no longer records the charges and revenue amounts described above that were previously recorded in Distribution because the variances for the charges and revenues are deferred in the Non-Heritage Deferral Account and are offsetting. This is an accounting presentation change only, and has no impact on BC Hydro's revenue requirements or rates." (BCUC IR 1.327.1)

g. Post BCTC integration, BC Hydro as the transmission owner reflects all of the cost of the TRR. However, BC Hydro as a transmission customer incurs PTP charges on behalf of external parties that are either reflected in the Cost of Energy or Powerex Net Income. The main purpose of the Intersegment Revenues balance is to facilitate consolidation by offsetting those PTP charges that are duplicated in the BC Hydro RRA. The PTP charges to Powerex are included in the Powerex Net Income and the TRR expense accounts. The PTP charges for BC Hydro's Skagit obligation are included in the domestic transmission Cost of Energy and the TRR expense accounts. The intersegment revenues offset these duplicated cost in the RRA.

66.2 In IR 1.328.4.1.2, BC Hydro states that "Line 18 of the table above include items such as changes in BCTC's net income (loss) which did not flow through to BCTC's Revenue Deferral Account, timing differences and related amounts between when the deferrals are recorded in each company, and deferral balances collected from customers other than BC Hydro." In addition, in response to IR 1.329.2, BC Hydro noted that there was a "one-time write off of certain BCTC IT assets prior to integration, $8.9 million (which write-off was reflected in BCTC's income statement and effectively borne by the Province)." Is the F2011 adjustment of $7.7 million in Line 18 above related to the $8.9 million write off of BCTC IT assets? Please confirm or explain otherwise.

66.2.1 If the Province absorbed the $8.9 million write off then that cost would not be charged to BC Hydro and should not be included in line 20 - BC Hydro Other. Please confirm.

66.2.2 For the $8.9 million write off of IT assets, what was the amount of the associated sustainment cost related to these assets and where have these savings been reflected in the operating cost schedules?

G. OPERATING COSTS

General

67.0 Reference: Operating Costs
Exhibit B-1-3, Amended Appendix A
F2011 NSA-12 Actual Results – Starting Point for Incremental Increase
Limited Data to Work With

"To allow comparability to test period costs and F2011 costs, the F11 RRA NSA costs and financial schedules have been restated to account for the Nature View reclassifications, and the elements of the BCTC integration that do not reflect any cost savings. That is, the "F11 RRA NSA-12" restatement accounts for the entirety of the Nature View reclassifications, but only items 1., 2., and 3. (not 4 and 5) of the BCTC integration described in section 1.3.3.1. The F11 RRA NSA-12 restatement of F11 RRA NSA costs, and financial schedules, assumes the integration of BCTC and BC Hydro at the beginning of F2011, for all twelve months of the fiscal year." (Chapter 1, p. 34)

67.1 Please confirm, or explain otherwise, that the F2011 Actual results included in Amended Appendix A (Column 5, Schedule 5.0) are organized in accordance with the Nature View presentation of costs, consistent with F2012 – F2014 Update Plan.

67.2 Amended Appendix A, Schedule 5.0 includes Nature View adjustments (Column 17) and BCTC adjustments (Column 18) to restate the F11 RRA NSA costs to F11 RRA NSA-12. Please explain the nature of each adjustment per Amended Appendix A, Schedule 5.0, Columns 17 and 18 by Row (i.e. Rows 10 through 17) and identify the corresponding account impacted by the adjustments (e.g. cost of energy).

67.2.1 Amended Appendix A, Schedule 5.0 includes BCTC adjustments (Column 18) to restate the F11 RRA NSA costs to F11 RRA NSA-12 for twelve months of BCTC integration. Please explain why the integration of BCTC results in a decrease in each of labour costs of $12.7 million (Column 18, Row 10), materials costs of $11.7 million (Column 18, Row 14) and capitalized overhead of $38.9 million (Column 18, Row 16). Please provide an explanation and support for each of the adjustments.

68.0 Reference: Rate Management
Exhibit B-15-1: IR 1.88.1, IR 1.88.2
NSA-12 to reflect integration of BCTC– Starting Point for Incremental Increase
Limited Data to Work With

"…4. The integration of BCTC resulted in the elimination or amalgamation of positions where there was a duplication of duties, and consequential cost savings.

5. Further cost savings were achieved in the course of the integration process that were not directly related to the elimination or amalgamation of duplicate positions." [Ref: Section 1.3.3.1]

In the response to BCUC IR 1.88.1, BC Hydro confirmed F11 NSA-12 does not include the savings identified in items 4 and 5 described in Section 1.3.3.1.

The response to BCUC IR 1.88.2 referenced the testimony of Charles Reid in Appendix 2 of Exhibit B-8 EU in the BC Hydro F11 RRA. His responses to questions 13 and 14 contained these statements:

A.13 … At this time BC Hydro **estimates** that the non-recurring implementation costs, in F2011, will be **about $17 million**, inclusive of both **operating and capital** expenditures.

A.14 … I **estimate** that F2011 **costs will be reduced by between $16 million and $23 million** as a result of the integration. The significant range arises from the fact that F2011 integration activities, and their timing, remain uncertain. [emphasis added]

The actual F2011 costs of the BCTC integration are now available.

"As shown on Schedule 1.0, there is no net impact on the total revenue requirements arising from either the Nature View reclassifications or the BCTC integration, for either the F2011 NSA-9 or F2011 NSA-12 restatements, since there are no net BCTC integration savings in F2011. The annual net BCTC integration savings (items 4. and 5. of the BCTC integration described in section 1.3.3.1) begin in F2012. (Exhibit B-1-3, p. 1-35)

68.1 Please provide the actual non-recurring implementation costs incurred for the BCTC integration, separating operating from capital expenditures.

68.2 Please provide the actual cost reduction in F2011 as a result of the integration, again separating operating from capital expenditures.

68.3 Please explain if the net of these costs are included in the F2011 Actuals and why these savings would not be an adjustment to the NSA-12 operating costs.

69.0 Reference: Operating Costs
Exhibit B-1-3: Section 1.3.5.2 and Section 8.14.1
Exhibit B-15-1: IR 1.87.1
Plan to achieve rate decrease (Table 1-A) – Operating Cost Reduction

The principal drivers of the increase in operating costs include: …

3. An increase in operating costs of $36 million due to the reduction in the amount of overhead that can be capitalized under IFRS." (Chapter 1, p. 28)

BCUC IR 1.87.1 requested an explanation of the "increase in operating costs of $36 million." The response to IR 1.87.1 referred to page 8-20 of the Amended Application which is quoted below.

As shown on line 7 of Schedule 18.0, BC Hydro is proposing to defer $178 million in F2012, $160.2 million in F2013, and $142.4 million in F2014. As shown on line 8 of Schedule 18.0, the reductions in deferred capital overhead **of $17.8 million** in F2013 **and $35.6 million** in F2014 are included in forecast operating costs. (Chapter 8, p. 20, lines 12-16) [emphasis added]

69.1 Please confirm the increased $36 million in operating costs referred to in section 1.3.5.2 is the $35.6 million in F2014 referred to in section 8.14.1.

69.1.1 If confirmed, please explain if the $17.8 million in F2013 from section 8.14.1 is referenced in the Application as being a principal driver of the operating cost increase.

69.2 Should the reference from section 8.14.1 of the Application not be the correct reference for the $36 million increase in operating costs referred to in section 1.3.5.2, please explain further, with references to the Application and Amended Appendix A Schedules, the source of the $36 million

increase in operating costs. Such explanation should include the detail to the KBU level, the prior five years' historical costs, and explanations, by year, for changes between the historical years and the test period.

70.0 Reference: Operating Costs
Exhibit B-15-1: IR 1.154.1
Plan to achieve rate decrease (Table 1-A) – Operating Cost Reduction

The response to BCUC IR 1.154.1 presented a subset of Amended Table 5-46 that details the $21.6 million reduction, primarily the result of the $35.9 reduction in IT Efficiencies.

Line 1 of New Table 1-A contains the business group operating cost reductions at $163 million.
Line 12 of New Table 1-A contains a reduction in forecast taxes of $14 million.

New Table 5-A contains the total gross additional reductions/savings of $176 million.
Line 26 of Amended Table 5-4 shows the $2.4 million change in the IPP Capital Lease costs.

Line 21 of Schedule 3 of Amended Appendix A shows a decrease in total gross taxes from $599.0 to $579.8 over the test period for a net $19.2 million reduction.

70.1 Please provide updated New Tables 1-A, 5-A and 5-4, if possible to one decimal place.

70.2 Please provide a schedule showing the adjustments to go from the gross reduction in operating of $176 million to the net reduction of operating of $163 million both before and after the required adjustments described above.

70.3 Please explain how these changes affect the proposed revenue requirement and rate increase.

<u>Labour</u>

71.0 Reference: Labour Costs
Exhibit B-15-1: IR 1.98.1, IR 1.103.1
Limited Data to Work With

The response to BCUC IR 1.103.1 included a spreadsheet with labour data, including gross operating cost labour and labour charged directly to specific and recurring capital for F2007 to F2014.

The response to BCUC IR 1.98.1 included the detail of FTEs by KBU and by category of FTE (i.e. gross operating, capital, and deferred operating) for F2007 to F2014.

71.1 Please provide the comparable BCTC schedules for those provided in the response to IR 1.103.1 and 1.98.1 for Actual F2007 – Actual F2010 and Actual April 1 – July 4, 2010 (3 months pre-integration). If the BCTC FTEs, calculated on the same basis as BC Hydro, are unavailable, please provide the relevant headcount figures in the response.

72.0 Reference: Labour Costs
Exhibit B-15-1: IR 1.89.1
Headcount on BCTC Integration and F2011 Year End Actual
Labour Costs / Application vs. Schedules

The response to BCUC IR 1.89.1 contains reference(s) to 2011 which should be to 2010, the date of integration of BCTC with BC Hydro.

72.1 Please confirm the BCTC Headcount was 471 on July 5, 2010 (not 2011). Please confirm the BC Hydro Headcount was 5,560 on June 30, 2010 (Deemed Date of Integration) (not 2011). If this is not confirmed, please provide the correct BC Hydro Headcount as of June 30, 2010. Please confirm the combined BC Hydro and BCTC Headcount at Integration was 6,031. If this is not confirmed, please provide the correct combined headcount at integration.

73.0 Reference: Labour Costs
Exhibit B-15-1: IR 1.89.3
NSA-12 Headcount for comparison to F2012-F2014
Labour Costs / Application vs. Schedules

The response to BCUC IR 1.89.3 states that 6,260 represented the F2011 **planned** regular hour FTEs for BC Hydro, as included in the F2011 RRA, plus the headcount for BCTC. The headcount for BCTC was used as an **estimate** of BCTC's FTEs. The 6,260 does not include any reductions related to the BCTC integration. [emphasis added]

The response to BCUC IR 1.89.1 states the combined headcount on integration was 6,031 and the BC Hydro headcount on March 31, 2011 was 5,832 for a reduction of 199 headcount. The same response states the BC Hydro non-overtime FTE as at March 31, 2011 was 5,805 including SMI and Site C.

The response to BCUC IR 1.89.3 states the actual F2011 regular hour FTEs as of March 31, 2011 were 5,743 and this number reflects reductions related to the BCTC integration. The 5,805 FTE less 62 for SMI and Site C yields the 5,743 FTE.

Please adjust the questions and answers in this IR for the confirmation of dates and numbers in the response related to IR 1.89.1.

73.1 At the time of the F2011 Evidentiary Update BC Hydro expected to achieve a reduction of 174 headcount by March 31, 2011. Please confirm an actual net headcount reduction of 199 was achieved by March 31, 2011 [6,031 - 5,832 = 199]. If this is not confirmed, please provide the correct amount.

73.2 Please explain the difference between the noted 250 reduction on integration of BCTC (referenced in BCUC IR 1.413.1) and the actual March 31, 2011 headcount indicating a 199 reduction. For example, is the net reduction a result of normal additions/turnover excluding BCTC and/or the delay in actual reductions due to the union bumping process?

73.3 Please provide the cost reduction between the expected 174 reduction and the assumed 199 reduction and whether this is part of the reported Actual F2011 and/or reported NSA-12 costs.

73.4 Please explain why the F2012-F2014 test year FTE should be compared to NSA-12 FTE when the NSA-12 FTE is based on planned/estimated numbers and does not reflect the actual BC Hydro FTE when adjusted for the net integration of BCTC.

Recognizing the FTEs do not exactly match the headcount, the change in regular hour FTEs from the F2011 Actual to the F2014 Update do not appear to match the stated 600 headcount reductions from BCTC integration to the end of F2014. This chart shows only a 62 FTE reduction from F2011 Actual to F2014; added to the 199 reduction from BCTC integration to the end of F2011, this is only a 261 reduction. The SMI and Site C FTEs increase by 95 from 62 in F2011 Actual to F2014 Update and are not included in line 41 on Schedule 16.

Change in Regular Hour FTE	**F2011 Actual**	**F2012 Update**	**F2013 Update**	**F2014 Update**
Regular Hour FTEs from line 41 on Schedule 16	5,743	5,909	5,735	5,681
Change from prior year		166	(174)	(54)
Change from F2011 to F2014				(62)

Remuneration from IR 1.96.1 ($ millions)	**F2011 Actual**	**F2012 Update**	**F2013 Update**	**F2014 Update**
BC Hydro	$607.4	$622.2	$615.5	$596.9
Add: BCTC	$16.6			
BC Hydro including Site C & SMI	$624.0	$622.2	$615.5	$596.9
Regular Hour FTE plus Site C & SMI	5,805	6,137	5,968	5,838
Average Remuneration per FTE ($)	$107,494	$101,385	$103,133	$102,244
Reduction in remuneration ($ millions)				$27.1
Equivalent FTE reduction				**265**

73.5 Please explain why the full reduction of 600 FTEs is not reflected in either the FTE or in the remuneration numbers. Does this indicate that roughly half of the cost of the 600 FTEs is still in the labour budget?

74.0 Reference: Labour Costs
Exhibit B-3-1: Amended Appendix A, Schedules 5.0 and 16.0
NSA-12 to reflect integration of BCTC
Labour Costs / Application vs. Schedules

The NSA-12 labour cost appears to be consistent with the average labour cost of F2011 Actual based on the regular hour FTEs. The F2011 Actual FTEs do not include the 471 BCTC employees for the first three months of 2010. Adjusting to add the BCTC FTE for three months and comparing the adjusted F2011 Actual to the F2011 NSA-12 yields an apparent overstatement of $28.5 million in labour cost.

Overstatement of NSA-12 Labour cost		F2011		F2011
		Actual		NSA-12
Labour (excluding Non-Current PEB)($ millions)	Sch. 5, line 20	$456.4		$491.9
Total FTE	Sch. 16, line 46	6,405		6,895
Average annual labour cost per FTE	Calculated	$71,257		$71,342
Regular Hours FTE	Sch. 5, line 41	5,743		6,260
Adjustment for 3 months of 471 BCTC	Calculated	118		
Adjusted for 12 months	Calculated	5,861		
Overstatement of NSA-12 FTE	Calculated			399
Overstatement of NSA-12 Labour ($ millions)				**$28.5**

74.1 Please confirm, or otherwise explain, the $28.5 million overstatement of the NSA-12 labour cost.

75.0 Reference: Labour Costs
Exhibit B-15-1: IR 1.96.1
Total Remuneration
Labour Costs / Application vs. Schedules

In the response to BCUC IR 1.96.1 the total remuneration for BCTC for the approximately three months of Fiscal 2011 is stated as $16.6 million. Based on 471 headcount at BCTC, this would indicate an average of about $141,000 per employee for a full year Fiscal 2011. Using the BCTC headcount from their 2010 Annual Report, the calculated average amounts per employee are $103,571 for F2009 and $104,641 for F2010. This indicates the F2011 actual includes non-typical payments in F2011.

A note to the BCTC 2011 FIA indicates the F2011 remuneration includes entitlements earned in respect of the prior fiscal year which were paid in the first quarter of Fiscal 2011.
[Ref: BCTC F2011 FIA, p. 17 of 22]

An arithmetic progression from F2009 and F2010 produces an average remuneration for F2011 of $105,722 per employee, and a total remuneration of $49,795,048 for a full fiscal year and approximately $12.449 million for the partial year in F2011.

75.1 Please confirm the logic of the calculations above, and the estimated approximately $12.449 million for the partial year in F2011.

75.2 If BC Hydro does not agree with $12.449 million estimated for the normalized F2011 partial year, please provide an estimated total remuneration for BCTC for a normalized partial F2011 year.

76.0 Reference: Labour Costs
Exhibit B-1-3: Amended Appendix A
Exhibit B-15-1: IR 1.89.3
Labour Costs / Application vs. Schedule

"BC Hydro has eliminated 250 positions related to the integration with BC Transmission Corporation in 2010." (Executive Summary, p. 2)

"On October 12-13, 2011, BC Hydro eliminated approximately 300 FTEs. A further 150 FTEs will be eliminated during the course of F2013 and F2014 from non-safety sensitive areas of the company. The reductions will be offset by 100 new front-line positions … for a net decrease of approximately 350 FTEs." (Chapter 5, p. 14)

"Approximately 45 per cent of the [300 October 12-13, 2011] FTE reductions were in regard to positions held by union affiliated employees who have displacement rights under their respective collective agreements. The displacement rights are expected to be fully exercised by mid-2012. In consequence, the FTEs and associated operating cost reductions in the Business Groups and KBUs are not fully reflected until F2014." (Chapter 5, p. 14, Reference 41e)

"The 5,743 represents the actual F2011 regular hour FTEs and reflects reductions related to the BCTC integration." (BCUC IR 1.89.3)

76.1 The following table is a summary of FTE reductions, based on the information provided in Exhibit B-1-3 (as referenced above). Please confirm if the following table is correct and inclusive of all planned and actual FTE reductions from F 2011 Actual to F 2014 Plan. If not confirmed, please provide an updated table.

	FTE Reduction Summary			
	Description	**FTEs**	**Date**	**Reference**
A	BCTC Integration FTE Reductions	250	F 2011	Exhibit B-1-3 Executive Summary, p. 2.
B	October 2011 FTE Reductions (Note 1)	300	Oct 12/13, 2011	Exhibit B-1-3 Chapter 5, p. 14.
C	F 2012 - F 2014 FTE Reductions	150	F 2012 - 2014	Exhibit B-1-3 Chapter 5, p. 14.
	Total	**700**		
Note 1	**October 2011 FTE Reductions by Affiliation**			
	Executive	0%		Exhibit B-1-3 Chapter 5, p. 14.
	Management and Professional	55%		Exhibit B-1-3 Chapter 5, p. 14.
	IBEW	42%		Exhibit B-1-3 Chapter 5, p. 14.
	COPE	3%		Exhibit B-1-3 Chapter 5, p. 14.

76.1.1 Please provide the percentage of BCTC Integration FTE Reductions (Reference A per table above) and the projected F2012 – F2014 FTE Reductions (Reference B per table above) by actual/estimated affiliation (i.e. Executive, Management and Professional, IBEW and COPE).

76.1.2 Please identify the time period when the BCTC Integration FTE Reductions (Reference A per table above) took effect.

76.2 The following analysis is an estimate of Regular Hour, SMI and Site C FTEs over the test period, excluding Overtime FTEs. Please confirm if the information contained within the following table is correct. If not confirmed, please provide an updated table.

Estimated F 2012 FTEs (Excluding Overtime)			
F 2011 Actual FTEs (Excluding Overtime)	5,805		Appendix A, Schedule 16.0, Column 5, Row 46 less Row 43
Add: F 2011 BCTC Headcount, Pro-rated for 3 Months	118	Note 1	
Less: FTE Reductions Due to BCTC Integration, Pro-rated for 6 Months	-125	Note 2	
Less: October 12/13, 2011 FTE Reductions, Normalized for Union-Affiliated FTEs and Pro-rated for 5.5 Months	-76	Note 3	
Estimated F 2012 FTEs (Excluding Overtime)	**5,722**		
Updated Plan F 2012 FTEs (Excluding Overtime)	6,138		Appendix A, Schedule 16.0, Column 9, Row 46 less Row 43
Difference	415		
Estimated F 2013 FTEs (Excluding Overtime)			
F 2012 Estimated FTEs (Excluding Overtime)	5,722		
Less: October 12/13, 2011 FTE Reductions, Normalized for Union-Affiliated FTEs and Pro-rated for 6.5 Months	-89	Note 3	
Less: October 12/13, 2011 FTE Reductions - Union-Affiliated Impact	-101	Note 4	
Add: Front-line FTE Additions	50	Note 5	
Less: 150 FTE Reductions	-41	Note 6	
Estimated F 2013 FTEs (Excluding Overtime)	**5,532**		
Updated Plan F 2013 FTEs (Excluding Overtime)	5,969		Appendix A, Schedule 16.0, Column 10, Row 46 less Row 43
Difference	437		
Estimated F 2014 FTEs (Excluding Overtime)			
F 2013 Estimated FTEs (Excluding Overtime)	5,532		
Less: October 12/13, 2011 FTE Reductions - Union-Affiliated Impact	-34	Note 4	
Add: Front-line FTE Additions	50	Note 5	
Less: 150 FTE Reductions	-41	Note 6	
Estimated F 2014 FTEs (Excluding Overtime)	**5,507**		
Updated Plan F 2014 FTEs (Excluding Overtime)	5,838		Appendix A, Schedule 16.0, Column 11, Row 46 less Row 43
Difference	332		
Total Cumulative Difference (Plan > Estimated)	**1,184**		

76.2.1 **Note 1** Per BCUC IR 1.89.3, "The 5,743 represents the actual F2011 regular hour FTEs and reflects reductions related to the BCTC integration." The 5,805 starting point above represents the Actual F 2011 Regular Hour FTEs (5,743), SMI FTEs (33) and Site C FTEs (29), and excludes Overtime FTEs per Amended Appendix A, Schedule 16.0, Column 5.

Given that BCTC Integration with BC Hydro took place on July 5, 2010, the assumption is that F 2011 Actual Regular Hour FTEs include BCTC FTEs for 9 months (July 5, 2010 - March 31, 2011). As such, estimated F 2012 Regular Hour FTEs are normalized for BCTC FTEs by adding 3 months of BCTC FTEs, as follows:

BCTC Headcount	471		Appendix A, Schedule 16.0, Column 8, Row 42.
Pro-rated for 3 Months	118		

Please confirm that the above assumption is accurate. If not confirmed, please explain otherwise and include the correct assumption in an updated table.

76.2.2 **Note 2** "BC Hydro has eliminated 250 positions related to the integration with BC Transmission Corporation in 2010." (Executive Summary, p. 2) Given the integration date of July 5, 2010, the assumption is that the 250 reductions were made evenly throughout F2011 and thus F2012 Plan must be normalized to account for this.

Please confirm that this assumption is accurate. If not confirmed, please explain otherwise and include the correct assumption in an updated table.

76.2.3 **Note 3** According to Exhibit B-1-3 Chapter 5, p. 14, "On October 12-13, 2011, BC Hydro eliminated approximately 300 FTEs." As such, the assumption is that the FTE reductions must be pro-rated to account for the FTE reduction for 5.5 months of F2012 and 6.5 months of F2013.

Please confirm that this assumption is accurate. If not confirmed, please explain otherwise and include the correct assumption in an updated table.

76.2.3.1 **Note 3** According to Exhibit B-1-3 Chapter 5, p. 14, Reference 41e, "Approximately 45 per cent of the [300 October 12-13, 2011] FTE reductions were in regard to positions held by union affiliated employees who have displacement rights under their respective collective agreements. The displacement rights are expected to be fully exercised by mid-2012. In consequence, the FTEs and associated operating cost reductions in the Business Groups and KBUs are not fully reflected until F2014."

As such, the assumption is that the 300 FTE reductions must be normalized to account for the fact that these union-affiliated reductions will not be fully realized until F 2014.

FTE Reductions October 12/13, 2011		300	Chapter 5, p. 14.
Affiliation Allocation			
Executive	0%	0	Chapter 5, p. 14.
Management and Professional	55%	165	Chapter 5, p. 14.
COPE	42%	126	Chapter 5, p. 14.
IBEW	3%	9	Chapter 5, p. 14.
Total		**300**	
Less: Union-affiliated		135	
Net FTE Reductions		**165**	
Net FTE Reductions Pro-rated (5.5 Month Reduction in F 2012)		**76**	
Net FTE Reductions Pro-rated (6.5 Month Reduction in F 2013)		**89**	

Please confirm that this assumption is accurate. If not confirmed, please explain otherwise and include the correct assumption in an updated table.

76.2.4 **Note 4** According to Exhibit B-1-3 Chapter 5, p. 14, Reference 41e, "Approximately 45 per cent of the [300 October 12-13, 2011] FTE reductions were in regard to positions held by union affiliated employees who have displacement rights under their respective collective agreements. The displacement rights are expected to be fully exercised by mid-2012. In consequence, the FTEs and associated operating cost reductions in the Business Groups and KBUs are not fully reflected until F2014."

The assumption is that "Mid-2012" referenced above is approximately July 2012, meaning that the union-affiliated reductions made in October 2011 will be realized for only 9 months of F2013 (July 2012 – March 2013) with the additional 3 month impact in F2014.

Total Union-affiliated Reductions		135	Note 3
Pro-rated (9 Month Reduction in F 2013)		**101**	
Pro-rated (3 Month Reduction in F 2014)		**34**	

Please confirm that the assumption is accurate. If not confirmed, please explain otherwise and include the correct assumption in an updated table.

76.2.5 **Note 5** According to Exhibit B-1-3 Chapter 5, p. 14, "100 new front-line positions" will be added in F2013 and F2014.

The assumption is that these additions will take place evenly throughout F2013 and F2014 and thus they are pro-rated as follows:

Addition of new front-line employees		100	Chapter 5, p. 14.
Pro-rated (6 Months in F 2013)		**50**	
Pro-rated (6 Months in F 2014)		**50**	

Please confirm that the assumption is accurate. If not confirmed, please explain otherwise and include the correct assumption in an updated table.

76.2.6 **Note 6** According to Exhibit B-1-3 Chapter 5, p. 14, a further 150 FTEs will be eliminated during F 2013 and F 2014.

The assumption is that these reductions will take place evenly throughout F2013 and F2014 and that the affiliation of reductions will be a similar composition to those outlined in Chapter 5, p. 14 (i.e. "... the reductions are approximately 55 per cent management and professional, 42 per cent COPE and 3 per cent IBEW."

FTE Reductions F 2013 / F 2014		150	Chapter 5, p. 14.
Affiliation Allocation			
Executive	0%	0	
Management and Professional	55%	83	
COPE	42%	63	
IBEW	3%	5	
Total		**150**	
Less: Union-affiliated		67.5	
Net FTE Reductions		**82.5**	
Net FTE Reductions Pro-rated (50% Reduction in F 2013)		**41**	
Net FTE Reductions Pro-rated (50% Reduction in F 2014)		**41**	

Please confirm that the assumption is accurate. If not confirmed, please explain otherwise and include the correct assumption in an updated table.

76.2.7 The analysis above identifies a cumulative difference of 1,184 FTEs over the test period. Please provide a summary of this difference by FTE category (i.e. Operating, Capital and Deferred). If the table provided is updated by BC Hydro in response to the IR, please provide the updated difference over the test period by FTE category (i.e. Operating, Capital and Deferred).

76.2.7.1 The following table summarizes Direct/Benefits/Variable Pay (Excluding PEB, Before Capital Charges, Including reductions and changes not identified by affiliation and excluding severance) per Operating FTE. Please confirm that the table is correct. If not confirmed, please provide an updated table.

Operating FTEs	3,542	3,866	4,335	4,558	4,275	4,223	4,067	4,025	BCH Response to BCUC IR 1.98.1
Direct/Benefits/Variable Pay (Excluding PEB, Before Capital Charges)	466,264	521,432	605,897	662,114	697,415	765,611	762,815	765,117	BCH Response to BCUC IR 1.103.1
Workforce Reduction - not identified by affiliation	-	-	-	-	-	-	- 1,100	- 4,500	BCH Response to BCUC IR 1.103.1
Compensation/ total rewards changes not identified by affiliation	-	-	-	-	-	- 6,500	- 18,600	- 31,000	BCH Response to BCUC IR 1.103.1
Direct/Benefits/Variable Pay (Excluding PEB, Before Capital Charges, Including reductions and changes not identified by affiliation and excluding severance)	466,264	521,432	605,897	662,114	697,415	759,111	743,115	729,617	
Less: Charged to Specific Recurring Capital	97,594	130,172	162,527	172,674	241,028	282,833	269,692	265,122	BCH Response to BCUC IR 1.103.1
Direct/Benefits/Variable Pay (Excluding PEB, Before Capital Charges, Including reductions and changes not identified by affiliation and excluding severance) Net of Charges to Specific Recurring Capital	368,670	391,260	443,370	489,440	456,387	476,278	473,423	464,495	
Direct/Benefits/Variable Pay (Excluding PEB, Before Capital Charges, Including reductions and changes not identified by affiliation and excluding severance) per Operating FTE	**104**	**101**	**102**	**107**	**107**	**113**	**116**	**115**	

76.2.7.2 The following table summarizes each FTE category (i.e. Operating, Capital and Deferred) as a percentage of Total FTEs. Please confirm that the table is correct. If not confirmed, please provide an updated table.

FTE Categories									
Operating FTEs	3,542	3,866	4,335	4,558	4,275	4,223	4,067	4,025	BCH Response to BCUC IR 1.98.1
Capital FTEs	941	1,179	1,350	1,329	1,666	1,861	1,858	1,853	BCH Response to BCUC IR 1.98.1
Deferred FTEs	187	271	422	466	464	571	556	472	BCH Response to BCUC IR 1.98.1
	4,670	**5,316**	**6,108**	**6,353**	**6,405**	**6,656**	**6,481**	**6,350**	
FTE Category as a % of Total									
Operating FTEs	76%	73%	71%	72%	67%	63%	63%	63%	
Capital FTEs	20%	22%	22%	21%	26%	28%	29%	29%	
Deferred FTEs	4%	5%	7%	7%	7%	9%	9%	7%	
	100%	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	

76.2.7.3 The following table estimates the impact of the cumulative difference of 1,184 FTEs identified in the analysis above on labour costs associated with Operating FTEs. Please confirm that the table is correct. If not confirmed, please provide an updated table.

Total Cumulative Difference FTEs (Plan > Estimated)	**1,184**		BCUC IR above
Operating FTEs as a % of Total FTEs	63%		BCH Response to BCUC IR 1.98.1
Estimated Total Cumulative Difference - Operating FTEs	751		
Direct/Benefits/Variable Pay (Excluding PEB, Before Capital Charges, Including reductions and changes not identified by affiliation and excluding severance) per Operating FTE (F2012 Plan) ($ thousands)	113		BCUC IR above
Total Estimated Impact of Cumulative Difference on Operating FTE Labour ($ thousands)	**84,745**		

77.0 Reference: Labour Costs
Exhibit B-15-1: IR 1.103.1, IR 1.98.1.3
Labour Costs / Application vs. Schedule

The response to BCUC IR 1.103.1 included a working spreadsheet with labour data, including gross operating cost labour and labour charged directly to specific and recurring capital for F2007 to F2014.

The response to BCUC IR 1.98.1 included the detail on FTEs by KBU by gross operating, capital, and deferred operating for F2007 to F2014.

77.1 The following table is a summary of Direct/Benefits/Variable Pay (Excluding PEB, Before Capital Charges, Including Workforce Reductions, Including Compensation / Total Rewards Changes and Excluding Severance) based on the information provided in the response to IR 1.103.1. Please confirm that the following table is correct. If not confirmed, please provide an updated table.

Total FTE Analysis ($ thousand)									
	F 2007 Actual	F 2008 Actual	F 2009 Actual	F 2010 Actual	F 2011 Actual	F 2012 Plan	F 2013 Plan	F 2014 Plan	Reference
Total FTEs	4,670	5,316	6,108	6,353	6,405	6,656	6,481	6,350	BCH Response to BCUC IR 1.98.1
Direct/Benefits/Variable Pay (Excluding PEB, Before Capital Charges)	466,264	521,432	605,897	662,114	697,415	765,611	762,815	765,117	BCH Response to BCUC IR 1.103.1
Workforce Reduction - not identified by affiliation							-1100	-4500	BCH Response to BCUC IR 1.103.1
Compensation/ total rewards changes not identified by affiliation						-6500	-18600	-31000	BCH Response to BCUC IR 1.103.1
Direct/Benefits/Variable Pay (Excluding PEB, Before Capital Charges, Including Workforce Reductions, Including Changes not identified by affiliation, Excluding Severance)	466,264	521,432	605,897	662,114	697,415	759,111	743,115	729,617	
Per FTE	**100**	**98**	**99**	**104**	**109**	**114**	**115**	**115**	
% Increase		-2%	1%	5%	4%	5%	1%	0%	

77.1.1 Please confirm if the Total Direct/Benefits/Variable Pay (Excluding PEB, Before Capital Charges, Including Workforce Reductions, Including Changes not identified by affiliation, Excluding Severance) (i.e. $729,617 thousand for F2014 Plan) includes pay for Operating, Capital and Deferred FTEs. If not confirmed, please provide an updated table inclusive of all FTE categories: Operating, Capital and Deferred.

