REQUESTOR NAME: Association of Major Power Consumers (AMPC)

INFORMATION REQUEST ROUND NO: 1

TO: BRITISH COLUMBIA HYDRO & POWER AUTHORITY

DATE: April 22, 2010

PROJECT NO: 3698592

APPLICATION NAME: Application for 2012-2014 Revenue Requirements

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1.0 **Topic:** Operating Costs, Productivity / Efficiency

Reference: Exhibit B-1-3, Application Overview, Page 1-6; Exhibit B-1-3, Page 2-3; Exhibit B-1-3, Page 5-9; Exhibit B-1-3, Page 5-11; Page 10-37, 10-38; F2011 NSA;

Explanation:

BC states:

> *"In the F11 RRA NSA, the parties were not able to agree on the appropriate level of operating expenditures in F2011. However, 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." (P 1-6)*

The NSA s.20 states:

> *20. The Parties are unable to agree on the appropriate level of operating expenditures for F2011, but recognize that an oral hearing late in F2011 will not resolve F2011 rates prior to the end of the fiscal year. To avoid this outcome, and to advance other NSP determinations, the Parties have agreed, among other settlement terms, that 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.*

A cost reduction of $35 million represents 3.28% of gross OM&A and $28 million (net of achieved BCTC) represents 2.85% of gross OM&A. Gross OM&A was $814.8 million in the F2010 RRA, $1.1866 Billion for F2010 Actual and $1.0678 Billion in the F2011 RRA. BC Hydro achieved a reduction of $7 million or 0.859% before BCTC in F2011.

BC Hydro has added back the full $35 million OM&A reduction for F2011, effectively negating any OM&A reductions agreed to or achieved in F2011.

BC Hydro further states:

> *"The integration of BC Hydro and BCTC is expected to result in approximately $25 million in annual savings beginning in F2012, … (P 1-11)*
>
> *Second, BC Hydro has also included further productivity savings in its operating cost budgets of approximately $5 million in F2012, $19 million in F2013, and $19 million in*

F2014. There is some uncertainty as to how these productivity savings will be achieved at this time; however, the current expectation is that the productivity savings will be achieved from implementation of projects arising from the IT&T Plan, ongoing outsourcing arrangements, and other process improvements and efficiencies. Further, BC Hydro is focused on reducing administrative and support services across the company; managing total headcount to ensure resources are shifted to priority operational areas with an emphasis on the safety and reliability of the system; …" (P 1-11)

And

"BC Hydro is making every effort to constrain costs while preserving its ability to deliver safe, reliable service to its customers." (P 2-3)

The productivity savings are 0.355% of gross OM&A in F2012, 1.268% in F2013 and 1.336% in F2014.

The Application (Exhibit B-1) speaks to financial constraints only 4 times with no further comment in the Amended Application as follows:

- *The plan over the next three years has been aligned with the corporate strategic objectives, and prioritized to address resource and financial constraints. (P 5-62)*
- *DCEO developed its F2012 to F2014 operating plans to meet its priorities and objectives by prioritizing core services, identifying and managing business risks, and responding to the overall financial constraints of the company. (P 5-133)*
- *Following the bottom-up element of the process, top-down financial constraints were applied which recognize the significant impact on rates of BC Hydro's capital program. (P 6-30)*
- *The portfolios are prioritized to maximise the value gained and mitigate the highest risks identified. Resource and financial constraints are applied at this stage, and projects that realize a lower value and are not required to mitigate a high risk are deferred to later years. (P 6-33, 34)*

  FTEs are calculated by taking the total number of hours worked in a given year divided by the average number of hours a full time employee would work per year (1,566 hours).BC Hydro also uses Headcount as a measure of the number of employees it has. Headcount is the physical number of active employees that BC Hydro has at a given time. The planned headcount equivalent included in this application, excluding Site C and SMI, is 6,000, 5,900 and 5,800 for F2012, F2013 and F2014 respectively… (P 5-28)

A review of contractors vs. employees was not addressed in the Application. The Amended Application does propose outsourcing of some activities and deferral of related costs.

On November 24, 2011 BC Hydro filed an Amended Application (Evidentiary Update) incorporating changes in the rate increase and Revenue Requirements in response to the Review Panel Report (RPR).

Request:

1.1 Provide the following statistics for F2007 to F2014 and include in a functional Excel spreadsheet as part of F12_F14 RRA APPX A.xls.

- Customers – Year-end and Average
- MWh Sales (from Appendix A, Schedule 4.0, Page 21)

- Km of Distribution Lines
- Km of Transmission Lines
- Employees – FTEs and (year-end) Head Count
- Employees – FTEs and Head Count for each of Site C and SMI
- Hours of Overtime Worked
- OM&A Cost per Customer
- OM&A Cost per MWh
- Customers per Distribution Km
- Distribution Cost per Km
- Transmission Cost per Km
- Cost per Employee
    - Salaries & Wages
    - Benefits
    - Total
    - Other Overhead Burden (see SLR)
    - Average Employee Cost per Year

1.2 Do the costs set out in Appendix A, Schedule 5.0, Line 13 (Services –Other) represent the costs of consultants and contractors?

1.3 Provide the number of consultants and contractors and payments to consultants and contractors for F2007 to F2014.

1.4 How does BC Hydro evaluate productivity and competitiveness in relation to the Standard Labour Rate (SLR)?

1.5 Provide the analysis by employee group (IBEW, OTEU, etc.) for the average number of hours a full time employee would work per year supporting the 1,566 hours. For example: 1950 hrs/yr – vacation – stat holidays – sick leave – time off - etc.

1.6 Provide the analysis by employee group (IBEW, OTEU, etc.) showing the average, minimum and maximum number of overtime hours worked per employee.

1.7 Provide a definition of financial constraints, overall financial constraints and dollar limits or percentage caps for debt financing, OM&A, capital expenditures, deferral accounts, rate increases and any other factors that were applied in real terms before and after the Review Panel Report.

2.0 **Topic:** Operating Costs, Arrow Water Systems Sale

Reference: Exhibit B-1-3, Page 5-5 – 5.6, Page 7-32;

Explanation:

BC Hydro states:

… higher expenditures related to the unplanned Arrow Water Systems divestiture ($11 million) … (P 5-5 to 5-6)

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On January 4, 2011, BC Hydro divested the assets 1 of the Arrow Water Systems to the Regional District of Central Kootenay at a nominal price. Costs related to the divestiture, including the write-down of assets, were not included in the F11 RRA NSA. Therefore, BC Hydro plans to apply to the BCUC before the end of F2011 for approval to establish a regulatory account to capture the costs associated with the divestiture of the Arrow Water Systems.

By Order No. G-90-11, the BCUC approved the establishment of the Arrow Water Systems Divestiture Costs Regulatory Account and the Arrow Water Systems Provision Regulatory Account. In F2011, the actual costs included in the Arrow Water Systems Divestiture Costs Regulatory Account were $7.7 million and the actual provision included in the Arrow Water Systems Provision Regulatory Account was $3.3 million. BC Hydro is not proposing any amortization of the balances in these regulatory accounts during the F2012 to F2014 period. (P 7-32)

Request:

2.1 Are there any other such operations where BC Hydro provides non-electric utility services at a loss or does not recover the full cost of services?

2.2 What has been the total costs, including operating losses of the non-electricity utility systems and services that have been paid by BCH ratepayers?

2.3 Why did BCH not increase domestic water supply rates so as to recover the full cost of providing the service and the investment?

2.4 Explain what the “actual costs” in the deferral account are and what the “actual provision” is.

2.5 Provide a schedule of fixed asset additions by year for the Arrow Water Systems.

3.0 **Topic:** Operating Costs, Regulatory Accounts

Reference: Exhibit B-1-3, Page 7-35;

Explanation:

BC Hydro states:

BC Hydro has included $2.5 million in its F2012 operating costs for capital investigation related to the NETL project. BC Hydro does not currently plan to apply for a regulatory account to defer the capital investigation costs incurred in F2012 related to the NETL project.

Request:

3.1 Confirm that the costs will ultimately, directly or indirectly, go into the Rate Smoothing Account.

4.0 **Topic:** Operating Costs, Regulatory Accounts

Reference: Exhibit B-1-3, Appendix P. Page 5 of 13;

Explanation:

BC Hydro has deferred $0.7 million in "Significant" Unplanned Maintenance Costs.

Request:

4.1 Provide a definition of "Significant" in relation to BC Hydro.

4.2 Provide a list of planned activities for F2011 with forecast costs (values) that were not carried out.

4.3 Provide a list of planned activities for F2012 that are planned and the status of those activities.

5.0 **Topic:** Operating Costs, Regulatory Accounts

Reference: Exhibit B-1-3, Page 8-3;

Explanation:

BC Hydro states:

> *From F2009 to F2011, Deemed Equity was equal to 30 per cent of the sum of BC Hydro's average debt and average equity balances for the year. The change to Deemed Equity means that BC Hydro will no longer earn a return on debt related to regulatory account balances (other than for DSM) or assets not yet in service. (P 8-3)*
>
> _____
>
> *There is a small increase (approximately $0.28 in this example) in the total bill over the test period under the proposed rate smoothing because the rate smoothing increases debt requirements and hence finance charges during the test period. (P 1-32)*

Request:

5.1 Confirm that regulatory account balances are supported either by both debt and equity or by debt only.

5.2 Confirm that customers will still pay 100% of debt financing costs.

6.0 **Topic:** Subsidiary Net Income, Regulatory Accounts

Reference: Exhibit B-1-3, Page 9-17;

Explanation: Table 9-D shows that PTP volumes remain virtually unchanged for the forecast period while Trade Income is being increased by averaging results for 5 years.

New Table 9-D **Scheduling Fee Determination**

Line No.	GW.h	Schedule Reference	F2011 Approved	F2012 Update	F2013 Update	F2014 Update	F2012 Plan	F2013 Plan	F2014 Plan
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	PTP Volumes:								
2	Long-Term PTP	Sch 3.4 L49	8,401	8,424	8,401	8,401	8,424	8,401	8,401
3	Short Term PTP	Sch 3.4 L58	6,769	3,236	3,236	3,236	3,236	3,236	3,236
4	Total PTP Volumes		15,170	11,659	11,636	11,636	11,659	11,636	11,636
5	NITS		12,369	11,569	11,569	11,569	11,569	11,569	11,569
6	Secondary Transmission		346	1,021	1,021	1,021	1,021	1,021	1,021
7	**Total Volumes**	**Sch 3.4 L45**	**27,885**	**24,250**	**24,227**	**24,227**	**24,250**	**24,227**	**24,227**
8	Scheduling, Control & Dispatch Cost ($ million)	Sch 3.4 L44	3.6	3.4	3.4	3.4	3.2	3.5	3.7
9	**Scheduling Fee ($/MW.h)**	**(L8 / L7) =Sch 3.4 L46**	**0.129**	**0.140**	**0.139**	**0.139**	**0.133**	**0.146**	**0.154**

(P 9-17)

Request:

6.1 Reconcile the PTP volume forecast with the proposed formula for PTP charge allocations and the increase in Trade Income.

6.2 Confirm that any variances in Trade Income will flow into a deferral account for future recovery from or credit to customers.

7.0 **Topic:** Operating Costs, Safety

Reference: Exhibit B-1-3, Appendix F (Amended);

Explanation:

The report states:

> *… Frequency performance has improved significantly compared to other Canadian electricity companies, the August 16, 2010 fatality at Cranbrook Substation reinforced statistics showing that BC Hydro experiences a serious safety incident on average every six months. (App F, P 1 of 8)*
>
> ———
>
> *At the time of the fatality, investigations and safety reviews had not definitively uncovered why these serious incidents continue to happen and recommendations and corrective actions coming out of these activities had not impacted safety performance in a consistent or sustainable way across the company. While progress was being made across the four pillars of the safety plan, something was missing. (App F, P 1 of 8)*
>
> ———
>
> *Unlike past strategy or project implementations where employees may only have had input at the outset and were not clear on whether they had been heard, the Safety Taskforce modeled engagement and talked to over 4,000 employees, seeking their feedback before finalizing the future state and the recommendations. (App F, P 3 of 8)*
>
> ———

The Safety Taskforce visited over 17 external companies in the Utilities and other best practice industries. These companies taught the Safety Taskforce about the key levers and efforts required to sustain culture change. There were three critical components. One, there was a leadership team that was aligned and focused on safety from the top to the frontline. Two, there was full engagement of the frontline, including testing and piloting of programs that impact them. Three, there was an understanding that culture change takes several years and the leaders (at all levels including the union) need to stay the course. The biggest learning for the Safety Taskforce was that they came away with hope. (App F, P 2 of 8)

(P 8 of 8)

Request:

7.1 Has BC Hydro considered that there may be a statistical aberration or clustering?

7.2 Confirm that over 4000 employees represents 2/3 of BC Hydro employees.

7.3 Provide the manpower hours and costs for the Safety Taskforce, experts and consultants.

7.4 List the 17 companies visited by the Taskforce and the locations of those visits.

7.5 How many safety studies and reports have been carried out in the last 10 years? Provide a list and costs for those studies and reports.

7.6 How many BC Hydro employees are directly involved in safety management?

7.7 Does BC Hydro have a program in place for input/suggestions from frontline employees subject to serious safety accidents?

7.8 Is BC Hydro now confident that it has “definitely uncovered why these serious accidents continue”? Explain.

7.9 What is the culture change that BC Hydro is implementing and what is the culture that BC Hydro is hoping for in practical terms?

7.10 Does the banner representing “Future Sate Vision” representative of the results of the work of the Safety Taskforce?

7.10.1 How is it used?

7.10.2 What does it mean?

8.0 **Topic:** Capital Expenditures and Additions

Reference: Exhibit B-1-3, Appendix J, Page 2 of 96;

Explanation: BC Hydro is constructing facilities to the LEED Gold standard.

