Dennis Swanson
Director, Regulatory Affairs

FortisBC Inc.
Suite 100 – 1975 Springfield Road
Kelowna, BC V1Y 7V7
Tel: (250) 717-0890
Fax: 1-866-335-6295
www.fortisbc.com

Regulatory Affairs Correspondence
Email:electricity.regulatory.affairs@fortisbc.com

November 26, 2013

Via Email
Original via Mail

British Columbia Utilities Commission
Sixth Floor
900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Inc. (FBC)

Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 (the Application)

Response to the British Columbia Utilities Commission (BCUC or the Commission) Information Request (IR) No. 2

On July 5, 2013, FBC filed the Application as referenced above. FBC respectfully submits the attached response to BCUC IR No. 2.

FBC notes that the responses to BCUC IR No. 2 question 26 series relate to the PBR Methodology, and will be submitted with the PBR Methodology IR responses.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Dennis Swanson

Attachments

cc (e-mail only): Registered Parties

A. PERFORMANCE BASED RATEMAKING (PBR) FORECAST – LOAD FORECAST

1.0 Reference: Exhibit B-1-1, Appendix E2, p. 25

Concordance with the Load Forecast Technical Committee's Recommendations

FortisBC Inc. (FBC) states that "[t]he Company checked the existing forecasting method with updated parameters for each load class and proposed appropriate changes to the residential customer count, the wholesale load and the lighting load classes. Please refer to Recommendation 8 for further detail" (Exhibit B-1-1, Appendix E2, p. 25).

1.1 Please explain what change FBC implemented for the lighting load class forecasting method since neither the lighting section of the Energy Forecast nor the Recommendation 8 section has provided any indication of a change.

Response:

There was no change in the forecasting method for the lighting load class.

The lighting load class was mentioned in the excerpt above by a typographical mistake. The preamble should read that "[t]he Company checked the existing forecasting method with updated parameters for each load class and proposed appropriate changes to the residential customer count and the wholesale classes. Please refer to Recommendation 8 for further detail (Exhibit B-1-1, Appendix E2, p. 25).

1.2 Please explain the rationale for proposing changes to the lighting load forecast method and demonstrate how the new forecast method is superior to the previous one.

Response:

Please refer to the response to BCUC IR 2.1.1.

2.0 Reference: Exhibit B-7, BCUC 1.73.0

Rate-Driven Savings

In response to British Columbia Utility Commission (BCUC) Information Request (IR) 1.73.2, FBC confirms that "it started to recognize rate driven savings due to price elasticity in its load forecast. FBC sees this as a slight adjustment in its forecast and not a change in methodology."

2.1 For each customer class, please provide a side-by-side comparison of the load forecast with and without rate-driven savings.

Response:

The table below summarizes the annual loads with and without rate-driven savings. The load with rate-driven savings is the final load forecast after all savings (DSM, RCR, CIP, Rate-driven), while the load without rate-driven savings is obtained by subtracting DSM, RCR and CIP from the before-savings forecast.

Year	Class	With Rate-Driven Savings (GWh)	Without Rate-Driven Savings (GWh)
2014	Residential	1,402	1,407
	Commercial	813	815
	Wholesale	581	583
	Industrial	389	391
	Lighting	13	13
	Irrigation	42	42
	Net	3,240	3,250
	Losses	278	281
	Gross	3,519	3,531
2015	Residential	1,405	1,409
	Commercial	825	827
	Wholesale	584	586
	Industrial	390	391
	Lighting	13	13
	Irrigation	42	42
	Net	3,258	3,268
	Losses	278	282
	Gross	3,537	3,551

2016	**Residential**	1,409	1,413
	Commercial	837	839
	Wholesale	587	589
	Industrial	389	391
	Lighting	13	13
	Irrigation	42	42
	Net	3,276	3,286
	Losses	278	284
	Gross	3,554	3,570
2017	**Residential**	1,417	1,421
	Commercial	845	848
	Wholesale	590	592
	Industrial	389	390
	Lighting	13	13
	Irrigation	41	42
	Net	3,295	3,305
	Losses	277	285
	Gross	3,572	3,590
2018	**Residential**	1,422	1,427
	Commercial	860	863
	Wholesale	594	595
	Industrial	388	389
	Lighting	13	13
	Irrigation	41	41
	Net	3,318	3,328
	Losses	277	286
	Gross	3,596	3,615

In response to BCUC 1.73.3, FBC states "[t]he response to BCUC 1.73.2 already shows fluctuating rate increases in the FBC service area, which may not have given customers a clear signal to respond to the rate changes and save energy. With much more stabilized rate increase proposed in the 2014-2018 PBR, FBC expects to see more price responses from customers."

2.2 Please explain why rate increases have fluctuated significantly during the 2007 PBR Plan (from 2007 to 2011).

Response:

Rate fluctuations are a function of variance in "cost parameters" that influence the Total Revenue Requirement in any particular year. The table below provides the following:

1. Approved Revenues during the period 2007 to 2011;
2. Calculates the "Relative Percentage Increase" year over year for individual parameters;
3. Calculates the "Contribution to Rate Increase" year over year for individual parameters; and
4. Provides high level remarks on variations.

Revenue Requirements Overview & Variance Analysis

#	Revenue Related Parameters	Approved 2007	Approved 2008	Approved 2009	Approved 2010	Approved 2011	% Variation over prior year 2008	2009	2010	2011	% Contribution to Rate Increase 2008	2009	2010	2011	Remarks
				($000s)				(%)				(%)			
1	Sales Volume (GWh)	3,077	3,087	3,107	3,199	3,162	0.3%	0.6%	3.0%	-1.2%					Function of Customer growth
2	Rate Base	764,617	822,847	907,977	975,113	1,093,241	7.6%	10.3%	7.4%	12.1%					Function of Capital Growth
3															
4	**REVENUE DEFICIENCY**														
5															
6	**POWER SUPPLY**														
7	Power Purchases	69,260	68,538	70,944	80,408	81,212	-1.0%	3.5%	13.3%	1.0%	-0.2%	0.9%	2.8%	0.3%	
8	Water Fees	7,976	7,858	8,480	9,068	9,381	-1.5%	7.9%	6.9%	3.5%	0.0%	0.2%	0.2%	0.1%	
9		77,236	76,396	79,424	89,476	90,593	-1.1%	4.0%	12.7%	1.2%	-0.2%	1.2%	2.9%	0.4%	Function of customer & Market dynamics
10	**OPERATING**														
11	O&M Expense	43,093	45,310	46,573	47,645	53,885	5.1%	2.8%	2.3%	13.1%	0.6%	0.5%	0.3%	2.4%	Certain Capital Sust. Proj moved to O&M in 2011
12	Capitalized Overhead	(8,619)	(9,062)	(9,315)	(9,529)	(10,777)	5.1%	2.8%	2.3%	13.1%	-0.1%	-0.1%	-0.1%	-0.5%	20% of Gross O&M
13	Wheeling	3,466	3,622	4,010	4,019	3,338	4.5%	10.7%	0.2%	-16.9%	0.0%	0.2%	0.0%	-0.3%	Fnction of volume & BC Hydro Rates
14	Other Income	(4,689)	(5,030)	(4,915)	(5,025)	(5,455)	7.3%	-2.3%	2.2%	8.5%	-0.1%	0.0%	0.0%	-0.2%	Function of "Third Party" Project dynamics
15		33,251	34,840	36,353	37,109	40,991	4.8%	4.3%	2.1%	10.5%	0.4%	0.6%	0.2%	1.5%	
16	**TAXES**														
17	Property Taxes	10,926	11,176	11,561	12,548	13,940	2.3%	3.4%	8.5%	11.1%	0.1%	0.1%	0.3%	0.5%	Function of Municipal Rates and Capital ,
18	Income Taxes	3,332	3,989	4,354	5,407	6,733	19.7%	9.1%	24.2%	24.5%	0.2%	0.1%	0.3%	0.5%	
19		14,258	15,165	15,915	17,955	20,673	6.4%	4.9%	12.8%	15.1%	0.2%	0.3%	0.6%	1.0%	
20	**FINANCING**														
21	Cost of Debt	28,610	31,762	34,803	36,765	40,505	11.0%	9.6%	5.6%	10.2%	0.8%	1.2%	0.6%	1.4%	Function of Rate Base, Equity Thick. & ROE
22	Cost of Equity	25,960	29,688	32,215	38,614	43,292	14.4%	8.5%	19.9%	12.1%	0.9%	1.0%	1.9%	1.8%	Function of Rate Base, Equity Thick. & Debt Rate
23	Depreciation and Amortization	30,565	34,356	37,504	42,028	45,498	12.4%	9.2%	12.1%	8.3%	0.9%	1.2%	1.3%	1.3%	Function of Depreciation Rates & Capital
24		85,135	95,806	104,522	117,407	129,296	12.5%	9.1%	12.3%	10.1%	2.7%	3.4%	3.7%	4.6%	
25															
26	Prior Year Incentive True Up	-	22	173	(322)	(1,089)	N/A	686.4%	-286.1%	238.2%	0.0%	0.1%	-0.1%	-0.3%	
27	Flow Through Adjustments	(338)	(42)	(435)	(1,068)	(2,129)	-87.6%	936.6%	145.4%	99.3%	0.1%	-0.2%	-0.2%	-0.4%	
28	AFUDC / CWIP shortfall		895	-	-	-	N/A	-100.0%	N/A	N/A	0.2%	-0.3%	0.0%	0.0%	
29	ROE Sharing Incentives	(2,185)	(2,159)	(1,181)	(1,300)	448	-1.2%	-45.3%	10.0%	-134.5%	0.0%	0.4%	0.0%	0.7%	
30		(2,523)	(1,284)	(1,443)	(2,690)	(2,770)	**-49.1%**	**12.4%**	**86.4%**	**3.0%**	0.3%	-0.1%	-0.4%	0.0%	Variation between "Approved" & "Actual"
31															
32	**TOTAL REVENUE REQUIREMENT**	**207,358**	**220,923**	**234,771**	**259,258**	**278,783**									
33															
34	Carrying Costs if any	10	27	(8)	17	-					0.0%	0.0%	0.0%	0.0%	
35															
36	**ADJ. REVENUE REQUIREMENT**	**207,368**	**220,950**	**234,763**	**259,274**	**278,783**									
37															
38	**LESS: REVENUE AT (PRIOR YEAR) APPROVED RATES**	**200,836**	**213,694**	**222,847**	**242,031**	**259,358**									
39															
40	**REVENUE DEFICIENCY FOR RATE SETTING**	**6,532**	**7,256**	**11,916**	**17,243**	**19,426**									
41															
42	**RATE INCREASES**	**3.30%**	**3.40%**	**5.30%**	**7.10%**	**7.50%**					**3.40%**	**5.30%**	**7.10%**	**7.50%**	
43															

2.2.1 How likely is it that the factors which caused significant fluctuations in rate increases during the 2007 PBR Plan would also cause significant fluctuations in rate increases in the proposed 2014-2018 PBR? Please discuss.

Response:

To the extent possible based on current information, FBC has, through the RSDM, mitigated rate volatility through the 2014-2018 period. In the absence of the RSDM, FBC customers would face a rate decrease in 2014, followed by a larger rate increase in 2015. The rate profiles with and without the RDSM are illustrated in Figure B7-1 of the Application.

Power Purchase Expense is the most significant area of potential rate variability in the 2014-2018 timeframe, but the variability resulting from the amortization of the 2012-2013 PPE variances and the impact beginning in 2015 of the WAX CAPA have already been addressed through the RSDM. In addition, as explained in Section C2 of the Application, FBC does not expect PPE variances of the same magnitude to occur in the future.

Some variation from the currently forecast revenue requirements components will occur, as a result of normal forecast variances or to circumstances beyond the Company's control, but FBC is unable to forecast such events at the present time.

3.0 Reference: Exhibit B-1-1, Appendix E2, p. 7; Exhibit B-7, BCUC 1.74.0; Exhibit A2-13, Pacific Institute for Climate Solutions (PICS), Media Release, September 30, 2013

Weather Normalization

On page 7, FBC states:

> "[t]he Company also investigated possible global warming effects through a long-term (30-year) trend analysis of HDD and CDD, <u>but no statistically significant trend of increasing temperature was found for any month except for July as summarized below</u>. Therefore, this load forecast does not explicitly address global warming effects. This is in line with the current utility practice according to surveys" (Exhibit B-1-1, Appendix E2) (Emphasis added).

3.1 For the month of July, please indicate by how many degrees Celsius the temperature has increased over the last 30 years. Please also elaborate on the implications of that increase in temperature in term of energy use and peak demand. Please provide any supporting data or information if necessary.

<u>Response:</u>

The analysis of the Environment Canada weather data for Penticton alone indicated a 0.17C increase. However, the weather data used is specific to Penticton and is inconsistent with other weather data within FBC's service territory. Therefore, the result of the analysis should not be used to validate any long term weather changes or to infer any implications of energy use or peak demand.

On page 2 of the PICS' Media Release dated September 30, 2013, and according to modeling performed by the Pacific Climate Impacts Consortium of the University of Victoria for British Columbia, there has been a statistically significant increase in winter temperatures of 2.1 degrees Celsius over 1900-2012 and of 1.1 degrees Celsius in summer temperatures over the same period.

3.2 Please explain why FBC finds no statistically significant trend of increasing temperature except for the month of July when there are public observations that show that both winter and summer temperatures have increased significantly over the last century and that winter temperatures have increased even more than the summer temperatures.

Response:

The Company relies on 30 years' worth of temperature data from its service territory only. As a result, FBC does not consider data going back to 1900 to be relevant to the forecast for 2014.

Throughout the PBR period each one year forecast will be based on recent historic actual data. The recent data intrinsically incorporates many factors, including, but not limited to, any climate change that may occur. Whether or not there is a long term 112 year trend is immaterial to the methodology.

3.3 Please re-calculate the analysis of HDD and CDD for the period 1900 to 2012 or for the longest period of time for which FBC has access to monthly temperature data. Please elaborate on the results.

Response:

The analysis completed for the preparation of the forecast for the test period considers weather data back to 1983. This data is used for normalization calculations. The remaining data used in the preparation of the forecast considers a shorter timeframe.

Consistent with prior forecasts, trends that may or may not be evident in the data from the early 1900s through 1982 are not considered relevant or used as inputs into any of the forecasting methodologies. FBC is not in possession of such aged data and has no application for it. FBC believes the accumulation and calculation requested is irrelevant to the requests made in the filing. FBC believes that such analysis is time consuming and irrelevant for the purpose of this filing.

The Company anticipates filing annual updates to the forecast and the input data to those forecasts will encapsulate all the variables implicitly present in the historic consumption data.

B. PBR FORECAST – POWER PURCHASE EXPENSE

4.0 Reference: Exhibit B-7, BCUC 1.83 to 1.91

Power Purchase Expense

> "The $2.25 Million adjustment to the 2012 and 2013 power purchase forecast is not a flow through from 2011. The adjustment was applied to the 2012 and 2013 power purchase forecast to account for potential market savings. It is comprised of a $0.75 Million adjustment proposed by the Company in its initial power purchase forecast and a further $1.5 million adjustment ordered by the Commission in the 2012-2013 RRA Decision (G-110-12)." (Ex. B-7, BCUC 1.83.1)

"FBC agrees that the variance in the PPE for the last test period (2012-2013) is a credit of over $23 million before the PPE adjustment and over $18 million after the adjustment." (Ex.B-7, BCUC 1.83.3)

> "This deferral account, which was approved by Order G-110-12, is to be maintained over the 2014 – 2018 PBR period, with the annual variances being flowed through in the following year's rates.
>
> FBC does not expect that future PPE variances from forecast will be comparable in size to those experienced in 2012 and 2013…" (Ex. B-7, BCUC 1.83.5.1)

"For the purposes of the 2014 Power Purchase Expense Forecast, FBC has estimated a further $2 Million reduction to BC Hydro expense based on current market forecasts." (Ex. B-1, p. 102)

4.1 FBC forecasts $87.2 million for Power Purchase Expense (PPE) in 2014 (Exhibit B-1-6, p. 96). Given the above discussion, why wouldn't the 2014 PPE forecast be closer to the $83.5 million currently projected for 2013, especially if all variances flow through to the PPE variance deferral account?

Response:

As shown in Table C2-5 of the Application, there is a 58 GWh (and associated capacity) expected increase in load for 2014 over 2013. This accounts for the majority of the increase. In addition, higher expected market prices result in less opportunity to displace more costly BC Hydro PPA energy.

FBC forecasts Power Purchase Expense to the best of its ability using information available at the time. The expense forecast is the amount that FBC expects to incur – if the PPE forecast were to be adjusted from that amount, it would be necessary to forecast the balance as an addition to the variance deferral account in 2014. To do otherwise would result in the Company not being afforded an opportunity to fully recover the costs of financing its expenditures (or conversely could expose customers to unnecessary costs of financing the deferral account).

4.2 If future PPE is forecast such that there is an equal probability of the actuals coming in above or below the forecast, should the amortization be spread over several years to smooth the impact on customer rates?

Response:

In Section 2.4 of the Application (Exhibit B-1, pages 99-100), FBC describes the approach it used to develop the power purchase expense forecast for 2014, and how it differs from the approach used to develop the 2012 and 2013 forecast used in FBC's 2012-2013 Revenue Requirements Application. FBC expects the revised approach will reduce the size of the future PPE variances from forecast however the main factors, aside from load, that will influence variances from the forecast will be actual market prices and future BC Hydro increases, and therefore variances from year to year may not be symmetrical.

In addition, annual rate impacts are also affected by many other factors, including other non-controllable deferral accounts which may also have actuals higher or lower than forecast and which may offset one another to some degree.

In any case, FBC believes that it is important to amortize the Power Purchase Expense Variance account in the following year to more closely align the timing of cost recovery with the benefit of the expenditure.

5.0 Reference: Exhibit B-7, BCUC 1.84.2 and Exhibit B-15 ICG 1.19.1

Power Purchase Expense

In response to BCUC 1.84.2, as to whether FBC undertook additional efforts to secure more low cost market sourced electricity in years when PPE was an 'at risk' cost, FBC states "[n]o. Regardless of whether it was a flow through or an 'at risk' item, FBC actively manages the power purchase expense budget with the objective of minimizing power purchase expense while maintaining security and reliability of supply." (Exhibit B-7, BCUC 1.84.2)

In Industrial Customers Group (ICG) 1.19.1, FBC shows the actual PPE variances and sharing since 2003.

5.1 Although FBC actively manages its PPE budget to minimize the variance between forecast and actual results, since 2010 these actions have still resulted in large variances. Does this imply that customers are best served by a continuation of the PPE variance deferral account with 100 percent of the variance flowing to customers?

Response:

In its response to BCUC IR 1.84.2, FBC was explaining that in either scenario it would actively manage its power purchase portfolio with the "objective of minimizing power purchase expense while maintaining security and reliability of supply". This is a different statement from saying that "FBC actively manages its PPE budget to minimize variances between forecast and actual results" as suggested by the question. If the objective was to simply minimize variances from the PPE budget, then FBC may not have sought to capture PPE savings in response to actual load and market conditions and opportunities as they arose between rate setting periods.

Nevertheless, as discussed in BCUC IR 1.84.1, FBC agrees that a continuation of the PPE variance deferral account is the appropriate method at this time to ensure that customers are receiving the full benefit of FBC's ability to capture market opportunities to generate savings, if and when those opportunities should arise. This is consistent with the Commission's finding in its 2012-2013 RRA Decision (page 34) which stated:

> *"The Commission Panel finds that a deferral account to capture variances between forecast and actual power purchase expense represents a reasonable attempt to manage uncertainty and approves establishing the Power Purchase Expense Variance Deferral Account as proposed by FortisBC. The Panel understands the complexity of managing the number of variables affecting the power purchase process and is in agreement that any positive or negative variances are most appropriately borne by the customer. The establishment of a Power Purchase Expense Variance Deferral Account*

is the most effective way to manage this process with variances being handled in customer rates in subsequent periods."

6.0 Reference: Exhibit B-11, BCPSO 1.69.1

Power Purchase Expense

The tables provided in response to BCPSO 1.69.1 show the average $/MWh for FBC's power supply.

6.1 For Market Purchases, please provide an estimate of the average cost in each of years 2010, 2011 & 2012.

<u>Response:</u>

Please refer to the following table:

	2010 Actual ($/GWh)	2011 Actual ($/GWh)	2012 Actual ($/GWh)
Average Market Cost	$ 35.40	$ 24.95	$ 27.39

7.0 Reference: Exhibit B-12, BCSEA 1.8.2; Exhibit B-10, CEC 1.54.3

Power Purchase Expense

FBC's response to BCSEA 1.8.2 states that:

> "FBC's main requirement from the market at this time is energy, not capacity and FBC does not anticipate any difficulty in acquiring energy supplies from the US market on an as needed basis. However, over the longer term as FBC's requirements grow, it may be prudent to consider other options due to price risk. The 2016 Resource Plan will re-examine the best resource options for FBC to meet customer capacity and energy and stand alone energy needs at that time."

In response to CEC 1.54.3, FBC states that:

> "[i]f BC Hydro rates increased at 10% per year, the assumptions behind this table would not change significantly in the short-term because FBC cannot replace the [Power Purchase Agreement (PPA)] with an equivalent resource without sufficient lead time. FBC's power purchase expense would increase but the Company's firm available resources will not change. FBC may have more opportunity to displace some PPA purchases with market purchases, if the market purchases are be more cost effective compared to the PPA. However, an equivalent market purchase does not exist, since no market purchase can replace the PPA with similar reliability, ability to shape deliveries and ability to meet FBC's remote loads.
>
> In the long-term, continued large increases to BC Hydro rates may significantly affect FBC's resource planning process. It may accelerate the need to bring on new generation resources, if they were to become more cost effective compared to the PPA."

7.1 Does the low capital cost and flexible operation of a natural gas generator located in the Okanogan provide maximum benefit to FBC ratepayers in terms of system reliability, flexibility to access the market when prices are low and low relative costs of generation when market prices are high? Please discuss.

Response:

FBC agrees that a natural gas generator located in the Okanagan may provide significant benefits to FBC ratepayers in terms of system reliability and flexibility. However, as FBC has not fully analyzed the benefits of a natural gas generator located in the Okanagan, it is difficult to determine if it provides the maximum benefit to customers at this time.

FBC's 2012 Long-Term Capital Plan stated that no additional generation resources have been assumed in the Okanagan area. However, it identified transmission projects that could potentially be deferred or eliminated if firm generation resources were appropriately sited in the Okanagan area. These generation resources would have the effect of offsetting area load and thus reducing bulk transmission deliveries. A similar, but generally smaller, effect is achieved by FBC's demand-side management (DSM) programs.[1]

As identified in the question, a natural gas generator located in the Okanagan could also increase FBC's resource option flexibility. FBC's 2012 Long Term Resource Plan identified a gas turbine as one of several resource options to be evaluated to supply future needs.[2]

FBC has been directed to include a portfolio analysis of resource options in future resource plans. A new gas plant will be one of the new resource options considered in such an analysis.

7.2 At today's natural gas prices and BC Hydro supply costs, would a natural gas generator be competitive with BC Hydro supply? Please show rough calculations.

Response:

The response to the question depends on a number of factors, including whether it is an existing or new plant, a CCGT or SSGT, plant size, heat rate, capacity factor, location, and carbon compliance costs.

Assuming the Commission was asking about a new plant, the BC Hydro draft Integrated Resource Plan dated August 3, 2013 looks at a number of gas plant configurations and price scenarios. Table 6-1 in the BC Hydro IRP[3] outlines some of those scenarios and calculates their corresponding Unit Energy Cost (UEC), and is summarized in the Table 1 below:

Table 1: Adjusted UECs of CCGT for Various Market Scenarios (2013 dollars)

Market Scenario	50 MW CCGT ($/MWh)	250 MW CCGT ($/MWh)	500 MW CCGT ($/MWh)
Scenario 1	$85.96	$60.51	$56.90
Scenario 2	$71.33	$45.99	$42.33

[1] FBC 2012 Integrated System Plan, Volume 1, 2012 Long-Term Capital Plan, June 30, 2011. Section 2.7.7, page 86, lines 9-16.
[2] FBC 2012 Long Term Resource Plan, Section 6.1.3, Table 6.1.3-A, page 75.
[3] BC Hydro Draft 2013 Integrated Resource Plan, August 3, 2013, Table 6-1, page 6-12.

Market Scenario	50 MW CCGT ($/MWh)	250 MW CCGT ($/MWh)	500 MW CCGT ($/MWh)
Scenario 3	$101.86	$76.29	$72.76
Scenario 4	$94.64	$68.87	$65.29
Scenario 5	$137.97	$111.02	$107.47

The UECs in Table 1 above are inclusive of BC carbon tax.

Table 5.2 in BC Hydro's IRP[4] also provided the base Natural gas price forecasts used in calculating UECs. These are summarized in Table 2 below:

Table 2: Natural Gas Price Forecast Scenarios (Real 2012 US$/MMBTU at Sumas)

Market Scenario	1	2	3	4	5
	Mid Electricity Mid GHG (Regional) Mid Gas	Low Electricity Low GHG (Regional) Low Gas	High Electricity High GHG (Regional) High Gas	Mid Electricity Mid GHG (Regional/Nat'l) Mid Gas	High Electricity High GHG (Regional/Nat'l) High Gas
2014	3.7	2.9	4.8	3.8	4.8
2015	3.7	2.8	4.9	3.8	4.9
2016	3.9	2.8	5.0	3.9	5.0
2020	4.2	2.9	5.7	4.5	5.7
2025	4.9	3.0	7.0	5.6	7.0
2030	5.2	2.9	7.7	6.0	7.7

1. PPA Cost Calculation:

The rates for 2013 based on current PPA charges are:

- Capacity = $6,670 per MW
- Energy = $39.10 per MWh

Making the simplifying assumption that 1 MW of PPA capacity and energy would be displaced for all hours of the year, the combined avoided PPA cost is:

- $39.10 * 8760 hours per year = $342,516 energy cost
- $6,670 * 12 months per year = $80,040 capacity cost

[4] BC Hydro Draft 2013 Integrated Resource Plan, August 3, 2013, Table 5-2, page 5-13.

Therefore the total blended PPA cost at current rates is $422,556/year or $48.24/MWh in 2013 dollars.

2. New CCGT Gas Plant UEC Calculation:

The calculation assumes a new gas plant will be available for January 1, 2014.

The current Sumas gas price for the 2013/14 gas year is US$4/MMBTU. This corresponds most closely to the Scenario 1 in the Sumas Gas Price Forecast above once it is converted to 2013 dollars.

The PPA is for 200MW. The closest size gas plant in Table 1 above is 250 MW.

Therefore as a simplifying assumption, the UEC for a 250 MW gas plant under Scenario 1 can be used as a reasonable proxy for the cost of energy from a natural gas generator at today's market prices. The UEC is $60.51.

3. CCGT Gas Plant Competitiveness

The results from the analysis above are:

RS3808 blended cost:	$48.24/MWh (2013$)
New 250 MW CCGT UEC:	$60.51/MWh (2013$)

Therefore, given the assumptions, a new 250 MW CCCT Gas plant would not be be competitive with BC Hydro RS3808 energy supply.

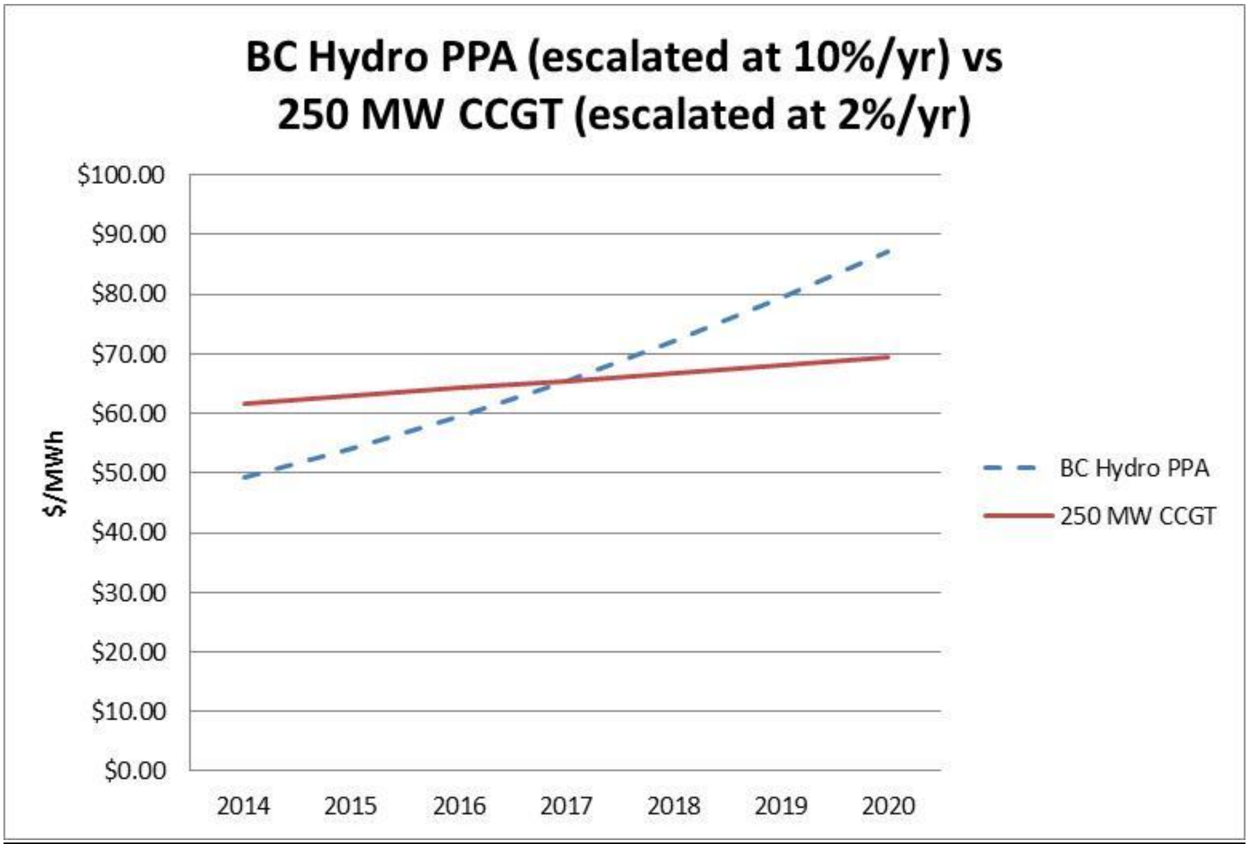
7.3 If BC Hydro rates rose by 10 percent per year while natural gas rates rose only with inflation (assume 2 percent), by what year would a FBC natural gas generator become cost effective?

<u>Response:</u>

As demonstrated in the graph below, the crossover point would be in 2017. FBC assumed the difference in escalation starts in 2015. Given that the commodity cost is the most significant factor in the energy cost of a new gas plant, FBC has made the simplifying assumption to inflate the UCC by 2% per year to be roughly comparable to escalating the gas price by 2% per year.

Given that the financing costs are fixed, FBC recognizes that this may over escalate the energy cost of a gas plant slightly, but believes that it still illustrates the point that in the long term, the PPA may not be the most economic resource to meet base load.

However, the BC Hydro PPA provides FBC a highly reliable resource with significant flexibility and optionality to optimize both capacity and energy costs that would not be available if it was replaced with a gas fired plant. This value of this flexibility would factor into FBC's decision making regarding future resource options. FBC expects to provide a full evaluation of future resource options as part of its next long term resource plan to be filed in 2016.



8.0 Reference: Exhibit B-12, BCSEA 1.18.1

Power Purchase Expense

FBC states that "[i]f the BCUC were to deny RS3808, and determine that FBC has no rights to BC Hydro energy at embedded costs under the Heritage Contract, FBC would need to replace that power immediately. FBC would likely contract a short-term replacement resource, possibly from BC Hydro, to give it time to contract or build a new long-term replacement resource. This would impact FBC's LRMC of $56.61, likely raising it significantly." (Exhibit B-12, BCSEA 1.118.1)

8.1 Please provide an estimate of how much the Long Run Marginal Cost (LRMC) would rise and the impact that would have on future power purchases during the proposed PBR period. Show the generation sources that likely would be built or contracted and their approximate cost to PPE.

Response:

During the PBR period it is not expected that any additional generation resources could be completed in time to provide supply, but the most likely generation replacement resource would be a CCGT, as discussed in the responses to BCUC IR 2.7.2 and 2.7.3. Since FBC fully expects the PPA to be renewed, detailed studies planning for the event that it would not be renewed were not completed as part of the PPA renewal process.

However, if the PPA were not renewed, in the short-term FBC would experience a very serious energy deficit and until the WAX plant comes online, a large capacity deficit as well. These shortages would be difficult to manage without compromising security of supply. In the short to medium term, until a new resource could be brought on-line, the Company expects that a bridging resource from BC Hydro would have to be negotiated that would likely cost about the same as PPA power without the inherent volume flexibility.

C. PBR FORECAST — OPERATION AND MAINTENANCE (O&M)

9.0 Reference: Exhibit B-7, BCUC 1.97.1

Base O&M, O&M Tracked Outside of the Formula

The following table was provided in response to BCUC 1.97.1:

	2012 Approved	2012 Actual	2013 Approved	City of Kelowna	Pension/ OPEB	Insurance	2013 Adjusted	Productivity (Sustainable Savings)	2013 Projection	2013 Deferrals			Incremental O&M	2013 Base
										PST	Pension	MRS		
Generation	2,282	2,331	2,492		(269)		2,223	64	2,287	3	137		350	2,777
Operations	19,920	19,730	20,816	(488)	(2,248)		18,081	122	18,203	53	769			19,025
Customer Service	6,624	6,768	7,541	(835)	(814)		5,892	(31)	5,861	15	333			6,209
Communications & External Relations	1,431	1,244	1,469		(159)		1,310	(29)	1,281	14	35			1,331
Energy Supply	1,069	988	1,124		(121)		1,003	-	1,003	2	52			1,057
Information Technology	2,841	2,925	2,974		(321)		2,653	14	2,667	38	124			2,827
Engineering and Project Management	2,701	2,615	2,791		(301)		2,490	31	2,521	5	141	900		3,567
Operations Support	1,223	1,240	1,252		(135)		1,117	(47)	1,070	2	51			1,123
Facilities	3,685	3,598	3,466		(374)		3,092	(77)	3,015	16	30		(909)	2,152
Environment, Health & Safety	925	894	953		(103)		850	-	850	1	59			910
Finance & Regulatory	4,392	3,823	4,271		(461)		3,810	(191)	3,619	6	201			3,826
Human Resources	1,840	1,816	1,874		(202)		1,672	-	1,672	4	80			1,756
Governance	1,792	2,134	2,373	(22)	(256)	(1,588)	507	117	624	10	31			665
Corporate	4,118	3,444	4,225		(456)		3,769	(425)	3,344	11	115			3,470
Total O&M	**54,843**	**53,544**	**57,621**	**(1,344)**	**(6,222)**	**(1,588)**	**48,467**	**(452)**	**48,015**	**180**	**2,158**	**900**	**(559)**	**50,694**

Note: AMI 2013 tracked outside of the PBR formula is zero

9.1 Please confirm that columns 2012 Approved and 2012 Actual exclude O&M costs that are tracked outside the PBR formula (i.e. Pension/OPEB [O&M portion], Insurance and the Advanced Meter Infrastructure [AMI] Project) and excluding the City of Kelowna, as asked for in the Information Request. If not confirmed, please explain otherwise.

Response:

Not confirmed. The 2012 Approved & 2012 Actual O&M:

1. Includes Pension/OPEB [O&M portion];
2. Includes Insurance;
3. Excludes Advanced Meter Infrastructure since project had not begun; and
4. Excludes City of Kelowna, as the acquisition happened in 2013.

9.1.1 If the preceding IR is not confirmed, please provide a revised table with both 2012 Approved and 2012 Actual columns excluding O&M costs that are tracked outside the PBR formula (i.e. Pension/OPEB [O&M portion], Insurance and the AMI Project) and excluding the City of Kelowna.

Response:

The relevant information has been provided in the following table:

	2012 Approved	City of Kelowna	AMI	Pension/ OPEB	Insurance	2012 Approved Adjusted	2012 Actual	City of Kelowna	AMI	Pension/ OPEB	Insurance	2012 Approved Adjusted
Generation	2,282	-	-	(165)	-	2,117	2,331	-	-	(172)	-	2,159
Operations	19,920	-	-	(1,437)	-	18,483	19,730	-	-	(1,458)	-	18,272
Customer Service	6,624	-	-	(478)	-	6,146	6,766	-	-	(500)	-	6,266
Communications & External Relations	1,431	-	-	(103)	-	1,328	1,244	-	-	(92)	-	1,152
Energy Supply	1,069	-	-	(77)	-	992	986	-	-	(73)	-	913
Information Technology	2,841	-	-	(205)	-	2,636	2,925	-	-	(216)	-	2,709
Engineering and Project Management	2,701	-	-	(195)	-	2,506	2,615	-	-	(193)	-	2,422
Operations Support	1,223	-	-	(88)	-	1,135	1,240	-	-	(92)	-	1,148
Facilities	3,685	-	-	(266)	-	3,419	3,596	-	-	(266)	-	3,330
Environment, Health & Safety	925	-	-	(67)	-	858	894	-	-	(66)	-	828
Finance & Regulatory	4,392	-	-	(317)	-	4,075	3,823	-	-	(283)	-	3,540
Human Resources	1,840	-	-	(133)	-	1,707	1,816	-	-	(134)	-	1,682
Governance	1,792	-	-	(129)	(994)	669	2,134	-	-	(158)	(1,499)	478
Corporate	4,118	-	-	(297)	-	3,821	3,444	-	-	(254)	-	3,190
Total O&M	**54,843**	**-**	**-**	**(3,957)**	**(994)**	**49,893**	**53,544**	**-**	**-**	**(3,957)**	**(1,499)**	**48,089**

10.0 Reference: Exhibit B-7, BCUC 1.1.1 and 1.96.2

Net Sustainable Savings

FBC states that a priority for the Company and its employees is to improve productivity and realize efficiencies in its operations. FBC also refers to "a number of examples of productivity achievements in 2012/2013 that FBC realized" that have contributed to the $452 thousand of net sustainable savings which are shown on Table C4-2 of the Application. (Ex. B-7, BCUC 1.1.1)

In another IR response, FBC provided a breakdown of the activities that support the $452 thousand of net sustainable savings, including brief explanations of the over expenditures / savings in each O&M department (Ex. B-7, BCUC 1.96.2). Part of this IR response is copied below for reference:

	2013 Approved	Productivity (Sustainable Savings)	2013 Projection	Activities Resulting in Over Expenditure or (Savings)	Reference
Generation	2,492	64	2,556	Increased efforts to meet legislative dam safety requirements	Tab C Section 4 pg 123
Operations	20,816	122	20,938	No Specific Activity	-
Customer Service	7,541	(31)	7,510	No Specific Activity	-
Communications & External Relations	1,469	(29)	1,440	No Specific Activity	-
Energy Supply	1,124	-	1,124	N/A	-
Information Technology	2,974	14	2,988	No Specific Activity	-
Engineering and Project Management	2,791	31	2,822	No Specific Activity	-
Operations Support	1,252	(47)	1,205	Reduction in labour for Supply Chain and vehicle costs for Fleet	Tab C Section 4 pg 149
Facilities	3,466	(77)	3,389	Reduction in labour due to integration	BCUC IR1 132.3
Environment, Health & Safety	953	-	953	N/A	-
Finance & Regulatory	4,271	(191)	4,080	Lower external auditor fees and labour	BCUC IR1 134.2
Human Resources	1,874	-	1,874	N/A	-
Governance	2,373	117	2,490	Higher insurance premiums and appraisal fees	-
Corporate	4,225	(425)	3,800	Lower Board Costs, Executive labour and non-labour costs, partially offset by increased Fortis Inc charges.	Tab C Section 4 pg 170-172
Total O&M	**57,621**	**(452)**	**57,169**		

The above table illustrates that many of the sustainable adjustments to the 2013 Approved budgets are not related to any specific activity. Additionally, some of the sustainable adjustments are attributable to external factors, such as "lower external auditor fees" in the Finance and Regulatory department and "lower board costs" in the Corporate department.

10.1 Please explain how any of the net sustainable savings can be attributable to FBC's internal efforts to support the submission that "a number of examples of productivity achievements in 2012/2013 that FBC realized" which contributed to the $452 thousand of net sustainable savings?

Response:

FBC provides further details supporting that the net sustainable savings are attributable to the Company's internal efforts. The examples include:

- Integration of the facilities manager role with FEI;
- Fleet insurance coverage modified resulted in lower fees;
- Reduction of an FTE in Finance resulting from efficiencies (please refer to the response to BCUC IR 1.134.2);
- Integration of the executive management team with FEI resulting in savings; and
- Lower external auditor fees partially attributable to economies of scale with the Fortis Group of Companies.

The savings highlighted would not be possible without the actions of Company.

Additionally, by the very act of reducing the O&M Base for these savings, the Company has committed to sustaining these savings over the PBR term. FBC has not submitted that every savings resulted from an incremental efficiency; the end result is that costs are lower, and are being sustained at a lower level. In addition the Commission, through this IR process, has the opportunity to assure itself of the prudency of the Company's spending.

As the $452 thousand of savings noted are considered sustainable and have been incorporated into the proposed 2013 O&M Base for the PBR Plan, the focus should not necessarily be on how the efficiencies are achieved (i.e. monitored using metrics for different areas). No matter how they have been achieved, they serve to reduce O&M for the future benefit of customers, and it is this direct relationship to rates and the prudency of the Company's spending that should be the focus of the Commission.

10.2 Please explain how any measurable savings or efficiencies during the proposed PBR may be attributable to internal efforts of FBC as opposed to being attributable to windfall gains or factors that are external to the Company?

Response:

Please refer to the response to BCUC IR 2.10.1.

FBC further explains that "productivity achievements are not just about reducing costs. Productivity is more than just reducing costs. It is also about meeting increased demand for resources, including improving customer service and options, using the same amount of resources available." (BCUC 1.1.1)

10.3 Please discuss how FBC can objectively measure productivity achievements if not from observing reduced costs. Are there other quantitative measures proposed?

Response:

In the context of the PBR Plan, in addition to measurement of productivity with reduced costs, the quantitative metrics that are available is the suite of proposed SQIs which contain a number of quantitative metrics important to customers. The proposed SQIs serve not only to ensure that customer service is maintained at adequate levels for the funding available but they can also be indicators of productivity. By maintaining service at adequate levels and reducing costs at the same time, the company is inherently realizing productivity by "achieving the same with fewer resources".

The proposed SQIs and the formula approach to O&M funding go hand-in-hand providing a framework that will deliver benefits to customers and the Company.

11.0 Reference: Exhibit B-7, BCUC 1.1.4 and 1.136.1-1.136.2

Integration

> "FortisBC remained committed after the 2012-2013 application to its efforts to realize on the opportunities that flow from integration, and believes that its present filing reflects that fact.
>
> It views integration as a means to achieve further productivity/efficiency by focusing on managing the level of O&M funding required to operate the Company and has taken initiative to explore and implement integration opportunities. Those efforts are reflected in the Application." (Ex. B-7, BCUC 1.1.4)

In some O&M departments, FBC is able to attribute certain full time equivalent (FTE) changes as a result of integration efforts. For example, FBC states that "[t]he reduction in FTEs from 2012 to 2013 [in the HR department] is related to the integration with FEI" (Ex. B-7, BCUC 1.136.2).

FBC states that "[t]he cross charges resulting from integration are shown in the non-labour expenses" (B-7, BCUC 1.136.6). However, it also appears that non-labour expenses may also include other external costs (consulting, travel, etc).

11.1 For any O&M departments that have experienced integration efforts with FortisBC Energy Inc. (FEI) in the last five years, please provide, in a table format, the total number of FTE for each O&M department. Please include an additional column to show the change in FTE as a result of integration efforts with FEI.

Response:

Integration between FBC and FEI is one avenue by which the Companies and their employees seek to improve productivity and realize efficiencies in operations. Section A3 of the Application describes the Company's focus on productivity and the contributions of process streamlining, leveraging of technology and integration opportunities to its goal of achieving efficiencies. It is therefore not always possible to create direct linkages between productivity initiatives and integration of the utilities. Nor is it possible to create direct linkages between the number of employees and integration initiatives when employees in both organizations have responsibilities in both utilities. Consequently, the number of employees is not a measure that captures the benefits of integration and FBC is unable to specifically identify changes in FTEs that resulted directly and solely from integration with FEI.

11.2 Please add to the above table, the net cross-charges to/from FEI as a result of integration efforts (excluding any other expenses that may be captured in non-labour expenses). Calculate the net effect of the reduced labour costs for each department which may be translated into increased cross-charges between FEI and FBC. The intent behind this question is to understand/measure the effectiveness of the integration efforts.

Response:

In order to measure the net effect of integration between FBC and FEI, it would be necessary to compare the cross-charges incurred to the costs that would have been incurred on a stand-alone basis. As FBC stated in the response to BCUC IR 2.11.1, it is unable to accurately isolate the impact of integration from other productivity-enhancing initiatives and factors. Accordingly there is no comprehensive list of integration initiatives, along with their costs and benefits. As well, some efforts may have led to improved productivity and others to improved efficiency.

FBC believes improvements and their sustainment should be measured and tracked at the highest and most beneficial level which is by the Company's total O&M spending year-over-year and has incorporated this into the 2013 O&M Base for the PBR Plan.

One department where the effectiveness of the integration efforts can be clearly demonstrated is Corporate O&M – Executive, beginning with the partial integration of the Executive in 2010 to the full integration of the Executive effective January 1, 2012 which is shown in the table below and has been incorporated into the 2013 Base O & M for the PBR Plan.

	2009 Actual	2010 Actual	2011 Actual	2012 Actual ($000's)	2013 Projection	2013 Approved	2013 Base
Executive	2,523	2,514	2,294	1,622	1,830	2,365	1,955

11.3 During the PBR period, would the results from integration efforts with FEI be equivalent to "efficiency gains" or "productivity gains"?

Response:

Integration efforts with FEI may contribute to efficiency or productivity gains for FBC and resulting net savings during the PBR period, which will be shared between ratepayers and the Company. However, not all integration efforts will lead to productivity gains with a net dollar savings. As stated previously, productivity is more than just about reducing costs as it is also about meeting increased demand for resources including improving customer service and options using the same amount of resources.

12.0 Reference: Exhibit B-7, BCUC 1.109.1

Generation Maintenance

BCUC 1.109.1 asked which utilities in Canada adhere to the CEATI maintenance practices. FBC responded that: "CEATI publications are generally in the form of industry best practices, benchmarking and guides developed by industry experts. These are adopted or endorsed by the sponsoring member utilities, as applicable." (Exhibit B-7, BCUC 1.109.1)

12.1 Please clarify which utilities in Canada adhere to the major electrical inspection after 10 years of continuous operation?

<u>**Response:**</u>

FBC does not know which utilities adhere to the CEATI best practices. Typically CEATI publications are in the form of industry best practices, benchmarking and guides developed by industry experts. A utility would consider these practices along with manufacturer's guidelines, and equipment operating condition to determine its inspection schedules.

12.2 Has FBC adhered to this prior to now?

<u>**Response:**</u>

Yes, FBC has adhered to industry best practices (including CEATI's), manufacturer's guidelines and equipment condition in determining its maintenance scheduling.

13.0 Reference: Exhibit B-7, BCUC 1.114.1

Operations

13.1 The table identifies the percentage of outages caused by "Tree Falling" since 2010. Please restate the table in actual numbers of outages caused by "Tree Falling" and update the 2013 YTD number.

Response:

The following table includes the number of outages since 2010 related to trees falling. The 2013 data is YTD to the end of September.

	Number of Outages Due to Trees Falling			
	2010	**2011**	**2012**	**2013 YTD**
Total	157	132	222	147

14.0 Reference: Exhibit B-7, BCUC 1.112.1

BC Hydro stop start requests

14.1 There were 267 unit stop/start requests in 2012. How many requests have been made so far in 2013?

Response:

The 267 unit stop/starts requests in 2012 are the number of additional start/stops BC Hydro had requested for system optimization, beyond the amount required to adjust for changing water flows throughout the year, to manage Kootenay Lake levels, and to account for unit outages. So far in 2013, BC Hydro has requested no additional unit start/stops for system optimization.

15.0 Reference: Exhibit B-7, BCUC 1.115.2

Operations

15.1 The table identifies the Operations O&M per customer since 2008. What would the O&M per customer statistics have been in the absence of Order G-195-10?

Response:

The Table below has been created as per the request above which is the 2011 CEP Decision that ordered certain capital sustaining (hot tap, stirrup connector replacement, pine beetle hazard tree removal, and brushing) work to O&M. However, additionally in the 2013 Base the incremental 2013 Deferred Pension component has also been normalized. This was done to ensure an even comparative base between the 2013 Approved, Projection & Base O&M (since 2013 Approved and the 2013 Projection does not have this specific additional pension component included in the data provided below).

Table BCUC IR2 15.1: Operations O&M Review Excluding G-195-10 ($ Thousands)

	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Approved	2012 Actual	2013 Approved	2013 Projection	2013 Base
Total O&M	$ 14,924	$ 15,057	$ 14,892	$ 18,604	$ 19,920	$ 19,730	$ 20,816	$ 20,938	$ 21,760
Less G-195-10	-	-	-	(3,518)	(3,147)	(3,169)	(3,153)	(3,153)	(3,193)
Pension Normalization	-	-	-	-	-	-	-	-	(769)
Adjusted O&M	**$ 14,924**	**$ 15,057**	**$ 14,892**	**$ 15,086**	**$ 16,773**	**$ 16,561**	**$ 17,663**	**$ 17,785**	**$ 17,798**
Average Customer	**108,722**	**110,286**	**111,552**	**112,756**	**113,588**	**113,587**	**124,581**	**121,566**	**121,566**
O&M per Customer	**$ 137**	**$ 137**	**$ 133**	**$ 134**	**$ 148**	**$ 146**	**$ 142**	**$ 146**	**$ 146**

16.0 Reference: Exhibit B-7, BCUC 1.122.1; Exhibit B-1, p. 138

Energy Supply

BCUC 1.122.1 asked FBC to provide evidence to demonstrate that the total labour cost of load forecasting charged to FBC (FBC costs plus charges from FEI) will be less than when FBC performed its own load forecasting.