77.1.2 Please provide a summary, comparable to the table provided above, of the Total Direct/Benefits/Variable Pay (Excluding PEB, Before Capital Charges, Including Workforce Reductions, Including Changes not identified by affiliation, Excluding Severance) per each FTE category: Operating, Capital and Deferred.

78.0 Reference: Labour Costs
Exhibit B-15-1: IR 1.98.1
FTE by KBU and expense category
Labour Costs / Application vs. Schedules

BC Hydro has provided FTEs by KBU and expense category in response to BCUC IR 1.98.1 with greater detail than provided in Amended Appendix Y of the F2011 RRA, although Schedule 16 of Amended Appendix A of the F2011 RRA had the KBU detail. The F2007 through F2009 consolidated Actuals are the same for all groups except Transmission and Distribution, called Field Operations in F2011. It appears the consolidated total BC Hydro FTEs in the response to BCUC IR 1.98.1 are approximately 100 FTE too low for F2007 through F2009.

During F2011 BC Hydro integrated BCTC and eliminated 199 FTE from the 250 reduced on integration of BCTC. During F2012, October 2011, BC Hydro eliminated 291 FTE of the 300 reported. A further 51 FTE are remaining from the BCTC related reductions, a further 9 from the 300 reduction in October 2011, and a further for the net 50 reductions to come in F2013 and F2014 are required to yield the net 600 FTE reductions. The table below is data extracted from the response to BCUC IR 1.98.1.

IR 1.98.1	F2011	F2012	Yr to YR Change	F2013	Yr to YR Change	F2014	Yr to YR Change	F2011 to F2014
Consolidated Total	6,405	6,656		6,481		6,350		
Less SMI and Site C	(62)	(228)		(233)		(157)		
BC Hydro Consolidated	6,343	6,428	85	6,248	(180)	6,193	(55)	(150)
Operating Total	4,275	4,223		4,067		4,025		
Less SMI and Site C	0	0		0		0		
BC Hydro Operating	4,275	4,223	(52)	4,067	(156)	4,025	(42)	(250)
Capital Total	1,666	1,861		1,858		1,853		
Less SMI and Site C	0	0		0		0		
BC Hydro Capital	1,666	1,861	195	1,858	(3)	1,853	(5)	187
Deferred Total	465	571		556		472		
Less SMI and Site C	(61)	(228)		(233)		(157)		
BC Hydro Deferred	404	343	(61)	323	(20)	315	(8)	(89)

78.1 Please advise if the Transmission and Construction Services figures for F2007 through F2009 are approximately 100 FTE too low because of not including the Construction Services (CBU) for those three years.

78.2 Please explain why the consolidated FTE reduction from F2011 to F2014, excluding SMI and Site C, is only 150 when it would be expected to be closer to 401.

79.0 Reference: Operating Costs
Exhibit B-15-1: IR 1.99.2
Employment Mix – BCTC
Labour Costs / Application vs. Schedules

The response to BCUC IR 1.99.2 on BCTC was filed as part of the response to BCUC IR 1.99.1 on BC Hydro. As shown in the table below, there is a discrepancy between the BCTC numbers filed for this IR and the numbers in the BCTC 2010 Annual Report. Although a small difference, under 3%, the discrepancy will run through various calculations.

BCTC Headcount Data	Source	F2006	F2007	F2008	F2009	F2010
BCTC Employees	BCTC 2010 Annual Report (p. 65 of 72)					
Regular		321	360	384	401	417
Temporary		19	37	40	47	57
Total		340	397	424	448	474
BCTC Employees	BCUC IR 1.99.1					
Full-time Permanent (FTR)			354	370	394	408
Part-time Permanent (PTR)			1	1	3	3
Full-time Temporary (FTT)			38	39	42	48
Part-time Temporary (PTT)			0	2	3	5
Rounding ?					-1	
Total			393	412	441	464
Difference			4	12	7	10
BCTC FTEs	BCTC 2010 Annual Report (p. 24 of 72)					
Defined as FTR at year-end				384	401	417

79.1 Please provide a definitive response for total BCTC headcount at the F2006 through F2010 year-ends.

80.0 Reference: Labour Costs
Exhibit B-1-3, Amended Appendix A
Exhibit B-15-1, IR 1.98.1
FTE's Increasing - FTEs Capitalized

The response to BCUC IR 1.103.1 included a working spreadsheet with labour data, including gross operating cost labour and labour charged directly to specific and recurring capital for F2007 to F2014.

The response to BCUC IR 1.98.1 included the detail on FTEs by KBU by gross operating, capital, and deferred operating for F2007 to F2014. The response notes that "Operating FTEs are shown on gross basis and include the allocation to capital through capital overhead. Capital relates to specific capital and does not include an allocation for capital overhead. BC Hydro does not separate the FTEs related to capital overhead within its financial systems."

80.1 Please confirm, or explain otherwise, if the costs identified as "Charged Directly to Specific and Recurring Capital" in the response to IR 1.103.1 (e.g., $241,028 [thousand] for F2011 Actual) relates to costs incurred for FTEs included in the category "Capital" per the response to IR 1.98.1 (e.g., 1,666 FTEs in F2011 Actual).

80.2 Please confirm, or explain otherwise, if the labour cost, before post-employment benefits and costs charged directly to specific and recurring capital, in the response to IR 1.103.1 (e.g., $697,415 [thousand] for F2011 Actual) relates to costs incurred for FTEs included in the cost categories "Operating" (e.g., 4,275 in F2011 Actual), "Deferred" (e.g., 464 in F2011 Actual) and "Capital" for example, 1,666 FTEs in F2011 Actual). This assumption is made given that the Average Cost per Employee per response to IR 1.103.1 is calculated using total FTEs (e.g. 6,405 in F2011 Actual) as opposed to "Operating" and "Capital" only.

80.2.1 If the labour cost, before post-employment benefits and costs charged directly to specific and recurring capital (e.g. $697,415 [thousand] for F2011 Actual) does not include charges related to "Deferred" FTEs, please provide a working spreadsheet similar to that provided in the response to BCUC IR 1.103.1 for Deferred FTEs. The working spreadsheet should summarize the following: total costs by cost type (i.e. direct, benefits, variable pay/gainsharing) and by affiliation (i.e. Exec, M&P, COPE, IBEW), post-employment benefits, and any adjustments (i.e. severance, workforce reductions not identified by affiliation, compensation/ total rewards changes not identified by affiliation). Please provide the working spreadsheet for F2007-F2011 Actual and F2012-F2014 Plan.

80.3 The following table is a summary of Costs Charged Directly to Specific and Recurring Capital ($ thousands) per Capital FTE. Please confirm if the following table is correct. If not confirmed, please provide an updated table.

Capital FTE Analysis	F 2007 Actual	F 2008 Actual	F 2009 Actual	F 2010 Actual	F 2011 Actual	F 2012 Plan	F 2013 Plan	F 2014 Plan	Reference
Capital FTEs	941	1,179	1,350	1,329	1,666	1,861	1,858	1,853	BCH Response to BCUC IR 1.98.1
Charged Directly to Specific and Recurring Capital ($ thousands)	97,594	130,172	162,527	172,674	241,028	282,833	269,692	265,122	BCH Response to BCUC IR 1.103.1
Charged Directly to Specific and Recurring Capital ($ thousands) per FTE	**104**	**110**	**120**	**130**	**145**	**152**	**145**	**143**	

80.3.1 Based on the table provided above, the Cost Charged Directly to Specific and Recurring Capital per Capital FTE has increased steadily from $104 (thousand) in F2007 Actual to $152 (thousand) in F2012 Plan. Please explain why the Cost Charged Directly to Specific and Recurring Capital per Capital FTE has increased each year.

81.0 Reference: Labour Costs
Exhibit B-15-1: IR 1.98.1
FTE by KBU and expense category
FTE's Increasing - FTEs Capitalized

The response to BCUC IR 1.91.1 provides Operating FTE for BC Hydro and BCTC for F2007 through F2010. The response to BCUC IR 1.98.1 provides the BC Hydro Operating FTE. The difference is essentially the BCTC total headcount. The response to BCUC 1.75.4 presented a capitalized overhead amount for BCTC.

BCTC Headcount Data	Source	F2006	F2007	F2008	F2009	F2010
BCH FTE & BCTC HC	IR 1.91.1		3,902	4,250	4,736	4,974
BC Hydro Operating FTE	IR 1.98.1		3,542	3,866	4,335	4,558
BCTC Operating Headcount	Calculated		360	384	401	416
BCTC Regular Employees	BCTC 2010 Annual Report (p. 65 of 72)	321	360	384	401	417
BCTC Total Employees	BCTC 2010 Annual Report (p. 65 of 72)	340	397	424	448	474
BCTC Gross OMA	IR 1.75.4		168	186	207	212
BCTC capitalized overhead	IR 1.75.4			8	13	14
As a % of Gross OMA				4.30%	6.28%	6.60%
As a % of Gross OMA	Trended backwards		3.50%			
BCTC Capital Headcount	Calculated		14	18	28	31
BCTC Operating Headcount	Calculated		383	406	420	443

81.1 Please explain if it would be appropriate and correct to apportion the BCTC total headcount to operating and capital headcount as shown in the table above.

82.0 Reference: Operating Costs – Customer Care
Exhibit B-15-1: IR 1.140.1
Key Account Management – Power Smart/Energy Conservation work
FTE's Increasing - FTEs Deferred

The response to BCUC IR 1.140.1 states the Customer Care department works directly with BC Hydro's largest customers through the Key Account Management group to deliver Power Smart programs. Key Account Management is responsible for working with transmission and large commercial customers, First Nations, institutions and communities to identify and take advantage of energy conservation opportunities. Key Account Managers interact with approximately 1,000 customers, which total more than 66,000 accounts and consume half of BC Hydro's domestic energy sales. These customers also comprise approximately half of the energy savings forecast within Power Smart programs.

82.1 Please confirm, or otherwise explain, the Key Account Management group plans to defer to DSM $22.8 million or 76% of its $30 million total budget for the F2012-F2014 period.

82.2 Please confirm, or otherwise explain, the $22.8 million deferred to DSM in not included in Schedule 5.0.

82.3 Please confirm, or otherwise explain, this deferral to DSM is based on "Direct program costs, indirect administration costs and allocated overhead, shall be deferred according to the intent of section 3450 - Research and Development, of the Canadian Institute of Chartered Accountants, Accounting Recommendations Handbook. Generally speaking, those criteria treat research costs as expenses and treat as assets, those development costs that have a high probability of achieving net financial benefits." from the response to BCUC IR 1.139.1.

82.4 The response to BCUC IR 1.401.2 refers to "Key Account Management charges costs to deferred DSM for activities that support the acquisition of DSM energy savings." Please confirm if the Key Account Management costs are viewed as "direct program costs", "indirect administration costs" or "allocated overhead" to DSM.

83.0 Reference: Operating Costs – Communications
Exhibit B-15-1: IR 1.146.1
Marketing and Brand Strategy – Power Smart/Energy Conservation work
FTE's Increasing - FTEs Deferred

Section 5.7.5.5 Marketing and Brand Strategy states "Because most of Marketing and Brand Strategy's work builds awareness of conservation and efficiency programs its costs are deferred in the DSM Regulatory Account". The response to BCUC IR 1.98.1 indicates 73 FTE in Communications booked to Deferred in F2012.

83.1 Please provide the F2012 gross operating costs for the Communications group, deferred costs, capitalized costs, and net operating costs. These should be separated by Office of the Senior Vice President, Capital Projects Communications, Corporate Communications, Marketing and Brand Strategy, and Community and Media Relations.

83.2 Please confirm which if these costs are included in Schedule 5.0 and where the other costs can be seen in Appendix A.

84.0 Reference: Operating Costs
Exhibit B-15-1: IR 1.100.1
Employee Demographics
Labour Retirements

BC Hydro filed employee demographic information for October 30, 2009 in Appendix Y of the F2011 RRA, and for March 31, 2011 in response to BCUC IR 1.100.1.

There was a net 36% increase in BC Hydro employees between F2007 and F2011. The 36% net increase includes the integration of BCTC and subsequent 250 employee reduction, and the 300 employee reduction in October 2011, recognizing the full reduction effect is delayed by bumping requirements in the union agreements.

84.1 Please explain how the net increased hiring since F2007 has impacted the employee demographics. For example, has the hiring focus been on hiring a younger workforce to be trained, or has the hiring been more of a match to the existing employee age profile? Please provide any available statistics on the movement of the demographic curve since F2007, and explain how this integrates with the long range employee resource plan.

84.2 Please explain if planned net employee reductions to the end of F2014 are expected to have any significant impact on the employee demographics.

84.3 For the chart provided in the response to BCUC IR 1.100.1, please provide the number and percentage of employees in the groups: (1) 55 years and over but under 60 years old, (2) 60 years and over but under 65 years old, (3) 65 years and over.

85.0 Reference: Operating Costs
Exhibit B-15-1: IR 1.101.1
Retirement Uptake
Labour Retirements

BC Hydro filed employee retirement uptake information for F2007 through F2014 in Appendix Y of the F2011 RRA, and updated this information in response to BCUC IR 1.101.1.

Retirement uptake for F2010 and F2011 were significantly lower than planned, and forecast F2012-F2014 are one percentage point lower than forecast in the F2011 RRA.

85.1 Please explain how BC Hydro has been dealing with the aging workforce issue as part of the overall strategy of implementing the workforce reduction following the integration of BCTC, the reductions in October 2011, and the planned reductions in F2012-F2014. For example, has there been a program to encourage older members of the workforce to retire earlier, thereby lowering the average employee age.

85.2 Please identify how many people have been hired, by year since F2006, as part of planned replacement of employees expected to retire.

85.3 Please comment if the recent, current, and anticipated economic situation in British Columbia has had a significant impact on the retirement uptake, and if this reduces the demographic risk profile for BC Hydro.

86.0 Reference: Labour Costs
Exhibit B-15-1: IR 1.91.1
Historical Operating Cost/FTE Trend
Labour / Salaries

The response to BCUC IR 1.91.1 indicates the Operating FTE for BCTC is the same as the total BCTC Regular Headcount as shown in the BCTC 2010 Annual Report; this allocates no BCTC Temporary employees to Operating. BCTC had a different definition of FTE than BC Hydro. The reference for the data is given as BCUC IR 1.109.1 and BCTC HC. The reclassification of BCTC charges added to normalize the operating costs appear to include the total remuneration for BCTC.

The response to BCUC IR 1.91.1 indicates a reduction of Operating FTEs from 4,974 in F2010 to 4,275 in F2011, a reduction of 699 FTEs. The response to BCUC IR 1.98.1 indicates a reduction of Operating FTEs from 4,558 in F2010 to 4,275 in F2011, a reduction of 283 FTE. The entire BCTC integration was 471 headcount including regular and temporary employees.

The response to BCUC IR 1.91.1 indicates the percentage change in BC CPI Inflation from F2007 to F2014 as 14.4% when 11.7% is the correct number. Similarly, the percentage changes from F2007 to F2014 presented in Table 1 are not the same as the total of the annual changes.

86.1 Please confirm, or otherwise provide, the correct reference for BC Hydro Operating FTE is BCUC IR 1.98.1.

86.2 Please confirm, or otherwise correct, the total BCTC remuneration has been included in the operating cost calculation.

86.3 Please explain why the BCTC regular headcount, not including any temporary headcount, is the appropriate number to add to the BC Hydro operating FTE for comparison in the Table 1.

86.4 Please confirm, or otherwise explain, the percentage change in BC CPI Inflation from F2007 to F2014 is 11.7%. Please explain why the percentage change from F2007 to F2014 is not the same as the sum of the annual changes for all the items listed.

86.5 Please explain where the reduction of 699 operating FTEs, from F2010 to F2011, can be seen in the Amended Application and/or in the responses to IRs. Please identify both the cost reductions and the FTE reductions.

87.0 Reference: Labour Costs
Exhibit B-15-1: IR 1.96.2
Total Remuneration
Labour / Salaries

BCUC IR 1.96.2 requested the weighted number of employees (to account for PTR, new hires, etc) and the average salary per employee for each of the years. The objective is to be able to see how the average salary has changed by year. The weighted number of employees will normalize to eliminate the bias created by the influx of new hires over the time period.

The response to BCUC IR 1.96.2 referred to the response for BCUC IR 1.103.2 which contains the average salary by year but only the year-end headcount.

87.1 Please provide the weighted number of employees for each of F2006 through F2011.

87.2 Please indicate if the approximately 100 CBU employees are included for F2007 through F2009 in the headcounts provided in the response to BCUC IR 1.103.2.

87.3 Please provide the regular hour FTE for F2006. Please indicate if the approximately 100 CBU employees are included for F2007 through F2009 in the FTEs shown on line 41 of Schedule 16 of Amended Appendix A, and whether they are included in the regular hour FTE for F2006 to be provided in this IR.

88.0 Reference: Operating Costs
Exhibit B-15-1: IR 1.97.1
Labour Costs – Salary Stratification
Labour / Salaries

The response to BCUC IR 1.97.1 is based on individuals and their salary information at year-end.

88.1 Please explain why the number of employees earning $75,000 or under as at year-end plus the number of employees earning over $75,000 as at year-end would exceed the headcount at year-end.

89.0 Reference: Operating Costs
Exhibit B-15-1: IR 1.103.1
Labour Costs
Labour / Salaries

The response to BCUC IR 1.103.1 detailed the direct, benefits, variable pay/gain-sharing and post-employment benefits, and total by Executive, M&P, COPE, IBEW/CBU with the applicable FTE, average cost per FTE (not employee) and annual CPI.

89.1 Please explain why the M&P direct cost increases 13.8% from F2009 to F2010 when the FTE increases only 7.2%.

89.2 Please explain why the M&P direct cost increases 2.4% from F2011 to F2012 when the FTE increases only 0.9%.

89.3 Please explain why the M&P direct cost increases 0.1% from F2013 to F2014 when the FTE decreases by 1.7%.

89.4 Please explain why the COPE direct cost increases 8.9% from F2009 to F2010 when the FTE increases only 1.8%.

89.5 Please explain why the COPE direct cost increases 11.6% from F2011 to F2012 when the FTE increases only 4.7%.

89.6 Please explain why the variable pay/gainsharing increased from F2007 to F2014 by 68% for Executive, by 56% for M&P, by 49% for COPE and by 75% for IBEW, compared to the increase in FTE. If BC Hydro calculates different percentages for the increases in variable pay/gainsharing net of the increase in FTE, please provide these. Have the variable pay/gain-sharing calculations been affected by the amount of increase in the deferral accounts?

90.0 Reference: Operating Costs
Exhibit B-15-1: IR 1.158.1
Overtime – Reporting and Monitoring
Labour / Salaries

The T&D Field Operations & Safety KBU represents approximately 48% of the total T&D FTE. The T&D annualized overtime for F2012 has dropped from F2009 to F2012, but is still averages 300-650 hours per IBEW employee. This is 19-42% overtime per T&D IBEW employee for the groups highlighted. The overtime report for the first six months in 2012 indicates the top 20 T&D IBEW employees are reporting overtime equal to 73% to 83% of their regular hours.

90.1 Please provide updated charts for the three charts presented for T&D Field Operations & Safety on page 4 of 8 in the attachment to the response of BCUC IR 1.158.1. Please provide the same three reports for T&D Grid Operations and for T&D Engineering.

The Generation Operations KBU reporting represents approximately 33% of the total Generation FTE. There is no multi-year data presented. The overtime report for the first seven months in 2012 indicates the top 20 Generation IBEW employees are reporting overtime equal to 48% to 107% of their regular hours.

90.2 Please provide charts equivalent to the three charts presented for T&D Field Operations & Safety on page 4 of 8 in the attachment to the response of BCUC IR 1.158.1. Please provide

these three reports for Generation Operations, for Generation Project Delivery, and for Generation Office of the Chief Engineer.

90.3 Please provide an updated overtime table for BC Hydro, F2007 through F2014, using the format of Table 2-2 on page 7 of 25 in Appendix Y of the BC Hydro F2011 RRA. It is anticipated that F2007 through F2009 will not properly include the CBU, and F2007 through F2011 will not fully include the BCTC employees.

91.0 Reference: Operating Costs
Exhibit B-15-1: IR 1.98.1, IR 1.103.1
FTEs and Labour Costs
Labour Costs / Application vs. Schedules

The response to BCUC IR 1.103.1 included a working spreadsheet with labour data, including gross operating cost labour and labour charged directly to specific and recurring capital for F2007 to F2014.

The response to BCUC IR 1.98.1 included the detail on FTEs by KBU by gross operating, capital, and deferred operating for F2007 to F2014. The response notes that "Operating FTEs are shown on gross basis and include the allocation to capital through capital overhead. Capital relates to specific capital and does not include an allocation for capital overhead. BC Hydro does not separate the FTEs related to capital overhead within its financial systems."

Amended Table 5-55 (Chapter 5, p. 236) summarizes the BC Hydro Current Service Pension Costs, as follows:

	F 2011	Amended RRA		
($ million)	NSA-12	F2012	F2013	F2014
Current Service Costs	54.1	74.7	77.2	79.8

91.1 Please complete the attached table as a summary of labour costs and FTEs by FTE category (i.e. Operating, Deferred and Capital).

LABOUR ANALYSIS BY FTE CATEGORY

	F2007 Actual		F2008 Actual		F2009 Actual		F2010 Actual		F2011 Actual		F2012 Plan		F2013 Actual		F2014 Actual	
	$	FTEs	$	FTEs	$	FTEs	$	FTEs	$	FTEs	$	FTEs	$	FTEs	$	FTEs
Operating																
Labour Cost (Note 1)																
Post-Employment Benefits																
Severance																
Workforce Reduction Not Identified by Affiliation																
Compensation / Total Rewards Not Identified by Affiliation																
Total Operating																
Capital																
Labour Cost (Note 1)																
Post-Employment Benefits																
Severance																
Workforce Reduction Not Identified by Affiliation																
Compensation / Total Rewards Not Identified by Affiliation																
Total Capital																
Deferred																
Labour Cost (Note 1)																
Post-Employment Benefits																
Severance																
Workforce Reduction Not Identified by Affiliation																
Compensation / Total Rewards Not Identified by Affiliation																
Total Deferred																

Note 1

Please provide Total Labour, inclusive of Direct, Benefits, Bonus/Incentive

91.2 Please complete the attached table as a summary of labour costs and FTEs by FTE category (i.e. Operating, Deferred and Capital) for BCTC (pre-integration with BC Hydro).

LABOUR ANALYSIS BY FTE CATEGORY - BCTC

	F2007 Actual		F2008 Actual		F2009 Actual		F2010 Actual		F2011 Actual (3 Months Pre-Integration with BC Hydro)	
	$	FTEs	$	FTEs	$	FTEs	$	FTEs	$	FTEs
Operating										
Labour Cost (Note 1)										
Post-Employment Benefits										
Severance										
Workforce Reduction Not Identified by Affiliation										
Compensation / Total Rewards Not Identified by Affiliation										
Total Operating										
Capital										
Labour Cost (Note 1)										
Post-Employment Benefits										
Severance										
Workforce Reduction Not Identified by Affiliation										
Compensation / Total Rewards Not Identified by Affiliation										
Total Capital										
Deferred										
Labour Cost (Note 1)										
Post-Employment Benefits										
Severance										
Workforce Reduction Not Identified by Affiliation										
Compensation / Total Rewards Not Identified by Affiliation										
Total Deferred										

Note 1

Please provide Total Labour, inclusive of Direct, Benefits, Bonus/Incentive

91.3 Please complete the attached table as a summary Current Service Cost per Amended Table 5-55 by FTE category (i.e. Operating, Deferred and Capital) for F2011 NSA 12, F2012 Plan, F2013Plan and F2014 Plan. Total per breakdown for each fiscal year should agree to total Current Service Costs per Amended Table 5-55 (Chapter 5, p. 236).

CURRENT SERVICE COSTS						
$ millions						
	F2011 NSA 12	F2012 Plan	F2012 Plan	F2014 Plan		Reference
Operating						
Capital						
Deferred						
Total Current Service Costs	**54.10**	**74.70**	**77.20**	**79.80**		Agreed to Amended Table 5-55 (Chapter 5, p. 236)

PENSION

SEE SECTION H. PENSION AND OTHER POST RETIREMENT BENEFITS

SERVICES (Services ABSU/Services BCTC/ Services Other)

92.0 Reference: Services Costs
Exhibit B-15-1: IR 1.106.1
Limited Data to Work With
Services Other

The response to BCUC IR 1.106.1 included an excel schedule for the detail of Services-Other by KBU for Actual F2009 to F2014 Update RRA. The same response also notes "… that F2011 is not comparable to prior years due the BCTC integration and the Nature View reclassifications as outlined in section 1.3.3 of the Amended Application."

92.1 Please include a comparable schedule for the detail of BCTC's Services – Other for Actual F2009, F2010 and April 1 - July 4, 2010 for the following cost categories: Consultants Expense, Contract Services, Line / Turnkey Cont., Dues, Fees and Other Charges, Travel and Expense. Assuming that the KBUs provided in the response to BCUC IR 1.106.1 do not apply to BCTC, at a minimum please provide the requested BCTC detail by aforementioned cost category.

92.2 In relation to the excel schedule provided in response to BCUC IR 1.106.1, please confirm if the only cost category impacted by the Nature View reclassifications is "IPP O&M Expenses". If not confirmed, please identify the cost categories in Actual F2011 (i.e. "Advertising", "Dues, Fees and Other Charges", "Travel & Expense") that are not comparable to prior years due to the Nature View reclassifications.

92.2.1 For each cost category identified as not comparable due to Nature View reclassifications, please describe each Nature View reclassification(s) that causes the cost category to not be comparable to prior years.

93.0 Reference: Services Costs
Exhibit B-15-1: IR 1.106.1
Services Other: Dues, Fees and Other Charges

The response to BCUC IR 1.106.1 included an excel schedule for the detail of Services - Other by KBU for Actual F2009 to F2014 Plan. The same response also notes "… that F2011 is not comparable to prior

years due the BCTC integration and the Nature View reclassifications as outlined in section 1.3.3 of the Amended Application."

93.1 The following table is a summary of the Dues, Fees and Other Charges cost category included in the excel schedule per the response to BCUC IR 1.106.1. Please confirm if the attached table is correct. If not confirmed, please provide an updated table.

Services - Other - Dues, Fees and Other Charges ($ Millions)	F 2009 Actual	F 2010 Actual	F 2011 Actual	F 2012 Plan	F 2013 Plan	F 2014 Plan
Total Dues, Fees and Other Charges	13.1	12.4	18.5	22.5	23.2	23.2
Total by KBU						
Corporate	5.6	5.2	7.4	6.8	6.6	6.8
Generation (& Engineering)	5.3	5.7	1.0	2.4	2.4	2.4
Field Operations / T&D	2.0	1.2	9.0	13.2	14.2	14.1
CC&C	0.2	0.3	1.1	0.0	0.0	0.0
Transmission	0.0	0.0	0.0	0.0	0.0	0.0
Total	**13.1**	**12.4**	**18.5**	**22.5**	**23.2**	**23.2**
Increase ($ Millions)		- 0.7	6.0	4.0	0.8	- 0.0
% Increase		-5%	48%	22%	3%	0%

93.1.1 Please describe the nature of the costs included in the cost category Dues, Fees and Other Charges.

93.1.2 Please provide the total Dues, Fees and Other Charges cost category for BCTC for F2009 Actual, F2010 Actual and April 1, 2010 – July 4, 2010 Actual (3 months F2011 pre-integration).

93.1.3 Is the Dues, Fees and Other Charges cost category impacted by the Nature View reclassifications? If yes, please describe the reclassification and quantify the reclassification amount for F2011 Actual.

93.1.4 The table prepared above identifies a 48 per cent increase from F2010 Actual to F2011 Actual. Please identify the reasons for the cost increase. For each reason identified, please quantify and describe the nature of the cost increase.

93.1.5 The table prepared above identifies a 22 per cent increase from F2011 Actual to F2012 Plan. Please identify the reasons for the cost increase. For each reason identified, please quantify and describe the nature of the cost increase.

94.0 Reference: Services Costs
Exhibit B-15-1: IR 1.106.1
Services Other: Travel and Expense

The response to BCUC IR 1.106.1 included an excel schedule for the detail of Services-Other by KBU for Actual F2009 to F2014 Update RRA. The same response also notes "… that F2011 is not comparable to prior years due the BCTC integration and the Nature View reclassifications as outlined in section 1.3.3 of the Amended Application."

"The operating costs in the Amended Application incorporate revised forecast savings from efficiency projects including … reduced travel and business expenses …" (Chapter 5, p. 11)

94.1 The following table is a summary of the Travel and Expense cost category included in the excel schedule per the response to BCUC IR 1.106.1. Please confirm if the attached table is correct. If not confirmed, please provide an updated table.

Services - Other - Travel and Expense ($ Millions)	F 2009 Actual	F 2010 Actual	F 2011 Actual	F 2012 Plan	F 2013 Plan	F 2014 Plan
Total Travel and Expense	26.4	23.8	17.6	19.7	19.6	19.7
Total by KBU						
Corporate	3.2	1.7	1.2	2.5	2.7	2.6
Generation (& Engineering)	8.2	7.4	4.8	5.6	5.8	5.7
Field Operations / T&D	13.9	13.9	10.8	11.6	11.1	11.5
CC&C	1.1	0.8	0.8			
Transmission	0.0	0.0				
Total	**26.4**	**23.8**	**17.6**	**19.7**	**19.6**	**19.7**
Increase ($ Millions)		- 2.6	- 6.2	2.1	- 0.2	0.1
% Increase		-10%	-26%	12%	-1%	1%

94.1.1 Please describe the nature of the costs included in the cost category Travel and Expense.

94.1.2 Please provide the total Travel and Expense cost category for BCTC for F2009 Actual, F2010 Actual and April 1, 2010 – July 4, 2010 Actual (3 months F2011 pre-integration).

94.1.3 Is the Travel and Expense cost category impacted by the Nature View reclassification? If yes, please describe the reclassification and quantify the reclassification amount for F2011 Actual.

94.1.4 Exhibit B-1-3 notes operating costs incorporate reduced travel and business expenses; however, the Travel and Expense cost category per the table prepared above presents a 12 per cent increase from F2011 Actual to F2012 Plan. Please describe why the Travel and Expense cost category has increased, despite reduced travel and business expenses.

95.0 Reference: Services Costs
Exhibit B-15-1: IR 1.106.1
Services Other: Accruals and Adjustments

The response to BCUC IR 1.106.1 included an excel schedule for the detail of Services-Other by KBU for Actual F2009 to F2014 Update RRA. Within the excel schedule, there are total amounts of 26.1 million in F 2009 Actual in the cost category "Accruals, Provs & Adjmts" and 21.9 million in F2010 Actual in cost category "Other Provisions/Adj".

95.1 Please describe what is included in the cost categories "Accruals, Provs & Adjmts" and "Other Provisions/Adj" and explain why these cost categories are not included in F2011 Actuals onward.

96.0 Reference: Operating Costs by Business Group
Exhibit B-15-1: IR 1.106.1
Services – Other
O&M / Services /Other - Advertising

96.1 Please explain the $1.1 million credit for Advertising expenses in Generation Operations for each of F2012 through F2014.

97.0 Reference: Operating Costs by Business Group
Exhibit B-15-1: IR 1.106.1
Services – Other
O&M / Services /Other – Consultants/Contractors

97.1 Please explain the approximately $22 million increase for Consultants Expense in F2012-F2014, from $3 million in F2011, in Corporate Costs.

97.2 Please explain the methodology change from F2011 to F2012-F2014 for ABS Flow-through costs.

BC Hydro is proposing the establishment of a regulatory account to defer the cost of $30.7 million for implementing new outsourcing arrangements for services previously outsourced to ABS under the Amended Master Agreement. Future analysis will need to be able to group the new outsourcing operating costs with the Services – ABSU for year-over-year comparisons. On Schedule 5 the Services – ABSU can be seen to drop $9.9 million from $109.2 million in F2011 Actual to $99.3 million in F2012. In the detail of Services – Other (IR 1.106.1) there is no obvious new entries for the ABSU replacement outsourcing costs. In the response to IR 1.107.2 on Consultants/Contractors there is no mention of a $9.9 million increase for the new outsourcing costs.

97.3 Please explain where the annual operating costs for the new outsourcing arrangements are being budgeted and reported in F2012-F2014, and where the amounts by year can be seen in the Application.

98.0 Reference: Services Costs
Exhibit B-15-1: IR 1.107.1
Services Other: Consultants / Contractors

The response to BCUC IR 1.107.1 states that BC Hydro has developed reports that show contractors and consultants by name, sorted by operations, maintenance or capital and requesting KBU for F2011; BC Hydro is currently validating the data in these reports.

The response also states that for F2012 through F2014 the following consulting categories are available for the business groups to budget: Supplemental Labour contracts, Civil Work, Contract Services, Line/Turnkey contracts, and Transportation/Moving costs; Actuals will be reported in these same categories in total dollars.

98.1 Please explain if reports showing consultants and contractors for F2011, the prior fiscal year completed in March 2011, will be available during this Revenue Requirement review process.

98.2 The response to APMC IR 1.12.1.2 states BC Hydro does not report costs using the Management Consulting cost category but in the response to APMC IR 1.12.4 BC Hydro filed its policy for Procurement of Management Consulting. Since BC Hydro is procuring Management Consulting services, please explain where the costs of Management Consulting services are reported. For

example, would services by BC Hydro's external auditor be reported under "Supplemental Labour Contracts" or "Contract Services"?