Request:

8.1 What is the construction standard policy of BC Hydro? Is it the LEED Gold standard?

8.2 If the standard is mandatory provide the legislation or regulations.

8.3 List the various types of facilities that are subject to the LEED Gold construction standard.

8.4 What is the increased cost associated with constructing to the LEED Gold standard?

8.5 Has BC Hydro done an analysis of the cost-benefit of construction standards? Provide any analysis that has been done.

9.0 **Topic:** Load Revenue and Forecast

Reference: Exhibit B-1-3, Appendix FF;

Explanation: BC Hydro states:

Transformative technologies have created the economic viability of significant shale gas plays in Northeast B.C. These plays are an immense energy resource that is forecast to be competitive against other such gas plays on the continent, despite the current low gas prices. The use of electric compression by producers in this area for operational flexibility, fuel and operations cost reductions and greenhouse gas abatement are predicted to result in significant load growth for BC Hydro. (App FF, P 10 of 134)

Industrial distribution *– over the long term the industrial distribution sales are above the 2008 Forecast. The increase is driven by anticipated new oil and gas loads to be connected to the distribution system in the Dawson Creek area. One factor that has lead to the increase in load is that BC Hydro received several new inquiries for service in this area since the development of the 2008 Forecast. (App FF, P 13 of 134)*

Oil and Gas and Remaining - sales to producers and processors of conventional and unconventional oil and gas (particularly shale gas) will make up the majority of sales to this segment over next 20 years. For F2017, large industrial oil and gas sales are about 1,900 GWh higher in the current forecast relative to 2008 Forecast. Excluding oil and gas sales in the Fort Nelson NIA, the increase is about 1,500 GWh. As previously indicated, the major factors leading to the increase in sales are revised forecasts of production, additional inquiries for electrical service, and a continued progress and investment towards developing the unconventional gas resource in Northeast B.C. This interest is led by technologies used to recover shale gas, which have created conditions to make recovery economically viable at relatively low market prices. (App FF, P 13 of 134)

Request:

9.1 Identify all capital projects completed in F2011 or F2012 or planned for providing service to the O&G sector with costs.

9.2 Produce Figure A6.5 without O&G.

10.0 Topic: Load Revenue and Forecast

Reference: Exhibit B-1-3, Appendix FF (New), Page 9, 101 of 134;

Explanation: BC Hydro states:

Inclusion of electric vehicle (EV) load – EV load impacts are constrained in the first ten years of the 2010 Load Forecast, resulting in an increase of only 38 GWh in F2017, but rising to 2,120 GWh by F2031; (App FF, P 9 of 134)

There are key barriers to the rapid adoption of EVs via large scale production. For example some designed EVs have a range that is too small (40 miles between charging for the Chevy Volt). While the average daily commute in the U.S. and Canada is less than 40 miles, most car owners want the option of taking an occasional trip of several hundred miles or more. The purchase price of EVs is relatively high compared to comparable gasoline cars. The difference is typically, between $15,000 and $20,000. This price difference is probably the most important barrier to the widespread adoption of EVs. For large scale introduction of EVs, a system of rapid charging facilities will be needed and at various locations such as shopping centers, city centers and rural highway areas. An infrastructure of repair facilities will also be required. Electric cars will have to prove their reliability. Design, style and size of EVs will have to be acceptable to the public. (App FF, P 101 of 134)

The development of improved battery technology is key to overcoming key obstacles to EV introduction. Finally, automobile manufacturers must take the risks and make the very large investments that will be needed to move from announcements to mass production of EVs. (App FF, P 13 of 134)

Addressing the potential DSM double counting issue raised in the 2008 LTAP results in a forecast increase of approximately 500 GWh in F2017.4 In the remainder of this document, this modification to the 2010 Load Forecast is referred to as: 'DSM/load integration'. (App FF, P 9 of 134)

Request:

10.1 What has BC Hydro spent on EV re-charging stations to date?

10.1.1 What is BC Hydro planning to spend on re-charging stations in each year of the test period?

10.2 How will BC Hydro be determing energy used to recharge EVs and billing/charging for energy used?

10.3 What rates will be charged for energy used to recharge EVs?

10.4 Quantify the DSM double counting error effect on the stated effectiveness of DSM programs.

11.0 Topic: DSM, Deferral Accounts

Reference: Exhibit B-1-3, New Appendix II, Page 54 of 250, Page 72 of 250; Page 105 of 250; Page 136-140 of 250; Page 173 of 250; Page 174 of 250;

Explanation: BC Hydro states:

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. In the Updated DSM Plan, the persistence of new program savings generated in each of the next four years is forecast to average 14.9 years. This programs only view is consistent with BC Hydro's approach to persistence in previous regulatory proceedings. However, substantial DSM savings are also now provided by the other two DSM tools; conservation rate structures and codes and standards. These DSM tools provide savings with persistence up to 30 years. Inclusion of these savings into the calculation would result in a considerably longer average persistence. … (New App II, P 54 of 250)

_____

*BC Hydro also revisited the amortization treatment for the current balance of the DSM Regulatory Account. The combined persistence of the balance and new expenditures between F2012 and F2015 is calculated at 14 years. The inclusion of savings from conservation rate structures and codes and standards results in a considerably longer average persistence, well in excess of 15 years. (New App II, P 54 of 250_*

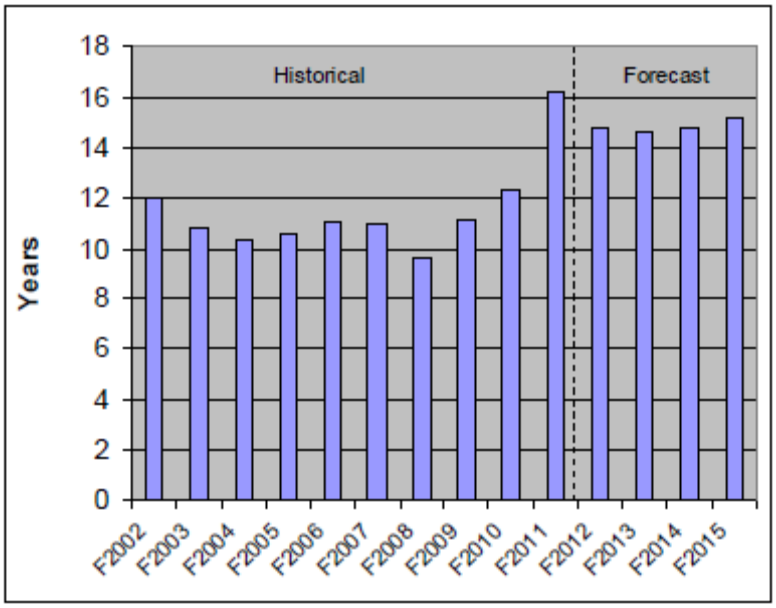
In carrying out its evaluation activities, BC Hydro is guided by the California Evaluation Framework, which is generally regarded as the leading protocol for DSM evaluation in North America. (New App II, P 72 of 250)

Table 3 Persistence of New Program Savings (Years)

	F2012-F2015
Residential Sector	
Behaviour	30
Lighting	14
Refrigerator Buy-back	7
Low Income	13
New Home	20
Appliances	15
Electronics	8
Renovation Rebate	19
Load Displacement	20
Commercial Sector	
Power Smart Partner	14
Product Incentive	9
New Construction	18
Load Displacement	20
Industrial Sector	
Power Smart Partner - Transmission	10
Power Smart Partner - Distribution	11
New Plant Design	30
Load Displacement	19
Cross Sectoral	
Sustainable Community	30
Lead by Example	14
Energy-Weighted Average Persistence	14.9

The program by program persistence values from Table 3 were multiplied by the new savings in each year to arrive at a weighted average persistence of new program savings by year. Figure 1 provides the results of this analysis. *(New App II, P 173 of 250)*

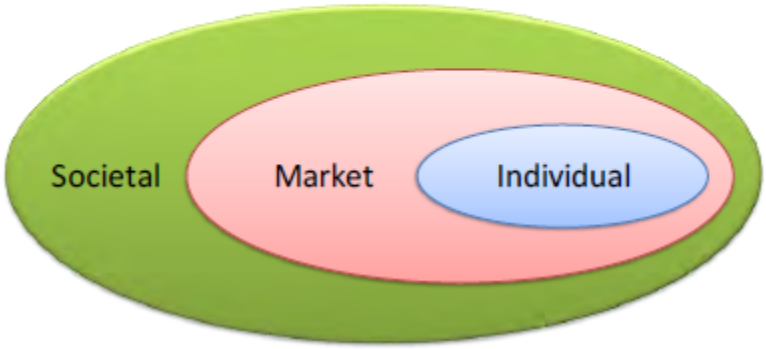
Figure 1 Weighted Average Persistence of New Program Savings (Years)



(New App II, P 174 of 250)

- Societal context – refers to the context of the community or society where societal norms and expectations and patterns of living and work influence market parameters and individual choices.

Figure 1 DSM Strategic Framework



(New App II, P 105 of 250)

BC Hydro employs three DSM tools and a number of 1 supporting initiatives spanning the individual, market and societal contexts to influence energy consumption and achieve targeted energy savings. (New App II, P 105 of 250)

Request:

11.1 Explain why BCH should claim credit for rate structures (and rate increases and levels) and Codes & Standards? Why should they be considered in evaluating DSM amortization periods?

11.2 How was the 10 year persistence for Industrial Transmission determined and when?

11.3 How does the persistence used in DSM amortization compare to persistence used to set industrial CBLs?

11.4 Provide the California Evaluation Framework and explain how it guides BC Hydro.

11.5 Provide the annual costs by sector (Residential, Commercial, Industrial) from F2009 to F2014 for M&V.

11.6 Does BCH employ a sampling approach to M&V?

11.7 Does BCH forecast an ever increasing deferral account balance for DSM?

11.8 Identify the tangible BC Hydro assets associated with the deferred DSM costs.

11.9 What methods other than deferral and amortization are used by utilities to recover DSM costs? Provide a listing by jurisdiction of methods of recovery and amortization periods.

11.10 Has BCH considered a rate rider to recover the remaining historical DSM deferral account balance while recovering current costs through a rate rider? i.e Has BCH considered a rate rider to recover annual DSM expenditures in the year incurred?

11.11 Provide the annual DSM costs by Customer Class / Group for Behavior for F2009 to F2014 (see Page 136-140 of 250).

11.12 Are Societal [Change] activities and costs included in Behavior?

11.13 Describe the activities and costs that are included in Behavior and provide the costs for each of the years F2011 to F2014.

11.14 What DSM costs are included in Operating Costs? Provide the amounts and where they are reported.

12.0 Topic: Operating Costs, Capital Expenditures and Additions

Reference: Exhibit B-1-3, Appendix CC, Recommendation 19;

Explanation: Additional information is required for Consultant and Contract Services.

Request:

12.1 Provide definitions for:

12.1.1 Consultant and Contract Services

12.1.2 Management Consulting

12.1.3 Contract Employees

12.2 Where in Operating Expenses are these costs reported?

12.3 How does a consultant's report inform a management decision or substitute for it?

12.4 Who reviews whether consulting services should be used at all?

12.5 How are 1-off/unique projects engineered and constructed?

12.5.1 Why would any such projects be done by BC Hydro?

13.0 Topic: Capital Expenditures and Additions

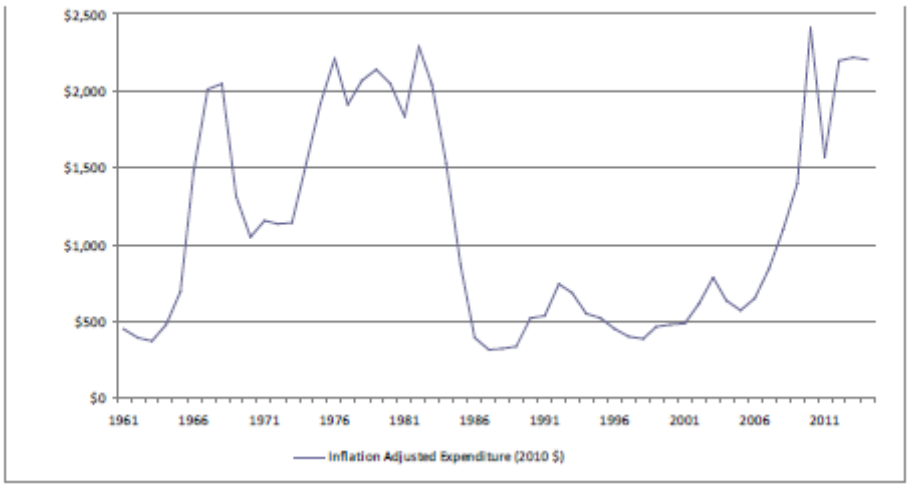
Reference: Exhibit B-1-3, Page 1-9;

Explanation:

BC Hydro states:

> *"The current capital program follows a 20-year period in which annual capital investments were relatively low, as shown in the following chart. The chart also shows that the current level of spending is similar to the level of spending during the construction in the 1960s, 1970s and 1980s, adjusted for inflation."*

Figure 1–1 BC Hydro Capital Expenditures, 1961-2014



(P 1-9)

Request:

13.1 Provide the years when BC Hydro was operating under a rate freeze.

14.0 Topic: Revenue Requirements / Rate Increases

Reference: Exhibit B-1-3, Page 1-18 to 1-20, Page 1-28 to 1-31, Page 2-3, Page 2-10 to 2-12; Page 7-26;

Explanation:

BC Hydro has provided the Gross View (increase in operating costs - line 2) from F2011 NSA-12 to F2012 of $342 million includes $178 million of reduced capitalized overhead arising from IFRS, an increase of $83 million in deferred Site C costs, and an increase of $22 million in deferred SMI Program costs) and Net View (the costs for each component of the revenue requirement that are recovered in existing rates) for Revenue Requirements in Table 1-1 and Table 1-2.