FBC responded:

> "[c]ost savings to date have primarily been through increased efficiency due to a common management approach to the gas and electric load forecast. Not only has this directly resulted in less electric side resources being used to produce the load forecast, but the quality of the electric forecast has benefited from adapting certain FEI practices such as the Industrial Survey format that resulted in increased response rates. Future savings potential is being explored though the use of a common load forecasting model and increased staff cross-training. As explained in the Application on page 139, lines 10-14, these cost savings are a critical part of the Power Supply group's ability to provide increased levels of support for the Power Supply function within the approved budget." (Exhibit B-7, BCUC 1.122.1)

16.1 Please identify the cross-charges from FEI as a result of the electric forecast now being managed under the purview of the gas utility's forecasting department.

<u>Response:</u>

The cross-charges from FEI for forecasting are labour charges totaling $10 thousand.

16.2 Table C4-13 of the Application indicates increased costs in each year for both Labour and Non-labour expenses for the Energy Supply department. Please confirm that there are no quantifiable savings at this time due to the integration with FEI.

<u>Response:</u>

FBC agrees that the dollar value of expenses related to the Energy Supply department has not decreased and that the achieved savings are not quantifiable. However, as stated in the same section as Table C4-13 on page 139 of the Application, "During 2013 the manager of the gas load forecast assumed responsibility for overseeing the electric load forecast; resource sharing such as this between the electric and gas utilities allow resources to be focused in a more efficient manner to provide increased levels of support for the Power Supply function within the approved budget."

17.0 Reference: Exhibit B-7, BCUC 1.129.1, 1.129.4 and 1.200.1

Mandatory Reliability Standards (MRS)

FBC provides the following tables showing the actual and projected costs for MRS:

	2011	2012	2013
Approved	$0.9M	$1.2M	$1.2M
Actual	$1.0M	$1.5M	$2.1M

(Ex. B-7, BCUC 1.129.1)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ -	$ 856	$ 1,328	$ 914	$ 1,709	$ 1,770
Non-Labour	-	160	171	273	379	380
Total O&M	$ -	$ 1,016	$ 1,499	$ 1,187	$ 2,088	$ 2,150

(Ex. B-1, Table C4-18)

17.1 Please confirm that all MRS related costs are included in the Engineering Services O&M department (aside from regulatory costs related to the MRS Inquiry). If not confirmed, please provide a table showing all MRS-related costs and identify which O&M department they accrue to.

Response:

The resources to achieve and maintain compliance with the MRS are drawn from a variety of business groups, including engineering, operations, information systems, generation, human resources and facilities. All costs associated with MRS (regardless of the business area where the MRS-related work takes place) are captured in the MRS O&M expenditures, as detailed in Table C4-18. No MRS-related costs are included in any other department O&M budgets.

17.2 Please confirm that MRS is no longer captured in capital-related expenditures. If not confirmed, provide a table showing the capital-related MRS costs in the 2013 Base and for the PBR period, including the number of capital-related FTEs.

Response:

FBC has completed the capital expenditures to become compliant with the standards currently adopted in British Columbia, and is not forecasting additional capital expenditures at this time. If new or modified standards become applicable, incremental capital expenditures would be treated as a Z-factor under the PBR plan.

17.3 Please expand Table C4-18 of the Application to include the number of FTEs for the period 2010 to 2013.

Response:

The quantity of Full Time Equivalents (FTEs) is difficult to calculate as the level of effort for MRS involves individuals from a variety of departments at varying degrees of involvement. The level of effort for ongoing compliance under the O&M budgets is best described with total labour hours per year, as shown below.

Year	2010	2011	2012	2013 (forecast)
Approximate Hours per year	-	12,000	15,000	20,000

17.4 Please expand Table C4-18 of the Application for the years 2014 to 2018. Include number of FTEs, Labour costs and Non-labour costs. If MRS-related costs are captured in other O&M departments, please include in the same table.

Response:

The requested costs are found in Table C4-20 on page 147 of the Application. FBC expects the number of employees to remain relatively consistent through the PBR term but has not forecasted employees at the department level.

FBC states that:

> "During 2012 the Company recorded an additional $0.3 million before tax of costs in the deferral account; in 2013 the incremental cost required to ensure that MRS compliance is maintained are estimated to be $0.9 million before tax" and now FBC "requests approval to amortize the deferred amounts in 2014" (Ex. B-1, p. 269).

FBC also states that:

> "WECC…conducted its first audit of FBC in 2012…Of the approximate costs incurred during the audit process, about $231,000 of internal labour costs were charged to O&M as budget in the 2012 Revenue Requirements. <u>The balance of the audit expenses, were recorded in a deferral account ($0.4 million net of tax)"</u> (Ex. B-1, p. 268) (Emphasis added).

However, in response to BCUC 1.200.3, it appears that the total audit expense in 2012 was $806 thousand.

17.5 Given that the total audit expense was $806 thousand and that $231 thousand was charged to O&M in 2012, the balance of the audit expenditures are $575 thousand. Please reconcile this balance with the 2012 deferred amount of $0.3 million (before tax) and/or the 2013 deferred amount of $0.9 million before tax.

<u>Response:</u>

The audit expense is a one-time expenditure related to the BCUC audit, which occurs every three years. The deferred amounts of $0.3 million and $0.9 million are ongoing expenditures to maintain compliance and are not related to audit expenses.

17.5.1 Please clarify how much of the deferred amounts relate to the 2012 MRS audit. Provide a reconciliation of the balances.

<u>Response:</u>

Please refer to the response to BCUC IR 2.17.5.

Exhibit A2-3 contains a set IRs which relates to FBC's 2012 Application for several deferral accounts (including MRS deferral). In IR 1.7.2 and 1.7.3 of Exhibit A2-3, FBC confirmed that of the $1.2 million budgeted for MRS costs in 2012 and 2013, none of that related to MRS audit costs, indicating the MRS audit cost is a one-time expenditure.

17.6 Given that the total 2012 audit-related expenses were $806 thousand, please explain why FBC has included this amount in the 2013 Base O&M? Wouldn't it be more appropriate to reduce this amount off the 2013 Base O&M so that it will more reasonably reflect annually-recurring expenses through the PBR formula? Why or why not?

Response:

2013 Base O&M includes annual expenditures for ongoing compliance. Official audits are not included in the base O&M, as they only occur once every three years and hence the uneven nature of these incremental expenditures would be problematic under a formulaic PBR calculation.

In IR question 1.7.1.2 of Exhibit A2-3, FBC states that "**the level of activity required to maintain compliance with MRS is much greater than was understood at the time of the 2012-13 RRA & ISP and Evidentiary Update**" [emphasis added] and therefore FBC sought to defer an incremental $1.2 million [$0.3 million in 2012 and $0.9 million in 2013] of MRS related expenses.

However, in the most recent BC Hydro MRS Assessment No. 6 of May 24, 2013, FBC indicated that for several of the MRS standards, there were:

"**No incremental costs** associated with the revision…

No incremental costs associated with the correction…

No incremental costs associated with implementation"

(BC Hydro MRS Assessment No. 6, Appendix C4[5], Column L, pp. 5-6) (emphasis added)

On page six of this report, FBC did specify some incremental costs associated with one of the MRS standards, which will require one-time costs of $175to $225 thousand and on-going costs of $8 to $12 thousand. In the Addendum report dated September 30, 2013, FBC states that:

"As FortisBC currently uses the criterion referenced, **FortisBC does not have any one-time incremental costs.**"(BC Hydro, Addendum to Assessment Report No. 6, Appendix C4[6], Column L, p. 2) (emphasis added).

[5] http://www.bcuc.com/Documents/Proceedings/2013/DOC_35210_B-1_BCH_MRS-Assessment-Report-No-6.pdf

17.7 Given these assertions in the MRS Inquiry proceeding, please explain how FBC can justify the appropriateness of the $1.2 million incremental MRS expenses that are deferred from 2012 and 2013 ($0.3 million in 2012 and $0.9 million in 2013).

Response:

Assessment Report 6 reviewed changes for standards not currently in effect in BC. FBC has reviewed the impact of the changes and has submitted the information through the assessment review process.

The costs of incremental MRS expenses that are deferred from 2012 and 2013 ($0.3 million in 2012 and $0.9 million in 2013) are required to maintain compliance with the current standards in effect in BC for those years. FBC anticipates that the costs will be maintained at 2013 levels for the PBR period, with the current approved standards and BC MRS program.

17.8 Provide a breakdown of the costs by each MRS standard for Base 2013 and for 2014–2018 in a table format.

Response:

FBC does not track costs on a per-standard basis (and indeed considers it infeasible to do so) and therefore is unable to provide the information in the requested format.

17.9 How much of these deferred expenses ($0.3 million in 2012 and $0.9 million in 2013) are related to the 2012 MRS audit?

Response:

The 2012 MRS audit expenses are not related to the deferred expenses listed in the question.

[6] http://www.bcuc.com/Documents/Proceedings/2013/DOC_35898_B-2_Report-Addendum.pdf

17.10 Please complete the following table for the years shown:

	2008 — RMS Agreement with WECC	2009	2010	2011	2012	2013
Number of MRS standards that apply to FBC						
The count of FTEs involved with RMS or MRS						
Total FTE Cost involved with RMS or MRS						

Response:

FBC is unable to provide the information in the requested format. Instead, the information provided below includes the number of standards for which FBC needed to comply, based on its registered functions, within each calendar year. Past submissions that included FTE counts did not provide a representative indication of the magnitude of effort required to achieve and maintain ongoing compliance. This is because during the period of 2010 to 2012, 42 requirements were under mitigation and 62 standards were revised.

	2008 RMS Agreement with WECC	**2009**	**2010**	**2011**	**2012**	**2013**
Number of MRS standards that apply to FBC		0	79	94 (8 are version changes and require compliance with both versions for the year)	94 (8 are version changes and require compliance with both versions for the year)	106 (21 are version changes and require compliance with both versions for the year)

	2008 RMS Agreement with WECC	2009	2010	2011	2012	2013
~~The count of FTEs involved with RMS or MRS~~ Total Operating hours	Information Unavailable	No additional operating hours	No additional operating hours.	Approximately 12,000 hours	Approximately 15,000 hours	Approximately 20,000 hours
~~Total FTE Cost involved with RMS or MRS~~ Incremental Operating Cost	Information Unavailable	No ongoing operating budget identified	No ongoing operating budget identified	$1.1million	$1.5million	$2.1million

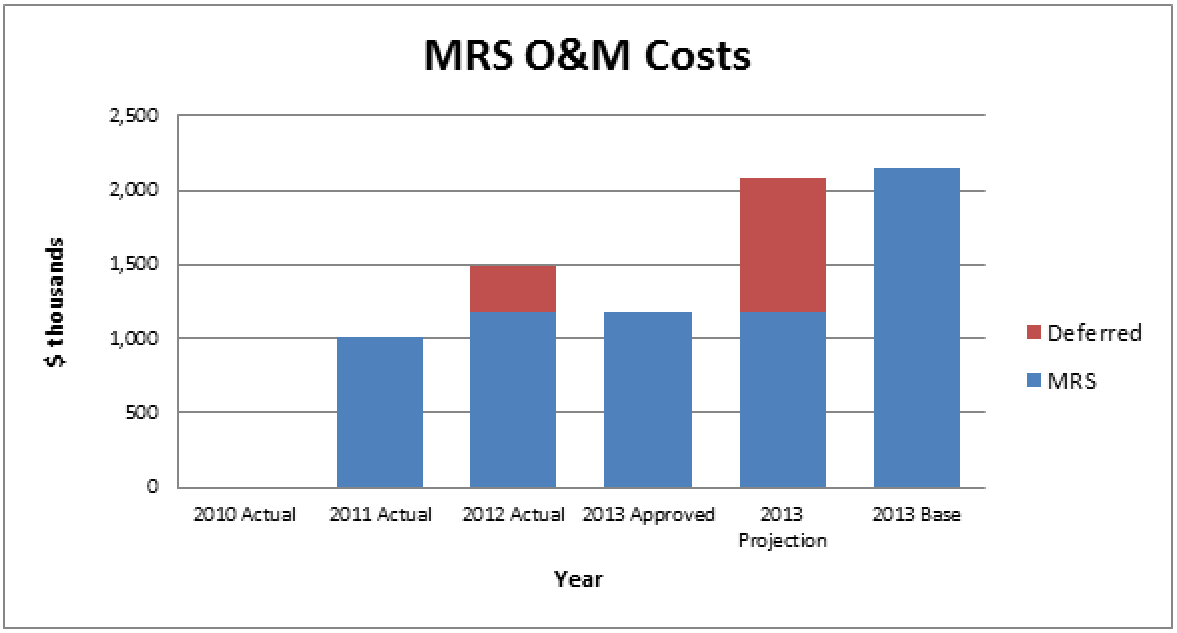
FBC expects the operating hours related to MRS compliance (other than for the official audit) to be consistent through the PBR term subject to potential changes to the MRS during the term.

18.0 Reference: Exhibit B-7, BCUC 1.36.1, Exhibit B-11, BCPSO 1.77.1.1

MRS Costs

FBC states that MRS will not be considered a Z-factor item because it is already part of the embedded O&M, "however if in the future there were cost increases arising from MRS requirements, that would be considered a Z-Factor because those cost increases are not controllable and are not in base O&M" (Exhibit B-7, BCUC 1.36.1).

The following graph was developed from FBC's response to BCSPO 1.77.1.1:



18.1 Given the trend in the MRS costs, please explain if FBC anticipates that these costs will decrease over time as FBC becomes compliant with the MRS standards. Why or why not?

Response:

FBC anticipates that the costs for MRS will remain as submitted through the PBR time period with the current approved standards, BC MRS program, processes and procedures. Adjustments to the BC MRS environment (standards, Rules of Procedure, BC Laws and Ministerial Orders, etc.) will be evaluated and impact determined, which could result in an increase or decrease in operating cost pressures. FBC will continue to manage the costs associated with BC MRS compliance to minimize impact on the customer rates while maintaining compliance to the satisfaction of BCUC/WECC.

18.2 Please explain if any capital and O&M costs associated with MRS non-compliance issues discovered after an audit may be considered prudent expenditures or not.

Response:

For clarity, FBC interprets "audit" to refer to the compliance audit performed by the MRS administrator (currently WECC) in accordance with the Commission's "Compliance Monitoring Program" (Appendix 2 to Rules of Procedure for Reliability Standards in British Columbia).

Capital and O&M expenditures to achieve MRS compliance after an audit can be prudently incurred for two main reasons:

- "Compliance audit" is one of the MRS compliance monitoring steps in the Commission's Compliance Monitoring Program. The audit is multi-purposed, including validation of compliance with applicable reliability standards and review of mitigating activities. The audit does not, and cannot, determine non-compliance; rather, the audit may identify areas of possible non-compliance. Identification of possible non-compliance allows adequate and timely mitigation of possible non-compliance so as to return a registered entity to compliance and minimize or prevent future similar violations. To consider expenses incurred to address the areas of possible non-compliance following a WECC audit imprudent will be inconsistent with the objectives of MRS compliance; and

- The Commission cannot categorically determine that expenses incurred after a MRS compliance audit are imprudent. Prudence determination is on a case-by-case basis. The Commission must ultimately determine whether the costs incurred are reasonable based on the facts that were known to, or ought to have been known to, FBC at the time FBC took the particular actions to achieve MRS compliance.

19.0 Reference: Exhibit B-7, BCUC 1.142.1

Operations

FBC provides a table showing the costs associated with training and salaries for the new PLT Apprentices, CPC Technician Apprentices and System Power Dispatchers for 2012 and 2013:

	Number Hired				Training Costs*			
	2012 Approved	2012 Actual	2013 Approved	2013 Projected	2012 Approved	2012 Actual	2013 Approved	2013 Projected
PLT Apprentices	2	4	6	6	$184,053	$120,389	$427,272	$155,495
CPC Apprentices	2	0	2	0	$99,762	$6,648	$19,949	$1,157
System Power Dispatchers	3	2	3	1	$849,133	$695,427	$652,049	$227,887

** Training costs include salaries and incremental costs (i.e. tools)*

19.1 For the CPC Apprentices line, please explain the $6,648 Training costs in 2012 when the number hired was zero.

Response:

Three CPC apprentices were hired in 2011 and commenced a four-year apprenticeship program. The 2012 training costs in the table above include the costs of training, schooling, and exams for those three apprentices already in the program.

19.2 For the CPC Apprentices line, please explain the projected $1,157 Training costs in 2013 when the projected number to be hired is zero.

Response:

Three CPC apprentices were hired in 2011 and commenced a four-year apprenticeship program. The 2013 training costs in the table above include the costs of training, schooling, and exams for those three apprentices already in the program.

20.0 Reference: Exhibit B-1, pp. 112-113

O&M – 2012 Postponed Expenditures

"While 2012 O&M was approximately $1.3 million lower than the approved amount, resulting from certain expenditures being postponed pending an RRA decision that was issued in August of that year, 2013 O&M is projected to be within 1.0 percent of approved." (Exhibit B-1, p. 112)

20.1 Please provide a breakdown of the $1.3 million in postponed expenditures with a description of each item, whether or not it is a one-off or recurring expense and the period in which the expense was incurred.

Response:

A breakdown of the $1.3 million variance in 2012 expenditures, as compared to 2012 Approved expenditures, can be found in the following table. This table includes expenditures, whether or not it is a one-off or recurring expense, and includes a description of each item and the period in which the expense was incurred.

Departments	2012 Actual	2012 Approved	2012 Variance	Variance Remarks	Variance Type	Future Provisions / Actions
Generation	2.3	2.3	0.0			
Operations	19.7	19.9	(0.2)	Minor Variance	N/A	N/A
Customer Service	6.8	6.6	0.1			
External Relations	1.2	1.4	(0.2)	Primarily: Unfilled Positions	One-Off	Incorporated in 2013 projection
Energy Supply	1.0	1.1	(0.1)	Primarily: Lower Training & Consulting	One-Off	Incorporated in 2013 projection
Information Technology	2.9	2.8	0.1			
Engineering	2.6	2.7	(0.1)			
Operations Support	1.2	1.2	0.0	Minor Variance	N/A	N/A
Facilities	3.6	3.7	(0.1)			
Environment, Health & Safety	0.9	0.9	(0.0)			
Finance & Regulatory	3.8	4.4	(0.6)	Primarily: Unfilled positions and Lower Audit Fees	Combination of One-Off & Recurring	Incorporated in 2013 projection
Human Resources	1.8	1.8	(0.0)	Minor Variance	N/A	N/A
Governance	2.1	1.8	0.3	Primarily: Higher Insurance	Uncontrollable	N/A
Corporate	3.4	4.1	(0.7)	Primarily: Lower Executive Costs	Combination of One-Off & Recurring	Incorporated in 2013 projection
Total O&M	**53.5**	**54.8**	**(1.3)**			

21.0 Reference: Exhibit B-1, pp. 113, 130; Exhibit B-7, BCUC 1.118.1

Customer Service

> "Forecast call volumes for 2014 to 2018 are expected to be higher than in 2012 due to the addition of City of Kelowna customers once they are transitioned to FBC's billing system and handled entirely by the Trail Call Centre as of January 2014. AMI implementation is also expected to increase call volumes until 2016, and then decline as the project benefits come to fruition." (Exhibit B-1, p. 130)

The following table was provided in response to BCUC 1.118.1:

	2010 Actual	2011 Actual	2012 Approved	2012 Actual	2013 Approved	2013 Projection	2013 Base	2014 Forecast
Labour (Excluding Pension and OPEB)	$3,783	$4,029	$ 4,241	$4,122	$ 4,311	$ 3,788	$4,111	$ 4,002
Non-Labour	1,646	1,673	1,841	2,050	1,876	2,006	2,021	2,061
Pension and OPEB	546	696	542	594	519	881	891	850
Insurance	-	-	-	-	-	-	-	-
City of Kelowna	-	-	-	-	835	835	835	663
Total O&M	$5,975	$6,398	$ 6,624	$6,766	$ 7,541	$ 7,510	$7,858	$ 7,576

21.1 Given that the City of Kelowna Customer Service department O&M is forecast to decrease by $172 thousand in 2014, should there be a downward adjustment to the 2013 Base O&M to reflect this? Please discuss why or why not.

Response:

No. The 2013 Base O&M reflects a reasonable starting point <u>in aggregate</u> for establishing the PBR formula. Individual budget components may vary, but in aggregate the 2013 O&M approved by the Commission is reasonable including the addition of the City of Kelowna.

21.2 Please recreate the table provided in response to BCUC 1.118.1 to include columns for 2010 Approved and 2011 Approved.

Response:

As noted in the response to BCUC IR 1.118.1, FBC's 2007 PBR Plan, like the proposed 2014 PBR Plan, did not allocate approved O&M Expense by department. Therefore there are no 2010 Approved and 2011 Approved values for Customer Service or any other department.

21.3 FBC submits that AMI implementation is expected to increase call volumes until 2016. Please confirm, or explain otherwise, that the O&M impact of this increased call volume due to AMI is included in the AMI O&M tracked outside of the formula (i.e. $368 thousand in 2014).

Response:

Confirmed.

21.4 FBC submits that forecast call volumes in 2014 to 2018 will be higher than in 2012 due to the City of Kelowna customers transitioning to the FBC billing system on January 1, 2014. Please confirm, or explain otherwise, that the O&M impact of this increased call volume is included in the incremental City of Kelowna O&M that is included in the Customer Service department O&M (i.e. $835 thousand in 2013 Base and $663 thousand in 2014 Forecast).

Response:

Confirmed.

21.5 Please explain what accounts for the Labour (excluding Pension and OPEB) increase of $323 thousand from 2013 projection to 2013 Base.

Response:

Since the Company does not track or forecast its pension and OPEB expense on a departmental basis, but rather includes it as part of the general benefit loading rate, the request to extract it pursuant to BCUC IR 1.131.1 resulted in an incorrect allocation and response.

The table below has been modified to reallocate pension and OPEB expense, resulting in no variance in labour (excluding Pension and OPEB) 2013 projection and 2013 base.

Table BCUC IR1 118.1 (Revised)

	2010 Actual	2011 Actual	2012 Approved	2012 Actual	2013 Approved	2013 Projection	2013 Base	2014 Forecast
Labour (Excluding Pension and OPEB)	$ 3,783	$ 4,029	$ 4,241	$ 4,122	$ 4,311	$ 4,150	$ 4,150	$ 4,002
Non-Labour	1,646	1,673	1,841	2,050	1,876	2,006	2,021	2,061
Pension and OPEB	546	696	542	594	519	519	852	850
Insurance	-	-	-	-	-	-	-	-
City of Kelowna	-	-	-	-	835	835	835	663
Total O&M	**$ 5,975**	**$ 6,398**	**$ 6,624**	**$ 6,766**	**$ 7,541**	**$ 7,510**	**$ 7,858**	**$ 7,576**

Note - FBC's 2007 PBR Plan, like the proposed 2014 PBR Plan, did not allocate O&M Expense by department.

21.6 Please explain what accounts for the Labour (excluding Pension and OPEB) decrease of $523 thousand from 2013 approved to 2013 projection.

Response:

Please refer to the response to BCUC IR 2.21.5.

The reason for the decrease of $161,000 from 2013 approved labour to projected labour is that less FBC labour and more FEU labour was used (which shows as a non-labour expense).

22.0 Reference: Exhibit B-1, p. 141; Exhibit B-7, BCUC 1.125.1

Exhibit A2-14, Article by IT developer – Habanero Consulting Group for Enterprise Solution

Savings on Regulatory Process

In the Application, FBC states:

> "[t]echnology is used throughout every area of the business, and requirements of technology in each business area increase as manual systems are replaced, and processes and requirements change. This drives the need for further enhancements, integration and mobilization of systems and technology." (Exhibit B-1, p. 141)

Exhibit A2-14 is an article from IT developer, Habanero which states:

> "<u>FortisBC saves approximately $57,000 per month on information request-related tasks</u> thanks to the Information Request System. Along with an <u>additional $100,000 in annual labour savings</u>, this adds up to a staggering $784,000 per year. These cost reductions have helped the organization improve their bottom line and better manage the financial implications that go along with an information request process … The Information Request System has saved FortisBC an estimated 60 per cent of the time resources previously needed to manage information requests." (emphasis added)

22.1 Please clarify which FortisBC company the article may be referring to (FEI,FBC or both).

<u>Response:</u>

FBC believes that the Habanero article is referring to the FortisBC Utilities (comprised of FortisBC Inc., FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc.). However, FBC submits that Habanero's statements are not completely accurate and are based on hypothetical assumptions.

22.2 What year was the Information Request system installed and savings observed?

Response:

The original version of the Information Request (IR) System was installed in the gas utilities environment in 2009.

The characterization of "savings" in the Habanero article is a general statement based on hypothetical assumptions of "avoided costs" as compared to the FortisBC Utilities maintaining the status quo which would have meant continuing to manage the growing volumes of IRs manually.

22.3 Please confirm, or otherwise explain, that the annual cost for internal staff to respond to IRs is included as part of Base O&M costs.

Response:

Confirmed, the cost for internal staff is included as part of Base O&M costs; FBC staffing levels have remained constant since 2010 despite the increasing complexity of regulatory processes. This is in part due to the IR System.

In 2008, the FEU began investigating the potential for available technology to automate the manual efforts being used at the time for processing IRs. The objective for the FEU was to reduce the manual processes required to respond to IRs which were cumbersome, repetitive and time consuming, and to achieve efficiencies. The efficiencies were related to managing the IR process more efficiently which would result in avoided cost savings by reducing the requirement to add staff in order to handle the increasing volumes of IRs. The FEU engaged Habanero to recommend a solution which would take advantage of recent developments in the IT industry with respect to sharing and collaboration platforms. The FEU determined that in order to manage IRs at the existing O&M level, it was necessary to undertake the development and implementation of the IR System. In 2009 the IR System was installed in the FEU environment. In 2011 the IR System was made available to FBC, which was an opportunity both to leverage existing technology and for integration of the gas and electric utilities' systems and processes to the benefit of both gas and electric customers.

By way of context, the FEU have been tracking statistics of the number of IRs they have been required to respond to on an annual basis since 2006. In 2006, the FEU responded to approximately 1,180 IRs. In 2007, the FEU responded to approximately 1,605 IRs, an increase of 36 percent. Based on the trend observed at that time demonstrating an increasing volume of IRs, the FEU recognized that in order to meet regulatory filing deadlines for IR responses with the current manual processes in place, additional staff would be required, which would increase

Base O&M costs. The number of IRs the FEU have responded to has been steadily increasing over the years, and in 2012, reached an all-time high of approximately 6,025 IRs – a 410 percent increase as compared to 2006. The FEU have surpassed the 2012 all-time high in 2013 thus far, having received approximately 7,230 IRs year-to-date.

FBC has been experiencing a similar trend. FBC began tracking IR statistics in 2011 and responded to approximately 2,970 IRs during that year. In 2012, FBC responded to approximately 5,330 IRs, an increase of 79.5 percent over the prior year, a record high. FBC has surpassed the 2012 record high in 2013 thus far, having received approximately 5,470 IRs.

Had the FEU not explored and ultimately developed and implement the IR System in 2009 and in 2011 extended it for FBC use, then most assuredly in order to meet filing deadlines and comply with the increasing regulatory process requirements, O&M cost increases would have been unavoidable for both FBC and the FEU.

22.4 Please confirm, or otherwise explain, the order of magnitude of the annual savings to FBC's regulatory process as a result of the IT system created by Habanero.

<u>Response:</u>

The productivity improvements and efficiencies gained by FBC since having access to the IR System in 2011 have allowed FBC to respond to a significantly increasing volume of IRs. Please also refer to the response to BCUC IR 2.22.3. It is important to note that FBC filed responses to this substantial increase in IRs without increasing staffing levels in the Regulatory Affairs department, and therefore, not increasing O&M for the department.

The "savings" referred to by Habanero in the article are hypothetical assumptions of efficiency and productivity gains. Rather than "savings", FBC and the FEU have avoided costs that, without the IR System, would have been incurred and increased O&M requirements for additional staff in many departments based on the requirements to respond to and process the substantial and exponentially increasing volume of IRs. The IR System has delivered productivity and efficiency improvements to the utilities' internal business processes for preparing, managing, completing and filing of IR responses.

The business process productivity and efficiency improvements of the IR System are unquantifiable because it is impossible to make a direct comparison with the circumstance of not having developed and implemented the IR System. Some of those unquantifiable benefits include:

- Avoided or Reduced O&M Costs for Overtime and Benefits: Responding to IRs are additive to the daily job responsibilities of each employee throughout all levels of the organization. Improved process and efficiencies of the IR System has contributed to reduced O&M requirements through avoided or reduced costs for overtime for eligible bargaining unit employees who are required to incur overtime in order to meet deadlines for responding to IRs. Many employees involved in the preparation of IR responses are M&E employees and not entitled to pay for overtime. However, the exponentially increasing volume of IRs requires M&E employees involved to work significant amounts of unpaid overtime under substantial stress. Without the IR System, it is highly likely that many M&E employees may have experienced fatigue or burnout that would have resulted in additional O&M and benefits costs as a result;

- Reduced External Experts/Consulting Fees: Experts and consultants required on certain types of regulatory proceedings are also involved in the preparation of responses to IRs. The IR System productivity and efficiency improvements have also served to keep fees and costs for experts and consultants related to responding to IRs as low as possible; and

- Meeting Filing Deadlines: Without the efficiencies and productivity improvements of the IR System, with the substantial increase in volumes, it is highly probable that the utilities would not have been able to meet all IR filing deadlines, and therefore, regulatory processes would have been lengthier, resulted in increased costs for the companies, delays to decisions, delays to implementation of projects or programs which could also have a negative impact on costs, all of which result in higher costs for ratepayers and pressure on rates.

In response to BCUC 1.125.1, FBC provides a breakdown of the O&M expenses in the IS department. Part of the response is copied below for reference:

	2010 Actual	2011 Actual	2012 Approved	2012 Actual	2013 Approved	2013 Projection	2013 Base	2014 Forecast
Labour (Excluding Pension and OPEB)	$1,574	$1,476	$ 1,476	$1,476	$ 1,566	$ 1,417	$1,538	$ 1,624
Non-Labour	1,128	1,172	1,177	1,236	1,219	1,242	1,278	1,304

22.5 Given that the IS department's Labour and Non-labour expenses have not materially changed throughout the period of 2010–2013, please explain where the IT savings from the Information Request System created by Habanero are shown.

Response:

Other than responding to IRs specifically directed at the IS department, the IS department does not have, and has never had responsibility for managing or processing IRs, and therefore, the IS department's Labour and Non-labour expenses never have included any costs associated with the general management or processing of IRs. There are no IS savings from the Information Request System, rather the IR System has allowed FBC and the FEU to avoid increases in O&M costs to add staff to manage the growing volumes. Please refer to the response to BCUC IR 2.22.4.

22.6 Please provide evidence/reconciliation to show that FBC has adjusted its 2013 Base O&M by the appropriate savings. If FBC has not adjusted the 2013 Base O&M for these annual savings, please explain why.

Response:

It was not necessary for FBC to adjust the 2013 Base O&M because the "savings" since 2011 have been avoided cost increases to O&M, and therefore, are already factored into the 2013 Base O&M in this Application. Please also refer to the response to BCUC IR 2.22.4.

22.7 Please explain if the cost of the IT system created by Habanero has been booked as a capital project.

Response:

The cost of the IT system developed by Habanero, the IR System, has been booked as an IT capital project by the FEU. When the IR System was extended for use to FBC in 2011, an appropriate IT capital cost allocation was booked to FBC.

23.0 Reference: Exhibit B-7, BCUC 1.131.1

Operations Support

The following table was provided in response to BCUC 1.131.1:

	2010 Actual	2011 Actual	2012 Approved	2012 Actual	2013 Approved	2013 Projection	2013 Base	2014 Forecast
Labour (Excluding Pension and OPEB)	$3,037	$2,993	$ 3,097	$2,931	$ 3,133	$ 2,779	$3,015	$ 3,184
Non-Labour	3,152	2,992	3,783	2,754	3,829	3,027	3,042	3,103
Recoveries	(5,633)	(5,186)	(6,053)	(4,868)	(6,087)	(5,247)	(5,453)	(5,591)
Pension and OPEB	438	517	396	423	377	646	654	595
Insurance	-	-	-	-	-	-	-	-
City of Kelowna	-	-	-	-	-	-	-	-
Total O&M	$ 993	$1,315	$ 1,223	$1,240	$ 1,252	$ 1,205	$1,258	$ 1,291

23.1 Please explain what accounts for the Labour (excluding Pension and OPEB) increase of $236 thousand from 2013 projection to 2013 Base.

<u>Response:</u>

The Company does not track or forecast its pension and OPEB expense on a departmental basis, but rather includes it as part of the general benefit loading rate. When the Company was requested to extract pension and OPEB expense pursuant to BCUC IR 1.131.1, there was an incorrect allocation and response.

The table below has been modified to reallocate pension and OPEB expense, resulting in no variance in labour (excluding Pension and OPEB) 2013 projection and 2013 base.

Table BCUC IR1 131.1 (Revised)

	2010 Actual	2011 Actual	2012 Approved	2012 Actual	2013 Approved	2013 Projection	2013 Base	2014 Forecast
Labour (Excluding Pension and OPEB)	$ 3,037	$ 2,993	$ 3,097	$ 2,931	$ 3,133	$ 3,048	$ 3,048	$ 3,184
Non-Labour	3,152	2,992	3,783	2,754	3,829	3,027	3,042	3,103
Recoveries	(5,633)	(5,186)	(6,053)	(4,868)	(6,087)	(5,247)	(5,453)	(5,591)
Pension and OPEB	438	517	396	423	377	377	621	595
Insurance	-	-	-	-	-	-	-	-
City of Kelowna	-	-	-	-	-	-	-	-
Total O&M	**$ 993**	**$ 1,315**	**$ 1,223**	**$ 1,240**	**$ 1,252**	**$ 1,205**	**$ 1,258**	**$ 1,291**

Note - FBC's 2007 PBR Plan, like the proposed 2014 PBR Plan, did not approve O&M Expense allocated by department.

23.2 Please explain what accounts for the Labour (excluding Pension and OPEB) decrease of $354 thousand from 2013 approved to 2013 projection.

Response:

Please refer to the response to BCUC IR 2.23.1 for revised Table BCUC IR 1.131.1.

The projected decrease of $85 thousand in labour costs compared to the 2013 approved is related to a reduction in labour requirements within the Procurement group and the interdepartmental transfer of labour from Operations Support to another department.

24.0 Reference: Exhibit B-7, BCUC 1.136.3

Human Resources

In response to BCUC 1.136.1, FBC provides a table showing the FTE change in the HR department:

Number of FTEs in FBC's HR Department from 2010-2013

2010	2011	2012	2013
14	11	14	11

FBC states that "[t]he reduction in FTEs from 2012 to 2013 [in the HR department] is related to the integration with FEI" (Ex. B-7, BCUC 1.136.2).

FBC also states that "[t]he cross-charges between FEI and FBC are a result of integration efforts." The net effect of these charges is $157,000 in 2012 and -$71,000 in 2013. (Ex. B-7, BCUC 1.136.3)

24.1 Please fill out the following table to illustrate the beneficial impact of the integration efforts with FEI in the HR department:

Human Resources	2012		2013		Change	
	# FTE	$	# FTE	$	# FTE	$
Labour	14		11		-3	
Non-Labour (Show Net Cross Charges only)		157,000		-71,000		
Net Change						

<u>Response:</u>

Please refer to the responses to BCUC IR 2.11.1 and 2.11.2.

24.2 For all O&M departments that have experienced some form of integration with FEI, please provide a similar table to illustrate the beneficial impact of the integration.

<u>Response:</u>

Please refer to the responses to BCUC IR 2.11.1 and 2.11.2.

25.0 Reference: Exhibit B-7, BCUC 1.144.5–1.144.7

Corporate Cost Allocation

FBC explains that:

> "both FEI and FBC are seeking approval to change the estimation of time allocation from an Executive time estimate to an estimate derived from the Massachusetts Formula. This methodology will be applied to each Executive's benefit loaded salary (excluding overhead charges). The only change, therefore, is in the allocation of time…" (Ex. B-7, BCUC 1.144.6)

25.1 Using the current method of time estimates, what is the proportion of and dollar value of Executive costs that have been allocated to FBC/FEI for each of the past 5 years?

<u>Response:</u>

Please refer to the response to BCUC IR 2.25.2 which compares the Time Estimate Methodology with the Massachusetts Formula Methodology for determining the allocation of Executive costs.

25.2 Applying the Massachusetts formula backwards to each of the last 5 years, what would have been the proportion of and dollar value of Executive costs allocated to FBC/FEI?

<u>Response:</u>

The sharing of executive costs between FBC and FEI only began part way through 2010, therefore there are no proportions or dollar values of shared Executive costs to be allocated prior to 2010, under either the Time Estimate Methodology or the Massachusetts formula methodology, between the regulated entities. Further, for the years 2010 and 2011, there was only partial sharing of Executive costs between FEI and FBC, as it was not until January 1, 2012 that all Executives for FBC and FEI had joint responsibilities in both companies. Therefore the resulting proportions and dollar value allocations of Executive costs under the Time Estimate Methodology are not consistent from 2010 to 2013, as there was only partial sharing of Executive Management team between FEI and FBC during this period of time. The Time Estimate Methodology is the method that was approved by the BCUC and used to allocate all labour costs, including Executive costs which were shared between FBC and FEI for the period 2010 through to 2013.

The retroactive application of the Massachusetts Formula to allocate Executive costs from 2010 to 2013 will be misleading due to partial sharing of costs prior to 2012 and the Massachusetts formula is generally utilized when there is already a substantial sharing of costs between entities.

As requested in BCUC IR 2.25.1, the following table shows the dollar value and proportion of Executive labour costs allocated using the Time Estimate Methodology, which is the method approved by the BCUC and used to allocate actual costs for 2010 to 2013:

Time Estimate Allocation for Executive Labour

	2010 Actual	2011 Actual	2012 Actual	2013 Projection
Executive base pay for those residing in FBC with general loading rate applied, including Executive Assistances (EAs) and before cross-charging [1]	$ 2,510	$ 2,500	$ 2,321	$ 2,596
Executive Cross charges allocated from FBC to FEI	(433)	(879)	(1,331)	(1,379)
Executive Cross charges allocated from FEI to FBC	252	428	469	390
Net Executive & EA Labour in FBC	**$ 2,329**	**$ 2,049**	**$ 1,459**	**$ 1,607**

Proportion of total loaded executive labour eligible for sharing amongst FBC and FEI				
Allocated to FBC	42%	38%	30%	30%
Allocated to FEI	58%	62%	70%	70%

The following table shows the dollar value and proportion of Executive labour costs by applying the Massachusetts Formula Methodology on a retroactive basis to allocate Executive costs:

Massachusetts Formula Allocation for Executive Labour

	2010 Actual	2011 Actual	2012 Actual	2013 Projection
Executive base pay for those residing in FBC with general loading rate applied, including Executive Assistances (EAs) and before cross-charging [1]	$ 2,510	$ 2,500	$ 2,321	$ 2,596
Executive Cross charges allocated from FBC to FEI	(450)	(943)	(1,461)	(1,514)
Executive Cross charges allocated from FEI to FBC	311	487	406	326
Net Executive & EA Labour in FBC	**$ 2,371**	**$ 2,044**	**$ 1,266**	**$ 1,409**

Proportion of total loaded executive labour eligible for sharing amongst FBC and FEI				
Allocated to FBC	44%	38%	23%	23%
Allocated to FEI	56%	62%	77%	77%

The following table compares the dollar value difference between the Time Estimate Methodology and the Massachusetts Formula Methodology on a retroactive basis:

	2010 Actual	2011 Actual	2012 Actual	2013 Projection
Increase (Decrease) in FBC Executive & EA Labour from applying Massachusetts Formula instead of Time Estimate allocation	**$ 42**	**$ (5)**	**$ (193)**	**$ (198)**

(1) Represents the fully loaded Executive and EA regular base pay (net of time away) which was described in the response to BCUC IR 1.144.7 as follows:

> *"To clarify the concept of fully loaded costs, this would include regular base pay (net of time away) plus a general benefits loading. Since FBC and FEI do not forecast individual benefits attributable for each Executive or employee, such as post-employment benefits, incentives, etc., a general benefit loading rate is applied to regular base pay (net of time away) to incorporate all such benefits for each employee. Included in the general benefit loadings are pension and OPEB expenses, short-term incentives and other benefits. Those Executive compensation costs that are funded by the shareholder, such as stock options and PSUs, are excluded from the general benefits loading and regulated O&M and therefore are not included in the fully loaded Executive costs."*

As FBC and FEI intend to apply the Massachusetts formula methodology to allocate Executive costs beginning on January 1, 2014 for the term of the PBR, the current expectation is that the proportion of total loaded executive labour eligible for sharing amongst FBC and FEI is consistent at approximately 23% and 77% from 2014 to 2018. While the drivers of the Massachusetts formula, including net revenues, payroll and average NBV of tangible capital assets plus inventories, could potentially change during the term of the PBR, the ratios derived from the Massachusetts formula are not expected to fluctuate significantly, the pool of fully loaded Executive labour costs is still subject to change. The relative ratio of the Massachusetts formula has remained relatively stable since 2010. Changes to salaries, time away and general benefit loading rates could still change which in turn would affect the actual dollar allocation of net executive labour in FBC.

FBC and FEI's requests to apply the Massachusetts formula for Executive labour costs beginning in 2014 is not intended to vary significantly from the Time Estimate Methodology. Rather it is a cost sharing methodology used, where there is substantial sharing and is well established and generally accepted in British Columbia and other regulatory jurisdictions. It has been described by the US Federal Energy Regulatory Commission (FERC) as the methodology that "seeks to maximize the direct assignment of costs to the various operating entities". Under 5.2.1.4 Cost Allocations on page 48 of Order G-110-12 which approved FBC's 2012-2013 RRA, both ICG and BCMEU stated that Executive costs should be allocated between FBC and FEI using the Massachusetts Formula. In the Commission Panel determination, it stated that "the Commission Panel accepts FortisBC's proposal to continue to allocate costs for executive time based on the executives' estimates until such time as alternatives have been reviewed and a new proposal is put forward by the Applicant."

As shown in the above tables, the difference between the Time Estimate Methodology and the Massachusetts formula methodology is less than $200 thousand, based on a historical view. Any resulting increases or decreases in Executive labour cost allocation for FBC will have an offsetting equivalent change in FEI. The difference going forward into the PBR period is also not expected to be materially different on overall O&M expense. However any differences that do arise from variances in the Massachusetts formula percentages or variances in the fully loaded Executive labour cost pool, will be managed by FBC and FEI throughout the PBR period and rates will be set according to the O&M formula.

FBC states:

> "[t]he results of the Massachusetts Formula for 2013 would allocate approximately 23 percent of the Executive <u>pooled</u> costs to FBC. FBC is requesting approval to allocate the <u>pooled</u> Executive costs (fully loaded labour costs with no overhead) to FBC and FEI using the Massachusetts Formula effective January 1, 2014." (Exhibit B-1, p. 172) (emphasis added)

FBC also states that:

> "under the Massachusetts formula, approximately 77 percent of the fully loaded salary of the Executive residing in FortisBC Inc. would be allocated to FEI (and FHI as described above) and approximately 23 percent of the Executive residing in FEI and FHI would be allocated to FortisBC Inc." (Exhibit B-7, BCUC 1.144.7)

25.3 Please clarify that the Executive costs of both FBC and FEI will first be pooled and then allocated to each of the companies based on the Massachusetts formula.

<u>Response:</u>

The Executive costs, which FBC interprets to be all Executive compensation, is not pooled and then allocated to each of the Companies. Rather the Massachusetts formula will be applied to the aggregate of all the fully loaded Executive wages, as described in the response to BCUC IR 1.144.7, as follows:

> *"To clarify the concept of fully loaded costs, this would include regular base pay (net of time away) plus a general benefits loading. Since FBC and FEI do not forecast individual benefits attributable for each Executive or employee, such as post-employment benefits, incentives, etc., a general benefit loading rate is applied to regular base pay (net of time away) to incorporate all such benefits for each employee. Included in the general benefit loadings are pension and OPEB expenses, short-term incentives and other benefits. Those Executive compensation costs that are funded by the shareholder, such as stock options and PSUs, are excluded from the general benefits loading and regulated O&M and therefore are not included in the fully loaded Executive costs."*

To clarify further, other benefit costs related to Executive compensation, such as short-term incentive pay and employee future benefits, are aggregated with short-term incentive pay and employee future benefits from other employee groups to determine a general benefit loading rate. This general benefit loading rate is then applied to the FBC and FEI Executive base salary to determine full loaded Executive costs. It is then the fully loaded Executive costs, and not the individual benefit costs attributable to each Executive, which are allocated between FBC and FEI using the Massachusetts formula.

25.4 Please complete the following table to show the proportion of cost allocations for each year of the PBR:

	Costs to:		
	FBC	FEI	Total
Executives Residing in FBC	23%	77%	100%
Executives Residing in FEI			
Total			

Response:

Please refer to the response to BCUC IR 2.25.5.

25.5 Please repeat the table for total dollars assigned to each utility forecast for each year of the PBR.

Response:

The response to BCUC IR 2.25.2 shows an approximate $200 thousand decrease to Executive Labour costs in 2013 Projection for FBC, which would result in a corresponding increase of approximately $200 thousand for FEI by applying the Massachusetts Formula on a retroactive basis, with the benefit of hindsight. To provide the Massachusetts formula on a prospective basis for the term of the PBR requires certain assumptions, as there are many factors that can, and will, influence the ultimate dollar allocation of Executive Labour costs.

If it is assumed that the 2013 variance between the Massachusetts Formula and the Time Estimate Methodology from BCUC IR 2.25.2 is indicative of the dollar allocation on a prospective basis, then this difference is not materially different relative to overall O&M expense. Any resulting increases or decreases in Executive labour cost allocation for FBC will have an offsetting equivalent change in FEI.

However, there is more of an argument that the 2013 variance between the Massachusetts Formula and the Time Estimate Methodology from BCUC IR 2.25.2 should not be indicative of the total dollars to be assigned to each utility forecast for each year of the PBR, solely from applying the Massachusetts Formula. It is expected that allocation of Executive labour costs will vary under the Massachusetts Formula due to a number of varying factors. The first step is determining the Massachusetts formula itself, which relies on net revenues, payroll and average NBV of tangible capital assets plus inventories, for which all these factors will vary throughout the term of the PBR. The second step involves establishing the pool of shared costs to which the Massachusetts formula is applied. This “pool” does not consist of all Executive compensation, pension and benefits, but rather is the aggregate of the fully loaded Executive pay, which is described in the response to BCUC IR 1.144.7 and BCUC IR 2.25.2. In addition to potential changes in Executive base pay, the actual benefit loading rate is subject to fluctuation as a result of the components of general benefit loading rate which includes various items such as pension and OPEB expense for all employee groups. Due to the host of factors subject to change, it is not expected that the total dollars assigned to each utility would materially change between the Massachusetts Formula Methodology and the results from the Formulaic O&M for 2014 to 2018.

The primary objective of applying the Massachusetts Formula is not to increase or decrease Executive Labour O&M, but rather is a simplified method that is generally accepted and well established in other jurisdictions to allocate costs where there is substantial sharing and responsibility. Any variances in Executive Labour costs, as compared to the Formulaic O&M, will be managed by the Company during the term of the PBR, much like any other O&M variances and challenges that arise. The PBR framework allows the Companies to manage these challenges within a pool of O&M expense and accepting that the Massachusetts formula Executive labour cost allocation is not materially different from the Time Estimate Methodology.

D. PBR FORECAST – CAPITAL EXPENDITURES

26.0 Reference: Exhibit B-7, BCUC 1.152.1.1

Capital Expenditure Schedule

FBC states "[a]t the Annual Review, FBC will submit financial schedules, including the formula-driven capital expenditure calculation, to support its revenue requirements. Detail of the Company's capital expenditures will continue to be included in its Annual Reports to the BCUC." (Exhibit B-7, BCUC 1.152.1)

26.1 Please confirm that "the Annual Review" is an Application to the Commission (in lieu of a revenue requirement application), which allows stakeholders to review the filed materials through information requests or other regulatory processes. If so, should the preamble be more clearly stated "**for** the Annual Review" to avoid the implication that it is an event?

Response:

This IR has been identified as relating to the PBR Methodology and will be submitted with the PBR Methodology IRs responses.

26.2 For the PBR Annual Review, will FBC submit financial schedules that include: a brief scope and a reference to the Long Term Capital Plan approved in 2012, a start date and an in-service date, and the total estimated cost, the actual cost at completion and the carry-over cost? Or does FBC only propose to submit the formula-driven capital expenditure amount calculation?

Response:

This IR has been identified as relating to the PBR Methodology and will be submitted with the PBR Methodology IR responses.

26.3 Please confirm that the information included in the financial schedules to be submitted for the Annual Review will include capital expenditures within the PBR formula and outside of the PBR formula.

Response:

This IR has been identified as relating to the PBR Methodology and will be submitted with the PBR Methodology IR responses.

27.0 Reference: Exhibit B-1, p. 207, Table C5-5, Generation Growth Capital Overview

27.1 Please explain why there is no generation growth capital expenditures included in Table C5-5. How does customer growth impact generation capital expenditures?

Response:

Customer growth does not directly impact generation capital expenditures, which are primarily a function of operating hours and regulatory compliance.

Please also refer to the response to BCUC IR 1.28.2.1.

28.0 Reference: Exhibit B-7, BCUC 1.166.1, BCUC 1.166.2, BCUC 1.166.3

Distribution Growth Capital, Fault Indicator Installation

28.1 As the installation of Fault Indicators will reduce the amount of time to locate outages, please provide a forecast of the O&M cost savings for each year of the PBR.

Response:

The Company believes that the primary benefit of the installation of fault indicators in the CoK area will be improved system reliability for customers, with less down time and shorter outages. FBC does not anticipate any material O&M cost savings from the fault indicator installation in the CoK area, since repairs due to cable failures are largely capitalized, with the old parts being retired

28.1.1 How does FBC plan to treat these potential cost savings? Do they flow to the ESM?

Response:

To the extent that fault indicator installation in the CoK area contributes to the Company's combined O&M cost savings, the savings will flow through to customers via the ESM where both customers and FBC will benefit. The Company believes that the advantage of PBR over traditional COS regulation is to provide management with the flexibility and oversight on the best way to reduce costs for the benefit of customers and the Company combined.