99.0 Reference: Services Costs
Exhibit B-15-1: IR 1.107.2
Services Other: Consultants / Contractors

Generation – F2011-F2012 [Sch. 5.2, line 13]: The expense increase of $18.5M is due to the accounting changes for Capital Project Investigation ($8.0M) which were not part of F2011 plan but are included in operating expenses in the F2012 Plan.

99.1 Please confirm this indicates that 100% of the Capital Project Investigations are performed by consultants and not by BC Hydro staff. If not confirmed, please explain.

In the response to BCUC IR 1.106.1, $29.6 million of the $32.9 budget is reported in the Environmental & Social Issues KBU. Understandably the Water License $3.2 million and Water License requirements costs would be reported in the Environmental & Social Issues KBU. In Section 5.4.3.1 Accounting Reclassifications is the statement: $8.0 million increase in the Office of the Chief Engineer for Capital Project Investigation (CPI) costs.

99.2 Please explain why the $8 million for Capital Project Investigations would be reported under Environmental & Social Issues and not be reported in the Office of the Chief Engineer.

99.3 Please confirm the Waneta operating and maintenance costs are budgeted and reported in Generation Operations. If not confirmed, please explain where they are located.

T&D – F2010-F2011 [Sch. 5.4, line 15]: With BCTC integration and the additional groups transferred into T&D (e.g. Engineering that was part of Generation) additional contractor and consultant costs were reflected.

From F2010 to F2011 T&D increased $21.7 million and Generation reduced by $12.5 million.

99.4 Please confirm the amount transferred from Generation to T&D, and the amount of increased work programs.

T&D – F2010-F2011: Higher work volumes due to increasing work programs increased contractors and consultant spend.

T&D – F2011-F2012: Higher work volumes due to increasing work programs have increased the planned spending on contractors. The net increase was $9.3 million.

99.5 Please explain further the increased work programs from F2010 to F2011 and from F2011 to F2012, a total of approximately $18.5 million.

Corporate-C&CS – F2011-F2012 [Sch. 5.1, line 13]: Consolidation of Corporate and C&CS, plus addition of BCTC. Corporate increased $20.9 million and C&CS decreased by $16.9 million.

99.6 Please explain the $4.8 million due to the addition of BCTC, and does this reduce to zero by the end of F2014.

100.0 Reference: Operating Costs by Business Group
Exhibit B-1-3: Chapter 5
Exhibit B-15-1: IR 1.106.1
Services – Other
O&M / Services /Other: Consultants and Contractors

"With respect to outsourcing, Accenture Business Services of British Columbia Limited Partnership (ABS) has been providing "back office" IT, human resources, customer care, finance and building & office facilities management services to BC Hydro since 2003." (Chapter 5, p. 15)

"BC Hydro has entered into a restructured agreement with ABS for obtaining the transactional components of customer care, human resources, accounts payable and office services (business process outsourcing (BPO) services)." (Chapter 5, p. 16)

"IT services have not been included as part of the restructured agreement with ABS. BC Hydro has instead elected to pursue a strategy to obtain these services by providers to drive incremental value and savings. Beginning in fall 2011, BC Hydro plans to go to market for the IT services with the goal of transitioning to new service providers by April 2013." (Chapter 5, p. 16)

"BC Hydro has already taken the data centre and facilities management services out to the market and has entered into new agreements to obtain data centre operation services from TELUS and facilities management services from SNC Lavalin Operations & Maintenance Inc." (Chapter 5, p. 16)

100.1 Please complete the attached table as a summary of costs associated with outsourcing "back office" IT, human resources, customer care, finance and building & office facilities management services.

CONTRACTORS AND CONSULTANTS ANALYSIS									
$ millions									
	F2007 Actual	F2008 Actual	F2009 Actual	F2010 Actual	F2011 Actual	F2012 Plan	F2012 Plan	F2014 Plan	Reference
Type of Service Included in Services - ABSU									Services - ABSU per Appendix A, Schedule 5.0, Row 11
IT Services									Chapter 5, Page 15
Human Resources									Chapter 5, Page 15
Customer Care									Chapter 5, Page 15
Finance									Chapter 5, Page 15
Data Centre Operation									
Building & Office Facilities Management Services									Chapter 5, Page 15
Total Services - ABSU	134.02	137.63	130.82	106.93	109.15	99.27	95.08	99.43	Agreed to Appendix A, Schedule 5.0, Row 11
Type of Service Included in Services - Other									Services - Other per Appendix A, Schedule 5.0, Row 13
Data Centre Operation (Telus)									Chapter 5, Page 16
Facilities Management Services (SNC Lavalin)									Chapter 5, Page 16
IT Services									Chapter 5, Page 16

MATERIALS
No IR's deemed necessary

BUILDING AND EQUIPMENT
No IR's deemed necessary

CAPITALIZED OVERHEAD
SEE SECTION R. IFRS

INCREMENTAL IMPACTS

101.0 Reference: Operating Costs
Exhibit B-15-1: IR 1.86.1
$35 million reduction in F2011 – Starting Point for Incremental Increase
Limited Data to Work With

The principal drivers of the increase in operating costs include the reduction in F2011 operating costs of $35 million in accordance with the F11 RRA NSA which did not continue in the test period. (Sec. 1.3.5.2)

The F11 RRA NSA included a reduction to F2011 operating costs of $35 million. BC Hydro's expectation was that $15 million of the $35 million could be achieved in F2011, with the remaining $20 million being absorbed by BC Hydro's shareholder. BC Hydro's actual operating results were close to this expectation. (Sec. 5.1.3)

101.1 Please provide the actual amount of the $35 million reduction that was achieved in F2011, not including the amount absorbed by the shareholder.

101.2 Please explain the methodology used by BC Hydro to produce the (nominally $15 million) reduction/savings in the four months from December 2010 to March 2011.

101.3 Please provide a listing of the operating cost items, with amounts, that were reduced to produce the savings/reduction.

101.4 Please provide the amount of the annual rate increase resulting from the inclusion in F2012, F2013 and F2014 of the $35 million that was reduced in the F2011 NSA to yield the Approved F2011 Plan, and was added back in this Application.

102.0 Reference: Operating Costs
Exhibit B-15-1: IR 1.90
$23 million reduction - Starting Point for Incremental Increase
Limited Data to Work With

The response to BCUC IR 1.90.1 did not answer the question regarding the $23 million increase in F2011 actual operating costs.

102.1 Please detail the higher than forecast $23 million in business group F2011 operating costs, by KBU, and explain the specific reasons for these operating cost increases by the lowest cost code available. The response should include, at the KBU level, the prior five years' historical costs, and explanations, by year, for changes between the historical years, and forward into the test periods, by the lowest cost code available.

102.2 Should the detail not be available at the KBU level, please detail the higher than forecast $23 million in business group F2011 operating costs, by business group, and explain the specific reasons for these operating cost increases by the lowest cost code available. The response

should include, at the business group level, the prior five years' historical costs, and explanations, by year, for changes between the historical years, and forward into the test periods, by the lowest cost code available.

As part of the bottom-up process, each key business unit (KBU) within the Business Group developed initial budgets. These budgets were subjected to detailed review within the Business Group for total cost, consistency with work and staffing plans, and alignment with BC Hydro and Business Group priorities. For the test period this included a discussion as to whether all current operating activities needed to continue. (Application, p. 5-8)

102.3 If the explanations of the $23 million additional operating costs are not available by KBU, please explain why, and include an explanation of how the KBU review of "current operating activities" as described on page 5-8 of the Application can be performed if the BC Hydro systems do not provide financial/management reporting for the current year with historical comparisons.

The response to BCUC IR 1.90.2 stated the F2011 Actual was higher than the F11 NSA-9 forecast and this variance was absorbed by BC Hydro's shareholder.

102.4 Please provide the amount absorbed by BC Hydro's shareholder as a result of the F2011 Actual, and explain exactly how the variance was absorbed by BC Hydro's shareholder. For example, was the done through a reduction of payments to the shareholder (please reference the adjustment in Schedule 9) or was it done through an increase to a deferral account.

103.0 Reference: Operating Costs
Exhibit B-1-3: Table 5-3, Amended Table 5-4, Amended Appendix A
Order G-180-10
F 11 Plan / Carry forward before non-current PEB
O&M Table 5-4 / Changes in the Base

"… to ensure a resolution of the F11 RRA in F2011, and to advance the F11 RRA NSA issues, the F2011 operating costs in the F11 RRA were reduced by $35 million. BC Hydro's current expectation is that $15 million of the $35 million reduction will be achieved in F2011, with approximately half of the $15 million attributable to the integration of BCTC. BC Hydro expects that its shareholder will absorb the remaining $20 million." (Chapter 1, p. 6)

"[Amended] Table 5-4 presents a summary of the outcome of the operating cost planning process, starting with the original operating cost target of $738.3 million from table 5-3." (Chapter 5, p. 9)

According to the Fiscal 2011 Revenue Requirements Application Negotiated Settlement Agreement, "BC Hydro's F2011 current operating costs shall be reduced by $35 million. For greater certainty, the parties agree that this operating cost reduction does not preclude a full review of BC Hydro's operating costs in its next RRA, nor does it imply acceptance by any Party of what an appropriate level of "base" operating expenditures should be."

Table 5-3 per Exhibit B-1-3 calculates the F11 Plan / Carry forward before non-current PEB as follows:

Table 5-3:	($ million)	Schedule 5.0 Reference
F11 RRA NSA-12 Operating Costs	754.5	Column 8, Row 9
Add back $35 million NSA adjustment	35	Column 8, Row 8
Deduct non-current PEB costs (pension and other)	-51.2	Column 8, Rows 18 and 19
F11 Plan/carry forward before non-current PEB	**738.3**	

103.1 Please confirm that the calculation of the "F11 Plan / carry-forward before non current PEB" per Table 5-3 has used Operating costs and Non-current PEB costs based on F11 RRA NSA-12, as opposed to Actual F2011 results, or explain otherwise.

103.2 Exhibit B-1-3 notes that "BC Hydro's current expectation is that $15 million of the $35 million reduction will be achieved in F2011, with approximately half of the $15 million attributable to the integration of BCTC. BC Hydro expects that its shareholder will absorb the remaining $20 million." (Chapter 1, p. 6) Please confirm that the F 2011 Actual Operating Costs before Regulatory Accounts per Amended Appendix A, Schedule 5.0, Row 22, Column 5, Schedule 5.0 does not include the $20 million absorbed by the shareholder, or explain otherwise.

103.2.1 Please confirm whether or not the "… half of the $15 million attributable to the integration of BCTC." (Chapter 1, p. 6) (i.e. $7.5 million reduction) is expected to continue into the test period. If not, please explain why the reduction of $7.5 million was realized in F2011 but does not apply to the test period.

103.2.1.1 Please describe the types of work represented by the $7.5 million expected to continue into the test period and provide a schedule of costs by resource category (i.e. Labour, Services [Other, ABSU], Materials, Buildings and Equipment).

103.2.2 Considering that "… half of the $15 million attributable to the integration of BCTC" (Chapter 1, p. 6) approximately $7.5 million of other savings were realized in the Actual F2011 Operating Costs. Please describe how these savings were achieved and provide a schedule of savings by resource category (i.e. Labour, Services [Other, ABSU], Materials, Buildings and Equipment).

103.3 The following table is a recalculation of Table 5-3 using Actual Operating costs and Non-current PEB costs based on Actual F2011 results per Amended Appendix A, Schedule 5.0. Given that F2011 Actual results only include 9 months of BCTC Integration, the table below has normalized for the 3 months pre-integration using the same adjustments as Schedule 5.0 to arrive at F 11 RRA NSA-12. Please confirm if the figures presented in the table below are accurate. If not confirmed, please provide a revised Table 5-3 based on F2011 Actual results that are comparable to the test period (i.e. including 3 months of actual BCTC pre-integration with BC Hydro).

		($ million)	Reference
	Actual F 2011 Operating Costs (Includes 9 months BCTC Integration)	765.76	Appendix A, Schedule 5.0, Column 5, Row 22
	Deduct Actual F 2011 non-current PEB costs (pension and other)	- 56.30	Appendix A, Schedule 5.0, Column 5, Row 6 & Row 7
A	**Estimated Actual F 11 Plan / Carry forward before non-current PEB**	**709.46**	
	12 Month BCTC Adjustment to NSA	62.54	Appendix A, Schedule 5.0, Column 18, Row 22
	Deduct 9 Month BCTC Adjustment to NSA	50.85	Appendix A, Schedule 5.0, Column 14, Row 22
B	**Estimated Actual BCTC Adjustment (3 months pre-integration)**	**11.69**	
C = A+B	**Estimated Actual F 11 Plan / Carr forward before non-current PEB**	**721.15**	
D	**F11 Plan/carry forward before non-current PEB**	**738.30**	Table 5-3, Chapter 5, p. 8
D-C	**Difference**	**17.15**	

103.3.1 Please calculate incremental rate impact (i.e. the impact on Amended Appendix A, Schedule 1.0, Row 28) for each year of the test period if the preliminary target per Row 1 of Amended Table 5-4 is calculated based on Actual F2011 Operating Costs and Non-current PEB costs (i.e. $721.15 million) as opposed to F11 RRA NSA-12 Operating Costs and Non-current PEB Costs (i.e. $738.3 million per Amended Table 5-3).

104.0 Reference: Operating Costs
Exhibit B-1-3: Amended Table 5-4
Amended Table 5-4 – Accounting Reclassifications
O&M Table 5-4 / Changes in the Base

Amended Table 5-4 includes Accounting Reclassifications in Rows 25 to 30 "… which are different from the Nature View adjustments discussed above, relate to expenditures that were previously transferred into regulatory accounts; increases in costs that would not have appeared as operating costs prior to the adoption of Nature View reporting; or are increases in operating costs due to changes to the classification of costs as a result of required accounting changes." (Chapter 5, p. 10)

104.1 Please confirm that Row 28 "Procurement depts. deferred in prior years" per Amended Table 5-4 relates to "… $3.0million of on-going costs associated with the OCPO that had previously been deferred by BCUC order…". (Chapter 5, p. 201) If not, please describe what Row 28 relates to.

104.1.1 Please confirm, or otherwise explain, the accounting treatment of costs per Row 28 Amended Table 5-4 has changed from deferral in prior years to inclusion in operating costs in F2012 Plan onward as part of the F2011 NSA.

104.2 Please explain the nature of the costs per Amended Table 5-4 Row 29 "Interconnection billable studies recovery (cost increase incl above)" and the rationale for the accounting reclassification from prior years to F 2012 onward.

104.2.1 Please explain what is meant by "… (cost increase incl above)" per Amended Table 5-4, Row 29.

105.0 Reference: Operating Costs
Exhibit B-1-3: Amended Table 5-4, Amended Appendix A, Appendix BB
Severance Costs
O&M Table 5-4 Increasing Costs

Amended Table 5-4 (Chapter 5, p. 12) and Amended Appendix A, Schedule 5.0, Line 17.1 include severance costs of 10.1 million, 5.6 million and 3.1 million in F2012 Plan, F2013 Plan and F2014 Plan, respectively for a total of $18.8 million.

"BC Hydro has eliminated 250 positions related to the integration with BC Transmission Corporation in 2010." (Executive Summary, p. 2) The bulk, approximately 199 FTE, of the reduction occurred in F2011.

"On October 12-13, 2011, BC Hydro eliminated approximately 300 FTEs. A further 150 FTEs will be eliminated during the course of F2013 and F2014 from non-safety sensitive areas of the company. The reductions will be offset by 100 new front-line positions … for a net decrease of approximately 350 FTEs." (Chapter 5, p. 14)

"BCTC savings were realized immediately after consolidation, however, the cost reductions were initially offset by the financial impact of integration, including severance, IT systems, administration, pension and legal costs although future year savings are expected." (Appendix BB, pp. 32-33 of 133)

105.1 Please prepare a schedule that summarizes the total severance cost by year from F2012 Plan to F2014 Plan) and by affiliation (i.e. Executive, Management and Professional, IBEW and COPE). Total per year should agree to total Severance Costs per Amended Appendix A, Schedule 5.0, Row 17.1.

105.2 Please explain why the severance and outplacement costs in the response to COPE IR 1.13.1 do not agree with the costs in Schedule 5.0, line 17.1.

105.3 Please explain why there are no severance costs shown on Schedule 5.0 for F2011 Actual.

106.0 Reference: Operating Costs
Exhibit B-1-3: Amended Table 5-4, Amended Tables 10, 16 and 46
Amended Table 5-4 – Required Cost Increase
O&M Table 5-4 Increasing Costs

"Amended Table 5-4 presents a continuity table of operating costs showing the year over year changes in planned operating costs included in the Application and the Amended F12-14 RRA." (Chapter 5, p. 11)

"The required cost increases (Table 5-4, Rows 10 to 18) have been grouped into categories that are common to all Business Groups" (Chapter 5, p. 11).

106.1 Please provide the detail of the required cost increases for the preceding five test periods (F2007 RRA, F2008 RRA, F2009 RRA, F2010 RRA and F2011 RRA) in a comparable format to Rows 10-18 per Amended Table 5-4 (Chapter 5, p. 12).

106.2 The following table is as a summary of the New Work required cost increase from Amended Table 5-4 Row 13 (Chapter 5, p. 12) compared to the sum of New Work required cost increases per Amended Table 5-16 (Chapter 5, p. 73) and Amended Table 5-46 (Chapter 5, p. 164). Please confirm that the following table is correct. If not confirmed, please provide an updated table.

	New Work ($ millions)	F 2012 Plan	F 2013 Plan	F 2014 Plan
A	New Work - Required Cots Increase (per Amended Table 5-4)	7.30	5.40	8.20
	T&D (per Amended Table 5-16)			
	Increased Trouble Volumes	2.00		
	Distribution Design Work	0.40		
	Contract Distribution Designers		1.00	
	Distribution Management System Implementation and Support		2.40	2.20
	Engineering Studies and Work Program Support		- 1.40	2.50
	RCE Program Implementation			3.00
	Total T&D New Work	2.40	2.00	7.70
	Corporate Group (per Amended Table 5-46)			
	Communications - Enhanced Public Information Program	3.00	- 1.10	- 1.40
	Procurement Costs	0.90	- 1.10	
	IT&T Costs	1.00	2.10	1.90
	Leadership Training Consultant Work		1.00	
	Total Corporate Group New Work	4.90	0.90	0.50
B	Total T&D and Corporate Group	7.30	2.90	8.20
A-B	Difference	-	2.50	-

106.2.1 Per the table attached above, please explain what accounts for the difference of $2.5 million for F2013 Plan between Amended Table 5-4 Row 13 (Chapter 5, p. 12) and the sum of New Work per Amended Table 5-16 (Chapter 5, p. 73) and Amended Table 5-46 (Chapter 5, p. 164).

106.2.2 Please explain the nature of the "IT&T Costs" and why incremental cost increases are required in each year of the test period.

106.2.3 Please explain the nature of the "Distribution Management System Implementation and Support" costs and why incremental cost increases are required in each of F2013 Plan and F 2014 Plan.

106.3 The following table is a summary of the Maintenance / Ageing Assets required cost increase from Amended Table 5-4 Row 11 (Chapter 5, p. 12) compared to the sum of Maintenance / Ageing Assets required cost increases per Amended Table 5-10 (Chapter 5, p. 38) and Amended Table 5-16 (Chapter 5, p. 73). Please confirm that the following table is correct. If not confirmed, please provide an updated table.

	Maintenance / Ageing Assets ($ millions)	F 2012 Plan	F 2013 Plan	F 2014 Plan
A	Maintenance / Ageing Assets - Required Cost Increase (per Amended Table 5-4)	18.40	10.50	6.00
	Generation (per Amended Table 5-10)			
	Maintenance costs	1.10	2.70	4.00
	Technical service reviews	1.10		
	Hydrology technical	1.20		
	Plant operations costs	2.10		
	Plant maintenance efficiencies	- 1.50		
	Burrard reduction to 3 units	- 0.30		
	Coatings		1.50	
	Maintenance efficiencies		- 0.50	- 1.00
	GRM Hydrology system efficiency projects		0.70	- 0.70
	Total Generation Maintenance / Ageing Assets (line 24)	3.70	4.40	2.30
	T&D (per Amended Table 5-16)			
	Transmission maintenance programs	6.80	0.60	1.70
	Distribution maintenance programs	4.90	5.50	2.00
	NIA Maintenance programs	1.40		
	Engineering studies and work program support	5.60		
	Total Corporate Group New Work	18.70	6.10	3.70
B	Total T&D and Corporate Group	22.40	10.50	6.00
A-B	**Difference**	- **4.00**	-	-

106.3.1 Per the table attached above, please explain what accounts for the difference of $4.0 million for F 2012 Plan between Amended Table 5-4 Row 11 (Chapter 5, p. 12) and the sum of the required cost increase for Maintenance / Ageing Assets per Amended Table 10 (Chapter 5, p. 38) and Amended Table 16 (Chapter 5, p. 73).

106.3.2 Per the table attached above, Distribution Maintenance programs have an incremental required cost increase in each fiscal year of the test period. Please describe why an incremental cost increase is required in each of F2012, F2013 and F2014 and explain why cost increases each year are expected to continue in the following years.

106.3.3 Per the table attached above, Distribution Maintenance programs have a required cost increase of 6.8 million in F2012 Plan related to Transmission and maintenance programs. Please explain why the $6.8 million cost is required to continue in each year of the test period.

106.3.4 Per the table attached above, T&D has a required cost increase of 5.6 million in F2012 Plan related to Engineering studies and work program support. Please explain why the $5.6 million cost is required to continue in each year of the test period.

106.3.5 Please provide the detail of the Maintenance / Ageing required cost increase per Row 11 of Amended Table 5-4 (Chapter 5, p. 12) by resource category (i.e. Labour, Services [ABSU, Other], Materials, Buildings and Equipment) for each year of the test period, F2012, F2013 and F2014.

Engineering

107.0 Reference: Operating Costs
Exhibit B-15-1: IR 1.142.2
O&M Maintenance Costs
Maintenance Costs

"Please provide the ratio of the above count to the number of COPE and IBEW field workers who work hands on with tools on the electric system.

RESPONSE:
For purposes of this question, field workers who work hands on with tools on the electric system are defined as all IBEW roles, with the exception of Storekeepers, Driver/Helpers, Material Handlers, Vehicle Tradespersons, Schedulers, Operators, and Automotive Partsman/Partswomen."

The following table was also submitted in the response:

Fiscal Year	Hands on Tools Employees	Safety Employees	Ratio - Hands on Tools Employees per Safety Employee
2011	**1,742**	**61**	**28.6:1**
2010	**1,665**	**60**	**27.8:1**
2009	**1,582**	**45**	**35.2:1**
2008	**1,152**	**41**	**28.1:1**
2007	**1,026**	**41**	**25.0:1**

107.1 Please confirm that the number of employees that work on the electric system shown in the above table has been corrected/normalized to include BCTC employees. If not confirmed, please explain otherwise.

107.2 Please explain why the number of employees has increased by [(1742-1026)/1026] X 100 = 69.8% over the last 4 years. Is this growth, which is well in excess of inflation, driven by system growth, delivery of the capital plan, strategic workforce planning, aging assets requiring more maintenance, maintenance backlog or other factors?

107.2.1 Please provide an estimation of the percentage of this growth in FTEs due to safety factors/programs/considerations.

107.3 Please explain if BC Hydro has a target ratio (as shown in the last column).

107.3.1 Does BC Hydro have any comparative benchmarking for any other electric utilities? If so, please provide the data.

107.4 Please replace the "Hands on Tools Employees" figures to include all IBEW roles and recalculate the ratios.

108.0 Reference: Operating Costs - Transmission & Distribution Business Group
Exhibit B-15: 1.133.1, Attachment 1
Trend of Maintenance Costs – Amended Tables 5-30 to 5-35
Maintenance Costs

"Historical transmission maintenance program costs have not been provided for the F2007 to F2010 period, as restated BCTC and BC Hydro expenditures that do not include intercompany loadings are not available at the program level for that period;"

108.1 Please provide BCTC's categorization of transmission maintenance programs and the costs associated with each program for the years F2007 through F2011. Please provide this data with and without estimates of intercompany loadings to the best of BC Hydro's ability, with explanations for the evaluation of the loadings.

108.2 Please explain how BC Hydro tracks transmission maintenance program expenditures against historic spending if no comparable amounts are available.

108.3 Please explain why Distribution Emergency Response is being forecast lower in F2012 through F2014 than any of the actual annual expenditures in each of the preceding five years. Please confirm the Distribution Emergency Response expenditures are non-discretionary, at least to a greater extent than most other planned maintenance programs.

109.0 Reference: Operating Costs - Transmission & Distribution Business Group
Exhibit B-15: 1.133.2
Trend of Work Orders – Table 1, Transmission Maintenance Work Orders; Table 2, Distribution Maintenance Work Orders; Table 3, NIA Maintenance Work Orders
Maintenance Costs

"When the individual work orders are created, they are then issued immediately for execution. Therefore, planned and issued work orders are the same and are shown as Planned in the tables below."

109.1 Please explain how BC Hydro confirms that 100 percent of over 200,000 work orders for transmission preventative maintenance that are planned and issued annually are actually completed, and also, please explain why in some years, less than 50 percent of NIA General Maintenance work orders are completed.

109.2 Does BC Hydro plan maintenance work in advance, such that it is able to forecast the number of work orders and the work to be completed in the forthcoming year? If so, please provide the number of planned work orders in each category.

110.0 Reference: Operating Costs - Transmission & Distribution Business Group
Exhibit B-15: 1.135.4
Total Vegetation and ROW Maintenance
Maintenance Costs

"As requested in the question, BC Hydro contacted Manitoba Hydro, Hydro One, Hydro Quebec and Bonneville Power and found that three of these four utilize a mixture of single and twin engine helicopters for conducting right-of-way surveys based on flight risk assessments, right-of-way configuration, locations and types of terrain."

110.1 Please identify the practices of the fourth entity contacted in the reference, and please provide the approximate percentage split between the use of single engine and twin engine helicopters.

110.2 Please identify whether BC Hydro continues to use single engine helicopters, and is so, the approximate percentage split between the use of single engine and twin engine helicopters. Is helicopter time tracked by BC Hydro, and if so, please provide the operating hours by year.

111.0 Reference: Operating Costs
Exhibit B-1-3: Appendix A, Schedule 5.0
Operating Costs - Maintenance
Maintenance Costs

Appendix A, Schedule 5.0, includes Operating Costs by resource in Row 10 through 22.

111.1 Please provide a list of resource categories per Schedule 5.0 Rows 10 through 22 that include Maintenance Costs.

111.1.1 Please confirm whether or not any Maintenance Costs are included in allocations to "Specific and Recurring Capital" and/or "Capitalized Overhead".

112.0 Reference: Operating Costs
Exhibit B-15-1: IR 1.119.1
Safety and Technical Training / Grown in Labour Due to Safety
O&M Safety

"Please confirm that these duties are the responsibility of the field work leader and explain if there is any duplication of efforts with the Operations Field Support, Work Methods or any of the other restructured departments.

RESPONSE:
It is the responsibility of the work leaders to identify hazards, ensure effective barriers are in place for the hazards and develop the Job Plan or Safety Management plan with the assistance of a Trades Training instructor or OSH Specialist as required, depending on the knowledge and experience of the work leader. There is no duplication of duties because the work leaders apply, on a job by job basis, the policies and procedures developed by the Operations Field Support and Work Methods groups."

112.1 Please discuss if the majority of the work is of a repetitive and fairly routine nature and whether or not the policies and procedures developed by the Operations Field Support and Work Methods groups have been published, rolled out, communicated/trained and utilized/practiced for several years, with the exception of a few updates/refinements.

112.1.1 Please discuss if every job requires some level of assistance (or confirmation) from a Trades Training instructor or OSH Specialist. If not, please provide an overall estimate of the percentage of jobs (i.e. a best guess order of magnitude) requiring the work leader to seek additional specific expertise from Operations Field Support and Work Methods groups.

113.0 Reference: Operating Costs
Exhibit B-15-1: IR 1.429.4
Safety Spending / Growth In Labour Due to Safety
O&M Safety

"Given that the area of safety is a complex and difficult issue, please discuss BC Hydro's plans going forward of balancing need and costs against being the best in the area of safety i.e. is the plan to forever increase funding for possible solutions until the goal of zero accidents is achieved?

RESPONSE:
BC Hydro is committed to integrating safety in all it does and conducting operations to minimize the chance of injury to employees, contractors, and the public, with the intended outcome of creating a workplace where employees and contractors work safely and no one experiences a serious work-related injury.

This is not done out of a perceived desire to be the best, but rather is considered to be consistent with the expectations of BC Hydro's workforce, stakeholders and regulatory agencies. BC Hydro is undertaking these expenditures in order to address the issue of its safety record, which as shown in Appendix T has an Injury Severity Rate among the worst of its peers."

113.1 In addition to FTE's and reorganization of various safety functions and responsibilities, please discuss what other expenditures are planned during the test period to address safety and indicate where they can be identified in the Application.

113.2 Does BC Hydro track its Safety related costs, specifically are IBEW timesheets coded to record time spent on safety training, attendance at safety meetings, developing safety management plans, tailboard meetings and any other safety related activities? If so, please provide a graph of the total of these expenditures during the 2007 to 2011 period by year for the corporation. The graph should be normalized to account for BCTC integration. Note – if Operators were the only IBEW trade employed by BCTC and the response would involve a great deal of effort to include them, then please state and exclude Operators from the data requested.

113.2.1 Please confirm that BCTC only had Operators that were IBEW employees and provide the numbers each year over the 2007 to 2011 period. If not confirmed, please explain otherwise.

114.0 Reference: Operating Costs
Exhibit B-15-1: IR 1.429.4.1, IR 1.142.2
Safety Spending / Growth in Labour Due to Safety
O&M Safety

"Please discuss the effectiveness of the increase in the number of safety personnel FTEs and related costs over the last 5 years in relation to the marginal gains advanced in the safety statistics.

RESPONSE:
It is not possible or reasonable to correlate the number of safety personnel to safety statistics because the achievement of improved safety outcomes is influenced by a wide range of factors including organizational culture, which can have a significant impact on safety performance and which requires many years of focused effort to change."

114.1 Please explain how BC Hydro justifies increases to the number of safety personnel if "It is not possible or reasonable to correlate the number of safety personnel to safety statistics." Are the justifications for Safety FTE additions based on growth in the IBEW workforce, hired to address a known problem or other? If not, please explain otherwise.

H. PENSION AND OTHER POST RETIREMENT BENEFITS

115.0 Reference: Pension and Other Post Retirement Benefits
Exhibit B-1-3, Chapter 5, Sections 5.8.1 and 5.8.2
Exhibit B-15, BCUC IR 1.166.2
Understanding the Balances

115.1 In response to BCUC IR 1.166.2 BC Hydro states that the total BC Hydro Current Pension Costs reported in Amended Table 5-55 include both Pension Costs and OPEB. Please split the table out between Current Service Costs for Pension and OPEB.

"Current service pension costs are sensitive to a change in the discount rate. A decrease in the discount rate will increase the current service pension costs while an increase in the discount rate will decrease the current service pension cost." (Exhibit B-1-3, p. 5-235)

115.2 Please confirm, or explain otherwise, that the forecast pension costs included in the application have considered the discount rate and this sensitivity is reflected in the forecast.

BC Hydro is requesting that variances in Non-Current PEB continue to be captured in the Non-Current Pension Cost Regulatory Account because of the continuing uncertainty and potential volatility of the capital markets. (p. 7-25)

115.3 Doesn't the uncertainty and potential volatility of the capital markets get captured by the actuarial valuation that is performed every three years, or by the annual projection?

115.4 Please confirm, or explain otherwise, the variance that BC Hydro is asking to be captured in the regulatory account is limited to the variance between what BC Hydro forecasts for the regulatory account and what is ultimately reported for financial reporting.

115.5 Please confirm, or explain otherwise, the difference between financial reporting and the actuarial valuation (experienced gains and losses) is captured in OCI which BC Hydro is requesting to have the ability to recover in rates.

Amended Table 5-56 sets out the non-current pension components.

115.6 Please confirm, or explain otherwise, that BC Hydro is requesting that only the Interest income and the Interest expense variance between forecast (revenue requirement) and actual (financial reporting) will be captured in the Non-Current Regulatory Account as the Amortization of actuarial losses and the Amortization of past service costs are proposed to be captured in the new IFRS Pension and OPEB regulatory account.

115.7 In consideration of the response to the previous IR's, please explain why variance between forecast and actual Interest Income and Interest Expenses for PEB should be captured in a regulatory account?

115.8 Table 5-56 includes the amortization of the Actuarial gain/losses and amortization of past service costs of $38.9 million and $34.7 million in F2013 and F2014 while schedules 2.2 line 129 shows a recovery of the same amount. Please explain how this does not result in a double recovery.

116.0 Reference: Pension and Other Post Retirement Benefits
Exhibit B-1-3, Chapter 8, Section 5.8
Exhibit B-15, IR 1.160.1
Accounting Standard Forecast Basis

116.1 Please confirm, or explain otherwise, that for F2014 IAS 19 rev. 2011, effective for fiscal years beginning on and after January 1, 2013 will apply to BC Hydro.