BC Hydro states:

> *"In the absence of the proposed rate smoothing, the planned current operating costs would be $893 million in F2012, $948 million in F2013 and $980 million in F2014; Annual adjustments for rate smoothing are shown in Table 7–8 and the increases from the prior year would be $127 million in F2012, $55 million in F2013 and $32 million in F2014. The majority of these operating cost increases are due to IFRS adjustments, and the elimination of credits to operating costs in F2011." (P 1-20)*

One-time credits of $104 million and $63 million in F2011 mitigated the rate increase in F2011 but added to the required rate increase in F2012 before rate smoothing. With the add-back of

the $35 million reduction in OM&A, the Revenue Requirements increase $202 million or a rate increase of 6.14% based on F2012 forecast revenue.

> *The contribution of Cost of Energy to the cumulative rate increase over the three-year period has increased from 4.1 per cent to 7.9 per cent. This increase is principally due higher IPP volumes ($468 million) and the reclassification of four IPP EPAs ($125 million), partially offset by the proposed transfer to the NHDA ($215 million). (P 1-130)*

A deferral of $438 million ($223 million + 215 million) in energy costs (rate smoothing) in F2011 deferred a 13+% increase over a number of years.

AMPC has attempted to summarize the effect of current deferred costs and one-time credits in the table below. In addition, BC Hydro pension and other post-employment benefit plans will be subject to a deferral account and future recovery (F2015).

Costs Deferred	F2011	F2012	F2013	F2014
OM&A				
Net Employment Costs	62.8	0.0	0.0	0.0
SMI	5.1	46.4	50.4	15.2
IFRS	0.0	186.0	160.2	142.4
IFRS Pension	0.0	0.0	761.9	0.0
DSM	127.6	184.6	199.8	236.3
Rate Smoothing				
Arrow Water System	11.0	0.0	0.6	0.1
Outsourcing Implementation	0.0	16.3	10.8	3.6
Total	206.5	433.3	1,183.7	397.6
Finance Charges				
Net Employment Costs	(1.2)	0.0	0.0	0.0
Finance Charges	100.1	4.0	0.0	0.0
SMI	1.5	13.4	33.2	46.0
IFRS	0.0	9.9	4.8	4.9
Cost of Energy	0.0	0.4	1.0	1.4
Rate Smoothing	0.0	28.1	39.4	52.7
Total	100.4	55.8	78.4	104.9
Return on Equity				
SMI	0.0	7.1	17.1	22.2
Total	0.0	7.1	17.1	22.2
Amortization & Recoveries				
SMI	0.0	0.0	0.0	0.0
DSM	0.0	0.0	(12.3)	(25.6)
Rock Bay Remediation	0.0	0.0	0.0	0.0
IFRS	0.0	0.0	(4.7)	(8.7)
IFRS Pension	0.0	0.0	(38.9)	(34.7)
Rate Smoothing	0.0	0.0	(62.3)	(0.5)
Total	0.0	0.0	(118.2)	(69.5)
Cost of Energy / D A Additions	218.5	65.9	103.2	46.3
BCTC	0.0	0.0	0.0	0.0
	218.5	65.9	103.2	46.3
Total Including DSM	525.4	562.1	1,264.2	501.5
Total Before DSM	397.8	377.5	1,076.7	290.8

BC Hydro sets out its forecast of long-term rate increases as follows:

> *"… BC Hydro's new current view of its rate increases over the next 10 years (from F2011 to F2020) is around 100 per cent cumulatively. The average annual increases from F2016 to F2020 are currently forecast at around 5 per cent per year. BC Hydro prepared this long-term rate increase forecast to inform its load forecasting and DSM plans. The rate forecast includes assumptions regarding the ongoing capital investment program, including the timing and cost of major projects currently anticipated. It also*

includes assumptions about the recovery of balances in regulatory accounts and any further additions to those accounts, ***excludes the IFRS changes described in this application, assumes no further additions to the Deferral Accounts, and excludes recoveries of some costs held in other regulatory accounts, such as First Nations settlement costs. Accordingly, the long-term rate forecast likely understates the continuing upward pressure on BC Hydro's rates beyond this test period.****" (Emphasis added) (P 2-2)*

Request:

14.1 Confirm that the AMPC table of Deferred Costs is correct or provide a revised table with explanations for changes.

14.2 Provide a table of revenue requirements and rate increases excluding the deferral of current period costs (including the costs in the fiscal period incurred) per the response to IR 14.1.

14.3 Provide a table of revenue requirements showing all deferrals (excluding cost of energy HDA, NHDA and TIDA) and rate smoothing as a single separate line item.

14.4 When were the increases in energy costs in F2011 of $223 million and $215 million identified?

15.0 **Topic:** Rate Management, Deferral Accounts & DARR, Regulatory Accounts

Reference: Exhibit B-1-3, Page 1-2, Page 1-15, Page 1-30, Page 7-30-7-33;

Explanation:

BC Hydro provided a Summary of Reductions to Revenue Requirements as set out below.

New Table 1-A Summary of Reductions

	($ million)	Total F12-F14	Govt Review	Evidentiary Update	Both
1	Business Group Operating Cost Reductions	(163)	(163)	-	-
2	Impact of Reductions in Forecast Capital Additions	(54)	(54)	-	-
3	Impact of Lower Actual F2011 Capital Additions	(61)	-	(61)	-
4	Increase in Forecast of Powerex Net Income	(136)	-	-	(136)
5	Higher PTP Allocation to Powerex	(39)	-	-	(39)
6	Impact of Change to DSM Amortization Period	(101)	(101)	-	-
7	Impact of Reductions in Forecast DSM Expenditures	(7)	(7)	-	-
8	Impact of Lower Actual F2011 DSM Expenditures	(19)	-	(19)	-
9	Impact of Lower Interest Rates	(161)	-	(161)	-
10	Refund of Credit Balances in Regulatory Accounts	(27)	-	-	(27)
11	Increase in Forecast Miscellaneous Revenues	(26)	-	(26)	-
12	Reduction in Forecast Taxes	(14)	-	(14)	-
13	Other	(10)	-	-	(10)
14	Total	(819)	(326)	(281)	(212)

(P 1-2)

The analysis below of the Reductions indicates that $304 million or 37% is under the control of BC Hydro, $185 million or 23% is external to BC Hydro and $329 million or 40% is an increase deferred until after F2014. A further $215 million in current Cost of Energy is being deferred until after F2014.

Request:

15.1 Confirm the following summary, description of and effect of the Reductions. If BC Hydro does not agree, provide a revised table with explanations of changes in the nature of the

Reductions as indicated.

New Table 1-A Summary of Reductions

$million	Total	Real BCH	Real External	Deferral
Business Group Operating Cost Reductions	163	163		
Impact of Reductions in Forecast Capital Additions	54	54		?
Impact of Lower Actual F2011 Capital Additions	61	61		?
Increase in Forecast of Powerex Net Income	136			136
Higher PTP Allocation to Powerex	39			39
Impact of Change to DSM Amortization Period	101			101
Impact of Reductions in Forecast DSM Expenditures	7	7		
Impact of Lower Actual F2011 DSM Expenditures	19	19		
Impact of Lower Interest Rates	161		161	
Refund of Credit Balances in Regulatory Accounts	27			27
Increase in Forecast Miscellaneous Revenues	26			26
Reduction in Forecast Taxes	14		14	
Other	10	?	10	
Total	818	304	185	329
Cost of Energy	215			215
	1,033	304	185	544

16.0 Topic: IFRS, Deferral/Regulatory Accounts

Reference: Exhibit B-1-3, Page 7-28 to 7-34; Page 8-22; New Appendix CC, Page 5 of 18;

Explanation:

BC Hydro is proposing amortization of Regulatory Accounts for IFRS deferrals, including overheads, pension and post-employment benefits based on estimates of the liability to be recognized. At the same time, BC Hydro is undertaking a more detailed study of capital overhead allocation and the estimated benefit liabilities are subject to change. BC Hydro states that the actual amount (estimated) will be calculated as at April 1, 2011.

> *… BC Hydro does not propose to add any further amounts to this account after conversion to IFRS is complete. (P 8-22)*

> *… BC Hydro currently estimates that the liability that must be recognized on transition to IFRS will be $762 million and BC Hydro is now proposing that the IFRS Pension Regulatory Account be amortized by $38.9 million and $34.7 million in F2013 and F2014 respectively, which results in the same revenue requirement impact as would have resulted under CGAAP. (P 7-28)*

> *… there will be other balance sheet adjustments that BC Hydro will be required to make at the time of conversion to IFRS. (P 7-33)*

… If the net impact of the balance sheet adjustments required at the time of conversion to IFRS (other than any impacts already addressed by the IFRS PP&E Regulatory Account or the IFRS Pension Regulatory Account) is material, then BC Hydro may seek BCUC approval to establish another regulatory account to prevent the net impact of the balance sheet adjustments from affecting the level of BC Hydro's retained earnings on conversion to IFRS. (P 7-33)

Recommendation 16: Revisit the current post-retirement benefit coverage for extended health and life insurance benefits provided to reduce the impact to ratepayers.

BC Hydro Response: Agreed. BC Hydro will revisit in conjunction with the Total Compensation Review planned in response to Recommendation #13, BC Hydro agrees to evaluate its Post Retirement Benefit design relative to market. A comprehensive legal review will also be conducted to understand the extent of change that is possible given the long history with the current program and the inclusion of post-retirement benefits within the collective agreements.

Timeline: F12-F14 (New App CC, P 5 of 18)

Request:

16.1 Provide a list and estimate of the other IFRS adjustments that BC Hydro has identified.

16.2 How accurate is the $762 million pension (previously $900 million) and the post-employment benefit plan liability estimate? Provide the analysis and reports supporting the $762 and $900 million amounts.

16.3 What is the potential variability in the benefits liability to be recorded under IFRS and what are the key factors that determine the liability?

16.4 How will changes in the benefit liability estimate be treated?

16.5 How will BC Hydro deal with changes (increases and decreases) in the IFRS deferrals and the resulting proposed amortization?

16.6 What opportunities exist for BC Hydro to reduce the pension and post-employment benefit plan costs?

16.7 What steps has BC Hydro taken in response to the review Panel Recommendation 16?

17.0 Topic: Cost of Energy: Water Rentals, Water Licenses, Water Use Plans, Remissions

Reference: Exhibit B-1-3, Page 1-22 to 1-23;

Explanation:

BC Hydro states:

"The move to the Nature View presentation has resulted in some costs being reclassified, such as the reclassification of the cost of water licences from energy costs to operating costs." (P 1-22, 1-33)

Request:

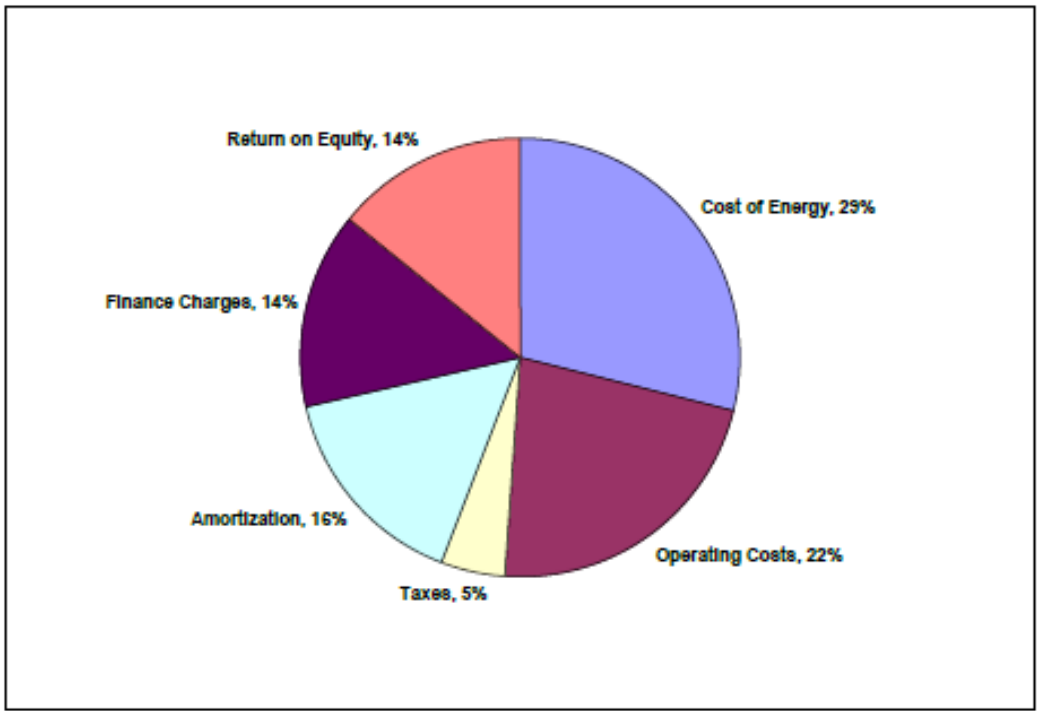
17.1 Define what BC Hydro means by each of: Water Rentals, Water Licences, Water Use Plans and Remissions and how each of these costs and credits are treated/reported.

18.0 Topic: Revenue Requirements

Reference: Exhibit B-1-3, Page 1-24; Exhibit B-1-3, Appendix E, Page 9 of 41;

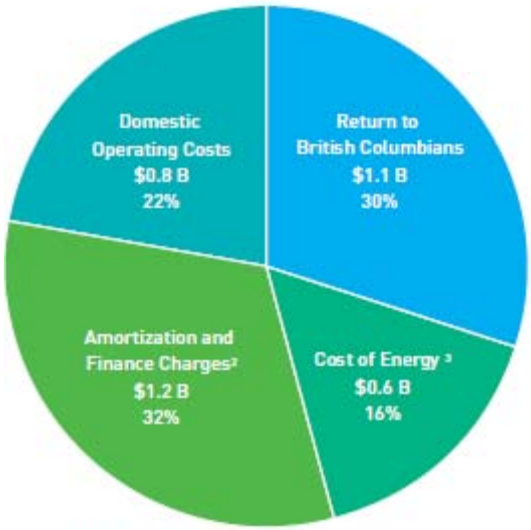
Explanation: BC Hydro has provided a 3 year summary pie chart of Revenue Requirements and a F2012 pie chart of Revenue Requirements.