29.0 Reference: Capitalization Policy

Exhibit B-7, BCUC 1.168.1

Tools and Equipment Adjustment

29.1 When did FBC last update the tools and equipment capitalization amount to $1,000?

Response:

The $1,000 capitalization amount was increased from $500 to $1,000 in 2007.

The $1,000 capitalization amount is not restricted to expenditures on tools and equipment. FBC's Capitalization Policy requires that in order to qualify as a capital expenditure the expenditures must be capital in nature and must be in excess of $1,000. This is done to avoid the administrative burden associated with setting up and maintaining capital assets under $1,000 in the asset subledger. The Company feels that the $1,000 level strikes the appropriate balance between the enhanced records of correctly recording these items as capital and the effort required to do so. For greater clarity, these items would accurately qualify as capital, but for smaller value capital items, the Company records them as a period expense.

29.2 Please provide the tools and equipment amount of $1,000 inflated to 2014 dollars.

Response:

Based on an average annual BC CPI of approximately 1.4% over the period 2007–2014F the capitalization amount of $1,000 would be inflated to approximately $1,100. However, the Company submits that there is no reason to inflate this amount.

Please refer to the response to BCUC IR 2.29.1.

29.3 Please discuss whether this minimum capitalization limit should be inflation adjusted on an annual basis. Why or why not?

Response:

The Company does not believe that the capitalization amount should be adjusted on an annual basis. Annual adjustments would have resulted in a change to the minimum capitalization amount of anywhere from $0 to a maximum of $25 in any year during the period 2007-2014F. Based on this, the additional expenditures that would meet the minimum capitalization amount would be very small as well. Further, employees would be required to remember capitalization amounts that would be of odd values and difficult to remember year over year.

In the Company's opinion, it is better practice to revise the amount in large increments and only when the amount is deemed to be materially different (i.e. a 50 percent increase).

30.0 Reference: Exhibit B-7, BCUC 1.170.1

Growth Capital — Delayed Projects

FBC states:

> "[p]roject[s] originally shown in the 2012 LTCP (for 2014 – 2018) that have since been delayed beyond the 2014 – 2018 PBR period include:
>
> - Meshing Kelowna Loop;
> - Beaver Valley South Solution;
> - RG Anderson Distribution Transformer Upgrade;
> - DG Bell Static VAR Compensator;
> - FA Lee Distribution Transformer Addition; and
> - Enterprise Substation." (Exhibit B-7, BCUC 1.170.1)

30.1 Please explain why each of the previously approved projects is now delayed beyond the 2014-2018 PBR period.

Response:

FBC notes that, as discussed in the 2012 LTCP, the Company did not seek Commission approval of specific projects and associated expenditures for projects beyond the 2012/13 window, but rather sought Commission acceptance of the Integrated System Plan, which included the 2012 LTCP, as being in the public interest under Section 44.1(6) of the *Utilities Commission Act.* As such, FBC does not consider the specific projects identified above to have been previously approved by the Commission.

Notwithstanding the explanation above, the last five projects listed above have all been deferred due to the current load forecast showing that these projects are not expected to be required prior to the end of the PBR term. The first project ("Meshing Kelowna Loop") was a reliability initiative that has been deferred since the precursor project ("Kelowna 138 kV Loop Fibre Installation") in the 2012/13 RRA was denied by the Commission. These projects are on hold pending further review by FBC.

30.2 Please provide the actual costs to-date by project and the total 2012 approved or budgeted expenses for each projects listed above.

Response:

No costs have been incurred to date with respect to these specific projects.

The forecast expenditures (including loadings) for the above projects, as provided as part of the 2012 LTCP, are detailed below:

- Meshing Kelowna Loop - $8.128 million;
- Beaver Valley South Solution - $21.534 million;
- RG Anderson Distribution Transformer Upgrade - $7.0925 million;
- DG Bell Static VAR Compensator - $37.316 million;
- FA Lee Distribution Transformer Addition - $12.029 million; and
- Enterprise Substation - $35.798 million.

30.3 Considering the length of the delay, does FBC feel that the Commission should rescind its approval of these projects? If not, why not?

Response:

As noted in the response to BCUC IR 2.30.1, FBC did not seek, nor receive, Commission approval of the specific projects and associated expenditures discussed in the 2012 LTCP. Rather, the Company sought Commission acceptance of the Integrated System Plan, of which the 2012 LTCP was a part of, as being in the public interest under Section 44.1(6) of the *Utilities Commission Act*. Indeed, the 2012 LTCP was intended to serve as a long term strategic plan for the management of FBC assets. As such, FBC does not believe any approval exists specific to these projects which could be rescinded by the Commission. Although it is conceivable that Commission acceptance of the 2012 LTCP as being in the public interest could be rescinded, the Company submits this would be inappropriate given the context in which the 2012 LTCP was developed and submitted.

30.3.1 Please confirm that FBC has reduced the 2013 Base capital to reflect these projects which have now been delayed beyond the PBR period. Please provide supporting evidence.

Response:

Not confirmed. As FBC has used the 2013 approved capital expenditures as a starting point for determining the 2013 Base capital, and given that none of the projects identified are part of the 2013 approved capital, no reduction to the 2013 Base capital is necessary.

FBC states:

> "…an increase in forecast expenditures of approximately $3 million related to the addition of certain projects necessitated by the acquisition of the City of Kelowna distribution assets. These projects were not previously identified in the 2012 LTCP. These projects include:
>
> - Spall Breaker House Reconfiguration;
> - Saucier Substation Project and Metering Upgrade; and
> - Fault Indicator Installation." (Exhibit B-7, BCUC 1.170.1)

FBC's Distribution Substation Automation Program (DSAP) was completed under Order No. C-11-07. In FBC's Distribution Substation Automation Program Progress Report No. 8, on page 7 FBC states "Saucier completed in 2007 under Station Assessment and Minor Planned Project at Dist. Stations' Amount spent was $52,000."

In response to a Commission letter dated July 6, 2012 requesting a recalculation of Table 4.1 Program Cost Summary to reflect certain scope reductions in the DSAP, FBC states:

> "The scope reductions relate to three distribution substations initially included in the DSAP and later removed from the Program. The circumstances are as follows.

Saucier Substation – the Saucier component of the DSAP included only transformer metering for monitoring purposes, which was installed under the Company's Station Assessment and Minor Planned Projects category of Station Sustaining capital expenditures, as reported in Project Report No. 1 to July 15, 2008. Associated costs were transferred from the DSAP to the sustaining capital project."

30.4 Please provide the scope for the current Saucier Substation Project and Metering Upgrade.

Response:

The scope for the Saucier Protection and Metering Upgrade covers the following aspects:

1. Upgrade the feeder protection (from electromechanical relaying to modern microprocessor-based protective relays);
2. Install per-feeder microprocessor-based metering;
3. Install remote tagging switches to allow remote control of feeder reclosers from the FBC System Control Centre (SCC);
4. Install a communication processor for remote access to the feeder relays; and
5. Upgrade the station remote terminal unit (RTU) to current standards to allow monitoring and operation of the feeder equipment from the SCC.

All of the work listed above is consistent with that conducted at other FBC legacy substations under the FBC Distribution Substation Automation Program (DSAP). For reference, the scope of work conducted at these other FBC legacy substations can be found in Table 2 of the DSAP application. Please also refer to the response to BCUC IR 2.30.5.

30.5 Please explain what additional work still needs to be performed at the Saucier Substation and why it has not been already completed.

Response:

It is important to note that prior to the purchase of the City of Kelowna utility assets by FBC, the Saucier substation was effectively two substations within the same property. The FBC-owned substation consisted only of the 138kV circuit breakers (and associated bus-work and switches), the 138/13-kV distribution transformer and the associated protection and metering devices. The remaining station equipment, including the distribution main and feeder breakers, and the associated protection and metering devices were all owned by the City of Kelowna.

The DSAP scope only included distribution equipment owned by FBC; in other words, only the distribution transformer at Saucier. The remaining distribution equipment could not be included in the scope of the application as it was owned by the City of Kelowna and hence not part of FBC's system assets. Accordingly, as noted in the preamble, the initial DSAP scope for Saucier only included the installation of transformer monitoring for the 138/13-kV transformer. During the regulatory process it was noted that this metering was in fact installed in an earlier project and thus was removed from the scope of the DSAP.

With the acquisition of the City of Kelowna utility assets, the distribution feeder breakers, protection relays and metering are now owned by FBC. The protection devices and meters face the same challenges identified for similar vintage equipment in the DSAP application: they are electromechanical devices for which spare parts are no longer available, are difficult and costly to maintain, and have no capability for remote monitoring or communications. The cited project will upgrade this remaining substation equipment to the modern devices used at other FBC substations. This is consistent with the Commission determination in the DSAP application which concluded: "[…] that replacing the existing legacy technology with new electronic technology is appropriate"[7].

[7] Appendix A to Order C-11-07, Page 11.

31.0 Reference: Exhibit B-7, BCUC 1.171.1

Sustaining Capital

"This difference of $37 million in forecast expenditures for the 2014 – 2018 period is primarily the result of shifts in the timing of a number of projects as well as updates to forecast expenditures for the PBR period, including:

- The timing of the expenditures for the Advanced Metering Infrastructure Project has shifted as compared to the forecast originally provided as part of the 2012 LTCP. As a result, additional expenditures of approximately $31 million are reflected in the 2014 – 2018 PBR forecast as compared to the 2012 LTCP (majority of AMI expenditures originally forecast in 2013); and
- The 2014 – 2018 PBR forecasts include expenditures of approximately $6.5 million related to the Business Technology Transformation project. This project was not previously identified in the 2012 LTCP." (Exhibit B-7, BCUC 1.171.1)

31.1 Please confirm that the Business Technology Transformation project referred to in BCUC 1.171.1 is the same as the one described on pages 218–219 in the Application.

Response:

Confirmed.

31.2 Please provide the expanded forecast costs for the line "Information Systems" in Table C5-6: Other Capital (Exhibit B-1, p. 216) to show all the capital expenditures.

Response:

"Information Systems"	2014	2015	2016	2017	2018
Infrastructure Sustainment	$1,207	$1,380	$1,423	$1,281	$1,104
Desktop Infrastructure Sustainment	$957	$976	$996	$1,016	$1,036
Application Enhancements	$728	$753	$785	$811	$845
Application Sustainment	$1,176	$1,220	$1,272	$1,325	$1,374
Transform	$1,118	$1,698	$1,207	$1,259	$1,306
PowerSense DSM Reporting Software	$104	$106	$108	$55	$56
Total	**$5,290**	**$6,134**	**$5,791**	**$5,747**	**$5,721**

31.3 Please provide the forecast capital and O&M cost savings for Business Technology Transformation project and the Business Technology Enhancements

Response:

The forecast capital expenditures for FBC Business Technology Transformation and Enhancements can be found below:

	$000s				
	2014	**2015**	**2016**	**2017**	**2018**
Business Technology Transformation	1,118	1,698	1,207	1,259	1,306
Business Technology Enhancements	728	753	785	811	845

FBC is unable to forecast at this time the O&M savings to be achieved over the PBR period as the detailed list of Transformation and Enhancement projects within each of the Business programs have not yet been identified for 2014 to 2018. As each of the discretionary projects in the subsequent portfolios in 2014 to 2018 proceeds through the Benefits Management practice detailed in the RRA Section C5: Capital Expenditures on page 218, the project will undergo the business case analysis that will determine alignment to the Company's strategic goals of safety, customer service, reliability and efficiency, and must have a defined investment analysis.

32.0 Reference: Exhibit B-1, p. 226

On-going AMI Sustaining Capital Expenditures

"As discussed in the application for the AMI project, the implementation of the AMI system will result in new sustainment capital costs associated with **IT hardware, licensing, and support** [emphasis added]. These sustainment capital requirements result from the addition of new software such as the **meter data management system, the head end system and network management system, and ongoing software licensing and support requirements** [emphasis added]. The forecast sustainment capital costs for the AMI system were incorporated in the project financial analysis included as part of the application for a CPCN for the project, however a request for approval of these sustainment capital expenditures was not included as part of the capital expenditure request associated with implementation of the project, particularly since these sustainment capital expenditures are only required once implementation of the AMI system has commenced. As such, the sustainment capital expenditures associated with IT hardware, licensing, and support for the AMI system are appropriately included in this application." (Exhibit B-1, p. 226)

32.1 Please confirm that although the capital costs for the AMI project are tracked outside of the PBR formula, the on-going sustainment capital (related to IT hardware, licensing, and support, meter data management system, the head end system and network management system, and ongoing software licensing and support requirements) are included in the 2013 Base capital and will be subject to the PBR formula.

Response:

Not confirmed. As illustrated on line 19 of Table B6-7 (Exhibit B-1), the sustainment capital expenditures associated with IT hardware, licensing, and support for the AMI system are tracked outside of the PBR formula. FBC believes this is appropriate given that the new sustainment capital costs associated with the implementation of AMI are not reflected in the 2013 Base.

32.1.1 Please confirm that these AMI-related ongoing sustainment costs are included in the Information Systems line of Table C5-3 on p. 182 of the Application. If true, please break out this line item to show AMI-related sustaining capital costs separately.

Response:

Confirmed. IT sustainment capital costs associated with AMI are included in the Advanced Metering Infrastructure line of Table C5-3 (Exhibit B-1). Please refer to the table provided below for the disaggregated sustainment costs:

	2014	2015	2016	2017	2018
	$000s				
AMI IT Hardware, Licensing, Support Sustainment Capital Costs	297	573	583	741	604

33.0 Reference: Exhibit B-1, pp.184–185

Asset Management Strategy

"The development of the Asset Management Strategy was initiated following the 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan BCUC Decision 5.2.2.3(a). For this initial stage of planning FBC engaged the support of KPMG LLP (KPMG) to perform a high-level review of asset management practices, systems and tools to identify priority improvement areas and set the roadmap forward." (Exhibit B-1, p. 184)

33.1 Please provide a copy of the Asset Management Strategy document in its current state.

Response:

Please refer to Attachment 33.1.

33.2 If available, please provide documentation of KPMG's high-level review.

Response:

Please refer to Attachment 33.2.

34.0 Reference: Exhibit B-1, pp. 184–188

Asset Management Strategy, Objectives and Principles

34.1 Please explain the relationships of FBC's asset management objectives and principles as applied to the sustainment capital, growth capital and other capital expenditures by project shown in the Application and how the projects in the Application were selected to go forward.

Response:

All capital expenditures in the application, whether growth, sustainment or other have been developed using an approach consistent with previous FBC capital applications developed since at least 2005; no fundamental changes to the portfolio selection methodology were in place at the time of the development of the application. Sustainment projects have been proposed on the basis that they are necessary to continue to provide safe and reliable service. Growth projects are put forward to meet ongoing load growth and to accommodate new customer connections in areas where such load growth is occurring. Other Capital expenditures such as Facilities, Fleet and Information Systems are necessary to provide the support infrastructure necessary for FBC to continue to operate as a long-term going concern. The ongoing development of an asset management approach does not change the necessity for any of these overall capital categories. Rather the ongoing asset management refinements are intended to ensure that capital expenditures deliver the greatest value to customers – in other words delivering safe and reliable service at the lowest reasonable cost.

34.2 Please provide a description of the process(es), tools and methods including, where relevant, linkages to FBC's asset management process used to identify, select, prioritize and pace the execution of projects in each investment category in the Application.

Response:

Please refer to the response to BCUC IR 2.34.1.

35.0 Reference: Exhibit B-7, BCUC 1.154.1

Asset Management, Consultant Cost Allocation

FBC states that the costs of the external consultants for development of a common Asset Management Strategy across both the Gas and Electric divisions, have been split evenly (50/50 split) between the two companies.

35.1 Please explain why the costs of the external consultant have been allocated evenly between FEI and FBC? Has FBC considered any other allocation method, such as by the weighted average number of customers in each division? Please explain.

Response:

The costs to date have primarily been associated with conducting a high-level review of both companies' asset management approaches and processes, and the definition of next steps to pursue to advance each organization. For consistency, these efforts considered each company from an equal perspective, and hence required roughly equal effort on the part of the consultant. On this basis the external consultant costs were allocated evenly between FEI and FBC, as each company benefited equally.

Going forward, as the implementation of specific recommendations is made, FBC will consider alternate allocation methods (such as by the weighted average number of customers) to appropriately reflect the benefits to each organization.

35.2 Based on the weighted average number of customers in each division, please provide the adjusted amounts for the cost of the external consultants.

Response:

Based on a customer count allocation for each division the total consultant costs would change from the current 50%/50% cost allocation to approximately 12%/88% for FBC/FEU, respectively.

36.0 Reference: Exhibit B-1, p.216, 223, Table C5-6: Other Capital

Furniture & Fixtures

Table C5-6: Other Capital ($ thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Other Capital						
Information Systems	4,271	5,290	6,134	5,791	5,747	5,721
Vehicles	2,360	1,948	1,783	1,749	1,907	1,945
Meters Changes	369	-	71	109	114	118
Telecommunications	166	156	159	162	166	169
Buildings	803	1,044	912	942	961	980
Furniture & Fixtures	110	260	531	87	88	90
Okanagan Long Term Solution	-	120	122	3,800	-	-
Advanced Metering Infrastructure	-	18,765	18,233	583	741	604
Total Other Capital	8,495	28,078	28,449	13,738	10,247	10,162

36.1 Please discuss and explain the increase in the 2015 forecast for Furniture & Fixtures in the above table.

Response:

The increase in 2015 forecast for Furniture and Fixtures is a result of furniture and flooring replacement that are end of life. Furniture replacement is targeted in sections which allow for a consistent annual budget, however, carpet replacement is completed on a per building basis, which causes an increase in the furniture and fixtures budget when replacement is required. In 2015 carpet replacement is required at several of the facilities, and as such, the forecast has increased. The carpet has well exceeded the expected 10 year life and has significant wear causing patching and safety issues. The life of the asset has been extended to its fullest and replacement is prudent.

37.0 Reference: Exhibit B-1, pp.216, 224–225, Table C5-6: Other Capital — Benvoulin Property

Okanagan Long Term Solution

FBC states:

> "[a]s part of the 2006 Capital Expenditure Plan, FBC requested capital funding of $3.2 million to support the purchase and initial development of 6.55 acres of agriculture land located north of the Benvoulin property, which was approved by Order G-8-06. Unfortunately, FBC was unable to get approval from the Agriculture Land Commission (ALC) to rezone this property. As such the Company did not proceed with the property acquisition." (Exhibit B-1, p. 224)

37.1 Please confirm the Okanagan Long Term Solution was formerly the called the Benvoulin property.

Response:

Confirmed. The Okanagan Long Term Solution was formerly called the Benvoulin Property Expansion in the 2006 Capital Expenditure Plan.

37.2 Please provide the details of the actual costs associated with the failed purchase and initial development of 6.55 acres of agriculture land located north of the Benvoulin property, which was approved by Order G-8-06.

Response:

The details of the actual costs associated with the failed purchase and initial development of 6.55 acres of agriculture land located north of the Benvoulin property were legal, consultant, internal labour, land option deposit totalling $149 thousand.

In August 2007, the total expenditures for this capital project were transferred to Non-regulated shareholder account.

37.2.1 Have all the costs been expensed, capitalized or accrued to Preliminary/Investigative Charges deferral account?

Response:

Please refer to the response to BCUC IR 2.37.2.

FBC provides the following table in Exhibit B-1, p. 216 of the Application:

Table C5-6: Other Capital ($ thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Other Capital						
Information Systems	4,271	5,290	6,134	5,791	5,747	5,721
Vehicles	2,360	1,948	1,763	1,749	1,907	1,945
Meters Changes	369	-	71	109	114	118
Telecommunications	166	156	159	162	166	169
Buildings	803	1,044	912	942	961	980
Furniture & Fixtures	110	260	531	87	88	90
Okanagan Long Term Solution	-	120	122	3,800	-	-
Advanced Metering Infrastructure	-	16,765	18,233	583	741	604
Total Other Capital	8,495	26,078	28,449	13,736	10,247	10,162

37.3 Please explain the forecast capital of $120,000 in 2014, $122,000 in 2015 and $3.8 million in 2016.

Response:

The 2014 and 2015 forecast capital expenditures are for the remaining approved funding from the 2011 Capital Plan for the Okanagan Long Term Solution. FBC continues to work through details of this plan. In 2016, the forecast of $3.8 million includes the costs for:

- Acquisition of the property north of our Benvoulin property;
- Acquisition of the rights to move land into the Agricultural Land Reserve (ALR); and
- Site development to complete civil work of the 6.55 acres to make it useable.

37.3.1 Please provide a timeline for the two-stage development of the 6.55 acres of land located north of (and adjacent to) the Benvoulin property.

Response:

The Okanagan Long Term Solution project proposes the completion of Phase I of the project in 2016.

Phase 1 of the project will include:

- Acquisition of 6.55 acres of land for FBC use;
- Acquisition of Rights to land to move into the ALR; and
- Site development to complete civil work of the 6.55 acres to make it useable.

Phase 1 of the project was approved previously in the 2006 Revenue Requirements Application and continues to be prudent and reasonable, independent of the second phase. The land will be used immediately for laydown, storage and parking. In addition, it will allow for better utilization of the existing Benvoulin site.

The conceptual design, timeline and estimated budget for the second phase of the Project have not been completed at this time.

37.3.2 Please provide the total forecast cost to develop stage 1 and stage 2 of the 6.55 acres of land located north of (and adjacent to) the Benvoulin property.

Response:

The total forecast cost to develop phase 1 is $3.8 million. Note the forecasted expenditures in 2014 and 2015 are described in the response to BCUC IR 2.37.3.

The conceptual design, timeline and estimated budget for phase 2 have not been completed at this time.

37.3.3 Please provide a cost benefit analysis of the total forecast cost for stage 1 and stage 2 to develop the 6.55 acres of land located north of (and adjacent to) the Benvoulin property. Please identify what year the savings are anticipated to occur and how this may impact the energy conservation measure (ECM).

Response:

The cost for Okanagan Long Term Solution Phase 1 is $3.8 million. This cost will be partially offset by the benefits of this phase, which FBC estimates annual savings of $200 thousand of O&M and $350 thousand of T&D Capital. FBC anticipates the full savings to begin in 2017. The phase 1 project is economically viable on its own merits, regardless of whether or not stage 2 proceeds.

Energy conservation considerations related to the design and construction of a building will not apply to phase 1 as this phase consists solely of a land purchase with civil work improvements for storage of materials and equipment. Phase 2 is likely to involve addition of a building footprint, however, the conceptual design, timeline and estimated budget have not been completed at this time.

37.3.4 Will FBC be filing a CPCN application for the stage 1 and stage 2 development of the 6.55 acres of land located north of (and adjacent to) the Benvoulin property? If not, why not?

Response:

FBC does not anticipate filing a CPCN application for Phase 1 of the Okanagan Long Term Solution and does not believe this is required. The project has undergone only minor changes since being approved in the 2006 Capital Expenditure Plan and the costs will be absorbed within the capital formula during the PBR period. Phase 1 includes the acquisition of the land and site development to make the land useable for storage of operating materials and equipment.

The Phase 2 timeline and method of approval has not been finalized at this time.

38.0 Reference: Exhibit B-7, BCUC 1.34.1, BCUC 1.34.2.2, BCUC 1.158.1 and BCUC 1.19.1

Excluded Major Capital Projects, PCB Compliance — Substations

FBC states "[t]he substation portion of the PCB Environmental Compliance program, which will be completed during 2014…" and "[w]ith respect to the PCB Environment Compliance, the activities associated with the project are driven by external regulation are non-recurring by the nature of the project (removal and/or containment of PCB contaminated equipment)." (Exhibit B-7, BCUC 1.34.2.2)

FBC states:

> "[w]ith respect to the legislative changes affecting distribution equipment containing PCBs, FBC has been aware of these changes for a number of years. Further, the legislative changes also provide an in-service exemption until 2025 for distribution equipment containing PCBs. Based on these factors; FBC has a certain amount of control over the level of costs associated with remediation of any PCB contaminated distribution equipment." (Exhibit B-7, BCUC 1.158.1)

38.1 Please provide the approved and actual (projected) expenditures related to PCB compliance for each of the years between 2008 and 2013.

Response:

Please refer to the following table:

PCB Compliance Expenditures

	2008	2009	2010	2011	2012[1]	2013F[2]
	$000s					
Approved	868	700	700	1,926	11,269	11,553
Actual	917	152	-	1,718	4,302	6,003

[1] Variance due to scope rationalization resulting in a shift in project schedule.
[2] Variance due to labour dispute between FBC and IBEW employees.

38.2 Considering that FBC has been aware of the PCB program for a number of years, please explain why FBC still considers "PCB Compliance – Substations" to be a Major Capital project to be excluded from the I-X mechanism in the 2014 – 2018 PBR Plan.

Response:

The response provided in BCUC IR 1.158.1 was with respect to the legislative changes related to distribution equipment containing PCBs. Indeed, draft regulations related to these legislative changes was first released in 2002, and was focused on the identification and imminent removal of pole-top electrical distribution equipment containing PCBs. In response to the proposed draft regulation, FBC established a PCB testing program for pole-top transformers, as first discussed in the Company's 2005 Capital Plan.

In 2008, the *PCB Regulations* were passed into law. The requirements were similar to the proposed draft regulations; however the regulations contained one major and unexpected difference not previously reflected in the proposed draft regulations related to PBC contaminated equipment located in substations. The regulations required this equipment to be removed from service by December 31, 2009. A provision for an extension to December 31, 2014 was included in the regulations, for which FBC applied and was granted approval.

There are a number of challenges associated with complying with the *PCB Regulations*, namely that the equipment immediately affected by the regulations is distributed throughout FBC's substation facilities, which had not been included in the PCB testing program initiated in 2005, as the draft regulations appeared to indicate the more immediate area of concern related to PCB contaminated distribution equipment such as pole-top transformers. Indeed, given the lumpy and non-recurring nature of the expenditures required to address the imminent 2014 legislative deadline for the removal and/or remediation of PCB-contaminated station equipment, FBC considers it appropriate to exclude these expenditures from the proposed PBR formula.

38.3 Please discuss and explain why the PCB Environmental Compliance program, which is well known to FBC, has been excluded from the PBR formula while the relatively new MRS program is included in the PBR formula.

Response:

With respect to the MRS program, FBC has completed the one-time capital expenditures to become compliant with the standards currently adopted in BC. As such, the Company is not forecasting further capital expenditures related to the adoption of future MRS standards. There are, however, ongoing sustaining capital expenditures related to the MRS Systems sustainment (related primarily to IT requirements) which are forecast to remain relatively stable throughout the 2014 – 2018 PBR period. As such, these expenditures are appropriately included in the 2013 Base Capital. If new or modified standards become applicable, any incremental capital expenditures required to achieve compliance would be treated as a Z-factor under the PBR plan.

In contrast, the costs associated with the PCB Environmental Compliance program for station equipment are lumpy and non-recurring in nature, and are not part of "steady-state" expenditures to which the PBR formula is intended to apply. As well, FBC is not forecasting any ongoing sustainment capital costs related to PCBs once compliance with the *PCB Regulations* has been achieved. Please refer to the response to BCUC IR 2.38.2 for a discussion regarding the appropriateness of excluding PCB Environmental Compliance expenditures for station equipment from the PBR formula.

39.0 Reference: Exhibit B-7, BCUC 1.34.1 and 1.34.4

Major Capital Projects Excluded from PBR Formula

FBC states that:

> "[t]he definitions of major capital and non-recurring capital are not exclusive. Both Regular Capital and Major Capital projects may be non-recurring in nature.
>
> For the purposes of the PBR Plan, it is the distinction between Regular Capital and Major Capital that is important: Major Capital projects are excluded from the formula-driven portion of capital expenditures…" (Ex. B-7, BCUC 1.34.1)

From the data supplied in response to BCUC 1.34.4, the following table was developed by Commission Staff:

Summary of Capital Expenditures by Year ($000s)			
Year	Major Capital	Regular Capital	Ratio of Major Capital to Regular Capital (%)
2007	58,898	70,291	84%
2008	42,396	57,191	74%
2009	45,774	53,395	86%
2010	75,455	55,035	137%
2011	27,757	48,452	57%
2012	10,301	42,091	24%
2013	67,584	65,609	103%
2014	8,762	63,996	14%
2015	-	68,950	
2016	-	52,103	
2017	-	53,183	
2018	-	54,060	

39.1 Please confirm that the ratio of Major Capital to Regular Capital is, on average for the PBR years 2007 to 2011, over 80 percent.

Response:

Confirmed.

39.2 Please confirm the average annual Regular Capital for the years 2007 to 2011 is $56,873.

Response:

Confirmed; however, FBC notes that this is an un-weighted average of nominal dollar amounts for the 2007 to 2011 period. As such, it is not directly comparable to average costs over another period of time.

39.3 Please confirm the average annual Regular Capital for the proposed 5 year PBR will be $58,458.

Response:

Confirmed; however, FBC notes that this is an un-weighted average of nominal dollar amounts for the 2014 to 2018 period. As such, it is not directly comparable to average costs over another period of time.

39.4 Please provide an explanation as to why there are no Major Capital expenditures identified for the years 2015–2018.

Response:

The response to BCUC IR 1.34.4 details those capital expenditures reflected in the revenue requirement forecast for the PBR period, but does not include any Major Projects for which FBC may seek future approval. Although in the past the forecasts associated with Major Projects such as these were included in the Revenue Requirements, for the purposes of this PBR Application, these Major Project forecasts have been excluded. Please refer to the response to BCUC IR 1.19.3 for detail regarding forecast capital expenditures that will be included under the proposed PBR formula, as well as forecast capital related to Major Projects for the 2014 – 2018 PBR period for which FBC may seek future approval.

39.5 Please discuss if it would be reasonable for FBC to apply a proxy of 80 percent of Regular Capital amount as a forecast for Major Capital for the years 2014–2018. Why or why not?

Response:

It would not be reasonable for FBC to apply a proxy of 80 percent of Regular Capital amount as a forecast for Major Capital for the years 2014-2018, as the average percentage during the 2014-2018 period is approximately 46 percent (as indicated in the Table below), when future expected Major Projects (AMI and PCB projects as well as unapproved CPCNs) are taken into account. Furthermore, given the variability of this ratio as shown in the table provided in this question, the degree of variability over time (24 to 137 percent) makes the use of an average value inappropriate; as such a method would not recognize the inherent differences in the size and scope of Major Projects.

Year	Summary of Expenditures by Year					
	Major PBR Capital	Regular PBR Capital	Total PBR Capital	Expected Future (Unapproved) CPCNs	Total Expected Major Capital	Ratio of Major Capital to Regular Capital
	A	B	A+B	C	A+C	(A+C)/B
2014	22,531	50,227	72,757	13,594	36,124	72%
2015	17,660	51,289	68,949	8,273	25,934	51%
2016	-	52,103	52,103	5,590	5,590	11%
2017	-	53,183	53,183	22,560	22,560	42%
2018	-	54,060	54,060	30,415	30,415	56%
2014-2018 Average Ratio of Major Capital to Regular Capital						**46%**

Note: All data based on the 5th July Filing (First Filing) of the RRA 2014

Please note, due to the uncertainty of which specific projects will be affected due to the delay in the execution of 2013 capital expenditures, the information provided above is based on the July 5, 2013 filing data as this information is most relevant for the purposes of evaluating the proposed PBR plan.

39.6 Please discuss FBC's reasoning for requesting that Regular Capital be included in the currently proposed PBR when the previous PBR did not include any capital expenditures in the PBR formula.

Response:

Although FBC did not include any capital expenditures under the previous PBR formula, the inclusion of regular capital expenditures under the proposed PBR formula for the 2014 – 2018 period offers an increased opportunity for regulatory efficiency as well as flexibility for the Company to manage these regular capital expenditures and capture efficiencies for the long term benefit of customers.

39.7 What are the implications to ratepayers by not including a forecast for Major Capital expenditures?

Response:

FBC does not believe there are any negative implications to rate payers associated with not including a forecast for Major Capital expenditures, as FBC is not requesting approval of any Major Capital expenditures as part of this application. However, FBC estimates an additional cumulative rate impact of approximately 1.8 percent over the 2014 – 2018 period related to the Major Capital expenditures for which FBC intends to seek CPCN approvals in the future.

40.0 Reference: City of Kelowna

Exhibit B-7, BCUC 1.147.2.2

Future Capital Expenditures

FBC states:

> "FBC has not included an adjustment in the 2013 Base calculation for capital projects related to the former City of Kelowna utility assets acquired in 2013, as the Company intends to absorb these future capital expenditures related to those assets within the capital funding as calculated under the proposed formula." (Exhibit B-7, BCUC 1.147.2.2)

40.1 For each year of the PBR term, please provide a forecast cost for the future capital expenditures related to the former City of Kelowna utility assets acquired in 2013.

<u>Response:</u>

The table provides below details the 2014 – 2018 capital expenditures associated with the assets formerly owned by the City of Kelowna that FBC intends to absorb within the proposed PBR formula.

	2014	2015	2016	2017	2018
Sustainment	**$000s**				
Distribution Line Condition Assessment	92	-	78	-	-
Distribution Line Rehabilitation	72	228	-	198	-
Distribution Line Rebuilds	613	659	685	699	713
Distribution Line Small Planned Capital	43	47	36	43	43
Distribution Urgent Repairs	110	122	93	115	115
Underground Cable Replacement	601	609	595	607	619
Underground Switcher Replacement	318	203	298	-	-
ArcFM Feeder System Audit	254	-	-	-	-
Sub-total	**2,103**	**1,868**	**1,785**	**1,662**	**1,490**
Growth					
Fault Indicator Installation	-	306	312	-	-
Spall Breaker House Reconfiguration	1,283	-	-	-	-
Saucier Substation Protection and Metering Upgrade	-	936	-	-	-
Distribution Unplanned Growth	42	47	36	44	44
Sub-total	**1,324**	**1,288**	**347**	**44**	**44**
Total	**3,427**	**3,156**	**2,133**	**1,706**	**1,534**

Note: differences due to rounding

41.0 Reference: Exhibit B-7, p. 179

Completed Projects, Cost Savings

41.1 Please confirm that Corra Linn Unit 3 completion, Corra Linn Unit 2 Life Extension, and Okanagan Transmission Reinforcement Project are completed projects.

Response:

Confirmed. Corra Linn Unit 3 Completion, Corra Linn Unit 2 Life Extension and the Okanagan Transmission Reinforcement Project are complete.

41.1.1 For the above projects, please provide the forecast cost savings by year due to increased efficiencies, increased capacities, loss reduction or other savings that will occur during the PBR term.

Response:

Where known, the forecast cost savings associated with increased efficiencies have already been incorporated in the PBR base calculation.

For a discussion of the increased efficiencies/capacities and cost savings associated with the Corra Linn U2 and U3 upgrades, please refer to the response to Gabana IR 1.1.

With respect to loss reduction, as presented in the 2012/13 Revenue Requirements Application and associated Evidentiary Update, FBC has forecast a loss reduction of approximately 10 GWh per year from 2014 going forward that results from the completion of the OTR project. This reduction has been accounted for in power purchase expense forecasts.

41.1.2 Please identify any portion of the cost savings and efficiencies increases that may result in cost reductions to O&M that are not already included in the Base O&M.

Response:

The Base O&M already includes all known cost savings and efficiency gains. Accordingly, there are no other portions to identify or report.

42.0 Reference: Exhibit B-1, p. 179-181; FBC 2012-2013 Revenue Requirements Application (RRA) and Integrated System Plan (ISP), Exhibit B-1, pp. 99–101

Elimination of Major Capital Projects

42.1 For the Major Capital project totaling $54.882 million, please discuss and explain why the following Major Capital projects were eliminated from the 2013 approved capital expenditure shown in Table C5-2 on page 181: Trail Office Lease Purchase, Okanagan Long Term Solution Project and Central Warehousing Project.

<u>Response:</u>

As noted in the response to BCUC IR 1.34.3, these projects are not recurring expenditures and are not representative of the type of ongoing requirements to which the proposed PBR mechanism is intended to apply.

Please note, the adjustment related to Central Warehousing as noted on page 179 of the Application (Exhibit B-1) was provided in error. There are no 2013 expenditures related to this project. The adjustments made to determine the 2013 Base are correctly noted in Table C5-2 on page 181 of the Application (Exhibit B-1).

42.2 As the Trail Office Lease Purchase had an NPV "benefit to customers of approximately $1.4 million using an 8 per cent discount rate" (FBC 2012-2013 RRA and ISP, Exhibit B-1, pp. 99-100), please show the cost savings to the customers during the proposed PBR term by year

<u>Response:</u>

Please refer to the table below for the cost savings in nominal dollars over the proposed PBR term. Note that amounts presented in the table below represent approximately $0.8 million of the $1.4 million NPV of benefits noted for the period of 2013 – 2021, discounted at 8 percent. These savings reflect the reduction in lease costs as described as non-labour O&M cost reductions on Page 152 of Section C4 of Exhibit B-1 partially offset by the increase in financing costs associated with the approximate $10.0 million cost to purchase the Trail Office building as shown on row 32, of Page 279 in Section E of Exhibit B-1-6.

	Forecast				
	2014	**2015**	**2016**	**2017**	**2018**
***Cost Savings**	(134)	(175)	(217)	(257)	(299)

**Savings noted in nominal dollars*

42.2.1 Please confirm that these cost savings have been included in the 2013 Base capital and Base O&M calculations. If not, why not?

Response:

Confirmed. As noted on pages 51-52 of Section B6 (Exhibit B-1), 2013 Base O&M has been reduced by the 2013 lease payment of $0.9 million for the Trail Office. As well, as shown in Table C5-2 (Exhibit B-1), 2013 Base capital expenditures exclude expenditures of $10.0 million related to the Trail Office Lease Purchase.

FBC states "FortisBC received approval (Order G-195-10) in its 2011 Capital Expenditure Plan to develop the long term space strategy. FortisBC plans to spend $0.07 million in 2012 and $0.08 million in 2013" (FBC 2012-2013 RRA, Exhibit B-1, p. 100).

42.3 Please provide an update on this capital expenditure and reasons as to why it has been eliminated from the 2013 approved capital expenditures.

Response:

The referenced expenditures were used to consider options for a solution to the space requirements for the Okanagan area, as discussed in section C5.6.8 from the Application (Exhibit B-1).

As this type of investigative spending is not recurring and not representative of the types of on-going requirements that the proposed PBR mechanism is intended to apply to, the associated expenditures have been appropriately excluded from the determination of the 2013 Base Capital.

42.4 Considering the magnitude of the costs for this project, please explain why this was classified as a Major Capital Project?

Response:

As this project was required to determine an appropriate long-term solution to the operational space constraints in the Kelowna region, FBC submits that the exclusion of these non-recurring expenditures from the determination of the 2013 Base Capital is appropriate. Although this project is not technically a "Major Project", the associated expenditures are non-recurring and are not related to sustainment requirements, hence the exclusion of these expenditures from the 2013 Base Capital. FBC notes that the "Major Projects" classification has been used to denote capital which has been excluded from the determination of the 2013 Base Capital and the application of the 2014-2018 PBR capital formula mechanism.

Please refer to the response to BCUC IR 1.34.3.

FBC states:

> "[b]y centralizing warehousing to Warfield the additional space leased at the Enterprise site will not need to be replaced when the lease expires. This will reduce costs to the organization by $600,000 annually. The project is estimated to cost $1.76 million in 2012" (FBC 2012-2013 RRA, Exhibit B-1, pp. 100-101).

42.5 Please provide an update on this capital expenditure and reasons as to why it has been eliminated from the 2013 approved capital expenditures.

Response:

The Central Warehousing Project was completed in 2012, but was inadvertently noted on page 179 (Exhibit B-1) as being eliminated from the determination of the 2013 Base Capital. Please refer to Table C5-2 which details the projects eliminated from the 2013 approved capital expenditures for determination of the 2013 Base Capital.

42.6 As the Warfield Central Warehouse is anticipated to reduce costs by $600,000 annually, please show how the cost savings will flow through to the customers during the proposed PBR term each year. Has it been included as a reduction to the Base O&M?

Response:

Yes the reduction has been included in the Base O&M. The decrease to Operating Expense is $0.2 million (net of $0.05 million in capitalized overhead) in 2013, as detailed in the 2012 – 2013 Revenue Requirements Evidentiary Update dated November 4, 2011, Section Operating Expense, Page 4 Line 4, which states, "The expiration of the Enterprise Road facility lease at the end of 2012 results in savings to Facilities Management Expense of $0.6 million in 2013…The lease savings impact both O&M Expense ($0.25 million) and capital project loadings ($0.35 million) in 2013 only."

43.0 Reference: Exhibit B-1, pp. 55–56

Cost Savings from Previously Approved Projects

FBC states:

> "[a]n ECM is a means of strengthening the incentive to pursue efficiency initiatives throughout the PBR term. The ECM does this by ensuring that the benefits of the efficiency gains are retained for a reasonable period after the PBR term. The benefit to customers of an ECM is that the greater efficiencies achieved throughout the PBR term become incorporated into rates going forward." (Exhibit B-1, pp. 55-66)

43.1 As there is no front-end ECM mechanism proposed in the Application, should cost savings from previously approved Capital (those included in the FBC 2012-2013 RRA & ISP and CPCNs, such as AMI), flow 100 percent to the ratepayer and not subject to the ESM (50/50 split)? Please discuss.

Response:

FBC is not aware of the benefits associated with a front end ECM, nor are there any ECM-type benefits to be carried forward from FBC's previous PBR (which did not include an ECM). However, the Company can confirm that all of the benefits of AMI are going to rate payers. Further, FBC has not proposed anything that will result in retroactive ratemaking associated with previously approved capital projects. FBC shows that 100% of the O&M savings related to AMI go to rate payers in the Application in Table B6-5 (Exhibit B-1, p.53).

43.2 Please identify previously approved capital projects in the 2012-2013 RRA and ISP and provide the forecast Capital and O&M cost savings that may occur during the proposed PBR term and the trailing ECM window.

Response:

Previously approved projects in the 2012-2013 RRA and ISP are listed below along with their approving orders.

Generation:

- Upper Bonnington Spill Gate Rebuild (G-195-10);
- Lower Bonnington Powerhouse Windows (G-195-10);

- Corra Linn Unit 2 Life Extension (C-5-09);
- All Plants Station Service (G-147-06); and
- Lower Bonnington and Upper Bonnington Plant Totalizer Upgrade (G-195-10).

Transmission and Stations:

- Okanagan Transmission Reinforcement (C-5-08).

General Plant:

- Okanagan Long Term Solution (G-195-10).

None of the projects identified above are forecast to result in incremental capital and/or O&M cost savings during the proposed PBR term and trailing ECM window.

43.3 Please identify previously approved CPCNs in the 2012-2013 RRA and ISP and provide the forecast Capital and O&M cost savings that may occur during the proposed PBR term.

Response:

As detailed in the response to BCUC IR 2.43.2, the only previously approved CPCNs in the 2012-2013 RRA and ISP are those for the Corra Linn Unit 2 Upgrade and Life Extension and the Okanagan Transmission Reinforcement project. Neither of these projects are forecast to result in capital and/or O&M savings during the proposed PBR term and the trailing ECM window.

The AMI project (approved subsequent to the 2012-2013 RRA and ISP) does include forecast O&M savings that will be realized during the 2014 – 2018 PBR term, as illustrated in Table B6-5 from the Application (Exhibit B-1).

43.4 Given that the AMI project is tracked outside of the PBR formulas, please clarify who is the beneficiary of these savings? Ratepayer or Shareholder? Or will the savings be shared through the ESM?

Response:

As the full forecast savings related to the AMI project are included in the determination of total O&M under PBR, the ratepayer is the sole beneficiary of the savings related to the project. These savings are comprised primarily of a reduction in manual meter reading costs, disconnection and reconnection costs, and meter exchange costs, offset by the addition of new operating expenses related to the AMI system. By tracking the savings related to this project outside of the PBR formula, FBC has committed to providing all benefits from the AMI project to customers. Further, as FBC has proposed to flow-through variances in power purchase expense, the benefit of any reduction in theft resulting in decreased losses will flow-through entirely to customers.

Please also refer to the response to BCUC IR 2.43.1.

43.4.1 Please explain why this method is appropriate.

Response:

Please refer to the response to BCUC IR 2.43.4.

44.0 Reference: Exhibit B-7, CEC 1.18.2

Base Year Capital and O&M Adjustments

44.1 Please provide a list of IT projects including SCADA and MRS that were completed at the time of the FBC 2012-2013 RRA.

Response:

FBC's Information Systems have primarily been in a sustainment mode for the past several years and there has been very little discretionary spending. Other than sustainment projects, only minor application enhancement work has been completed to meet changing business needs and required legislated changes. Specifically, there were four annual Information Systems capital projects completed, namely:

- Infrastructure Sustainment;
- Desktop Sustainment;
- Application Sustainment; and
- Application Enhancement.

Additionally, Information Systems supported the development of the Customer Service PowerSense Program through the implementation of a Demand Side Management System.

Similar to Information Systems, the SCADA and MRS Systems Sustainment program funded annual sustainment projects for Supervisory Control and Data Acquisition (SCADA) software systems and infrastructure located at System Control Centre (SCC) or the Backup Control Centre (BCC) and communications infrastructure directly connecting the SCC to the BCC. Additionally, as Mandatory Reliability Standards (MRS) standards continued to evolve, this program funded MRS-related system upgrade projects at the Backup Control Centre that was deemed necessary to maintain compliance with these standards.

Specifically, within the SCADA and MRS System Sustainment project, the following work was completed:

- SCC Host "C" Installation to provide required test environment for the SCADA server;
- Redundant backup communications from Benvoulin to BCC for MRS compliance;
- IRIG Time Synch Install and Redundant Inter Control Communication Protocol Link Install at BCC;
- Lake Levels web application upgrades; and

- Upgraded firewalls from PIX501 to ASA5505 standard for MRS compliance.

44.1.1 Please provide financial evidence of all improvements in cost reduction and the dollar amounts of the Capital and O&M cost savings.

Response:

Business technology systems have primarily been in a sustainment mode for the past several years, and there has been little discretionary spending. Other than sustainment projects, only minor enhancement work has been done to meet changing business needs and required legislated changes. Due to this benefits attributable to IS initiatives were not specifically tracked, and, therefore, cannot be provided. Benefits from past projects have been assumed to have contributed to controlling operating costs and optimizing systems supporting the capital program.

44.2 Please explain if FBC included any other cost savings in its adjustments to the Base Capital or O&M amount that may occur as a result of its capital expenditures.

Response:

Please refer to the response to BCUC IR 2.44.1.1. No other cost savings have been included in the adjustments to the Base Capital or O&M amounts.

45.0 Reference: Exhibit B-1, pp. 226–231

Certificates of Public Convenience and Necessity (CPCN)

45.1 Please confirm the data and provide the missing data in the following table:

	CPCNs during the PBR	Application Filed	Estimated Start Date	Estimated In-Service Date	Preliminary Estimate (million)	2012 LTCP (million)	PBR Forecast Cost (million)	2012 LTCP Reference
1	Kelowna Bulk Transformer Capacity Addition	2016		2019	14.5	26		Table 2.8 (a)
2	Grand Forks Transformer Addition	2016			5.9	16		Table 2.8 (a)
3	Ruckles Substation Upgrade;	2015			5.9			Distribution Substation Automation Project
4	Central Okanagan Substation	2017			24	24		Appendix J
5	Grand Forks to Warfield Fibre Installations	2013			4.8	16		LTCP 2.8.3, p. 101
6	Corra Linn Spillway Concrete and Spill Gate Rehabilitation	2016/2017	2015		21.6	28		Table 2.5 (a), Table 2.5.1, Appendix J
7	Kootenay Long Term Facilities Strategy	2013				16		Table 5 & Appendix J
8	Upper Bonnington Unit 1, 2, 3 Refurbishment	2015	2016			57		Table 2.5 (a)
	Total CPCN Amount							

Response:

The following table provides the requested information. Please note the column titled "PBR Forecast" has been eliminated as this information is provided in the "Preliminary Estimate" column.

	CPCNs during the PBR	Application Filed	Estimated Start Date	Estimated In-Service Date	Preliminary Estimate (million)	2012 LTCP (million)	2012 LTCP Reference
1	Kelowna Bulk Transformer Capacity Addition	2016	2017	2019	14.5	26	Table 2.8 (a)
2	Grand Forks Transformer Addition	2016	2017	2019	5.9	16	Table 2.8 (a)
3	Ruckles Substation Upgrade;	2015	2016	2019	5.9	N/A	Distribution Substation Automation Project
4	Central Okanagan Substation	2017	2018	2019	24	24	Appendix J
5	Grand Forks to Warfield Fibre Installations	2014	2014	2015	4.8	16	LTCP 2.8.3, p. 101
6	Corra Linn Spillway Concrete and Spill Gate Rehabilitation	2016/2017	2015	2033	21.6	28	Table 2.5 (a), Table 2.5.1, Appendix J
7	Kootenay Long Term Facilities Strategy[1]	TBD	2014	2016	16.4	16	Table 5 & Appendix J
8	Upper Bonnington Unit 1, 2, 3 Refurbishment	2015	2016	2019	21	57	Table 2.5 (a)
Total CPCN Amount					114.1	183	

[1]*The timing of this project is currently under review.*

45.2 Please explain the difference between the forecast amounts in the 2012 LTCP and the PBR.

Response:

The differences between the forecast amount provided in the 2012 LTCP and the updated forecasts as provided in the response to BCUC IR 2.45.1 are due primarily to improvements in the class of estimate provided. The forecast estimates in the 2012 LTCP were estimated at an AACE class 4 or 5 level based on FBC estimating guidelines (AACE No. 18R-97). Since the submission of the 2012 LTCP, estimates for the Grand Forks to Warfield Fibre Installation, Kelowna Bulk Transformer Capacity Addition, and the Kootenay Long Term Facilities Strategy have been refined to an AACE class 3 level. All other projects identified in the response to BCUC IR 2.45.1 are presently estimated at an AACE class 4 level.

45.3 If any of the proposed CPCNs are less than the $20 million threshold approved in Order G-52-05, please explain why it may be a proposed CPCN. Please also explain why FBC believes that the expenditures for each of these projects should be excluded from the PBR.

Response:

Section C5.7 of the Application provides the following reasons for projects to be filed as a CPCN, even if they are less than $20 million:

a) The project is likely to generate significant public concerns,

b) FBC believes for any reason that a CPCN application should proceed,

c) After presentation of a Capital Plan to FBC stakeholders, a credible majority of those stakeholders express a desire for a CPCN application or

d) The Commission determines that a CPCN application should proceed.