116.2 Please confirm, or explain otherwise, that the three following standards will apply to BC Hydro in regards to Pension:

- F2012 CGAAP
- F2013 IFRS IAS 19
- F2014 IFRS IAS 19R

BC Hydro confirmed in BCUC IR 1.160.1 that the following components related to Pensions under CGAPP:

- Current Service Cost
- Interest Income
- Interest Expense
- Amortization of the transition asset/liability
- Amortization of actuarial gain/losses (Remeasurement)
- Amortization of Past Service Costs

And the following four components under IFRS:

- Current Service Cost
- Interest Income
- Interest Expense
- Past Service Cost

116.3 Please confirm that the IFRS components identified in response to BCUC IR 1.160.1 are in accordance with IAS 19.

116.4 Please confirm the three following Defined Benefit Pension components under the new IFRS 19R standard which will be applicable to BC Hydro in F2014:

- Service Cost (Income statement)
- Net Interest (Income Statement)
- Remeasurement or Experienced Gains and Losses (Other Comprehensive Income)

116.4.1 What will the components be for OPEB in F2013 and F2014, and will the treatment be the same as for Pensions under IAS 19R? If not, please explain the differences.

116.5 BC Hydro confirmed that there is no existing or proposed regulatory account, which captures variance in Current Service Costs. Given that in each of the three years of the test period a different accounting standard is to apply please explain under what standard the forecasts Current Service Costs (Pension and OPEB) in F2012, F2013 and Service Costs in F2014 were made.

116.5.1 If not made under the applicable standard, please explain why not?

116.6 Given that in each of the three test period a different account standard is to apply please explain which account standard applied to Non-Current Pension Cost and Non-Current OPEB in each of the test periods

116.6.1 If not made under the applicable standard, please explain under what standard the forecasts Non-Current Pension and OPEB forecasts were made in each year of the test period.

117.0 Reference: Pension and Other Post Retirement Benefits
Exhibit B-1-3, Chapter 5, Section 5.8
Exhibit B-15: IR 1.161, IR 1.162, IR 1.165
Current Service Cost Pension and OPEB
Forecast

As provided in response to BCUC IR 1.162.3 there is not approved or proposed regulatory account to capture variance in forecast to actual Current Pension or Current OPEB costs. BC Hydro is requesting that over the test period $232.7 million in Current Pension and Current OPEB cost be recovered in rates. (Exhibit B-15, IR 1.161.1 and 1.165.1)

117.1 Please carve out the current service costs of Pension and current service costs of OPEB from Amended Appendix A, Schedule 5.0, line 10 for F2007 to F2014.

117.2 Are the forecasts in the Application (Amended Table 5-55) prepared by BC Hydro's actuary? If not, who prepared them and why are they not prepared by the actuary?

117.3 In response to BCUC IR 1.162.1 BC hydro provided a table of the discount rate from the external actuary. Please provide a similar table for forecasting Current Pension Cost including the rate used to forecast for regulatory purposes and the actual rate used for financial reporting.

117.4 Please provide support for the forecast reduction in the discount rate between F2011 and the test period.

On page 5-236 of the Application BC Hydro says the discount rate used to estimate the current service pension costs is determined on the measurement date (December 31) for each year under CGAPP and is calculated by the external actuary.

117.5 Does BC Hydro have an updated discount rate for December 31, 2011 that will impact the F2012 current service cost forecast? If yes, what is the impact to the current service costs as forecasted in Amended Table 5-55.

Pension

BC Hydro Registered Pension Plan								$ millions (income)													
	Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Forecast	Forecast
Fiscal Year	2006	2006		2007	2007		2008	2008		2009	2009		2010	2010		2011	2011		2012	2013	2014
Current Service Costs	26.2	30.0	(3.8)	31.0	33.5	(2.5)	32.0	36.1	(4.1)	38.5	40.2	(1.7)	40.0	31.2	8.8	47.3	47.9	(0.6)	62.5	64.8	67.2
			-			-			-			-									
Non-current service costs:			-			-			-			-									
			-			-			-			-									
Interest cost on pension obligations	143.1	135.2	7.9	137.2	136.2	1.0	140.9	146.4	(5.5)	147.4	152.0	(4.6)	155.2	154.7	0.5	155.2	164.4	(9.2)	168.0	175.1	182.5
Expected return on plan assets	(129.1)	(138.6)	9.5	(141.2)	(151.5)	10.3	(145.8)	(177.4)	31.6	(183.6)	(188.6)	5.0	(190.5)	(138.8)	(51.7)	(154.2)	(159.8)	5.6	(175.4)	(183.3)	(191.7)
Amortization of net actuarial losses	17.6	16.3	1.3	14.8	16.0	(1.2)	12.9	5.4	7.5	1.5	8.6	(7.1)	0.5	34.9	(34.4)	36.8	36.9	(0.1)	42.5	37.9	33.7
Amortization of transitional asset	(17.6)	(17.6)	-	(17.6)	(17.6)	-	(17.6)	(17.6)	-	(17.6)	(17.6)	-	(17.6)	(17.6)	-	(17.6)	(17.6)	-	(18.4)	-	-
Amortization of past service costs	1.0	1.0	-	1.0	1.0	-	1.0	1.0	-	1.0	1.0	-	1.0	1.0		1.0	1.0	-	1.0	1.0	1.0
Total	15.0	(3.7)	18.7	(5.8)	(15.9)	10.1	(8.6)	(42.2)	33.6	(51.3)	(44.6)	(6.7)	(51.4)	34.2	(85.6)	21.2	24.9	(3.7)	17.7	30.7	25.5
			15			8			30			(8)									
Number of FTEs eligible for benefits	4,316	4,398		4,675	4,670		4,763	5,315		5,974	6,108		6,104	6,353		6,895	6,405		6,656	6,481	6,350
(BC Hydro plans using FTEs and not headcount)																					
Cost per FTS	6,070	6,821		6,631	7,173		6,718	6,792		6,445	6,582		6,553	4,911		6,860	7,479		9,390	9,998	10,583

117.6 BC Hydro provided a table in response to BCUC IR 1.161.1 relating to **Pension** current and non-current expense. The table provided above is the BC Hydro table with totals provided in red. Please confirm the mathematical accuracy of the totals in red.

BC Hydro states on page 5-235 of the Application (Exhibit B-1-3) that "the increase in the expected current service pension costs in F2012 is principally due to a decrease in the discount rate."

In response to IR 1.162.1 BC Hydro provided the discount rate used by the external actuary for Current Service Pension Costs for F2006-F2014. BC Hydro has forecast the same discount rate of 5.31 percent for F2012, F2013, and F2014.

117.7 As evident in the table above BC Hydro has forecast an increasing Pension Current Service cost per FTE at $9,390 in F2012, $9,998 in F2013, and $10,583 in F2014 even though the discount rate is staying the same. Please explain the reason for the increasing Current Pension expense (Pension component only, please) and provide additional support for your calculation.

PENSION					
BC Hydro Registered Pension Plan					
	Actual	Forecast	Forecast	Forecast	Total
Fiscal Year	2011	2012	2013	2014	
Current Service Costs	47.9	62.5	64.8	67.2	
Number of FTEs eligible for benefits	6,405	6,656	6,481	6,350	
(BC Hydro plans using FTEs and not headcount)					
Cost per FTS	7,479	9,390	9,998	10,583	
Current Service Cost at F2011 rates	47.9	49.8	48.5	47.5	145.7
Revenue Requirement Reduction		12.7	16.3	19.7	**48.8**
					-
					-
Current Service Cost at F2012 rates		62.5	60.9	59.6	183.0
Revenue Requirement Reduction			3.9	7.6	**11.5**

117.8 Please confirm that if the rate per employee were to remain at the same in each of the test period years, as in F2011, the current service costs relating to Pension would be reduced by $48.8 million, and if it were at the F2012 level it would be reduced by $11.5 million.

OPEB

OPEB					
BC Hydro Other Post Employment Benefits (OPEB)					
	Actual	Estimate	Forecast	Forecast	**TOTAL**
Fiscal Year	2011	2012	2013	2014	
Current Service Costs	9.9	12.2	12.4	12.6	**37.2**
Number of FTE's eligible for benefits	6,405	6,656	6,481	6,350	
BC Hydro plans using FTEs and not headcount.					
Cost per FTE	1,545.7	1,832.9	1,913.3	1,984.3	
Current Service Cost at F2011 rates		10.3	10.0	9.8	**30.1**
Revenue Requirement Reduction		1.9	2.4	2.8	**7.1**
Current Service Cost at F2012 rates		12.2	11.9	11.6	**35.7**
Revenue Requirement Reduction		-	0.5	1.0	**1.5**

117.9 As evident in the table above (data from BCUC 1.165.1) BC Hydro has forecast an increasing OPEB Current Service cost per FTE at $1,832.9 in F2012, $1,913.3 in F2013, and $1,984.3 in F2014 even though the discount rate is staying the same (BCUC 1.162.1). Please explain the reason for the increasing Current OPEB expense (OPEB component only, please) and provide additional support for your calculation.

117.10 Please confirm that if the rate per employee were to remain at the same in each of the test period year as in F2011, the current service costs relating to OPEB would be reduced by $7.1 million, and if it were at the F2012 level it would be reduced by $1.5 million.

118.0 Reference: Pension and Other Post Retirement Benefits
Exhibit B-1-3: Chapter 5, Section 5.8; Chapter 7, Section 7.3.19
Exhibit B-15: IR 1.163.2, IR 1.168.1
Non-Current Service Cost Pension and OPEB
Forecast

118.1 Please update the table in IR 1.163.2 to include the discount rate used to forecast the RRA and the discount rate used for financial reporting in F2006 to F2011.

> "…the BCUC approved the establishment of a regulatory account to defer the difference between forecast and actual non-current pension costs…" (Chapter 7, Section 7.3.19)

118.2 Please confirm, or explain otherwise, that "forecast" relates to the forecast in the revenue requirements application and "actual" mean amounts reported for financial reporting purposes.

119.0 Reference: Pension and Other Post Retirement Benefits
Exhibit B-16, AMPC IR 1.16.2
Exhibit B-15: IR 1.163.3, IR 1.167.2
Transition Adjustment

119.1 Please reconcile the IFRS transition adjustment of $762 million as reported in Exhibit B-16, AMPC IR 1.16.2 with the responses to BCUC IRs 1.163.3 and 1.167.2.

120.0 Reference: Pension and Other Post Retirement Benefits
Exhibit B-1-3, Chapter 5, Section 5.8.1
REMEASUREMENT
Treatment of Remeasurement (experienced gains/losses) in F2013 and F2014

120.1 Please confirm that BC Hydro is requesting to have the remeasurement, in both F2013 and F2014, recorded in a deferral account (IFRS Pension and OPEB) for recovery in a future period.

120.2 Please confirm, or explain otherwise, that without regulatory approval to record the remeasurement in a deferral account BC Hydro would be reporting it in OCI under IAS 19 (optional) in F2013 and IAS 19R (mandatory) in F2014.

120.3 If approval to record the remeasurement in a deferral account for regulatory purposes is granted, how will BC Hydro report the remeasurement for financial reporting in F2013 under IAS 19 and in F2014 under IAS 19R?

120.4 On page 5-235 of the Application BC Hydro states that the next **actuarial valuation** (remeasurement) will be performed on December 31, 2012. Has the **actuarial projection** been performed as of December 31, 2011, and if not, why not? If it has been performed, please provide the results.

120.4.1 If the **valuation** is to be done before transition to IFRS, will this affect the IFRS RE adjustment on transition of $762 million that BC Hydro is requesting be captured in an IFRS Pension regulatory account? And if so, will this be the valuation amount be the amount used to determine the addition?

120.5 Please confirm that the forecast additions for remeasurement in F2013 and F2014 are zero but there is expected to be an actual projected remeasurement in F2013 and F2014.

120.6 When does BC Hydro expect to have its actuarial valuation? On December 31, 2015 for F2016?

BC Hydro states that: "Under IFRS, these experienced gains and losses [remeasurement] would be included in other Comprehensive Income, and therefore would not be eligible for recovery from or refund to customers." (Exhibit B-1-3, p. 7-26)

120.7 Please confirm, or explain otherwise, that there is no forecast balance relating to remeasurement in F2013 or F2014 and BC Hydro is not requesting any amortization of additions during the test period until the next RRA.

120.8 Once there is a remeasurement balance in OCI, either a projection or valuation, (in the next RRA) would it not be possible for BC Hydro to request recovery of the OCI balance in a future RRA? If yes, why is approval to record the variance in a deferral account at this time necessary?

120.9 Currently under CGAPP, what is the treatment with OCI in determining rates, determining ROE and determining the Dividend to the Province? If different, what is the expected treatment under IFRS?

I. CAPITAL EXPENDITURES AND ADDITIONS

General

121.0 Reference: DCAT
Exhibit B-15, 1.238.1
Exhibit B-16, IR 1.9.1
Exhibit B-1-3, Amended Appendix J, p. 86, Amended Appendix I, Growth Transmission line 25
Forecast Capital Additions

"Three large industrial loads have been nominated for interconnection to the Dawson Creek area transmission system by mid 2012 which add 41 MW to the area peak load. The System Impact Study for these connections shows that two of these loads cannot be served without voltage support to the existing 138 kV transmission system."

121.1 Please confirm that the Dawson Creek to Chetwynd Area Transmission Project (DCAT) continues to be forecasted as a capital addition in F2014 for $206.3 million as reflected in Amended Appendix I, Growth Transmission, line 25.

121.2 Please confirm that the DCAT CPCN Application is currently suspended pursuant to BC Hydro's request.

121.2.1 Please provide the forecasted in service date if different from October 2013 (F2014) due to the suspension of the DCAT proceeding.

121.3 Please identify the forecast amount of ROE, financing costs, and depreciation that is being forecast to be recovered in rates directly relating to the DCAT capital addition in F2014.

121.4 Please confirm that the costs of energy and capacity requirements in respect of the DCAT project have been factored into and included in the Amended Application.

121.4.1 Please reference where in the Amended Application this can be traced.

121.4.2 What is the incremental impact on rates in F2014 due to the DCAT project capital addition including the impact on COE?

122.0 Reference: Capital Expenditures and Additions
Exhibit B-15, 1.204.1, Attachment 1
F2011-F014 Capital Expenditures
CPCN

122.1 For all capital expenditures (except transmission customer requested projects, generation interconnections and distribution customer driven projects) listed in BCUC 1.204.1, Attachment 1 that are forecast to be capital additions in the test period, please identify those projects for which construction has not yet begun for the purposes of section 45(5) of the Act, and for each such project, identify when construction is forecast to begin. Please provide this information both as a separate listing and integrated into Attachment 1.

123.0 Reference: Capital Expenditures and Additions
Exhibit B-15, 1.181.1, New Table 6-D Revised
Plan to Achieve the Rate Decrease (Table 1-A) Forecast Capital Additions

123.1 Response to IR 1.181.1 did not include projects under the "Changed Circumstances" heading. Please update the response to IR 1.181.1 to include "Changed Circumstances" Capital Additions.

124.0 Reference: Capital Expenditures
Exhibit B-15, 1.183.1
Exhibit B-1-3, Appendix C-2, Amendments to Heritage Special Direction No. 2
Prudency Review

124.1 Please confirm that the Commission may request a prudency review for costs to be recovered in rates during the test period for expenditures incurred by the authority before April 1, 2011 (specifically the Ashton Creek Shunt Capacitor Banks). If not, why not.

124.2 Please explain BC Hydro's view of when the Commission may call for a prudency review on a specific capital expenditure which occurred before April 1, 2011 under the OIC 20 amendments to HC2.

125.0 Reference: Capital Expenditure
Exhibit B-15: IR-1.188.1, IR 1.188.2, IR-1.189.1, IR 1.204.1 Attachment 1, IR 1.222.1, IR-1.223.1, IR 1.227.2, IR 1.256.1
Exhibit B-1-3, Amended Appendix I
Incomplete information based on request

In IR-1.188.1, IR 1.188.2, IR-1.189.1, IR 1.204.1, IR 1.222.1, IR-1.223.1, IR-1.227.2 and IR 1.256.1, we had requested information on the original estimated in-service date, initial capital expenditure date, last capital expenditure date and % completion at March 31, 2011 for each project in Amended Appendix I. This information has been summarized in Attachment 1 to IR 1.204.1 but the information is incomplete.

125.1 In an excel worksheet format, please update Attachment 1 in IR 1.204.1 for all projects included in Amended Appendix I to include all outstanding information for:

a. Original estimated In-Service date (reference column (f))

b. Initial Capital Expenditure Date (reference column (e))

c. Last Capital Expenditure Date (reference column (g)) (Please include in all capital asset categories and specify a specific year for all projects)

d. % Completion March 31, 2011 (reference column (d)) (Please explain why "TBD" and "n/a" is applicable where this information has been included here)

125.2 In Amended Appendix I, the dates in the "Revised Estimated In-Service Date" only include a few dates for specific projects. Please confirm that the dates under the "Estimated In-Service Date" column are applicable when there are no entries under the "Revised Estimated In-Service Date" column for the other projects.

125.2.1 If this is not the case, please update the "Revised Estimated In-Service Date" column for the appropriate in-service date for all projects in Amended Appendix I.

125.3 Please add a column to Attachment 1 to identify the anticipated project status (i.e. Identification, Definition, Implementation or Completed) at the end of the test period.

126.0 Reference: Exhibit B-15, BCUC 1.204.1 Amended Attachment 1
Unfinished Construction - Hydroelectric Generation

126.1 Please confirm the following project entries and update the entries if/where warranted:

Line	Description	Spending to F10 plus F11	Total Costs	Current Stage	Expenditures in Test Period	Adds During Test Period	Stage at End of Test Period	In Service/Cap Add Year	Costs After IS Year
28	Waneta Dam	841.0	840.9-845.9	COMP	0.0	**0.8**	COMP	F11	**0.8**
40	GMS Crane	2.9	3.3-3.9	IMP	0.0	**0.1**	?	F11	**0.1**
53	LB1 Turb	12.0	13.9-17.7	IMP	**0.2**	12.1	?	F12	**0.2**
56*	RUS Stage1	15.3	15.2-21.6	IMP*	0.9*	10.3*	COMP*	?	?
61	SFL SPOG	19.2	61.2-66.1	IMP	41.4	49.0	COMP	F13	**2.4**
62	SCA Intake	18.9	19.8-28.5	IMP	0.3	0.0	?	F11	**0.3**

126.1.1 *BCUC 1.219.2.1 states "The Ruskin Right Abutment Upgrade, Stage 1 Project is complete, and no further work is required." Please reconcile.

Line	Description	Spending To F10 plus F11	Total Cost	Current Stage	Expenditures in Test Period	Adds During Test Period	Stage at End of Test Period	In Service/Cap Add Year	Costs After IS Year
69	WAN Dam	0.1	12.5	DEF	6.6	6.1	COMP? See App. J p.35	F14	App. J p.35 **5.8?**
70	BR2 U5,6	**1.1**	TBD	IDENT	**1.0**	0.0	TBD	**TBD**	TBD
72	CMS G1,2	**1.9**	TBD	IDENT	**2.0**	0.0	TBD	**TBD**	TBD
81	LAJ Seismic	**3.1**	50+	IDENT	**5.6**	0.0	**TBD**	**TBD**	TBD
82	LB CQD ING	**1.0**	TBD	IDENT	**4.0**	0.0	**TBD**	**TBD**	TBD
86	SCA Dam	**4.9**	TBD	IDENT	**9.0**	0.0	**TBD**	**TBD**	TBD
131	ABF Redev	92.8	95.0	IMP	0.0	**2.9**	COMP?		**2.9**
134	REV U5	236.8	248.9	**COMP**	**9.4**	0.0	COMP	**F11**	**9.4**
135	MCA U5,6	76.8	638.7-738.7	IMP	271.7	**32.1****	IMP	F15/16	TBD

126.1.2 **Which part of the project is a capital addition at this early phase of the project?

126.1.3 For the last column on lines 28 to 69 and 131 and 134, please explain if these are these trailing costs, IDC or other.

126.1.4 Please add a column, complete with the pertinent data, of the date the first capital expenditure was charged to the above projects: 70, 72, 81, 82, and 86. Note: please provide the specific year and not a general "pre 2007" or other such entry.

127.0 Reference: Capital Additions and Expenditures
Exhibit B-15, 1.216.1.3, 1.253.2
Bundling of Projects

"Nothing precludes the combination of several of the projects in the future when they are released if there are procurement, resourcing or other efficiencies to be gained in doing so. When projects are planned in the Identification Phase, BC Hydro does seek opportunities to gain efficiencies by bundling with other projects or seeking procurement, staffing or other efficiencies against separate projects."

"For projects that are implemented in stages, for approval purposes the project cost is defined to include all reasonably anticipated stages of the project."

<u>John Hart</u>

127.1 Please explain why the projects, listed in amended Appendix I associated with John Hart (specifically line items 65, 112, 113 and 114) are not bundled into a single CPCN application such that the Commission has the full view of the capital investments required at this facility over the planning horizon. For greater certainty, it is recognized that the construction of all these projects need not occur simultaneously/concurrently based on priority timing; however each project could be included in a single EAR with each asset added to PPE as they are completed and placed in service.

127.1.1 Please confirm that the John Hart replacement project is currently in the Definition phase and explain why the definition costs for projects 112, 113 and 114 are not bundled with the larger project number 65.

127.1.2 Given the advanced state of the JHT Replacement application, please confirm, or explain otherwise, that projects 112, 113 and 114 will be bundled into a single EAR with project 65 and if the total exceeds the CPCN threshold limit BC Hydro will be include all these projects as a single CPCN application (BCUC 1.219.3). If not, why not.

WAC Bennett

127.2 Please explain why the projects, listed in amended Appendix I associated with the WAC Bennett dam (specifically line items 88, 89, 90 and 91) are not bundled into a single EAR (and if the CPCN limit is likely to be exceeded) such that the Commission has the full view of the capital investments required at this facility over the planning horizon. For greater certainty, it is recognized that the construction of all these projects need not occur simultaneously/concurrently based on priority timing, however each project could be included in a single EAR with each asset added to PPE as they are completed and placed in service.

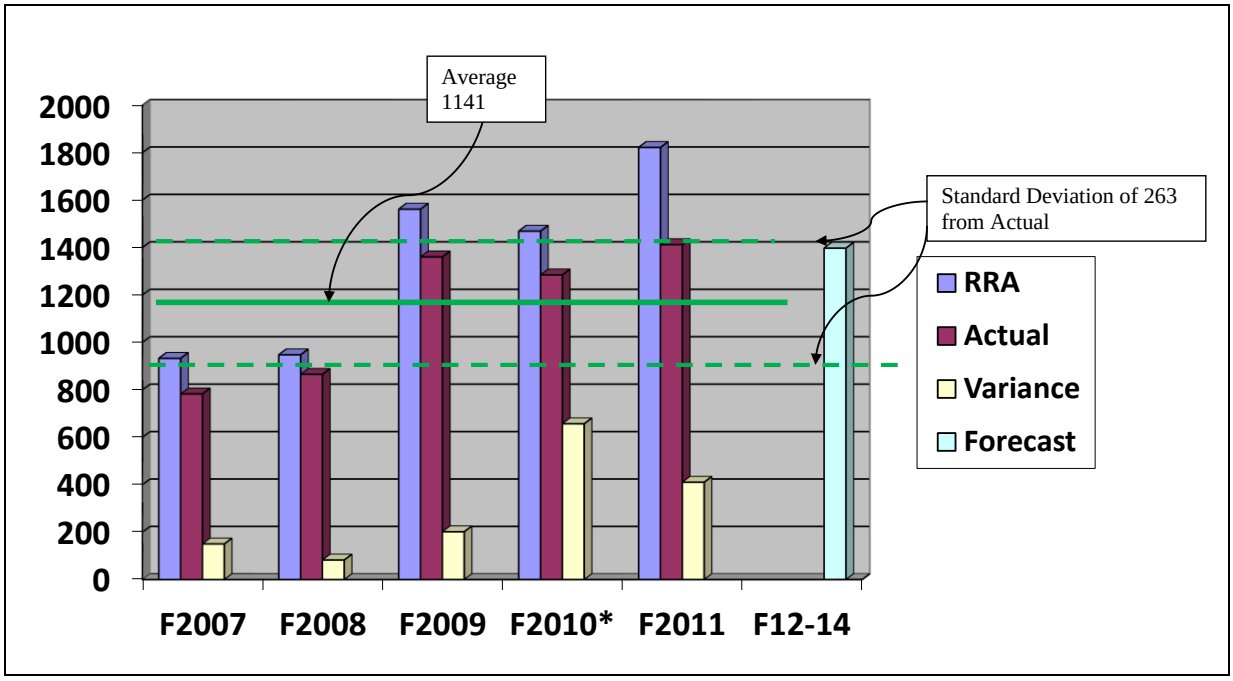
127.2.1 Please confirm that the four WAC Bennett dam projects no. 88, 89, 90 and 91 are currently in the Definition phase and will be bundled into a single project and submitted as a CPCN (subject to the $100 million threshold guideline). If not, why not.

127.3 Please confirm that the Commission can require that the aforementioned JHT and WAC projects be bundled into individual CPCN applications regardless of the threshold amount.

128.0 Reference: Capital Additions and Expenditures
Exhibit B-15, 1.87.1, 1.87.5
Forecast to Actual Capital Additions

"The forecast capital additions in the F07/F08 RRA compliance filing were $932.5 million for F2007 and $947.5 million for F2008, resulting in a variance of $(149.9) million in F2007 and $(82.2) million in F2008. BC Hydro confirms the other numbers in the above table."

128.1 Please confirm or otherwise correct the following graph of Capital Spending.



* **Waneta onetime $841 million excluded**

128.2 As shown in the figure above, the average (mean) is 1141 and the standard deviation (σ) is 263. Please estimate the confidence interval for one standard deviation away from the mean (i.e. [-σ, +σ]).

128.2.1 Would BC Hydro view that the data follows a normal distribution, thus a 68% confidence interval that the forecasted expenditures will fall between 1403 and 877? Please explain why or why not?

Projects delays attributed to "Lower than forecast capital additions in any one fiscal year can be due to a number of factors such as: delays to the in-service date as a result of construction or other project issues; the completion of projects below the expected cost; regulatory processes or decisions; requirements for public consultation; and decisions to delay or cancel planned projects. In addition, certain customer interconnection projects may be delayed due to changes in customer scheduling and timelines or project cancellation by the customer." (BCUC 1.87.3)

"The lower than forecast capital additions from F2007 to F2011 has generally not resulted in a backlog of capital projects. In instances where a project deferral or cancellation contributes to lower than forecast capital additions, the resources originally assigned to the project become available for new projects within the capital plan".(BCUC 1.87.4).

128.3 Please confirm that delays for the most part are attributed to: regulatory, contract/construction, IPP interconnect, final design, stakeholder and First Nation consultation and that cost savings can be summarized as associated with direct construction, no requirement to use the allocated contingencies, lower capital overhead rates, and project cancellation/deferment.

128.3.1 Please confirm that these historical disruptive forces are likely to continue to affect the delivery of 100% of the capital plan or discuss otherwise.

128.3.2 Please confirm, or explain otherwise, that BC Hydro has failed to meet its planned capital additions over the 2007 to 2011 period by an average of 10%.

128.4 Please calculate, for each year of the test period, the incremental impacts on rates, if the forecast of capital additions was reduced by 8%, by 10% and by 12 % and present the results in a table format.

Hydroelectric Generation

129.0 Reference: Capital Expenditures and Additions
Exhibit B-15: 1.204.1 Amended Attachment 1, Line 72; Exhibit B-1-3 Amended Appendix J, p. 37, 1.219.6, Attachment 1, pp. 1, 4, 5 and 29, 1.200.3
CMS G1/2 Replacement
Specific Projects

"The CMS G.S. Plant Evaluation Report (MEP360) determined that upgrading the CMS turbine, generator, and transformer would increase the turbine rated output from 70MW to a nominal 75MW with a maximum output of 85MW. The upgraded turbines will produce a maximum output of 86.9MW, giving a maximum generator output of 84MW (0.95 power factor). Tests have shown that the generator is capable of producing 85MW. However, further studies need to be done to determine whether it is feasible to operate the generator at this higher load for an extended period." (p. 4)

"The current generators are not capable of delivering the increased capacity that is available from the completed turbine upgrade of Cheakamus Unit 1 (F2009 IDS) and Unit 2 (anticipated F2012 ISD)." (Appendix J, p. 37)

In 2006 "[t]he estimated cost to repair the units was found to be compatible to the cost of a new generator." (Appendix J, p.37)

"The solutions for refurbishment or upgrade received from generator manufacturers in 2008 did not provide the desired content for an Alternative selection. Work continues to evaluate the options of refurbishment verses replacement." (Appendix J, p. 37)

"This is a challenging project with several viable technical solutions, including replacement and refurbishment alternatives. Based on market feedback received in F2009, BC Hydro confirmed the technical risks associated with refurbishing the generators. However, the costs proposed by generator manufacturers for refurbishment and replacement alternatives were considerably more than BC Hydro had expected. <u>The project was deferred</u> during F2010 while BC Hydro re-prioritized and focused resources on higher priority work. <u>The re-prioritization process ultimately confirmed the necessity of the project</u> (emphasis added). In F2011, BC Hydro determined that <u>further information on the condition of the existing generators was required</u> before confirming a preferred alternative. (emphasis added) BC Hydro engaged external experts to conduct a non-invasive mechanical evaluation of the generators and in light of the evaluation BC Hydro re-assessed the risks and benefits of the replacement and refurbishment solutions. The results of this assessment were used to complete the feasibility-level design. The Identification Phase will be completed shortly. Most of the $2 million in capital expenditures over the test period is not for the Identification Phase, but rather will be required to complete the Definition Phase."

129.1 The project is currently shown to be in the Identification phase (line 72) during the test period with ISD shown as TBD. Given the level of projected spending during the 3 test period years of 0.4, 0.5, 1.1, please confirm the project is likely to be in service some time in, or after, F2016.

129.1.1 Please explain why a like-for-like refurbishment/replacement project is forecast to take over a decade (F2002 to F 2016).

129.2 Please confirm, or explain otherwise that CMS has a nameplate capacity of 140MW but is operated at up to 157 MW (which would indicate the stators are operating above nameplate and likely to require replacement or upgrading). (Attachment 1, p.4)

The CMS G.S. Plant Evaluation Report (MEP360) determined that upgrading the CMS turbine, generator, and transformer would increase plant efficiency by 5%, resulting in an energy gain of 44 GWh a year (date presumed to be 2001 or earlier); (Attachment 1, p.4);

129.3 Please confirm that the transformers have been replaced with upgraded units.

CMS Unit Upgrade CAR #31566 was approved in December 2001. (Attachment 1, p. 1);

Electrical equipment to allow for extended operation of the generator at the upgraded power factor is not included in the costs estimates or benefits and will need to be justified based upon a detailed assessment of the condition of the equipment to be undertaken during completion of definition phase (of the Turbine Replacement project). (emphasis added) (Attachment 1, p.29)

129.4 Please confirm this CAR #31566 deliverable was met and the report submitted.

One of the generators inspected in 2006 identified three major areas of concern: stator core waves, hot spots and sole plate cracking and have an EHR of "poor". (Appendix J, p. 37)

129.5 Please explain what additional information is required (in addition to that provided in BCUC 1.200.3), that would take 3 years and $2.1 million of Definition costs, in addition to the $1.9 million spent to F2011 (total $4.0 million) to determine that it is necessary to replace the generators. (BCUC 1.204.1, Attachment 1, line 72)

129.5.1 If no addition information is required, please explain what is hampering the decision to proceed with stator replacements.

129.5.2 Please explain if "the costs proposed by generator manufacturers for refurbishment and replacement alternatives were considerably more than BC Hydro had expected" are in excess of $4.0 million ($1.9 spent to F11 and $2.1 during the test period) and if yes, by how much.

129.5.3 Please explain why the stators were not purchased and installed by GE Canada under the terms of the Strategic Partnering Agreement as was done with the contract for the turbines. Please confirm that GE submitted a budget price in the capital cost estimate.

129.6 Please explain why the turbines and generators were not replaced as a complete matched set. Why the piecemeal approach? Was this option considered and a budget estimate acquired from a manufacturer(s)? Please discuss.

129.7 Please provide the calculation for the cost of incremental capacity associated with the upgraded stator capacity project and compare that cost to the present market for capacity.

129.8 Please explain if these stator replacements are considered a Resource Smart project in addition to replacing equipment at end of life.

Diesel and Thermal Gas

No IR's Deemed Necessary

Transmission

130.0 Reference: Capital Expenditures and Additions
Exhibit B-15, CONFIDENTIAL 1.232.6
Transmission Sustaining Capital Projects
Unplanned Expenditures

130.1 Please explain how the unplanned expenditures arose, and please describe how BC Hydro negotiated the cost.

130.2 What compelled BC Hydro to complete the transaction in F2011 if it was unplanned prior to the F2011 RRA?

131.0 Reference: Capital Expenditures and Additions
Exhibit B-15, CONFIDENTIAL 1.236.2
Transmission Capital Projects
Project Scope and Standards

131.1 Please explain the reliability benefit afforded to the MRT substation by having redundant transformer capability when it is connected to a radial line. Please quantify this benefit in terms of the effect on the standard reliability indices with and without the redundant transformer capacity using BC Hydro's average probability of transformer failure. What is BC Hydro's policy for redundant transformer capacity for substations served by radial lines?