Figure 1–2 Composition of Average Revenue Requirements, F2012 to F2014



(P 1-24)

TOTAL ESTIMATED F2012 REVENUE REQUIREMENT—$3.8 BILLION[1]



[1] Does not include miscellaneous and non-tariff revenue.

[2] Amortization and Finance Charges are increasing due to the increased capital expenditures. Includes amortization of regulatory accounts such as Demand-Side Management (DSM).

[3] Includes IPP purchases and market purchases of electricity. Net of Trade Income and miscellaneous non-tariff revenues.

Note: Chart may not add due to minor rounding.

(App E, P 9 of 41)

Request:

18.1 Provide a stacked bar graph and area graph for F2010 to F2014 for both the Gross and Net (Current) Revenue Requirements in the format of Figure 1-2 and the summary information as per the pie chart in the Service Plan (App E).

18.2 Reconcile the growth in Finance Charges with the Growth in Return on Equity.

18.3 Confirm that BC Hydro recovers 100% of debt costs and a return on deemed equity of 30%.

18.3.1 Provide a table of the Finance Charges (Debt Costs) and Equity Return for the years F2007 to F2014.

18.4 Provide, for F2007 to F2014: total debt, total actual equity, total actual capital, and the amount of deemed equity capital.

18.5 Confirm that BC Hydro does not earn a return on equity on deferral accounts but does recover all debt financing costs.

18.6 Provide, for F2007 to F2014: the total capital in the deferral accounts, and quantify the associated debt and equity (real or otherwise).

18.7 Quantify the amount of equity (deemed or otherwise) that is related to deferral accounts that does not attract a return on equity.

19.0 Topic: Subsidiary Net Income (Powerex) & Allocation of PTP Charges to Powerex

Reference: Exhibit B-1-3, Page 8-11

Explanation: BCH states:

Other factors affecting the lower forecast Trade Income are the reduced flexibility in the BC Hydro generation system as BC Hydro integrates intermittent resources, excess generating capacity in key markets and the appreciation of the Canadian dollar. (P 8-11)

Request:

19.1 Explain "reduced flexibility in the BCH generation system" and provide examples for illustrative purposes.

19.2 Provide forecast details on the impact of reduced flexibility in the BC Hydro generation system on Trade Income for F2012, F2013 and F2014.

19.3 Explain "excess generating capacity in key markets" and provide examples for illustrative purposes.

19.4 Provide forecast details on the impact of excess generating capacity in key markets on Trade Income for F2012, F2013 and F2014.

19.5 Provide forecast details on the effect of appreciation of the Canadian dollar.

20.0 **Topic:** Subsidiary Net Income (Powerex) & Allocation of PTP Charges to Powerex

Reference: Exhibit B-1-3, Page 8-11;

Explanation: BCH states:

The forecast Trade Income and Powertech net income for the test period are provided on Schedule 1.0, line 17.

Request:

20.1 Confirm that Trade Income and Powerex Net Income have the same meaning. If not, explain the difference.

21.0 **Topic:** Subsidiary Net Income (Powerex) & Allocation of PTP Charges to Powerex

Reference: Exhibit B-1-3, Appendix A, Page 2 of 57, Line 17

Explanation: In Schedule 1.0, Powerex Net Income is shown in Line 17. Additional information is required to understand Trade Income and the variability.

Request:

21.1 Provide a detailed financial breakdown of the components of Powerex Net Income for F2011 (actual), F2012, F2013 and F2014.

22.0 **Topic:** Subsidiary Net Income (Powerex) & Allocation of PTP Charges to Powerex

Reference: Exhibit B-1-3, Page 8-11;

Explanation: BCH states:

In the Amended F12-F14 RRA, forecast Powerex net income has been increased to $133 million in F2012 and $113 million in F2013 and F2014. These forecasts are reflective of the actual average Powerex net income over the last five years. Using a five-year average as the basis of forecasting Powerex net income is reasonable given the year-to-year volatility in market conditions. (P 8-11)

Request:

22.1 Using the same forecasting methodology as in the original Application (Exhibit B-1),

provide a current forecast for Trade Income by year and compare to the forecast in the Amended Application.

22.2 Compare the forecast from IR 22.1 to the forecast in the revised Application (Exhibit B-1-3) and identify the amount that would go into a deferral account if the forecast from IR 22.1 was correct.

23.0 Topic: Subsidiary Net Income (Powerex) & Allocation of PTP Charges to Powerex

Reference: Exhibit B-1-3, Page 8-13

Explanation: BCH states:

> *In consequence BC Hydro does not perceive, at this time, any value in continuing to investigate and develop potential market opportunities for export sales in excess of self-sufficiency requirements, whatever those might turn out to be. Accordingly, the business group within Powerex that was established for the purpose of investigating and developing such opportunities has been disbanded, the associated positions eliminated, and the commitment to develop a cost-allocation mechanism made superfluous. (P 8-13)*

Request:

23.1 Confirm whether there was any study, business case or documentation, etc. completed on the investigation of potential market opportunities for export sales in excess of self-sufficiency requirements. If so, provide copies of this material.

24.0 Topic: Subsidiary Net Income (Powerex) & Allocation of PTP Charges to Powerex

Reference: Exhibit B-1-3, Page 8-25; Amended Appendix A, Schedule 3.4, Line 19

Explanation: Schedule 3.4, line 19 (BC Hydro PTP Charges) indicates that Actual F2011 charges were $54.1 million.

BC Hydro states that:

> *BC Hydro is no longer proposing to change to the method of allocating Point-to-Point transmission (PTP) charges to Powerex. (P 8-25)*

The BC Hydro PTP Charges in Schedule 3.4 (line 19) in the original Application and the amended Schedule 3.4 (line 19) show only $0.3 million in variation.

Request:

24.1 Describe the methodology that is being proposed for allocating PTP charges.

24.2 Advise whether F2012, F2013 and F2014 for BC Hydro PTP Charges (Line 19) are based on the old methodology for allocating PTP charges or if not, describe the methodology used.

24.3 Advise whether F2012, F2013 and F2014 for Powerex PTP Charges (Line 18) are based on the old methodology for allocating PTP charges or if not, describe the methodology used.

25.0 **Topic:** Other: RECs

Reference: Exhibit B-1-3, Amended Appendix M; Appendix N, Page 1 of 2;

Explanation: Powerex states that:

> *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. (App N, P 1 of 2)*

In order to get an indication of the magnitude of the GWhs and revenues associated with the RECs sold from BC Hydro to Powerex more data is requested.

Request:

25.1 Provide data on the GWhs of RECs that are sold from BC Hydro to Powerex for each year from F2007 to F2011.

25.2 Provide BCH and Powerex revenues on the sales of RECs for F2007 to F2011.

25.3 Provide the GWhs RECs that are forecast to be sold from BC Hydro to Powerex for each of F2012, F2013 and F2014.

25.4 Provide Powerex revenue projections resulting from the RECs sold from BC Hydro to Powerex for each of F2012, F2013 and F2014.

26.0 **Topic:** Non-Tariff and Inter-Segment Revenues

Reference: Exhibit B-1-3, Page 8-10; 8.8 Inter-Segment Revenues

Explanation: Inter-Segment Revenues includes mark to market gains/losses on electricity hedges with Powerex for market purchases.

Request:

26.1 Does BCH have a risk management policy that addresses electricity hedges for market purchases? If so, provide a copy of this policy.

26.2 Does BC Hydro continue to hedge market electricity purchases?

26.3 Explain the rationale for BCH implementing electricity hedges for market purchases.

26.4 Describe BCH's hedging policy for electricity hedges with Powerex for market purchases and the transactional costs, if any, for implementing these electricity hedges.

26.5 Explain how hedging with a subsidiary results in any real hedging of prices.

26.6 Provide the hedging results / Gains (Losses) (actual, mark to market, etc.) for F2007 to F2011 to date.

27.0 **Topic:** Cost of Energy

Reference: Exhibit B-1-3, Page 4-4;

Explanation: BCH states that:

> *The forecast used in the Application is the annual average across all the ensembles and this average therefore shows both surplus market sales and market purchase volumes for each forecast year, as shown on Schedule 4.0. The increase in likelihood of surplus sales during the test period reflects progress toward self-sufficiency.*

Request:

27.1 What is the impact on surplus sales if there is a change in the self-sufficiency criteria (as defined in the Clean Energy Act) for BC Hydro.

27.1.1 Average Water is used instead of Critical Water and there is no Insurance requirement.

27.1.2 Average Water is used instead of Critical Water but BC Hydro is able to acquire competitive supplies that can be sold into the market at a price that on average exceeds the nominal cost of purchases.

27.2 Discuss the impact of this change on the corresponding Cost of Energy forecast for the test period.

28.0 Topic: Cost of Energy

Reference: Exhibit B-1-3, Page 4-6;

Explanation: BCH states that:

All transactions between Powerex and BC Hydro, as governed by the TPA, are transacted at market prices.

Request:

28.1 Explain the Transfer Pricing Agreement between Powerex and BC Hydro as it applies to both electricity and natural gas.

28.2 Explain why transactions between BC Hydro and Powerex are done at market prices versus on a sale price less a transaction fee.

28.3 Comment on why Mid-C market prices (Mid-C adjusted for transmission to the B.C. border) are used in the TPA.

28.4 Since transactions between Powerex and BC Hydro (and vice versa) can occur on any hour, comment on the applicability of using a flat HLH or LLH Mid-C index as opposed to an hourly index which might be more reflective of transactions occurring during any specific hour.

28.5 Describe the types of products that Powerex makes use of on the BC Hydro system (both generation and transmission related).

28.5.1 Confirm whether the TPA addresses all of these products.

28.5.2 Explain how the TPA compensates BC Hydro for Powerex use of these products?

28.6 Describe how Powerex uses storage in the BC Hydro system.

28.7 Explain how Powerex's use of storage (both seasonally, inter-day and inter-hour) is addressed in the TPA.

28.8 Comment on the type of products that BC Hydro requests Powerex to acquire on its behalf and the products BC Hydro uses in Powerex's energy portfolio.

28.8.1 Explain how the TPA compensates Powerex for these products.

28.9 Have there been any reviews or audits of the TPA to determine if this is a reasonable method for compensating Powerex and BC Hydro. If so, provide copies of these reports.

29.0 Topic: Cost of Energy: MCM

Reference: Exhibit B-1-3, Page 4-6 to 4-8;

Explanation: BCH states that:

The Marginal Cost Model (MCM) suite is the primary set of tools used by BC Hydro to coordinate its major reservoir operations with IPP purchases, thermal generation and market purchases and sales. (P 4-6)

Request:

29.1 Provide details on how the MCM is used in decision-making and provide specific examples for illustrative purposes.

29.2 Provide and discuss any reviews or audits associated with decisions made using the MCM.

29.3 What access, if any, does Powerex have to the MCM?

29.4 Does Powerex contribute to the cost of the MCM? And if so, what is the cost allocation?

29.5 Comment on the potential for any commercial applications for this model that could be a potential revenue generator for BC Hydro.

30.0 Topic: Cost of Energy

Reference: Exhibit B-1-3, Page 4-9 – 4-10, New Table 4-A

Explanation: In New Table 4-A, in FY011 Net Purchases from Powerex increased 27.2% and Market Electricity Purchases increased 6.7% from F2011 NSA-9.

BC Hydro states that:

The actual average cost of market purchases in F2011 was $33.9 per MWh, lower than the forecast price of $41.7 per MWh in the F11 RRA NSA. (P 4-10)

And _____

Total system inflow for F2011 was 86 per cent of normal, lower than the forecast of 90 per cent of normal included in the F11 RRA NSA. (P 4-9)

In addition, New Table 4-A shows 53 GWh of Surplus Sales in F2011.

Request:

30.1 Provide a breakdown of purchase costs on a $/MWh basis for the Net Purchases from Powerex and for the Market Electricity Purchases shown in New Table 4-A.

30.2 Provide details on the justification for Surplus Sales given that BC Hydro was experiencing low system inflows.

30.3 Provide a breakdown of sales by volume on a $/MWh basis for the Surplus Sales as shown in New Table 4-A.

31.0 Topic: Cost of Energy

Reference: Exhibit B-1-3, Page 4-22, Amended Table 4-3(ii)

Explanation: The Amended Table 4-3(ii) Natural Gas for Thermal Generation provides natural gas costs in $million for each of BCH's thermal generation facilities; Burrard, Fort Nelson.

Request:

31.1 Provide a breakdown of the natural gas costs by their various components (such as gas, transportation, taxes, etc.) for the Amended Table 4-3(ii).

32.0 **Topic:** Cost of Energy

Reference: Exhibit B-1-3, Page 4-11 to 4-14;

Explanation: BCH's assumption is for normal inflows in F2013 and F2014 resulting in a storage energy content of 12,600 GWh and 11,900 GWh respectively.

Request:

32.1 Were there any sensitivity tests done for inflows other than the assumption of normal inflows?

32.1.1 Provide the results of any sensitivity test runs and the impact on the Cost of Energy ($million).

32.2 Why is the storage less in F2014 than in F2013?

33.0 **Topic:** Cost of Energy

Reference: Exhibit B-1-3, Page 4-10, New Table 4-B, Page 4-23

Explanation: New Table 4-B includes a line item "Other" which is included in the Cost of Energy. Other contributed $22.6 million to the Cost of Energy (F2011 Actual).