The proposed CPCNs that are forecast to be less than the $20 million threshold are:

- Grand Forks Transformer Addition;
- Grand Forks to Warfield Fibre Installations;
- Kelowna Bulk Transformer Capacity Addition;
- Kootenay Long Term Facilities Strategy;
- Ruckles Substation Upgrade; and

- Central Okanagan Substation.

With respect to the Grand Forks Transformer Addition and the Grand Forks to Warfield Fibre Installation projects, FBC was previously directed by the BCUC (see G-195-10 and G-110-12) to file CPCN applications for these projects.

With respect to the Kelowna Bulk Transformer Capacity Addition (KBTCA) project, and the Kootenay Long Term Facilities projects, FBC previously committed to filing CPCN applications for these projects. For the KBTCA project, preliminary estimates indicated a cost in excess of the $20 million threshold. Although this forecast cost has since been revised to less than $20 million, FBC still intends to seek a CPCN as initially planned. With regard to the Kootenay Long Term Facilities project, FBC initially intended to seek a CPCN as the project planning was forecast to fall between capital expenditure applications. Although the project has been delayed, FBC still intends to seek a CPCN as originally planned, however the timing of the application is still being determined.

The remaining CPCN projects with forecast expenditures less than $20 million are both station infrastructure projects (Ruckles Substation Upgrade and Central Okanagan Substation). Given the profile and potential public concern sometimes associated with station infrastructure projects, FBC believes a CPCN application provides the most effective mechanism to both examine and address any concerns or issues regarding these types of projects.

As the proposed PBR formula (including the determination of the 2013 Base) is intended to apply to steady-state operations, and not incremental expenditures related to large one-time projects which are typically the subject of CPCN applications, it would not be appropriate to capture CPCN projects under the proposed PBR-based capital spending formula. As noted by B&V, capital projects such as those subject to a CPCN application can impact productivity as costs may increase without any change in capacity or number of customers. As such, the exclusion of the CPCN capital is considered an appropriate means of addressing the lumpy nature of this type of capital under a PBR plan.

It should also be noted that projects subject to a CPCN application often involve significant public interest and scrutiny, which is in contrast to projects captured under the proposed PBR formula. The CPCN application process provides an efficient and effective means of examining and addressing any concerns regarding these types of projects. As such, FBC believes its proposal to exclude CPCN capital expenditures from the PBR formula is appropriate.

Please also refer to Section C6.2.5 from the Application (Exhibit B-1) for a discussion of why the exclusion of CPCN capital is appropriate for FBC's proposed PBR Plan.

45.4 Provide a list of potential Capital and O&M cost savings that could result from these projects.

Response:

Presently, the Kootenay Long Term Facilities Strategy is the only project discussed in section C5.7 of the Application (Exhibit B-1) that will result in forecast O&M savings. These anticipated O&M savings, based on the current project proposal, are related to the retirement of the South Slocan Administration and Warehouse Buildings, disposal of the Castlegar District Office, operational efficiencies and a reduction of two Kootenay region fleet vehicles. The amount and timing of any O&M savings associated with the Kootenay Long Term Facilities Strategy project will be further discussed as part of the CPCN application for the project, but are not expected to be realized until after project completion in 2019.

46.0 Reference: Exhibit B-1, pp. 55–59, 179–180 and 226–231

Base Capital for PBR and Excluded Expenditures

"FBC has used the approved capital expenditures for 2013 from the 2012-2013 RRA Decision as the starting point for the capital formula. Similar to the methodology used to arrive at the 2013 O&M Base for PBR, adjustments are made to the 2013 Approved capital to arrive at the '2013 Capital Base'. These include:

1. Adjustment for non-recurring major projects, as detailed in Table C5-2; and
2. Adjustments to include 2013 actual 'non-controllable' items equivalent to those included in the Base O&M calculation

These adjustments determine the starting point or base for capital expenditures in the upcoming PBR period." (Ex. B-1, pp. 55–56)

"In order to set the base level of capital expenditures for application of the PBR formula, FBC uses 2013 Approved capital expenditures as a starting point, less those expenditures which are not representative of on-going requirements." FBC eliminated "major or non-recurring types of capital" when preparing Table C5-2. (Exhibit B-1, p. 179)

46.1 Please confirm that "Major Projects" identified in Table C5-1 are those capital expenditures that are excluded from the capital PBR formula for 2014-18. If not, please explain.

Response:

Confirmed, the 2013 Approved Major Projects identified in Table C5-1 (Errata 2) are excluded from the determination of the 2013 Base Capital to be applied to the proposed PBR formula for the 2014-2018 period.

46.2 Please provide a table showing the breakdown of Regular Capital for the years 2010 to 2018. Provide another table showing the breakdown of Major Capital for the same period.

Response:

The requested breakdown of Regular Capital and Major Capital is provided in the tables below. Please note, due to the uncertainty of which specific projects will be affected due to the delay in the execution of 2013 capital expenditures, the information provided below is based on the July 5, 2013 filing data as this information is most relevant for the purposes of evaluating the proposed PBR plan. Expenditures for 2010 – 2013 include loadings and AFUDC, and exclude costs of removal.

2010	Actual Expenditure ($000s)
Generation - Regular Capital	
All Plants Upgrade Station Service Supply	1,228
SLC Plant Completion	649
UBO Old Unit Repowering (Ph.1)	318
LBO & UBO Comm. Network Comp.	257
All Plants Lighting Upgrade	256
UBO Extension Trash Rack Gantry Replacement	204
Generation Regular Capital less than $0.2 million	876
Subtotal Generation - Regular Capital	**3,788**
Generation - Major Projects	
SLC U1 Life Extension (replace turbine)	1,591
COR U1 Life Extension (replace Turbine)	9,647
COR U2 Life Extension (replace turbine)	3,505
Subtotal Generation - Major Projects	**14,743**
Total Generation Capital	**18,531**
Transmission-Station-Distribution Regular Capital	
Naramata Rehab	(506)
Huth Split Bus	241
Capitalized Inventory	(580)
Recreation Capacity Increase Stage 1,2,3	3,447
Kelowna Distribution Capacity Requirements	493
30L Conversion Slocan / Coffee Creek Stns	3,689
Distribution Automation	1,488
Protection & Communication Upgrades	680
Transmission Line Sustaining	3,428
Station Sustaining	3,140
Customer New Connections	15,927
Distribution Condition Assessment	605
Distribution Rehabilitation	2,779
Distribution Pine beetle Hazard Allocation	856
Distribution ROW Reclamation	578
Distribution Line Rebuilds	1,031
Small Planned Capital	644
2010 FortisBC Forced Upgrades (Gross)	3,265
Distribution Urgent Repairs	385
Copper Conductor Replacement Program	2,226
PIC Audit	234
Small Capacity Improvements Unplanned	749
Airport Way Upgrade (Ellison Feeder 3)	822
Beaver Park Feeder 2 to Fruitvale Feeder 1 Distribution Tie Upgrade	837
Transmission-Station-Distribution Regular Capital less than $0.2 million	498
Subtotal Transmission-Station-Distribution Regular Capital	**46,957**

2010	Actual Expenditure ($000s)
Transmission-Station-Distribution Major Projects	
Okanagan Transmission Reinforcement	55,715
Benvoulin Distribution Source	11,435
Subtotal Transmission-Station-Distribution Major Projects	**67,150**
Total Transmission-Station-Distribution Capital	**114,107**
Other - Regular Capital	
Mandatory Reliability Compliance (MRC)	1,811
Vehicles	1,318
Metering	187
Information Systems	4,309
Telecommunications	52
Buildings	948
Furniture & Fixtures	268
Tools & Equipment	507
Subtotal Other - Regular Capital	**9,400**
Other - Major Projects	**-**
Total Other Capital	**9,400**
Total Gross Capital Expenditures	**142,038**
Reconciliation to Table C5-1	
Less Loadings	(14,686)
Less AFUDC	(4,733)
Add Costs of Removal	7,872
Total Capital Expenditures from Table C5-1	**130,491**

2011	Actual Expenditure ($000s)
Generation - Regular Capital	
All Plants Upgrade Station Service Supply	927
All Plants Minor Sustaining Projects	469
South Slocan Fire Panel	269
Lower Bonnington Power House Windows	244
South Slocan Plant Automation	208
Generation Regular Capital less than $0.2 million	346
Subtotal Generation - Regular Capital	**2,463**
Generation - Major Projects	
Corra Linn Unit 1 Life Extension (replace Turbine)	2,990
Corra Linn Unit 2 Life Extension (replace Turbine)	12,090
Subtotal Generation - Major Projects	**15,080**
Total Generation Capital	**17,543**
Transmission-Station-Distribution Regular Capital	
Ellison Sexsmith Transmission Tie	638
Huth Split Bus	3,612
Capitalized Inventory & Transformers	727
30L Conversion Slocan / Coffee Creek S/Stns	314
Transmission Line Urgent Repairs	412
Transmission Right of Way Acquisition / Easements	354
Transmission Line Condition Assessment	459
Transmission Line Rehabilitation	1,216
Station Life & Deficiency/Condition Assessment Program	612
Station Unforseen /Urgent Repairs	702
Lambert 230kv Switch Replacement	313
Okanagan Mission Load Tap Changer (LTC) Upgrade	901
Add Arc Flash Detection to Legacy Metal Clad Switchgear	286
Passmore - 19L Breaker	1,907
Creston Substation Protection Upgrade	314
Distribution Station Automation	2,162
Protection Upgrades (LEE to Vernon 230kV Protection Upgrade)	1,741
Communication Upgrades	234
Gross New Connects System Wide	16,409
Distribution Unplanned Growth Projects	981
Distribution Condition Assessment	1,080
Distribution Rehabilitation	2,222
Distribution Line Rebuilds	1,610
Small Planned Capital	685
Distribution Forced Upgrades	1,463
Distribution Urgent Repairs	1,541
Transmission-Station-Distribution Regular Capital less than $0.2 million	217
Subtotal Transmission-Station-Distribution Regular Capital	**43,112**

2011	Actual Expenditure ($000s)
Transmission-Station-Distribution Major Projects	
Okanagan Transmission Reinforcement	12,821
Benvoulin Distribution Source	993
PCB Environmental Compliance	1,718
Subtotal Transmission-Station-Distribution Major Projects	**15,533**
Total Transmission-Station-Distribution Capital	**58,644**
Other - Regular Capital	
Mandatory Reliability Compliance (MRC)	872
Buildings 2011	1,178
Emergency Building Upgrades	109
Furniture & Fixtures	230
Fleet	2,664
Automatic Vehicle Locator (AVL)	431
Telecommunications	315
Infrastructure Upgrade	1,144
Desktop Infrastructure Upgrade	952
SAP Operations Systems Enhancements	1,268
AM / FM Enhancements	464
Customer Service Systems Enhancements	1,001
Meter	316
Tools	609
Subtotal Other - Regular Capital	**11,554**
Other - Major Projects	
Kootenay Long Term Facility Strategy	433
Okanagan Long Term Solution	190
Subtotal Other - Major Projects	**624**
Total Other Capital	**12,178**
Total Gross Capital Expenditures	**88,365**
Reconciliation to Table C5-1	
Less Loadings	(15,590)
Less AFUDC	(1,833)
Add Costs of Removal	5,267
Total Capital Expenditures from Table C5-1	**76,209**

2012	Actual Expenditure ($000s)
Generation - Regular Capital	
All Plants Concrete & Structural Rehabilitation	269
Upper Bonnington Spillgate Rebuild / Upgrade	1,614
Lower Bonnington Power House Windows	463
All Plants Minor Sustaining Projects	773
Upper Bonnington Old Plant Various Unit Upgrades	217
Lower Bonnington, Upper Bonnington & Corra Linn Fire Panels	280
All Plants Upgrade Station Service Supply	1,217
Generation Regular Capital less than $0.2 million	127
Subtotal Generation - Regular Capital	**4,959**
Generation - Major Projects	
Corra Linn Unit 1 Life Extension (replace Turbine)	46
Corra Linn Unit 2 Life Extension (replace Turbine)	2,600
Corra Linn Unit 3 Completion	281
Subtotal Generation - Major Projects	**2,927**
Total Generation Capital	**7,886**
Transmission-Station-Distribution Regular Capital	
Huth Split Bus	1,266
Capitalized Inventory	247
Transmission Line Urgent Repairs	490
Transmission Right of Way Acquisition / Easements	439
6 Line / 26 Line River Crossing Reconfiguration	498
Transmission Line Condition Assessment	461
Transmission Line Rehabilitation	2,469
21-24 Lines Rebuild (Generation Plants)	714
27 Line Rebuild (Corra Linn - Salmo)	959
Station Assessment / Minor Planned Projects	1,337
SCADA Systems Sustainment	767
Station Unforseen /Urgent Repairs	568
Add Arc Flash Detection to Legacy Metal Clad Switchgear	361
Protection Upgrades (F.A. Lee Stn. to Vernon 230kV Protection Upgrade)	(403)
Communication Upgrades	388
New Connects System Wide	15,665
Distribution Small Growth Projects	639
Distribution Unplanned Growth Projects	777
Distribution Condition Assessment	847
Distribution Rehabilitation	2,882
Distribution Line Rebuilds	1,051
Small Planned Capital	600
Distribution Forced Upgrades	1,151
Distribution Urgent Repairs	2,313
Transmission-Station-Distribution Regular Capital less than $0.2 million	465
Subtotal Transmission-Station-Distribution Regular Capital	**36,948**

2012	Actual Expenditure ($000s)
Transmission-Station-Distribution Major Projects	
Okanagan Transmission Reinforcement	3,825
PCB Environmental Compliance	4,167
Subtotal Transmission-Station-Distribution Major Projects	**7,992**
Total Transmission-Station-Distribution Capital	**44,940**
Other - Regular Capital	
Mandatory Reliability Compliance (MRC)	112
Buildings	1,536
Furniture & Fixtures	113
Fleet	1,944
Automatic Vehicle Locator (AVL)	15
Telecommunications	99
Infrastructure Sustainment	1,219
Desktop Infrastructure Sustainment	1,223
Applications Enhancements	1,267
Application Sustainment	1,192
Power Sense DSM Reporting Software	115
Meter	446
Tools	531
Subtotal Other - Regular Capital	**9,812**
Other - Major Projects	
Kootenay Long Term Facility Strategy	360
Okanagan Long Term Solution	48
Central Warehousing	1,634
Subtotal Other - Major Projects	**2,042**
Total Other Capital	**11,854**
Total Gross Capital Expenditures	**64,680**
Reconciliation to Table C5-1	
Less Loadings	(15,510)
Less AFUDC	(489)
Add Costs of Removal	3,710
Total Capital Expenditures from Table C5-1	**52,393**

2013	Actual Expenditure ($000s)
Generation - Regular Capital	
All Plants Concrete & Structural Rehabilitation	384
All Plants Minor Sustaining Projects	1,074
UBO Old Plant Various Unit Upgrades	514
UBO, SLC & Corra Linn Power House Windows	215
LBO, UBO & Corra Linn Fire Panels	312
All Plants Public Safety & Security	214
Generation Regular Capital less than $0.2 million	37
Subtotal Generation - Regular Capital	**2,750**
Generation - Major Projects	
COR U2 Life Extension (replace Turbine)	450
Subtotal Generation - Major Projects	**450**
Total Generation Capital	**3,200**
Transmission-Station-Distribution Regular Capital	
Ellison Sexsmith Transmission Tie	7,107
Capitalized Inventory & Transformers	478
Transmission Line Urgent Repairs	498
Transmission Right of Way Acquisition / Easements	414
6 Line / 26 Line River Crossing Reconfiguration	720
Transmission Line Condition Assessment	502
20 Line Rebuild (Warfield Terminal - Salmo)	2,072
Transmission Line Rehabilitation	2,544
21-24 Lines Rebuild (Generation Plants)	1,625
Station Assessment / Minor Planned Projects	910
SCADA Systems Sustainment	759
Station Unforseen /Urgent Repairs	734
Add Arc Flash Detection to Legacy Metal Clad Switchgear	497
Communication Upgrades	414
Gross New Connects System Wide	16,070
Ellison Feeder 2 - Sexsmith Feeder 1 Tie	1,141
Distribution Small Growth Projects	932
Distribution Unplanned Growth Projects	730
KSA2 - Saucier Feeder Upgrade	626
Distribution Condition Assessment	1,491
Distribution Rehabilitation	1,697
Distribution Line Rebuilds	2,913
Small Planned Capital	896
Underground Cable Replacement	1,404
Distribution Forced Upgrades	2,231
Distribution Urgent Repairs	2,852
41 Line Salvage & Distribution Underbuild Rehabilitation	736
Switcher Replacements	1,322
Transmission-Station-Distribution Regular Capital less than $0.2 million	294
Subtotal Transmission-Station-Distribution Regular Capital	**54,607**

2013	Actual Expenditure ($000s)
Transmission-Station-Distribution Major Projects	
COK Acquisition	37,766
PCB Environmental Compliance	12,781
Subtotal Transmission-Station-Distribution Major Projects	**50,547**
Total Transmission-Station-Distribution Capital	**105,154**
Other - Regular Capital	
Buildings	907
Kootenay Long Term Facility Strategy	(513)
Okanagan Long Term Solution	50
Central Warehousing	906
Furniture & Fixtures	125
Fleet	3,054
Telecommunications	187
Application Sustainment	1,238
Infrastructure Sustainment	1,143
Desktop Infrastructure Sustainment	1,147
Applications Enhancements	1,271
Power Sense DSM Reporting Software	905
Meter	703
Tools	467
Subtotal Other - Regular Capital	**11,589**
Other - Major Projects	
Trail Buildings Purchase	10,000
Advanced Metering Infrastruture	13,834
Subtotal Other - Major Projects	**23,834**
Total Other Capital	**35,423**
Total Gross Capital Expenditures	**143,777**
Reconciliation to Table C5-1	
Less Loadings	(16,174)
Less AFUDC	(449)
Add Costs of Removal	6,039
Total Capital Expenditures from Table C5-1	**133,193**

Note: 2013 Forecast based on July 5th filing data.

The table provided below details the breakdown of forecast expenditures for Regular Capital and Major Projects for 2014-2018 by Generation, Transmission-Station-Distribution, and Other Capital. The forecast expenditures are based on the five year capital forecast as discussed in Section C5 of the Application (Exhibit B-1), and not the capital expenditures as determined by the PBR formula. The forecast expenditures exclude loadings and AFUDC and include costs of removal. For the 2014-2018 period, Major Projects are those capital expenditures excluded from the formula –driven portion of the PBR Plan (AMI and PCB projects as well as future CPCN projects).

Regular Capital	**2014**	**2015**	**2016**	**2017**	**2018**
	($000s)				
Generation	3,155	2,940	2,944	3,010	2,847
Transmission-Station-Distribution	40,225	39,835	39,233	41,379	45,867
Other Capital	9,610	10,788	13,738	10,247	10,162
Major Projects	**2014**	**2015**	**2016**	**2017**	**2018**
	($000s)				
Generation	-	-	3,743	14,620	8,555
Transmission-Station-Distribution	10,886	-	1,848	7,941	21,860
Other Capital	25,239	25,934	-	-	-
Pension Adjustments	(345)	(789)	(1,233)	(1,608)	(1,915)
Total Capital Expenditures	**88,770**	**78,708**	**60,272**	**75,588**	**87,376**
Reconciliation to Table C5-3					
Less Major Projects (except AMI and PCB Compliance)	13,594	8,273	5,590	22,560	30,415
Total Forecast Capital Expenditures as per Table C5-3	**75,176**	**70,435**	**54,681**	**53,028**	**56,961**

Note: 2014-2018 Forecast based on July 5th filing data.

47.0 Reference: Exhibit B-1, pp. 55–56

2013 Base Capital

"FBC has used the approved capital expenditures for 2013 from the 2012-2013 RRA Decision as the starting point for the capital formula. Similar to the methodology used to arrive at the 2013 O&M Base for PBR, the adjustments to arrive at the 2013 Base Capital include:

1. Adjustment for non-recurring major projects, as detailed in Table C5-2; and

2. Adjustments to include 2013 actual 'non-controllable' items equivalent to those included in the Base O&M calculation." (Exhibit B-1, p 55-56)

FBC has provided Table C4-2 illustrating that there are sustainable O&M savings which would be used to adjust the 2013 Approve O&M figure in order to arrive at the 2013 Base O&M. However, to arrive at the 2013 Base capital figure, FBC proposes to adjust the 2013 Approve capital by the 2 items listed in the preamble above.

47.1 Please provide a list of the capital investments made during the last RRA (2012–2013) that would have resulted in capital savings (avoided capital) during subsequent periods. Please clarify whether FBC has included these capital savings as a downward adjustment to the 2013 Base capital, similar to the approach used to determine the 2013 Base O&M?

<u>Response:</u>

By their nature, most capital investments also result in some degree of future avoided capital. This is typically most evident with sustainment capital projects: by investing in consistent and appropriate levels of sustainment capital, the likelihood of future uncontrolled equipment failures is greatly reduced. Major equipment failures can result in significant damage to assets and can be very costly to repair (especially when compared to ongoing sustainment capital costs). The associated adverse safety and reliability impacts, while difficult to quantify in dollar terms, can also be substantial.

Similar to maintenance activities, if insufficient levels of sustainment capital are invested, then the average asset age will increase and hence the overall asset health will deteriorate over time. On this basis, most of the capital investments made during the 2012-13 RRA term will result in future avoided capital (and hence a listing is superfluous). Quantifying this future capital savings is very difficult. However, FBC has approached this issue on the basis that if appropriate levels of sustainment capital are invested as proposed in the 2014-18 PBR plan, then the likelihood of sporadic high-cost and/or recurrent low-cost unforeseen failures is greatly mitigated. Additionally, the need to increase future capital investments to catch-up with deferred work is reduced. Hence, the savings associated with increased unforeseen failures or significant future capital increases is already incorporated in the proposed PBR plan.

Please refer to the responses to BCUC IRs 2.43.2 and 2.43.3.

47.2 Of these expected capital savings during the PBR term, should the ratepayers receive 100 percent of the benefits as opposed to a 50/50 sharing through the ESM, given that the investments were made prior to the start of the PBR? Please explain why or why not.

Response:

As discussed in the response to BCUC IR 2.47.1, given that FBC has proposed a level of sustainment capital necessary to avoid sporadic high-cost and/or recurrent low-cost unforeseen failures, customers are already receiving 100 percent of the benefit associated with the avoidance of these capital costs. Simply put, the level of 2013 Base Capital is lower than it otherwise would be in the absence of these avoided capital costs.

E. FINANCING AND ACCOUNTING POLICIES

48.0 Reference: Exhibit B-1, p. 245; Order G-117-11; Exhibit B-7, BCUC 1.175; Exhibit A2-2, Appendix A of FBC's 2012 BCUC Annual Report

US GAAP Reconciliation

48.1 Please confirm, or explain otherwise, that Appendix A of FBC's 2012 BCUC Annual Report reconciles amounts reported under Canadian GAAP for financial reporting purposes to amounts reported under US GAAP for regulatory accounting purposes.

<u>Response:</u>

Confirmed. The reconciliation in Appendix A of FBC's 2012 BCUC Annual Report is consistent with Commission Order G-117-11, which approved FBC to adopt US GAAP for regulatory accounting purposes, and stated that:

> *"each of the Fortis BC Utilities' entities adopting US GAAP shall prepare a <u>reconciliation of amounts reported for regulatory accounting</u> to those amounts that would otherwise be reported <u>under 2011 Canadian GAAP</u>. This reconciliation should be included in annual reports and revenue requirements applications up to December 31, 2014."* [emphasis added]

The first part of this excerpt of G-117-11 clearly refers to regulatory accounting, while the comparative to the second amount is only referring to "2011 Canadian GAAP". The latter has been interpreted as 2011 Canadian GAAP used for external financial reporting purposes prior to changeover (i.e. Canadian GAAP prior to Canadian accounting standard-setters adopting IFRS as generally accepted accounting principles in Canada) since the BCUC has only approved US GAAP for regulatory purposes for 2012 and, effective January 1, 2012, pre-changeover Canadian GAAP no longer exists as a financial reporting option for FBC. Canadian GAAP prior to 2011 has been replaced with either IFRS or ASPE (Accounting Standards for Private Enterprises). Therefore, Appendix A includes a reconciliation from the amounts reported under US GAAP for regulatory accounting purposes and the estimated amounts reported under Canadian GAAP for external financial reporting purposes.

Despite the fact that pre-changeover Canadian GAAP no longer exists as a financial reporting option, the column labeled "Corporate Canadian GAAP" in Appendix A is the estimated amount that would be reported under 2011 Canadian GAAP for external financial reporting purposes.

The column labelled "Regulated Adjustment" indicates the adjustments required to reconcile from "Corporate Canadian GAAP" to "Regulated".

48.2 Please provide a 2012 reconciliation of amounts reported for **regulatory** accounting under US GAAP to amounts that would otherwise be reported for **regulatory** accounting under Canadian GAAP.

Response:

In theory, there would be no difference between US GAAP and pre-changeover Canadian GAAP for regulatory accounting purposes as they both permit accounting based on the regulator's actions, while IFRS currently does not currently permit rate-regulated accounting.

FBC interprets this question as a request for a reconciliation that differs from what is currently required under Commission Order G-117-11, as discussed in the response to BCUC IR 2.48.1, and that the request is hypothetical in nature with the benefit of hindsight. Additionally, the question is being interpreted that the reference to Canadian GAAP is actually referring to pre-changeover Canadian GAAP from 2011, which no longer exists as a financial reporting option for FBC, and not IFRS which is what is published as current Canadian GAAP.

In addition, if the intent of the question is an attempt to isolate the impact of adopting US GAAP for regulated accounting purposes using hindsight, it is actually misleading to compare to pre-changeover Canadian GAAP from 2011. When the FortisBC Utilities made initial application to the BCUC on February 9, 2011 for approval to adopt US GAAP for regulated accounting purposes, the options included only US GAAP or IFRS and did not include a third option of pre-changeover Canadian GAAP as it no longer existed as an accounting option for FBC. If the intent of the Commission or Commission staff is to determine the effect of adopting US GAAP for regulatory purposes, the only option in 2012 and onwards that US GAAP can be compared to is IFRS, which would result in significant differences and would be very complex to reconcile. In absence of an IFRS comparison, there should be a degree of comfort in that FBC has not brought forward any significant accounting issues that arise specifically from US GAAP as part of its 2014-2018 PBR Application. In other words, when comparing the drivers in determining the revenue requirements for the PBR period, there are none that are specifically attributable to US GAAP.

Despite the lack of relevance in preparing a reconciliation for 2012 reported amounts comparing regulatory accounting for US GAAP to regulatory accounting for pre-changeover Canadian GAAP, it has been included as follows, with the caveat that a certain amount of assumptions have been required to estimate the pension and OPEB items without performing a full actuarial accounting valuation.

RECONCILIATION OF FINANCIAL STATEMENTS
US GAAP vs. Pre-Changeover Canadian GAAP
REGULATED BALANCE SHEET
YEAR ENDED DECEMBER 31, 2012

	US GAAP Regulated	REF	Reconciled Items	CGAAP Regulated
ASSETS				
Plant and Equipment & Intangibles	1,615,456	(1)	127	1,615,583
Less accumulated depreciation	(395,823)			(395,823)
	1,219,633		127	1,219,760
Other Assets	12,288	(2)	(91)	12,197
Non-Rate Base Assets	161,152			161,152
	173,440		(91)	173,349
Goodwill	-			
Current Assets				
Cash	1,164			1,164
Accounts receivable	41,514	(3)	124	41,638
Prepaid expenses	929			929
Inventory	469			469
	44,076		124	44,200
TOTAL ASSETS	**1,437,149**		**160**	**1,437,309**
CAPITAL AND LIABILITIES				
Capitalization				
Shareholder's Equity				
Common shares	180,122			180,122
Retained earnings	293,201	(4)	3	293,204
Total Shareholder's Equity	473,323		3	473,326
Long-Term Debt				
Secured debentures	25,000			25,000
Unsecured debentures	600,000			600,000
Term bank loans and other	34,977			34,977
Total Long-Term Debt	659,977		-	659,977
Contributions in Aid of Construction	97,671			97,671
Capital Lease and Finance Obligations (non-rate base)	25,531			25,531
Pension and other post-employment benefits (non-rate base)	18,941	(1)	154	19,095
Asset Retirement Obligation (non-rate base)	2,785			2,785
Deferred Income Taxes (non-rate base)	110,202			110,202
Deferred Income Taxes	418			418
	157,877		154	158,031
Current Liabilities				
Accounts payable and accrued liabilities	39,904			39,904
Income taxes payable	1,059	(5)	1	1,060
Accrued interest	7,338	(5)	2	7,340
	48,301		3	48,304
TOTAL CAPITAL AND LIABILITIES	**1,437,149**		**160**	**1,437,309**

RECONCILIATION OF FINANCIAL STATEMENTS
US GAAP vs. Pre-Changeover Canadian GAAP
STATEMENT OF REGULATED EARNINGS
YEAR ENDED DECEMBER 31, 2012

	US GAAP Regulated	REF	Reconciled Items	CGAAP Regulated
			($ thousands)	
REVENUE				
Sale of power	282,943	(3)	124	283,067
Other	9,166			9,166
	292,109		124	292,233
EXPENSES				
Power purchase costs	75,999			75,999
Operating costs	42,573	(1)	118	42,691
Wheeling	4,813			4,813
Property taxes	13,912			13,912
Water fees	9,253			9,253
Depreciation and Amortization of Deferreds	48,588			48,588
	195,138		118	195,256
EARNINGS FROM OPERATIONS	96,971		6	96,977
OTHER INCOME	104			104
INTEREST EXPENSE				
Long-term debt	38,422			38,422
Short-term debt	265	(5)	2	267
	38,687		2	38,689
REGULATORY INCENTIVE ADJUSTMENTS	781			781
EARNINGS BEFORE INCOME TAXES	57,607		4	57,611
INCOME TAXES	9,097	(5)	1	9,098
NET EARNINGS	**48,510**	(4)	**3**	**48,513**

Footnote References for Balance Sheet and Income Statement:

1. Pre-changeover Canadian GAAP would result in an increase of approximately $245 thousand in pension and OPEB expense of which approximately $127 thousand would have been included in capital expenditures and approximately $118 thousand in O&M expense. The components of this change in pension and OPEB expense are as follows (expressed in $000s):

Increase in Pension Expenses under Canadian GAAP	437
Amortization of US GAAP Pension Transitional Obligation	(183)
Amortization of US GAAP OPEB Transitional Obligation	(163)
Subtotal - Pension Adjustment	91
Increase in OPEB Expenses under Canadian GAAP	154
Total Increase in Pension and OPEB Expenses under Canadian GAAP	245

2. The change in other assets is due to the difference between Pension and OPEB expenses, assets and obligations under US GAAP and pre-changeover Canadian GAAP, as follows (expressed in $000s):

Increase in Pension Expenses under Canadian GAAP	(437)
US GAAP Pension Transitional Assets removed under Canadian GAAP	(2,011)
US GAAP Pension Transitional Obligation removed under Canadian GAAP	2,194
US GAAP OPEB Transitional Assets removed under Canadian GAAP	(1,800)
US GAAP OPEB Transitional Obligation removed under Canadian GAAP	1,963
Total adjustment under Canadian GAAP	(91)

   Note that FBC utilized a September 30 measurement date under pre-changeover Canadian GAAP, as compared to a December 31 measurement date required under US GAAP (and IFRS), therefore 2012 pension and OPEB net benefit cost adjustment was expected to be increased due to a decrease in the discount rate of 4.5% to 4.25%. In addition, and for simplicity purposes, the US GAAP Pension and OPEB Transitional Obligations have been offset against the Prepaid Pension Costs included in Other Assets.

3. The increase in pension and OPEB expense under pre-changeover Canadian GAAP would have resulted in a recalculation of revenue requirements resulting from increases in O&M expense, rate base, cost of debt, allowed equity and income taxes. Accounts receivable in the balance sheet has been correspondingly adjusted.

4. The increase in pension and OPEB expense under pre-changeover Canadian GAAP would increase capital expenditures and therefore rate base, thereby increasing net earnings (allowed return on equity).

5. The increase in pension and OPEB expense under pre-changeover Canadian GAAP would have increased net earnings (allowed return on equity), which then increases cost of debt and income taxes. The relevant balance sheet accounts for interest and income taxes have been correspondingly adjusted.

48.2.1 Please provide an explanation for each reconciling item included in the reconciliation provided in the response to the preceding IR.

Response:

Please refer to the response to BCUC IR 2.48.2.

48.2.2 For each reconciling item provided in the preceding IR, please discuss if FBC anticipates that the reconciling items for 2013 and beyond will vary significantly from those reported in 2012 and explain why or why not.

Response:

All reconciling items in the response to BCUC IR 2.48.2 pertain to pension and OPEB and this difference was previously highlighted in FBC's 2012-2013 RRA, under the heading "Generally Accepted Accounting Principles (GAAP) Used in Determining Revenue Requirements" of Tab 2 - Accounting Policy, which stated that "the accounting policies included in pre-changeover CGAAP, including the ability to recognize rate regulated accounting, are generally consistent with US GAAP for regulatory purposes, with the exception of the accounting for employee future benefits." While the 2012 pension and OPEB expense increased by approximately $245 thousand from US GAAP to pre-changeover Canadian GAAP, pension and OPEB expense will continue to differ, magnify on a prospective basis, and become more costly and complex to reconcile.

Pension and OPEB expense are included in loadings that affect capital expenditures and rate base. Based on FBC's depreciation policy, which has been approved by the BCUC, depreciation is calculated on a straight-line basis on the utility property, plant and equipment in service at the beginning of the year. As such, the 2012 regulatory accounting differences in capitalizing pension and OPEB expense will not manifest themselves in depreciation until 2013, at which point capital expenditures balances will begin to diverge and become more complex. To appropriately track the relevant regulatory accounting differences in pre-changeover Canadian GAAP capital expenditures, rate base, cost of debt, cost of equity, income taxes, depreciation, O&M expense and revenue, FBC would be required to invest in creating and maintaining another accounting system to track in parallel with US GAAP for regulatory purposes. The concept of maintaining a second set of accounting records and system solely for purposes of hypothetical exercise contradicts the whole principle behind adopting US GAAP for regulated accounting purposes which was to maintain consistency between regulatory and external reporting.

While the pension and OPEB balances, used for both Appendix A of the BCUC Annual Report and for the response to BCUC IR 2.48.2, have been estimates made by an external actuary, a more complete and costly actuarial accounting valuation would be required each year on a prospective basis. This is also expected to become more complex as FBC's employee future benefits measurement date was September 30 under pre-changeover Canadian GAAP and required to be December 31 under US GAAP (and IFRS). Differences in pension and OPEB expense will magnify as actuarial assumptions will potentially change between the differencing three months, particularly the discount rate which has a greater sensitivity on net benefit cost. As stated in the response to BCUC IR 1.175.2 there would be "*incremental actuarial services to compile and re-create pension and OPEB balances that would have been reported under pre-changeover Canadian GAAP which are no longer tracked or maintained*."

To conclude, continuing to prepare the reconciliation in Appendix A of the Annual Report as required under Commission Order G-117-11, or the reconciliation requested in the response to BCUC IR 2.48.2, will become increasingly costly and complex, while providing minimal relevance, hence FBC's request in the 2014-2018 PBR Application to discontinue the US GAAP to Canadian GAAP reconciliation starting with the 2013 BCUC Annual Report.

49.0 Reference: Exhibit B-1-6, pp. 2 and 4–5

Depreciation Rates

"Depreciation expense for 2014 through 2018 has been updated to reflect the changes in depreciation rates for AMI meters, AMI Computer Equipment and Software, AMI Communications Structures and Equipment approved pursuant to Order C-7-13." (Exhibit B-1-6, p. 5)

According to Table 2 of Exhibit B-6-1 on page 2, the increase to depreciation expense between 2014 through 2018, as compared to the Original Application (Exhibit B-1), is $3,316 thousand.

"Based on experience gained from executing recent capital plans, the Company is currently projecting a lump-sum carry-over from 2013 to 2014 and 2015." (Exhibit B-1-6, p. 4)

49.1 Please provide a comparison of the depreciation rates used in both the original Application (Exhibit B-1) and the Evidentiary Update (Exhibit B-1-6) for each of AMI meters, AMI Computer Equipment and Software, AMI Communications Structures and Equipment.

Response:

The comparison follows:

RRA 2014 First Filing (5th July 2013) Exhibit B-1	Depr. Rate
AMI Meter	5.00%
AMI Computer Equipment & Software	5.01%
AMI Communications Structure & Equip.	8.05%

RRA 2014 Evidentiary Update Filing Exhibit B-1-6	Depr. Rate
AMI Meter	5.00%
AMI Computer Equipment & Software	10.00%
AMI Communications Structure & Equip.	6.67%

49.2 Please explain if the $3,316 thousand increase in depreciation and amortization expense is the annual increase as compared to the original Application or the cumulative increase between 2014 through 2018.

Response:

The $3,316 thousand increase in depreciation and amortization expense is the cumulative increase between 2014 through 2018 as indicated in the Table below.

Please refer to the response to BCPSO IR 2.29.1.

Depreciation & Amortization (Incremental)	**2014**	**2015**	**2016**	**2017**	**2018**	**Total**
	($000s)					
Depreciation & Amortization	(604)	(489)	1,720	1,313	1,375	**3,316**

49.2.1 If the $3,316 thousand increase in depreciation and amortization expense is the cumulative increase between 2014 through 2018, please provide a breakdown by year.

Response:

Please refer to the responses to BCUC IR 2.49.2 and BCPSO IR 2.29.1.

49.2.2 Please provide a breakdown of the $3,316 thousand increase in depreciation and amortization expense, by year, between the following:

i. Increase attributable to changes in depreciation rates for AMI meters, AMI Computer Equipment and Software, AMI Communications Structures and Equipment;

ii. Increase attributable to lump-sum carry-over of capital projects from 2013 to 2014 and 2015; and

iii. Other.

Response:

The difference of $3,316 thousand in Depreciation and Amortization expense from the July 5, 2013 filing is primarily driven by directives in the AMI Decision and the changes incorporated in the October 18, 2013 Evidentiary Update, including the deferral of 2013 capital in addition to certain changes to Deferred Charges and other factors affecting the balance and amortization of the RSDM.

The table below provides a breakdown of the cumulative $3,316 thousand increase in depreciation and amortization expense, by year:

Depreciation Variance	2014	2015	2016	2017	2018	Total
AMI Meter Related	-	(728)	(12)	(12)	(12)	**(764)**
AMI Computer Equipment & Software Related	-	(70)	796	796	796	**2,318**
AMI Communication Structure & Equipment Related	-	110	276	222	167	**775**
All Other Capital Project Variance Related	(1,121)	11	(722)	(836)	(949)	**(3,617)**
Total Depreciation Variance	**(1,121)**	**(677)**	**338**	**170**	2	**(1,288)**
Deferred Amortization Variance	**2014**	**2015**	**2016**	**2017**	**2018**	**Total**
Deferred Amortization AMI Related	209	35	1,332	1,332	1,332	**4,240**
All Other	308	153	50	(189)	41	**363**
Total Deferred Amortization Variance	**517**	**188**	**1,382**	**1,143**	**1,373**	**4,604**
Total Depreciation & Amortization Variance	**(604)**	**(489)**	**1,720**	**1,313**	**1,375**	**3,316**

50.0 Reference: Exhibit B-7, BCUC 1.178.6–1.178.7

Capitalized Overhead

FBC provides the total dollars charged to Capitalized Overhead for the years 2010 to 2013 and the forecast for 2014–2018 as:

	Actual				Forecast				
	2010	2011	2012	2013	2014	2015	2016	2017	2018
Capitalized Overhead	9,529	10,777	10,969	11,524	12,277	12,349	12,192	12,476	12,660

FBC also states that “[i]t could be possible to utilize a percentage of forecast capital expenditures as an overheads capitalized allocator, however that approach would introduce higher variability in customer rates.” (Exhibit B-7, BCUC 1.178.7)

50.1 Using the table above, please include another line showing the Actual/Forecast capital expenditures for the same period. Please calculate the ratio of the capitalized overhead as a percentage of capital expenditures.

Response:

Please note that the following capital expenditure data for years 2010-2012 is from Table D3-2, Page 255 of Exhibit B-1 of the Application and capital expenditure data for years 2013–2018 is from Table C5 – 3, revised Page 182 of the Evidentiary Update October 18, 2013, Exhibit B-1-6.

($000s)

	Actual			Base	Forecast				
	2010	2011	2012	2013	2014	2015	2016	2017	2018
Capitalized Overhead	9,529	10,777	10,969	11,524	12,277	12,349	12,192	12,476	12,660
Base Capital Expenditures	55,036	48,452	42,091	49,180	102,716	80,432	54,681	53,028	56,960
Capitalized Overhead as a Percentage of Base Capital Expenditures	17.3%	22.2%	26.1%	23.4%	12.0%	15.4%	22.3%	23.5%	22.2%

50.1.1 What is the average capitalized overhead rate using this method for the years 2010–2013?

Response:

The average capitalized overhead rate for the years 2010-2013, using capitalized overhead dollars as a percentage of base capital expenditures, is 22.3 percent.

Please refer to the response to BCUC IR 2.50.1.

50.1.2 Using the average capitalized overhead rate in the preceding question, please calculate the forecast capitalized overhead dollars for the years 2014-2018. Compare the rate increases for each year using this method versus the rate increase each year using the current method.

Response:

The following table illustrates the impact of utilizing a percentage of forecast base capital expenditures as an overheads capitalized allocator. Applying such an allocator can result in significant rate impacts and volatility. This methodology is problematic from a number of perspectives including:

- Determining the appropriate allocation factor. In this example, taking an average of 2010 to 2013 results in a higher allocation factor due to the relative low capital expenditures in the years 2011, 2012 & 2013; and
- Capital expenditures can be much more variable year over year than Operating and Maintenance expenditures and thereby can introduce greater variability in the relative amount of overheads capitalized year over year under this methodology.

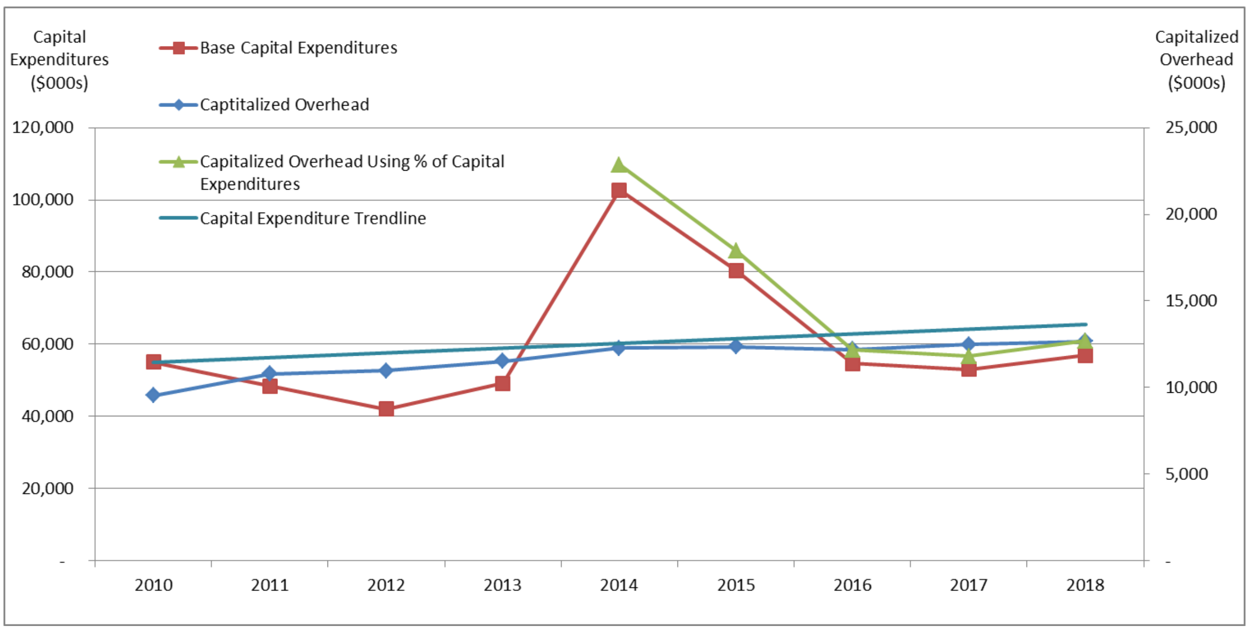
The Company is of the opinion that an overheads capitalized allocation factor that is a function of Operating and Maintenance expense provides an overheads capitalized amount that is more stable and thereby reduces variability in customer rates.

	($000s)				
	Forecast				
	2014	**2015**	**2016**	**2017**	**2018**
Capitalized Overhead calculated as 20% of O&M Expense	12,277	12,349	12,192	12,476	12,660
Capitalized Overhead calculated as 22.3% (response to BCUC IR 2.50.1.1) of Base Capital Expenditures (response to BCUC IR2.50.1)	22,906	17,936	12,194	11,825	12,702
Rate Increase with Capitalized Overhead calculated as 20% of O&M Expense	3.30%	3.60%	3.60%	3.60%	3.60%
Rate Increase (Decrease) with Capitalized Overhead calculated as 22.3% (response to BCUC IR 2.50.1.1) of Base Capital Expenditures (response to BCUC IR 2.50.1)	(1.20%)	6.30%	6.20%	3.90%	3.30%

50.1.3 Please plot another line in the graph provided in response to BCUC 1.178.7 using this method.

Response:

The green plot line illustrates the variability of Capitalized Overhead dollars when applying the 22.3 percent capitalization overhead rate calculated in BCUC IR 2.50.1.1 to the forecast base capital expenditures over the 2014 – 2018 PBR period. Please refer to the responses to BCUC IRs 2.50.1 and 2.50.1.2.



51.0 Reference: Exhibit B-7, BCUC 1.179.4

Direct Overhead Loading

FBC explains that:

> "[t]he Direct Overhead loading for T&D capital projects is a loading methodology that allocates T&D costs that could be directly charged to the T&D capital but to take advantage of administrative efficiencies, the costs are charged to a holding account then allocated from that account using a Direct Overhead rate" (Exhibit B-7, BCUC 1.179.4).

51.1 Please explain why generation projects do not require this kind of loading methodology.

Response:

Generation projects do not include this type of loading because all Generation work includes an absorption loading amount designed to recover all of the costs incurred by Generation for the work undertaken. This absorption loading methodology has been adopted because FBC Generation operates and maintains several hydro-electric generating stations under contract for other third party entities. In order to allocate the appropriate Generation costs to the various third parties, the Company applies a Generation Absorption loading to each hour charged to the third party accounts. In this manner, all direct labour costs also attract an absorption loading amount.

This is different than the T&D Direct Overhead loading amount. The T&D Direct Overhead loading amount is only applied to T&D capital work and is a methodology that allocates direct costs to T&D capital work using an overhead loading percentage.

F. DEFERRAL ACCOUNTS

52.0 Reference: Exhibit B-1, pp. 285–288

Deferred Charges and Credits

52.1 For any deferral accounts with a variance between the 2013 additions approved by Order G 110-12 and the 2013 additions provided in Exhibit B-1 (Table 1-B), please provide the amount of the variance with an explanation to support the variance.

<u>Response:</u>

Table 1 – B in Exhibit B-1 was updated in the Company's October 18, 2013 Evidentiary Update filing (Exhibit B-1-6). The following analysis compares the deferral account additions approved by Order G-110-12 with the 2013 forecast additions in Table 1 – B of the Evidentiary Update (Exhibit B-1-6).

Note: all amounts are after tax impacts.

Account	Approved Additions	Forecast Additions	Variance	Comments
	($000s)			
Demand Side Management	5,909	4,455	(1,454)	Underspend in 2013 due to a drop in program participation following the termination of two provincial co-funding programs (commercial lighting, and residential home retrofit).
Deferred Debt Issue Costs	1,410	94	(1,316)	Due to variances in rate base, the $105 million debt issuance originally forecast in the second half of 2013 is now forecast to be issued as $100 million in the first half of 2014. Therefore the related debt issue costs have also been shifted from 2013 to 2014, with the exception of certain fees incurred in 2013 to set up the shelf prospectus program approved pursuant to Order G-74-13.
2014-2015 Capital Expenditure Plan (Engineering)	562	359	(203)	Lower than expected third-party consultant costs for preliminary engineering (less work was required to be outsourced).
2014 Revenue Requirements and 2014-15 CEP (Regulatory)	50	371	321	Refer to the response to BCUC IR 1.194.3.1.

Account	Approved Additions	Forecast Additions	Variance	Comments
	($000s)			
Prepaid Pension Costs & Other Post Employment Benefits (OPEB)	979	-3,780	(4,759)	As discussed in Section C4.3.3.4.2 of Exhibit B-1, the increase of this account as a credit amount is primarily due to the 2013 actuarial estimate of pension/OPEB expense that was completed to forecast 2013 is approximately 70 percent higher than the actuarial estimate that was completed in 2011 to establish the 2012-13 RRA forecasts and approved amounts. The increase in pension/OPEB expense is primarily due to the lower interest rate environment. Also contributing to this variance is lower pension contributions based on actuarial funding valuations.
Right of Way Encroachment Litigation	0	22	22	Refer to the responses to BCUC IRs 1.131.2.1, 1.208.4, 1.208.5 and 1.208.6.
Joint Pole Use Audit 2013	187	74	(113)	Variance due to costs for 2013 Audit lower than initially forecast, as well as timing. Project completion in 2013 delayed and will carry over into 2014.
Irrigation Ratepayer Group Consultation & Load Research	0	15	15	Variance due to timing. Installation of metering in 2012 delayed. Project carryover into 2013.
Variance Accounts				
Power Purchase Expense Variance	0	-6,643	(6,643)	Savings attributable to a combination of lower loads than forecast and favourable market conditions allowing displacement of forecast purchases under the BC Hydro PPA with market purchases. See also Section C2.3 (updated in the Evidentiary Update Exhibit B-1-6).
Revenue Variance	0	4,199	4,199	Variances in revenue mostly attributable to weather related load variances, customer usage rate variances and customer count load variances. Variance also includes adjustment to revenue arising from FBC's acquisition of the utility assets of the City of Kelowna. See also Section D 4.5.1.