131.2 What is the cost of the redundant transformer capacity in the MRT substation project?

132.0 Reference: Capital Expenditures and Additions
Exhibit B-15, 1.253.1
Transmission Capital Projects
Project Scope and Standards

132.1 Please explain whether asbestos containment procedures would have mitigated the need for a new control room building at the Vanderhoof Substation. What increased safety risks, costs or other issues would have been created by not building a new control room?

Distribution

133.0 Reference: Capital Expenditures and Additions
Exhibit B-15, 1.262.1
Distribution Growth Capital Projects
Project Scope and Standards

133.1 Please identify the amount and cost of feeder upgrades that could be deferred by revising BC Hydro's standard to accommodate an increase in the planning capacity for 25 kV distribution feeders from 12 MVA to 15 MVA.

134.0 Reference: Capital Expenditures and Additions
Exhibit B-15, 1.264.1
Distribution Capital Projects
Project Scope, Standards and Costs

134.1 Please explain why overhead and finance charges account for over 30 percent of the "FJN new feeder to Taylor" project.

135.0 Reference: Capital Expenditures and Additions
Exhibit B-15, CONFIDENTIAL 1.267.3
Sustainment – Asset Replacement
Utility Standards for Fused Cutout Replacement

135.1 Please provide BC Hydro's statistics for fused cutout failures in the last three years.

135.2 Please explain why BC Hydro is pursuing a mass replacement strategy of fused cutout switches when other approaches can be adopted, and appear to be adopted across the industry.

Information Technology and Telecom

136.0 Reference: IT&T Projects
Exhibit B-15, IR 1.279.3, IR 1.279.3.1, IR 1.154.1
Exhibit B-16, AMPC IR 1.58.1, Attachment 1, AMPC IR 1.58.2, AMPC IR 1.58.2.1, AMPC IR 1.58.4, AMPC IR 1.58.9
Operating cost savings from IT&T Projects

In response to BCUC IR 1.279.3.1 and BCUC IR 1.154.1, BC Hydro shows the reductions in the IT efficiencies in the test period as follows:

Corporate Groups (Subset of Amended Table 5-46)
Corporate-wide savings from IT&T projects, procurement and other initiatives
Savings / Efficiencies - Specific Categories

$'s in millions	Original RRA	Restated RRA	Other Changes	Amended RRA
Outsourcing	(2.7)	(2.7)	(5.6)	(8.3)
IT Efficiencies	(1.5)	(1.5)	1.3	(0.2)
Procurement Savings	(0.4)	(0.4)	(0.8)	(1.2)
Total - F2012 Plan	**(4.6)**	**(4.6)**	**(5.1)**	**(9.7)**
Outsourcing	(5.1)	(5.1)	(2.4)	(7.5)
IT Efficiencies	(13.3)	(13.3)	14.3	1.0
Procurement Savings	(0.7)	(0.7)	(2.0)	(2.7)
Incremental Increase	(19.1)	(19.1)	9.9	(9.2)
Total - F2013 Plan	**(23.7)**	**(23.7)**	**4.8**	**(18.9)**
Outsourcing	(14.7)	(14.7)	14.2	(0.5)
IT Efficiencies	(4.2)	(4.2)	3.4	(0.8)
Procurement Savings	(0.3)	(0.3)	(0.5)	(0.8)
Incremental Increase	(19.2)	(19.2)	17.1	(2.1)
Total - F2014 Plan	**(42.9)**	**(42.9)**	**21.9**	**(21.0)**
F2012 - F2014				
Total Outsourcing	**(33.0)**	**(33.0)**	**(7.4)**	**(40.4)**
Total IT Efficiencies	**(35.3)**	**(35.3)**	**35.9**	**0.6**
Total Procurement Savings	**(2.9)**	**(2.9)**	**(6.9)**	**(9.8)**
Total F2012 - F2014 Plan	**(71.2)**	**(71.2)**	**21.6**	**(49.6)**

A portion of the IT efficiencies savings has been reallocated to the 'Unidentified Savings' line item in the Amended Table 5-46, as the specific projects which drive the efficiencies were not yet determined. In addition IT savings have been reallocated from Corporate to T&D for 'automation and enhanced processes / systems' as noted on Amended Table 5-16 on lines 31 and 53. The balance of the reduction in savings from IT efficiencies results from the removal of indirect benefits which are not expected to result in financial savings. The net reduction in IT efficiency savings as a result of these changes is approximately $36 million.

Although IT efficiencies were anticipated in the F12-F14 RRA, the savings were not defined at the project level, and therefore a breakdown of changes by project from the Application to the Amended Application is not available.

136.1 From the response above, it appears that originally IT efficiencies savings were estimated to be $35.3 million and in the Amended RRA there are no IT efficiencies savings. It appears that IT efficiencies will have a cost of $0.6 million. Please confirm if this understanding is correct or explain otherwise.

136.1.1 Please provide a table showing the original amounts, amounts transferred to Table 5-16, and the net amounts of IT efficiencies.

In Attachment 1 of its response to AMPC IR 1.58.1, BC Hydro provided a summary of IT&T projects from F2007 to F2014. From that listing, a summary of those projects greater than $10 million and with an implementation date within the test period is listing below:

		Amended F12/F14 RRA				
Project Name	F11 NSA	F12 Plan	F13 Plan	F14 Plan	Total Cost	Implementation Date
Plan & Schedule Work	8.0	5.3	15.8	10.3	33.7	F2012-F2014
Project & Portfolio Management (PPM)	7.0	8.1	-	-	21.6	F2011-F2012
Microsoft Enterprise Agreement (F2009)	-	0.8	-	-	15.0	F2009-F2012
Distribution Management System (DMS)	3.0	2.7	5.7	-	14.7	F2013
EMPower (formerly HR Systems Replacement)	4.6	7.6	-	-	14.6	F2012
Supply Chain	-	6.6	7.8	-	14.4	F2013
Radio Technology Upgrade	2.4	6.4	7.0	-	13.9	F2013

Furthermore, in its response to APMC IR 1.58.2.1, BC Hydro summarized the type of benefits and reductions that IT&T projects can deliver as follows:

The types of benefits and reductions that IT&T projects deliver can be summarized into three areas:

- **Direct benefits which result in financial savings to the organization (e.g., FTE reductions, support cost reductions);**
- **Indirect benefits (e.g., cost increase avoidance, productivity savings that result in staff saving a small portion of time each day which can then be used for other tasks); and**
- **Improved operational capability and risk mitigation to support corporate goals (e.g., reliability, extended life for utility assets, safety and compliance related business objectives).**

136.2 For each of the above projects over $10 million that are expected to be in service in the test period, please prepare a table summarizing and quantifying the direct benefits and indirect benefits.

136.2.1 Please show where these estimated benefits and savings are reflected in the Amended RRA schedules.

136.2.1.1 If they have not been included in the Amended RRA schedule, please explain why.

137.0 Reference: IT&T Projects
Exhibit B-15, IR 1.280.1, IR 1.280.2, IR 1.190.7, IR 1.253.2
Capital investigative cost on IT&T Projects

From BCUC IR 1.280.2, the following table shows IT&T projects in the identification phase:

				REVISION and EVIDENTIARY UPDATE					
	Project Name	Revised Estimated In-Service Date	Development Stage	F2011 Actual	F2012 Update	F2013 Update	F2014 Update	Forecast Remaining Expenditures	Total Project Cost
5	Asset Management	TBD	Identification	-	-	1.0	2.0	TBD	TBD
8	Budget Processing	F2015	Identification	-	-	-	1.5	0.5	2.0
11	Call Centre Upgrade	F2013	Identification		2.0	2.0	-	-	4.0
2	Customer Relationship Management (CRM)	TBD	Identification	-	-	-	6.0	TBD	TBD
12	Data Centre Move (Swing Equipment)	F2012-F2014	Identification		1.0	4.5	0.5	-	6.0
13	Distribution Management System (DMS) Phase 2	F2014	Identification		-	-	2.5	-	2.5
15	Energy Management System Upgrade	F2015	Identification		-	-	2.3	2.3	4.5
7	Enterprise Field Mobility	F2013	Identification	0.7	2.8	2.3	1.8	-	7.5
14	Generation Resource Management	F2015	Identification		-	0.9	0.9	0.9	2.6
6	Geographic Information System (GIS)	TBD	Identification	-	-	-	1.0	TBD	TBD
9	Microsoft Service Agreement (F2013)	F2013	Identification		-	2.0	-	-	2.0
10	Microsoft Service Agreement (F2014)	F2014	Identification		-	-	2.0	-	2.0
16	Security Information and Event Manager	F2013	Identification		1.4	1.1	-	-	2.5
3	Supply Chain	F2013	Identification	-	6.6	7.8	-	-	14.4
4	Talent Management Integration	F2015	Identification	-	-	-	3.0	3.0	6.0
					13.8	21.5	23.4	6.6	56.0

In response to BCUC IR 1.280.2, BC Hydro stated that "there is no difference in the accounting treatment between costs incurred during the Identification Phase and CPI costs (i.e., both are expensed as incurred). The "Development Stage" identified in Amended Appendix I refers to the project stage at the application filing date. The projects identified in the table above are expected to move through development stages during the test period. As these projects move into subsequent phases (e.g., Definition Phase and Implementation Phase), most associated project costs will be capitalized."

137.1 Please confirm that the total project cost included above represents the total estimated cost of the project as it moves from the identification phase through to the implementation phase and that it does not represent the cost for the Identification Phase only.

137.2 Please confirm that the "Total Project Costs' column does not include the Identification phase costs. If it does, please explain why.

137.3 Please quantify the amount of project cost to be spent in the identification phase for the projects above and identify where these cost are expensed in the Amended RRA schedules in Appendix A.

137.3.1 If the above table does not include any costs associated with the identification phase, please estimate what the identification project costs are expected to be and where they are expensed in the Amended RRA schedules.

138.0 Reference: IT&T Projects
Exhibit B-15, IR 1.276.1, IR 1.276.1.1
Exhibit B-1-3, Amended Appendix U
Project and Portfolio Management
Prudency Review

In the amended application, the updated project cost for Project and Portfolio Management increased to $22 million and is expected to go into service in F2012.

In the F2011 RRA application, Appendix I, p. 13, total cost estimated for this project was $15 million; a 47% ($7 million) cost variance in F12.

138.1 What month in F2012 does BC Hydro forecast the Project will go into service?

138.2 Given that the in-service date is in F2012, please provide a detailed summary of the actual costs incurred to date compared to the forecast F2011 $15 million costs. Please provide an explanation for variances by cost driver.

139.0 Reference: Capital Expenditures and Additions
Exhibit B-1-3, Appendix R
Exhibit B-16: COPE IR 1.58.1, AMPC IR 1.58.1
IT Capital Expenditures
Specific Projects

COPE IR 1.58.1 requested an update to Table 5-7 "IT Capital Expenditures" from the BC Hydro F09/10 RRA to extend the table back through fiscal 2003. The response referenced AMPC IR 1.58.1. Although the table provided in the response to AMPC IR 1.58.1 extends forward to F2014, it only goes back to F2005.

139.1 Please revise the response to AMPC IR 1.58.1 so that it extends back through Fiscal 2003 as requested in COPE 1.58.1.

According to the AMPC IR1.58.1 response attachment, the Enterprise Financials Upgrade project was estimated at $7.2 million in the F2009-F2010 RRA, $14.1 million in the F2011 RRA, and $16.3 million in the Amended F2012-F2014 RRA.

On page 6 of the Financial Replacement Project business case, included in AMPC IR 1.58.4 response attachment 1, it states that the total Authorized Amount for the project was $18.7 million. It further states at page 6:

"SAP licensing and common infrastructure costs to support the BC Hydro's overall SAP program including this project are addressed under a separate business case. PeopleSoft Financials decommissioning costs of $200K are also not included in this business case …"

139.2 Please provide the total cost (showing both capital and operating dollars) to implement the Enterprise Financials Upgrade, including the SAP licensing and common infrastructure, decommissioning the PeopleSoft Financials system, new hardware, integration to other systems, training, and any other incremental costs. Please confirm the EFU was completed in F2011 and there are no capital costs in the test period. Please confirm the amount of sustainment and related costs that will be expensed in the test period.

139.3 Please explain what projects are included in the "SAP program" reference on page 6 of the Financial System Replacement Project business case, and provide the total cost of the program. Please provide a table of SAP ERP related projects in F2012-14 including for each project the costs prior to F2012, F2012-14 by year, and future expected costs.

Bullet 4 on page 5 of the Financial System Replacement Project business case states:

> "It will conform to the BC Hydro Information Technology & Telecommunications (IT&T) Strategy to leverage a single SAP ERP environment, facilitating enablement of IT sustainment cost savings in the long-term."

The strategy to use a "single SAP ERP environment" does not appear to be outlined in the BC Hydro Information Technology & Telecommunications Five Year Plan in Appendix R.

139.4 Please explain if the "single SAP ERP environment" is the SAP program referenced on Page 6 of the Financial System Replacement Project business case.

139.5 Please explain when and by whom this single SAP ERP environment program was approved. Please provide a copy of the business case and indicated where the program is listed in the revised response to AMPC IR 1.58.1.

139.6 Please explain what IT sustainment cost savings have been achieved by the SAP program projects to date. Please provide an illustrative table.

Properties

140.0 Reference: Properties
Exhibit B-15, BCUC IR 1.283.3, BCUC IR 1.280.2, BCUC IR 1.190.7, IR BCUC 1.253.2
Capital Investigative Cost

From BCUC IR 1.283.3, the following table shows IT&T projects in the identification phase:

	Project Name	Estimated In-Service Date	Development Stage	F2011 Actual	Total F12-F14 Update
	Field Building Rebuilding:				
7	Nanaimo (Note 1)	F2015	Identification	-	15.0
8	Vernon	F2015	Identification	-	7.3
9	Victoria	F2016	Identification	-	1.0
10	Kamloops	F2016	Identification	-	4.0
					27.3

In response to BCUC IR 1.283.3 and BCUC IR 1.280.2, BC Hydro stated that "there is no difference in the accounting treatment between costs incurred during the Identification Phase and CPI costs (i.e., both are expensed as incurred). The "Development Stage" identified in Amended Appendix I refers to the project stage at the application filing date. The projects identified in the table above are expected to move through development stages during the test period. As these projects move into subsequent phases (e.g., Definition Phase and Implementation Phase), most associated project costs will be capitalized."

140.1 Please confirm that the total project cost included above represents the total estimated cost of the project as it moves from the identification phase through to the implementation phase and that is does not represent the cost just for the Identification Phase.

140.2 Please quantify the amount of project cost to be spent in the identification phase for the projects above.

140.2.1 Please identify where these cost are expensed in the Amended RRA schedules in Appendix A.

140.2.2 If there are no costs associated with the identification phase in the above table, please estimate what the identification project costs are expected to be and where they are expensed in the Amended RRA schedules.

141.0 Reference: Properties
Exhibit B-15, IR 1.285.1
Exhibit B-1-3, Amended Appendix U
Prince George Field Building
CPCN Threshold

141.1 In its response to BCUC IR 1.285.1, BC Hydro stated that it is not planning to file a separate application for the Prince George Field Building Project. However, in Amended Appendix U, p. 6, BC Hydro notes that it anticipates it will be filling an application for the New Prince George Building Properties project. Please confirm if BC Hydro will be filing an application under its Capital Project Filing Guidelines, and if not why not.

142.0 Reference: Properties
Exhibit B-15, BCUC IR 1.286.1
Strategic Property Purchases
Supporting documentation outstanding

142.1 In its response to BCUC IR 1.286.1, BC Hydro stated that "providing details of these strategic property purchase would undermine BC Hydro's commercial position and may cause BC Hydro to incur higher costs than would otherwise be the case. Accordingly, BC Hydro declines to response." Please provide evidence for this request on a confidential basis.

J. SMART METERS AND INFRASTRUCTURE (SMI) PROGRAMS

143.0 Reference: Smart Metering and Infrastructure Program
Exhibit B-1-3, Chapter 7, Section 7.3.17
Exhibit B-15: IR 1.289.1; 1.289.2
SMI Regulatory Account Additions and Amortization

In response to BCUC IR 1.289.1 BC Hydro states: requested additions to the SMI Regulatory Account relate to BC Hydro's actions regarding all components required to comply with section 17 of the CEA and the Smart Meter and Smart Grid Regulation and do not comprise solely of costs related to the smart metering component of the SMI Program.

143.1 For each of the test periods please provide a table that list the dollar amount of the requested additions to the SMI regulatory account and break those out between costs relating to the smart metering component and cost related to anything else. If the 'anything else' balance is material please provide details of what is included.

In IR 1.289.2 the BCUC asked BC Hydro when it anticipated commencing amortization of the SMI Program regulatory account and BC Hydro responded – "after this test period".

143.2 Clearly it has to be either never or after the test period. Please answer IR 1.289.2 providing a time after the test period when BC Hydro anticipates commencing amortization of the account.

144.0 Reference: Smart Metering and Infrastructure Program
Exhibit B-1-3, Chapter 7, Section 7.3.17
Exhibit B-15, IR 1.291
Accelerated Amortization of Old Meters
SMI Regulatory Treatment

BC Hydro is requesting that $38.8 million in F2012 and $27.3 million in F2013 relating to accelerated depreciation of the existing revenue meters be deferred in the SMI regulatory account for recovery at some future period. (Exhibit B-1-3, Section 7.3.17)

BC Hydro states it is appropriate to defer the amount of the increased amortization that would be recorded because deferral provides for better matching of these amounts with the benefits provided by the SMI Program. (Response to BCUC IR 1.291.2.1)

144.1 Please confirm, or explain otherwise, that accelerated depreciation (amortization) as described in response to BCUC IR 1.291.2 would be expensed in the test period under both CGAPP and IFRS.

144.2 Please explain what the benefits are of the old meters SPECIFICALLY (note: this IR does not relate to the benefits of the entire program just to the old meters).

144.3 What would the incremental rate impact be in each of the test periods if the accelerated depreciation were to be treated as required under CGAPP and IFRS (i.e. expensed)?

145.0 Reference: **Smart Metering and Infrastructure Program**
Exhibit B-1-3, Chapter 7, Section 7.3.17
Exhibit B-15, IR 1.291
|Exhibit B-16: BCSEA IR 1.27.5; BCOAPO IR 1.4
Matching Principal
SMI Regulatory Treatment

The Matching Principle

The *matching principle* is one of the cornerstones of the accrual basis of accounting. Under the matching principle, when you record revenue, you should also record at the same time any expenses directly related to the revenue. Thus, if there is a cause-and-effect relationship between revenue and the expenses, record them in the same accounting period.

145.1 Please confirm that the matching principal as discussed in response to BCUC IR 1.291.1.1 is an accounting principal?

145.2 Please explain why Hydro states that the reason to defer the costs is to provide for better matching when CGAPP (which reflects the matching principal) requires theses costs to be expensed?

SMI Program Costs and Benefits											
January 2011 SMI Business Case											
Year ($ million)	Prior to F2011	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020
SMI Program Benefits											
Revenue			0.2	2.6	33.9	64.9	84.6	75.5	68.1	59.2	50.0
Capital Savings			0.4	3.4	5.3	2.7	2.3	2.5	3.2	4.9	2.6
Energy and Capacity			4.3	26.0	49.7	56.0	61.1	79.1	79.5	81.5	95.6
Operating Savings			4.3	20.9	38.6	38.5	39.4	41.3	44.7	48.2	45.5
Total Benefits	0.0	0.0	9.2	53.0	127.6	162.1	187.3	198.3	195.6	193.8	193.7
SMI Program Costs											
Implementation	45.0	55.7	370.4	344.0	94.5	0.0	0.0	0.0	0.0	0.0	0.0
Sustaining Capital				4.1	9.5	9.6	16.1	20.5	13.0	11.9	13.8
Benefit Related			15.1	24.2	38.3	37.7	38.8	25.4	25.8	26.5	15.3
Operating Costs			8.3	14.5	18.4	19.5	21.2	20.8	20.7	22.6	22.8
	45.0	55.7	393.8	386.7	160.6	66.8	76.2	66.7	59.5	61.1	51.9

In response to BCSEA IR 1.27.5 BC Hydro provided the above table.

145.3 Using the table above, on a year by year basis, please identify all the Benefits that are reflected in the test period.

145.4 Using the table above, on a year by year basis, please identify all the Costs that are reflected in the test period.

145.5 Please explain how this meets the BC Hydro matching concept?

Reference: **Exhibit B-1-3, page 1-10**

1.4.3 The Application states that BC Hydro proposes to defer the majority of the revenue requirement impact and the initial recovery of the costs of the SMI program. What costs associated with the SMI program are not being deferred and therefore impacting on the F2012 to F2014 revenue requirements?

BCOAPO IR 1.4.3

RESPONSE:

As explained in section 7.3.17 page 7-24 implementation of the SMI Program results in the realization of energy related benefits in the test period that are not being deferred. Please also refer to the response to BCSEA IR 1.27.1.

145.6 The above in BCOAPO IR 1.4.3 and BC Hydro's response: BC Hydro has not responded to this IR as asked. Again, what costs associated with the SMI program are not being deferred and therefore impacting the test period.

RESPONSE: BCAOPO IR 1.4.2

In addition to SMI Program energy-related benefits identified in Table 7-5 of the Amended Application, BC Hydro has included (on the line entitled KBU Operating Costs – SMI Benefit Related in Amended Table 7-4 of the Amended Application) the realization of operational savings as further detailed in the following table.

($ million)	F2012	F2013	F2014
KBU Operating Costs - SMI Benefit Related			
Meter Reading	0.2	14.4	25.8
Billing Exception Processing	-	-	0.6
Load Research	-	-	0.1
Outage Management	-	0.8	0.9
Distribution Optimization	-	0.7	0.9
Meter Sampling	-	-	(0.4)
Remote Disconnect/Reconnect	-	1.9	4.5
DSM Continuous Optimization - Large Customer	-	-	0.3
Total KBU Operating Costs - SMI Benefit Related	0.2	17.8	32.7

145.7 In response to BCOAPO IR 1.4.2 BC Hydro identified KBU operating cost benefits that are reflected in the test period. If no costs are reflected in the test period, please explain how BC Hydro's matching concept is achieved?

146.0 Reference: **Smart Metering and Infrastructure Program**
Exhibit B-1-3: Chapter 7, Section 7.3.17; Amended Appendix J, p. 149
Exhibit B-15: IR1.292; IR 1.293
Exhibit B-16, BCSEA IR 1.27
Capitalization of SMI costs
SMI Regulatory Treatment

RESPONSE: BCSEA IR 1.27.1

Confirmed as it relates to SMI Program costs incurred during the F2012 to F2014 period that would otherwise be expensed in the period in which they are incurred. BC Hydro is not requesting the deferral of expenditures related to the SMI Program that are eligible for capitalization.

BC Hydro states in response to BCSEA IR 1.27.1 that BC Hydro is not requesting any costs eligible for capitalization to be deferred.

146.1 Please detail all the SMI Program costs that are eligible for capitalization and identify which will be capitalized during the test period.

RESPONSE: BCUC IR 1.293.1

Not confirmed. Energy-related benefits are included in the revenue requirement in each year of the test period as identified in lines 11 through 17 and Table 7-5 on page 7-24 of the Amended Application. Benefits that are being deferred that are related to the SMI Program are shown in Amended Table 7-4, in the line entitled KBU Operating Costs – SMI Benefit Related.

For each year of the test period, BC Hydro has requested the deferral of all SMI Program costs not eligible for capitalization under CGAAP together with capital related costs.

146.2 In Response to BCUC IR 1.293.1 BC Hydro states that BC Hydro is requesting that CGAPP costs that are eligible for capitalization to be deferred. Please reconcile response to BCUC IR 1.293.1 with BC Hydro's response to BCSEA IR 1.27.1.

SMI Program Costs and Benefits January 2011 SMI Business Case											
Year ($ million)	Prior to F2011	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020
SMI Program Benefits											
Revenue			0.2	2.6	33.9	64.9	84.6	75.5	68.1	59.2	50.0
Capital Savings			0.4	3.4	5.3	2.7	2.3	2.5	3.2	4.9	2.6
Energy and Capacity			4.3	26.0	49.7	56.0	61.1	79.1	79.5	81.5	95.6
Operating Savings			4.3	20.9	38.6	38.5	39.4	41.3	44.7	48.2	45.5
Total Benefits	0.0	0.0	9.2	53.0	127.6	162.1	187.3	198.3	195.6	193.8	193.7
SMI Program Costs											
Implementation	45.0	55.7	370.4	344.0	94.5	0.0	0.0	0.0	0.0	0.0	0.0
Sustaining Capital				4.1	9.5	9.6	16.1	20.5	13.0	11.9	13.8
Benefit Related			15.1	24.2	38.3	37.7	38.8	25.4	25.8	26.5	15.3
Operating Costs			8.3	14.5	18.4	19.5	21.2	20.8	20.7	22.6	22.8
	45.0	55.7	393.8	386.7	160.6	66.8	76.2	66.7	59.5	61.1	51.9

In response to BCSEA IR 1.27.5 BC Hydro provided the above table.

146.3 Please reconcile this table to Amended Appendix J, p. 149.

146.4 Please identify any costs in the table above that are eligible for capitalization in the test period.

146.5 In response to BCSEA IR 1.27.3 BC Hydro identified the number of smart meters that have been installed. Before the meters are considered in-service (installed) are they reported in Unfinished Construction for regulatory accounting? For financial reporting?

146.5.1 If not, where are they are they reported for regulatory reporting and financial reporting?

146.6 What is the CGAPP and IFRS treatment for the meters in-service (installed)? If no regulatory treatment were available, would they be reported in PP&E with amortization commencing at the date they are installed? If not, what would the CGAAP and IFRS treatment be?

146.7 In response to BCUC IR 1.292.2 BC Hydro states that the smart meter capital assets do not impact Schedule 13 (Capital expenditures and additions) or Schedule 9 (Return on Equity / Rate Base) – if not included in capital expenditures or capital additions or unfinished construction where are they reported?

146.7.1 After the meters go in-service where will they be reported for regulatory and financial reporting purposes?

146.8 Under the proposed regulatory treatment are the in-service meters part of Rate Base?

146.8.1 If yes, please explain why they are not reflected in Schedule 9.

146.8.2 If not part of Rate Base, why does BC Hydro feel they are entitled to a ROE at all?

146.9 In response to BCUC IR 1.292.1 BC Hydro showed the calculation for the proposed deferred ROE addition to the SMI regulatory account. Please reconcile the Rate Base shown in BCUC IR 1.292.1 to the table of costs reported in response to BCSEA IR 1.27.5 and to Amended Appendix J, p. 149.

In response to BCUC IR 1.292.2.1 BC Hydro states that "The F2014 in-service date noted in Appendix J applies to the SMI Program in its entirety, and includes the smart metering, theft detection, and advanced telecom components." Given that the entire SMI Program will be in-service in F2014 why would BC Hydro be requesting to defer the amortization, financing costs, and ROE in F2014?

147.0 Reference: **Smart Metering and Infrastructure Program**
Exhibit B-1-3, Chapter 7, Section 7.3.17
Exhibit B-15, IR 1.292.3
Financing Costs
SMI Regulatory Treatment

RESPONSE: BCUC IR 1.292.3

The detailed calculation for the deferred financing costs in F2012, F2013 and F2014 is as follows:

($ million)	F2012	F2013	F2014
Mid-Year Net Debt	266.4	646.8	890.3
Cost of Debt (per cent)	5.03	5.13	5.17
Finance Charges	13.4	33.2	46.0
Less Interest on Deferral Accounts	(4.3)	(10.4)	(16.8)
Net Deferred Financing Costs	9.1	22.8	29.2

147.1 Please provide support for the Mid-Year Debt amounts in each of the test periods. Please break this out between costs included directly in the regulatory account and costs that are capitalized outside of the regulatory account (i.e. the meters).

147.2 Please confirm, or explain otherwise, that the Net Deferred Financing Charges are due to financing costs of the capital assets.

148.0 Reference: **Smart Meters and Infrastructure**
Exhibit B-15, BCUC 1.51.1
Energy Theft Loss Reduction
Detection of Theft

"The initial implementation of system devices (i.e., feeder and transformer meters), which are a key element of the theft detection solution, is planned to commence in F2012 and continue through to the end of F2014. System device installation will continue thereafter, as required by system growth. BC Hydro expects that the realization of theft detection benefits will lag the installation of system devices by a period of about 6 months."

148.1 Please explain why energy theft can go undetected after the installation of smart meters. What percentages of diversions (number and estimated energy) are occurring away from metered installations, where the diversion does not compromise the actual or intended meter location?

148.2 Please identify the annual amount of energy theft BC Hydro estimates will be eliminated, both annually and cumulatively, by quantity and value, simply by installation of location-specific smart meters.

148.3 Please identify BC Hydro's estimate of the split between reduced costs and increased revenues annually from reduced energy theft.

149.0 Reference: Smart Meters and Infrastructure
Exhibit B-15, BCUC IR 1.326.1
Energy Theft Loss Reduction
Detection of Theft

149.1 Please explain why the "Loss of existing recoveries from existing theft detection methods (i.e., without SMI)" decreases in F2013 by a value greater than the increase in "Recoveries for new theft detection methods (i.e., with SMI)"? Does BC Hydro intend to reduce existing theft detection and recovery activities while SMI is being implemented, and if so, why?

K. DEPRECIATION

Clarification

150.0 Reference: Depreciation
Exhibit B-15, BCUC IR 1.316.1
Commencement of Depreciation under IFRS
Clarification

In response to IR 1.18 6.2, BC Hydro defines a completed project under IFRS as follows:

> **Completed Project (IFRS): A project is complete when the following criteria are met:**
>
> **a) the constructed asset is available for use,**
>
> **b) any required testing (including trial runs) of the asset is complete and the results of the testing indicate that the asset is ready for productive use, and**
>
> **c) all expected capital costs have been incurred.**

Under IAS 16.55, "depreciation of an asset begins when it is available for use." There is only one criterion for the commencement of depreciation under IFRS but BC Hydro's policy above has three.

150.1 If the constructed asset is available for use but not all expected capital costs have been incurred (i.e. Trailing cost), when would BC Hydro expect to commence depreciation and how does this comply with IAS 16.55?

150.2 What is BC Hydro's policy for the treatment of "trailing cost" once the constructed asset is available for use? Please show where trailing cost would be included in the schedules in Amended Appendix A.

Amortization

International Financial Reporting Standards

151.0 Reference: IFRS
Exhibit B-1-3, Chapter 8, Section 8.14.5
Mass Asset Retirement

1.305.6.1 If forecast depreciations rates are accurate why would a loss be forecast?

BCUC IR 1.305.6.1

RESPONSE:

The useful lives that BC Hydro uses to determine depreciation expense represent the average life of assets for each asset class. A loss results when an asset is retired prior to attaining the useful life for the asset class. For example, if a pole is retired after 20 years in-service and the useful life of poles is 50 years, 60 per cent (30/50) of the original costs (the remaining net book value) of the asset is recorded as a loss.

151.1 In response to BCUC IR 1.305.6.1 BC Hydro states that of a part of a mass asset is retired early then a loss needs to be recorded and recovered from rate payers. Given that the useful lives of assets for each asset class is based on the average life, is it not expected that a statistically equally amount of the mass asset pool will retire late and result in a not $0 impact to ratepayers?

151.2 Please fully explain how assets that live longer than the average life are forecast to be reflected in future revenue requirements under IFRS.

151.3 If the useful lives are on average forecast properly, please explain why a mass asset provision would be required.

151.4 In the event that a large loss occurs as a result of a onetime mass asset retirement, would BC Hydro not have the ability to come to the Commission and request recovery in rates in a future period?

152.0 Reference: **Provisions and Other**
Exhibit B-15-1: IR 1.10.5, IR 1.443.1
Exhibit B-1-3, Chapter 8, Section 8.14.5
IFRS - Mass Asset Retirement

RESPONSE: BCUC IR 1.443.1

The amounts for gains and losses on tangible and intangible assets are $2.4 million for F2012, $7.1 million for F2013 and $5.9 million for F2014. These amounts are included as part of lines 62 to 66 on Schedule 5.0.

RESPONSE: BCUC IR 1.10.5

Yes, BC Hydro is at risk for some of the forecast items presented in the Revenue Requirement Application.

Specifically, BC Hydro is at risk for variances from Plan on the following items:

Forecast Item	Amended Appendix A reference
Miscellaneous revenues	Schedule 15.0
Operating costs	Schedule 5.0, line 9 less lines 5 and 6
Provision and other costs	Schedule 5.0, lines 62 to 66 (1)
IFRS Mass Asset Harmonization costs and Amortization	Schedule 5.0, line 67; Schedule 7.0, line 26
Taxes	Schedule 6.0

Note 1 - lines 62 to 66 mainly includes Gains/losses on Asset Disposals and ARO Accretion.

152.1 Please confirm that the Provision and other costs that are recovered in rates refers exclusively to gains and losses on tangible and intangible assets for amounts as reported in response to BCUC IR 1.443.1.