In addition, BCH states:

> *Prior to F2012, the line item for "Other" components of the Cost of Heritage Energy, as shown on Schedule 4.0, included Load Curtailment Costs, System Operations Fund Offsets, Water Use Plan Water Licence Costs, and Compensation and Mitigation Costs. (P 4-23)*

Request:

33.1 Provide a breakdown (in $million) for each of these cost components.

34.0 **Topic:** Cost of Energy

Reference: Exhibit B-1-3, Page 4-16 to 4-17, New Figure 4-A, New Figure 4-B, New Figure 4-C

Explanation: BCH provides new updated forecast electricity (Mid-C) and gas (Sumas) market prices based on actuals and forward curves as of April 6, 2011.

Request:

34.1 Provide a forecast using the most current forward price curve showing the impact / change in cost of energy.

34.2 Are the forecasts prepared (or audited) by an independent source or prepared by BC Hydro?

34.3 Discuss the methodology on how these forecasts are derived.

34.4 Discuss the assumptions that went into the preparation of these forecasts.

34.5 Does BCH conduct any sensitivity analysis around using different electricity and natural gas price forecasts? If so, provide the result of these analyses as they relate to the Cost of Energy.

35.0 **Topic:** Cost of Energy

Reference: Exhibit B-1-3, Page 4-26, Amended Table 4-5

Explanation: BCH states that:

> *A total of 35 contracts have now been terminated including 11 contracts since the filing of the F2011 RRA. The contracts have been cancelled for various reasons such as unexpected construction cost increases, financing obstacles and permitting difficulties. (P 4-26)*

Request:

35.1 Provide a breakdown of the number of cancelled contracts according to the various reasons for termination.

35.2 In each of these cases, comment on BC Hydro's actions and plans to work with the IPP developer to mitigate these obstacles, other than to terminate the contracts.

36.0 **Topic:** Cost of Energy

Reference: Exhibit B-1-3, Page 4-27 to 4-28, Table 4-6 and Amended Table 4-6

Explanation: Amended Table 4-6 was updated but did not include the No. of EPAs.

Request:

36.1 Update the Amended Table 4-6 IPP and Long-Term Purchase Volumes to include No. of EPAs (and forecast EPAs) consistent with Table 4-6 in the Application.

37.0 **Topic:** Cost of Energy

Reference: Exhibit B-1-3, Page 4-28 to 4-30, Amended Table 4-6, Amended Table 4-7

Explanation: The amended Tables 4.6 and 4.7 show IPP and Long-Term Purchase Volumes and Costs in aggregate format.

The above referenced tables include long-term purchases associated with the Integrated Power Offer which were not initially included with the original Application.

Successful projects were selected in August 2011 in the Bioenergy Phase 2 Call and therefore not reflected in the foregoing summary.

BCH states that:

> *Under that agreement Rio Tinto Alcan has the option to sell its surplus energy, subject to tie-line constraints, to BC Hydro at a price of approximately $60 per MWh over the test period. (P 4-28)*

Request:

37.1 For each IPP and Long-Term Purchase listed in the above referenced tables, provide details on the purchase prices (by volume) on a $/MWh basis for each line item. Where there are legitimate confidentiality issues, provide a range of prices for a group of contracts.

37.2 What assumptions were made about new calls during the test period (F2012 – F2014) in preparing Amended Tables 4-6 and 4-7?

37.3 Revise Amended Tables 4-5, 4-6 and 4-7 to include the successful Bioenergy Phase 2 projects.

38.0 **Topic:** Cost of Energy

Reference: Exhibit B-1-3, Amended Appendix A, Page 21 of 55, Schedule 4.0 line 11

Explanation: Energy from IPPs and Long-Term Commitments (line 11) contribute 66%, 66% and 72% for F2012, F2013 and F2014, respectively to the Total Gross CoE (Line 18).

Request:

38.1 Discuss mitigation measures, if any, for reducing the energy costs of IPPs and Long-Term Commitments.

38.2 Has BCH undertaken any audit of any of the IPP and Long-Term Commitment contracts with the purpose of reducing the Cost of Energy? Discuss the recommendations arising from these audits.

39.0 **Topic:** Cost of Energy

Reference: Exhibit B-1-3, Page 4-31;

Explanation: BCH states that:

> *Certain energy purchases by BC Hydro from Powerex under the TPA create limited rights and obligations for Powerex to purchase energy back from BC Hydro for later use in electricity trade. These purchases by BC Hydro are allocated to the Trade Account. Net transfers to or from the Trade Account are shown as Net Purchases or Sales from Powerex. (P 4-31)*

Request:

39.1 Describe how the Trade Account operates. Provide a numerical example for illustrative purposes.

39.2 Explain how BCH and Powerex are each compensated under the TPA as it relates to the Trade Account.

39.3 Do the rights and obligations affect the balances in deferral accounts between years? Which accounts?

40.0 **Topic:** Cost of Energy

Reference: Exhibit B-1-3, Page 4-31 to 4-32;

Explanation: BCH states that:

> *Approximately one-third of the energy supplied in these areas is purchased by BC Hydro from IPPs. (P 4-31)*

Request:

40.1 List the IPP contracts that serve the NIA.

40.2 Provide a breakdown of these contracts by $/MWh and their associated volumes or at a minimum, if there are confidentiality issues, provide the range of prices.

41.0 **Topic:** Cost of Energy

Reference: Exhibit B-1-3, Amended Appendix A, Page 22 of 55, Line 41;

Explanation: Line 41 shows NIA Unit Costs ($/MWh) of 229.5, 249.3 and 267.5 for the updated F2012, F2013 and F2014, respectively

Request:

41.1 Explain the reasons why Unit Costs for NIA are so high on a $/MWh basis.

41.2 Explain the reasons the F2012–F2014 (update) costs have increased on a year-to-year basis from F2008-F2011 (actual) on a $/MWh basis.

41.3 Discuss mitigation measures, if any, for reducing the costs of servicing the NIA.

42.0 Topic: Subsidiary Net Income, Point to Point (PTP) Charges

Reference: Exhibit B-1-3, Page 1-33 to 1-34;

Explanation: BC Hydro has revised (increased) the allocation of PTP costs between BC Hydro and Powerex after proposing a decrease in the allocation in the original Application.

Request:

42.1 Confirm that the cap on Trade Income remains at $200 million.

42.2 Provide a forecast of the PTP allocation between BC Hydro and Powerex for F2012 to F2016 and provide an explanation of the changes in PTP allocations.

42.3 What net impact on revenue requirements will an increase in PTP charges to Powerex have as long as the Trade Income Cap is not reached?

43.0 Topic: Depreciation and Amortization

Reference: Exhibit B-1-3, Page 1-42, Page 8-1 to 8-2; Appendix G;

Explanation: BC Hydro is seeking approval of depreciation rates on certain plant components, in part due to changes proposed on the basis of IFRS requirements.

Request:

43.1 Provide the current and proposed depreciation rates, capital cost of the affected plant accounts and the change in depreciation expense resulting from the changes in depreciation rates.

44.0 Topic: Deferral Accounts and DARR

Reference: Exhibit B-1-3, Page 1-42; Page 2-6 – 2-10; Appendix H;

Explanation: BC Hydro was proposing to return to a 5 year deferral account recovery (approximately) from a 10 year recovery based on Table 7-3 (Appendix H, Table 2) but subject to a net bill increase of not more than 10% in each of F2013 and F2014.

BC Hydro is now proposing that the DARR remain unchanged at 2.5%.

The HDA and NHDA accounts have been depositories for more than energy cost variances (HDA from average water; NHDA from cost variances), including sales variances.

Request:

44.1 Identify the amounts by year, other than cost of energy variances from forecast that have been recorded in the HDA and NHDA accounts since the DARR was implemented.

44.2 Provide a table of only energy costs for the HDA and NHDA accounts and TIDA amounts for F2010 to F2014 and DARR (energy cost) recoveries based on the 10 year formula agreed to in the F2011 NSA.

44.2.1 Deduct the $233 million cost of energy deferral for Rate Smoothing from F2011 and the proposed deferral of $215 million in F2012 and show the adjusted balance.

44.3 Prepare a table similar to Amended Table 2-3 of deferral accounts other than HDA and NHDA cost of energy identifying those accounts that BC Hydro currently deems to be recoverable through the DARR and those that not currently recovered through a rate rider.

44.4 Confirm that the Rate Smoothing deferral account (as determined by BC Hydro; excluding other rate smoothing deferrals) will be recovered over 3 years under the BC Hydro proposal but only if the rate increase remains under 10%.

44.5 Calculate what additional rate rider (non-energy DARR) would be needed to recover the deferral accounts other than the HDA and NHDA energy costs only over 5 years, 10 years and 15 years for:

a. All other deferral accounts including Rate Smoothing,

b. All other deferral accounts excluding Rate Smoothing.

45.0 Topic: GMS 3 Regulatory Account

Reference: Exhibit B-1-3, Page 1-43; Page 7-15 to 7-19; Appendix AA;

Explanation: BC Hydro is requesting full recovery of the GMS 3 costs and transfer of the costs to the Heritage Deferral Account (HDA).

Request:

45.1 File all exhibits (reports), transcripts (testimony) and argument from the F2009 and F2010 Revenue Requirements Proceeding relating to the GMS 3 failure and costs.

45.2 Confirm that all of the current (F2012-F2014 RRA) BC Hydro evidence is from current or former BC Hydro employees.

45.3 Provide references in the current GMS 3 evidence to the use of DO NOT USE (DNU) shear pins.

46.0 Topic: Load Revenue and Forecast, Capital Expenditures and Additions: Fort Nelson, Dawson Creek, Chetwynd

Reference: Exhibit B-1-1, Page 3-8 to 3-9; Page 6-50; Page 6-52; Page 6-61; Appendix J, GDAT Project, DCAT Project;

Explanation: BC Hydro is anticipating increased oil and gas loads in northeast BC.

The DCAT Project consists of extending the 230 kV transmission system to Bear Mountain Terminal in Dawson Creek to meet the area's high load growth, primarily from oil and gas development. The forecast capital cost of the project ranges from $150 to $250 million. BC Hydro plans to apply for a CPCN for the project in spring 2011. (P 6-50)

The GDAT Project is in the identification phase and has an estimated cost of $75 to $300 million and is in addition to the DCAT project and is to proceed in early 2011 in order to attain the earliest in-service date possible. (Amend App J, P 99)

_____

This area [Fort Nelson] of the province is not connected to the BC Hydro integrated system, so the generating station is the primary electricity supply for Fort Nelson and the surrounding area. (Amend App J, P 75)

Request:

46.1 Describe the types of loads (compression, pumping, processing, etc.) that BC Hydro expects to serve by area in northeast BC and the supply, transmission and distribution facilities available to serve the loads and whether the loads are as a result of fuel switching or new resource development.

46.2 Confirm that Fort Nelson is connected to the Alberta grid.

46.3 What is the expected economic life of the load associated with shale gas development? Please discuss assumptions concerning shale gas well decline rates, drilling activity, expected hydraulic fracturing frequency, and policy limitations to future development, including water licences and species at risk legislation.

47.0 **Topic:** Capital Expenditures and Additions, Government Review and BC Hydro Responses;

Reference: Exhibit B-1-3, Page 5-30

Explanation: BC Hydro leads the planning and execution of generation capital projects.

Request:

47.1 Does Generation Project Delivery include Site C?

47.2 Provide the details of project staffing and costs, including for example, engineering.

47.3 How does BC Hydro plan to deal with project staffing levels as projects are completed and the nature of projects changes?

47.4 Provide the number of contract and consulting personnel and costs for generation capital projects by project.

48.0 **Topic:** Capital Expenditures and Additions, Aging Infrastructure

Reference: Exhibit B-1-3, Page 5-62 to 5-64;

Explanation: BC Hydro states:

A large portion of the transmission system was built in the 1960s and 1970s and will soon be at or exceeding end-of-life condition. Similarly, a large portion of the distribution system has, or soon will, exceed design life. (P5-63)

and, _____

Ageing infrastructure and prolonged use of the system at or near capacity have combined to create a trend of degrading reliability performance. (P 5-64)

Request:

48.1 Explain what is meant by a large and a huge proportion in terms of percentage of

Transmission and Distribution plant, historical dollar value and replacement cost.

48.2 How does prolonged use at or near capacity degrade reliability performance?

48.3 For each of Transmission and Distribution, explain with details, age and condition descriptions which components (poles, lines, circuit breakers, transformers, insulators, sub-stations, etc.) are at end of life.

49.0 Topic: Capital Expenditures and Additions, Technology

Reference: Exhibit B-1-3, 5-64 to 5-65;

Explanation: BC Hydro states:

Technology will also provide new opportunities for automation, real-time intelligence, visibility into system status, and improved system control. (P 5-64)

_____

… Given the long life span of electricity infrastructure, sub-optimal choices today could have long-term negative impacts.

The automation of the distribution system is an example of a technology-enabled change in the system operations. It will encompass the application of computerized power equipment and control devices in substations and on distribution feeders with near real-time communications capability to: monitor, protect and control the distribution networks, locate, isolate, and restore faults automatically; and to optimize network reliability, capacity utilization, and energy efficiency. (P 5-65)

Request:

49.1 Explain how the cost-benefit of technology is evaluated, how benefits are monitored and who is at risk and accountable for achieving the benefits.

49.2 Give examples of sub-optimal choices and explain the long-term negative impacts.

49.3 Give examples of optimal choices today that will have known and measurable long term benefits that exceed the costs and risks.

50.0 Topic: Operating Costs: Workforce, Capital Expenditures and Additions

Reference: Exhibit B-1-3, Page 5-67;

Explanation: A “high-performance” workforce is critical to the success of T&D. A number of publications referenced above are attached that discuss a high performance workforce.

Request:

50.1 Explain what BC Hydro T&D means by a “high-performance” workforce and how it is or will be achieved and measured.

51.0 Topic: Operating Costs: Trouble Expenditures

Reference: Exhibit B-1-3, Page 5-84 to 5-85;

Explanation: BC Hydro identifies an increase in trouble expenditures of $3 million per year in F2013 and F2014.