Account	**Approved Additions**	**Forecast Additions**	**Variance**	**Comments**
	($000s)			
HST Removal/Reform Variance	0	607	607	Variance due to revenue requirement impact of reinstating PST, conversion costs and the 1 percent corporate tax rate increase reintroduced to balance the 2013/14 BC provincial budget as a result of eliminating HST. See also Section D 2.3.1. (updated in the Evidentiary Update Exhibit B-1-6).
Pension & OPEB Expense Variance	0	3,914	3,914	As discussed in Section C 4.3.3.4.2, the increase in this account, which is initially forecast as nil, is primarily due to the 2013 actuarial estimate of pension/OPEB expense that was completed to forecast 2013 is approximately 70 percent higher than the actuarial estimate that was completed in 2011 to establish the 2012-13 RRA forecasts and approved amounts. The increase is primarily due to the lower interest rate environment.

53.0 Reference: Exhibit B-1-6, pp. 285–288

Deferred Charges and Credits

53.1 For all deferral accounts included in Table 1-B of Exhibit B-1-6, please provide a table with the following information:

i. name of deferral account;
ii. financing costs approved by Order G-110-12;
iii. financing costs proposed in Exhibit B-1 and Exhibit B-1-6;
iv. amortization period approved by Order G-110-12; and
v. amortization period proposed in Exhibit B-1 and Exhibit B-1-6.

Response:

Please refer to the following tables.

	2013				2014			
	Financing		Amortization		Financing		Amortization	
Name	Proposed in Ex. B-1 & B-1-6	Approved by Order G-110-12 or other where noted	Proposed in Ex. B-1 & B-1-6	Approved by Order G-110-12 or other where noted	Proposed in Ex. B-1 & B-1-6	Approved by Order G-110-12 or other where noted	Proposed in Ex. B-1 & B-1-6	Approved by Order G-110-12 or other where noted
Energy Policy								
Demand Side Management	Rate Base	Rate Base[1]	10	10[2]	Rate Base	Rate Base[1]	15	N/A
Revenue and Power Supply Variance								
Rate Stabilization Deferral Mechanism (RDSM)	N/A	N/A	N/A	N/A	Rate Base	N/A	5	N/A
Power Purchase Expense Variance	ST	ST	N/A	N/A	Rate Base	ST	1	1
Revenue Variance	ST	ST	N/A	N/A	Rate Base	ST	1	1
Generic Cost of Capital (GCOC) Revenue Requirements Impact	N/A	N/A	N/A	N/A	Rate Base	N/A	1	N/A
Non-Controllable Items								
Pension & Other Post Employment Benefits (OPEB) Expense Variance	ST	ST	N/A	3	Rate Base	ST	11 (EARSL)	N/A
Prepaid Pension Costs and OPEB Liability	WACD	WACD	Life of Future Benefits	Life of Future Benefits	Rate Base	WACD	Life of Future Benefits	Life of Future Benefits
US GAAP Pension and OPEB Transitional Obligation	WACD	WACD	12	12	Rate Base	WACD	12	12
Property Tax Asset Valuation Review	ST	ST	N/A	N/A	N/A	ST	N/A	N/A
Interest Expense Variance	N/A	N/A	N/A	N/A	Rate Base	N/A	3	N/A
Insurance Expense Variance	N/A	N/A	N/A	N/A	Rate Base	N/A	1	N/A
Tax Variance	N/A	N/A	N/A	N/A	Rate Base	N/A	1	N/A
Property Tax Variance	N/A	N/A	N/A	N/A	Rate Base	N/A	3	N/A
Preliminary and Investigative Charges								
Preliminary and Investigative Charges	N/A	N/A	N/A	N/A	Rate Base	N/A	transferred to capital project or expensed (USoA)	transferred to capital project or expensed (USoA)
Kelowna Bulk Transformer Capacity Addition (KBTCA) Project	WACD	WACD	amortized into rates	amortized into rates	Rate Base	WACD	1	1
Regulatory Compliance								
2014-2018 Performance Based Ratemaking (PBR) Application	WACD	WACD	N/A	N/A	Rate Base	WACD	5	N/A
2014-2018 Annual Reviews	N/A	N/A	N/A	N/A	Rate Base	N/A	1	N/A
BC Hydro Application for Power Purchase Agreement with FBC	N/A	N/A	N/A	N/A	Rate Base	N/A	1	N/A
BCUC Generic Cost of Capital Proceeding	WACC	TBD[3]	N/A	N/A	Rate Base	TBD	2	N/A
BCUC Inquiry into the Mandatory Reliability Standards (MRS) Program	WACC	TBD[3]	N/A	N/A	Rate Base	TBD	1	N/A
Kettle Valley Expenditure Review	WACC	TBD[3]	N/A	N/A	Rate Base	TBD	1	N/A
Transmission Customer Rate Design	WACC	TBD[3]	N/A	N/A	Rate Base	TBD	1	N/A
City of Kelowna Acquisition Legal and Regulatory Costs	ST	ST[4]	N/A	N/A	Rate Base	ST[4]	1	N/A
Advanced Metering Infrastructure 2007 Application Costs	WACD	WACD[5]	N/A	N/A	Rate Base	WACD[5]	1	N/A

[1] G-47-89
[2] G-58-06
[3] G-23-13
[4] C-4-13
[5] G-162-09

	2013				2014			
	Financing		Amortization		Financing		Amortization	
	Proposed in Ex. B-1 & B-1-6	Approved by Order G-110-12 or other where noted	Proposed in Ex. B-1 & B-1-6	Approved by Order G-110-12 or other where noted	Proposed in Ex. B-1 & B-1-6	Approved by Order G-110-12 or other where noted	Proposed in Ex. B-1 & B-1-6	Approved by Order G-110-12 or other where noted
Other								
Earnings Sharing Mechanism (ESM) Deferral	N/A	N/A	N/A	N/A	Rate Base	N/A	1	N/A
Right of Way Reclamation (Pine Beetle Kill)	Rate Base	Rate Base[6]	10	10[6]	Rate Base	Rate Base[6]	10	10[6]
2012 Integrated System Plan - Engineering	WACD	WACD	5	5	Rate Base	WACD	5	5
2014-2018 Capital Expenditure Plan	WACD	WACD	N/A	N/A	Rate Base	WACD	2	N/A
2012 MRS Audit	WACC	TBD[3]	N/A	N/A	Rate Base	TBD[3]	1	N/A
MRS 2012-2013 Incremental O&M Expense	WACC	TBD[3]	N/A	N/A	Rate Base	TBD[3]	1	N/A
City of Kelowna Acquisition Customer Benefit	ST	ST[4]	N/A	N/A	Rate Base	ST[4]	1	N/A
Deferred Debt Issue Costs	Rate Base	Rate Base	Term of Debt	Term of Debt	Rate Base	Rate Base	Term of Debt	Term of Debt
Deferred Debt Issue Costs (2013)	WACD	WACD	Term of Debt	Term of Debt	Rate Base	WACD	Term of Debt	Term of Debt
Accounting Treatment of Existing Meters (AMI Project)	N/A	N/A	N/A	N/A	Rate Base	Rate Base[7]	5	5[7]
Residual								
2011 Flow-Through and ROE Sharing Adjustments	Rate Base	Rate Base	1	1	Rate Base	Rate Base	discontinue 2015	N/A
2012 Deferred Revenue	ST	ST[4,8]	1	1[4,8]	Rate Base	ST[4,8]	discontinue 2014	N/A
Harmonized Sales Tax (HST) Removal/Provincial Sales Tax (PST) Implementation Project	ST	ST	N/A	N/A	Rate Base	ST	discontinue 2015	N/A
Section 71 Filing (Waneta Expansion Power Purchase Agreement)	Rate Base	Rate Base[9]	3	3[9]	Rate Base	Rate Base[9]	discontinue 2015	N/A
Cost of Service and Rate Design Application	Rate Base	Rate Base[9]	4	4[9]	Rate Base	Rate Base[9]	discontinue 2015	N/A
2012-2013 Revenue Requirements and 2012 Integrated System Plan	WACD	WACD	2	2	Rate Base	WACD	discontinue 2015	N/A
2011 Revenue Requirements Application Costs	Rate Base	Rate Base[10]	1	1[10]	Rate Base	Rate Base[10]	discontinue 2014	N/A
BC Hydro Waneta Transaction Application	Rate Base	Rate Base[10]	3	3[10]	Rate Base	Rate Base[10]	discontinue 2014	N/A
Residential Inclining Block Rate	Rate Base	Rate Base[11]	1	1	Rate Base	Rate Base[11]	discontinue 2015	N/A
Implementation of New Rate Structures	Rate Base	Rate Base[11]	1	1	Rate Base	Rate Base[11]	discontinue 2015	N/A
Irrigation Rate Payer Group Consultation and Load Research	ST	ST	1	1	Rate Base	ST	discontinue 2015	N/A
Negotiation of New PPA between BC Hydro and FBC	WACD	WACD	2	2	Rate Base	WACD	discontinue 2015	N/A
Right of Way Encroachment Litigation	WACD	WACD	N/A	1[12]	Rate Base	WACD	discontinue 2015	N/A
Trail Office Lease Cost	Rate Base	Rate Base[13]	lease term	lease term[13]	Rate Base	Rate Base[13]	discontinue 2014	N/A
Trail Office Rental to SD20	Rate Base	Rate Base[13]	lease term	lease term[13]	Rate Base	Rate Base[13]	discontinue 2014	N/A
Princeton Light and Power Computer Software	Rate Base	Rate Base[14]	7	7[14]	Rate Base	Rate Base[14]	discontinue 2014	N/A
Princeton Light and Power Deferred Pension Credit	Rate Base	Rate Base[14]	7	7[14]	Rate Base	Rate Base[14]	discontinue 2014	N/A
US Generally Accepted Accounting Principles Conversion Cost	Rate Base	Rate Base[10]	2	2	Rate Base	WACD	discontinue 2015	N/A
Joint Pole Use Audit, 2008	Rate Base	Rate Base[12]	5	5[12]	Rate Base	Rate Base[12]	discontinue 2014	N/A
Joint Pole Use Audit, 2013	WACD	WACD	2	2	Rate Base	WACD	discontinue 2015	N/A
Demand Side Management Study	Rate Base	Rate Base[9]	3	3[9]	Rate Base	Rate Base[9]	discontinue 2014	N/A
MRS Implementation	WACD	WACD	3	3	Rate Base	WACD	discontinue 2015	N/A
Revenue Protection	Rate Base	Rate Base	1	1	Rate Base	Rate Base	discontinue 2015	N/A

[6] G-147-07
[7] C-7-13
[8] G-159-12
[9] G-184-10
[10] G-162-09
[11] G-24-11
[12] G-193-08
[13] G-41-93
[14] G-159-06

54.0 Reference: Exhibit B-1, p. 1 and pp. 261–264

New Deferral Accounts

The Application proposes a flow through treatment for those items in which FBC submits that it has limited or no control over (Exhibit B-1, p. 1). As such, FBC is proposing several deferral accounts for the purpose of capturing certain forecasting variances:

- Insurance Expense Variance
- Interest Expense Variance
- Income Tax Variance
- Property Tax Variance

(Exhibit B-1, pp. 261-264)

During the review of FBC's 2012-2013 RRA, FBC provided its opinion on the level controllability for certain accounts. Some of those accounts are the same as that which are proposed in the current PBR Application:

Deferral Account	Completely Non-Controllable/Primarily Non-Controllable/Somewhat Controllable/May be Controllable
Power Purchase Expense Variance Deferral Account	Primarily Non-controllable (1)
Revenue Variance Deferral Account	Completely Non-controllable (2)
Income Tax Variance Deferral Account	Primarily Non-controllable (3)
HST Removal or Reform Variance Deferral Account	Primarily Non-Controllable (4)
Property Tax Asset Variance Deferral Account	Completely Non-controllable (5)
Interest Expense Variance Deferral Account	Somewhat controllable (6)
Pension and Other Post-Employment Benefits Expense Variance	Completely Non-controllable (7)
Insurance Expense Variance Deferral Account	Somewhat controllable (8)

(FortisBC 2012-2013 RRA & ISP, Exhibit B-8, BCUC 2.28.1)

54.1 Given FBC's submission that one of the benefits of a PBR plan is "its effectiveness in incenting the utility to capture efficiencies" (Exhibit B-1, p. 26), please discuss whether approval of these variance accounts would be contrary to the intent of the PBR, particularly for those items which are "somewhat controllable".

Response:

The request for approval of the Insurance Expense Variance, Interest Expense Variance, Income Tax Variance and Property Tax Variance deferral accounts included in the 2014-2018 PBR application will not affect FBC's incentive to capture efficiencies, as these deferral accounts contain several elements and factors that are substantially or completely uncontrollable, regardless of the Company's incentive for efficiency. FBC's view that a PBR plan will provide effectiveness in incenting the utility to capture efficiencies is based on the result of prudent management decisions of costs that are more controllable in nature, rather than the variance on the elements of income tax, interest expense, insurance and property tax expense that have been requested for deferral in the 2014-2018 PBR application. The uncontrollable nature of these items is not contrary to the intent of PBR.

Further, the reference to the 2012-2013 RRA information request in the preamble to this IR is not representative of FBC's opinion of controllability on the various requested deferral accounts. The Company's opinions of controllability was submitted as part of the 2012-2013 RRA, while the excerpt of the response to BCUC IR 2.28.1 only shows the initial response with no additional context provided. Rather than look at a very general response in an attempt to suggest that FBC will not be incented to find efficiencies, it is germane to elaborate on FBC's requested deferral accounts for the 2014-2018 PBR Application and how they differ from the deferral accounts originally requested as part of the 2012-2013 RRA.

The *Interest Expense Variance Deferral Account* included in FBC's 2014-2018 PBR Application captures variances in interest rates, volumes and timing of issuances on long term debt; as well as variances in interest rates only for short-term debt. These sorts of variances result from external capital market and economic factors, therefore these uncontrollable interest expense variances can, and will, occur independent of a PBR plan or FBC's incentive to find efficiencies. Variances on the short-term debt volumes and financing fees have not been requested as part of the 2014-2018 Interest Expense Variance Deferral Account and it therefore differs from the Interest Expense Variance Deferral Account included in the 2012-13 RRA which was requested to capture all interest expense variances. The background on the reference to "Somewhat controllable" Interest Expense Variance Deferral Account in the response to 2012-2013 RRA BCUC 2.28.1 was based on the Company's ability to potentially influence the terms of its banking agreements at the time of renewal. However, even the attempt to influence pricing is restricted by the market conditions that exist at the time of the banking agreement renewals as well as the consideration by the banking syndicate for recent regulatory decisions.

The *Insurance Expense Variance Deferral Account* included in FBC's 2014-2018 PBR Application captures variances in insurance premiums. These insurance premium variances can result from external insurance market and economic factors, therefore this uncontrollable insurance expense variance can, and will, occur independent of a PBR plan or FBC's incentive to find efficiencies. Variances on first and third party liability and asset valuations (appraisal fees) have not been requested as part of the 2014-2018 Insurance Expense Variance Deferral Account and therefore this deferral account differs from the Insurance Expense Variance Deferral Account included in the 2012-13 RRA which was requested to capture all insurance expense variances. The background on the reference to “Somewhat controllable” Insurance Expense Variance Deferral Account in the response to 2012-2013 RRA BCUC 2.28.1 was based on FBC’s ability to obtain economies of scale with the Fortis Group of Companies on insurance premiums as compared to seeking the same premiums from the insurance market on a stand-alone basis. However, the economies of scale on insurance premiums is already embedded in the forecasted insurance expense for the PBR period and the Company would not propose to seek out insurance premiums on a stand-alone basis.

The *Tax Variance Deferral Account* included in FBC’s 2014-2018 PBR Application captures variances resulting from the impact of changes in tax laws or accepted assessing practices, audit reassessments in respect of any tax year, and impacts on taxes of changes in accounting policies at Federal, Provincial, Municipal or any other level of jurisdiction which can, and will, occur independent of a PBR plan or FBC’s incentive to find efficiencies. The background on the reference to “primarily non-controllable” Income Tax Variance Deferral Account in the response to 2012-2013 RRA BCUC 2.28.1 was elaborated on in the original response to the IR which indicated that “should these completely uncontrollable changes occur, there is the potential for incremental compliance costs, such as changes to information systems and compliance costs, for which the Company may have a degree of control in managing costs.” The reference to the minor element of compliance cost that potentially may be influenced by the Company is what designated this deferral account as “primarily non-controllable” in the 2012-2013 RRA, and such costs have also been asked for as part of the 2014-2018 PBR application.

The *Property Tax Variance Deferral Account* included in FBC’s 2014-2018 PBR Application captures all variances between actual and forecast property taxes as the variances are driven primarily by legislation, market values of properties and/or political programs. The factors mentioned are completely beyond the Company’s control and similar to the other described deferral variance factors previously described, can occur independent of a PBR plan or FBC’s incentive to find efficiencies.

54.2 If these variance accounts are not approved, please discuss whether FBC would be agreeable to an incentive mechanism to deal with the potential variances, such as a reward of retaining 10 percent of savings achieved. Please explain why or why not.

Response:

FBC is not supportive of such an incentive mechanism on these costs as these requested deferral accounts serve to benefit the customers and Company by ensuring that only the true costs are paid for and avoids the potential for windfall gains and losses. These costs are uncontrollable in nature and represent asymmetric risks, thus the proper treatment under PBR are as variance deferral accounts. Further, the Company does not understand how the suggested 10 percent figure is derived since it has no correlation to what causes the variances in these cost of service items. FBC's view is that a PBR plan will provide effectiveness in incenting the utility to capture efficiencies based on the result of prudent management decisions of costs that are more controllable in nature, rather than the variance on the uncontrollable elements included in income tax, interest expense, insurance and property tax expense requested for deferral in the 2014-2018 PBR application.

54.2.1 If such incentive mechanisms are put in place, should the X-factor in the proposed PBR be adjusted? If so, on what basis?

Response:

No. FBC believes that since the calculated TFP is negative and the proposed X-Factor is positive, resulting in a significant stretch factor, there is no need to adjust the proposed X-Factor. The largest of these factors - Power Purchase Expense - is not part of the calculation of the X-Factor to begin with, meaning no adjustment is necessary. Similarly, the revenue variance is not a factor in the PBR as it operates as a decoupling method. In short, there is no reason to include any adjustment to the X-Factor.

54.3 In order to streamline the use of deferral accounts, would it be appropriate to eliminate deferral treatment for recurring non-controllable items and instead use the average cost for the past five years to determine the costs recoverable during the PBR? Please explain why or why not.

Response:

No, it would not be appropriate to eliminate the requested deferral accounts as discussed in the responses to BCUC IRs 2.54.1 and 2.54.2 and it would be further unreasonable to use an average cost for the past five years. This incorrectly suggests that a simple trend from the last five years can be used to forecast costs for 2014 to 2018 and completely ignores the fact that many elements of these costs are not predictable, hence the requested deferral treatment. For example, the insurance markets, the capital markets, economic conditions and legislative tax laws in place during the period of 2009 to 2013 will most likely differ in the 2014-2018 period and those differences have been contemplated in FBC's forecasts for the 2014-2018 PBR application. The intent of the deferral account requests are to ensure that only the true costs are paid for and avoid the potential for windfall gains and losses, as opposed to a sole objective of streamlining the number of deferral accounts.

55.0 Reference: Exhibit B-1, p. 239–240 and p. 264; Exhibit B-7, BCUC 1.183.1

Property Tax Deferral Account

55.1 Please provide the Approved and Actual property tax expense for each of 2010, 2011, 2012 and 2013.

Response:

The Approved and Actual property tax expense for 2010 through 2012, as well as the Approved and Projection property tax expense for 2013, are as follows:

	Approved	Projection
	($000s)	
2013	15,085	14,867

	Approved	Actual
	($000s)	
2012	14,532	13,912
2011	13,940	13,408
2010	12,548	12,238

55.2 Please discuss why FBC does not propose a Z-factor treatment for property tax variances related to changes to property assessments or property tax rates.

Response:

The suggested Z-factor treatment for property tax variances would have a narrower scope in terms of the variances it would capture, as compared to the requested Property Tax Variance Deferral Account. The requested Property Tax Variance Deferral Account in Section D 2.2.3 of FBC's 2014-2018 PBR Filing would capture all variances between actual and forecast property tax expense. Therefore, the requested deferral account would include not only changes to property assessments or property tax rates, but also variances in property tax expense which would result from variances between forecast and actual revenue from electricity consumed in municipalities and changes in the underlying taxable assets. In addition, the requested Property Tax Variance Deferral Account in Section D2.2.3 of the PBR Filing would also allow for a consistent regulatory treatment with FEI.

56.0 Reference: Exhibit B-1, p. 261; Exhibit B-7, BCUC 1.185.1; Exhibit B-1-6, p. 261

Rate Stabilization Deferral Mechanism (RSDM)

56.1 Please provide a table in the same format as that provided in response to BCUC 1.185.1 using the revised RSDM initial credit of $24.375 million included in the Evidentiary Update (Exhibit B 1 6).

Response:

The requested table follows:

Rate Stabilization Parameters	2014	2015	2016	2017	2018	Total
Rate Stabilization Component (Pre Tax)	32,939	-	-	-	-	**32,939**
Tax Component	(8,564)	-	-	-	-	**(8,564)**
Amortization of Rate Stabilization Component (Pre Tax)	-	(2,030)	(15,783)	(10,901)	(4,225)	**(32,939)**
Tax Component	-	528	4,104	2,834	1,099	**8,564**
Net Rate Stabilization Component (Post Tax)	**24,375**	**(1,502)**	**(11,679)**	**(8,067)**	**(3,127)**	**-**

56.2 The original IR question asked for the detailed calculations to support the initial balance. Please provide a detailed calculation in a working excel document to support how the pre-tax rate stabilization component is derived. The detailed calculation should support the revised balance in the Evidentiary Update.

Response:

As indicated in the response to BCUC IR 1.185.1, the determination of the Rate Stabilization Deferred amount is empirical in nature. FBC could not reasonably produce a working model that isolated the calculation of the RSDM from its much larger and more complex revenue requirements model. The Company has attempted to clearly explain the method of calculation and provided an illustrative table showing the components involved in the calculation.

Two basic assumptions are the premise of determining rate stabilization amount:

1. The rate stabilization amount in 2014 and its subsequent amortization during 2015-2018 should be such as to generate a 3.3 percent Rate Impact in 2014 followed by a uniform Rate Impact thereafter during 2015-2018; and

2. The rate stabilization amount in 2014 and its subsequent amortizations during 2015-2018 should be such that it balances to zero by the end of 2018.

The rate stabilization amount in 2014, its subsequent amortization during 2015 to 2018 and the rate impacts of 3.3 percent in 2014 followed by 3.6 percent during 2015-2018 are derivatives of the above assumptions.

General Methodology followed:

Step-1: The revenue requirements and the associated rate impacts are first modeled as shown in Section-C of the Table below.

Step-2: A post tax rate smoothing component is then applied to achieve the targeted rate impacts

Please refer to Line 24 Section-B of the Table below.

Collateral: Due to the introduction of the rate smoothing, differences occur in the following components:

Impact
a) Income Tax: Please refer to Line 15, Sections B & C of the Table below.
b) Cost of Debt: Please refer to Line 18, Sections B & C of the Table below.
c) Cost of Equity: Please refer to Line 19, Sections B & C of the Table below.

Step-3: Continue with Step-2 until the targeted rates are achieved ensuring that the cumulative smoothing volume falls to zero by the end of the test period (2018).

	Revenue Requirement Parameters	**Section -C** Final RRA (Evidentiary Update) with Rate Smoothing					**Section -B** Incremental Adjustments for Rate Smoothing					**Section -A** Evidentiary Update without Rate Smoothing				
1	**REVENUE DEFICIENCY**	**2014**	**2015**	**2016**	**2017**	**2018**	**2014**	**2015**	**2016**	**2017**	**2018**	**2014**	**2015**	**2016**	**2017**	**2018**
2																
3	**POWER SUPPLY**															
4	Power Purchases	87,163	115,590	134,063	136,938	140,550	-	-	-	-	-	87,163	115,590	134,063	136,938	140,550
5	Water Fees	9,928	10,532	10,479	10,688	10,902	-	-	-	-	-	9,928	10,532	10,479	10,688	10,902
6		97,091	126,122	144,541	147,626	151,452	-	-	-	-	-	97,091	126,122	144,541	147,626	151,452
7	**OPERATING**															
8	O&M Expense	61,386	61,744	60,960	62,378	63,302	-	-	-	-	-	61,386	61,744	60,960	62,378	63,302
9	Capitalized Overhead	(12,277)	(12,349)	(12,192)	(12,476)	(12,660)	-	-	-	-	-	(12,277)	(12,349)	(12,192)	(12,476)	(12,660)
10	Wheeling	5,224	4,856	4,952	5,050	5,208	-	-	-	-	-	5,224	4,856	4,952	5,050	5,208
11	Other Income	(7,582)	(7,630)	(7,781)	(7,755)	(7,819)	-	-	-	-	-	(7,582)	(7,630)	(7,781)	(7,755)	(7,819)
12		46,751	46,621	45,939	47,198	48,030	-	-	-	-	-	46,751	46,621	45,939	47,198	48,030
13	**TAXES**															
14	Property Taxes	15,903	16,329	16,612	16,975	17,290	-	-	-	-	-	15,903	16,329	16,612	16,975	17,290
15	Income Taxes	10,815	5,379	3,710	7,079	10,287	8,417	(823)	(4,314)	(2,917)	(1,110)	2,399	6,201	8,024	9,996	11,396
16		26,718	21,708	20,322	24,054	27,577	8,417	(823)	(4,314)	(2,917)	(1,110)	18,301	22,530	24,636	26,971	28,686
17	**FINANCING**															
18	Cost of Debt	42,454	42,833	44,840	45,631	45,880	(179)	(481)	(451)	(186)	(25)	42,633	43,315	45,291	45,816	45,904
19	Cost of Equity	43,616	45,538	47,160	47,740	48,019	(420)	(839)	(598)	(236)	(31)	44,035	46,377	47,758	47,976	48,050
20	Depreciation and Amortization	57,169	55,578	59,938	61,870	64,253	-	-	-	-	-	57,169	55,578	59,938	61,870	64,253
21		143,239	143,949	151,938	155,241	158,151	(598)	(1,320)	(1,049)	(422)	(56)	143,837	145,269	152,987	155,663	158,207
22	**FLOW THROUGH ADJUSTMENTS**															
23	Flow Through Adjustments	(14,772)	-	-	-	-	-	-	-	-	-	(14,772)	-	-	-	-
24	Rate Smoothing	24,375	(1,502)	(11,679)	(8,067)	(3,127)	24,375	(1,502)	(11,679)	(8,067)	(3,127)	-	-	-	-	-
25		9,603	(1,502)	(11,679)	(8,067)	(3,127)	24,375	(1,502)	(11,679)	(8,067)	(3,127)	(14,772)	-	-	-	-
26																
27	**TOTAL REVENUE REQUIREMENT**	323,403	336,898	351,061	366,051	382,083	32,193	(3,645)	(17,042)	(11,406)	(4,292)	291,209	340,543	368,103	377,457	386,376
28																
29	**LESS: REVENUE AT APPROVED RATES**	312,924	325,108	338,710	353,165	368,650	-	32,363	(3,664)	(17,144)	(11,487)	312,924	292,745	342,375	370,309	380,137
30	**REVENUE DEFICIENCY for Rate Setting**	10,479	11,790	12,351	12,886	13,434	32,193	(36,008)	(13,377)	5,737	7,195	(21,714)	47,798	25,728	7,149	6,239
31																
32	**RATE INCREASE**	**3.30%**	**3.60%**	**3.60%**	**3.60%**	**3.60%**	**10.20%**	**-12.70%**	**-3.90%**	**1.70%**	**2.00%**	**-6.90%**	**16.30%**	**7.50%**	**1.90%**	**1.60%**

56.3 Given that the purpose of this deferral account is for rate smoothing, please explain why it is appropriate to apply a rate base treatment.

<u>Response:</u>

Like all deferral accounts, the RSDM captures a difference in timing between expenditures and recovery of costs from ratepayers. There is no distinction to be made between deferral accounts based on the purpose of the account, whether for rate smoothing or other reasons, and in fact a given deferral account may serve more than one purpose (as in the case of a large and uncontrollable cost, which is deferred in order to properly allow recovery of the cost, and which may then be amortized in such a manner as to mitigate rate volatility).

FBC explains in Section D3.2 Deferral Account Financing (page 246) that if the utility is able to forecast a balance for the deferral account and include it in revenue requirements, as it does for the RSDM, that is the preferred treatment. All non rate base accounts should be afforded WACC treatment so that the utility is afforded the opportunity to earn a fair return on costs prudently incurred to provide service to customers.

In the case of the RSDM, rate base treatment results in lower rates than non rate base treatment because the RSDM is a <u>credit</u> to rate base, which reduces both the cost of equity (shareholder return) and income tax components associated with the RSDM balance, compared to financing the credit only at the Company's WACD.

FBC states that:

"[t]he effect of the RSDM is to eliminate significant rate variances arising from factors that are known at the time of filing the Application and to satisfy the terms of Commission Order E-15-12 issued in May 2012" and that "[a]ll other flow-through and deferral items will be captured in the appropriate and respective accounts, not in the RSDM…" (Exhibit B-7, BCUC 1.185.3)

56.4 Please specify what are the "rate variances arising from factors that are known at the time of filing the Application"? Is this specifically referring to the rate impacts from the WAX CAPA? If not, please provide supporting details for all the factors which contribute to the initial balance.

Response:

The statement refers to the current forecasts of all cost accounts over the 2014-2018 period, which are summarized in Appendix G of the Evidentiary Update (Exhibit B-1-6). The impact of the WAX CAPA is included in the Power Purchase Expense forecast at page 1, line 8 of Appendix G. The RSDM balance is the amount required to levelize the forecast rate increases from 2015-2018 and to be fully amortized at December 31, 2018, based on the approved 3.3 percent interim increase effective January 1, 2014. The rate profile that would occur in the absence of the RSDM, based on the current 2014-2018 revenue requirements forecast in Appendix G, is shown graphically on Page 75 of the Evidentiary Update (labelled "PBR O&M and Capital Formula").

Since the revenue requirements for 2015-2018 will be reforecast in the Annual Reviews and FBC is not seeking approval of those amounts, only the high-level forecasts in Appendix G are included in this Application.

57.0 Reference: Exhibit B-1, p. 262; Exhibit B-7, BCUC 1.186.1.1

BC Hydro Application for New PPA with FortisBC

FBC explains that it has included $175,000 as the 2013 addition to the regulatory deferral accountBC Hydro Application for PPA with FBC, based on a forecast for the possibility of an oral hearing.

57.1 Given that the Commission has established a written hearing in Order G-117-13 to review the BC Hydro application, please explain whether this deferral account should now be reduced. Please clarify where this is reflected in FBC's Evidentiary Update filed October 18, 2013.

Response:

FBC did not reforecast the costs of this proceeding in its Evidentiary Update.

The Company's response to BCUC IR 1.211.2 explains that any variances from forecast deferral account balances will be trued up in the following year, as is the usual practice. Actual costs will be recorded in the deferral account as incurred and amortization will be recorded at the amount approved, with the result that the future balance (at December 31, 2014) equals the difference between actual and forecast, and is amortized in the subsequent year. In this manner, total amortization expense will be equal to actual expenditures.

58.0 Reference: Exhibit B-1, pp. 52–53, p. 166; Exhibit B-7, BCUC 1.143.3 and BCUC 1.187.1

Insurance Expense Deferral Account

In the Application, FBC is proposing that variances from forecasts of third-party premiums be subject to deferral treatment and refunded to, or recovered from, customers in later years (Exhibit B-1, p. 166).

In response to BCUC 1.143.3, FBC also provides the approved versus actual insurance premiums over the last five years:

	Forecast	Actual	Variance
2008	1,331,160	1,294,369	36,791
2009	1,398,004	1,210,868	187,136
2010	1,370,450	1,159,002	211,448
2011	1,211,000	1,216,582	<5,582>
2012	1,272,000	1,275,616	<3,616>

58.1 Cumulatively, the variances from the last five years amount to over $426,000. Please explain how FBC has treated these variances in the past. Are they simply absorbed in the O&M budget?

<u>Response:</u>

Variances between forecast and actual amounts for the 2007-2011 PBR agreement were split 50%/50% between customers and the Company, as part of the earnings sharing mechanism in place during the PBR period. In 2012, the variance between forecast and actual was included in the Company's O&M Expense.

58.2 If the deferral treatment is approved in this Application, does this mean that customers only pay for the insurance premium costs that are actually incurred?

<u>Response:</u>

Yes.

58.3 Please clarify how the deferral treatment will be "refunded to, or recovered from, customers in later years" (Ex. B-1, p. 166). Is FBC proposing a flow through of the actual insurance premium costs in each subsequent year of the PBR? Or is FBC proposing an amortization period of more than 1 year on the annual balances of this proposed deferral account?

Response:

FBC states on page 263 of Exhibit B-1 (lines 29-31) that it is requesting approval to amortize the Insurance Expense Variance over a one-year period, thus the total variance for each year will be flowed through in the subsequent year.

The following table was provided in response to BCUC 1.187.1:

Insurance Premiums

	Approved	Actual
2011	$1,211,000	$1,216,582
2012	$1,272,000	$1,275,616
2013	$1,335,000	$1,400,000 (Projected)

Insurance Expense

	Approved	Actual
2011	$1,393,000	$1,398,582
2012	$1,441,000	$1,946,359
2013	$1,449,000	$1,566,000 (Projected)

FBC states that:

"Insurance expense includes insurance premiums, asset valuations and first and third-party liability costs, however the Insurance Expense Variance Deferral Account referred to in D4.3.4 on page 263 of Section D4 of the 2014-2018 PBR Application is meant to only capture variances between forecast and actual insurance premiums" (Ex. B-7, BCUC 1.187.1).

58.4 Is the difference between the Insurance Premiums table and the Insurance Expense table related to asset valuations and first and third-party liability costs? If not, please explain otherwise.

Response:

Yes, this is the only difference.

58.5 Please explain why FBC has proposed to only capture the variance between Forecast and Actual Insurance Premiums in the Insurance Expense deferral account, rather than the entire Insurance Expense variance.

Response:

The primary reason FBC proposes to only capture the variance between Forecast and Actual Insurance Premiums in the Insurance Expense deferral account is to provide for consistent treatment between Electric and Gas divisions. Insurance premiums are outside the control of FBC, being subject to conditions in the insurance market which can be volatile at times.

58.6 Please explain the reasons for the variance between the 2013 Approved and Actual Insurance Premiums.

Response:

Variance between 2013 Approved and Actual Insurance Premiums relate to higher than expected premiums for coverage related to property and liability insurance. FBC forecast an annual increase of 5 percent for Insurance Premiums year over year. For the 2013 renewal, insurable values increased by 7.9 percent, primarily as a result of asset valuations completed on the four generation facilities on the Kootenay River. The additional premium for the increase in asset values along with the addition of new coverage for Cyber & Privacy Liability provided for Projected 2013 Actual Premiums being $65 thousand over 2013 Approved.

58.7 To avoid confusion on the purpose of this deferral account, does FBC agree that a more proper name is “Third Party Insurance Premium Deferral Account”? Why or why not?

Response:

FBC agrees that the deferral account could be renamed "Insurance Premium Variance Deferral Account".

59.0 Reference: Exhibit B-1, pp. 53

Insurance Expense Deferral Account

59.1 Table B6-5 of Exhibit B-1 (p. 53) includes $1,588 thousand of Base 2013 Insurance expense that is tracked outside of the PBR formula. Does this relate to the entire Insurance expense (i.e. premiums, asset valuations and first and third-party liability costs) or only a portion of Insurance Expense? Please explain.

Response:

The figures used in Table B6-5 of Exhibit B-1 (p. 53) do reflect the entire Insurance expense (premiums, asset valuations and first & third party liability costs). Insurance expense is proposed to be tracked outside of the PBR formula, to be re-forecast every year at the annual review. FBC proposes to only capture the variance between Forecast and Actual Insurance Premiums in the Insurance Expense Variance Account to provide for consistent treatment between Electric and Gas divisions. The forecast of insurance expense for 2014 is as follows:

2014 Forecast Insurance Expense

- Insurance Premiums - $1,460 thousand
- First & Third Party Liability Expense - $274 thousand
- Asset Valuations - $0 (This expense is incurred every four years and is included in 2017 forecast)
- Total - $1,734 thousand

FBC would not object to changing the method of determining O&M Expense in order to exclude only insurance premiums from the I-X formula, providing that 2013 Base O&M Expense is revised to include the forecast $274 thousand of First and Third Party Liability Expense.

59.1.1 If the entire Insurance Expense is proposed to be tracked outside of the formula, please explain why only the variance between Forecast and Actual Insurance Premiums are forecast to be captured in the Insurance Expense deferral account.

Response:

Please refer to the response to BCUC IR 2.59.1.

59.2 2014 Forecast Insurance Expense is $1,734 thousand. Please provide a breakdown of the 2014 Forecast Insurance Expense between insurance premiums, asset valuations, third-party liability costs and other.

Response:

Please refer to the response to BCUC IR 2.59.1.

59.2.1 Please provide an explanation for the 9 percent increase in Insurance Expense from 2013 Base to 2014 Forecast.

Response:

The 9 percent increase in Insurance Expense is accounted for as follows:

	2013	2014 Forecast	Variance
	($000s)		
Premiums	$1,422	$1,460	$38
Appraisal Fees	$60	-	$(60)
1^{st} & 3^{rd} Party Claims	$106	$274	$168
Total	$1,588	$1,734	$146

a) The increase in insurance premiums from the 2013 Base to 2014 Forecast is due to market factors outside the control of FBC. These factors can include large global losses, catastrophic risks such as earthquakes, hurricanes and forest fires, as well as through general market conditions related to the unpredictability of investment returns and loss history;

b) Asset Appraisals are undertaken every 4 years as required for insurance purposes; and

c) First and Third Party Liability Expenses have increased from the 2013 Base to the 2014 Forecast due to:

   i. Fluctuation in the number and significance of claims;

   ii. The increase in the Company's customer base (increased by 13% due to the acquisition of City of Kelowna's assets) which has a direct correlations to the First and Third Party Liability Expenses (assumption that additional customer base will increase claims by a similar rate);

   iii. The increase in third party adjusting fees by 20% in 2013; and

   iv. The potential for liability deductibles to increase.

The Insurance Expense forecast for 2014 has taken all of the above variables into account.

60.0 Reference: Exhibit B-1, pp. 232, 236, 263–264; Exhibit B-7, BCUC 1.190.5.1

Interest Expense Variance Deferral

The following response was provided to BCUC 1.190.5.1:

"a) All interest expense variances (the entire $1,800 thousand) related to Long-term debt interest rates and long-term debt average balances are to be deferred.

b) Short-term interest expense variances driven by differences between approved forecast short-term interest rates of 3.48% and projected short-term interest rates of 2.40%, resulting in a variance of $343 thousand, are to be deferred, while the short-term interest expense variance driven by differences between forecast and projected average short term debt balances ($11 thousand) are not deferred.

c) Short-term interest expense variances driven by differences between forecast standby rate of 30 basis points and the actual standby fee rate of 20 basis points, resulting in a variance of $118 thousand, are to be deferred, while the remaining financing fee costs of $278 thousand are not deferred." (Exhibit B-7, BCUC 1.190.5.1)

60.1 Please explain why FBC proposes to capture all variances related to long-term debt interest expense (i.e. interest rates and long-term debt balance), but for short-term debt only proposes to capture the variance between the interest rate and not the forecast and projected (or actual) short-term debt average balances.

Response:

FBC's proposal for the Interest Expense Variance Deferral was based on two considerations. For regulatory consistency, FBC's proposal mirrors the currently approved FEI mechanism for Interest Expense Variance Deferral. This mechanism has been approved and accepted by the Commission and consistency with the FEI deferral mechanism is logical.

Additionally, FBC proposes to capture all variances related to long-term debt interest expense and the interest rate components of short-term interest expense, since these are the primary components of interest expense which are not controllable in nature. While the Company may intend to issue long-term debt in a specified period for a desired term and coupon rate, all of these variables are affected by the supply and demand dynamics of public debt markets and general economic conditions, all of which are beyond FBC's control and influence. Given the size of long-term debt issues, material changes in the timing of the debt issue can have material impacts on the amount of long-term interest expense. The same lack of controllability for long-term debt interest rates also applies to the short-term debt interest rates. The variances on interest expense on short-term debt average balances are excluded as the average short term debt balances are somewhat less volatile over a given year and less effected by purely external factors.

60.2 For financing fees, please explain why FBC proposes to capture the variance between the approved and projected (actual) standby fee rate but not the variance related to the approved versus projected (or actual) remaining financings fees costs (i.e. $278 thousand in 2013).

Response:

FBC proposes to capture the variance between approved and actual standby fee rate as, similar to long-term and short-term interest rates, these are a component of interest expense which are not controllable in nature. Standby fees are the charge to compensate the bank syndicate for providing continued access to the operating credit facility on short notice. Standby fee rates are determined based on a lending agreement between the Company and a syndicate of eight chartered Canadian banks and are driven by financial market conditions that exist at the time of the bank agreement renewals. The remaining financing fee costs included in interest expense, such as banking renewal fees, security deposit interest and demand line interest, are potentially less volatile and therefore somewhat more controllable by the Company and therefore have not been requested for deferral treatment.

60.2.1 Please describe what the remaining $278 thousand variance related the remaining financing fees costs relates to.

Response:

The remaining $278 thousand 2013 projected financing fee variance relates to variances in Standby fee interest expense based on the undrawn credit line volume, variances on banking agreement charges, variances on demand line interest and other miscellaneous interest costs, including interest due to customers on outstanding security deposits. These variances have not been requested for deferral treatment as part of the 2014-2018 PBR Application.

60.3 Please explain the single and double asterisks that are in Table 1 of the response to BCUC 1.190.5.1. Are there accompanying footnotes that were intended?

Response:

There are no accompanying footnotes to Table 1 included in the response to BCUC IR 1.190.5.1. Table 1 is primarily a direct copy of Table D1-3: Overview of Forecast Interest Expense (page 236) from the 2014-2018 PBR Plan Application (Exhibit B-1), which included footnotes.

> "As part of an Evidentiary Update filing, FortisBC will provide an update to its interest expense forecast for 2013 and 2014 which would flow the variance in interest expense back to customers, no different than what would be accomplished with a deferral account." (Exhibit B 7, BCUC 1.189.6)
>
> FBC also confirms that it will forecast interest expense for each year during the PBR period and update the forecast as part of the Annual Reviews (Exhibit B-7, BCUC 1.190.3).

60.4 If the deferral treatment is approved, would FBC agree that the annual variances accruing to the interest expense deferral account would be minimal given that it is meant to capture only the difference between the forecast interest (at the annual review) versus the actual interest at the time of the debenture issue?

Response:

FBC does not agree with the assumption that the annual variances accruing to the interest expense deferral account will necessarily be minimal. While FBC will utilize updated projections made by Canadian Chartered Banks for forecasts of Treasury Bills and benchmark Government of Canada Bond interest rates at each Annual Review for the PBR period, there is the potential for significant interest expense variability subsequently occurring based on changes in market conditions, the Company's credit rating at the time of issuance and financing requirements for CPCN capital expenditures incurred outside of the Capital PBR formula. One only has to look to the interest expense variability that occurred during the financial crisis of 2008 and 2009. During this financial crisis, FBC's indicative interest rates fluctuated 200 basis points between January and June of 2009, causing significant variability in interest rates. As such, FBC recognizes that with the passage of time between setting approved forecasts and actuals that there is still the very real potential for significant volatility.

61.0 Reference: Exhibit B-1, p. 264; Exhibit B-7, BCUC 1.191.3; Exhibit B-1-6, p. 285

Tax Variance Deferral Account

"This account will capture the impact of changes in tax laws or accepted assessing practices, audit reassessments in respect of any year, and impacts on taxes of changes in accounting policies at Federal, Provincial, Municipal or any other level of jurisdiction. The account would also accumulate any required compliance costs, including changes to information systems." (Exhibit B-1, p. 264)

With respect to the treatment of income taxes during the last PBR period, FortisBC submits the following in response to BCUC IR 1.191.3:

"Pursuant to Commission Order G-58-06, the "Z" Factor Provision under FortisBC's 2007-2011 PBR Agreement allowed for the recovery or refund of costs that arose from changes in Acts of legislation or regulation of government, which included changes in the Income Tax Act, tax regulations and income tax rates."

61.1 Please confirm, or explain otherwise, that any variance between forecast and actual expenses that are not related to the "impact of changes in tax laws or accepted assessing practices, audit reassessments in respect of any year, and impacts on taxes of changes in accounting policies at Federal, Provincial, Municipal or any other level of jurisdiction" would be applied to the approved forecast figures in any given year in order to calculate the additions to the tax variance deferral account and **will not** accrue to the tax variance deferral account additions.

<u>Response:</u>

Variances between forecast and actual tax expenses that are not related to the "impact of changes in tax laws or accepted assessing practices, audit reassessments in respect of any year, and impacts on taxes of changes in accounting policies at Federal, Provincial, Municipal or any other level of jurisdiction" will not accrue to the requested Tax Variance Deferral Account. Instead, these differences will affect the achieved return on equity prior to applying the Earnings Sharing Mechanism under PBR, the same as any other cost of service item not subject to deferral treatment.

61.2 Please explain why FBC has proposed deferral account treatment for income tax variances, rather than the Z-factor treatment that was approved during the last PBR period.

Response:

The proposed Tax Variance Deferral Account included as part of the 2014-2018 PBR Plan Application is expected to capture variances of the same nature as those under the Z factor treatment of FBC's 2007-2011 PBR period. However, to establish greater certainty and reduce any ambiguity as to the nature of variances to be accrued to the Tax Variance Deferral Account, FBC has explicitly requested a stand-alone deferral account with a more detailed description on pages 241-242 of Section D 2.4.1 *Request for Tax Variance Deferral Account* and on page 264 Section D 4.3.6 *Tax Variance* in the 2014-2018 PBR Plan Application.

Included in Section D 2.4.1 is another reason for establishing a deferral account in that it "would be consistent with the Tax Variance deferral account approved by the BCUC for FBC's sister companies, FEI (Commission Order G-141-09) and FEW (Commission Order G-138-10)". Establishing a Tax Variance Deferral Account or treating such variances as a Z factor would both result in the variances being deferred and collected from, or refunded to, customers in future rates. Therefore there is no anticipated advantage or disadvantage under either treatment except, as previously stated, FBC believes that the Tax Variance Deferral Account provides more explicit language and certainty around the variances that it can defer, as well as provide consistent regulatory treatment with FEI and FEW.

61.2.1 Please discuss the pros and cons for each of a) proposed deferral account treatment and b) Z-factor treatment of income tax variances.

Response:

Please refer to the response to BCUC IR 2.61.2.

61.3 Is the proposed amortization one or three years for this deferral account? Please explain why.

Response:

The amortization period of the Tax Variance Deferral Account is described on page 242 of FBC's 2014-2018 PBR Filing from July 5, 2013, Section D 2.4.1: *"FBC is requesting the Commission to approve any variances to be accumulated in this rate base deferral and amortized over a one year period."* The amortization period of one year was selected for consistency with FEI and FEW. Additionally, the shorter amortization period avoids contributing to the accumulation of other tax timing differences that manifest in the form of deferred income taxes, which are not collected in FBC's rates pursuant to Commission Order G-37-84.

The 2013 additions to the Tax Variance deferral account are $309 thousand (Exhibit B-1-6, p. 285).

61.4 Given that FBC's proposal for the Income Tax variance account was denied by the Commission in the 2012-2013 RRA & ISP Decision (Order G-110-12), please explain why FBC is including this $0.3 million in the newly proposed Tax Variance Deferral Account for 2013.

Response:

As described in the response to BCUC IR 1.173.1, the $309 thousand is the result of 0.75 percent increase in the 2013 Corporate Tax Rate and appropriately included in the HST Removal or Reform Variance Deferral Account. However, the $309 thousand has been incorrectly double-counted in Table 1-B Deferred Charges and Credits (2013) as part of the 2014-18 PBR Evidentiary Update Filing on October 18, 2013.

The $309 thousand was correctly included as part of the 2013 additions of $711 thousand to the HST Removal or Reform Variance Deferral Account, on line 50 of page 286 of Table 1-B Deferred Charges and Credits (2013), which was approved pursuant to Order G-110-2. The inclusion of the $309 thousand in the HST Removal or Reform Variance Deferral Account is corroborated with the reconciliation included on Table D2-1: Deferral of 2013 PST Impact and Removal of HST on page 241 of the Evidentiary Update on October 18, 2013.

Conversely, the 2013 addition of $309 thousand to the Tax Variance Deferral Account on line 18 on page 285 of Table 1-B Deferred Charges and Credits (2013) should be removed as it is a nil amount. The December 31, 2013 totals on lines 73, 75 and 77 on page 286 of Table 1-B Deferred Charges and Credits (2013) exclude the double count of the $309 thousand in the Tax Variance line item, therefore the ending total balances of 2013 deferred charges and credits are correct.

On line 48 of Table 1-B Deferred Charges and Credits (2014), the opening balance of the HST Removal or Reform Variance Deferral Account for 2014 of $304 thousand is understated by the $309 which has been included on line 16 in the opening balance of the Tax Variance Deferral account for 2014 and is therefore overstated by $309 thousand.

An Errata will be provided to remove the double-counting in 2013 Table 1-B and reclass the $309 thousand from the opening balance of the Tax Variance Deferral Account (line 16) in 2014 to the opening balance of the HST Removal or Reform Variance Deferral Account (line 48) for 2014.

Since none of the 2013 rate base total, the 2014 rate base total, or the total 2014 amortization have been affected, as the error is contained only within Table 1-B – Deferred Charges for 2013 and 2014, there is no resulting impact on the proposed revenue requirements for 2014 to 2018.

62.0 Reference: Exhibit B-1-6, p. 286; Exhibit B-1, p. 286

Harmonized Sales Tax (HST) Removal / Provincial Sales Tax

2013 additions to the HST) Removal / Provincial Sales Tax Variance deferral account are $711 thousand. This is an increase of $309 thousand as compared to the Original Application. (Exhibit B-1, p. 286)

62.1 Please provide detailed calculations in a working excel document to support the 2013 additions to the Harmonized Sales Tax (HST) Removal / Provincial Sales Tax deferral account.

Response:

Please refer to Attachment 62.1.