152.1.1 If not confirmed, please explain what other cost listed in lines 62 to 66 are recovered in rates.

152.2 Which line on Schedule 1 are gains and losses on tangible and intangible assets included in?

152.3 For the years F2007 to F2011, please provide BC Hydro's forecast and actual provision for gains and losses on tangible and intangible assets.

152.4 On page 8-23 (Exhibit B-1-3) BC Hydro states that "BC Hydro's current practice under CGAPP is to recognize gains and losses for assets that are tracked on an individual basis." Are the gains and losses that are reported in lines 62 to 66 the losses that BC Hydro is referring to on p. 8-23 of the Application?

Gannett Fleming Report

153.0 Reference: Depreciation
Exhibit B-15: BCUC IR 1.306.1, BCUC IR 1.307.3.1
Gannett Fleming Depreciation Study
New Asset Component Useful Lives

In the comparison of the new component useful lives from the Gannett Fleming Depreciation Study, BC Hydro prepared a comparison with its peers as follows:

New Component Name	BC Hydro's Proposed useful life (years)	Peer #1 Proposed useful life (years)	Peer #2 Proposed useful life (years)	Peer #3 Proposed useful life (years)	Peer #4 Proposed useful life (years)
Cable, Submarine >= 60kV – Major Inspection	5	NA (1)	NA	NA	NA
Tower – Major Overhaul, Corrosion protection	30	NA (2)	45	NA	10
Cable, submarine, pumping plant and instrumentation	25	NA (3)	NA	NA	NA
Pole structure cross arms > 60 kV	30	37	35	NA	NA (3)
Distribution cutouts	25	30	35	NA	NA (3)
Instrumentation – Digital	25	26	25	15	10
Instrumentation – Analog	40	30	NA (4)	NA (4)	43
Penstock, steel – Coatings	25	NA	NA	NA (1)	NA (2)
Major Maintenance – Rewedging	25	33	NA (1)	NA (1)	25
Major Maintenance – Gas Turbines	7	NA (1)	NA (3)	NA	NA (3)
Buildings – Envelope (5)	30	NA (3)	40	55	65
Buildings – HVAC Systems and Components	15	NA (3)	NA (3)	10	15 - 20

NA – no corresponding asset class at peer utility

(1) Item is treated as operating cost
(2) Activity is not required
(3) Has not been separately componentized
(4) All analog instrumentation has been replaced with Digital instrumentation
(5) Nature of building components within asset class vary significantly among peer utilities.

153.1 From the above table, the following new components have no comparatives with any of BC Hydro's four peers: Cable, Submarine >= 60kV – Major Inspection; Cable, submarine, pumping plant and instrumentation; Penstock, steel – Coatings; and Major Maintenance – Gas Turbines. For each of the above four new components please justify why it is necessary for BC Hydro to segregate these components when none of their peers have.

153.1.1 Please quantify the depreciation impact from these four new components for the test period and their impact on the revenue requirement rate for each year.

153.2 From the above table, the following new components have lower proposed useful lives than any of its peers: Pole structures cross arms>60kV; Distribution cutouts; and Buildings – Envelope. For each of these three asset components, please justify why BC Hydro's asset useful life is consistently lower than its peers.

153.2.1 Please quantify the depreciation impact from these three new components for the test period using the upper and the lower range of the available useful lives of its peers group and the range of their impact on the revenue requirement rate.

153.3 In the response to IR 1.307.3.1, BC Hydro notes that the composite rates do not take into consideration the new asset component useful life for capital additions. Please confirm that the depreciation impact on the new asset component useful live in Schedule 18.0, line 14 includes the related depreciation impact on capital additions in Schedule 13.0.

153.3.1 If not, please quantify the depreciation impact dollar impact for the test period and its impact on the revenue requirement rate for each year.

L. CAPITAL STRUCTURE AND RETURN ON EQUITY

154.0 Reference: Rate Base
Exhibit B-1-3, Amended Appendix A, Schedule 10
Exhibit B-16, AMPC IR 1.18.2
Finance Charges and ROE

In response to AMPC IR 1.18.2 BC Hydro states: "Over the test period, total finance charges and total return on equity account for about the same portion of the total revenue requirement since the weighted average cost of debt multiplied by 80 per cent of rate base is approximately equal to the allowed rate of return on equity multiplied by 30 per cent of rate base."

154.1 Amended Appendix A Schedule 10 shows mid-year Rate Base during the test period of roughly $14 million. Given that 80% of $14 million Rate Base is $11 million and 30% of $14 million Rate Base is approximately $4 million how can the interest on $11 million be almost equal to a return on $4 million?

155.0 Reference: Return on Equity
Exhibit B-1-3, Amended Appendix A, Schedule 9
Exhibit B-15, IR 1.309.1
BC Hydro F2011 Financial Statements
Dividend to the Province & Other Comprehensive Income (OCI)

In response to BCUC IR 1.309.1 BC Hydro explains that part of the reason for the larger than forecast dividend to the Province is due to the higher than actual Accumulated Other Comprehensive Income.

BC Hydro's F2011 financial statements note 15: Other Comprehensive Income and Other Accumulated Comprehensive Income is as follows:

OTHER COMPREHENSIVE INCOME

(in millions)	2011	2010
Other Comprehensive Income		
Unrealized loss on derivatives designated as cash flow hedges	$ (24)	$ (150)
Reclassification to income on deriviatives designated as cash flow hedges	44	245
Other Comprehensive Income	$ 20	$ 95

Comprehensive income consists of net income and other comprehensive income (OCI). OCI represents the changes in shareholder's equity during a period arising from transactions and changes in the fair value of available for sale securities and the effective portion of cash flow hedging instruments. Amounts are recorded in OCI until the criteria for recognition in the consolidated statement of operations are met.

ACCUMULATED OTHER COMPREHENSIVE INCOME

(in millions)	2011	2010
Accumulated other comprehensive income (loss), beginning of year	$ 53	$ (42)
Other comprehensive income for the year	20	95
Accumulated Other Comprehensive Income, End of Year	$ 73	$ 53

Amended Appendix A, Schedule 9 (Exhibit B-1-3) reports F2011 and forecast F2012 Other Comprehensive Income as follow:

Return on Equity
($ million)

Line	Column	Reference	F2011 NSA-12	F2012 Update	F2013 Update	F2014 Update
			8	9	10	11
	Shareholder's Equity					
1	Retained Earnings - Begining of Year		2,679.1	2,806.9	3,238.0	3,696.2
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0
3	Gross Return on Equity	Line 49	588.4	594.5	566.4	599.1
4	Dividend to Province	Line 15	(346.4)	(163.3)	(108.2)	(181.9)
5	Distribution to Province		0.0	0.0	0.0	0.0
6	Retained Earnings - End of Year		2,921.1	3,238.0	3,696.2	4,113.4
7	Accum Other Comp Income		53.1	73.0	73.0	73.0
8	Total Shareholder's Equity		2,974.1	3,311.0	3,769.2	4,186.4

155.1 Please confirm, or explain otherwise that the $53.1 million and $73.0 million in F2011 and F2012 reported in Schedule 9 for AOIC are the same as reported in BC Hydro's F2011 financial statements.

155.2 Please confirm that the Dividend to the Province is partially driven by unrealized gains/losses on derivatives designated as cash flow hedges.

155.3 Does BC Hydro's cost of service model that determines the Revenue Requirement (Schedule 1) included 'realized' gains and losses on derivatives designated as cash flow hedges?

155.3.1 If not, why not?

155.3.2 If yes, in which Schedules in Amended Appendix A are forecast derivatives designated as cash flow hedges reported.

155.3.3 If yes, is there a deferral/regulatory account that would pick up the variance between forecast and actual? If yes, which deferral/regulatory account is it.

156.0 Reference: Prescribed Rate of Return
Exhibit B-16, IR 1.37.1
Exhibit B-1-3, Chapter 8, Section 8.5
Risk - ROE

156.1 Given the benchmark Return on Equity is now scheduled for a regulatory process (Order G-20-12), how does BC Hydro expect to handle changes to the ROE and its impact of BC Hydro's prescribed Rate of Return?

M. FINANCE CHARGES

157.0 Reference: Finance Charges
Exhibit B-15: IR 1.316.1, IR 1.316.5, IR 1.316.5.1, IR 1.316.5.2
Cash Requirements & Working Capital

In its response to BCUC IR 1.316.1, BC Hydro noted that there was an understatement of $0.5 billion in cash requirements in the original application and provided the following components of the cash requirements in the amended RRA:

$ billion	Total F12-F14 Change
Total Cash Requirements	
Error in Original Application [1]	0.5
Increase in Capital Expenditures [2]	0.3
Lower Dividends [3]	(0.1)
Increase in net Cost of Energy [4]	0.2
Cash flow impacts of Cost Reductions [5]	0.2
Working Capital & Other changes [6]	0.1
Total Increase in Cash Requirements	1.2

Notes:
[1] Subsequent to the original RRA filing, an error was discovered which resulted in the cash requirements for the original RRA being understated by approximately $0.5 billion over the test period. Procedures have since been put in place to mitigate the risk of similar errors re-occurring. The additional procedure includes another review step in the process where the cash flows are discussed between the Net Income forecast and Treasury analysts to better understand the inputs.
[2] Please refer to the response to BCUC IR 1.316.4 for explanation of the increase.
[3] See Amended Appendix A, Schedule 8.0, Line 2.
[4] Increase in the forecast Cost of Energy in the F2012 to F2014 period. See schedule 2.2, Line 9. These amounts are being deferred.
[5] See table above showing cash flow impacts of cost reductions.
[6] Mainly relates to the timing of expenditures and revenues.

157.1 What did the $0.5 billion error in cash requirements relate to?

157.2 As noted in BCUC IR 1.316.5, the change in Working Capital & Other between the original and amended RRA resulted in an increase in cash requirements of $0.9 billion. In the summary above, it shows that Working Capital & Other changes are now at $0.1 billion, a change of $0.8 billion. BCUC IR 1.316.5.1 and BCUC IR 1.316.5.2 requested supporting schedules to show the calculation of the Working Capital & Other amount and a forecasted balance sheet but this information was not provided. Please provide the following:

157.2.1 Please provide supporting schedules to show the compilation of the Working Capital & Other amounts shown in Amended Appendix A, Schedule 8.0, line 13.

157.2.2 Please provide the forecasted balance sheet for the test period used to derive the Working Capital & Other amounts.

158.0 Reference: Finance Charges
Exhibit B-16, BCOAPO IR 1.52.3
Exhibit B-15, IR 1.317
Exhibit B-1-3, Amended Table 8-1
Plan to achieve the rate decrease (Table 1-A) Lower Interest Rates
Updated Interest Rates

In response to BCOAPO IR 1.52.3, BC Hydro provided the following table on its timing and amounts of borrowing for the test period:

Borrowing Requirements						
	F2012		F2013		F2014	
	$ million	%	$ million	%	$ million	%
LTD Debt						
April 11, 2011 (Actual)	500	4.53				
June 6, 2011 (Actual)	500	4.32				
September 30, 2011 (Actual)	50	3.77				
October 27, 2011 (Actual)	300	3.8				
March	100	3.46				
June			850	3.65	725	4.3
September			875	3.65	750	4.3
ST Debt	685	0.97	327	1.26	929	2.2
Total	2,135		2,052		2,404	

The forecasted amended interest rates used in the Amended RRA are as follows:

Amended Table 8-1 Interest Rate and Exchange Rate Forecasts

		F12-F14 RRA			Amended F12-F14 RRA			Difference		
		F2012	F2013	F2014	F2012	F2013	F2014	F2012	F2013	F2014
		1	2	3	4	5	6	7 = 4 - 1	8 = 5 - 2	9 = 6 - 3
1	Canadian Short-Term Interest Rate (%)	1.66	3.01	4.20	0.97	1.26	2.20	(0.69)	(1.75)	(2.00)
2	U.S. Short-Term Interest Rate (%)	0.53	1.90	3.75	0.16	0.23	0.71	(0.37)	(1.67)	(3.04)
3	Canadian Long-Term Interest Rate (%)	3.94	4.85	5.85	3.46	3.65	4.30	(0.48)	(1.20)	(1.55)
4	U.S. Long-Term Interest Rate (%)	3.57	4.64	5.64	3.02	3.02	3.48	(0.55)	(1.62)	(2.16)
5	USD$/CAD$ Exchange Rate	0.986	0.984	0.976	0.994	0.996	1.004	0.008	0.012	0.028

158.1 The actual long term debt financing from April 11, 2011 to October 27, 2011 has come in at rates ranging from 3.8% to 4.53% compared to 3.46% used in the Amended RRA. The annualized actual interest cost compared to the forecasted interest cost on the long term debt issued is as follows:

($ million) Long Term Debt Issued	Interest rate	annual finance charges
$500	4.53%	$22.65
500	4.32%	21.60
50	3.77%	1.89

300	**3.80%**	**11.4**
$1,350		**$57.54**
$1,350	**3.46%**	**$46.71**
Increase in finance charges		**$10.83**

Please confirm the interest charges on the actual long term debt issues results in additional financing charges of $10.83 million on an annualized basis or correct otherwise.

158.1.1 Please quantify the total impact of the actual financing charges on the long term debt issued to date for the test period and its impact on the revenue requirement rates for each year in the test period.

158.2 For F2012, BC Hydro forecasted short term borrowings were estimated at $685 million. Has BC Hydro made any short term borrowing and if yes, at what interest rate?

158.2.1 If applicable, please quantify the total impact of the actual interest rate on short term debt compared to the forecasted short term debt for the test period and its impact on rates.

158.3 For the forecasted interest rates in the Amended RRA, please compare those rates to the most current market rates.

158.3.1 Using the most current market rates for forecasted long term and short term debt, please quantify impact on the RRA and its rates for each year.

158.3.2 What are the most recent forecast of interest and foreign exchange rates from the Province's Treasury Board?

159.0 Reference: Finance Charges
Exhibit B-15, IR 1.320.3.1
Growth Rate of Debt

In analyzing the trend analysis on finance charges in BCUC IR 1.320.3.1, BC Hydro noted that "although F2013 cash requirements were 7 per cent higher than F2012 cash requirements, total Net Debt (mid-year) increased by 14.7 per cent from $12,437.8 million to $14,272.1 million as a result of cash requirements for the year. The total volume of debt is a more significant driver of Gross Finance Charges than the annual change in cash requirements."

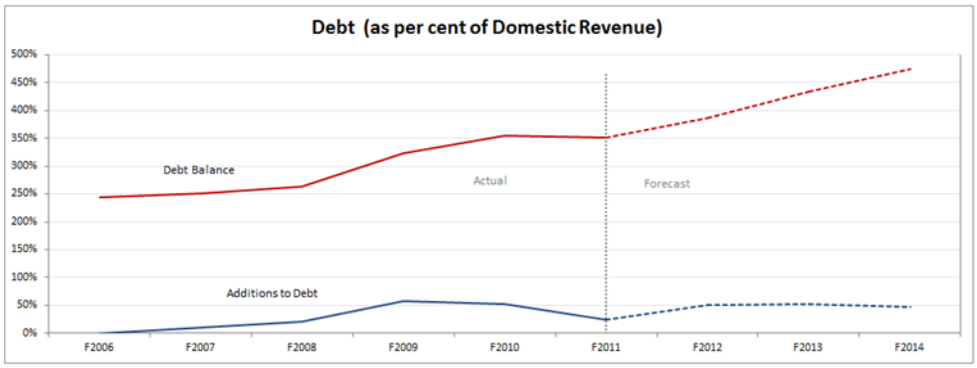
159.1 Please explain why the F2013 total net debt has increased by 14.7 percent when F2013 cash requirements have only increased by 7 percent.

159.1.1 What other factors would increase the volume of debt besides the cash requirements?

159.1.1.1 For each year within the test period, please provide a table showing a reconciliation of the cash requirements to the total volume of debt and identifying other factors impacting the volume of debt.

160.0 Reference: Performance Measures
Exhibit B-15, IR 1.351.1-1.351.3
Benchmarking

160.1 BC Hydro has modified the requested finance benchmarks by substituting the Total Annual Rate Revenue as the denominator (ref. IR 1.351.1). BC Hydro's rational is that is not meaningful to use the average number of customer accounts due to the variation in the size of customers. The use of Total Annual Rate Revenue in the denominator may be misleading due to the 48% increase in Total Annual Rate Revenue between F2006 to F2014. The large increase in Total Annual Rate Revenue has the effect of understating increasing debt levels. As an alternative, the following graph was prepared using Domestic Revenue as the denominator. Please confirm whether it is accurate and provide a revised version if it is not.



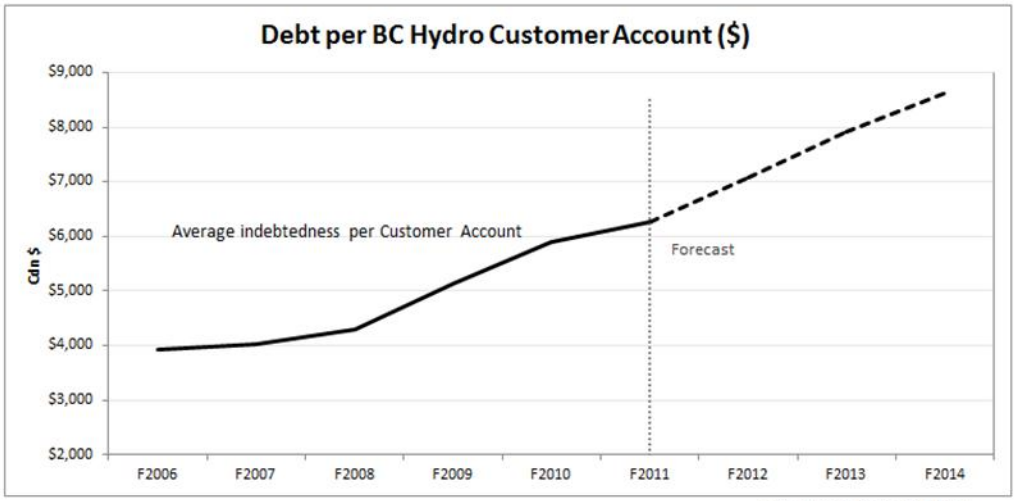
Data source: BCUC IR 1.351.1

Benchmark Inputs ($ millions)	F2006	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014
Debt account additions	N/A	289.4	602.6	1,616.3	1,561.0	823.7	1,724.2	1,832.6	1,668.8
Total net debt balance	6,627.0	6,916.4	7,519.0	9,135.3	10,696.3	11,520.0	13,244.2	15,076.8	16,745.6
Domestic Revenues	2,710.2	2,749.1	2,856.5	2,833.0	3,017.6	3,270.3	3,426.8	3,469.1	3,524.6

160.2 BC Hydro has stated that it would not be meaningful to provide financial metrics that use the total number of customers as the denominator due to the wide variation in the size of customers. Please reconcile this with BC Hydro's past benchmarking practices (e.g. reliability, customer satisfaction, operating costs) that specifically use the total number of customers as a basis to compare performance internally and among peer utilities.

160.2.1 Published reports by peer utilities in North America indicate that there is reliance upon benchmarking metrics that include the following: (iii) KWh sold per distribution end-user customer, (iv) installed MVA capacity per 1000 customers, (v) percent new customers, (vi) distribution line capital spending per end-use customer, (vii) capital spending per end-use customer, (viii) distribution O&M spending per customer. Please confirm whether BC Hydro is of the opinion that these metrics are meaningful or not.

160.3 The graph below summarizes the average level of debt that BC Hydro has incurred or is planning to incur on behalf of each of their customers. For example, it indicates that by the end of F2014 the average debt per customer account will be $8,627.00. In order to address BC Hydro's concern that there is a wide variation in the size of customer, please provide an updated version to the graph that segments the average debt per account into residential, commercial, and large industrial. Please also provide an electronic copy that includes tabular data and assumptions.



Data source: BCUC IR 1.351.1

	F2006	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014
Total net debt balance ($ million)	6,627.0	6,916.4	7,519.0	9,135.3	10,696.3	11,520.0	13,244.2	15,076.8	16,745.6
Average Number of Account	1,686,568	1,717,369	1,748,461	1,780,567	1,812,424	1,838,446	1,867,824	1,904,273	1,941,017
Average Debt per Customer ($)	3,929	4,027	4,300	5,131	5,902	6,266	7,091	7,917	8,627

N. TAXES

161.0 Reference: Taxes
Exhibit B-1-3: Amended Appendix A, Schedules 2.2 and 6.0
Regulatory Accounts – Total Taxes
Taxes

"… in the F09/F10 Decision the BCUC approved the establishment of a regulatory account to defer differences between actual and forecast school taxes and grants-in-lieu during F2009 and F2010, plus interest.

The F11 RRA NSA provided that this regulatory account be extended until the review of the valuation of BC Hydro's distribution system is complete and the impacts of BC Hydro's costs are determined." (Chapter 7, p. 19)

"As part of the plan to achieve rate increases of 8 percent in F2012 and 3.91 percent in F2013 and F2014, BC Hydro is proposing the refund in F2012 the credit balance of $13.4 million in the Total Taxes Regulatory Account at the end of F2011." Chapter 7, p. 19)

"… BC Hydro proposes that the Total Taxes Regulatory Account by closed after the refund of the credit balance in the account." (Chapter 7, p. 20)

"School taxes are based on the assessed value of taxable assets prepared by B.C. Assessment and school tax rates established by the Province." (Chapter 8, p. 7)

161.1 The following table is a summary of the variance between Total Taxes per RRA or NSA and Actual Total Taxes from F2009 to F2011. Please confirm that the following table is correct. If not confirmed, please provide an updated table.

	F2009 RRA	F2009 Actual	F2009 Variance	F2010 RRA	F2010 Actual	F2010 Variance	F2011 NSA	F2011 Actual	F2011 Variance	Reference
Grants in Lieu	58.77	58.95	0.18	61.42	62.04	0.61	64.84	64.69	- 0.15	Appendix A, Schedule 6.0, Row 17
School Taxes	109.64	107.79	- 1.85	116.65	110.56	- 6.09	116.55	111.19	- 5.36	Appendix A, Schedule 6.0, Row 18
IPP Capital Leases	-	-	-	-	-	-	1.60	1.54	- 0.06	Appendix A, Schedule 6.0, Row 19
Total Before Regulatory Accounts	**168.40**	**166.74**	**- 1.67**	**178.07**	**172.60**	**- 5.47**	**182.99**	**177.41**	**- 5.58**	

161.2 The following table is a summary of activity within the Total Taxes Regulatory Account, from F2009 (the fiscal year the account was established) to F2011. Please confirm that the table is correct. If not confirmed, please provide an updated table.

F2009 Actual Addition	- 1.67	Appendix A, Schedule 2.1, Column 2, Row 80 / Agreed to table per BCUC IR above
F2010 Actual Addition	- 5.44	Appendix A, Schedule 2.1, Column 3, Row 80 / Agreed to table per BCUC IR above
F2011 Actual Addition	- 5.58	Appendix A, Schedule 2.1, Column 5, Row 80 / Agreed to table per BCUC IR above
F2010 Actual Interest	- 0.30	Appendix A, Schedule 2.1, Column 3, Row 79
F2011 Actual Interest	- 0.40	Appendix A, Schedule 2.1, Column 5, Row 79
Total F2011 Actual Taxes Regulatory Account	**- 13.38**	Appendix A, Schedule 2.1, Column 5, Row 81

161.3 Based on the tables above, the majority of the variance (which subsequently becomes an addition to the Total Taxes Regulatory Account) between the RRA or the NSA Total Taxes and Actual Total Taxes relates to School Taxes. Please confirm during which month each year the value of taxable assets prepared by B.C. Assessment and school tax rates established by the Province are made available to BC Hydro.

161.3.1 Please confirm if the value of taxable assets prepared by B.C. Assessment or the school tax rates established by the Province are available for any of F2012, F2013 and F2014. If available, please provide the available information in the response.

161.3.2 Please provide the forecast school tax rates and forecast value of taxable assets for F2012, F2013 and F2014.

161.3.3 Please provide the actual value of taxable assets prepared by B.C. Assessment for F2007, F2008, F2009, F2010 and F2011.

161.4 The following table is a summary of Total Taxes from F2007 Actual to F2014 Plan. Please confirm that the table is correct. If not confirmed, please prepare an updated table.

	F2007 Actual	F2008 Actual	F2009 Actual	F2010 Actual	F2011 Actual	F2012 Plan	F2013 Plan	F2014 Plan	Reference
Grants in Lieu	48.72	54.53	58.95	62.04	64.69	67.72	72.11	77.48	Appendix A, Schedule 6.0, Row 17
% Increase, Grants in Lieu		12%	8%	5%	4%	5%	6%	7%	
School Taxes	98.33	104.05	107.79	110.56	111.19	114.22	119.02	123.14	Appendix A, Schedule 6.0, Row 18
% Increase, School Taxes		6%	4%	3%	1%	3%	4%	3%	
IPP Capital Leases	-	-	-	-	1.54	2.00	2.00	2.10	Appendix A, Schedule 6.0, Row 19
Total Before Regulatory Accounts	**147.05**	**158.57**	**166.74**	**172.60**	**177.41**	**183.94**	**193.13**	**202.72**	Appendix A, Schedule 6.0, Row 20

O. NON-TARIFF AND INTER-SEGMENT REVENUES

162.0 Reference: Non-tariff Revenues
Exhibit B-15: IR 1.324.1, IR 1.324.2
Exhibit B-16, BCOAPO IR 1.53.1
Exhibit B-1-3, Amended Appendix A, Schedule 15.0
Miscellaneous Revenue – Distribution Revenue
Plan to achieve rate decease Table 1-A miscellaneous revenue

In its response to BCUC IR 1.324.1, BC Hydro noted "as the result of the utilization of the Nature View presentation, $13.6 million was reclassified from recoveries to revenue and is included in the F2011 Actual column." Also, in response to IR 1.324.2, BC Hydro provided the components of the distribution revenues follows:

	$ million	F2011 Actual	F2012 Plan	F2013 Plan	F2014 Plan
1	Scrap Sales	8.8	6.0	6.0	6.0
2	Connection Revenue	2.1	1.1	1.1	1.1
3	Damage to Plant and House Moves	7.5	5.2	5.2	5.2
4	Secondary Use	2.2	2.1	2.1	2.1
5	NIA	0.5	-	-	-
6	Other	1.8	1.1	1.2	1.0
7	Total	22.9	15.5	15.6	15.4

162.1 Please extend the above table to provide the comparatives for F2008 to F2010 on the nature view presentation basis (i.e. include reclassified recoveries).

162.2 The revenue for F2012 has dropped by $7.4 million per year compared to actuals for F2011 as a result of lower scrap sales ($2.8 million), lower damage to plant and house moves ($2.3 million), lower connection revenue ($1 million) and other. If the F2011 actuals were used to estimate the revenue from scrap sales, connection revenue and damage to plant and house moves, this would increase the miscellaneous revenues for the test period by $18.3 million. Please justify why scrap sales, connection revenue and damage to plant and house moves should not be estimated based on the F2011 actuals.

162.2.1 Please quantify the impact on rates if $18.3 million in miscellaneous revenues was added to the RRA and determine its impact for each year within the test period.

162.3 Between the original application and the amended application, the increase in miscellaneous revenue of $23 million was mainly attributable to the change in distribution revenues. In its response to BCOAPO IR 1.53.1, BC Hydro noted that "was an error for Distribution non-tariff revenue. This was corrected in Amended Schedule 15.0". However, the F2011 distribution revenues increased by $13.6 million as a result of the reclassification of recoveries from operating expenses as noted in the response to IR 1.324.1. Of the $23 million in increased miscellaneous revenues, how much is attributable to the reclassification of recoveries and how much is due to real growth in miscellaneous revenue?

P. CHAPTER 9 OATT & ALLOCATION OF CORPORATE COSTS FOR TRANSMISSION RR

No IR's Deemed Necessary

Q. SUBSIDIARY NET INCOME (POWEREX) & ALLOCATION OF PTP CHARGES TO POWEREX

163.0 Reference: Powerex
Exhibit B-1-3, Amended Appendix M – Transfer Pricing for Renewable Energy Credits
Renewable Energy Credits
Annual cost of Carbon Offsets

BC Hydro purchased 30,000 tonnes of carbon offsets from the Pacific Carbon Trust to achieve carbon neutrality in its corporate operations (direct and indirect emissions from buildings, fleet vehicles and paper use) for calendar year 2010 as per the B.C. Carbon Neutral Government Regulation. At the posted price of $25 per tonne, carbon offsets cost BC Hydro $750,000 per year.

BC Hydro has, in response to Provision 9(vi) of the F11 RRA NSA, signed an October 17, 2011 transfer price mechanism for Renewable Energy Credits (RECs) under which no transfer price will be charged to Powerex during a given year unless the net income of Powerex for that year is greater than $200 million.

163.1 Can the RECs be utilized under the Pacific Carbon Trust's BC Fuel Switching GHG Protocol, or any similar arrangement, to replace the purchase of carbon offsets? Would it be more beneficial to BC Hydro ratepayers to utilize the RECs to replace the purchase of carbon offsets? Would it be more beneficial to BC Hydro ratepayers to sell the RECs to other Crown entities rather than providing the RECs to Powerex at no cost?

164.0 Reference: Allocation of PTP Charges to Powerex
Exhibit B-15: BCUC IR 1.331.2, BCUC 1.327.1 Attachment 1; Exhibit B-1-3, Amended Appendix A, Schedule 3.0
Point to Point Revenue Calculation - Clarification

BC Hydro provided the following table in its response to IR 1.331.2 on its internal PTP revenue in the TRR:

The table below summarizes BC Hydro's forecast PTP volumes and revenues.

Line No,	B.C.Hydro - $ million	Reference	F2012	F2013	F2014
1	Skagit -230 MW Long Term PTP		11.8	12.3	12.7
2	Other - BC Hydro Long Term PTP		29.6	31.0	31.9
3	Other - BC Hydro Short Term PTP		7.3	7.3	7.3
4	**Total Point to Point**	**Sch 3.4 L65**	**48.7**	**50.6**	**51.8**
	BC Hydro Volumes (in MWh's)				
5	Skagit -230 MW Long Term PTP		2,020,320	2,014,800	2,014,800
6	Other - BC Hydro Long Term PTP		5,085,936	5,072,040	5,072,040
7	Other - BC Hydro Short Term PTP		2,287,866	2,287,866	2,287,866
8	**Total PTP Volume**	**Sch 3.4 L53+L56**	**9,394,122**	**9,374,706**	**9,374,706**
	BC Hydro $MWh				
9	Skagit -230 MW Long Term PTP	Sch 3.4 L53	$ 5.82	$ 6.11	$ 6.28
10	Other - BC Hydro Long Term PTP	Sch 3.4 L53	$ 5.82	$ 6.11	$ 6.28
11	Other - BC Hydro Short Term PTP	Sch 3.4 L52	$ 3.21	$ 3.21	$ 3.21

BC Hydro notes that the revenue shown for Skagit on line 1 of this table differs from Amended Appendix A, Schedule 3.0 line 40. The total PTP revenue from BC Hydro is correct as filed and the Powerex PTP revenue shown on Schedule 3.0 line 39 is also correct.

The PTP revenue in Amended Appendix A, Schedule 3.0 and from BCUC IR 1.327.1 Attachment 1 is as follows:

PTP Revenue	F2012	F2013	F2014	
Powerex PTP	25.5	26.2	27.0	Amended Appendix A, Sch 3.0, l.39
BC Hydro PTP (Skagit)	11.1	11.1	11.1	Amended Appendix A, Sch 3.0, l.40
Distribution PTP	12.1	13.3	13.7	BCUC IR 1.327.1 Attachment 1, l.11
	48.7	50.6	51.8	

164.1 There is a cumulative difference of $3.5 million in the BC Hydro PTP (Skagit) revenues in the above Table in the response to IR 1.331.2 and Amended Appendix A, Schedule 3.0, line 40. Please reconcile and explain the difference.

164.1.1 BC Hydro notes that the amounts in Amended Appendix A, Schedule 3.0 are correct. Does that mean that either the volumes used above or the calculated OATT PTP rate used to derive the BC Hydro (Skagit) revenue is incorrect? Please explain.

164.2 Please explain how the Other - BC Hydro Long Term PTP and Other – BC Hydro Short Term PTP in lines 2 and 3 from the table above are allocated between Powerex PTP and Distribution PTP.

164.2.1 Please explain how the Powerex PTP volumes are forecasted for the test period.

R. INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

<u>IFRS Potential REGULATORY ACCOUNT – IFRS Transition</u>

165.0 Reference: IFRS PP&E Regulatory Accounts
Exhibit B-1-3, Chapter 8, Section 8.14.2
Exhibit B-15: IR 1.334.1, IR 1.336.7, IR 1.5.1
Additional Impact of IFRS to Deferral Balance

The F2011 RRA was filed as a one year RRA because of the anticipated changes due to IFRS. Starting April 1, 2012 BC Hydro will be reporting under IFRS. In response to BCUC IR 1.334.1 BC Hydro has outlined the IFRS accounting changes that were addressed in the Application. In addition it has identified several additional transition adjustments that it anticipates applying to the Commission for in Q1 F2013 to be recorded in the IFRS Transition Regulatory Account for recovery after the test period.

165.1 Given the material nature of IFRS adjustments, why did BC Hydro not provide the FULL IFRS transition impact in the F2012-F2014 RRA or ARRA?