Request:

51.1 Explain what is meant by trouble expenditures and complexity of trouble response.

51.2 Provide the total trouble expenditures in each year from F2007 to F2014.

51.3 Do trouble expenditures remain unchanged in the Amended Application?

52.0 **Topic:** Capital Expenditures and Additions, Operating Costs: AIM, ASP, Major Projects, Portfolio Projects and Projects Management

Reference: Exhibit B-1-3, Page 5-86 to 5-89, Page 5-96;

Explanation: The 4 KBUs and departments appear to be very similar and have the same or overlapping responsibilities.

> *The [AIM] KBU is responsible for the asset management of the transmission and distribution system … AIM comprises six departments: Asset Strategy and Planning; Interconnections; Asset Risk & Performance Management; Asset Data & Information; Advanced Infrastructure and Research & Development; and the Office of the Vice President, AIM. AIM was formed from the integration of the Distribution Strategic Asset Management group and the Smart Grid Development team of BC Hydro, and the System Planning and Asset Management group of BCTC … (P 5-86)*
>
> _____
>
> *The ASP department is responsible for the planning of expansion, improvement, refurbishment and maintenance of the transmission and distribution system and includes the following groups: Growth Strategy and Planning, Sustainment Strategy and Planning, Vegetation Strategy and Planning, Revenue Metering Systems Management. (P 5-89)*
>
> _____
>
> *The Major Projects department is responsible for the execution of projects generally exceeding $50 million in capital cost or requiring either a CPCN or Environmental Assessment Certificate. Typically, these projects also require substantial First Nations and stakeholder consultations and a customized project delivery approach. While the AIM KBU has accountability for developing the capital plan and asset management solutions, Major Projects is generally involved in the early stages of these projects due to the size, complexity, and stakeholder engagement requirements. (P 5-96)*

Request:

52.1 Are there a Vice-President, ASP and a Vice-President Major Projects as well as a Vice-President, AIM?

52.2 Explain the rationale for having 4 distinct groups responsible for projects.

52.3 Explain why BC Hydro would not form a project team for projects that is still responsible to the same organizational unit.

53.0 **Topic:** Operating Costs: BC Hydro Organization

Reference: Exhibit B-1-3, Page 5-28, Table 5-8; Page 5-40, Table 5-11; Page 5-42, Table 5-12; Page 5-75, Table 5-17; Page 5-77, Table 5-19; Page 5-88, Table 5-21; Page 5-95, Table 5-23; Page 5-99, Table 5-25; Page 5-104, Table 5-27; Page 5-107 – 5-108, Table 5-29; Page 5-137, Table 5-39; Page 5-178, Table 5-41; Page 5-145, Table 5-44; Page 5-166, Table 5-47; Page 5-170, Table 5-49; Page 5-188, Table 5-51; Page 5-196, Table 5-53; Exhibit B-1-3,

Appendix A, Schedule 16.0, Page 52-53 of 55; Exhibit B-1-3, Page 5-186; Exhibit B-1-3, Appendix V; Exhibit B-1-3, Page 5-14, Page 5-17;

Explanation: BC Hydro has provided high level organization chart and tables of FTEs for KBUs. The charts do not identify management positions, staff positions and overlapping functional positions such as HR, Accounting, etc.

> *Vacancy management refers to the initiative to manage vacancies as they arise within the headcount targets as discussed in section 5.2.1 through the use of a Vacancy Management Team (**VMT**), established in the fall of 2009. The VMT comprises cross-company human resources managers, tasked with managing BC Hydro's planned workforce targets, led by Corporate Human Resources.*
>
> *In F2012, the VMT's mandate will include reducing administrative and support services across the company and shifting resources to front-line operational areas. This mandate will be achieved through workforce analysis, and examining opportunities to streamline, reduce or eliminate work.*
>
> _____
>
> *From a functional perspective the majority of the workforce reductions that occurred in October 2011 are in communications, customer care, environment, finance, human resources, information technology, properties, enterprise risk and strategy. From an organizational perspective, all Business Groups have eliminated FTEs but the majority are in the Corporate Groups. From an affiliation perspective, the reductions are approximately 55 per cent management and professional, 42 per cent COPE and 3 per cent IBEW. (P 5-14)*
>
> _____
>
> *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 requesting BCUC approval to establish a new regulatory account for the actual costs to implement new contracts with ABS, TELUS, SNC Lavalin, and yet to be determined suppliers of outsourced IT services. (P 5-17)*

The table below summarizes the information from Exhibit B-1-3. The Review Panel Report suggests that a reduction of 1200 employees to 4800 was more reasonable but recommends a 1000 employee reduction. BC Hydro is planning a net reduction over 3 years of 600 employees after adding 100 more.

Full-Time Equivalents (FTEs)		F2007 Actual	F2008 Actual	Actual	Actual	Actual	F2012 Update	F2013 Update	F2014 Update
	Reference								
Line	Column	0	1	2	3	5	9	10	11
	Summary								
41	Regular Hour FTEs	4,075	4,661	5,377	5,635	5,743	5,909	5,735	5,681
42	Regular Hour Headcount from BCTC	-	-	-	-	-	-	-	-
43	Overtime Hour FTEs	595	639	692	666	600	518	512	512
44	Smart Metering & Infrastructure	0	13	26	34	33	143	149	73
45	Site C	-	3	14	18	29	85	84	84
46	Total	4,670	5,316	6,108	6,353	6,405	6,656	6,481	6,350
	Headcount								
	BCH Reductions - Exhibit B-1-1-3, Page 1-13								
	BCTC						250		
	October						300		
	Future (Total 150)							75	75
	Additions (Total 100)							(50)	(50)
							550	25	25
	Review Panel Report - Exhibit B-1-1-3, Appendix BB								
	Employees						6,000		
	Downsize the Workforce (Total 1000)						1,000		
	More Reasonable Staffing Level (Employees)						4,800		

Request:

53.1 Provide the Headcount information for F2007 to F2014.

53.2 Identify the annual costs per employee and in total for the difference between a 1200 employee reduction, a 1000 employee reduction and a 600 employee reduction.

53.3 Confirm that the Review Panel reductions included the BCTC integration and employee reductions already completed and those planned.

53.4 Provide a complete BC Hydro organization chart or charts showing all management positions and staff positions by function with a Head Count and FTEs.

53.5 Provide tables similar to Appendix 16.0 showing the number of management positions and staff positions with FTEs and Head Count.

53.6 How many Human Resource Managers and groups are there in BC Hydro?

53.7 How many Accounting and Finance managers and groups are there in BC Hydro?

53.8 How many Information Systems managers and groups are there in BC Hydro?

53.9 Provide examples of how VMT's have and will achieve their mandate and the role of the operational managers in achieving the mandate.

54.0 Topic: Operating Costs: Total Rewards

Reference: Exhibit B-1-3, Page 5-189; Page 5-236 – 5-237; Page 7-25 – 7-26;

Explanation:

The Total Rewards department ensures that BC Hydro has a competitive mix of base pay, variable pay, benefits, pensions and related programs necessary to attract, retain

*and motivate appropriately qualified employees within Public Sector Employers' Council (**PSEC**) Guidelines. Within this department, the Compensation group evaluates BC Hydro's compensation approach relative to market; the Benefit Design group ensures that there are appropriate benefit products to support employees at different stages and changes in their life and career; and the Employee Wellness group provides services and programs to help employees achieve a healthy lifestyle and work/life balance.*

Annually, this department conducts a market assessment for benchmark roles for all affiliations (including executive roles). From an external market competitiveness perspective, BC Hydro compares to the P50 (median) of the compensation market. (P 5-189)

Table 5–55 BC Hydro Current Service Pension Costs

	($ million)	F2011 NSA-12	F2012 Plan	F2013 Plan	F2014 Plan
		1	2	3	4
1	Current Service Costs	54.1	76.1	78.7	81.3

*The table [5-56] separates the portion relating to pension benefits and other post employment benefits (**OPEB**) which include post retirement medical and dental benefits and the supplemental pension plan.*

Table 5–56 Non-Current Post-Employment Benefit Costs, F2011-F2014

	F2011			F2012			F2013			F2014		
	NSA			RRA			RRA			RRA		
($ million)	Pension Benefit	OPEB	Total	Pension Benefit	OPEB	Total	Pension Benefit	OPEB	Total	Pension Benefit	OPEB	Total
Interest Income	(154.2)	-	(154.2)	(167.7)	-	(167.7)	(174.4)	-	(174.4)	(181.5)	-	(181.5)
Interest Expense	155.2	19.7	174.9	160.5	19.7	180.2	165.7	20.3	186.0	171.1	21.1	192.2
Amortization of Transitional (Asset) Liability	(17.6)	9.5	(8.1)	(17.6)	9.0	(8.6)	-	-	-	-	-	-
Amortization of Actuarial (Gains) Losses	36.8	0.8	37.6	51.1	0.8	51.9	46.0	0.7	46.7	41.3	0.6	41.9
Amortization of Past Service Costs	1.0	-	1.0	1.0	-	1.0	1.0	-	1.0	1.0	-	1.0
Total	**21.2**	**30.0**	**51.2**	**27.3**	**29.6**	**56.8**	**38.3**	**21.0**	**59.3**	**31.9**	**21.7**	**53.6**

(P 5-236 - 5-237)

BC Hydro also requests that the Non-current Pension Cost Regulatory Account be expanded to also include the difference between forecast and actual non-current other post-employment benefit costs, beginning in F2013. As discussed in section 8.14, under CGAAP the experience gains and losses related to the other post-employment benefits plan are amortized over the average expected remaining service life of the employee group. (P 7-26)

Request:

54.1 Does BC Hydro consider itself to be a public sector or private sector employer?

54.2 Is the compensation evaluation based on private sector Total Rewards or public sector Total Rewards?

54.3 How is a balance achieved between private sector pay and public sector benefits?

54.4 Are the total pension costs the sum of the Current and Non-Current pension costs?

54.5 Provide the total annual benefits (including past service costs) and total annual salaries and wages to which benefits apply and percentage of benefit costs to total salaries and wages.

54.6 What opportunities does BC Hydro have to manage the other post-employment benefit plans and costs?

54.7 Identify the cost and earnings risks that BC Hydro and its shareholder bear that are not addressed or would not be addressed through a deferral account.

55.0 **Topic:** BC Hydro Organization

Reference: Exhibit B-1-3, Page 5-158 – 5-159;

Explanation: BC Hydro states that Corporate Groups continue to execute "core responsibilities

Request:

55.1 Provide a definition of core responsibilities as distinct from a job description or job responsibilities and relate them to the various corporate groups listed.

55.2 Discuss core responsibilities as opposed to core competencies.

56.0 **Topic:** Capital Expenditures and Additions: SMI, Deferral Accounts: SMI

Reference: Exhibit B-1-3, Page 6-8 – 6-10;

Explanation:

Table 6–1 Capital Expenditures by Business Function

	($ million)	F2011 NSA-12	F2012 Plan	F2013 Plan	F2014 Plan
		1	2	3	4
	Capital Expenditures				
1	Hydroelectric Generation	376.2	372.4	465.2	544.3
2	Diesel Generation	8.8	12.7	14.8	12.3
3	Thermal Generation	63.5	57.8	14.0	4.0
4	Transmission Lines	177.9	312.2	456.3	591.3
5	Transmission Substations	244.3	402.5	354.5	313.7
6	SDA Substations	129.1	0.0	0.0	0.0
7	Distribution	423.8	414.0	423.4	449.9
8	Information Technology	80.2	75.5	74.1	73.4
9	Vehicles	21.0	35.0	26.0	21.0
10	Properties and Other Capital	92.4	138.4	99.4	105.5
11	Smart Metering & Infrastructure	54.3	0.0	0.0	0.0
12	HPOP Properties for Resale	(20.9)	(20.9)	(1.8)	0.0
13	Demand Side Management	184.4	189.0	225.3	263.0
14	**Total (Schedule 13.0, Line 14)**	1,835.0	1,988.6	2,151.2	2,378.4

(P 6-8)

Amended Table 6-1 Capital Expenditures by Business Function

	($ million)	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
	Capital Expenditures									
1	Hydroelectric Generation	372.4	465.2	544.3	314.0	409.2	501.8	(58.4)	(56.0)	(42.5)
2	Diesel Generation	12.7	14.8	12.3	11.7	13.8	8.3	(1.0)	(1.0)	(4.0)
3	Natural Gas Generation	57.8	14.0	4.0	50.8	6.3	2.8	(7.0)	(7.7)	(1.2)
4	Transmission Lines	312.2	456.3	591.3	348.5	726.4	685.2	36.3	270.1	93.9
5	Transmission Substations	402.5	354.5	313.7	258.0	442.9	362.4	(144.5)	88.4	48.7
6	SDA Substations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Distribution	414.0	423.4	449.9	329.7	318.6	314.7	(84.3)	(104.8)	(135.2)
8	Information Technology & Telecom	83.5	82.1	81.4	85.4	70.5	69.9	1.9	(11.6)	(11.5)
9	Vehicles	35.0	26.0	21.0	32.0	7.0	15.0	(3.0)	(19.0)	(6.0)
10	Properties and Other Capital	130.4	91.4	97.5	97.2	76.9	92.7	(33.2)	(14.5)	(4.8)
11	Smart Metering & Infrastructure	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	HPOP Properties for Resale	(20.9)	(1.8)	0.0	(12.7)	0.0	0.0	8.2	1.8	0.0
13	Demand Side Management	189.0	225.3	263.0	184.6	199.8	236.3	(4.4)	(25.5)	(26.7)
14	Total	1,988.6	2,151.2	2,378.4	1,699.2	2,271.4	2,289.1	(289.4)	120.2	(89.3)

The Amended F12-F14 RRA forecast capital expenditures reflect a reduction of $541 million in capital expenditures due to IFRS offset by increases in expenditures for major transmission line projects for a net reduction of $259 million over the test period from the Application. Additional information on changes in forecast capital expenditures is provided in sections 6.5, 6.6, 6.7, 6.8 and Amended Appendix I Additional information on DSM expenditures is provided in Appendix II.