63.0 Reference: Exhibit B-1, pp. 159, 265; Exhibit B-7, BCUC 1.194.3.1, Exhibit B-1-6, p. 287

2014–2018 PBR Application

Additions to the 2014–2018 PBR Application deferral account are $500 thousand in 2013 and $700 thousand in 2014 (Exhibit B-1-6, p. 287).

63.1 Please provide a breakdown of the actual incremental costs incurred to-date and the forecast incremental costs that will be incurred related to the 2014–2018 PBR Application. The total should agree to the 2013 and 2014 additions to the 2014–2018 PBR Application deferral account.

Response:

The requested information is provided in the table below.

		Forecast		
	2013 YTD	2013	2014	Total
	($000s)	($000s)		
BCUC and Intervener Costs	27	60	450	510
Legal Fees	17	250	130	380
Consulting Fees	84	150	80	230
Staff and Other expenses	35	40	40	80
Total Expenditure	163	500	700	1,200
Income Tax Effect	(42)	(129)	(182)	(311)
Net Expense	121	371	518	889
Deferred Financing Cost		11		11
Total Additions to Deferred Charges		382		900

63.2 Please provide a comparison of the total forecast costs associated with the 2014–2018 PBR Application and the total actual costs related to the 2012-2013 RRA and ISP Application. Please confirm that PACA funding is included in all of the deferral accounts listed under the heading "Regulatory Compliance" in Table 1-B, Tab E of the Application.

Response:

The requested information is provided in the table below.

	2014-2018 PBR	2012-13 RRA
	($000s)	
BCUC and Intervener Costs	510	516
Legal Fees	380	434
Consulting Fees	230	920
Staff and Other expenses	80	536
Total Expenditure	1,200	2,405
Income Tax Effect	(311)	(601)
Net Expense	889	1,804

FBC confirms that PACA funding is recorded in the deferred accounts for Regulatory Compliance.

64.0 Reference: Exhibit B-7, BCUC 1.197.2; Exhibit B-1, Tab E, Table 1-B

2014–2018 Capital Expenditure Plan

"FBC has incurred approximately $361 thousand of preliminary engineering costs to the end of July 2013." (Ex. B-7, BCUC 1.197.2)

According to Table 1-B, the balance of the 2014–2018 Capital Expenditure Plan deferral account at December 31, 2012 is $200 thousand and the 2013 additions are $483 thousand.

64.1 Please provide a breakdown of the additions to the 2014–2018 Capital Expenditure Plan deferral account, by year, with a description of the nature of the costs.

Response:

Expenditures relating to the 2014 – 2018 Capital Expenditure Plan deferral account are provided in the following table.

2014 - 2018 Capital Expenditure Plan Review ($ Thousands)

	2012 Actual	2013 Forecast	Total
Labour	$ 158	$ 294	$ 452
Consulting	96	$ 180	276
Other Expenses	5	$ 9	14
Subtotal	**$ 259**	**$ 483**	**$ 742**
Financing Cost	8	29	37
Tax Impact	(67)	(128)	(195)
Total	**$ 200**	**$ 385**	**$ 585**

65.0 Reference: Exhibit B-7, BCUC 1.202.2; Exhibit B-1, p. 286

City of Kelowna Acquisition Customer Benefit

The 2013 additions to the City of Kelowna Acquisition Customer Benefit are $2,610 thousand (Exhibit B 1, p. 286).

The following schedule of 2013 additions to the Revenue Variance deferral account was provided in response to BCUC 1.202.2:

		($000s)
2013 Approved Revenue per BCUC Order G 110-12	A	303,732
City of Kelowna Revenue per BCUC Order C-4-13	B	6,799
Total 2013 Approved Revenue	C=A+B	**310,531**
Projected Revenue 2013	D	304,875
Projected Revenue Variance 2013	E=C-D	**5,656**
Less Income Tax	F	(1,414)
Projected 2013 Revenue Variance 2013 (after tax)	G=E+F	**4,242**

(see Exhibit B-1, Section E, Page 299, Line 5)

65.1 Is the City of Kelowna Acquisition Customer Benefit of $2,610 thousand included in the 2013 approved revenue requirements including the City of Kelowna of $310,531 thousand?

Response:

The City of Kelowna Acquisition Customer Benefit of $2,610 thousand was over-collected and was therefore included in the 2013 approved revenue requirements including the City of Kelowna of $310,531 thousand. This was done to maintain customer rates at 4.2 percent during 2013.

This over collection in 2013 was captured in a deferral account and will reduce the Revenue Requirements in 2014, thus reducing customer rates in 2014.

Please also refer to Exhibit B-1, Section-E, Table 2-C, Line-9.

65.1.1 If yes, please explain if the ratepayer is bearing the cost of the customer benefit through the additions to the revenue variance deferral account and receiving the same amount of benefit through the City of Kelowna

Acquisition Customer Benefit deferral account, with a net revenue requirement impact of $nil.

Response:

As indicated in the response to BCUC IR 2.65.1, the City of Kelowna Acquisition Customer Benefit of $2,610 thousand will be refunded to the customers in 2014 (through the 2014 Rate Setting Process). This in turn will reduce the Revenue Requirements in 2014, thus reducing customer rates in 2014.

66.0 Reference: Exhibit B-1, pp. 269–270; Exhibit B-7, BCUC 1.203.1–1.203.3.1; Order G-163-12

On-Bill Financing (OBF) Participant Loans

"OBF Loans will carry the 4.5 per cent rate prescribed by regulation, and are paid off in monthly installments over a 10 year term." (Exhibit B-7, BCUC 1.203.3)

"While the balance in this account will be reduced by principal and interest repayments, there will still be a balance outstanding at year-end." (Exhibit B-7, BCUC 1.203.3.1)

"FBC is approved to establish two new non-rate base deferral accounts:

…(ii) OBF Financing Deferral Account: a new non-rate base deferral account attracting AFUDC, to capture, on a net-of-tax basis, the principal loan balances provided to participating customers of the OBF Pilot Program and the applicable interest charges and recoveries." (Order G-163-12)

66.1 Please confirm, or explain otherwise, that FBC will earn 4.5 percent plus AFUDC on the outstanding loan balance each year.

Response:

FBC will not earn 4.5 percent plus AFDUC on the outstanding loan balance each year.

Pursuant to Commission Order G-163-12, which approved the OBF Pilot Program, there are three components attributable to the OBF Pilot Program loans, which include (1) AFUDC, (2) the 4.5 percent loan interest rate and (3) the interest rate buydown.

1. Since FBC will be providing OBF Program participants with the loan funds, these balances will form part of FBC's investment, which is financed with a combination of debt and equity, pursuant to the approved capital structure of FBC. This means that for 2014 the loan balances will attract FBC's cost of financing, which is the after-tax Weighted Average Cost of Capital ("WACC"), also known as AFUDC, which consists of debt and equity returns and has been approved pursuant to Commission Order G-163-12. To clarify, FBC does not earn AFUDC, rather the debt component is meant to offset the FBC's incremental interest costs to finance the loans. It is only the equity component of AFUDC that provides a return to FBC. It should also be noted that FBC's WACC could be subject to change as a result of the Generic Cost of Capital proceeding stage 2 and future revenue requirements applications.

2. Section 4(1)(a) of the Improvement Financing Regulation under section 17.1 of British Columbia's *Clean Energy Act* requires FBC to provide the loans to participants "at a fixed rate that does not exceed 4.5 annual percentage rate." So while the weighted

average of the loan balances would attract FBC's WACC, the participating customers are financing the loans at 4.5 percent, which is at a lower cost than the Utilities' WACC. In other words, the interest paid by participants is in the form of interest income and it is being used to offset the incremental cost of financing, therefore FBC does not earn a return on the 4.5 percent component.

3. Having participating customers pay the true cost of financing for the loan balances may have been prohibitive in attracting participants to the OBF Pilot Program. Therefore the difference between the FBC's costs to finance the loans at the WACC and the interest revenue received from Pilot Program participants, results in a revenue shortfall that must be recovered. This shortfall amount is referred to as the "interest rate or loan buy-down" which is deferred pursuant to Order G-163-12 and recovered from all customers.

66.2 Please explain why FBC seeks approval to transfer this deferral account from non-rate base (as directed by Order G-163-12) to rate base effective January 1, 2015.

Response:

Assuming the question is referring to the OBF Financing Deferral account, Order G-163-12 does not require the transfer of this deferral amount to rate base effective January 1, 2015. FBC is seeking approval for this transfer for the reasons articulated in the response to BCUC IR 1.203.3.1.

"In accordance with Commission Order G-163-12, FBC created a non-rate base deferral account attracting AFUDC to capture, on a net-of-tax basis: the OBF Pilot Program costs." (Ex. B-1, p. 265)

66.3 Please identify the line item of Table 1-B, in Tab E of the Application that contains the On-Bill Financing Pilot Program and OBF Participant Loans deferral account.

Response:

The OBF Pilot Program and OBF Participant Loans are not included in Table 1-B. Table 1-B shows only the deferred charges for which FBC seeks rate base treatment in 2014. The OBF

Pilot Program costs will be transferred to rate base effective January 1, 2015 (see Section D 4.4.2 of Exhibit B-1). FBC is seeking approval to transfer the OBF Participant Loans account to rate base effective January 1, 2015 (see Section D4.5.2 of Exhibit B-1).

The forecast additions, recoveries, and balances of these two accounts in 2013 and 2014 are shown below.

	Balance at Dec. 31, 2012	Additions and Transfers	Add Deferred Financing Cost	Less Taxes	Amortized / Transferred to Other Accounts	Deferred Interest Amort.	General Amortization	Balance at Dec. 31, 2013
				($000s)				
On Bill Financing (OBF) Pilot Program	11	26	2	(7)	-	-	-	32
On Bill Financing (OBF) Participant Loans	-	220	7	(58)	-	-	-	168

	Balance at Dec. 31, 2013	Additions and Transfers	Add Deferred Financing Cost	Less Taxes	Amortized / Transferred to Other Accounts	Deferred Interest Amort.	General Amortization	Balance at Dec. 31, 2014
				($000s)				
On Bill Financing (OBF) Pilot Program	32	34	4	(10)		(3)	-	57
On Bill Financing (OBF) Participant Loans	168	240	21	(68)	(16)	(5)	-	340

67.0 Reference: Exhibit B-1, p. 266 and 270; Exhibit B-7, BCUC 1.205.2 and 1.211.1.1

Section 71 (Waneta Expansion Capacity Agreement Application)

"The deferred costs also include expenditures arising from an application for reconsideration of E-29-10 filed by the Industrial Customers Group on November 10, 2011." (Exhibit B-1, p. 270)

FBC notes a variance of $296 thousand between the approved and actual December 31, 2012 balance, due to "Increased expenditures arising from an application for reconsideration of Order E-29-10 filed by the Industrial Customers Group on November 10, 2011." (Exhibit B-7, BCUC 1.211.1.1)

"On December 12, 2012, FBC applied to the Commission for approval to establish certain deferral accounts." (Exhibit B-1, p. 266)

67.1 Please explain why FBC did not apply for recovery of the costs associated with the reconsideration of Order E-29-10 in the 2012-2013 Revenue Requirements and Review of ISP application or the December 12, 2012 FBC application for approval to establish certain deferral accounts.

<u>Response:</u>

FBC treated the reconsideration application as a continuation of the initial Section 71 filing and accordingly did not segregate the costs of the reconsideration application and the initial application. Final disposition of the reconsideration application occurred after the completion of the 2012-2013 revenue requirements process, with the issuance of Order E-15-12 on May 30, 2012 accepting the WAX CAPA pursuant to section 71 of the UCA.

The December 2012 application was, as noted in the preamble, an application to establish deferral accounts that were not in existence at the time. As stated, the Company considered that the costs of the reconsideration application were appropriately captured in the initial Section 71 filing account and that no further approval was necessary to record the costs in this existing deferral account. The December 2012 application did not seek recovery of any deferred amounts, since in FBC's view the appropriate forum to seek recovery is the next occurring revenue requirements application, that is, the 2014 revenue requirements application.

The costs of FBC's participation in the reconsideration phase of the Section 71 application were necessary and prudent to defend FBC's assertion that the Commission did not err in its decision in Order E-29-10. In the end, the Commission agreed with FBC and upheld its decision. There is no basis on which to deny the recovery of these costs.

68.0 Reference: Exhibit B-1, p.273

CPCN Projects Preliminary Engineering

FBC states:

> "FBC incurs preliminary and investigative engineering costs in the development of capital projects which are to be approved by way of a CPCN application. As the Company does not intend to include in revenue requirements the impact of forecast CPCN projects until approved and entering plant in service, it is appropriate to retain the preliminary and investigative costs outside of rate base, attracting AFUDC. Following approval of the CPCN application, costs will be transferred to the capital project" (Exhibit B-1, p. 273).

68.1 For clarity, if a CPCN Application is not approved, please explain how these costs would be recovered by FBC.

Response:

If a capital project does not proceed, the preliminary and investigative engineering costs are not eligible for capitalization. As long as the costs were prudently incurred, they are eligible for recovery through rates, and FBC would likely apply to the Commission for inclusion in the subsequent revenue requirements application.

69.0 Reference: Exhibit B-1, p. 285–288; Exhibit B-7, BCUC 1.211.1

Power Purchase Expense Variance Deferral Account

69.1 Please provide detailed calculations in a working excel document to support the 2012 and 2013 additions of ($8,437) thousand and ($6,120) thousand, respectively, to the Power Purchase Expense Variance deferral account.

<u>Response:</u>

The detailed calculation is shown in the table below that supports the Power Purchase Expense Variance deferral accounts for 2012 and 2013. A working speadsheet is included as Attachment 69.1. Please also refer to Exhibit B-1, p. 299, Table 2-C, lines 6 &7.

Power Purchase (with Water Fees)	Approved	Actual / Forecast	Variance	Income Tax Shield	After Tax Amount
Power Purchase 2012	87,149	75,999	11,150	(2,787)	8,362
Water Fees 2012	9,353	9,253	100	(25)	75
Total (2012)	**96,502**	**85,252**	**11,250**	**(2,813)**	**8,438**
Power Purchase 2013	91,942	84,266	7,676	(1,919)	5,757
Water Fees 2013	9,871	9,387	484	(121)	363
Total (2013)	**101,813**	**93,653**	**8,160**	**(2,040)**	**6,120**

Note: Minor differences due to rounding

69.2 Please confirm, or explain otherwise, that the power purchase expense variance deferral account captures variances in both load and cost, while the revenue variance account captures variances for load only.

<u>Response:</u>

Confirmed. The Power Purchase Expense Variance deferral captures both price and volume variances.

The Revenue Variance deferral account captures only volume variances, as the price is set through approved rates which do not change during the test period. Therefore, there is no price variance on Revenue.

70.0 Reference: Exhibit B-1, p. 273

Preliminary and Investigative Charges Deferral Account

70.1 Please provide a breakdown and an explanation for the forecast 2014 additions to the Preliminary and Investigative Charges Deferral Account.

Response:

The forecast 2014 additions of $0.150 million are related to preliminary and investigative engineering associated with regular capital projects. These expenditures are managed as a single item, and may vary from year to year depending on the need for preliminary engineering for regular capital projects. As such, no breakdown is available.

Please also refer to the response to BCUC IR 1.182.1.

71.0 Reference: Exhibit B-1-6, p. 285

Generic Cost of Capital (GCOC) Revenue Requirements Impact

2013 additions to the GCOC Revenue Requirements Impact deferral account are $3,611 thousand.

71.1 Please provide a detailed calculation in a working excel document to support the 2013 additions to the GCOC Revenue Requirements Impact deferral account.

Response:

The relevant calculation for the GCOC Revenue Requirements Impact deferral account has been shown in the table below.

Calculation of GCOC
Revenue Requirement Deferral Impact

Approved Rate Base 2013 ($000s):	1,203,669	A
Equity Ratio	40.0%	B
Post GCOC ROE	9.90%	C
Pre GCOC ROE	9.15%	D
Pre GCOC Equity Earnings ($000s):	47,665	E=A*B*C
Post GCOC Equity Earnings ($000s):	44,054	F=A*B*D
Variance ($000s):	**3,611**	**G=E-F**

72.0 Reference: Exhibit B-1-6, p. 269

2007 AMI Application Costs

"In the July 23, 2013 decision approving the AMI Project, the Commission determined that the costs of the 2007 application and regulatory process should not form part of the Project, and directed FBC to apply for recovery in its next revenue requirements application. FBC proposes to amortize the 2007 application costs in 2014." (Exhibit B-1-6, p. 269)

72.1 Please provide the rate of return that FBC proposes for the 2007 AMI Application Costs deferral account and explain why.

Response:

FBC will apply its WACD to the deferral account in 2013, consistent with the treatment of the preliminary and investigative spending deferral account that recorded the project development and CPCN application costs (to which AFUDC was applied). The Company requests rate base treatment of the account in 2014, consistent with its requested treatment for the costs of its other accounts related to regulatory proceedings.

73.0 Reference: Exhibit B-1-6, p. 266

City of Kelowna Acquisition Legal and Regulatory Costs

"In its final submission in the Phase 2 proceeding on September 12, 2013, FBC requested that the $0.5 million cap for closing, legal and regulatory costs for the acquisition set in Order C-4-13 be lifted or determined to be inapplicable to Phase 2 in order to permit recovery of Phase 2 costs, explaining that the cost estimate provided in Phase 1 of the acquisition proceeding was related only to the purchase of the assets, not to issues of rate discrimination, and that Phase 2 was not contemplated at the time that FBC's cost estimate was provided." (Exhibit B-1-6, p. 266)

73.1 For each of 2012 and 2013, please provide a breakdown of the additions to the City of Kelowna Acquisition Legal and Regulatory Costs deferral account between Phase 1 and Phase 2 costs.

Response:

The requested information is provided below.

	2012	2013	Total
		($000s)	
Phase I	140	360	500
Phase 2 (Forecast)	-	125	125
Total Expenditure	140	485	625
Income Tax Effect	(35)	(125)	(160)
Net Expense	105	360	465
Financing Costs			19
Deferred Balance			484

73.1.1 Please provide a breakdown of the Phase 2 costs identified in the preceding IR.

Response:

The forecast of Phase 2 costs is provided in the table below.

	2013 ($000s)
BCUC and Intervener Costs	60
Legal Fees	60
Consulting Fees	-
Staff and Other Expenses	5
Total Expenditure	125
Income Tax Effect	(32)
Net Expense	93

Note: Excludes Financing Costs

73.2 Please explain if the lifting of the $0.5 million cap for the acquisition has been approved by the Commission.

Response:

Yes. On November 22, 2013, the Commission issued its decision in the City of Kelowna Phase 2 proceeding (Order G-191-13). Regarding the regulatory costs of the Phase 2 proceeding, the Order states:

> *"The cap of $0.5 million set in Order C-4-13 for recovery of FortisBC's closing, regulatory process and legal costs is not applicable to the Phase 2 Proceeding. FortisBC is approved to separately recover the regulatory costs associated with the Phase 2 Proceeding. FortisBC is to establish a similar non-rate base deferral account attracting interest at FortisBC's approved short-term interest rate to capture the regulatory costs of the Phase 2 Proceeding. FortisBC is to apply for disposition of the Phase 2 deferral account as part its 2014-2018 Multi-Year Performance Based Ratemaking Revenue Requirements Application."*

FBC has proposed to amortize the CoK Phase 2 costs in 2014.

73.3 What is the rate impact from the amortization of the Phase 2 proceeding costs in 2014?

Response:

The rate impact in 2014, absent the RSDM, would be approximately 0.03 percent.

74.0 Reference: Exhibit B-1, pp. 285–288

Table 1-B — Deferred Charges and Credits

74.1 Please explain the difference between the Amortized / Transferred to Other Accounts column and the General Amortization column in Table 1-B.

Response:

Generally, the column "Amortized/Transferred to Other Accounts" is used to transfer costs to other accounts such as O&M and capital. The "General Amortization" column is used to amortize costs to depreciation and amortization expense.

75.0 Reference: Exhibit B-7, BCUC 1.180.1

Financing of Deferral Accounts

FBC discusses the Commission's recent Pacific Northern Gas Ltd. (PNG) decision as it pertains to deferral accounts and states that:

> "FBC respectfully notes that the Commission has applied its principles in an inconsistent manner. For example, in its decision (on page 40):
>
> *'Therefore, the Panel denies the $887,000 capital additions for the Rio Tinto Alcan modernization project for 2013. The Panel directs PNG to place the costs incurred for the RTA project in the test year 2013 into a non-rate base,* ***non-interest bearing deferral account****. PNG is directed to apply for approval of the capital costs associated with the RTA project as part of its 2014 RRA.'* **[emphasis added]**
>
> These amounts are clearly of a capital nature and therefore, using the Commission's own principles, should attract a WACC return, but have been denied any return at all." (Ex. B-7, BCUC 1.180.1)

The Commission also states in the PNG decision that it:

> "is not persuaded that the forecast for the purchase price of new vehicles is justified…The Panel notes that PNG did not provide a more accurate cost estimate for the project and that negotiations with RTA were still underway at the time of PNG filing its responses to the second round of IRs. **Therefore, the Panel denies the $887,000 capital additions for the Rio Tinto Alcan modernization project for 2013.**"[8]

75.1 Taken into context, it appears that the Commission's denial of the PNG project relates to the finding that there was insufficient support and justification for the capital project. Accordingly, the capital expenditure was denied. Does FBC agree with this observation?

<u>Response:</u>

No. If the project was denied, then there would be no reason for the Commission to approve a deferral account. FBC's reading of the preamble indicates that the capital additions were denied for 2013 only, and that by placing them into a deferral account, they will be considered for approval in the future. Since the only method that PNG can be held whole for these

---

[8] In the Matter of Application for Approval of 2013 Revenue Requirements for the PNG-West Service Area Decision, p. 40

expenditures, if they are approved, is to record WACC (AFUDC) on the expenditures as they are made, then the Commission has effectively denied PNG a fair return on these capital costs. The only alternative is that the Commission intended, if the costs were subsequently approved, to allow PNG to record AFUDC on a retroactive basis in the deferral account. FBC does not believe this to be an accepted regulatory practice.

75.2 If the PNG capital expenditure was approved on the basis that the project was necessary and in the public interest, and that the costs were reasonable, does FBC believe that such costs would accrue into PNG's Construction Work in Progress or certain other capital accounts, which would be allowed a rate base return?

Response:

Refer to the response to BCUC IR 2.75.1 where FBC discusses that the deferral account would not have been approved had the Commission actually denied the costs. FBC agrees that had such costs been approved they would have accrued into Construction Work in Progress at the time they were incurred and earned AFUDC during the construction phase. This does not, however, address the absence of a fair return on the costs prior to the determination of whether they were necessary and in the public interest.

76.0 Reference: Exhibit B-7, BCUC 1.180–1.182; Exhibit B-1, Tab E Financial Schedules

Financing of Deferral Accounts

"FBC (and FEI, FEVI and FAES) have stated on the record in various proceedings that they do not agree with the conclusions reached by the Panel" with regards to the Commission's determinations on the financing of deferral accounts, established in the last RRA decision[9] (Exhibit B-7, BCUC 1.180.1).

"FBC considers that, regardless of whether the Commission characterizes these assets as 'capital' or 'regulatory', a utility will not be able to capitalize them with 100% debt…" (Exhibit B-7, BCUC 1.180.1)

"…the return on deferral accounts that is afforded the utility is to compensate for the time period that the deferral is being <u>financed</u> by the utility. This is the case whatever the nature or time period of recovery for the account." (Exhibit B-7, BCUC 1.181.3) (emphasis added)

76.1 In Table 1-B of the Application, FBC provides all of its current and proposed deferral or variance accounts, separated into several categories. Please explain whether these headings are meant to generally describe the intended purpose for each category of deferral accounts.

<u>Response:</u>

The general categories used by FBC to describe its deferral accounts are explained in more detail in Table D4-1 at page 258 of the Application. Table D-4 generally describes the reasons for deferring the charges or credits.

76.2 Given that it is FBC's view that the financing costs to be allowed on all deferral accounts should reflect its true cost of financing, please discuss why it is appropriate that all deferral accounts, regardless of their intended purpose, should be allowed a rate base return. For example, deferral accounts for the purpose of rate smoothing, variances accounts that capture variance in forecasts, regulatory costs which have amortization periods to match for the timing of benefits derived.

---

[9] In the Matter of An Application by FortisBC 2012–2013 Revenue Requirements and Review of 2012 Integrated System Plan Application (FBC 2012-2013 RR & ISP), Decision pp. 103-106

Response:

Section D 3.2 clearly describes the reasons that FBC believes the majority of deferred accounts should be held in rate base. The "purpose" of the deferral accounts does not have any bearing on the utility's cost of financing the account. As FBC states on page 248 of the Application:

> *"Allowing deferrals to attract a rate base rate of return recovers the costs associated with the timing difference when there is an outlay of funds and when those costs are recovered from ratepayers. A rate base rate of return is the only logical and consistent approach to be applied…"*

76.2.1 Please discuss what "financing" is incurred by FBC for each of the categories listed in Table 1-B.

Response:

The Company finances all of its assets, including deferred accounts, with a mix of debt and equity, in proportions and at rates approved by the Commission, that is, the Weighted Average Cost of Capital. The Company also finances timing differences between expenditures and revenue in the same way (through the Allowance for Working Capital component of rate base). There is no distinction to be made between the categories by which FBC classifies, for convenience, its deferral accounts, in terms of the financing that the Company incurs to finance the various accounts.

76.3 In order to streamline the management of deferral accounts, would it be appropriate to create a materiality threshold that would require amounts of $1.0 million or less to be amortized over one year? Please explain why, or why not.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 2.334.1a. The response is similar to the FEI response to that IR.

FBC does not believe this approach is appropriate as it has requested and received approval for a specific amortization period for each individual deferral account based on consideration of the specific circumstances of that deferral.

This change could potentially result in changing the amortization period from year to year. For example, if an account had a balance under $1 million in one year, it would be amortized the next year, however if the balance increased to $2 million the following year, it would revert back to its existing approved amortization period. This has the potential to be administratively burdensome and confusing.

Additionally, the potential rate impacts could be material to FBC customers, given the size of the threshold proposed in the question to FBC's total revenue requirement of just $323.4 million.

Lastly, FBC will usually seek to request or modify amortization periods for deferral accounts to keep customer rates manageable, depending on the forecasted activity in each account. Adopting a blanket policy that is out of FBC's control may serve to create rate fluctuations that are unnecessary and could more easily be managed under the existing policies.

G. PENSION AND OTHER POST-EMPLOYMENT BENEFITS (OPEB)

77.0 Reference: Exhibit B-1, pp. 53 and 58; Exhibit B-7, Attachment 213.1

Pension and OPEB Expense

77.1 Please complete the following schedule of Forecast 2014 Pension and OPEB Expense.

Pension Expense	
OPEB Expense	
Subtotal 2014 Pension & OPEB Expense	
Amortization of US GAAP Pension Transitional Obligation	
Amortization of 2005 CICA OPEB Liability	
Amortization of US GAAP OPEB Transitional Obligation	
Total 2014 Pension & OPEB Expense	
O&M Portion	
Capital Portion (Base Capital)	
Capital Portion (Major Projects)	

<u>Response:</u>

The schedule in the question has been completed as follows:

Pension and OPEB Expense		**2014 Forecast**
($ thousands)		
Pension Expense		8,159
OPEB Expense		3,314
Subtotal 2014 Pension & OPEB Expense		11,473
Amortization of US GAAP Pension Transitional Obligation		183
Amortization of 2005 CICA OPEB Liability		480
Amortization of US GAAP OPEB Transitional Obligation		163
Total 2014 Pension & OPEB Expense		**12,299**
O&M Portion		5,904
Capital Portion (Base Capital)	5,625	
Capital Portion (Major Project)	770	6,395
Total 2014 Pension & OPEB Expense		**12,299**

Note: Minor Difference due to Rounding

77.1.1 If the Subtotal 2014 Pension & OPEB Expense does not agree to the Tower Watson projection in Exhibit B-7, Attachment 213.1, please explain why.

Response:

The subtotal 2014 Pension and OPEB Expense of $8,159 thousand and $3,314 thousand, respectively, included in the response to BCUC IR 2.77.1 agrees to the 2014 Pension and OPEB net benefit cost projections included in Exhibit B-7, Attachment 213.1.

As shown in the responses to BCUC IRs 2.77.1, 1.213.1 and 1.213.4, it is necessary to include in Total 2014 Pension & OPEB Expense the Amortization of US GAAP Pension Transitional Obligation of $183 thousand, the Amortization of the 2005 CICA OPEB Liability of $480 thousand and the Amortization of US GAAP OPEB Transitional Obligation of $163 thousand, all of which were approved for recovery as Pension & OPEB expense pursuant to BCUC Order G-110-12.

77.1.2 If the O&M portion does not agree toForecast 2014 in Exhibit B-1, Table B6-5 of $5,904 thousand, please explain why.

Response:

The 2014 Pension and OPEB Expense O&M portion of $5,904 thousand, which was provided in the response to BCUC IR 2.77.1 and includes the various transitional obligation amortizations approved for recovery in Pension & OPEB expense pursuant to BCUC Order G-110-12, agrees to Exhibit B-1, Table B6-5: Forecast O&M Formula Results on page 53 of Section B6 of the 2014-2018 PBR Plan Application (Exhibit B-1).

77.1.3 If the Capital portion (Base Capital) does not agree to 2014 Forecast in Exhibit B-1, Table B6-7 of $6,396 thousand, please explain why.

Response:

The 2014 Base Capital portion of Pension & OPEB expense estimated at $5,625 thousand and the 2014 Major Capital Project portion of Pension & OPEB expense estimated at $770 thousand, both which were provided in the response to BCUC IR 2.77.1, are in aggregate $6,396 thousand, which agrees to Exhibit B-1, Table B6-7: PBR Capital Formula Inputs and 5 Year Forecasts on page 58 of Section B6 of the 2014-2018 PBR Plan Application.

It is incorrect to conclude that only the Base Capital portion of Pension & OPEB expense of $5,625 thousand should be added to Total Capital under PBR. However, the entire 2014 Pension and OPEB expense attributable to both base and major capital of $6,396 thousand has been excluded from the formulaic capital in order to isolate it and track it separately as all variances between actual and approved Pension and OPEB costs are captured in a deferral account. The entire 2014 capital portion of $6,396 thousand is an actual capital cost that is forecast to be incurred in 2014 and, as such, should be included in the Total Capital Under PBR for 2014 of $100,299 thousand for 2014 on page 58 of the October 18, 2013 Evidentiary Update (Exhibit B-1-6).

77.2 Please complete the following schedule of Approved and Actual 2012 and 2013 Pension and OPEB Expense.

	Approved (Order G-110-12)	Actual	Difference
Pension Expense			
OPEB Expense			
Subtotal 2012 Pension & OPEB Expense			
Amortization of US GAAP Pension Transitional Obligation			
Amortization of 2005 CICA OPEB Liability			
Amortization of US GAAP OPEB Transitional Obligation			
Total 2012 Pension & OPEB Expense			
	Approved (Order G-110-12)	**Actual**	**Difference**
Pension Expense			
OPEB Expense			
Subtotal 2013 Pension & OPEB Expense			
Amortization of US GAAP Pension Transitional Obligation			
Amortization of 2005 CICA OPEB Liability			
Amortization of US GAAP OPEB Transitional Obligation			
Total 2013 Pension & OPEB Expense			

Response:

The schedule in the question has been completed as follows:

Pension and OPEB Expense	**Approved (Order G-110-12)**	**Actual**	**Difference**
	($ thousands)		
Pension Expense	4,691	8,700	4,009
OPEB Expense	2,726	2,872	146
Subtotal 2012 Pension & OPEB Expense	7,417	11,572	4,155
Amortization of US GAAP Pension Transitional Obligation	183	183	-
Amortization of 2005 CICA OPEB Liability	480	480	-
Amortization of US GAAP OPEB Transitional Obligation	163	163	-
Total 2012 Pension & OPEB Expense	**8,243**	**12,398**	**4,155**

Pension and OPEB Expense	**Approved (Order G-110-12)**	**Forecast**	**Difference**
	($ thousands)		
Pension Expense	4,039	8,923	4,884
OPEB Expense	2,825	3,213	388
Subtotal 2013 Pension & OPEB Expense	6,864	12,136	5,272
Amortization of US GAAP Pension Transitional Obligation	183	183	-
Amortization of 2005 CICA OPEB Liability	480	480	-
Amortization of US GAAP OPEB Transitional Obligation	163	163	-
Total 2013 Pension & OPEB Expense	**7,690**	**12,962**	**5,272**

Note: Minor Difference due to rounding

77.2.1 Please provide the actuary report to support the actual 2012 pension and OPEB expense.

Response:

Please refer to Attachment 77.2.1 filed confidentially as it contains the actuarial report to support the actual 2012 pension and OPEB expense.

78.0 Reference: Exhibit B-1, p. 285; Exhibit B-7, BCUC 1.214.2

Pension and OPEB Expense Variance Deferral Account

78.1 Please discuss the pros and cons of maintaining the three year amortization period for the Pension and OPEB Expense Variance Deferral Account, rather than moving to the proposed 11 year amortization period based on the Expected Average Remaining Service Life of the benefit plans.

Response:

The disadvantage of using a three year period for Pension and OPEB Expense Variance Deferral Account have been discussed in detail in the response to BCUC IR 1.214.2 which discusses the appropriateness around using the 11 year amortization period based on the EARSL. The pros of using a shorter amortization period, such as three years, would be lower debt and equity financing costs as compared to longer amortization periods which would impose a higher accumulation of debt and equity financing costs. However, the shorter amortization period would put upward pressure on revenue requirements through increased amortization expense during the early part of the PBR period as there is an approximate $9.4 million variance in 2012 and 2013 Pension and OPEB expense to be recovered from customers over a shorter period of time. For the Pension & OPEB variances that result during the 2014-2018 PBR period, it is not known whether the variances will either be costs to be recovered from customers in future rates, or savings to be refunded to customers in future rates and therefore the expected revenue requirements impact is not known at this time.

79.0 Reference: Exhibit B-1, p. 242, 285–288; Exhibit B-7, BCUC 1.211.1

Prepaid Pension Costs and OPEB Liability

79.1 Please provide detailed calculations to support the 2012 and 2013 additions of ($12,010) thousand and ($5,091) thousand, respectively, to the Prepaid Pension Costs and OPEB Liability deferral account. Please provide separate calculations for each of pension and OPEB costs.

<u>Response:</u>

The following table provides detail of 2012 and 2013 additions for Prepaid Pension Costs and OPEB Liability deferral accounts (with explanatory footnotes).

	2012 Actual	2013 Projection
	($000s)	
Additions to the Prepaid Pension Cost Deferral Account		
Contributions based on external actuarial funding valuation	6,764	6,388
Pension Expense approved pursuant to G-110-12 (see response to BCUC IR 2.77.2)	(4,691)	(4,039)
Variance between actual pension expense and approved (see response to BCUC IR 2.77.2)	(4,009)	(4,884)
Initial recognition of US GAAP Pension Transitional Obligation in Deferred Charges effective January 1, 2012 (approved per G-110-12) [(1)]	(2,194)	-
Net change in Prepaid Pension Cost Deferral Account	(4,130)	(2,535)
Additions to the OPEB Liability Deferral Account		
Contributions based on external actuarial funding valuation	480	657
OPEB Expense approved pursuant to G-110-12 (see response to BCUC IR 2.77.2)	(2,726)	(2,825)
Variance between actual OPEB expense and approved (see response to BCUC IR 2.77.2)	(146)	(388)
Initial recognition of 2005 CICA OPEB Liability in Deferred Charges effective January 1, 2012 (approved per G-110-12) [(2)]	(3,525)	-
Initial recognition of US GAAP OPEB Transitional Obligation in Deferred Charges effective January 1, 2012 (approved per G-110-12) [(2)]	(1,963)	-
Net change in OPEB Liability Deferral Account	(7,880)	(2,556)
Total Net Change in Prepaid Pension Cost & OPEB Liability Deferral Accounts	**(12,010)**	**(5,091)**

Notes:

(1) Included in Section 5.4.5.iii – Prepaid Pension Costs, on page 25 of Tab 5 – Rate Base of FBC's 2012-2013 RRA, filed June 30, 2011, it stated that "the 2012 change in this Prepaid Pension cost account balance will reflect a reduction of $2.2 million, the offset which is recognized in the Pension Transitional Obligation Deferral Account, a separate Rate Base deferral account. The Company is requesting approval to recognize the total Prepaid Pension Costs as a rate Base deferral account". On page 121 of BCUC Order G-110-12, dated August 15, 2012, the Commission Panel Determination on both the Prepaid Pension Costs indicated that "the Commission Panel approves this deferral account as a non-rate base deferral account".

(2) Included in Section 5.4.5.v – Other Post-Employment Benefits (OPEB), on page 29 of Tab 5 – Rate Base of FBC's 2012-2013 RRA, filed June 30, 2011, it stated that "the 2012 change in the OPEB liability account balance will reflect the initial recognition of a $3.5 million 2005 CICA transitional adjustment and a $2.0 million US GAAP transitional adjustment, both of which will be offset in a separate Rate Base deferral account." On page 122 of BCUC Order G-110-12, dated August 15, 2012, the Commission Panel Determination on Other Post-Employment Benefits Deferral Accounts that "the Commission Panel approves the creation of a non-rate base deferral account".

79.2 Please provide a continuity schedule of the Prepaid Pension Costs and OPEB Liability deferral account, broken out between pension costs and OPEB costs. Please provide the continuity schedule in the same format as Table 1-B of Exhibit B-1.

Response:

The following is a continuity schedule in the format of Table 1-B of Exhibit B-1 which segregates Prepaid Pension Costs and OPEB Liability deferral accounts for 2012, 2013 and 2014 pursuant to the Evidentiary Update filed October 18, 2013.

($000s)

	Actual Balance at Dec 31, 2011	Additions and Transfer	Add Deferred Financing Cost	Less Taxes	Amortized/Transferred to Other Accounts	Deferred Interest Amort	General Amortization	Actual Balance at Dec 31, 2012
Prepaid Pension Costs	6,346	(4,130)	296	1,024	-	(450)	(46)	3,040
OPEB Liability	(9,354)	(7,880)	(1,042)	2,267	-	730	(161)	(15,441)
	(3,008)	(12,010)	(746)	3,291	-	280	(207)	(12,401)

	Actual Balance at Dec 31, 2012	Additions and Transfer	Add Deferred Financing Cost	Less Taxes	Amortized/Transferred to Other Accounts	Deferred Interest Amort	General Amortization	Projection Balance at Dec 31, 2013
Prepaid Pension Costs	3,040	(2,535)	78	694	-	(536)	(46)	695
OPEB Liability	(15,441)	(2,556)	(1,291)	1,006	-	939	(161)	(17,504)
	(12,401)	(5,091)	(1,213)	1,700	-	403	(207)	(16,809)

	Projection Balance at Dec 31, 2013	Additions and Transfer	Add Deferred Financing Cost	Less Taxes	Amortized/Transferred to Other Accounts	Deferred Interest Amort	General Amortization	Forecast Balance at Dec 31, 2014
Prepaid Pension Costs	695	2,427	-	-	-	-	-	3,122
OPEB Liability	(17,504)	(2,593)	-	-	-	-	-	(20,097)
	(16,809)	(166)	-	-	-	-	-	(16,975)

80.0 Reference: Exhibit B-1, pp. 285–288; Exhibit B-7, BCUC 1.211.1

US GAAP Pension and OPEB Transitional Obligation

80.1 Please confirm, or explain otherwise, that the US GAAP Pension and OPEB Transitional Obligation deferral account is a combination of the following three items: i) US GAAP Pension Transitional Obligation, ii) 2005 CICA OPEB Liability and iii) US GAAP OPEN Transitional Obligation.

Response:

FBC confirms that the US GAAP Pension and OPEB Transitional Obligation deferral account, shown on line 13 of Table 1-B on page 287 of Section E of the Evidentiary Update filed on October 18, 2013 (Exhibit B-1-6), is comprised of the i) US GAAP Pension Transitional Obligation, ii) the 2005 CICA OPEB Liability and the iii) US GAAP OPEB Transitional Obligation, all of which were approved pursuant to BCUC Order G-110-12.

80.2 Please provide a continuity schedule of the US GAAP Pension and OPEB Transitional Obligation deferral account, broken out into the three components identified in the preceding IR. Please provide the continuity schedule in the same format as Table 1-B of Exhibit B-1 and include January 1, 2012–December 31 2012, January 1, 2013–December 31 2013 and January 1, 2014–December 31 2014.

Response:

The following is a continuity schedule in the format of Table 1-B of Exhibit B-1 which segregates the i) US GAAP Pension Transitional Obligation, ii) the 2005 CICA OPEB Liability and the iii) US GAAP OPEB Transitional Obligation, all of which were approved pursuant to BCUC Order G-110-12, for the years 2012, 2013 and 2014, the latter two of which are based on the Evidentiary Update filed October 18, 2013 (Exhibit B-1-6).

($000s)

	Actual Balance at Dec 31, 2011	Additions and Transfer	Add Deferred Financing Cost	Less Taxes	Amortized/Transferred to Other Accounts	Deferred Interest Amort	General Amortization	Actual Balance at Dec 31, 2012
US GAAP Pension Transitional Obligation	-	2,194	61	(564)	(183)	(4)	46	1,550
2005 CICA OPEB Liability	-	3,525	94	(904)	(480)	(8)	103	2,329
US GAAP OPEB Transitional Obligation	-	1,963	52	(504)	(164)	(5)	58	1,401
	-	7,682	207	(1,972)	(827)	(17)	207	5,280

	Actual Balance at Dec 31, 2012	Additions and Transfer	Add Deferred Financing Cost	Less Taxes	Amortized/Transferred to Other Accounts	Deferred Interest Amort	General Amortization	Projection Balance at Dec 31, 2013
US GAAP Pension Transitional Obligation	1,550	-	113	(28)	(183)	(8)	46	1,490
2005 CICA OPEB Liability	2,329	-	166	(42)	(480)	(16)	103	2,062
US GAAP OPEB Transitional Obligation	1,401	-	100	(25)	(164)	(9)	58	1,360
	5,280	-	379	(95)	(827)	(33)	207	4,911

	Projection Balance at Dec 31, 2013	Additions and Transfer	Add Deferred Financing Cost	Less Taxes	Amortized/Transferred to Other Accounts	Deferred Interest Amort	General Amortization	Forecast Balance at Dec 31, 2014
US GAAP Pension Transitional Obligation	1,490	-	-	-	(183)	-	-	1,307
2005 CICA OPEB Liability	2,062	-	-	-	(480)	-	-	1,582
US GAAP OPEB Transitional Obligation	1,360	-	-	-	(164)	-	-	1,196
	4,911	-	-	-	(827)	-	-	4,084

Also note that the forecast continuity schedules for the 2012 and 2013 i) US GAAP Pension Transitional Obligation, ii) the 2005 CICA OPEB Liability and the iii) US GAAP OPEB Transitional Obligation were previously provided in Table 5.4.5-2 Comparison of Pension Accounting Balances under US GAAP and IFRS and Table 5.4.5-4 Comparison of OPEB Balances under US GAAP and IFRS, both of which were included in Tab 5 Rate Base of FBC's 2012-2013 RRA, filed June 30, 2011.

80.3 Please provide a copy of the Commission Order that approved the 2005 CICA OPEB Liability deferral account.

Response:

Commission Order G-110-12 provided approval to include in deferred charges the 2005 CICA OPEB Liability deferral account and the offsetting amount in OPEB Liability deferral, beginning on January 1, 2012.

The request by FBC for the BCUC to approve inclusion of the 2005 CICA OPEB Liability deferral account in deferred charges was described in Section 5.4.5.vi – US GAAP OPEB Transitional Obligation Deferral, on page 30 of Tab 5 – Rate Base of FBC's 2012-2013 RRA, filed June 30, 2011, which stated that:

> *"The US GAAP OPEB Transitional Obligation deferral account has been requested for inclusion in the Rate Base as part of the determination of the 2012/13 Revenue Requirements application. This requested Rate Base deferral account includes* ***two components****:*
>
> *Firstly, under US GAAP, it would be necessary for FortisBC to recognize the historical cumulative difference between CGAAP and US GAAP OPEB net benefit costs, referred t herein as an OPEB transitional obligation, in the forecast amount of $2.0 million, as of January 1, 2012. This amount is comprised of the remaining unamortized net transition obligations under CGAAP (which would be fully amortized under US GAAP) and the net benefit cost for three months, resulting from the change in measurement date from September 30 to December 31 as required under US GAAP. The Company also proposes the recovery of this OPEB transitional adjustment over 12 years.*
>
> *Secondly, the requested deferral account also includes the forecast remaining transitional obligation of $3.5 million relating to the* ***CGAAP OPEB liability****. As directed under Commission Order G-52-05, FortisBC began amortizing the accumulated* ***CGAAP 2005 OPEB liability*** *over the EARSL when the Company transitioned from the cash basis to accrual accounting for OPEBs, which was phased-in over a three year period. While the amortization of the CGAAP OPEB transitional obligation has been included in the OPEB expense since 2005, the actual deferral amount has not been previously recognized in Rate Base and has been tracked as a Non-Rate Base deferral account. The Company proposes to recognize the 2005 CICA OPEB transitional adjustment in the US GAAP OPEB Transitional Obligation Rate Base deferral beginning in 2012 and it will be offset by an equal amount in Rate Base included in the US GAAP OPEB Liability Account, previously described. In addition to recognizing the transitional obligation difference between CGAAP and US GAAP OPEB liabilities, it is necessary to still complete the amortization of the difference between the regulatory OPEB balance and the CGAAP OPEB balance from 2005."* [emphasis added]

Page 123 of Commission Order G-110-12, dated August 15, 2013, under the title " US GAAP OPEB Transitional Obligation Deferral Account" stated the following regarding the inclusion of the 2005 OPEB Liability Deferral as a component of the US GAAP OPEB Transitional Obligation Deferral Account:

> *"FortisBC also proposes that a remaining transitional obligation in the amount of $3.5 million which resulted from a change from cash to accrual accounting for* ***OPEB under Canadian GAPP in 2005*** *be recognized in the US GAAP OPEB Transitional Obligation Rate Base Deferral Account. It has been tracked to this time in a Non-Rate Base deferral account. An amount equal to the US GAAP OPEB Transitional Obligation Deferral Account is proposed to be offset against the US GAAP OPEB Liability Deferral Account.*

> *FortisBC forecasts a $4.1 million ($5.5 million before tax) increase to this account in 2012."* [emphasis added]

Also on page 123 of Order G-110-12 is the Commission Panel Determination stating that:

> *"the Commission Panel approves the creation of a US GAAP OPEB Transitional Obligation"*

It is important to note that the initial recognition of the 2005 CGAAP OPEB Liability, as one of two components of the US GAAP OPEB Transitional Obligation, as a debit to FBC' s deferred charges effective January 1, 2012, was fully offset by an increase to the OPEB Liability deferral Account (as a credit to deferred charges).

While the recognition of the 2005 CGAAP OPEB Liability and equal offset was approved for recognition beginning on January 1, 2012, the annual amortization of the 2005 CGAAP OPEB Liability, by way of transitioning from the cash to accrual basis for OPEB accounting under CICA 3461, was approved for recovery in rates since January 1, 2005, pursuant to page 31 of Commission Order G-52-05, as follows:

> *"For 2005 the Company will include in expense the current cost under the cash basis plus one-third of the accrued expense as if it were in full compliance with Section 3461 and the change were adopted prospectively beginning in 2005."*

As such, pension & OPEB expense which has been approved by the Commission from 2005 through to 2013 has always included an annual amortization of the 2005 CGAAP OPEB transitional obligation for recovery in rates resulting from Commission Order G-52-05. The only change since that decision was the approval of recognizing the 2005 CGAAP OPEB Liability in deferred charges on January 1, 2012 pursuant to Commission Order G-110-12.

Commission Order G-110-12 is included as Attachment 80.3.

80.3.1 The US GAAP OPEB Transitional Obligation deferral account balance is $nil at December 31, 2011, according to the table provided in BCUC 1.211.1, Line No. 18. If the 2005 CICA OPEB Liability deferral account was approved prior to 2012, please explain why this balance is $nil.

Response:

Please refer to the response to BCUC IR 2.80.3.

80.4 The amount Amortized / Transferred to Other Accounts is $827 thousand in 2013 and the General Amortization is $207 thousand in 2013. Please describe the differences between these two amounts and how they are determined.

Response:

The amount "Amortized / transferred to Other Accounts" of $827 thousand, on line 15 of the Table 1-B Deferred Charges and Credits (2013), on page 285, Section E of the October 18, 2013 Evidentiary Update (Exhibit B-1-6), is the amortization of a combination of the following three US GAAP pension & OPEB transitional obligations: i) US GAAP Pension Transitional Obligation, ii) 2005 CICA OPEB Liability and iii) US GAAP OPEB Transitional Obligation, as shown in the response to BCUC IR 2.80.2. All three amounts were approved pursuant to BCUC Order G-110-12 as part of FBC's 2012-13 RRA and are transferred out of the Table 1-B (2013) deferred charge schedule with the offset in benefit loading.

The "General Amortization" of $207 thousand, on line 15 of the Table 1-B Deferred Charges and Credits (2013), on page 285, Section E of the October 18, 2013 Evidentiary Update, is the amortization of the tax effects of the US GAAP pension & OPEB transitional obligations, as shown in the response to BCUC IR 2.80.2. This general amortization was approved pursuant to BCUC Order G-110-12 as part of FBC's 2012-13 RRA and is transferred out of the Table 1-B (2013) deferred charge schedule with the offset in amortization expense.