In response to BCUC IR 1.336.7 BC Hydro has stated that they anticipate filing an application with the Commission in Q1 for the inclusion of IFRS impact into the IFRS Transition Regulatory account and/or some of the existing regularly accounts for recovery after the test period. BC Hydro has forecast that this will likely exceed $100 million dollars.

165.2 In response to BCUC IR 1.5.1 BC Hydro confirmed a table outlining the forecast balance in the Deferral and Regulatory accounts on a test year by test year basis. Please update the table to reflect BC Hydro's best forecast of additional deferrals related to IFRS.

New EPA Capital Leases under IFRS
FILED CONFIDENTIALLY

Reduction in Capitalized Overhead

166.0 Reference: Reduction in Capitalized Overhead
Exhibit B-1-3: Chapter 8, Section 8.14.2; Amended Appendix A, Schedule 5
Exhibit B-15, IR 1.342.1
DCAT, BCUC IR 1.55.1
Planned Capital Overhead Amount vs. COH

BC Hydro states "The Capital Overhead (COH) rate is established at the beginning of each fiscal year for each of BC Hydro business groups and is determined by dividing the planned capital overhead amount by the planned capital expenditures eligible for COH." (DCAT BCUC IR 1.55.1)

Amended Schedule 5, line 16, columns, X, Y, and Z show the amount of Operating costs that are planned to be capital overhead under CGAPP in the three test periods. BC Hydro states in the Application that only $100 million is directly attributable to Capital and under IFRS the difference is to be expensed in the test periods. To reduce the impact on rates BC Hydro is proposing that the difference between the amount eligible for capitalization under CGAPP and IFRS will be tempered into rates through the use of a deferral account as outlined in the table in response to BCUC IR 1.342.1.

166.1 Please confirm, or explain otherwise, that the Capitalized overhead study will used to determine if the $100 million is the correct amount that is eligible for capitalization (the Planned Capital Overhead Amount from the DCAT quote above) and does not determine the Capitalized Overhead (COH) rate.

166.2 Please confirm, or explain otherwise, that the planned Capital Overhead Amount under CGAPP for the test periods is currently around 27% (Amended Schedule 5, line 16, divided by the sum of lines 10-15 for columns X, Y, Z) and BC Hydro is expecting the results of the new Capitalized Overhead study to produce Capital Overhead Amount of approximately 10% ($100 million divided by the sum of Amended Schedule 5, lines 10-15 for columns X, Y, Z).

166.3 Please confirm, or explain otherwise, that the Capital Overhead (COH) Rate which is apply to capital expenditures is the amount from Amended Schedule 5, line 16 divided by the planned capital expenditures for the year (business group) and will change in each of the test years depending on the amount of forecast capital expenditures.

166.4 Please confirm, or explain otherwise, that if capital expenditures were greater than forecast in the Revenue Requirements BC Hydro would eventually recover (depreciation and ROE) in rates more than the Planned Capital Amount (Schedule 5, line 16) forecast in the Application. And if forecast capital expenditures were less than forecast in Revenue Requirements BC Hydro would recover less as show in the variance columns in Schedule 5, line 16.

166.5 Please confirm or explain otherwise that the amount of Actual Capitalized Overhead reported in Schedule 5, line 16, for F07-F11 agrees to the actual amount of Overhead Capitalized to Capital Expenditures in each of those years.

167.0 Reference: IFRS PP&E Regulatory Account
Exhibit B-1-3, Chapter 8, Section 8.14.2
Exhibit B-15, IR 1.341.3, IR 1.342.1
COH and IDC - Financing Costs

1.341.3 How much current financing costs will be attributed to this proposed regulatory account in each of the test periods?

RESPONSE:

Please refer to the table below for the amount of current financing costs that relates to the proposed IFRS PP&E Regulatory Account in each of the test periods.

$ million		Forecast	
	F2012	F2013	F2014
IFRS PP&E Regulatory Account			
End of Year Balance (Amended Appendix A, Schedule 2.2, Line 125)	186.0	341.5	475.2
Mid-Year Balance	93.0	263.8	408.4
Current Financing Costs (Line 2* Line 4)	4.4	12.1	18.7
Interest Rate (Amended Appendix A, Schedule 2.2, Line 168)	4.75%	4.57%	4.59%

167.1 What would the impact be on rates be in each of the test periods if the IFRS PP&E Regulatory account was not approved and the amounts were expensed in each of the test periods as required under IFRS (for both IDC and COH)?

167.2 Please confirm that at the end of F2022 BC Hydro has forecast that the ending balance in the Regulatory Account will be 813.7 million. (BCUC IR 1.342.1)

167.3 Assuming the interest rate remains the same as in F2014, what will the cumulative financing charges be on the proposed IFRS PP&E Regularly account between F2012 and F2022?

167.3.1 Assuming an interest rate increase to 5.59% in F2015 – F2022?

167.3.2 Assuming an interest rate of 6.65% in F2015 – F2022, the average rate of F2008-F2010?

167.4 Assuming the interest rate remains the same as in F2014 what will the cumulative financing charges be on the proposed IFRS PP&E Regularly account between F2012 and F2042 when to account is fully amortized?

168.0 Reference: IFRS PP&E Regulatory Account
Exhibit B-1-3, Chapter 8, Section 8.14.2
Exhibit B-15: IR 1.342.1, 1.342.3
Depreciation Rate

1.342.3 Has BC Hydro considered declining the amortization period each year so that by year 10 the deferred amount if fully amortized. For example year one additions would have an amortization period of 9 years, year 2 additions and amortization period of 8 years, and so on. Please discuss this option.

RESPONSE:

BC Hydro did not consider this option.

Based on the description, during the 10-year period, BC Hydro's recovery of costs would be accelerated, rate increases would be more pronounced, and rates would generally be higher than would result under CGAAP and under BC Hydro's current proposal.

168.1 Please prepare a table similar to the one in BCUC IR 1.342.1 incorporating an amortization period of ten years (resulting in a closing balance of 0$).

168.2 Based on an interest rate equal to F2014, what would the total finance costs be between F2012 – F2014 if a ten year amortization period were incorporated?

168.3 Based on an interest rate equal to F2014, what would the total finance costs be between F2012 – F2022 if a ten year amortization period were incorporated?

168.4 What would the incremental impact on rates be in F2012, F2013, and F2014 if the amortization period was reduced from 40 year to 10 years?

<u>Pension and Other Post Retirement Benefits</u>

SEE SECTION H, PENSION

Mass Asset Retirement
SEE SECTION K, DEPRECIATION

IDC Capitalization

169.0 Reference: IFRS PP&E Regulatory Account
Exhibit B-1-3, Chapter 8, Section 8.14.6
Exhibit B-15, IR 1.342.1
IDC Capitalized

BC Hydro is proposing to put in the IFRS PP&E Regulatory account $8 million in F2012. On page 8-24 of the Amended Application BC Hydro states that there also $11 million in F2013 and $13 million in F2014. The table confirmed in response to BCUC IR 1.342.1 shows a onetime addition of $8 million.

169.1 What is the treatment of the $11 million in F2012 and $13 million in F2014?

169.2 Are they included in forecast finance costs (expensed in the test period)?

169.2.1 If yes, why was the same treatment not proposed for the $8 million in F2012?

169.2.2 If no, where are the $11 and $13 million being deferred?

S. BENCHMARKING

170.0 Reference: Performance Measures
Exhibit B-15-1: IR 1.345.1
Trend Analysis, Benchmarking and Cost Consciousness at BC Hydro
Benchmarking

The February 2011 Navigant Consulting report attached to the response to BCUC IR 1.345.1 provided operational cost comparison data for BC Hydro Generation relative to other utilities, various findings and related commentary. Notable extracts from the reports and associated IR(s) are:

Operations: The stations with fully-staffed control rooms (GMS and Revelstoke) performed at expected levels. There may be opportunities for performance improvement here. Other leaders who have reduced the number of operators or broadened the roles of their operations staff to perform certain maintenance activities to support maintenance staff have reduced their operations costs.

170.1 Please indicate if the roles of the GMS operators will be broadened to perform certain maintenance activities to reduce maintenance costs. If not, please explain the reasons why and also address why the GMS Operations model is different from the REV model.

Plant Maintenance: All stations benchmarked were at or below expected levels when costs were compared within their respective peer groups. With the exception of Revelstoke, plant performance levels were poorer than their peers, especially in plant availability. Cost and plant performance declines may indicate plant maintenance activities may need to be adjusted to improve overall plant maintenance performance. Of particular concern is GM Shrum, whose cost increases and plant performance declines may indicate that action is necessary to reverse negative performance trends.

170.2 Please explain if plant availability is lower at GMS, JOR and LB1 than at REV and the peer group studied on purpose, in order to balance cost and availability.

Other Maintenance: Waterways & Dams maintenance costs were better than expected for Jordan River and Lake Buntzen One but poorer than expected for GM Shrum and Revelstoke. GM Shrum and Revelstoke were the two highest cost stations in the peer group. Buildings & Grounds maintenance costs were about average for GM Shrum and Revelstoke, but the smaller stations fell into the highest cost quartile.

170.3 Please explain why GMS and REV costs would be the highest costs in the peer group.

170.4 Please explain why JOR and LB1 would have high quartile buildings and grounds maintenance costs.

Investment: The average investment spending per MW capacity over the last five years for BC Hydro's generating stations was higher than average for all stations except Revelstoke. The profile for the expenditures, concerning where the money was spent, was different than the panel averages for the generating stations. BC Hydro spending, overall, has increased dramatically for all stations when compared to earlier benchmarks. Plant performance problems identified in the maintenance section may be indicative of historically low levels of investment over many years. Increased levels of investments over the last five years may begin to address these maintenance performance problems.

170.5 Please discuss if increased capital spending is providing positive results (in terms of lower maintenance costs and improved performance) and provide an order of magnitude estimate of the anticipated reduction in operating and maintenance costs for the subsequent test period.

170.6 Please discuss if the lower levels of investment spending at REV is due to its age relative to the test group or other factors.

Support: BC Hydro support costs are slightly higher than the industry average, as measured by this program. Other leaders have shown that support costs can be reduced by: Improved visibility and control over support costs that are passed on to the projects is the first step in getting a handle on costs. Flattened management structures for support services provider organizations have eliminated bureaucracy and reduced costs for some utilities. Sharing of support services with other organizations can reduce overall support costs. Decentralizing and moving certain support services to the line organizations (i.e., purchasing, warehousing, human resources) decreased overall costs.

170.7 Please discuss why support costs would be higher than the industry average. Is the report suggesting that BC Hydro support services may be top heavy in the areas of management structure and overall bureaucracy?

170.7.1 Are there similar findings/observations in the 2011 Government Review of BC Hydro to suggest BC Hydro has high support costs? Please discuss.

170.7.2 Please discuss BC Hydro's plans to reduce support costs over the immediate and beyond the test period time horizon.

Engineering Services: BC Hydro's engineering expenditures were above average for all stations. Given the significantly increased level of investment at the stations, higher than average engineering charges are to be expected.

170.8 Please discuss when the current investment spike is anticipated to level off i.e. in 5, 10 or more years.

170.9 Please any provide details not mentioned above on the useful direction that BC Hydro received from the Navigant Consulting report, and how action has or will be taken as a result, including cost implications.

170.10 Please indicate the period of the data collected in the February 2011 report, when BC Hydro anticipates participating in a similar comparison study in the future, and what similar generation operational cost reporting BC Hydro will include in its next RRA filing.

171.0 Reference: Performance Measures
Exhibit B-15-1, IR 1.346.1
Performance Measures at BC Hydro
Benchmarking

BCUC IR 1.346.1 requested Electric Utilities Costing Group benchmarking studies as these were anticipated to contain useful operational cost comparisons to other utilities. The five reports submitted in response to this IR contain reliability related information.

171.1 Please provide copies of any operational cost comparisons, internal, external, or third party peer reviews that BC Hydro has done or participated in over the last five years, for transmission and distribution costs.

171.2 Please provide copies or any transmission operational cost comparisons, internal, external, or third party peer reviews that BCTC did or participated in over the last five years of its existence.

171.3 Please indicate when BC Hydro anticipates undertaking and/or participating in transmission and/or distribution operational cost studies in the future, and what similar operational cost reporting BC Hydro will include in its next RRA filing.

172.0 Reference: Performance Measures
Exhibit B-15-1: IR 1.346.1, IR 1.347.1
Expert Testimony
Benchmarking

The response to BCUC IR 1.347.1 indicates one of the prime reasons that BC Hydro has not participated in any corporate wide costing studies in the last few years is the lack of meaningful data in recent studies. The response also raises the issue of comparability of utilities operating in various business and/or regulatory environments, as well as the issue of lack of comparability due to confidential masking of the other participants in studies.

The response indicates that the BC Hydro T&D operations group see benchmarking as a useful tool for identifying potential areas of improvement, identifying areas that do not require further investment or change effort and finally for keeping track of trends within the utility sector, and references the confidential response to BCUC IR 1.346.1.

The response also indicates that BC Hydro will be undertaking some benchmarking studies to report back to the Government on its progress in undertaking work related to the Government Review Recommendations.

172.1 Please indicate whether the comparability issue, utilities operating in various business and/or regulatory environments, means there are no costs of and/or benefits from work activity undertaken at BC Hydro that can be compared to any other utility. Please indicate if the answer is different when the other utilities can be identified.

172.2 Please provide, on a confidential basis if required, the specific references to operational (not reliability) cost comparisons in the reports supplied in response to BCUC IR 1.346.1.

172.3 Please indicate when the benchmarking studies being undertaken to report back to the Government on BC Hydro's progress will be available and filed as part of this Application.

173.0 Reference: Performance Measures
Exhibit B-15-1, BCUC IR 1.349.1
Benchmarking: Labour and G&A
Benchmarking

"The Enterprise Strategy Department, which was eliminated as part of the workforce reductions in October this year (please refer to section 5.7.7.4 in the Amended Application), previously undertook work associated with corporate wide cost benchmarking."

173.1 Please provide copies of all corporate wide cost benchmarking done prior to the elimination of the Enterprise Strategy Department.

174.0 Reference: Performance Measures
Exhibit B-15, IR 1.348.3, IR 1.349.2, IR 1.350.2, and IR 1.351.2
Benchmarking

"For each of the following utilities, please provide the same benchmark information as the question above for the most current reported 5-year historical period: (1) Hydro Quebec; (2) FortisBC; (3) New Brunswick Power; (4) Portland General Electric; (5) Nova Scotia Power. Please also prepare graphical and tabular summaries that compare BC Hydro to these five utilities."

174.1 BC Hydro has acknowledged that it does not have the necessary data to provide the requested benchmark comparisons with other utilities. Please provide an estimate of the cost and time required to perform a benchmark study that includes the requested information as outlined in the above referenced IRs.

T. STATUS OF PAST DIRECTIVES

No IR's deemed necessary

U. GM SHRUM 3

175.0 Reference: GMS 3 Cost of Repair
Exhibit B-15: 1.392.1; CONFIDENTIAL 1.392.4
$29.5 million Net Opportunity Cost
Lost Export Revenue and Cost of Forced Import

'The "opportunity cost of lost capacity" is more fully stated as the "value of lost export revenue and cost of forced imports resulting from the loss of capacity associated with the Unit 3 outage".'

175.1 Please provide separate calculations for each of the lost export revenue and the cost of forced imports in the style of the spreadsheet provided in the response to BCUC 1.392.4. Please also explain BC Hydro's definition of "forced imports".

176.0 Reference: GMS 3 Cost of Repair
Exhibit B-15, 1.392.2
$29.5 million Net Opportunity Cost
Value of stored water

"The cost of the outage depends on both the value of lost capacity during the outage and the offsetting value of the energy retained in storage after the outage was complete."

176.1 Please explain why the offsetting amount is the value of energy retained in storage, rather than the amount of energy and plus the associated capacity value from the repaired unit.

177.0 Reference: GMS 3 Cost of Repair
Exhibit B-15, 1.8.1
$29.5 million Net Opportunity Cost

Cost of energy variances arise as a result differences between forecast and actual for the following three components: differences in load, differences in source of supply, and differences in cost of supply.

177.1 Please confirm or explain otherwise that the opportunity costs is a variance in Costs of Energy as a result in a difference between actual to forecast Cost of Energy relating to source of supply.

															$ 247.7
As provided by BCH - BCUC IR 1.8.1															
Heritage Deferral Account															
	Opening Balance	Energy	Commodity Risk (gains/losses on derivatives)	Notional Water Rental	Skagit and Ancillary Revenue	Load Curtailment	Transfer to GMS 3	Other	total adjustments	Amortization	Interest	Ending Balance			
F2005	$ -	$ 139.2	-$ 22.8	$ 10.7	$ 3.5	$ -	$ -	$ 0.3	$ 130.9	$ -	$ 7.0	$ 137.9			
F2006	$ 137.9	$ 62.9	$ 29.7	-$ 0.2	$ -	$ -	$ -	$ -	$ 92.4	$ -	$ 10.4	$ 240.7			
F2007	$ 240.7	-$ 34.6	$ 4.2	$ 4.9	$ 1.0	$ -	$ -	$ 1.1	-$ 23.4	-$ 53.3	$ 14.1	$ 178.1			
F2008	$ 178.1	-$ 58.0	$ 1.9	-$ 2.9	$ 5.0	-$ 5.0	$ -	$ 2.8	-$ 56.2	-$ 50.2	$ 6.3	$ 78.0			
F2009	$ 78.0	$ 192.6	$ 91.4	$ 0.7	-$ 5.4	$ -	-$ 21.2	$ 1.5	$ 259.6	-$ 22.6	$ 13.9	$ 328.9			
F2010	$ 328.9	$ 8.2	-$ 10.7	$ 9.3	$ 3.2	$ -	-$ 8.3	$ 1.4	$ 3.1	-$ 29.3	$ 22.2	$ 324.9			
F2011	$ 324.9	-$ 33.5	$ 1.1	$ 1.6	$ 3.4	$ -	$ -	-$ 0.5	-$ 27.9	-$ 62.7	$ 13.4	$ 247.7			
TOTALS		$ 276.8	$ 94.8	$ 24.1	$ 10.7	-$ 5.0	-$ 29.5	$ 6.6	$ 378.5	-$ 218.1	$ 87.3	$ 247.7			

177.2 In response to BCUC IR 1.8.1 BC Hydro provide the data in the above table. Please confirm, or explain otherwise, that the $29.9 relating to the Net Opportunity Costs is the total from the column titled "Transfers to GMS 3".

177.3 Please confirm, or explain otherwise, that the $29.5 million relates to a Cost of Energy variance and is reflected in the Energy column in the table provided above.

177.4 If the $29.5 GMS 3 COE variance was captured in the Energy column in the table above, which specific cost component in Schedule G, BC Hydro Deferral Account Report for the year end March 21, 2008 does this variance relate to?

177.4.1 If it does not relate to a specific cost component listed in Schedule G, BC Hydro Deferral Account Report for the year end March 21, 2008, what authorization did BC Hydro have to record the variance in the HDA in the first place?

177.5 Please confirm, or explain otherwise, that if the BCUC Reasons for Decision in the F09/F10 RRA directed BC Hydro to segregate all the GMS 3 direct and indirect costs.

178.0 Reference: GMS 3 Cost of Repair
Exhibit B-15: CONFIDENTIAL BCUC 1.392.4
$29.5 million Net Opportunity Cost
Lost Export Revenue and Cost of Forced Import

178.1 The calculation of the value of lost export revenue appears to assume that exports would occur in each instance that exports were occurring and incremental exports were possible. Is this interpretation correct, and if so, how are market constraints factored into this analysis? Does the market have the ability to take whatever volume BC Hydro is willing to put into the market at the prices indicated?

178.2 Please explain why the range of data in LLH EMO (capped by outage capacity) is much greater than the capacity of GMS 3 and is sometimes a negative value, and why the HLH EMO (capped by outage capacity) does not have either characteristic.

<u>Engineering</u>

179.0 Reference: GMS 3 Cost of Repair
Exhibit B-1-3, Appendix AA, Attachment 13 – Project Completion Report, p. 447
Exhibit B-15, CONFIDENTIAL 1.391.1
Cost of Unit Disassembly and Reassembly
Selection of Competitive Bids

"After the investigations were completed and the extent of damage to the turbine components was known, Voith proposed a re-assembly cost greater than $6.0M. Following detailed negotiations with Voith it was decided to proceed with this work on a cost plus basis. The reassembly was successfully completed for a cost of $5.0M." (Exhibit B-1-3)

"The Voith Siemens was a cost plus proposal. No estimate of costs from Voith Siemens was received; however, BC Hydro relied upon an internal cost estimate prepared by BC Hydro engineering staff of $1.452 million for unit disassembly and partial reassembly and $2.028 million for complete unit reassembly, with both of these estimates reflecting un-inflated costs without contingency." (Exhibit B-15)

179.1 Please explain if Voith Siemens was awarded the work before the investigations were completed.

179.2 Please explain how BC Hydro evaluated the bids of Alstom and Weir/American Hydro in selecting Voith Siemens as the successful bidder. Please provide the bid analysis materials.

V. GOVERNMENT REVIEW AND BC HYDRO'S RESPONSES

Reporting

180.0 Reference: BC Hydro Initial Response to Government Review
Exhibit B-15-1, BCUC IR 1.409.1
Revised 5 year plan, 10 year capital plan and long term rate increase forecast
Reporting

"In the Spring of 2012 (early fiscal 2013), a revised 5 year plan will be presented to the Board and the Minister, as well as a 10 year capital plan and a long term rate increase forecast." [Response #1]

BCUC IR 1.409.1 asked if BC Hydro would be filing, as part of this Application and prior to the beginning of the Oral Hearing, the revised 5 year plan, 10 year capital plan, and long term rate increase forecast. The BC Hydro response did not answer the question.

180.1 Please provide the current status, percentage completion, and expected completion date for each of the revised five-year plan, ten-year capital plan, and long-term rate increase forecast.

180.2 Please explain if BC Hydro will be filing any or all of these documents with the BCUC prior to the Oral Hearing phase of this application.

Operational Efficiencies

181.0 Reference: BC Hydro Initial Response to Government Review
Exhibit B-15-1, IR 1.414.1
IT Project benefits and efficiencies
Plan to achieve rate decrease

Recommendation 11 of the Government Review recommended BC Hydro "Implement stronger commitment and oversight to the Information Technology and Telecommunications Plan to change business processes necessary to ensure benefits and efficiencies are fully achieved during this rate period." BC Hydro's response was that "The projects will ensure that the benefits and efficiencies will be delivered as planned."

The Amended F12-F14 RRA reflects changes to Corporate Costs from the original Application resulting in cost increases of $21.9 million due to reduced corporate-wide savings from IT&T projects, procurement and other initiatives." (Section 5.7.9)

The response to BCUC IR 1.414.1 explained the Corporate-wide savings from IT&T projects, procurement and other initiatives represented anticipated savings that have not yet been allocated to the business groups, and referred to the responses to BCUC IR 1.150.1 for an explanation of savings realization and BCUC IR 1.154.1 for an explanation of the net reduction in savings of $21.6 million.

There is no explanation in the responses to IR 1.150.1 and 1.154.1 that explains the net reduction in savings of $23 million other than the wording "Indirect savings (e.g., process improvements and operational efficiencies) are also expected but are not quantified in the form of budgets. BC Hydro

reports actual expenditures relative to budgets, and not relative to the projected savings for the individual projects."

181.1 Please confirm BC Hydro does not track and report the savings from IT capital projects that were part of the project justification and approval process.

181.2 Please explain the decision making process for approving IT capital projects and how the "value" of these projects justifies the expenditures, and if cost reductions are part of the "value".

181.3 Please describe how BC Hydro tracks and reports the achievement of "value" or "benefit" on any capital projects.

Labour Costs

182.0 Reference: BC Hydro Initial Response to Government Review
Exhibit B-15-1, IR 1.439.2
Changes in Organization Structure
Labour – Growth Trend

In the response to BCUC IR 1.439.2 BC Hydro stated all executives **that report to the CEO** are paid within the "executive" salary range and do not belong to a pay grouping, and that all other senior managers in the table are paid at M&P (management and professional) pay grouping 47, which is the highest of the pay grouping categories that range from 40 to 47. [emphasis added]

The November 4, 2011 organization chart on page 1 of 5 of Amended Appendix V indicates 6 "BC Hydro" VP level direct reports to the CEO, for a total of 7 executive in the "executive" salary range. There are 10 VP level and 2 Executive Director positions, on the same organization chart, that report to positions reporting to the BC Hydro CEO; a total of 19 positions. The President & CEO of Powerex is excluded from this count since Powerex FTE and salary are not included in this Application.

The table on page 2 of 2 on the response to BCUC IR 1.439.2 shows 19 CEO, VP level and Executive Director positions as of November 11, 2011 (F2012), again not including the President & CEO of Powerex.

In the response to BCUC IR 1.95.5 BC Hydro stated the types of positions that are included in the Executive SLR **include** CEO, Executive VPs, VPs, Senior VPs and Executive Directors. [emphasis added]

In the response to BCUC IR 1.95.6 BC Hydro indicates 18 employees that received VP salary treatment including one who was on leave, for a net 17 active employees as at the end of F2011.

In the response to BCUC IR 1.103.1 BC Hydro indicated for the "executive" salary level there were 11 FTE for F2008, 21 FTE for F2011 and F2012. Note these are FTE and not the headcount of the other responses and therefore could be higher due to overtime.

In the response to BCUC IR 1.104.3 BC Hydro indicates in the table on page 2 of 6 of the response a total of 24 headcount for "executive" as at the end of F2011.

In the response to BCUC IR 1.99.1 the headcount for BC Hydro and BCTC is 5,313 for F2008. In the response to BCUC IR 1.89.1 the headcount is 5,832 and the FTE are 5,805 for F2011, a difference of 27. In Schedule 16 of Appendix A the F2012 Update FTE are 5,909+143+85=6,137 plus the 27 adjustment to yield a projected 6,164 headcount. The anticipated increase in total headcount from F2008 to F2012 is 16 per cent.

The objective of these questions is to understand the growth in "executive" level positions from F2008 to F2011 and then F2012, which in part will explain the increase in overall salary costs at BC Hydro.

182.1 Please clarify the response to BCUC IR 1.439.2 to explain if there are positions other than direct reports to the CEO that are paid in the "executive" pay category.

182.2 Please clarify exactly which positions are included in the "executive" salary range. For example, is the listing provided in the response to BCUC IR 1.95.5 all of the positions or does that response just include some of the positions that are included in the "executive" SLR/salary category.

182.3 Please expand on the response to BCUC IR 1.95.6 to provide the active (non-leave) headcount that receive VP salary treatment anticipated as of the end of F2012. Or as of a specific date in late March 2012.

182.4 Please expand on the response to BCUC IR 1.104.3 to provide the active (non-leave) headcount in the "executive" category anticipated as of the end of F2012. Or as of a specific date in late March 2012.

182.5 Please confirm the number of active employees in the "executive" pay category as at the end of F2008, F2011, and anticipated for the end of F2012. Please provide the percentage increase in "executive" from F2008 to F2012. Please compare the percentage increase in executive to the 16% increase in total employees from F2008 to F2012. If BC Hydro is unable to provide the number of active employees in the "executive" pay category anticipated for the end of F2012, please compare the percentage increase in "executive" between F2008 and F2011, which could be as high as 300% based on the IR responses, to the 10% increase in total employees from F2008 to F2011.

182.6 Please explain the organizational or other structural complexities that have changed at BC Hydro from F2008 to F2012 that has required the significant increase in members of the "executive" pay category. If necessary as part of the explanation, please provide the comparative numbers and ratios for BC Hydro prior to the creation of BCTC and the original outsourcing to ABSU.

<u>Operational and Capital Procurement Practices</u>

183.0 Reference: Operational and Capital Procurement Practices
Exhibit B-15: IR 1.424.0; Appendix CC – BC Hydro Initial Response
Capital Project Procurement

"Government Review Item: (26) Continue to work with vendors through the Joint BC Hydro/Supplier Working Group to improve contractual (both commercial and technical) language and involve vendors in risk transfer strategies to ensure risks are allocated appropriately between BC Hydro and vendors.

BC Hydro response (26) Agreed. Building on recommendations from the Supplier Engagement Review, BC Hydro's objective is to have strong working relationships with suppliers such that they are interested in pursuing work with BC Hydro, they clearly understand risks and will work collaboratively with BC Hydro in bringing innovative solutions to business and technical problems.
First round of consultations with associations and key suppliers has taken place and their input and suggestions have been incorporated into the following items: 1. Supplier debriefings; 2. Supplier complaints; and 3. Supplier interaction guidelines.

These items are in the process of being rolled out. The next round of association meetings will be in Fall 2011."

183.1 Please confirm, or explain otherwise, that this Joint BC Hydro/Supplier Working Group is still active and meetings continue to take place and more are scheduled. If not, please explain why not.

183.1.1 Please submit the 2011 and 2012 minutes of these meetings.

183.2 Please submit the specific changes to BC Hydro's written procurement of goods and services policies as a result of the recommendations from this working group. For greater clarity, if BC Hydro has a written policy(s) please submit the written policy(s) before and after any adopted changes such that the changes can be identified.

183.2.1 Please include the anticipated or actual effective date of any such changes planned or adopted to the policy(s).

184.0 Reference: Operational and Capital Procurement Practices
Exhibit-15, IR 1.424.1
Capital Project Procurement

184.1 Please discuss any further specific plans, in addition to those stated in BCUC 1.424.2 and 1.424.5, that BC Hydro has to address these concerns and indicate when these plans, if any, will be put into practice.

185.0 Reference: Exhibit BCUC 1.424.5
Operational and Capital Procurement Practices
Capital Project Procurement

"With specific reference to recommendation 23, BC Hydro is continuing with its Strategic Sourcing program. BC Hydro has recently commenced development of a three-year procurement plan which is expected to be completed in F2012 that should optimize savings from procurement of common goods and services." (BCUC IR 1.424.5)

185.1 Please explain how this new procurement plan differs from the present procurement plan and why this new plan is expected to result in further savings.

185.1.1 Please provide a ballpark magnitude of the costs to develop this new procurement plan i.e. less than $1 million, less than $5 million, less than $10 million, etc.

185.2 In the two examples given in the response to recommendation 26, please explain how the quoted savings can be estimated without simultaneously testing the market with and without the RFP improvements. For greater certainty, what leads BC Hydro to believe actual savings were realized a result of the RFP improvements and not just due to market conditions.

186.0 Reference: Exhibit B-15, BCUC 1.425.2
BC Hydro Initial Responses to Government Review
Capital Project Procurement

Please discuss what controls are in place to prevent duplication of efforts (for example funding of traditional use studies), between the Crown, Crown actors and third parties, both internally and externally, for consultation with First Nations.

186.1 The response did not include third parties. For example, if a third party funded a Traditional Use Study as a condition of doing business in an asserted territory, is there any register in place to avoid duplication of this study funded by Crown agencies? If not, why not.

W. OTHER

Historical Information

187.0 Reference: Approach to presentation of information
Exhibit B-15-1, IR 1.433.1
Uniform System of Accounts (USoA)

In the response to BCUC IR 1.433.1 BC Hydro stated that going forward, BC Hydro's adoption of the BCUC Uniform System of Accounts (USoA) is intended to fulfill the continuity of expenditure classification commitment and to minimize the impact of internal organizational changes on the presentation of financial information. While the USoA reporting design has been in place since April 2010, the integration of BCTC and subsequent internal reorganizations have allowed BC Hydro to verify, test and where necessary, modify the mappings, to confirm period over period consistency. The F2012 Annual Report to the BCUC will be filed on the basis of the USoA.

In the response to BCUC IR 1.78.5 BC Hydro stated they can only provide information in the USoA format prior to F2011 through significant manual effort. In the response to AMPC IR 1.65.1 BC Hydro stated providing the historical data in USoA format posed certain challenges as the historical information was not captured at the same level of detail.

187.1 Please provide an estimate of the number of person months required to re-cast the F2009 through F2011 data into the USoA reporting. This would provide a full five years of comparable historical information for the F2015 RRA.

Safety

See Operating Costs

Reliability

188.0 Reference: Reliability
Exhibit B-15: 1.430.1, 1.429.1

"Investments to address reliability performance are driven and limited by the need to meet and maintain the corporate reliability targets"; (Response to BCUC IR 1.430.1)

"BC Hydro's measures of CAIDI (Customer Average Interruption Frequency Index) and SAIFI (System Average Interruption Frequency Index) are generally in the bottom fourth quartile among North

American utilities. BC Hydro would like to prevent any deterioration in this result and improve where it is cost effective to do so." (Response to BCUC IR 1.429.1)

188.1 Given that BC Hydro generally is in the bottom fourth quartile among North American utilities, please explain what factors are considered in determining cost effective improvements.

188.2 In the absence of a corporate wide enterprise risk matrix, how does BC Hydro currently rank reliability of customer service against all other competing sources for capital and operating funds? Please explain.

188.3 Given the increasing distribution assets approaching end of life, such as wood poles and underground cable, does BC Hydro anticipate a significant spike in spending will be required to prevent reliability from decreasing further? Please discuss BC Hydro's plans to address this issue.