(P 6-9)

Table 6–2 Capital Additions by Business Function

	($ million)	F2011 NSA-12	F2012 Plan	F2013 Plan	F2014 Plan
		1	2	3	4
	Capital Additions				
1	Hydroelectric Generation	497.6	325.4	358.6	266.9
2	Diesel Generation	10.5	11.5	15.8	15.6
3	Thermal Generation	10.1	151.9	11.6	3.1
4	Transmission Lines	77.7	252.5	518.9	695.5
5	Transmission Substations	228.3	290.0	191.6	159.6
6	SDA Substations	100.9	0.0	0.0	0.0
7	Distribution	436.6	243.7	321.6	386.4
8	Information Technology	105.3	52.2	52.6	46.1
9	Vehicles	26.4	46.3	28.3	22.3
10	Properties and Other Capital	115.3	165.5	80.9	124.6
11	Smart Metering & Infrastructure	54.3	0.0	0.0	0.0
12	HPOP Properties for Resale	(20.9)	(20.9)	(1.8)	0.0
13	Demand Side Management	184.4	189.0	225.3	263.0
14	**Total (Schedule 13.0, Line 36)**	1,826.5	1,707.1	1,803.3	1,983.0

(P 6-10)

Amended Table 6-2 Capital Additions by Business Function

	($ million)	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
	Capital Additions									
1	Hydroelectric Generation	325.4	358.6	266.9	259.1	283.7	113.1	(66.3)	(74.9)	(153.8)
2	Diesel Generation	11.5	15.8	15.6	8.9	19.2	8.0	(2.6)	3.4	(7.6)
3	Natural Gas Generation	151.9	11.6	3.1	143.5	7.3	2.7	(8.4)	(4.3)	(0.4)
4	Transmission Lines	252.5	518.9	695.5	83.7	201.3	303.3	(168.8)	(317.6)	(392.2)
5	Transmission Substations	290.0	191.6	159.6	209.3	204.5	402.3	(80.7)	12.9	242.7
6	SDA Substations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Distribution	243.7	321.6	386.4	259.2	277.3	278.0	15.5	(44.3)	(108.4)
8	Information Technology	52.2	52.6	46.1	89.7	104.7	45.7	37.5	52.1	(0.3)
9	Vehicles	46.3	28.3	22.3	32.0	7.1	15.1	(14.3)	(21.2)	(7.2)
10	Properties and Other Capital	165.5	80.9	124.6	126.9	63.5	32.6	(38.6)	(17.4)	(92.0)
11	Smart Metering & Infrastructure	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	HPOP Properties for Resale	(20.9)	(1.8)	0.0	(12.7)	0.0	0.0	8.2	1.8	0.0
13	Demand Side Management	189.0	225.3	263.0	184.6	199.8	236.3	(4.4)	(25.5)	(26.7)
14	Total	1,707.1	1,803.3	1,983.0	1,384.2	1,368.4	1,437.1	(322.9)	(434.9)	(545.9)

As indicated in Amended Table 6-2 capital additions have decreased between the original Application and the Amended F12-F14 RRA by $1.3 billion over the test period. This figure includes reductions of $393 million due to the impact of IFRS and $56.6 million due to reduced expenditures on DSM, but excludes the increase in forecast capital additions of $218 million due to a reduction in Customer Contributions in Aid. Net of these numbers, forecast capital additions have

(P 6-10)

SMI Program capital costs are excluded from the above table since BC Hydro is proposing deferral of all costs (both operating and capital related) in F2012, F2013 and F2014.

Request:

56.1 Provide Table 6-1 and Table 6-2 with SMI expenditures and for Table 6-1, Site C expenditures for each year.

56.2 Confirm that the DSM expenditures do or do not include in-home devices and identify the annual cost if they do.

56.3 Reconcile the expenditures in Table 6-1 to the capital additions in Table 6-2 showing completed projects and work in progress.

56.4 Confirm that ROE on smart meters is included in Revenue Requirements.

56.5 Provide a schedule with costs showing when the SMI components will be in service and the amounts that will be included in deferral accounts.

56.6 Provide the increase/change in Financing Costs and ROE related to the smart meters.

56.7 Under normal regulatory practice and IFRS / GAAP, when would these costs normally be included in costs and recovered in rates?

56.8 What benefits/savings are included in the test period for which the costs are being deferred?

57.0 Topic: Capital Expenditures and Additions

Reference: Exhibit B-1-3-1, Page 6-11 – 6-12; Appendix U;

Explanation: BC Hydro has provided a table of capital expenditures reviewed by the BCUC.

Table 6–3 Capital Expenditures Reviewed by the BCUC

	Particulars ($ million)	BCUC Order No.	Total Cost Accepted by the BCUC	Total Cost of Project per Appendix I
	Hydroelectric Generation			
1	Revelstoke Unit 5	C-8-07	280.0	250.0
2	G.M. Shrum Units 1-5 Turbine Replacement	G-1-10	262.0	246.9–313.9
3	Mica 5/6 (Definition Phase Funding)	G-69-09	30.0	700.0–800.0
4	Stave Falls Spillway Gates Replacement	G-81-10	61.5	66.9–71.8
5	Hugh Keenleyside Spillway Gates Project	G-177-10	90.2	90.7–102.5
	Thermal Generation			
6	Fort Nelson Resource Smart Upgrade	G-75-09	140.1	139.8–154.6
	Transmission			
7	Vancouver City Central Transmission	C-3-10	200.9	177.0–195.0
8	Columbia Valley Transmission Project	C-5-10	154.1	132.0–209.0
	Demand Side Management			
9	Demand Side Management (F2009-F2011)	G-91-09	418.0	382.1

(P 6-11)

Amended Table 6-3 Capital Expenditures Reviewed by BCUC

	Particulars ($ million)	BCUC Order No.	Total Cost Accepted by the BCUC	Total Cost of Project per Appendix I	Total Cost of Project per Amended Appendix I
	Hydroelectric Generation				
1	Revelstoke Unit 5	C-8-07	280.0	250.0	249
2	G.M. Shrum Units 1-5 Turbine Replacement	G-1-10	262.0	246.9–313.9	203 -290
3	Mica 5/6	G-69-09	30.0 (Definition Phase Funding)	700.0–800.0	639-739
4	Stave Falls Spillway Gates Replacement	G-81-10	61.5	66.9–71.8	61-66
5	Hugh Keenleyside Spillway Gates Project	G-177-10	90.2	90.7–102.5	83 - 95
	Thermal Generation				
6	Fort Nelson Resource Smart Upgrade	G-75-09	140.1	139.8–154.6	134 – 149
	Transmission				
7	Vancouver City Central Transmission	C-3-10	200.9	177.0–195.0	177
8	Columbia Valley Transmission Project	C-5-10	154.1	132.0–209.0	133
	Interior to Lower Mainland Project	C-4-08 / G-166-11	602.1	540-780	709
	Demand Side Management				
9	Demand Side Management (F2009-F2011)	G-91-09	418.0	382.1	363.2

(P 6-12)

Capital Project Filing Guidelines

Background

In Directive 31 of the 2008 Long-Term Acquisition Plan (**LTAP**) Decision,[1] the British Columbia Utilities Commission (**BCUC**) requested that BC Hydro develop a set of guidelines for the filing and review of capital projects by the BCUC. This document sets out BC Hydro's Capital Project Filing Guidelines (**Guidelines**). With the integration of British Columbia Transmission Corporation (**BCTC**), a single regulatory filing approach is being established for all BC Hydro capital projects, including transmission.

1. Expenditure Thresholds

BC Hydro has established three different expenditure threshold levels for capital projects, as follows:

- $100 million for generation and transmission (including Substation Distribution Asset (**SDA**) components[2]) projects;
- $50 million for distribution and building projects; and
- $20 million for information technology and telecommunication (**IT&T**) projects.

The expenditure threshold trigger is the Authorized cost estimate. There may be exceptions to this approach; BC Hydro may file applications with the BCUC for capital projects below these expenditure threshold levels.

(App U)

Request:

57.1 Describe the distinction between what is reviewed by the BCUC and what is subject to a CPCN approval by the BCUC?

57.2 Provide tables showing the capital expenditures (Table 6-1) and additions (Table 6-2), expenditures reviewed by the BCUC, expenditures approved by the BCUC through an approval process such as a CPCN application, projects not reviewable under the CEA and the percentage of projects and expenditures approved by the BCUC.

57.3 How are projects linked or aggregated or disaggregated in evaluating whether they trigger the expenditure thresholds in particular where projects are dependent on each other? For example,

a. Human Resources systems

b. Communications, Protection, Distribution Management systems

c. Properties

58.0 Topic: Capital Expenditures/Additions: IT / IT&T

Reference: Exhibit B-1-3, Appendix J; Appendix BB, CC; Pages 1-10, 1-11, 5-13, 5-16, - 5-18, 5-159, 5-164 – 165, 5-186, 5-207, 5-209, 5-234, , 6-6, 6-15, 6-25 – 26, 6-68 – 71, 6-75; Amended Appendix I, Pages 25 of 45, 38-41, Amended Appendix J, Pages 136, 155, 158, 165; Appendix R, Page 7 of 34;

Explanation: BC Hydro has identified a number of IT / IT&T projects, many of which increased in cost. They include:

Transformational initiatives that are underway and will be at various stages of the project life cycle during the F2012 to F2014 period include (total planned project capital expenditures shown in parentheses):

- *Project & Portfolio Management ($21 million);*

- *EMPower (formerly Human Resources Information System Replacement Initiative) ($15 million);*
- *Distribution Management System ($13 million); and*
- *Plan & Schedule Work (total cost to be determined).*

In the Amended RRA, the following are the updated total planned capital expenditures for the following projects:

- *Project & Portfolio Management ($22 million);*
- *Distribution Management System ($15 million); and*
- *Plan & Schedule Work ($34 million).*

The increase in Distribution Management System expenditures is due to refined cost estimates resulting in higher expected project costs. More definitive cost estimates for the Plan & Schedule work project have also been received since the Application was filed, and the project is now expected to go into service during the test period. In the Application the Plan and Schedule Work forecast expenditures were $16.3 million. The increase to $34 million has been offset by reallocation of budgets from other IT projects over the test period. Forecast expenditures for EMPower have not changed from the Application.

In addition to the above, transformational initiatives that are planned to commence during the F2012 to F2014 period include:

- *Customer Relationship Management;*
- *Geographic Information System;*
- *Asset Management;*
- *Enterprise Field Mobility; and*
- *Supply Chain.*

Additional details on these initiatives are provided in Appendix J.

6.10.2 Supporting Technology Foundation

Key initiatives to be undertaken during the F2012 to F2014 period include (total planned project capital expenditures shown in parentheses):

- *Radio Technology Upgrade ($13 million); and*
- *Common Desktop Standard 4 ($3 million) to modernize BC Hydro's end user computing environment.*

Additional details on the Radio Technology Upgrade are provided in Appendix J, page 137. The total planned project capital expenditures for the Radio Technology Upgrade is $14 million, and $4 million for the Common Desktop Standard project in the Amended F12-F14 RRA. Refer to Amended Appendix J, page 160. (P 6-70 - 6-71)

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 requesting BCUC approval to establish a new regulatory account for the actual costs to implement new contracts with ABS, TELUS, SNC Lavalin, and yet to be determined suppliers of outsourced IT services.This proposal is further discussed in section 7.4.4. (P 5-17)

The Office of the Chief Information Officer is working to ensure realization of the expected benefits across the organization, including associated operating expenditure reductions. (App R, P 7 of 34)

RPR Recommendation: 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.

BCH Response: Agreed. BC Hydro has recently combined all IT and technology functions together under the Office of the Chief Information Officer. The Executive Team forms the governance committee that oversees all information technology, telecommunications and technology programs. As part of the IT&T five year plan, there are several transformational projects planned or underway that will drive major process improvements and operational efficiencies. These include the human resources processes and systems (EmPower) project, supply chain processes and system project and the plan, schedule, work (PSW) project. The projects will ensure that the benefits and efficiencies will be delivered as planned. F12-F14 (App CC, Recommendation 11, P 5 of 19)

The corporate wide investment in IT&T was consolidated and prioritized. The operational expenditures account for $69 million while the capital planned expenditure is $90 million. A number of financial improvements were made and resulted in reduced capital and operating costs of $23million. Those reductions have been realized however our technology costs continue to grow due to growth in the organization. Subsequent plans are in place to further reduce IT&T costs. (App R, P 3-5)

The governance group is comprised of senior business leaders who have direction oversight of the business operations and can interpret the need for technology enablement into their business and the overall BC Hydro perspective. (App R, P 3-5)

Request:

58.1 Provide a table of IT projects from F2007 to F2014 showing all of the project cost estimates with changes and the date of the estimates, the actual cost, the date the project was implemented or canceled and the expected benefits.

58.2 What is meant by: “including the associated operating expenditure reductions”?

58.2.1 Summarize the type of benefits and reductions that IT&T projects deliver.

58.3 How much had been spent on the HR Systems Replacement Project estimated to cost $10.2 million in the F2011 RRA before it was cancelled and where are the costs reported?

58.3.1 Where are the costs of all other cancelled IT&T projects reported?

58.4 Provide copies of all business cases and reviews, reports or audits of IT projects listed in response to 58.1 above.

58.5 Provide the benefits and cost reductions by year for the new outsourcing arrangements and confirm that they have been included in the Revenue Requirements and that all of

the costs have been included in deferral accounts.