The determination of the "Amortized / Transferred to Other Accounts" of the US GAAP Pension Transitional Obligation deferral was described in Section 5.4.3.iv on page 26 in Tab 5 Rate Base of FBC's 2012-2013 RRA, which stated the following:

> *"The Company also proposes the recovery of this Pension Transitional Obligation Deferral Account over the approximate Expected Average Remaining Service Life (EARSL) of the Company's pension plans of approximately 12 years (11.5 year EARSL rounded up) to phase the transitional difference into rates."*

The determination of the "Amortized / Transferred to Other Accounts" of the 2005 CICA OPEB Liability was described in the response to BCUC IR 2.80.3 based on Commission approval pursuant to Order G-52-05. This same "Amortized / transferred to Other Accounts" of the 2005 CICA OPEB Liability is further described in Section 5.4.3.vi on pages 30-31 in Tab 5 Rate Base of FBC's 2012-2013 RRA, as follows:

> *"As directed under Commission Order G-52-05, FortisBC began amortizing the accumulated CGAAP 2005 OPEB liability over the EARSL when the Company*

> *transitioned from the cash basis to accrual accounting for OPEBs, which was phased-in over a three year period. While the amortization of the CGAAP OPEB transitional obligation has been included in the OPEB expense since 2005, the actual deferral amount has not been previously recognized in Rate Base and has been tracked as a Non-Rate Base deferral account".*

The determination of the "Amortized / Transferred to Other Accounts" of the US GAAP OPEB Transitional Obligation was also described in Section 5.4.3.vi on pages 30 in Tab 5 Rate Base of FBC's 2012-2013 RRA, as follows:

> *"Firstly, under US GAAP, it would be necessary for FortisBC to recognize the historical cumulative difference between CGAAP and US GAAP OPEB net benefit costs, referred to herein as an OPEB transitional obligation, in the forecast amount of $2.0 million, as of January 1, 2012. This amount is comprised of the remaining unamortized net transition obligations under CGAAP (which would be fully amortized under US GAAP) and the net benefit cost for three months, resulting from the change in measurement date from September 30 to December 31 as required under US GAAP. The Company also proposes the recovery of this OPEB transitional adjustment over 12 years."*

H. LABOUR INFLATION, BENEFITS, AND OTHER HR MATTERS

81.0 Reference: Exhibit B-1, Appendix C3; Exhibit B-7, BCUC 1.218.1 and 1.218.3.1

Incentive Pay in Pensionable Earnings

"The forecasted and actual 2012 portion of executive pension expense relating to incentive pay was approximately $160 thousand. The forecasted 2013 portion of executive pension expense relating to incentive pay was approximately $155 thousand, while the actual 2013 portion of executive pension expense relating to incentive pay was approximately $165 thousand." (Exhibit B-7, BCUC 1.218.1)

"FBC has conducted an informal survey of the gas and electric utilities listed in response to BCUC IR 1.218.3 whose operations FortisBC considers to be similar to its own. These companies included ATCO, BC Hydro, Enbridge Gas Distribution, FortisAlberta and Manitoba Hydro. Of these companies, only one did not have an incentive pay program. For the remaining four companies, three of them included incentive pay in pensionable earnings, although most had limits on how much is included. Of these three, all of them also recovered the pension expense from ratepayers." (Exhibit B-7, BCUC 1.218.3.1)

81.1 Please provide the Forecast and Actual 2012 and the Forecast and Projected 2013 pension expense related to incentive pay for non-executive employees.

Response:

When forecasting for rate-setting purposes, the Company does not isolate pension expense between incentive pay and all other pensionable earnings, therefore the forecasted 2012 and 2013 Forecast requests have been estimated based on high level extrapolation, rather than relying on detailed records or supporting forecasts. The actual 2012 pension expense attributable to incentive pay for non-executive employees was approximately $180 thousand as compared to a 2012 forecast of approximately $190 thousand. The projected 2013 pension expense attributable to incentive pay for non-executive employees was approximately $190 thousand as compared to a forecast of approximately $200 thousand.

This incentive pay, which is included in pensionable earnings, is an integral part of the entire compensation package for FBC's non-executive employees. The incentive pay program puts focus on results which when achieved support the interests of all stakeholders. The pension expense associated with the STI program is appropriately included in benefit loadings and revenue requirements.

81.2 For the three companies that included incentive pay in pensionable earnings, please provide the limits on the portion of incentive pay that is included in pensionable earnings and recovered fully from ratepayers.

Response:

For the two companies surveyed that had a limit, the incentive pay eligible to be included in pensionable earnings was set to 100 percent of the payout amount in one case, and to a maximum of 15 percent of salary in the other case. FBC also refers to the more comprehensive survey results included in Appendix C3, which found that, of the 15 regulated utilities surveyed, 11 include the entire incentive pay in pensionable earnings, 2 include a portion of incentive pay in pensionable earnings, and 2 do not include incentive pay in pensionable earnings. Of the 2 utilities that include a portion of incentive pay in pensionable earnings the limit is 15 percent of base salary.

FBC notes that the amount of incentive pay included in pensionable earnings is part of the overall compensation package for management, which for FBC is targeted to the median of a peer group of companies.

81.3 Which Canadian energy utilities were excluded from the peer group and why? In particular, why were the electric utilities in Quebec, Newfoundland, Nova Scotia and New Brunswick excluded?

Response:

The question asked in BCUC IR 1.218.3 was “Please identify the companies in FBC’s peer reference group in Appendix C3 that are regulated utilities.” The companies listed in the preamble were the regulated utilities considered to be similar to FBC that were included in FBC’s peer reference group relating to pensions and benefits. The electric utilities in Quebec, Newfoundland, Nova Scotia and New Brunswick were excluded from that peer reference group because the companies included in the peer reference group represented regulated utilities whose non-union employees are primarily located in Western Canada; this was one of the parameters used to determine which companies were included in the original pensions and benefits survey in Appendix C3.

82.0 Reference: Exhibit B-1, p. 114; Exhibit A2-4, FHI Statement of Executive Compensation;

Exhibit B-7, BCUC 1.219.8.1

Executive Employees — Comparable Organizations

"Please refer to Attachment 219.8 for a list of companies, prepared by the Hay Group, that are comparable to FBC (measured by annual revenue) using the Commercial Industrial Comparator Group." (Exhibit B-7, BCUC 1.219.8.1)

Exhibit B-7, BCUC 1.219.8.1 includes a list of Canadian electric and natural gas companies, along with their annual revenue.

82.1 Please recreate the Summary of Observations included in the Hay Group Executive Compensation Benchmarking using only those companies included in Attachment 219.8 of Exhibit B-7.

Response:

The Summary of Observations that was recreated using only those companies included in Attachment 219.8 of Exhibit B-7 is included in Attachment 82.1.

82.2 Does Hay Group have the data available to recreate the Summary of Observations included in the Hay Group Executive Compensation Benchmarking using those companies listed in BCUC 1.219.8.1? If not, please explain why not. If yes, please recreate the Summary of Observations included in the Hay Group Executive Compensation Benchmarking using only those companies listed in Exhibit B-7, BCUC 1.219.8.1.

Response:

Hay Group does not have the data available to recreate the Summary of Observations noted above using those companies listed in BCUC 1.219.8.1, because the majority of companies listed do not participate in Hay Group's database.

82.3 Does Hay Group have the data available to recreate the Summary of Observations included in the Hay Group Executive Compensation Benchmarking using those companies listed in Attachment 219.8 and BCUC 1.219.8.1? If not, please explain why not. If yes, please recreate the Summary of Observations included in the Hay Group Executive Compensation Benchmarking using only those companies listed in Attachment 219.8 and BCUC 1.219.8.1.

Response:

Please refer to the response to BCUC IR 2.82.1 for a recreation of the Summary of Observations for the companies listed in Attachment 219.8.

As per the response to BCUC IR 2.82.2, Hay Group does not have the data available to recreate the Summary of Observations noted above using those companies listed in BCUC 1.219.8.1, because the majority of companies listed do not participate in Hay Group's database.

Because Hay Group does not have the data available with respect to the companies listed in BCUC 1.219.8.1, there is not adequate data available to recreate the Summary of Observations for the combination of companies listed in the attachments referenced above.

83.0 Reference: Exhibit B-7, BCUC 1.220.2

Executive Employees – Compensation Studies

"In 2011, FBC engaged Towers Watson to conduct a review of the competitiveness of the Company's pension and benefit programs, including vacation, holidays and other paid time off." (Exhibit B-7, BCUC 1.220.2)

83.1 Please discuss if FBC has plans to employ Towers Watson or another organization to conduct a review of the competitiveness of the Company's pension and benefit programs for all employees.

Response:

FBC does not have any current plans to employ a consultant to conduct a review of the competitiveness of the Company's pension and benefit programs for all employees. The benefits and pension programs have not changed since 2011, which is when the last review was conducted. Changes to pension and benefit programs aren't typically made on an annual basis. Therefore, FBC expects the results would be similar to those included in Attachment 222.5, provided in response to BCUC IR 1.222.5.

84.0 Reference: Exhibit B-7, Attachment 221.1

2013 Short Term Incentive Plan Targets – Executives

The 2013 Short-term Incentive Plan Targets were provided in Exhibit B-7, Attachment 221.1.The targets and weightings provided are as follows:

CORPORATE COMPONENT

The targets and weightings for 2013 are:

			2013 Targets			
Category	**Measurement**	**2012 Results**	**Minimum 50%**	**Target 100%**	**Maximum 150%**	**Weight**
Financial	Regulated Earnings	$48.5	Plan -2% $43.2M	Plan $44.1M	Plan +2% $45.0M	30%
Safety	All Injury Frequency Rate (AIFR)	1.72	Target +10% 1.80	Average of last 3 years 1.64	Target -10% 1.48	10%
	Recordable Vehicle Incidents	22	Target +10% 30	Average of last 3 years 27	Target - 10% 24	10%
Customer	Customer Service Index (CSI)	8.4	8.3	8.5	8.7	12.5%
	System Average Interruption Duration Index (SAIDI)	1.95	Target +5% 2.33	Average of last 3 years 2.22	Target -5% 2.11	12.5%
Regulatory	Regulatory Performance	-	Subjective	Subjective	Subjective	25%
TOTAL						**100%**

84.1 Please explain why, in FBC's opinion, it is appropriate to award bonuses in instances where 100 percent targets are not met (i.e. targets are between minimum 50 percent level and target 100 percent level).

Response:

A band approach is used to set short-term Incentive plan targets. The band is the span of values between the threshold and the maximum.

When setting the short-term incentive plan targets, consideration is given to what measures would be appropriate year over year. The scorecard approach provides a narrow range of measures that will drive desired results rather than a precise number or target.

The threshold of 50 percent is set in close relation to the 100 percent target. In relation to the 100 percent target, thresholds are set as follows:

- Regulated earnings: -2 percent
- Safety: +10 percent

- Customer service: -2 percent
- System disruption: +5 percent

Thresholds (and maximums) provide a narrow range in which appropriate measures and performance expectations can be set. FBC believes it is appropriate to award bonuses in instances where 100 percent targets are not met, because the range is sufficiently narrow that performance within the range is appropriate to incent.

84.2 Please explain how the financial targets, measured by regulated earnings, are linked to ratepayer benefits.

Response:

The Financial category, Regulated Earnings, reflects the productivity culture of the Company. Savings resulting from productivity initiatives are ultimately reflected in Regulated Earnings. Earnings increase when operating costs decrease which translates into a positive impact on customer rates.

For a discussion of the Company's priority focuses, FEI responded to CEC IR 1.8.1, appended below:

8. Reference: Exhibit B-1, Page 11

3.1 PRODUCTIVITY FOCUS

A priority for FEI and its employees is to improve productivity and realize efficiencies to more effectively manage rates for our customers while maintaining a customer service focus. Employees are encouraged to assess work and ensure that it is being performed as efficiently and productively as possible. When evaluating productivity opportunities, maintaining a customer focus remains a priority, helping strike a balance between lower costs while providing the appropriate level of service and quality.

8.1 Please provide a list of the other priority focuses of the Company, in addition to productivity and describe how these may or may not help to manage rates for customers.

Response:

As stated in Exhibit B-1, the overall priority for FEI and its employees is to improve productivity and realize efficiencies to manage rates effectively for our customers while maintaining a customer service focus.

The priority focuses of the company are reflected in its balanced scorecard. As indicated in Exhibit B-1, FEI uses a balanced scorecard approach to deliver on a number of key success measures critical to the business. The scorecard is currently comprised of four categories of measures, with six measures in total, that describe and guide the company's overall performance in meeting the targets. The four categories of measures include Financial, Safety, Customer and Regulatory. These categories reflect the priorities of the company.

Of the four categories on the scorecard, the Financial category best incorporates the productivity focus of the company. Savings resulting from productivity initiatives will ultimately be reflected in the financial component and eventually to help manage rates for customers.

The Regulatory performance category highlights the importance of achieving success on regulatory issues and agreements for the benefit of both customers and the shareholder. Depending on the issue, this may or may not help to manage rates for customers.

The remaining two categories on the scorecard, Safety and Customer, are focused on ensuring the company is able to deliver a safe and reliable service while maintaining a customer service focus.

The Safety category helps to ensure focus on achieving employee safety through lost time and vehicle accidents. Creating a safe working environment for employees will support the delivery of a safe and reliable service to customers. Additionally, it may result in lower lost time injuries and vehicle accidents which may lead to reduced costs. The Customer category captures customers' satisfaction with the company's performance in certain aspects of the business and public safety awareness. This category helps to maintain a customer service focus in the organization.

Please also refer to the responses to BCUC IRs 1.5.1 and 1.221.5.1 for further discussion of how the corporate scorecard categories are linked to ratepayer benefits

84.3 For the Safety and Customer categories, please provide the ratepayer benefits in instances where the target is not met (i.e. targets are between minimum 50 percent level and target 100 percent level). For example, if the All Injury Frequency Rate is above the average of the last three years.

Response:

As discussed in the response to CEC IR 2.84.1, the scorecard provides a narrow range of performance measures to drive results, rather than a precise number or target. The range is designed to be sufficiently narrow that performance within the range incents the desired behavior and outcome. There is a balance achieved in establishing scorecard targets with performance ranges to ensure that the desired outcome continues to the benefit of all stakeholders (customer, shareholder, employee). Setting the performance range for each measure is done to incent behavior without being so punitive if a target is missed by a small margin as to have focus on that measure lost for the calendar year. Maintaining focus on all scorecard measures throughout the year is to the benefit of all stakeholders.

When targets are missed, the performance range maintains focus on the delivery of a safe and reliable service, while maintaining a customer service focus at the lowest reasonable cost. This is in the customers' best interests.

84.4 Please provide examples of the 'subjective' factors that are considered in determining the targets for the Regulatory category.

Response:

The Regulatory performance category highlights the importance of achieving success on regulatory issues and agreements for the benefit of both customers and the shareholder. Factors considered include bringing forward key regulatory applications and issues for review and decision in a timely manner; leading the regulatory process efficiently; and maintaining constructive relationships with stakeholders throughout the process.

84.4.1 Please explain how the targets under the Regulatory category provide ratepayer benefits.

Response:

By performing on the Regulatory category, such as by bringing forward key applications like the proposed multi-year PBR agreement for consideration, customers have the potential to benefit over the term of the agreement.

Efficient use of staff resources to prepare and respond to quality applications enables these same resources to return to "running the business" sooner than would otherwise be possible which is in the customer's best interests.

84.5 Please provide examples of the individual targets that are set under the short-term incentive plan and include an explanation of how these individual targets provide benefits to ratepayers.

Response:

Individual objectives are employee-specific. However, employees are required to set objectives which support the categories of corporate objectives described above. Objectives are expected to be specific, measurable, achievable, relevant, and timely.

An example of an individual financial target for a manager responsible for a budget would be to ensure that they are on-budget at year-end. If a manager is 0-2 percent over budget, they achieve between the minimum and target, whereas if a manager is 0-2 percent under-budget, they achieve between the target and the maximum.

An example of a customer target for a manager with customer responsibilities might be to ensure that all customer comments are responded to within a certain time frame.

An example of a regulatory target for an exempt employee with regulatory responsibilities might be to ensure that all information requests are responded to sufficiently and in a timely manner.

These individual targets provide benefits to ratepayers because they support the achievement of corporate objectives. Please refer to the response to BCUC IR 1.221.5.1 for a further explanation as to how the corporate objectives benefit ratepayers.

85.0 Reference: Exhibit B-7, BCUC 1.221.1.2, Attachment 221.1

2013 Short Term Incentive Plan Targets — Executives

According to the 2013 Short-term Incentive Plan Targets in Exhibit B-7, Attachment 221.1, the target bonus level as a percentage of salary is 50 percent for the president and CEO and 30–40 percent for the vice presidents.

The following table of short-term incentive payments to FBC executives for the last five years was provided in response to BCUC 1.221.1.2:

Short-term Incentive Payments to FBC Executives for the Last Five Years

	Actual STI as % of Salary				
	2008	2009	2010	2011	2012
President & CEO	56.94%	60.00%	79.08%	85.00%	76.92%
EVP HR, Customer and Corporate Services	41.86%	45.65%	56.96%	67.62%	60.34%
EVP Network Services, Engineering and Generation	41.86%	45.65%	43.48%	65.74%	60.49%
VP Finance & CEO	44.19%	45.65%	52.17%	63.83%	68.02%
VP Operations Support, Gen Counsel & Corporate Services	49.50%	46.67%	48.00%	54.16%	50.74%
VP Resource Planning	38.64%	45.65%	50.00%	-	-
VP Energy Solutions & External Relations	-	-	46.95%	63.50%	58.94%
VP Energy Supply & Resource Development	-	-	46.36%	59.76%	68.97%
VP Strat Plan, Corporate Development and Regulatory Affairs	-	-	62.79%	63.83%	68.02%
VP Customer Service	-	-	-	-	46.48%

85.1 Based on the table provided in response to BCUC 1.221.1.2, please confirm or explain otherwise that in each year between 2009 and 2012, the short-term incentive pay for each executive exceeded the target bonus level as a percentage of salary.

Response:

Short-term incentive (STI) pay is based on the attainment of corporate and individual objectives, each with a 50/50 weighting. In each of the years noted above (i.e. 2009 to 2012), the corporate result met or exceeded target. This and individual performance resulted in the corporate component of each executive's STI being greater than 100 percent of target.

86.0 Reference: Exhibit B-1, pp. 114-115; Exhibit B-7, BCUC 1.225.1

Executive Compensation

86.1 The response to BCUC IR 1.225.1 completes the following table for 9 specific executive roles:

Year	Salary	Option - Based Awards	Annual Incentive Plans	Pension Value	Other Compensation	Total Compensation
	Cost Allocated to Principal Company					
2013						
2012						
2011						
2010						
	Cost Allocated to FortisBC					
2013						
2012						
2011						
2010						

86.2 Please complete the table included in the preamble to this IR for any executive positions with a portion of compensation charged to FBC that are missing from the response to BCUR 1.225.1. Where 2013 amounts have not yet been determined, please provide an estimate.

Response:

The Executive compensation table included in the response to BCUC IR 1.225.1 included executives employed by FBC, FHI or FEI at the time the FBC and FEI 2014-2018 PBR Applications were submitted. The table below updates the response provided in BCUC IR 1.225.1 to include Executives employed by the Companies prior to mid-2013. The update provides the fully loaded compensation, using an average benefit load charge out. For further details and discussion of the benefit load allocations charged between FEI and FBC, please refer to the response to BCUC IR 2.25.2.

The segregation of the Executive compensation components (Salary, Option Based Awards, Annual Incentive Plans, Pension Value, Other Compensation) in the table requested as part of BCUC IR 1.225.1 is based on the requirements of FBC's Annual Information Form filing. 51-904F *Statement of Executive Compensation* requires that companies report and segregate Executive compensation on a historical actual basis. As such, all 2013 projections in the updated table are estimates. Compensation is not routinely forecast into the requested components by Executive. These assumptions include the 2013 Annual Incentive Plans which have been budgeted at the maximum and therefore are subject to high variability. No option-based awards are included in the updated table for 2013, as expense associated with options is not part of cross-charges between FEI and FBC, and most importantly, are not expenses included in customer rates for either FBC or FEI.

President & CEO - employed by FBC

Year	Salary	Option - Based Awards	Annual Incentive Plans	Pension Value	Other Compensation	Total Compensation Paid by Principle Company	Less non regulated awards	Total regulated compensation	Compensation charged out to FEI using an average benefits load	Total Net Compensation Remaining Prior to other recoveries
		Cost Allocated to Principle Company - FBC								
2013 Projection	535,600	-	402,000	136,000	65,000	1,138,600	-	1,138,600	(534,000)	604,600
2012	520,000	255,530	400,000	135,539	44,615	1,355,684	(255,530)	1,100,154	(525,000)	575,154
2011	500,000	277,399	425,000	102,175	56,195	1,360,769	(277,399)	1,083,370	(551,000)	532,370
2010	453,192	186,173	310,000	80,698	94,442	1,124,505	(271,173)	853,332	(287,000)	566,332

EVP HR, Customer and Corporate Services - employed by FBC

Year	Salary	Option - Based Awards	Annual Incentive Plans	Pension Value	Other Compensation	Total Compensation Paid by Principle Company	Less non regulated awards	Total regulated compensation	Compensation charged out to FEI using an average benefits load	Total Net Compensation Remaining Prior to other recoveries
		Cost Allocated to Principle Company - FBC								
2013 Projection	298,500	-	179,000	50,000	25,000	552,500	-	552,500	(298,000)	254,500
2012	290,000	53,450	175,000	50,915	21,374	590,739	(53,450)	537,289	(293,000)	244,289
2011	281,000	58,459	190,000	42,335	9,441	581,235	(58,459)	522,776	(310,000)	212,776
2010	252,846	55,196	131,000	35,475	43,366	517,883	(55,196)	462,687	(128,000)	334,687

EVP Network Services, Engineering and Generation - employed by FBC

Year	Salary	Option - Based Awards	Annual Incentive Plans	Pension Value	Other Compensation	Total Compensation Paid by Principle Company	Less non regulated awards	Total regulated compensation	Compensation charged out to FEI using an average benefits load	Total Net Compensation Remaining Prior to other recoveries
		Cost Allocated to Principle Company - FBC								
2013 Projection	287,900	-	173,000	43,000	11,000	514,900	-	514,900	(287,000)	227,900
2012	264,000	48,651	159,700	44,285	24,472	541,108	(48,651)	492,457	(267,000)	225,457
2011	251,000	52,226	165,000	34,405	5,354	507,985	(52,226)	455,759	-	455,759
2010	230,000	55,619	100,000	32,550	4,398	422,567	(55,619)	366,948	-	366,948

VP Energy Solutions & External Relations - employed by FEI

Year	Salary	Option - Based Awards	Annual Incentive Plans	Pension Value	Other Compensation	Total Compensation Paid by Principle Company	Less non regulated awards	Total regulated compensation	Compensation charged out to FBC using an average benefits load	Total Net Compensation Remaining Prior to other recoveries
		Cost Allocated to Principle Company - FEI								
2013 Projection	283,700	-	170,000	48,000	14,000	515,700	-	515,700	(77,000)	438,700
2012	275,546	50,806	162,500	46,485	6,575	541,912	(50,806)	491,106	(78,000)	413,106
2011	267,590	55,699	170,000	39,566	16,993	549,848	(55,699)	494,149	(88,000)	406,149
2010	262,000	63,345	123,000	42,000	18,231	508,576	(63,345)	445,231	(48,000)	397,231

VP Finance & CFO - employed by FBC

Year	Salary	Option - Based Awards	Annual Incentive Plans	Pension Value	Other Compensation	Total Compensation Paid by Principle Company	Less non regulated awards	Total regulated compensation	Compensation charged out to FEI using an average benefits load	Total Net Compensation Remaining Prior to other recoveries
		Cost Allocated to Principle Company - FBC								
2013 Projection	260,000	-	156,000	40,000	12,000	468,000	-	468,000	(259,000)	209,000
2012	243,600	44,895	165,700	39,683	15,236	509,114	(44,895)	464,219	(246,000)	218,219
2011	235,000	48,899	150,000	34,925	11,336	480,160	(48,899)	431,261	(19,000)	412,261
2010	230,000	55,619	120,000	32,550	9,531	447,700	(90,619)	357,081	(9,000)	348,081

VP Strat Plan, Corporate Development and Regulatory Affairs - employed by FHI

Year	Salary	Option - Based Awards	Annual Incentive Plans	Pension Value	Other Compensation	Total Compensation Paid by Principle Company	Less non regulated awards	Total regulated compensation	Compensation charged out to FBC using an average benefits load	Total Net Compensation Remaining Prior to other recoveries
		Cost Allocated to Principle Company - FHI								
2013 Projection	260,000	-	156,000	43,000	19,000	478,000	-	478,000	(106,000)	372,000
2012	243,435	44,895	165,700	39,485	14,583	508,098	(44,895)	463,203	(103,000)	360,203
2011	234,904	48,899	150,000	36,875	16,254	486,932	(48,899)	438,033	-	438,033
2010	222,327	51,985	135,000	31,000	25,237	465,549	(51,985)	413,564	-	413,564

VP Operations Support, Gen Counsel & Corporate Services - employed by FBC

Year	Salary	Option - Based Awards	Annual Incentive Plans	Pension Value	Other Compensation	Total Compensation Paid by Principle Company	Less non regulated awards	Total regulated compensation	Compensation charged out to FHI using an average benefits load	Total Net Compensation Remaining Prior to other recoveries
		Cost Allocated to Principle Company - FBC								
2013 Projection	249,900	-	131,000	31,000	19,000	430,900	-	430,900	(289,000)	141,900
2012	237,725	43,818	120,600	35,669	18,044	455,856	(43,818)	412,038	(279,000)	133,038
2011	230,800	35,061	125,000	32,819	20,991	444,671	(35,061)	409,610	(260,000)	149,610
2010	225,000	54,402	108,000	31,900	18,581	437,883	(74,402)	363,481	(208,000)	155,481

VP Customer Service - employed by FEI

Year	Salary	Option - Based Awards	Annual Incentive Plans	Pension Value	Other Compensation	Total Compensation Paid by Principle Company	Less non regulated awards	Total regulated compensation	Compensation charged out to FBC using an average benefits load	Total Net Compensation Remaining Prior to other recoveries
		Cost Allocated to Principle Company - FEI								
2013 Projection	222,500	-	100,000	30,000	13,000	365,500	-	365,500	(61,000)	304,500
2012	215,806	26,321	100,400	32,485	15,156	390,168	(26,321)	363,847	(61,000)	302,847
2011	205,784	28,572	125,000	25,813	14,635	399,803	(28,572)	371,232	(52,000)	319,232
2010*	189,115	13,230	79,000	29,000	7,934	318,279	(13,230)	305,049	(49,000)	256,049

*Joined executive October 2010

VP Energy Supply & Resource Development - employed by FEI

Year	Salary	Option - Based Awards	Annual Incentive Plans	Pension Value	Other Compensation	Total Compensation Paid by Principle Company	Less non regulated awards	Total regulated compensation	Compensation charged out to FBC using an average benefits load	Total Net Compensation Remaining Prior to other recoveries
		Cost Allocated to Principle Company - FEI								
2013 Projection	266,000	-	160,000	44,000	13,000	483,000	-	483,000	(145,000)	338,000
2012	258,356	47,640	178,300	41,485	3,394	529,175	(47,640)	481,535	(146,000)	335,535
2011	250,827	52,256	150,000	34,665	8,605	496,353	(52,256)	444,097	(125,000)	319,097
2010	241,661	58,512	102,000	33,000	28,043	463,216	(58,512)	404,704	(55,000)	349,704

VP Power Supply & Strategic Planning - employed by FBC

Year	Salary	Option - Based Awards	Annual Incentive Plans	Pension Value	Other Compensation	Total Compensation Paid by Principle Company	Less non regulated awards	Total regulated compensation	Compensation charged out to FEI using an average benefits load	Total Net Compensation Remaining Prior to other recoveries
		Cost Allocated to Principle Company - FBC								
2013 Projection	-	-	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-	-	-
2011	36,269	-	-		103,317	139,586	-	139,586	-	139,586
2010	230,000	55,619	115,000	32,550	1,656	434,825	(55,619)	379,206	-	379,206

*Left executive March 2011

EVP, Finance, Regulatory & Energy Supply - employed by FEI

Year	Salary	Option - Based Awards	Annual Incentive Plans	Pension Value	Other Compensation	Total Compensation Paid by Principle Company	Less non regulated awards	Total regulated compensation	Compensation charged out to FBC using an average benefits load	Total Net Compensation Remaining Prior to other recoveries
		Cost Allocated to Principle Company - FEI								
2013 Projection	-	-	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-	-	-
2011	306,473	63,797	-	70,883	1,461,505	1,902,658	(63,797)	1,838,861	(126,000)	1,712,861
2010	292,327	68,919	150,000	52,000	33,433	596,680	(68,919)	527,760	(68,000)	459,760

*Left executive December 2011

VP Operations - employed by FEI

Year	Salary	Option - Based Awards	Annual Incentive Plans	Pension Value	Other Compensation	Total Compensation Paid by Principle Company	Less non regulated awards	Total regulated compensation	Compensation charged out to FBC using an average benefits load	Total Net Compensation Remaining Prior to other recoveries
		Cost Allocated to Principle Company - FEI								
2013 Projection	46,362	-	-		1,002,041	1,048,403	-	1,048,403	-	1,048,403
2012	245,789	45,333	125,000	67,485	144	483,751	(45,333)	438,418	(79,000)	359,418
2011	234,904	48,899	125,000	10,805	10,496	430,104	(48,899)	381,205	-	381,205
2010	230,000	55,619	96,000	10,000	7,902	399,521	(55,619)	343,902	-	343,902

*Left executive March 2013

VP Business Planning - employed by FEI

Year	Salary	Option - Based Awards	Annual Incentive Plans	Pension Value	Other Compensation	Total Compensation Paid by Principle Company	Less non regulated awards	Total regulated compensation	Compensation charged out to FBC using an average benefits load	Total Net Compensation Remaining Prior to other recoveries
		Cost Allocated to Principle Company - FEI								
2013 Projection	-	-	-	-	-	-	-	-	-	-
2012	61,923	-	-		105,000	166,923	-	166,923	-	166,923
2011	229,904	47,857	105,000	(92,365)	11,920	302,316	(47,857)	254,459	(38,000)	216,459
2010	225,000	54,402	92,000	116,000	14,549	501,951	(54,402)	447,549	(21,000)	426,549

The summary executive compensation table requested as part of BCUC IR 2.86.6, which includes the total actual compensation for 2011 through 2013, is also included below in this response. This table does not include the requested historically approved amounts as further explained below.

To clarify why the level of requested componentization cannot be reasonably provided for historical forecast purposes, it is necessary to reiterate which items are forecast for rate-setting purposes. The pension values, annual incentive plans and other compensation amounts related to the Executive are grouped with the pension values, annual incentive plans and other compensation amounts of other employee groups in order to determine a benefit loading rate. It is this general benefit loading rate that is applied to the base pay, net of time away, to determine the Executive labour amounts allocated among the companies. This concept is explained in BCUC IR 1.144.7 which states that "since FBC and FEI do not forecast individual benefits attributable for each Executive or employee, such as post-employment benefits, incentives, etc., a general benefit loading rate is applied to regular base pay (net of time away) to incorporate all such benefits." Each component of compensation included in the format provided to response to BCUC 1.225.1 is not directly charged out among FEI and FBC as those costs are included, along with other benefits, in a general loading that is applied to all employees including both executive and non-executive employees.

Based on the practice of billing the Executive out using their fully loaded wage (net of time away), it is not possible to reasonably reconcile compensation set out in the response to BCUC IR 1.225.1 (Annual Information Form filing purposes) to the fully loaded pay eligible for allocation among the regulated utilities as shown in the response to BCUC IR 2.25.2.

It is important to note that the number of executives decreased from 2011 to 2013; a weighted average number of executives has been applied to the table. Also of note is that in order to reasonably compare the amounts in the table below, total compensation has been normalized by removing severance compensation.

	Salary	Option - Based Awards	Annual Incentive Plans	Pension Value	Other Compensation	Total Compensation
2013 Projected						
Total Compensation	2,710,462	-	1,627,000	465,000	198,105	5,000,566
Average Number of Executives	9.2	9.2	9.2	9.2	9.2	9.2
Average per Executive	295,579	-	177,426	50,709	21,604	545,318
2012 Actual						
Total Compensation	2,856,180	661,339	1,752,900	533,516	163,593	5,967,528
Average Number of Executives	10.3	10.3	10.3	10.3	10.3	10.3
Average per Executive	278,652	64,521	171,015	52,050	15,960	582,198
2011 Actual						
Total Compensation	3,264,455	818,023	1,880,000	372,901	232,472	6,567,851
Average Number of Executives	12.3	12.3	12.3	12.3	12.3	12.3
Average per Executive	266,486	66,777	153,469	30,441	18,977	536,151

86.3 Please recreate the tables provided in response to BCUC 1.225.1 including an estimate of 2013 amounts that have not yet been determined.

Response:

Please refer to the response to BCUC IR 2.86.2.

86.4 For each executive position employed by FBC, please discuss the methodology that is used in order to charge out compensation to other utilities (i.e. FEI or FHI).

Response:

Please refer to the response to BCUC IR 2.25.2 for the allocation methodology of compensation between FBC and FEI. For any fully loaded Executive costs that are allocated to FHI, the Time Estimate Methodology, discussed fully in the response to BCUC IR 2.25.2, is utilized. As discussed in that response, fully loaded Executive costs, which are allocated among the companies, differ from all compensation components provided in the response to BCUC IR 1.225.1.

86.5 For each executive position employed by FEI or FHI with a portion of compensation charged out to FBC, please discuss the methodology that is used in order to charge out compensation to FBC.

Response:

Please refer to the response to BCUC IR 2.25.2 for the allocation methodology of fully loaded Executive costs between FBC and FEI. As discussed in that response, fully loaded Executive costs, which are allocated among the companies, differ from all compensation components provided in the response to BCUC IR 1.225.1.

86.6 Please complete the following summary of total executive compensation charged to FBC for each of 2011 Approved, 2011 Actual, 2012 Approved, 2012 Actual, 2013 Approved and 2013 Projected, including employees that are employed by FBC, FHI and FEI. For any 2013 amounts that are not yet determined, please provide an estimate.

	Base Salary	Short-term Incentive Pay	Long-term Incentive Pay	Pension Value	Other Benefits	Total Executive Compensation
Total Compensation						
Number of Executives						
Average per Executive						
Total Compensation Charged to FBC						

Response:

Please refer to the response to BCUC IR 2.86.2.

87.0 Reference: Exhibit B-1, p. 116; Exhibit B-7, BCUC 223.1.1

Unionized Employees

"Going forward, per a Letter of Understanding included in the collective agreement, a joint market comparator survey is to be conducted in advance of the collective agreement expiring" (Exhibit B-7, BCUC 223.1.1).

87.1 Please provide the expiration date of the collective agreement and the anticipated date that the comparator survey is expected to be conducted.

Response:

The COPE (Customer Services Centre) collective agreement expires on March 31, 2014. The comparator survey is expected to be completed in February 2014.

87.2 Please complete the following compensation schedule for unionized employees for each of 2011 Approved, 2011 Actual, 2012 Approved, 2012 Actual, 2013 Approved and 2013 Projected. Where 2013 amounts are not yet determined, please provide an estimate.

	Base Salary	Incentive Compensation	Pension Value	Other Benefits	Other Compensation	Total Compensation
Total						
FTEs						
Average per FTE						

Response:

The various components of the requested compensation table from BCUC IR 2.87.2 (Unionized employees) and BCUC IR 2.88.3 (Management & Exempt) appear to be based on FBC's Annual Information Form (AIF) filing. The content of the AIF is dictated by *Form 51-904 Statement of Executive Compensation,* which requires companies to specifically report and segregate Executive compensation into various compensation components, but it is always on a historical actual basis, not on a forecast basis. As such, FBC tracks the requested compensation components, such as actual other benefits, pension and other compensation for the few executive employees, as this is a requirement for continuous disclosure filings. Since it is not a securities commission requirement to maintain such recordkeeping for all other employee affiliates (union groups and management & exempt), not all the requested compensation values can be provided for employee affiliates, even on an actual basis.

Not only is it ambiguous as to what is being requested as part of other benefits and other compensation, FBC also does not track such compensation components by employee affiliate as they would be accumulated as part of a general loading rate. Additionally, it is not clear what is meant by pension value for employee affiliates (union groups and management & exempt), therefore, the Company has assumed it is the accounting value of the current service cost of the defined benefit pension expense as calculated under CICA 3461 for 2011 and ASC 715 for 2012.

Since the Company does not isolate or report on compensation or FTE by employee affiliate (union groups and management & exempt) for forecast or rate-setting purposes, the requested 2011, 2012 and 2013 Approved information, as well as the 2013 Projection, has not been provided.

Unionized Employees

2011 Actual	Base Salary(1)	Incentive Compensation(2)	Pension Value	Other Benefits	Other Compensation	Total Compensation
Total	$ 26,888,000	$ -	$ 3,202,000	n/a	n/a	$ 30,090,000
FTE's	383.63	383.63	383.63	383.63	383.63	383.63
Average per FTE	$ 70,000	$ -	$ 8,000	n/a	n/a	$ 78,000

2012 Actual	Base Salary(1)	Incentive Compensation(2)	Pension Value	Other Benefits	Other Compensation	Total Compensation
Total	$ 27,137,000	$ 9,000	$ 4,720,000	n/a	n/a	$ 31,866,000
FTE's	382.10	382.10	382.10	382.10	382.10	382.10
Average per FTE	$ 71,000	$ 24	$ 12,000	n/a	n/a	$ 83,000

Notes:

1) Base salary excludes employees on long-term disability.

2) COPE customer service affiliate (excludes grandfathered employees) is eligible for incentive

BCUC IR 2.88.3 requests the same compensation table for Management & Exempt employees and due to the same reasons explained above, the following table has been provided.

Management & Exempt Employees

2011 Actual	Base Salary(1)	Incentive Compensation	Pension Value	Other Benefits	Other Compensation	Total Compensation
Total	$ 14,230,000	$ 3,135,700	$ 1,217,000	n/a	n/a	$ 18,582,700
FTE's	144.00	144.00	144.00	144.00	144.00	144.00
Average per FTE	$ 99,000	$ 22,000	$ 8,000	n/a	n/a	$ 129,000

2012 Actual	Base Salary(1)	Incentive Compensation	Pension Value	Other Benefits	Other Compensation	Total Compensation
Total	$ 15,433,000	$ 2,996,830	$ 1,224,069	n/a	n/a	$ 19,653,899
FTE's	160.03	160.03	160.03	160.03	160.03	160.03
Average per FTE	$ 96,000	$ 19,000	$ 8,000	n/a	n/a	$ 123,000

Note:

1) Base salary excludes employees on long-term disability.

87.2.1 Please provide any amounts in the tables provided in response to the preceding IR that are not recovered from the ratepayer.

Response:

Per the response to BCUC IR 1.223.1.1, the tables provided in response to the preceding IR are summaries of a review FBC conducted of wage rates for comparable jobs with comparable organizations, including information from publicly available collective agreements. FBC has no information about whether or to what extent these amounts are recovered from ratepayers within these organizations.

From the perspective of FBC, all compensation amounts payable to unionized employees are and have always been recoverable from the ratepayer.

88.0 Reference: Exhibit B-1, p. 115; Exhibit B-7, BCUC 1.221.1–1.222.3, Attachment 221.1

Management & Exempt (M&E) Employees

"Average actual compensation for FBC M&E employees for 2013 is at 95% of the market median for the various ranges." (Exhibit B-7, BCUC 1.222.2.3)

"Short-term incentive pay recognizes and rewards the achievement of individual and corporate objectives by putting compensation at risk. The value of short-term incentive pay assigned to each broad band is positioned at approximately the market median for the peer group and ranges from 5-25% of regular earnings, with the maximum payout set at 150% of target. The amount of incentive pay is based on 50% on the achievement of individual objectives, and 50% on the achievement of corporate objectives." (Exhibit B-7, BCUC 1.222.3)

88.1 How does the average actual compensation for FBC M&E employees of 95 percent of the market median compare to the percentage of the market median for the FBC executive employee group?

Response:

FBC's response to BCUC Confidential IR 1.1.1 provided a description of how actual compensation for individual executive employees compares to the market.

As a group, average actual compensation for executive employees for 2013 is 102 percent of the market median for salary, and 99 percent of the market median for total direct compensation.

The difference between relative ranking for the M&E group versus the executive group can be explained by the tenure of the executive team (e.g. average of 16 years) compared to the tenure of the M&E group which includes new hires generally hired below the 100 percentile.

88.1.1 For FBC M&E employees, what is the target percentage of the market median and why is this reasonable?

Response:

The target percentage is 100 percent of the market median for FBC M&E employees. The market median is also referred to as the midpoint. The salary range is built around the market median (80 percent range minimum and 110 percent is the range maximum). The compa-ratio represents an individual salary placement within the range as a percentage of the market median. FBC utilizes compa-ratios to prudently manage its salary administration practices including the planning and controlling of salary budgets. Where Individual salary placements are above the range maximum, careful review is undertaken and generally, these positions are eligible for annual lump sum base payments as opposed to base pay increases so as to manage wage escalation beyond the range maximum. This results in prudent management of individual salaries within the accepted range for the position which is sound and reasonable compensation management.

As discussed in previous responses, FBC designs its M&E compensation program to be market-competitive, which assists the Company in retaining and attracting qualified competent talent.

88.2 Please provide the short-term incentive plan targets for the M&E employee group approved for 2013, similar to those provided for the FBC executive employee group in Attachment 221.1 of Exhibit B-7.

Response:

The short-term incentive plan targets for the M&E employee group approved for 2013 are found in the following table.

Band	Weightings		Target Bonus Level
	Individual	Corporate	
5	50%	50%	20%
4	50%	50%	15%
3	50%	50%	10%
2	50%	50%	10%
1	50%	50%	5%

88.2.1 For each category of corporate objectives, please discuss how the targets provide a benefit to FBC ratepayers.

Response:

Please refer to response to BCUC IR 1.221.5.1 for an explanation of how each category of corporate objectives provides a benefit to FBC ratepayers.

The short-term incentive targets associated with each M&E salary band assist with the attainment of corporate objectives and therefore the enhancement of those benefits to ratepayers. Because this component of pay is performance-based, and because individual objectives are linked to the corporate scorecard categories, employees are motivated to do their best to meet their objectives in order to realize their incentive payout. This in turn assists FBC with meeting its corporate objectives, which benefits ratepayers.

88.2.2 Please discuss the types of individual objectives that are included in the short-term incentive plan targets and discuss how these objectives provide a benefit to FBC ratepayers.

Response:

The type of individual performance objectives that are included in the short-term incentive plan targets are those that support overall corporate objectives, and which link individual efforts to corporate scorecard results.

In establishing individual performance objectives a balance between objective and subjective measures is to be achieved. An example of a subjective measure is leadership competence (how we do what we do). Objective measures are developed using the "SMART" model (i.e. Specific, Measureable, Attainable, Relevant and Timely) and are intended to align to one of the corporate scorecard categories. Individual objective examples would be built around departmental Operating and Maintenance budgets, departmental AIFR, departmental Recordable Vehicle Incident Rates, completion of a specific personal project within budget and on schedule. This list is not exhaustive, but represents the types of individual performance objectives (objective and subjective) that are common. These performance objectives link individual effort to the corporate scorecard and in so doing incent and reward top performers.

This process ensures clarity of focus at the individual level and allows FBC to recognize and reward accomplishments that drive business results, which in turn provide benefits to the ratepayer.

88.2.3 Does FBC award M&E employees incentive compensation when targets are not met (i.e. targets are between minimum 50 percent level and target 100 percent level), similar to the executive incentive compensation program? If yes, please discuss why, in FBC's opinion, it is appropriate to award bonuses in instances where 100 percent targets are not met.

Response:

As noted in the preamble, incentive pay for M&E employees at FBC is dependent upon both corporate and individual performance. The purpose of incentive pay is to incent and award performance that is aligned with corporate goals.

With respect to corporate objectives, no incentive is paid out unless the financial gateway of 85 percent is met. Any other measure that does achieve a minimum threshold in any given year is attributed zero, which impacts the overall scorecard result.

FBC believes it is appropriate to pay incentive pay in cases where the minimum targets are met because:

- A band approach is used to set short-term incentive plan targets. The band is the span of values between the threshold and the maximum'
- When setting the short-term incentive plan targets, consideration is given to what measures would be appropriate year over year. The scorecard approach provides a narrow range of measures that will drive desired results rather than a precise number or target'
- The minimum threshold (of 50 percent) is set in close relation to the 100 percent target. For earnings the threshold is set at -2 percent, Safety +10 percent, Customer Service -2 percent and for System disruption +5 percent; and
- Thresholds (and maximums) provide a narrow range in which appropriate measures and performance expectations can be set.

FBC believes it is appropriate to pay incentive within the range between threshold and maximum because the range is set deliberately narrow to incent and award performance that is aligned with corporate goals.

88.2.4 For each year between 2008 and 2012, please provide the total actual short-term incentive compensation awards for M&E employees as a percentage of total base salary for M&E salaries.

Response:

The total actual short-term incentive compensation awards for M&E employees as a percentage of total base salary for M&E salaries is shown in the table below.

Year	STI target as a % of Base
2008	10.14%
2009	12.80%
2010	12.73%
2011	16.50%
2012	13.26%

For the period 2008 to 2011, FBC's short-term incentive plan was based 100 percent on the achievement of corporate targets. In 2012, the M&E compensation framework was aligned for FBC and FEI, as discussed in previous IRs, and the STI plan was revised to incent both corporate and personal performance.

88.3 Please complete the following compensation schedule for M&E employees for each of 2011 Approved, 2011 Actual, 2012 Approved, 2012 Actual, 2013 Approved and 2013 Projected. Where 2013 amounts are not yet determined, please provide an estimate.

	Base Salary	Incentive Compensation	Pension Value	Other Benefits	Other Compensation	Total Compensation
Total						
FTEs						
Average per FTE						

Response:

Please refer to the response to BCUC IR 2.87.2.

88.3.1 Please provide any amounts that are not recovered from the ratepayer in the tables provided in response to the preceding IR.

Response:

All compensation amounts for M&E employees are recoverable from the ratepayer.

89.0 Reference: Pension, OPEB and Benefit Programs

89.1 Please provide a list of all pension, OPEB and benefit programs available to each of executive, management and exempt and unionized employees.

Response:

Please refer to the response to BCMEU IR 1.13.1, which includes CONFIDENTIAL Attachment 13.1, for information regarding all benefit programs available to current executive, management and exempt and unionized employees at FBC.

Please refer to the response to BCUC IR 2.89.2 for a list of all pension and OPEB programs available to each affiliation of current employee.

89.2 For each pension and OPEB plan identified above, please provide details of the plan, including: i) whether the plan is defined benefit or defined contribution, ii) percentage of contributions for each of employer and employee and iii) FBC's legal obligation under the plan (i.e. related terms included in collective bargaining agreements).

Response:

A summary of each pension plan available to the different employee groups at FBC is included in Attachment 89.2.

89.3 For each defined benefit pension and OPEB plan identified above, please discuss if FBC has considered transitioning from a defined benefit plan to a defined contribution plan in order to minimize the costs borne by ratepayers. Please discuss the process that would be required in order to make such a transition.

Response:

Effective January 1, 2002, the DB Plan for non-union employees was closed to new entrants. Active employees at January 1, 2002 were provided with a one-time option to move into the DC Plan or stay in the DB Plan. All non-union employees hired after January 1, 2002 participate in the DC Plan. As at January 1, 2013 there were only 18 active non-union employees still participating in the DB Plan.

Union employees continue to participate in DB Plans. The requirement to provide these DB Plans is contained in the applicable collective agreements. Accordingly, any move from these DB Plans to DC Plans would need to be negotiated with the respective unions. To date the unions have not expressed any willingness to discuss transitioning from DB Plans to DC Plans.

90.0 Reference: Exhibit B-1-6, p. 3

IBEW Labour Dispute

90.1 Please provide a general update to the IBEW labour dispute situation.

Response:

On September 25-26, 2013, FBC and the IBEW met with the assistance of mediator Vince Ready. The Company and the union agreed to let the mediator make recommendations on all unresolved items. On October 3, 2013 the Company was advised that the IBEW membership did not ratify the recommendations.

On October 24, 2013, the Company and the union resumed negotiations and reached a tentative agreement on October 26, 2013. The Company and IBEW bargaining team signed the Memorandum of Agreement and agreed to recommend ratification of the MOA to their respective parties. On October 30, 2013, the Company was advised that the IBEW membership did not ratify the tentative agreement.

90.2 FBC indicates that the labour disruption has been ongoing since June 26, 2013 (Ex. B-1-6, p. 4). When does FBC anticipate that workers may return to their positions?

Response:

It is anticipated that FBC employees will return to work following the successful ratification of a new collective agreement, the timing of which cannot be determined.

90.3 Please discuss the issues that have led to this labour dispute.

Response:

At the commencement of bargaining, FBC communicated its desire for a short-term, simple deal with market-competitive wage increases. The Company agenda comprised of one proposal aimed at giving more flexibility to the Company to organize its work through the ability to set job qualifications in its job descriptions. This approach is common to each of the Company's four other collective agreements. The Company was not seeking any concessions to employee wages, benefits or pensions.

The IBEW agenda included 130 proposals overall, and was aimed at securing significant enhancements, including an 18% wage increase over a three-year term. In response to the Company's failure to meet the IBEW's monetary expectations, the IBEW left the bargaining table on January 23, 2013 to take a strike vote.

The IBEW received a strike mandate from its membership on February 18, 2013. Partial job action by the IBEW commenced on May 16, 2013 and escalated up to June 26, 2013 and culminated with the threat of removal of all IBEW employees from the System Control Center. In response, the Company declared a lockout for the purpose of enacting the Essential Services Order in order to protect system integrity and public and employee safety. This decision resulted in a lockout for approximately 200 IBEW and 30 COPE employees who have chosen to respect the legal picket lines.

Since the declaration of the lockout, a recommendation from the union-recommended mediator has been provided and one tentative agreement has been reached; however, the IBEW has not yet successfully ratified either the mediator's recommendation or the signed tentative agreement.

90.4 Please discuss how the issues involved with the current labour dispute may transpire into impacts to the ratepayer.

Response:

FBC does not believe that the issues involved in the current labour disruption will have any negative impacts on customers in the 2014 – 2018 period.

90.5 Please describe the "Essential Services Order" and what impact that has had on this labour dispute.

Response:

The Labour Relations Board designates essential services when directed to do so by the Minister of Labour and Citizens' Services. This occurs when the Minister considers that a labour dispute poses a threat to the health, safety or welfare of the residents of the province. Both parties (and in some cases, other interested parties as well) are involved in the determination of what is ultimately contained in an essential service order.

In this case, the Essential Services Order designated certain FBC facilities, productions and services to be necessary or essential to prevent immediate and serious danger to the health, safety or welfare of the residents of British Columbia. The Order has had the impact of fulfilling these objectives.

A copy of the Essential Services Order is provided in Attachment 90.5.