Uniform System of Accounts

189.0 Reference: Corporate Groups Operating Costs
Exhibit B-15-1, IR 1.444.1
Uniform System of Accounts (USoA)

BC Hydro replaced its financial reporting systems with the SAP financial reporting systems, effective for F2011. As the implementation design for the SAP financial systems was significantly advanced at the time BC Hydro received the USoA Directives, BC Hydro is currently incorporating the BC Hydro USoA into the SAP financial reporting systems, and the new reporting will be available effective for the F2012 Annual Financial Report to the BCUC. In compliance with the directives, BC Hydro has prepared financial information, in the BC Hydro USoA format **using** the SAP financial systems as well as **manual procedures**. (Appendix DD, Section 1.2.2, p.2) [emphasis added]

BCUC IR 1.444.1 requested more detail on the manual procedures to understand if this was a temporary situation or would be part of the on-going, annual reporting process. The response to this IR refers to the response for BCUC IR 1.433.1, which does not make reference to manual procedures required for the USoA reporting. The same response indicates the USoA classifications have been configured into SAP financials through mapping and association of various data elements, and that the F2012 Annual Report to the BCUC will be filed on the basis of the USoA.

189.1 Please explain if, and when, the USoA reporting will be an automated process on an ongoing basis.

AMPC IR 1.65.1 asked how the USoA reports would provide interested parties with meaningful and comparable information. BC Hydro's response included allowing for year-over-year comparisons regardless of how BC Hydro is internally organized, and the reporting would reflect a high degree of alignment between management reporting and regulatory reporting. A high level sample of operating reported using USoA is included in Appendix DD.

189.2 Please provide an example of a USoA operating cost to budget report, at the lowest management reporting level, showing the lowest level of cost codes available in the BC Hydro financial systems.

Internal Audit Reports

190.0 Reference: Internal Audit Reports
Exhibit B-15, BCUC IR 1.445.2
Internal Audit Reports
Issue: follow up on outstanding internal audit reports

190.1 Please provide a copy of the following internal audit reports:

Procurement Process Controls

Provide assurance that the newly designed procurement process controls are in place and working effectively.

Internal Audit Reports completed and issued in F2012 (excluding Powerex).

Fort Nelson Generating Station Upgrade Project

Provide assurance that the Fort Nelson Generating Station Resource Smart Upgrade (FNG) Project is being appropriately managed and is on-track to successfully deliver its stated objectives.

Market Operations and Development System

Provide assurance that the Market Operations and Development System (System), an integrated suite of business applications, was effectively implemented and is in compliance with the Open Access Transmission Tariff (OATT).

Customer Connection and System Process Improvement

Perform a high level review of the Distribution Customer Connection and System Improvement Process in its current state and identify gaps for efficiency improvements.

Corporate Policy Compliance

Review compliance with corporate policies and procedures across BC Hydro and its subsidiaries for expenditures not processed through BC Hydro's purchasing department. Areas of coverage included: expense claims (executives and employees) and expenditures using payment requisitions, local purchase orders, fuel and corporate credit cards.

Contract Management & Administration

To review the effectiveness of contract management and administration practices at BC Hydro and assess specific contracts for compliance with policies and procedures. This audit focused on the post award phase and contract management practices.

X. DEMAND SIDE MANAGEMENT (DSM)

191.0 Reference: DSM
Exhibit B-1-3B, Appendix II, Section 3.6, Amended Table II-3-5, p. 17
Modified TRC Test

191.1 Please confirm that the "TRC Test" column shown in Amended Table II-3-5 includes benefit cost ratios calculated under the Amendments to the DSM Regulation (Ministerial Order M335). Please also confirm that this benefit cost test is referred to as the "Modified TRC" and "MTRC" by the BC government and other utilities.

192.0 Reference: DSM
Exhibit B-1-3B, Appendix II, Attachment 5, Table 5
Residential and Commercial Load Displacement

192.1 BC Hydro has $0 budgeted for the Residential and Commercial Load Displacement programs in F2012-F2013. Please explain what approval BC Hydro is seeking from the Commission for these Programs in this Application? If it is approval as part of BC Hydro's s.44.2 expenditure schedule, what is the Commission assessing if there are no planned expenditures for these Programs?

193.0 Reference: DSM
Exhibit B-1-3B, Appendix II, Attachment 5, Tables 4 and 5; Exhibit B-15, BCUC 1.464.1.1
Industrial Sector Programs

Program	BC Hydro Incentive Costs ($ million) Table 4			Total BC Hydro Costs ($ million) Table 5		
	F2011	F2012	F2013	F2011	F2012	F2013
Power Smart Partner - Transmission	4.2	20.3	20.3	7.0	26.3	26.5
Load Displacement	0	12.6	24.4	0	12.8	24.9
Compiled from Exhibit B-1-3B, Attachment 5						

		F2008	F2009	F2010	F2011	F2012	F2013
Industrial Sector							
Power Smart Partner - Transmission	All End-Uses and Technologies	Up to $0.02/kWh (Levelized) See below	Up to $0.02/kWh (Levelized) See below	Up to $0.045/kWh (Levelized) See below	Up to $0.045/kWh (Levelized) See below	Up to $0.045/kWh (Levelized) See below	Up to $0.045/kWh (Levelized) See below
Power Smart Partner - Distribution	All End-Uses and Technologies	$0.023 - $0.051/kWh (Levelized) See below	$0.023 - $0.051/kWh (Levelized) See below	$0.023 - $0.051/kWh (Levelized) See below	$0.023 - $0.051/kWh (Levelized) See below	$0.023 - $0.051/kWh (Levelized) See below	$0.023 - $0.051/kWh (Levelized) See below
New Plant Design	All End-Uses and Technologies	$0.035/kWh (Levelized)	$0.035/kWh (Levelized)	$0.035/kWh (Levelized)	$0.035/kWh (Levelized)	$0.035/kWh (Levelized)	$0.035/kWh (Levelized)
Load Displacement	n/a	See below	See below	See below	See below	See below	See below

"Load Displacement Program: Incentives for industrial load displacement projects vary by project and use the Power Smart Partner-Transmission program incentive structure as a guideline." (BCUC 1.464.1.1)

193.1 Power Smart Partner – Transmission total program costs are forecast to increase from $7.0 in F2011 to $26.3 million in F2012 (Table 5) and this increase is largely made up of customer incentives that are forecast to increase from $4.2 million to $20.3 million in the same years. Please explain why the levelized incentive was increased from up to $0.02/kWh to up to $0.45/kWh from F2009 to F2010.

193.1.1 Why did BC Hydro not step the incentive up and test customer take-up at different levels? How does BC Hydro know it is not paying more than is necessary to induce customer participation in this program? What process did BC Hydro go through to determine the optimum level of incentive for this program?

193.1.2 Please confirm that the incentives in the Power Smart Partner – Transmission program are paid to a maximum of the project cost but do not factor in customer energy savings. Is it correct that BC Hydro pays 100% of the incremental cost of the installed measure(s) up to the total project cost? Is it correct that the customer pays 0% of the incremental cost of the measure and, usually, experiences energy bill savings? Please explain why customer bill energy savings are not factored in, in some way, into the financial

incentive provided by BC Hydro? Could BC Hydro not calculate a highly probable energy savings range and reduce the incentive by some portion of the energy bill savings?

193.2 Industrial Sector Load Displacement is forecast to increase from $0 in F2011 to $12.8 million in F2012 and $24.9 million in F2013 (Table 5). These total BC Hydro costs are largely made up of customer incentives which are forecast as $12.6 million in F2012 and $24.4 million in F2013. BC Hydro only provides a very general explanation of how these incentives are calculated. Please provide the detailed formula or calculation of the incentives given under the Industrial Load Displacement program. If no formula exists, please provide internal memoranda or documents describing how financial incentives for the Industrial Sector Load Displacement program are determined and negotiated with customers.

193.2.1 Please provide an example of a calculation and the resulting incentive.

193.3 Please fill in the following table for all incentives provided or forecast to be provided under the Power Smart Partner – Transmission program and the Industrial Load Displacement program which were/will be greater than $1 million.

Program	**F2011**		**F2012**	
	Amount of Incentive ($ million)	**Recipient**	**Amount of Incentive ($ million)**	**Recipient**
Power Smart Partners - Transmission				
Industrial Load Displacement				

194.0 Reference: DSM
Exhibit B-15, BCUC 1.446.02, Electronic Attachment 1
Incremental Energy Savings

194.1 The Incremental Energy Savings worksheet includes a number of negative net energy savings in several time periods. Please explain why BC Hydro is reporting negative net incremental energy savings in so many programs and in so many different years?

194.2 Please explain the term "net energy savings since F2003"

194.3 Please explain the link, if any, between the "net energy savings since F2003" worksheet and the cumulative energy savings worksheet. Why doesn't the incremental savings from 2003 through F2012 equal cumulative savings for F2012?

195.0 Reference: DSM
Bonbright *et al*, 1988, Principles of Public Utility Rates, pp. 29-30;
Exhibit B-15, BCUC 1.449.1
Competitive DSM Services

According to Bonbright et al (1988: 29-30), in the Principles of Public Utility Rates:

"[M]ost economists in the United States prefer competition to regulation based on the normative standard of allocative and internal efficiency ... [R]egulation is a questionable substitute for competition under conditions of natural monopoly and is a very poor substitute indeed when an industry is naturally competitive."

BC Hydro, in its response to BCUC IR 1.449.1, states "There are fundamental limitations to a workably competitive market for DSM electricity savings in British Columbia because of the structure of the electricity market itself. … BC Hydro does not consider there to a be a workably competitive market for the delivery of entire programs in British Columbia at this time … [BC Hydro] considers there to be a workable competitive market for the delivery of components of selected DSM programs in British Columbia."

195.1 Does BC Hydro agree that a preference should be given to competition over regulation where markets are workably competitive? Please explain.

195.2 Is it BC Hydro's position that it is the only entity that could have overall responsibility for spending the DSM electricity budget in its service area? If yes, what market barriers would have to be removed in order to enable a third party provider to take overall responsibility for DSM such as occurs in Nova Scotia, Vermont and Oregon?

195.3 What steps is BC Hydro taking now to utilize more competitive DSM services?

196.0 Reference: DSM
Exhibit B-15, BCUC 1.456.1.2, 1.456.1.2.1, 1456.3
Overlapping DSM Programs and Attribution of Energy Savings

"BC Hydro and FEU do not apply attribution rules to reported natural gas savings for the purpose of the TRC Test. Where applicable, BC Hydro includes full customer costs and FEU partner costs in the TRC so as to match electricity and natural gas costs and benefits. BC Hydro reports all natural gas savings that it estimates result from the program.

BC Hydro is of the view that BC Hydro and FEU including the same natural gas savings in their DSM reporting and cost-effectiveness analysis is appropriate so long as costs and benefits are matched in DSM cost-effectiveness analysis." (BCUC 1.456.1.2.1)

196.1 Does double counting of energy savings not occur when both BC Hydro and the FEU including the same natural gas savings in their DSM reporting and cost-effectiveness analysis?

196.1.1 Is it not important for the province to have an accurate account of the energy savings from DSM in BC, especially given that there are provincial energy and greenhouse gas reduction targets?

196.1.2 How can the province obtain an accurate picture of energy savings when utilities are including the same savings in their DSM reporting?

196.2 Please provide support showing that it is best practice: i) to not have attribution rules among utilities offering programs in the same market; ii) for multiple utilities offering programs in the same market to include the energy savings claimed by other utilities in their DSM reporting and cost-effectiveness analysis.

"Commercial Power Smart Partners - FEU operates a similar program to BC Hydro." (BCUC 1.456.1.2)

196.3 Could BC Hydro and the FEU integrate their similar programs? If not, why not? If so, what steps has BC Hydro taken to integrate this program already?

"BC Hydro is of the view that to the extent that further opportunities to partner with the Province and FEU on DSM programs arise in the future, BC Hydro expects that they will be identified and considered by the three parties through the ongoing partnerships." (BCUC 1.456.3)

196.4 Please list the specific BC Hydro DSM programs that can be integrated with LiveSmart BC and the FEU? What steps is BC Hydro taking now to integrate these programs?

197.0 Reference: DSM
New Appendix CC, Province of BC Review of BC Hydro, pp. 5, 6, 42, 43;
Exhibit B-15, BCUC 1.463.2.1
Staffing Costs

The June 2011 Province of BC report titled 'Review of BC Hydro' stated on page 5 and 6 "... between 2006 and 2010 … BC Hydro experienced a 41% employee growth ... resulting in a significant impact to costs during those years. … In addition to the direct labour associated with operations and capital projects, BC Hydro executive also acknowledged that back office and support functions experienced similar, uncontrolled expansion." The report recommended on page 43 that BC Hydro "Accelerate the pace and magnitude of change to develop an organizational structure that reflects the reasonable level of internal and external staffing that reduces costs passed on to ratepayers."

The report also stated on page 42 "BC Hydro has committed to (but has yet to have fully realized) further improving organizational effectiveness and efficiency through the following actions: … outsourcing; and maintaining or reducing staffing levels as appropriate."

BC Hydro, in its response to BCUC IR 1.463.2.1 included the following table showing all DSM FTEs and compensation by function.

Function		Actual F2008 (Note 1)	Actual F2009	Actual F2010	Actual F2011	Plan F2012	Plan F2013
Power Smart Executive, Strategy, Quality Assurance	FTEs	n/a	15	16	16	15	14
	Average Compensation ($)	99,072	87,598	88,275	106,498	114,108	119,081
	Staff with Compensation > $100,000	9	8	8	9	11	10
Operations	FTEs	n/a	62	65	62	63	59
	Average Compensation ($)	61,289	70,536	75,685	82,835	84,778	87,630
	Staff with Compensation > $100,000	6	18	18	24	27	27
Evaluation, Measurement and Verification	FTEs	n/a	22	27	28	28	28
	Average Compensation ($)	75,983	83,401	85,613	97,134	94,962	96,857
	Staff with Compensation > $100,000	8	9	10	10	14	14
Marketing	FTEs	n/a	70	73	72	69	64
	Average Compensation ($)	65,446	77,243	85,461	92,274	95,364	97,889
	Staff with Compensation > $100,000	18	20	26	29	39	37
Innovation and Conservation Leadership	FTEs	n/a	14	16	19	16	14
	Average Compensation ($)	68,236	84,811	98,295	113,876	116,228	116,800
	Staff with Compensation > $100,000	9	7	9	14	14	12
Customer Care	FTEs	n/a	51	55	55	59	59
	Average Compensation ($)	88,490	88,404	94,038	99,464	99,236	101,215
	Staff with Compensation > $100,000	29	31	32	35	49	49
Communications	FTEs	n/a	12	89	72	67	60
	Average Compensation ($)	26,587	41,206	35,550	43,453	47,365	51,793
	Staff with Compensation > $100,000	5	0	6	8	11	11
Other (e.g., IT, Legal)	FTEs	n/a	10	14	7	6	5
	Average Compensation ($)	53,139	76,089	80,244	63,588	72,811	74,266
	Staff with Compensation > $100,000	1	3	5	0	1	1
Total DSM Deferred	FTEs	n/a	256	356	331	322	302
	Average Compensation ($)	59,385	77,796	69,288	79,763	83,648	87,179
	Staff with Compensation > $100,000	85	96	114	129	166	161

Note 1 In F2008, DSM FTE data was not reportable from BC Hydro financial systems and is not available for this table.
Note FTEs reflect hours charged to the department and includes employees from other cost centres who may not perform DSM work on a regular basis; Compensation excludes employees who do not perform DSM work on a regular basis.

197.1 Please describe what is included in the average compensation figures in the table above, for example does it include overtime, bonus, cashed-out vacation, pension (employee and employer) etc.

197.2 Please update the table provided in response to BCUC IR 1.463.2.1 to show the total percentage increase from F2008 to F2013 in average FTE compensation for each function. Please also provide the increase in the BC Consumer Price Index (CPI) over the same period. Please explain any significant differences between the F2008 to F2013 increase in average FTE compensation and BC CPI over the same period.

197.3 Please explain the increase in staff levels for each function from F2008 to F2013.

197.4 What steps has BC Hydro Power Smart taken to "develop an organizational structure that reflects the reasonable level of internal and external staffing that reduces costs passed on to ratepayers"?

198.0 Reference: DSM
AMPC 1.11.4; California Evaluation Framework, pp. 21, 27; The Brattle Group, 2011, Measurement and Verification Principles for Behavior-Based Efficiency Programs, p. 2; Exhibit B-15, BCUC 1.466.3, Attachment 2, p. 20
Independent Measurement and Valuation

In response to AMPC IR 1.11.4 BC Hydro provided the link to the California Evaluation Framework and states "BC Hydro uses the Framework to inform decisions when planning DSM evaluation work."

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) [emphasis added]

The Brattle Group 2011 paper titled Measurement and Verification Principles for Behavior-Based Efficiency Programs states on page 2:[1]

> In the past, programs have been carried out without matching control groups and sometimes with no control groups at all. Others have been conducted with control groups but with no pre-treatment measurements. All such inadequacies impair the internal validity of the programs to varying degrees. Without a control group in the design, it is impossible to control for non-treatment variables that change between the pre-treatment and treatment periods (such as the economy, or general changes in attitudes toward energy use brought about by other exogenous factors). Without pre-treatment data, it is difficult to know if the treatment and control groups were comparable or not before the treatment was introduced. If systematic pre-treatment differences exist, they suggest that there may be a self-selection bias in the sample that needs to be dealt with. Having a randomized control group and sufficient amount of pre-treatment data for both treatment and control groups could address majority of these concerns.

BC Hydro, in BCUC IR 1.466.3 Attachment 2 (An Evaluation of the Residential Inclining Block Rate for fiscal year 2010), page 20, states "A statistical analysis of customer characteristics indicated that customers on the inclining block rate and those assigned to the single step (flat rate) equivalent were not comparable prior to the introduction of the inclining block rate. This meant that the assumptions required to conduct a valid difference of means test were not met."

198.1 Please describe the services included in the DSM Evaluation, Measurement and Verification (E,M&V) F2012/2013 budget. For each service, please provide a breakdown of the budget between costs related to in-house provided services and costs related to third party provided services.

198.2 Does BC Hydro consider that there is a potential conflict of interest in a utility both undertaking DSM activities and being responsible for DSM E,M&V? Please explain why or why not.

198.3 How does BC Hydro follow 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.

198.4 What percentage of the total impact and process evaluations and other E,M&V work that has been completed in the past three years has been completed by third party evaluators and what percentage has been completed by the E,M&V department of PowerSmart?

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[1] http://opower.com/uploads/library/file/17/opower-brattle_group-mv_principles_document-_final.pdf

198.4.1 Why doesn't BC Hydro use third party evaluators more than it has in the past three years?

198.5 Was BC Hydro able to use the RIB control group (customers assigned to the single step (flat rate) equivalent) in its E,M&V of the RIB rate? If yes, please describe the results. If no, how does BC Hydro's E,M&V control for non-treatment variables such as the economy or general changes in attitudes toward energy use brought about by other exogenous factors?

199.0 Reference: DSM
Exhibit B-15, BCUC 1.466.3
Cost Effectiveness Screening – TRC

$$\frac{\text{PV (avoided electric energy costs + avoided electric generation capacity costs + avoided electric transmission and distribution capacity costs + avoided natural gas costs + customer non-energy benefits + utility non-energy benefits)}}{\text{PV (BC Hydro non-incentive costs + BC Hydro allocated supporting initiative costs + customer costs + partner organization program costs)}}$$

199.1 Does BC Hydro include 100% of the incremental costs of measures in its cost effectiveness analysis under the MTRC screening model? If so, please explain the cost components that equal the incremental cost of measures.

199.1.1 If Incremental costs = customer costs + financial incentives, would BC Hydro exclude financial incentives from its MTRC screening analysis? If so, why?

199.1.1.1 Under what circumstances would BC Hydro include financial incentives under the MTRC?

199.2 In general, when BC Hydro raises financial incentives for Programs, what process does it undertake to determine the optimum level of incentive that induces maximum customer participation but does not pay more than is necessary to induce participation? Does BC Hydro undertake market research with its customers? Does BC Hydro benchmark its financial incentives against those provided in other jurisdictions and set its level based on a benchmark?

200.0 Reference: DSM
Exhibit B-1-3B, Appendix II, Section 1.1, pp. 9, 130-132, 225; Exhibit B-15, BCUC 1.468.4; Public Utilities Fortnightly, August 2008, Ahmad Faruqui, Inclining Toward Efficiency
Cost of Conservation Rates

BC Hydro, on page 9 of New Appendix II to its Application, is requesting $10.2m for rate structure DSM expenditure for F2012 and F2013. BC Hydro, in response to BCUC IR 1.468.4 states "The estimated deferred operating cost to develop and file a comprehensive residential rate application is approximately $3.5m."

BC Hydro, on pages 130 to 132 of New Appendix II to its Application indicates that F2012 and F2013 planned rate structure expenditures are primary due to:

- Residential Inclining Block: Development and filing of a comprehensive residential rate application.
- Large General Service Rate: Post-implementation customer support

- Medium General Service (MGS) Rate: support MGS customers as they move to their new conservation rate structure.
- Small General Service Rate: no changes to this rate structure are planned.
- Transmission Service Rate: Ongoing post-implementation customer support.

BC Hydro, on page 225 of New Appendix II to its Application, includes the following table:

Table 5 Benefit Cost Ratios of Electricity Savings: Fiscal 2008 to Fiscal 2011

	Benefit Cost Ratios		
	Utility Test	All Ratepayers Test	Non Participant Test[4]
Rate Structures			
Residential	21.1	21.1	1.2
Commercial	10.6	10.6	1.0
Industrial[1]	15.3	15.3	1.0
Total Rate Structures	**17.3**	**17.3**	**1.1**

Ahmad Faruqui, in an August 2008 article by Public Utilities Fortnightly, stated on page 26 that "The costs associated with including block rates likely will be small, arising from the need to make simple modifications in billing systems, train customer-service personnel and educate consumers on how to deal with the rates."[2]

200.1 Please explain why BC Hydro has not included in the Rate Structure All Ratepayer Test Ratios an estimate of the direct or indirect cost to consumers of reducing their consumption in response to the conservation pricing signal.

200.2 Please provide an annual breakdown of the amount spent/budgeted on each rate structure from F2008 to F2013 by activity type (such as rate design modeling, conservation and customer impact analysis, bill and revenue impact analysis, customer and stakeholder consultation, development of an application to the BCUC, post-implementation customer support).

200.3 Please explain why BC Hydro requires $10.2m for conservation rate design when rate design changes appear to be limited to incremental changes to the existing residential inclining block tariff.

200.4 Does the $10.2m requested for conservation rate design include any activities which could be considered part of normal utility rate related activities (for example, ongoing customer support) that would still be required in the absence of conservation rates? Please explain.

[2] http://www.soprisfoundation.org/PDFs/PUF_IncliningTowardEfficiency.pdf

201.0 Reference: DSM
Exhibit B-16, AMPC 1.11.7
DSM Amortization Period

201.1 Please provide the year and amount at which the DSM regulatory account balance will peak with an amortization period of: a) 5 years for all expenditures from F2012 onward; b) 10 years for all expenditures from F2012 onwards.

202.0 Reference: DSM
Exhibit B-1-3B, p. 3-17; Exhibit B-16, COPE 1.39.1, Attachment 1, Tabs Weightings, Persistence, and Calculation of Annual Weighted Average Persistence; Exhibit B-16, COPE 1.39.3; Exhibit B-15, BCUC 1.458.3, Exhibit B-16, BCSEA 1.5.1, 1.5.3; Exhibit B-15, BCUC 1.458.2, Attachment 1
DSM Amortization Period - Persistence

"BC Hydro has revisited the persistence of DSM savings to ensure DSM amortization is aligned with DSM costs and benefits over time and has found that since the 2008 LTAP, the average persistence of new program savings has increased as the mix of new savings has shifted toward programs with longer persistence." (Exhibit B-1-3B, p. 3-18)

202.1 Please confirm that the "average persistence" referred to in the preamble refers to the energy weighted average persistence presented in Attachment 1 to COPE 1.39.1.

	A	H	I	J	K	L	M	N	O
1	**Program Weightings**								
2									
3		**Actual F2008**	**Actual F2009**	**Actual F2010**	**Actual F2011**	**Forecast F2012**	**Forecast F2013**	**Forecast F2014**	**Forecast F2015**
4									
5	**DSM Programs**								
6	*Residential Sector*								
7	Behaviour	0%	0%	2%	1%	1%	1%	1%	1%
8	Lighting	5%	29%	9%	4%	2%	2%	1%	0%
9	Refrigerator Buy-back	7%	8%	4%	6%	2%	3%	3%	2%
10	Low Income	0%	1%	1%	2%	1%	1%	1%	1%
11	New Home	1%	3%	1%	1%	0%	1%	0%	0%
12	Appliances	0%	1%	1%	1%	0%	0%	0%	0%
13	Electronics	0%	0%	2%	1%	1%	1%	1%	1%
14	Renovation Rebate	0%	2%	2%	2%	1%	2%	1%	1%
15	Load Displacement	0%	0%	0%	0%	0%	0%	0%	0%
16									
17	*Commercial Sector*								
18	Power Smart Partner	11%	9%	11%	17%	23%	17%	18%	15%
19	Product Incentive	7%	18%	21%	19%	5%	9%	9%	6%
20	New Construction	1%	3%	6%	3%	3%	3%	5%	2%
21	Load Displacement	0%	0%	0%	0%	0%	0%	0%	0%
22									
23	*Industrial Sector*								
24	Power Smart Partner - Transmission	53%	26%	34%	4%	19%	21%	20%	20%
25	Power Smart Partner - Distribution	15%	0%	1%	12%	9%	14%	11%	9%
26	New Plant Design	0%	0%	7%	27%	3%	9%	7%	5%
27	Load Displacement	0%	0%	0%	0%	30%	13%	21%	33%
28									
29	*Cross Sectoral*								
30	Sustainable Community	0%	0%	0%	0%	0%	0%	0%	0%
31	Lead by Example	0%	0%	0%	1%	0%	1%	1%	4%
32									
33	**Total Programs**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

202.2 Please explain, in detail, the process by which BC Hydro determines weightings for its DSM programs. Is energy savings the only factor? Is it the annual or cumulative energy savings? Please clarify if the weighting methodology differs for Actual and Forecast numbers.

202.2.1 Please discuss whether the current methodology results in the persistence of Industrial DSM measures having greater weight in the overall average of programs?

202.3 Given that energy savings are not the only benefits produced by DSM Programs, would it be more appropriate to weight the persistence by other factors, or to include other factors, for example the number of measures installed rather than the energy savings?

	A	B	C	D
1	**Program Persistence**			
2				
3		F02-F07 Actuals	F08-F11 Actuals	F12-F32 Forecast
4				
5	**DSM Programs**			
6	*Residential Sector*			
7	Behaviour	n/a	30	30
8	Lighting	9	11	14
9	Refrigerator Buy-back	11	7	7
10	Low Income	n/a	10	13
11	New Home	20	20	20
12	Appliances	n/a	16	15
13	Electronics	n/a	10	8
14	Renovation Rebate	20	20	19
15	Load Displacement	n/a	n/a	20
16				
17	*Commercial Sector*			
18	Power Smart Partner	10	10	14
19	Product Incentive	10	9	9
20	New Construction	5	18	18
21	Load Displacement	n/a	n/a	20
22				
23	*Industrial Sector*			
24	Power Smart Partner - Transmission	11	9	10
25	Power Smart Partner - Distribution	n/a	11	11
26	New Plant Design	9	30	30
27	Load Displacement	11	n/a	19
28				
29	*Cross Sectoral*			
30	Sustainable Community	n/a	n/a	30
31	Lead by Example	n/a	10	14

202.4 Please explain why the persistence of the following programs is forecast to increase from F11-F12: Residential Lighting; Residential Low Income; Commercial Power Smart Partner; Cross Sectoral Lead by Example. Please provide any research, impact studies, other measurement and verification work or any other research or empirical support for these increases.

202.5 Will the forecast increased persistence for the Sustainable Community program be applied retrospectively to the energy savings from measures that have already been installed? If not, please explain how the increased persistence will be applied when the BC Hydro is winding down the program and the weighting for this program is 0% going forward.

202.6 Please explain why the Industrial Load Displacement program persistence was "n/a" for F08-F11 and increased from 11 years in F02-F07 to 19 years for F12-13?

202.6.1 Does BC Hydro expect self generation equipment installed under the Load Displacement program to last for 19 years? If so, please explain how this persistence number will be applied under Tariff Supplement No. 74, the CBL Determination Guidelines. Will a 19 year persistence be applied under the applicable sections of that Tariff Supplement to adjust customers' CBLs for customer-funded and BC Hydro-funded DSM projects?

202.7 Please file Reference 15 from Attachment 1 to BCUC 1.458.2: Skumatz Economic Research Associates, Inc. (SERA Inc.). Lessons Learned and Next Steps in Energy Efficiency Measurement and Attribution: Persistence of Energy Efficiency Behaviour.

202.8 From the Reference list in Attachment 1 to BCUC 1.458.2, BC Hydro appears to rely heavily on internal E,M&V work as reference for its persistence values. Why does BC Hydro not rely more on external work or look at both external and internal work to determine the best persistence value?

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Calculation of Annual Weighted Average Persistence**														
2															
3		Actual F2002	Actual F2003	Actual F2004	Actual F2005	Actual F2006	Actual F2007	Actual F2008	Actual F2009	Actual F2010	Actual F2011	Forecast F2012	Forecast F2013	Forecast F2014	Forecast F2015
4															
5	**DSM Programs**														
6	*Residential Sector*														
7	Behaviour	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.5	0.2	0.2	0.3	0.2	0.2
8	Lighting	1.4	1.4	3.7	2.7	0.7	1.5	0.6	3.2	1.0	0.4	0.2	0.3	0.1	0.0
9	Refrigerator Buy-back	0.0	0.3	0.6	0.8	0.5	0.6	0.5	0.5	0.3	0.4	0.2	0.2	0.2	0.1
10	Low Income	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.1	0.2	0.2	0.1
11	New Home	2.3	1.0	0.7	0.5	0.5	0.8	0.1	0.7	0.1	0.2	0.1	0.1	0.0	0.0
12	Appliances	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.1	0.1	0.1	0.1
13	Electronics	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.1	0.0	0.1	0.1	0.1
14	Renovation Rebate	0.8	0.1	0.1	0.1	0.1	0.1	0.1	0.4	0.3	0.4	0.1	0.4	0.2	0.2
15	Load Displacement	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16															
17	*Commercial Sector*														
18	Power Smart Partner	0.8	3.5	1.8	1.1	0.8	0.7	1.1	0.9	1.1	1.7	3.2	2.4	2.6	2.1
19	Product Incentive	0.0	0.0	0.1	0.2	0.3	0.4	0.6	1.6	1.9	1.7	0.5	0.8	0.8	0.5
20	New Construction	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.5	1.1	0.5	0.5	0.6	0.8	0.4
21	Load Displacement	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22															
23	*Industrial Sector*														
24	Power Smart Partner - Transmission	6.7	4.5	3.3	1.8	1.4	6.7	4.8	2.3	3.1	0.4	1.9	2.1	2.0	2.0
25	Power Smart Partner - Distribution	0.0	0.0	0.0	0.0	0.0	0.0	1.6	0.0	0.1	1.3	1.0	1.5	1.3	1.0
26	New Plant Design	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	2.2	8.1	0.9	2.8	2.2	1.6
27	Load Displacement	0.0	0.0	0.0	3.4	6.8	0.3	0.0	0.0	0.0	0.0	5.8	2.5	3.9	6.4
28															
29	*Cross Sectoral*														
30	Sustainable Community	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	Lead by Example	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1	0.2	0.5
32															
33	**Average Persistence of Programs**	**12.0**	**10.8**	**10.3**	**10.5**	**11.0**	**11.0**	**9.6**	**10.6**	**12.0**	**15.8**	**14.8**	**14.6**	**14.8**	**15.2**

202.9 Does BC Hydro consider the Actual F2011 Calculation of Annual Weighted Average Persistence to be representative of a normal DSM year? Is an Annual Weighted Average Persistence of 8.1 for the Industrial New Plant Design normal?

202.10 Please provide the complete persistence data from the Technical Reference Manuals (or other similar documents) from at least three other jurisdictions in North America.

202.11 In response to BCSEA 1.5.1 BC Hydro states: "BC Hydro is proposing to change the amortization period for all past and future DSM expenditures in the DSM Regulatory Account" and in response to BCSEA 1.5.3 BC Hydro responds that "[t]he weighted average persistence of electricity savings attributable to the unamortized balance in the DSM regulatory account…is 12.3 years." Please justify changing past expenditures to a 15 year amortization period given BC Hydro's response to BCSEA 1.5.3.

202.12 Please provide the most recent three prior versions of the Power Smart Effective Measure Life and Persistence document that was provided as Attachment 1 to BCUC 1.458.2.

203.0 Reference: DSM
Exhibit B-15, BCUC 1.460.1
Stakeholder Committee

"The Committee does not audit or confirm electricity savings or approve program funding or transfers of funding."

203.1 Does BC Hydro think the committee members would be interested if BC Hydro transferred significant amounts from one budget line item to another? For example from Residential programs or Low Income programs to Industrial programs?

203.2 Why does BC Hydro not set a threshold for program or sector budget transfers above which it would consult and receive approval from its Stakeholder Committee before making the transfer?

203.2.1 If BC Hydro were to implement this practice, what would BC Hydro view as an appropriate threshold? 30% of program or sector budget?