58.6 Name the members of the "governance group".

58.7 Provide a list of IT&T projects with cost increases that the IT&T governance team has not approved.

58.8 Confirm that transferring costs to another project such as SMI is not a reduction in costs.

58.9 Provide the details and support for the reduced capital and operating costs claimed by the OCIO.

59.0 Topic: Capital Expenditures/Additions: Properties / Facilities

Reference: Exhibit B-1-3, page 5-203 – 204, Page 5-215 – 216, Pages 6-21, 6-24, 6-71 – 72, 6-74; Amended Appendix I, Page 26 of 45, Page 41 – 45 of 45; Appendix J, Pages 170 - 194; Appendix BB, Pages 72, 79, 81, CC;

Explanation: BC Hydro has identified a number of property / facilities projects, many of which have significantly increased in cost as set out in Appendix J.

RPR Recommendation: Postpone the office renovation work at both headquarters and field offices currently underway or scheduled until new needs assessments are completed following this review.

BCH Response: BC Hydro agrees to complete a needs assessment for headquarters and field buildings, including owned and leased space. The intention is to confirm ongoing business requirements, including meeting reliability, asset health, operational and financial drivers for the renovations. F12 (App CC, Recommendation 42, P14 of 19)

New Table 6-G **Summary of Capital Addition Reductions – Properties**

Category	Reduction ($ million)
Changed Circumstances	-
Risk-based Deferrals	(152)
Managed Reductions	(3)
Total	(155)

Nineteen of the thirty-four larger properties projects, and a handful of smaller projects, were not considered eligible for deferral because they were already in the Implementation Phase, had already been completed, were to be in-service in the test period, or were otherwise mandatory. Of the remaining projects eligible for risk-based deferral, virtually all have been deferred: the capital additions associated with the projects eligible for deferral was $158 million, and as shown in the table above, $152 million of those additions have been deferred. (P 6-24)

Other risk-deferred work included projects … to improve trails, bridges and facilities at BC Hydro's recreation sites throughout the province … (P 6-21)

Request:

59.1 Provide a table of Property / facilities projects from F2007 to F2014 showing all of the project cost estimates with changes and the date of the estimates, the actual cost, the date the project was completed or canceled, the cost of land, the cost of structures and the cost per square foot and any improvement and furnishing costs.

59.2 Provide the BC Hydro construction standards for the facilities listed above or confirm that all facilities are designed and constructed to the LEED Gold standard.

59.3 Provide the BC Hydro policy with respect to public recreational properties including expenditures, infrastructure funding (BCH vs. gov't) and charges for access.

59.4 Provide the properties and equipment costs associated with the employee hiring and employee reductions in response to the RPR.

60.0 Topic: Capital Expenditures and Additions

Reference: Exhibit B-1-3, Page 6-15, Page 6-68; Exhibit B-11, Executive Summary, Page 1; Exhibit B-1-3, Appendix BB (RPR); Exhibit B-1-3, Appendix CC Recommendations: 23-39, 41, 42;

Explanation:

BC Hydro plans to invest approximately $6 billion over the next three years to renew, upgrade and expand capital infrastructure across the province. (Exh. B-1-3, Executive Summary, Page 1)

As a result of the regulatory environment and corporate culture BC Hydro has become very risk adverse, increasing both operating and capital costs and limiting the potential effectiveness of the organization. We observed many examples of excessive planning, over engineering of projects and the use of multiple layers of contingencies and reserves in order to satisfy various stakeholders and regulatory agencies. (RPR Page 2, 3)

… risk planning does not always produce effective outcomes, for example, a BC Hydro commissioned vendor survey identified that BC Hydro is paying excessive risk premiums to contractors. Risk management needs to be improved to ensure risks are appropriately allocated and successfully transferred to vendors at the lowest costs. (RPR Page 5)

There is a tendency for BC Hydro to exert significant control over their projects which limits vendors' flexibility to deliver the project in a way that may be advantageous to both parties. BC Hydro acknowledges that they over manage their capital projects to ensure quality workmanship of contractors. BC Hydro's approach to procurement and risk allocation has resulted in multiple change orders for their projects of up to 114% of the original individual contract value and 13% of the total project value. (RPR Page 8, 9)

The panel is recommending that BC Hydro reduce its contingencies and project reserves, set preliminary price expectations, better control soft project costs and use a more strategic approach to assigning internal staff resources to capital projects. (RPR Page 9)

While BC Hydro has sufficient risk planning processes in place to identify risks, it has not been as effective in utilizing the risk information in managing costs and mitigating financial risks. For example, a vendor survey identified that BC Hydro is paying excessive risk premiums to their contractors. Risk management needs to be improved to ensure risks are appropriately allocated and successfully transferred to vendors at the lowest costs. The key to successfully managing risks with vendors is to ensure there is clear understanding and agreement on risk transfer. BC Hydro must ensure their contract language and project management reflect the agreed responsibilities and that risks transferred to vendors remain within the vendor's control. BC Hydro also needs to improve their contingency budgeting for capital projects and to consider the reasonableness of their funding requests when identifying strategies to mitigate risks. An insufficient focus on costs creates an incentive to build excessive contingencies on project budgets which allows for poor cost containment in their risk oversight. For example, BC Hydro encountered a large number of change orders on some capital projects. Specifically, BC Hydro encountered several large design revisions during the construction period of the Aberfeldie Redevelopment Design Bid Build project at a cost of $12M for additional general contractor, engineering and mechanical fees (26% of the original contract values). The high number of change orders noted on files is an indicator of ineffective risk allocation. (RPR Page 28)

Additionally, BC Hydro is undertaking further cost-management measures, that are expected to result in capital projects coming into service at costs lower than would otherwise be the case, including some projects that will come into service in the test period. It is not possible at this time to identify the specific projects or associated capital cost reductions arising from those measures, but for the purpose of forecasting capital additions in the test period BC Hydro includes such cost reductions in "managed reductions". (P 6-15)

New Table 6-C Capital Addition Reductions – Amended F12-F14 RRA

Category	Capital Addition Reductions ($ million)				
	Generation	T&D	Properties	IT&T	Total
Capital Additions - F12-F14 RRA (CGAAP)	1,117	3,249	298	175	4,839
(Reductions)/Increases					
Changed Circumstances	(203)	137	_	122	56
Risk-based Deferrals	(43)	(428)	(152)	(32)	(655)
Managed Reductions	(8)	(30)	(3)	(6)	(47)
Net (Reduction)/Increase	(254)	(321)	(155)	84	(646)
Capital Additions - Amended F12-14 RRA	863	2,928	143	259	4,193
IFRS Impact	(53)	(340)	_	_	(393)
Capital Additions - Amended F12-F14 RRA (IFRS)	810	2,588	143	259	3,800

(P 6-15)

The "Managed Reductions" of $47 million represents only 0.97% of capital additions.

Request:

60.1 Identify the changes to forecast capital expenditures by project that have been made to reflect the Review Panel observations and recommendations.

60.2 Has BC Hydro evaluated the causes for change orders? Provide any reports and audits on capital project costs and change orders.

61.0 Topic: Capital Expenditures and Additions

Reference: Exhibit B-1-3, Page 6-68;

Explanation: BC Hydro heavy duty fleet units will include Safety by Design features.

> ***Safety-by-Design*** *is an approach that introduces safety control measures into the design stage of projects and eliminates hazards to the extent possible, through the expected life of the facility being built. The concepts are being applied throughout BC Hydro, as well as to BC Transmission Corporation and external design consultants.*

Request:

61.1 Define what is meant by Safety by Design for fleet and heavy duty vehicles.

61.2 What do the Safety by Design features mean in supplier alternatives and costs?

62.0 Topic: Deferral Accounts & DARR, Regulatory Accounts

Reference: Exhibit B-1-3, Page 7-1; Page 7-8 to 7-10; Exhibit B-1-3, Appendix H;

Explanation: The Cost of Energy Deferral Accounts are the HDA, NHDA and TIDA accounts. BC Hydro is requesting that the 10 year recovery of the cost of energy deferrals under DARR agreed to in the F2011 NSA be set aside and the earlier table reflecting a 5-year recovery (approximately) be reinstated, subject to a 10% rate increase cap.

> *Based on the asymmetry and volatility experienced in the period from F2005 to F2011 as set out in Table 7–1, BC Hydro remains of the view that it is appropriate to include the net impact of load variance in the cost of energy Deferral Accounts. (P 7-8)*

In the Amended Application, BC Hydro is proposing that the 2.5% DARR be maintained *"As part of the plan to achieve rate increases of 8 per cent in F2012 and 31 3.91 per cent in F2013 and F2014 …"*

Request:

62.1 Confirm that only the cost of energy Deferral Accounts were originally intended to be recovered through the DARR.

62.2 List the non-cost of energy costs have been recorded in or transferred to the cost of energy Deferral Accounts since inception.

62.3 Has BC Hydro considered a separate rate rider (RARR) to recover Other Deferral and Regulatory Accounts?

63.0 Topic: Capital Expenditures and Additions: Site C, Deferral Accounts: Site C

Reference: Exhibit B-1-3, Page 2-6; Page 5-227 to 5-230;

Explanation: The capital cost of Site C has increased by $2.3 billion to $7.9 billion based on

recent announcements. *Yurkovich said the 20-per-cent increase in the cost estimate reflects inflation for labour and material costs, but also includes a 22-per-cent increase in its generating capacity to 1,100 megawatts and a more seismically sound design. It is also expected to deliver 11-percent more electricity than Site C's initial design at a cost of between $ 87 and $ 95 per megawatt hour.* (Vancouver Sun, May 19, 2011)

Deferred costs for Site C are forecast to be $531.9 million at the end of F2014.

Request:

63.1 Is there a more current cost estimate for Site C?

63.2 When is the unconditional approval to proceed with Site C expected?

63.3 Is the estimated cost of Site C actual constructed cost (nominal)?

63.4 Is the cost per MWh quoted in the article levelized?

63.5 Provide the forecast revenue requirements (cost of service) for Site C and the annual cost per MWh for a 50 year forecast period in table and graph format and the levelized cost per MWh and provide a fully functional Excel spreadsheet.

64.0 Topic: Cost of Energy: IPP Supply, ICP

Reference: Exhibit B-1-3, Page 4-3, Page 4-6; Page 4-26 to 4-30; Table 4-7, 4-8;

Explanation: A table of unit IPP supply cost is provided below and was prepared from the volumes and costs provided by BC Hydro.

Cost per MWh	No. of EPAs	F2010 Actual	F2011 Forecast	F2012 Plan	F2013 Plan	F2014 Plan
Pre-2000 EPAs	18	$ 63.79	$ 60.92	$ 61.96	$ 63.07	$ 63.60
Island Cogen	1	78.16	71.33	270.98	258.17	274.29
2000 Green RFEOI	3	37.80	36.43	28.76	35.95	39.87
2001 Green Energy Call	13	54.81	54.62	55.38	56.08	56.64
2002 CBG Call	2	69.60	82.58	82.71	84.07	93.27
2002/03 GPG Call	7	54.80	55.21	56.99	57.61	58.22
F2006 Call (incl. Brilliant)	29	87.16	86.48	86.92	88.10	89.29
Alcan 2007 EPA	1	53.60	57.72	62.51	63.93	64.91
Bioenergy Call - Phase I RFP	4	109.93	105.40	105.48	107.66	109.65
2009 Clean Power Call	25				117.81	124.43
Standing Offer Program	6	100.00	87.93	90.59	88.13	88.75
Forrest Kerr EPA	1					
Integrated Power Offer				117.16	116.47	116.20
Total	110	$ 63.81	$ 66.64	$ 74.55	$ 77.71	$ 83.05

As of April 1, 2010, BC Hydro entered into a revised contract for ICG that permits the plant to be economically dispatched by BC Hydro. (P 4-6)

*The reduction in the average volume of IPP deliveries during the test period is primarily due to the gas-fired Island Cogeneration Plant (**ICG**) being economically dispatched down due to high fuel cost, including the impact of the Carbon Tax. (P 4-3)*

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The increase in IPP volumes also includes amounts from three customers who signed contracts under the Integrated Power Offer during the latter half of F2011, at an average price of $116 per MWh over the test period; and a forecast increase in Island Generation thermal plant generation to meet Vancouver Island winter reliability requirements. (P 4-28)

Request:

64.1 Provide the range of IPP unit costs for each line in the above table.

64.2 Provide a table and graph of the forecast market prices and forecast ICP variable/fuel cost for the forecast period.

64.3 Explain why ICP is needed for security of supply.

65.0 **Topic:** Comparative Reporting, Uniform System of Accounts

Reference: Exhibit B-1-3, Page 8-31 – 8-32;

Explanation:

… this application does not reflect USoA classification of costs. In the Evidentiary Update, BC Hydro will include consolidated schedules of operating costs and capital expenditures in a form that complies with the USoA. BC Hydro will also include a summary of its USoA classification methodology, including BC Hydro amendments to the USoA and related rationale.

Request:

65.1 Explain how consolidated schedules and amendments to the USoA classifications comply with the USoA and provide interested parties with meaningful and comparable information.

66.0 **Topic:** Capital Expenditures and Additions: Northwest Transmission Line (NTL)

Reference: Exhibit B-1-3, Appendix J, NTL;

Explanation: The estimated project cost is $364-525 million with $180 million umbrella agreement between AltaGas and BCTC and $130 million in funding from the Federal Green Infrastructure Fund.

The project is now estimated to cost between $500 and $615 million, with $197 million to be contributed by industry and up to $130 million to be contributed by the Federal government. In addition the in-service date is now forecasted to be F2015.

Request:

66.1 Explain what is meant by the $180 umbrella agreement in terms of funding for the project.

66.2 What is meant by “up to $130 million to be contributed by the Federal government”.

66.3 Provide a schedule setting out the total capital costs of the NTL, the funding of the project and nature of the funding (CIAC, Refundable Contribution, Facilities Contribution, Guarantees, etc.) and how much of the cost will be recovered through rates.

66.4 Where costs and funding have changed over time, provide a history of the capital costs and funding.