"In 2013, 69 jobs were filled as of May 1, 2013, an increase of 39 percent over the same time period in 2012" (Exhibit B-1, p. 163).

90.6 Please provide a breakdown of the number of IBEW employees in each operating department. Please include a tally of the number of employees in each operating department who have resigned since the start of the lock-out.

Response:

The number of FBC employees who are IBEW members for each operating department prior to the IBEW labour dispute as at June 1, 2013 is provided in the table below. Also provided in that table are the resignations of IBEW members during the labour dispute (June 26 to October 31, 2013).

Business Area	Jun-13	Resignations	Oct-13
Customer Service	18		18
Environment, Health & Safety	2		2
Generation	47	1	46
Operations	109	15	94
Operations Support	20		20
TOTALS	**196**	**16**	**180**

Note that these figures exclude inactive employees (e.g. employees on long-term disability).

When discussing the Company's high-demand positions, FBC identifies the following positions:

- Mid-Level Managers
- Engineers
- Power Line Technicians
- Communication Protection & Control Technicians
- Power System Dispatchers
- SAP Information Technology Roles

(Exhibit B-1, p. 118)

90.7 For those employees who have resigned during this lock-out situation, please identify how many are in each of the high-demand positions listed above.

Response:

The number of FBC employees in positions identified in the preamble who have resigned during the labour dispute (between June 26, 2013 to October 31, 2013) are reflected in the below table.

Position	Resignation
Mid-Level Managers	0
Engineers	1
Power Line Technician	11
Communication Protection & Control Technicians	1
Power System Dispatchers	2
SAP Information Technology Roles	1
TOTAL	**16**

A subsequent resignation from a Power System Dispatcher was received after October 31, 2012, in addition to a retirement by a Power System Dispatcher that will take effect after the labour dispute ends. This increases the number of Power System Dispatchers that have left their roles during the labour dispute to four.

90.8 Please provide an estimate of the recruitment/training required for each of the high-demand positions listed above. Please express in time (months/years) and in dollars.

Response:

The positions FBC may need to recruit for as a result of resignations during the IBEW labour dispute include Power Line Technicians, Communication Protection & Control Technicians, and Power System Dispatchers.

Consistent with FBC's approach to each vacancy, these vacancies will be used as an opportunity to evaluate how the Company will manage its workload. When the most effective way to manage workload going forward is to recruit and search for external applicants, active recruitment will be undertaken. Based on past experience, recruitment costs on average range from $10,000-$15,000 per hire, based on administration (including recruiting labour costs), agency fees (if needed), candidate screening and the interview/selection process.

Training costs vary depending on the trade skill level required at the time of hire. The duration of the training period can span 2-5 years. Based on past experience, training costs (not including wage/benefit costs) on average range from $7,000-$15,000 per hire based on compliance training (including external training), salary and travel expenses as well as the cost of internal and on-the-job training.

90.8.1 Please discuss how FBC plans to treat these incremental recruitment/training expenses that may incur during the PBR period? Will FBC manage through the O&M budgets or will this be treated as a z-factor item? Please also discuss why the proposed treatment is reasonable.

Response:

Any incremental recruiting and training expenses would be managed by FBC through the approved O&M budgets during the 2014-2018 PBR period. The Company believes that any costs related to staffing turnover are a cost of doing business that should be incorporated into each department's budgets and managed accordingly.

90.9 Please discuss how FBC has been managing the require workload during this lock-out period? How does FBC determine whether any replacement workers are properly trained and qualified to perform in any particular position in the interim?

Response:

FBC has been using qualified management and excluded staff to perform IBEW work during this labour dispute, as permitted under the *Labour Relations Code* and the Essential Service Order in place between FBC and the IBEW. To manage the workload, some lesser priority work has been postponed until after the labour dispute has ended. FBC notes that it has <u>not</u> relaxed its criteria or processes for determining whether an individual is considered qualified to carry out work normally done by IBEW workers. For example, only management staff who are already trade-certified and have demonstrated the necessary competencies can carry out PLT or electrician duties. Other non-qualified individuals are instead assigned to support roles or must be continuously supervised by qualified workers.

90.10 What is the normal ratio of managers to workers? What is the current ratio of managers to workers during the lock-out period?

Response:

FBC has 161 positions outside of bargaining units. These positions are a combination of management and exempt (M&E) employees, which can include employees who have direct reports in our natural gas operations. M&E can include people working without direct supervisory responsibilities in managerial functions in such areas as human resources and legal, for example.

M&E have individual duties in addition to some who manage direct reports. Of the total number of electricity employees, 73 have direct reports meaning that we have one manager for every seven employees.

The ratio of FBC managers to FBC employees is 1:7.

90.11 How does FBC ensure that safety and system reliability has been maintained during this lock-out period? Provide evidence or any statistics to support your response.

Response:

The ongoing labour disruption has not altered FBC's focus on ensuring safety and maintaining reliability.

Ensuring Safety

Since the disruption began, Management & Exempt (M&E) staff have been providing essential services and performing other operational functions that would normally be performed by IBEW labour. Prior to being considered qualified to perform bargaining unit work, M&E staff must possess appropriate trade qualifications to do the work (if required for the role) and must have successfully completed any required FBC courses related to safety and system operations. 24/7 coverage has been maintained during the labour disruption with appropriate staff available in key locations throughout the service territory who are able to respond to outages and other emergency situations such as damaged poles or failed conductors.

FBC safety statistics support the conclusion that M&E staff have been working safely. As shown in the table below, FBC's AIFR (All Injury Frequency Rate) performance for the period since the labour disruption began has improved compared to the prior period.

	Medical Treatment Injuries	**Lost Time Injuries**	**AIFR**
Jan 1, 2013 to Jun 30 2013 [1]	5	5	4.29
Jul 1, 2013 to Oct 31, 2013 [2]	0	1 [3, 4]	0.93

[1] Approximate start of labour disruption (actual date was June 26, 2013)

[2] Most recent complete month for which statistics are available.

[3] COPE office staff injury unrelated to M&E staff providing essential services work

[4] One M&E Lost Time Injury occurred on November 1, 2013 which has not been captured in this table. This injury will increase Lost Time Injuries from 1 to 2 and the AIFR from 0.93 to 1.85 (as at the time of filing). WorkSafeBC has not concluded their investigation into this incident (as at the time of filing).

Finally, WorkSafeBC has been contacted on a number of occasions since June 26, 2013, the date the labour disruption began, with allegations of unsafe work practices by M&E staff. Every inquiry received from WorkSafeBC has been investigated and addressed accordingly.

Maintaining Customer and Generation Reliability

As discussed above, during the labour disruption M&E staff have been providing essential services and performing other operational functions that would normally be supplied by IBEW labour. 24/7 coverage has been maintained during the labour disruption with appropriate staff available in strategic locations throughout the service territory who are able to respond to customer outages or equipment failures.

While some outage durations have been longer than desired due to limited availability of internal resources to respond, there has been no observable negative impact on system performance.

Indeed, for the third quarter of 2013, the SAIDI and SAIFI normalized results were better than the previous three year average. Several lightning storms throughout August caused tree-related outages on both the transmission and distribution systems. On August 6 and 7, one of these storms qualified as a Major Event Day with a total of 2,331 customers affected for a total of 38,196 customer outage hours. The majority of customers affected were in the Slocan Valley with a large tree falling on a radial transmission line serving this area that resulted in damage to the structures. Later in the month, between August 25 to 29, storms resulted in several outages with the majority of customers affected in the Crawford Bay/Kaslo areas, affecting 4,370 customers for a total of 40,479 customer hours.

With respect to Generation operations, on July 13, 2013 the Company experienced a fire in the Corra Linn Unit 2 generator which caused significant damage to the generator cables and switchgear. Investigations conducted internally and in conjunction with the insurer suggest that the root cause was due to a latent defect in the generator terminal connections. This installation was completed in December 2011, during the Unit Upgrade and Life Extension and hence the failure occurrence was unrelated to the current labour disruption. Since the failure, FBC M&E staff have worked on repairing the damaged equipment to restore the unit as quickly as possible. The planned return-to-service date is mid-December with the critical path item being the manufacturing and delivery of replacement switchgear.

Following is a summary of the reliability statistics to the end of Q3. The generation forced outage rate (FOR) for 2013 is shown both including the Corra Linn unit failure event (actual) and with this single event excluded (normalized).

	SAIFI		SAIDI		Generation FOR	
	Actual	**Normalized**	**Actual**	**Normalized**	**Actual**	**Normalized**
End of Oct 2013 Actual	1.17	1.08	2.74	1.83	3.79	0.07
Year-End Forecast 2013	1.36	1.28	3.02	2.11	4.35	0.08
Three-year Rolling Average (2010 to 2012)	1.73	1.64	2.87	2.22	0.22	N/A
Annual 2012	1.53	1.27	3.86	1.95	0.56	N/A
Annual 2011	1.38	1.38	1.86	1.86	0.02	N/A
Annual 2010	2.27	2.27	2.87	2.84	0.09	N/A

Summary:

Based on the information provided above, FBC submits there is no evidence to suggest that safety or system reliability has been compromised during the period of labour disruption.

90.12 How does FBC ensure that scheduled maintenance and other requirements are being performed during this time? Please discuss how the current labour situation may have any long-term effects on system reliability and safety?

Response:

FBC completed the bulk of scheduled maintenance activities prior to the labour disruption. Large programs such as vegetation management were not affected, as this work is historically carried out by external contractors. Limited maintenance activities resumed as permitted by the new Essential Services Order received on September 13. FBC has also been continuing to conduct required maintenance and testing to ensure ongoing compliance with the BC MRS requirements.

FBC acknowledges that some scheduled maintenance work has not been completed due to the labour disruption. Please refer to BCUC IR 2.90.13 for discussion of these programs.

FBC does not believe the labour disruption will have any long term effects on system reliability and safety.

In its Evidentiary Update, FBC states that “[t]he Company acknowledges that the labour disruption will result in a decrease in certain IBEW labour costs. However, there will also be cost increases in certain other areas as a result of the labour disruption…” (Ex. B-1-6, p. 3).

90.13 What are the savings in labour costs due to the lock-out situation? What are the incremental labour expenses paid to the replacement workers/contractors who are managing those positions in the interim?

Response:

The Company is in the midst of an ongoing labour dispute, therefore is unable to quantify any savings or increases in labour expense with certainty at this time.

FBC is not experiencing incremental labour expenses due to the use of replacement workers or contractors. Using replacement workers or contractors in such circumstances is prohibited under Section 68 of the BC Labour Code and our Essential Services Order. Please refer to the response to BCUC IR 2.90.5, Attachment 90.5, for a copy of the Essential Services Order.

Pursuant to Order G-110-12, any variances in O&M expense from what was approved for 2012 and 2013 are not passed on to ratepayers. Therefore, any savings or increases in O&M expense that would result from the labour disruption occurring during 2013 should not be passed on to ratepayers. Further, as at the time of filing the October 18, 2013 Evidentiary Update, FBC had indicated that there was no projected net savings or overages as a result of the ongoing labour dispute.

However, FBC acknowledges that certain O&M expense that was forecast and approved for 2013 relate to scheduled and necessary maintenance work. Specifically, there are certain line maintenance programs that are included within the Utility Operations group which are part of annual programs to ensure employee and public safety and maintain reliability, as well as minor maintenance projects and certification programs within the Generation group which are required to facilitate operations. Parts of these programs that were scheduled for 2013 and estimated to be $0.8 million, but have not been completed due to the labour disruption, will be required to be performed in 2014 in addition to the scheduled 2014 programs. FBC's 2014 O&M under the PBR formula does not contemplate the shift of these required 2013 operational programs, which have already been approved to be performed by the BCUC.

In the absence of any additional regulatory mechanism, the catch-up of these 2013 programs will put pressure on 2014 O&M, which would result in variances in O&M labour expense from what was requested. FBC's 2014-2018 PBR Application includes an Earnings Sharing Mechanism that would result in 50% of these incremental operational program costs being passed on to ratepayers in 2014 because the labour disruption affected the Company's ability to complete the programs in 2013. Therefore, FBC will be setting up a deferred O&M expense account as a credit to deferred charges for approximately $0.8 million as at December 31, 2013. This deferred O&M expense regulatory mechanism would then be drawn down in 2014 as the carryover operational program work is conducted. Recognizing this liability account will avoid any incremental 2013 earnings to be flowed to the Company as a result of the shift in O&M between years, while still allowing for this previously approved work to be performed with no impact on customer rates in 2014.

As a result of the carry-over of capital expenditures from 2013 to future years, FBC states that there are increased benefits loading charged to 2013 O&M as opposed capital. Additionally, there is a greater proportion of the labour and vehicle costs being charged to 2013 O&M expenses rather than capital.

90.14 Please provide a high-level summary of the "carry-over of capital expenditures from 2013 to future years." Please discuss how FBC plans to manage this additional capital work during the PBR term?

Response:

There are two reasons why capital expenditures forecast to be performed in 2013 are being carried over to future years. The first is the later than anticipated decision on the 2012-2013 RRA, where Order G-110-12 was not received until August 2012. This resulted in a delayed start on certain capital projects, which meant work was pushed into 2013. The second is the ongoing labour disruption between FBC and its IBEW employees, where the IBEW received a strike mandate from its membership on February 18, 2013 which provided 72 hour strike notice and altered how the Company planned its capital work. Further to this, partial job action by IBEW staff affected overall productivity, and escalated until June 26, 2013 when the Essential Services Order was enacted. The Company is operating under an Essential Services Order which initially outlined certain types of work that could be performed by the Company, it has since been modified to reflect expectations for support in emergency circumstances. The majority of capital work does not meet the definition of "essential"; and when combined with the limitations of available internal resources and constraints on the use of external contractors, the result is that certain capital work scheduled for 2013, which already included work rescheduled from 2012, is now being carried over into 2014.

As discussed in Section 4 of the Evidentiary Update, the Company recognizes that successfully completing this level of capital activity in 2014 will present challenges to engineering, project management, operations and construction resources. At the same time, the significant uncertainties regarding the duration of the labour disruption, the resulting impacts on internal crew resources post-settlement and the availability of future contractor resources, all mean FBC is unable to foresee which specific projects may be completed in 2014 and which will be completed in 2015.

FBC believes the previously approved capital work can be completed in 2014 and 2015. For purposes of the capital formula being proposed for the 2014-2018 PBR term, the Formulaic Capital has not changed; however an adjustment in 2014 and 2015 to Capital Tracked Outside of Formula has been included to complete the previously approved 2012/2013 capital expenditures.

90.15 Please discuss any long-term operational and maintenance impacts due to this delay of capital expenditures of 2013. Will FBC manage through the O&M budget and capital budgets derived from the proposed formulas or will this be treated as Z-factor items? Please also discuss why the proposed treatment is reasonable.

Response:

The Company does not believe there will be any long-term impacts on O&M as a result of the delayed capital expenditures of 2013.

For capital, the Formulaic Capital proposed in the 2014-2018 PBR Application has not changed; however an adjustment in 2014 and 2015 to Capital Tracked Outside of Formula has been included to complete the previously approved 2012/2013 capital expenditures. There are no additional Z-factors being proposed in the capital budget related to the labour disruption.

For O&M, please refer to the response to BCUC IR 2.90.13.

90.16 Please explain how meters are being read during this lock-out period. Is customers' consumption being estimated?

Response:

On September 13, 2013, the Essential Services Order ("ESO") was amended to permit FBC to read meters (prior to this date, meter reading was not a permitted ESO activity). On September 13th, FBC began utilizing the services of Management and Exempt ("M&E") staff to read meters. As there are insufficient M&E staff available to read all customer meters, the priority has been to obtain reads for customer moves, high bill concerns, and large power consumption accounts.

During the labour dispute, most bills have been estimated based on historical consumption. FBC's plan once a negotiated settlement is reached in this labour dispute is to obtain verified meter reads for all our customers. When the Company has those meter reads, it will do an analysis of customers' bills and ensure that estimates have not created higher billed amounts than would have been calculated if the meters were being read. Residential customers will have their actual consumption spread evenly over the estimate period to mitigate the concerns of estimated meter reads in conjunction with the Residential Conservation Rate.

90.17 Please explain how these labour disputes will impact FBC's Five Year Workforce Plan?

Response:

FBC does not anticipate that the current labour dispute with the IBEW will materially impact the Five Year Workforce Plan. It is expected that once the labour dispute is resolved, the resulting collective agreement will provide current and future employees with employment and wage stability, which FBC believes will assist in attracting and retaining employees as required, which in turn will assist with achieving anticipated results under the Workforce Plan.

It was noted in the response to BCUC IR 2.90.7 that a number of employees holding key roles within operations have resigned during the period of the labour dispute. Once the labour dispute is resolved, FBC plans to assess its workforce needs to determine the extent to which the positions need to be replaced. It is possible that the number of employees FBC is required to recruit for certain positions will be greater than described in the Workforce Plan. However, because these positions would be replacements, no further additions to headcount are expected.

90.18 Has FBC been monitoring customer service during the lock-out period? If yes, how is customer service being measured? If not, why not?

Response:

Yes, FBC has continued to collect customer service operational and satisfaction metrics during the lock-out period. These standard metrics include: telephone service factor, contact centre satisfaction and first-contact resolution. In addition, FBC has continued to randomly poll customers to calculate the directional Customer Satisfaction Index (CSI) metric. CSI results show that overall satisfaction increased from 7.9 in Q2 to 8.1 in Q3. The field services sub-score, which makes up 25 percent of the overall satisfaction score, increased from 8.6 to 9.1 in the same period.

90.18.1 What are the general customer concerns during this lock-out period and how has FBC been dealing with these complaints/concerns?

Response:

Customer concerns during the lock-out period are primarily related to:

- Billing estimates;

- Delays in new service construction projects; and
- Delays in other types of field work such as temporary disconnections and upgrades.

With respect to billing estimates, FBC has been working with customers to understand changes in consumption patterns that may have impacted the accuracy of the billing estimates. Then, the estimate is revised based on the understanding that once an actual meter reading is received, the balance may change. In escalated cases, management has been sent out to obtain a verified reading.

With respect to customer concerns about delays in new electrical service construction projects, the customer's right, as contained in Schedule 74 of the Tariff, to choose to contract new electrical service construction work, through the use of third party contractors, has been upheld by the Labour Relations Board. Customers, therefore, are using contractors to complete new electrical service construction work during the labour dispute.

Where disconnections and/or upgrades are a customer priority, and where the work would not compromise essential service work, exempt FBC staff are completing the work.

I. GENERAL

91.0 Reference: Exhibit B-1, pp. 26, 156, 232, 236 and 263-264; Order C-7-13

2014–2018 Annual Reviews

"The activities associated with Regulatory O&M expense include the provision for regulatory services such as the **preparation of all revenue requirements**, cost of capital and rate design applications, applications for CPCNs, energy supply applications and providing interpretations, education and communication of regulatory requirements and policies to departments throughout the Company." (Exhibit B-7, BCUC 1.192.1)

"With regard to other types of regulatory applications, FBC has experienced a dramatic increase, not decrease, in regulatory demands throughout the Company, which are not expected to be mitigated by PBR." (Exhibit B-7, BCUC 1.192.1.1)

91.1 According to the Reasons for Decision accompanying Order C-7-13, the following CPCN development costs were included in the Advanced Metering Infrastructure project capital costs:

Table 8-2

Table 5.1.1.a - AMI Project Development and Regulatory Costs

	Activity	Cost
	($000s)	
1	2007 AMI Application	275
2	2012 AMI Application	2,217
3	Consultants	423
4	Regulatory Process (forecast)	2,000
5	**Total**	**4,915**

(Exhibit B-1-1, p. 73)

91.2 Please provide an estimate of actual Regulatory O&M expenses incurred in each of 2012 and 2013 related to the 2012-2013 RRA and ISP Application.

Response:

FBC estimates that O&M expenditures of approximately $0.2 million and $0.05 million were incurred in 2012 and 2013 respectively for activities related to the 2012-2013 RRA and ISP application. These costs relate primarily to the following:

- Preparation for and attendance at the oral hearing process to review the application;
- Preparation and review of final and reply submissions;
- Preparation and review of compliance filing as directed by G-110-12; and
- Calculation and update of tariff rates.

It is expected that these regulatory O&M expenses will still occur during the 2014-2018 PBR period in relation to the annual review process, preparation and submission of updated financial schedules and forecasts, calculation and update of tariff rates, as well as any additional process determined to be required under the PBR plan.

91.3 How were Annual Review O&M expenses treated in the previous PBR period? Please discuss.

Response:

Regulatory O&M expenses related to the Annual Reviews in the previous PBR period were expensed in the year incurred. Incremental costs (including BCUC costs, intervener costs, annual review location costs, contractor costs and legal costs) associated with Annual Reviews were treated as deferred charges and amortized into customer rates.

91.4 Regarding "other types of regulatory applications", please confirm or explain otherwise, that FBC typically applies for deferral account or capital treatment of any O&M expenses incurred that are incremental to approved O&M expense. For example, according to Order C-7-13, CPCN Development and Regulatory Costs of $4,915 thousand were included in the project capital costs for the AMI project.

Response:

Confirmed, however these incremental expenses do not include any internal labour charged to Regulatory O&M. With respect to the referenced development and regulatory costs of $4,915 thousand for the AMI project, these costs are comprised of the following:

- Approximately $0.3 million related to the 2007 AMI CPCN application;
- Approximately $2.0 million related to oral hearing (PACA, consultants, legal, etc.); and
- Approximately $1.6 million related to development of the 2012 AMI CPCN application (incremental non-regulatory labour, travel, consultants, legal review).

FBC notes that approximately 1.5 FTEs were dedicated to the AMI CPCN application development and regulatory review with the associated labour costs absorbed as part of overall Regulatory O&M.

92.0 Reference: Power Factor

Exhibit B-7, BCUC IR1.228.1

FBC states: "[s]ince kVA metering inherently includes var consumption, these customers are already being penalized for var consumption through higher bills (in that the var consumption results in higher kVA demand charges than if their power factor was maintained at exactly 1.0)" (Exhibit B-7, BCUC 1.228.1).

92.1 Are these collected penalties applied to correcting the power factor of the transmission and distribution systems thereby reducing the VARs required to be purchased from other energy suppliers?

Response:

FBC does not have the option to purchase reactive power from other energy suppliers; FBC can only purchase real power (both energy and demand) measured in watts, not vars or volt-amperes. Instead, FBC is contractually obligated to "use its best efforts to plan and operate" at zero var flow (unity power factor) at its interconnection points with BC Hydro. Hence, all reactive power requirements must be met entirely within the FBC system. With respect to 'collected penalties', please also refer to the response to BCUC IR 2.92.1.1.

92.1.1 If not, please explain if the penalties are included in Other Revenues and applied as a revenue offset to the total Revenue Requirement?

Response:

For clarity, there is no defined power factory "penalty" listed on a customer's bill. Rather, there is simply a demand charge which is calculated as per the tariff rate. Hence, customers with a poor power factor pay a higher demand charge than they otherwise would if they maintained a higher power factor. Billing revenue from all customer demand charges is included with energy sales revenue and is used to offset the total Revenue Requirement. There is no distinction between demand charge revenue from customers above or below the power factor requirement in the FBC tariff, nor does FBC consider there to be any useful purpose served by such a distinction.

92.1.2 For FBC purchases of capacity or energy, please provide the total cost of VARs purchased or provided by FBC in the Base year.

Response:

There are no purchase costs associated with reactive power. Please refer also to the response to BCUC IR 2.91.1.

93.0 Reference: AMI Volt/VAR Optimization (VVO)

AMI Application, Exhibit B-1, pp. 99–101,

System Losses

"The study found that FortisBC could conserve 50,072 MWh or more per year by installing and operating a Smart Grid VVO system on its entire electric distribution system" (AMI Application, Exhibit B-1, p. 99).

Table 6.2.A — Conservation Voltage Reduction Costs and Savings shows the annual savings of using VVO to be $2.6 million and an estimated cost of VVO of $8.9 million (AMI Application, Exhibit B-1, p. 100).

93.1.1 Now that the AMI CPCN Application has been approved by the Commission, is FBC considering the implementation of VVO to reduce system losses and improve power factor?

Response:

The timing for the implementation of CVR / VVO was explored in the AMI application and information requests. In the response to CEC IR 1.23.3 (Exhibit B-11 of the AMI CPCN process), FBC noted:

" […] As discussed in Section 6.2 of the Application, Conservation Voltage Reduction (CVR) has been assessed; however, at this time all forms of CVR show an overall negative payback for customers at this time. On that basis, CVR is not considered to currently be in the interest of ratepayers and was thus not included in the financial analysis for the proposed AMI Project."

Since that application, no new information has come to light which would alter this conclusion.

94.0 Reference: VVO Opportunities

AMI Application, Exhibit B-1, Appendix C-2, p. 17

Fortis BC CVR_VVO Report, August 2011

"FortisBC serves the communities of Summerland, Penticton, Kelowna, Grand Forks and Nelson; however, no energy conservation based on their loads was included in this evaluation. The total wholesale 2010 billed kWh was 2,323,012,537 kWh. The potential conservation available for these communities, using the same assumptions and percentages as for the FortisBC direct customer conservation, is approximately 46,015 MWh, almost equivalent to the savings estimated in the analysis. The author recommends that Fortis BC consider some means of including this large potential conservation opportunity at some time." (AMI Application, Exhibit B-1, Appendix C-2, p. 17)

94.1 Is FBC considering including the recently acquired City of Kelowna and the other wholesale customers in a larger VVO scheme? If not, why not?

<u>Response:</u>

The concept of CVR (VVO) essentially involves the creation of a "feedback loop" where voltage information from customer revenue meters is used to modify the operation of distribution voltage control equipment such as tapchangers, voltage regulators and capacitors. This allows the distribution system to be operated at the lowest optimal voltage (which reduces distribution system losses and thus overall energy consumption) while still maintaining adequate voltage levels at all customer end-points.

By necessity, CVR requires near-real-time voltage information from customers' meters, as well as the ability to control the operation of the distribution equipment discussed above. In the case of the wholesale municipal customers of Summerland, Penticton, Grand Forks and Nelson, FBC neither owns nor operates the customer billing meters nor the distribution systems for these utilities. On that basis, it is not possible for FBC to incorporate these distribution systems into a future FBC CVR scheme. If any of those utilities choose to implement CVR for the benefit of their own systems, then it would be necessary for those utilities to install and operate the necessary CVR control system; it would not be necessary or possible for FBC to participate in any case.

With respect to the City of Kelowna distribution system, these assets are now part of the larger FBC transmission and distribution system. On that basis, they would be evaluated for inclusion in any future FBC CVR system if one were implemented.

95.0 Reference: B&V Invoices

Exhibit B-10, CEC 1.74.5

FBC states:

> "[f]or the work invoiced to date B&V have provided its expert PBR advice to both FEI and FBC. The current invoicing is allocated approximately 75% to FEI and 25% to FBC because FEI is farther along in its proceeding. The Companies expect that the costs will be approximately split equally between FEI and FBC once both proceedings are completed." (Exhibit B-10, CEC 1.74.5)

95.1 Please explain why the costs of the B&V consultant will be approximately split equally between FEI and FBC once both proceedings are completed rather than by the average number of customers in each division.

Response:

The Companies consider that B&V's effort is driven by the regulatory processes for FBC as well as FEI, and therefore the most appropriate allocation is to split the costs equally between FBC and FEI. The average number of customers does not drive the costs from B&V; rather the regulatory process for each company drives the costs. As discussed in the response to CEC IR 1.74.5 the Companies believe that the costs will be approximately split once the proceedings are completed.

96.0 Reference: Cost of Service Allocation and Rate Design (COSA)

96.1 Please clarify whether FBC plans to file a COSA application during the PBR term. If so, when?

Response:

The Company anticipates that it will file a COSA after the Advanced Metering Infrastructure (AMI) project has been fully deployed and at least one year of the data made available by the AMI system has been collected. This would mean that the Company could file a COSA as early as 2017.

J. DEMAND SIDE MANAGEMENT (DSM)

97.0 Reference: Exhibit A2-10, Aligning Utility Incentives with Investment in Energy Efficiency, pp. 4-5 and 4-9;

Exhibit B-1-1, Attachment H, p. 18;

Exhibit B-7, BCUC 1.232.2, 1.232.2.1 and 1.192.1;

Exhibit A2-15, ACEE Saving Energy Cost-Effectively 2009 Report, p. 3;

Nova Scotia Utility and Review Board Decision, Nova Scotia Power 2013 General Rate Application, p. 103[10];

BCUC Order G-55-95, DSM Amendments to the Uniform System of Accounts for Gas & Electric Utilities, Appendix A, p. 2

DSM Amortization period

A Resource of the National Action Plan for Energy Efficiency 2007 Report titled *Aligning Utility Incentives with Investment in Energy Efficiency* (Exhibit A2-10) states:

> "[c]apitalization currently is not a common approach to energy efficiency program cost recovery... With a very few exceptions, capitalization is no longer the method of choice for energy efficiency cost recovery... in several states capitalization was abandoned, in part because the total costs associated with recovery (given the cost of the return on investment) were rising rapidly..." (p. 4-5)

> "An early study (Reid, 1988) of energy efficiency capitalization found that amortization programs for conservation expenditures ranges from three to 10 years. ...carrying substantial regulatory assets on the balance sheet can hurt a utility's financial rating" (pp. 4-6, 4-7)

Table H-6 (Exhibit B-1-1, Attachment H, p. 18) and the response to BCUC 1.232.2.1 present FBC's effective measure life assumptions. An American Council for an Energy-efficient Economy (ACEEE) study titled *Saving Energy Cost-Effectively: A National Review of the Cost of Energy Saved Through Utility-Sector Energy Efficiency Programs*, September 2009 states on page 3: "...we use 13 years for electricity [estimated measure life]... which [is] the average measure lifetimes from the 10 program portfolios that provided measure lifetime estimates." (Exhibit A2-15, p.3)

[10] http://www.nspower.ca/site-nsp/media/nspower/NSPI%202013%20GRA%20-%201%20DE%2002-04.pdf

The Nova Scotia Utility and Review Board Decision on the Nova Scotia Power 2013 General Rate Application states on page 103: "In the 2009 Rate Decision, the Board approved the amortization of Demand Side Management expenditures for 2008 and 2009 over six years starting in 2009."

Commission Order G-55-95 requires rapid write-off (over two to three years) for significant or material non-recurring DSM costs, and normal write-off (over three to 10 years) for recurring costs that qualify as assets. A utility may also apply for a normal write-off longer than 10 years. (Exhibit A2-16, Appendix A, p. 2)

97.1 Please list and describe all DSM related deferral accounts for which FBC is requesting a change in amortization period.

Response:

FBC is proposing to change the amortization period from 10 years to 15 years for the following deferral accounts:

DEMAND SIDE MANAGEMENT
EM Motors
EM Industrial Efficiency
EM Pumps and Fans
EM Compressors
EM New Process Design/EMIS
EM Commercial Lighting
EM BIP (Building Improvement Program) New
EM BIP Retro
EM Ground Source Heat Pumps
EM New Home Program
EM Home Improvement (Building Envelope)
EM Water Savers
EM Residential Lighting
EM Water Handling Infrastructure
EM Air Source Heat Pumps
EM Administration Kelowna Office
EM Time of Use-Load Shift (ETS)
EM Conservation Culture
EM Low Income Program
EM Consumer Electronics
EM Supporting Initiatives
EM Appliance Rebate Programs
On-Bill Financing (OBF) Pilot Program

97.2 Is FBC requesting a change in amortization period for future DSM spending only, or also for past DSM spending? Please explain.

Response:

FBC is proposing a change in the amortization period of past and future DSM expenditures from 10 years to 15 years. Please refer to Section D4.4.1, page 265 of the 2014-2018 PBR Plan Application (Exhibit B-1).

97.3 Does FBC agree that that capitalization of DSM expenditures is not currently a widely used DSM cost recovery method? If no, please explain why not.

Response:

The view of FBC is that the financial treatment of DSM expenditures is well-established and appropriate. Capitalization is certainly widely used in British Columbia, as it is the method currently used by all three British Columbia utilities currently engaged in DSM.

FBC also notes that the treatment of DSM expenditures has recently been considered by the BCUC. Both FBC and the FortisBC Energy Utilities are of the view that the financial treatment of DSM for utilities in British Columbia has been well established through numerous and recent time and resource- consuming regulatory proceedings and decisions by Commission Panels. Should Commission Staff wish to revisit these recent decisions, they are free to do so. In the interests of fairness, should Commission Staff wish to re-open the matter of the financial treatment of DSM in British Columbia, such a review would need to encompass the three British Columbia utilities engaged in DSM: the FortisBC Energy Utilities, FBC, and BC Hydro.

Provincial policy actions justify ongoing utility investment in DSM programs. Furthermore, as explained in BCUC IR 2.97.6, FBC has obtained multiple examples of North American utilities who have capitalized some type of demand side management costs as “Regulatory Assets” on their audited external financial statements.

97.3.1 Apart from the six year amortization period for DSM approved for Nova Scotia Power in 2012, is FBC aware of any other Canadian jurisdiction (other than BC) that allows deferral and amortization of DSM expenses?

If yes, please provide details including the amortization period allowed and those jurisdictions with no amortization.

Response:

Time constraints did not permit an exhaustive study, but Newfoundland Power has a 7-year amortization, and Maritime Electric uses a 5-year timeframe. Manitoba Hydro reportedly changed to expensing DSM in 2012 to comply with IFRS protocols.

97.3.2 Please confirm that FBC is already at the upper-limit of the three to ten year DSM write-off period for DSM expenditures that qualify as assets (Appendix A to Order G-55-95).

Response:

Confirmed. FBC notes the Order allows for a longer amortization period, namely:

> *"A utility may apply for a normal write-off longer than 10 years."*

The Company has provided the justification in this Application for an amortization period longer than ten years in Appendix H of the Application.

97.4 Does FBC agree that carrying large regulatory assets on the balance sheet can weaken a utility's financial rating? If no, please explain why not.

Response:

FBC interprets the question's reference to "financial rating" as a utility's rating by external, third party credit rating agencies, such as Moody's or DBRS. To clarify, the existence of regulatory assets on a utility's balance sheet does not, in and of itself, weaken a utility's credit rating. The impact on a credit rating from the existence of regulatory assets will depend on a number of factors, including, but not limited to, the size of the regulatory asset balance itself.

The rating agencies may assess the financial risk of a utility around its regulated assets based on factors such as the size of the regulatory asset relative to the overall rate base of the company, the rate of return and capitalization of the regulatory asset, the likelihood of the regulated assets to be added to its rate base, the degree of regulatory lag and whether the deferral balance is pre-approved by the regulator, the perceived risk of disallowance by the regulator of the recovery of the regulatory asset balance in customer rate.

In the instance of FBC's DSM expenditures, which are referenced to in the preamble to this question, such risks are mitigated as FBC's DSM expenditures are expected to be generally pre-approved during the term of the PBR, included in rate base and recovered from customers. It is also expected that a utility's credit rating would more likely be adversely affected if there was not a set period of time to recover regulatory assets from customers. In the case of FBC's DSM expenditures, any change in the amortization period by a few years is not going to adversely affect the credit ratings as there is a set period for which these costs will be recovered from customers which supports matching the benefit and is already in place within the rate-regulated industry of British Columbia.

97.4.1 Please estimate FBC's DSM deferral account balances for each year from 2014 to 2023 (showing annual additions/amortization), assuming DSM annual spending in future years is consistent with that forecast over the PBR period, for the following DSM amortization periods: 10 years, 15 years. Please provide supporting calculations and assumptions.

Response:

Please refer to tables below for the DSM deferral account balances for each year from 2014 to 2023.

1

Table BCUC IR2 97.4.1: DSM 15 Years

Year	Beginning Balance	Additions	Amortization	Ending Balance
2014	$ 17,142	$ 2,221	$ 1,326	$ 18,037
2015	18,037	2,347	1,474	18,910
2016	18,910	2,330	1,630	19,610
2017	19,610	2,368	1,786	20,192
2018	20,192	2,412	1,944	20,660
2019	20,660	2,463	2,104	21,019
2020	21,019	2,515	2,269	21,265
2021	21,265	2,568	2,436	21,397
2022	21,397	2,622	2,575	21,444
2023	21,444	2,678	2,702	21,420
	$ 199,678	**$ 24,524**	**$ 20,245**	**$ 203,956**

* Minor differences due to rounding

** Additions forecasted to increase at 2.11% commencing in 2019

2

Table BCUC IR2 97.4.1: DSM 15 Years Supporting Calculations

Year	Unamortized Balance	Remaining Years	Annual Amortization	Total Amortization	Summation Range
2006	$ 258	8	$ 32		
2007	436	9	48		
2008	843	10	84		
2009	1,377	11	125		
2010	1,860	12	155		
2011	3,270	13	252		
2012	4,651	14	332		
2013	4,455	15	297		
2014	2,221	15	148	1,326	2006 to 2013
2015	2,347	15	156	1,474	2006 to 2014
2016	2,330	15	155	1,630	2006 to 2015
2017	2,368	15	158	1,786	2006 to 2016
2018	2,412	15	161	1,944	2006 to 2017
2019	2,463	15	164	2,104	2006 to 2018
2020	2,515	15	168	2,269	2006 to 2019
2021	2,568	15	171	2,436	2006 to 2020
2022	2,622	15	175	2,575	2007 to 2021
2023	2,678	15		2,702	2008 to 2022
	$ 41,673		**$ 2,782**	**$ 20,245**	

* Minor differences due to rounding

Table BCUC IR2 97.4.1: DSM 10 Years

Year	Beginning Balance	Additions	Amortization	Ending Balance
2014	$ 17,142	2,221	2,230	$ 17,133
2015	17,133	2,347	2,452	17,028
2016	17,028	2,330	2,686	16,672
2017	16,672	2,368	2,834	16,207
2018	16,207	2,412	2,961	15,657
2019	15,657	2,463	3,034	15,086
2020	15,086	2,515	3,051	14,551
2021	14,551	2,568	3,037	14,082
2022	14,082	2,622	2,885	13,820
2023	13,820	2,678	2,630	13,867
	$ 157,379	**$ 24,524**	**$ 27,799**	**$ 154,104**

* Minor differences due to rounding

** Additions forecasted to increase at 2.11% commencing in 2019

Table BCUC IR2 97.4.1: DSM 10 Years Supporting Calculations

Year	Unamortized Balance	Remaining Years	Annual Amortization	Total Amortization	Summation Range
2006	$ 258	3	$ 86		
2007	436	4	109		
2008	843	5	169		
2009	1,377	6	229		
2010	1,860	7	266		
2011	3,270	8	409		
2012	4,651	9	517		
2013	4,455	10	446		
2014	2,221	10	222	2,230	2006 to 2013
2015	2,347	10	235	2,452	2006 to 2014
2016	2,330	10	233	2,686	2006 to 2015
2017	2,368	10	237	2,834	2007 to 2016
2018	2,412	10	241	2,961	2008 to 2017
2019	2,463	10	246	3,034	2009 to 2018
2020	2,515	10	251	3,051	2010 to 2019
2021	2,568	10	257	3,037	2011 to 2020
2022	2,622	10	262	2,885	2012 to 2021
2023	2,678	10		2,630	2013 to 2022
	$ 41,673		**$ 4,414**	**$ 27,799**	

* Minor differences due to rounding

97.4.2 For the same time period, DSM funding options and DSM amortization options as above, please also model i) the annual rate impact for customers and ii) the DSM related return to the FBC shareholder.

Response:

Please find below the relevant Tables indicating:

1. Energy Management (DSM) Post Tax Additions;
2. Energy Management (DSM) Post Tax Amortization;
3. Annual Overall Rate Impact;
4. Annual Overall Return on Equity;
5. Annual Rate Impact – DSM Component only; and
6. Annual Overall Return on Equity – DSM Component only,

for both 15 year and 10 Years of Amortization Schemes:

For 15 Year Amortization Period:

Energy Management (DSM) impact Analysis (15 Year Amortization Period)	**2014**	**2015**	**2016**	**2017**	**2018**
Energy Management (DSM) Additions Post Tax	2,221	2,347	2,330	2,368	2,412
Energy Management (DSM) Amortization Post Tax	(1,326)	(1,474)	(1,630)	(1,786)	(1,944)
Annual Overall Rate Impact	3.3%	3.6%	3.6%	3.6%	3.6%
Annual Overall Return on Equity (to FBC Shareholders)	43,616	45,538	47,160	47,740	48,019
Annual Rate Impact differential for DSM Capital only	0.5%	0.0%	0.0%	0.0%	0.0%
Return on Equity (to FBC Shareholders) for DSM Capital Only	18	50	79	102	122

For 10 Year Amortization Period:

Energy Management (DSM) impact Analysis (10 Year Amortization Period)	2014	2015	2016	2017	2018
Energy Management (DSM) Additions Post Tax	2,221	2,347	2,330	2,368	2,412
Energy Management (DSM) Amortization Post Tax	(2,230)	(2,452)	(2,686)	(2,834)	(2,961)
Annual Overall Rate Impact	3.7%	3.6%	3.6%	3.6%	3.6%
Annual Overall Return on Equity (to FBC Shareholders)	43,600	45,488	47,073	47,614	47,855
Annual Rate Impact differential for DSM Capital only	0.9%	0.0%	0.0%	0.0%	0.0%
Return on Equity (to FBC Shareholders) for DSM Capital Only	2	0	(8)	(23)	(42)

Note-1: Data beyond 2018 cannot be provided at this time.
Note-2: No DSM Load (GWh) savings has been considered in the analysis.

97.4.3 Does FBC consider that, given the DSM amortization period also affect returns to FBC's shareholder, changes to the DSM amortization period should be considered as part of a separate review of DSM shareholder incentives? Please explain why or why not.

Response:

FBC believes that a decision to extend the DSM amortization period can be made in the current proceeding on the basis of the evidence on hand. Any review of DSM shareholder incentives, whether separate or not, can proceed independently of this accounting decision. The Company also submits that the Commission's previous decisions relating to FBC's DSM amortization periods have been done within the past revenue requirements proceedings in a similar fashion as is being requested in this Application.

97.5 FBC states in BCUC 1.232.2: "...the concept of matching costs and benefits is a key accounting principle that is applied to capital expenditures by depreciating capital assets over their useful lives."

97.6 In the absence of specific Commission approval to defer and amortize DSM expenditures, what does FBC consider to be the applicable accounting authority's guidance on how DSM expenditures of this nature should be treated (i.e. expense or capitalize)?

Response:

There would be no specific guidance under US GAAP that contemplates treatment of these types of expenditures. However, whether these types of expenditures generally meet the definition of an asset can be assessed.

The general definition of an asset under US GAAP is provided in the Financial Accounting Standards Board ("FASB") Concept 6, *Elements of Financial Statements*, which defines an asset as "probable future economic benefits obtained or controlled by a particular entity as a result of past transactions or events".

With respect to DSM expenditures, there is probable future economic benefits resulting from investment in demand side management programs because these programs will result in a decrease in future energy demand. From the perspective of FBC, the lower demand results in decreased future power supply costs. Therefore, there could be an argument that DSM expenditures, or at least a portion of them, could potentially meet the definition of an asset in the absence of specific Commission approval.

Furthermore, with respect to common industry practice, in addition to BC Hydro and the FortisBC Energy Utilities, the following companies have capitalized some type of demand side management programming or energy efficiency programs as "Regulatory Assets" on their balance sheets, indicating that at least a part of their DSM programs are capitalized:

- Manitoba Hydro (Source: Audited Financial Statements – March 31, 2013);
- Idaho Power (Source: IDACORP Inc. Audited Financial Statements – December 31, 2012);
- New Jersey Resources Corporation (Source: Audited Financial Statements – September 30, 2012);
- Minnesota Energy Resources Corporation, North Shore Gas Company, The Peoples Gas Light and Coke Company, and Wisconsin Public Service Corporation (Source: Integrys Energy Group Inc. Audited Financial Statements – December 31, 2012); and
- Duke Energy Corporation (Source: Duke Energy Corporation Audited Financial Statements – December 31, 2012).

97.6.1 In providing its guidance, would the applicable accounting authority have considered the matching principle and all other accounting principles to reach its pronouncement? If not, please elaborate.

Response:

The "matching principle" would not have considered all other accounting principles. Instead, all accounting guidance considers the concept of matching costs with the associated benefits.

The matching of costs and benefits is an accounting concept, not an accounting principle. In other words, there isn't a pronouncement which discusses matching costs and benefits that is published by the Financial Accounting Standards Board ("FASB"). However, FASB Statement of Financial Accounting Concept 6, *Elements of Financial Statements*, was published as non-authoritative guidance and is one of a series of publications in FASB's conceptual framework for financial accounting and reporting. Statements in the series are intended to set forth objectives and fundamentals that will be the basis for development of financial accounting and reporting standards.

Some applicable sections of this statement are included below:

> *146. Matching of costs and revenues is simultaneous or combined recognition of the revenues and expenses that result directly and jointly from the same transactions or other events. In most entities, some transactions or events result simultaneously in both a revenue and one or more expenses. The revenue and expense(s) are directly related to each other and require recognition at the same time. In present practice, for example, a sale of product or merchandise involves both revenue (sales revenue) for receipt of cash or a receivable and expense (cost of goods sold) for sacrifice of the product or merchandise sold to customers.*

> *147. Many expenses, however, are not related directly to particular revenues but can be related to a period on the basis of transactions or events occurring in that period or by allocation. Recognition of those expenses is largely independent of recognition of particular revenues, but they are deducted from particular revenues by being recognized in the same period.*

> *149. However, many assets yield their benefits to an entity over several periods, for example, prepaid insurance, buildings, and various kinds of equipment. Expenses resulting from their use are normally allocated to the periods of their estimated useful lives (the periods over which they are expected to provide benefits) by a "systematic and rational" allocation procedure, for example, by recognizing depreciation or other amortization.*

97.7 FBC states in BCUC 1.192.1 that the requested 15 year amortization period would be consistent with that used by BC Hydro. Please confirm that BC Hydro's amortization period for DSM expenditures was set by Order in Council No. 314, Direction No. 3 to the Commission, and that no similar direction has been issued regarding FBC.

Response:

Confirmed.

97.8 Please explain why FBC assumes a measure life of 15.9 years, when a 2009 study by ACEEE referenced above found an average electricity measure life of 13 years.

Response:

FBC believes it is appropriate to use a figure based on its own programs. The FBC measure life of 15.9 years is calculated based on the weighted average of the Company's 2014-18 DSM program measures, and presumably the ACEEE figure was based on a different mix of program measures it studied at the time.

97.8.1 Please provide a comparison of the measure life assumptions of FBC to those used by BC Hydro and the California DEER Database for the following DSM measures:

i. HVAC – draft proofing;
ii. Heat pump upgrade – air source;
iii. Energuide 80;
iv. Lighting – screw-in;
v. Heap pump water heater; and
vi. Lighting controls.

Response:

EML (Effective Measure Life) shown in years:

Technology	FBC	BC Hydro 2007 CPR	DEER 2008
HVAC - Draftproofing	25	25	11
Heat Pump Upgrade - Air Source	20	20	15
EnerGuide80	30	30	NA
Lighting - Screw-in	11	9.4/20 *	16
Heat Pump Water Heater	15	20	10
Lighting - Controls	15	10	8
		* CFL/LED	

As per Commission directive, FBC references other utility EML databases in lieu of resource intensive measure life determinations. In the first instance FBC uses BC Hydro figures, supplemented with other more current sources where available. For example, the Heat Pump Water Heater lifespan is sourced from the Regional Technical Forum, sponsored by BPA and the Northwest Energy Efficiency Alliance. The longer measure life shown for (commercial) Lighting controls is moot, since this measure is not included in the 2014-18 DSM Plan.

97.9 Please explain any significant differences. Please identify any benefits/disadvantages to ratepayers from Commission approval of FBC's request to increase amortization to 15 years. Please specifically include if a longer amortization i) is required to mitigate rate shock (if yes, please provide evidence) and ii) will increase costs to customers over time (by increasing the return to the FBC shareholder).

Response:

Please refer to the response to BCUC IR 2.97.8.1 for an explanation of significant differences.

The ratepayers benefit from the appropriate temporal matching of costs and benefits, otherwise costs will be incurred (amortized) over a shorter time frame than the benefits (largely power purchase costs) will flow. Specifically:

1. While increasing the amortization period from 10 to 15 years does have a rate smoothing effect, it is not required, nor intended, to mitigate rate shock; and

2. Generally speaking, a by-product of including an item in rate base for a longer period of time is an accumulation of higher debt and equity financing costs.

97.10 Please confirm an increased amortization period reduces utility rates in the first five years. Also, please confirm when using economic principles in the first five years of the amortization change a lower price, all else being equal, increases demand. If confirmed, could the amortization change negatively impact demand and conservation as outlined in the Clean Energy Act?

Response:

All else being equal, lower electricity prices mean increased demand. If the purpose of the amortization period was to influence rates to incent conservation, then a shorter amortization period or no amortization at all would be "better" since it would increase rates to customers in the short term. However, the purpose of an amortization period is to match costs and benefits, which is what the proposed 15 year amortization period achieves.

98.0 Reference: Exhibit B-1-1, Attachment H, p. 4; FBC 2012-2013 RRA and ISP, BCOAPO Final Submission, pp. 17, 18

Consistency with ISP: Previously approved LRMC

FBC states: "The 2012 [Long Term Resource Plan] and the associated 2012 Long Term DSM Plan were predicated on a levelized market price of $84.94/MWh" (Exhibit B-1-1, Attachment H, p. 4).

BCOAPO (now BCPSO)indicates in their Final Submission on the 2012/13 FBC RRA and Integrated System Plan (ISP) that FBC's adoption of a market power proxy for DSM occurred late in the proceeding (FBC 2012-2013 RRA & ISP, BCOAPO Final Submission, pp. 17, 18).

98.1 Please provide i) a history of the DSM avoided cost of power estimate for the 2012 FBC RRA and ISP Proceeding, ii) the reason behind any changes made to this estimate during the 2012/13 proceeding and/or from the methodology used prior to the 2012/13 Application and iii) the effect, if any, on the 2012/13 DSM budget request as a result of these changes.

Response:

As FBC states in the Application:

1. In the first 2012/2013 plan, FBC was using the first iteration of the DSM regulation the use of a blended LRMC based on a blended clean call/market price (on a 28/72 split), resulting in a value of $101.34 per MWh. In December 2011, the current regulation was introduced which permitted a maximum 10 percent mTRC, for which FBC used a "BC clean call" avoided cost of $111.96 per MWh. The balance of the avoided cost was calculated using $84.94 per MWh.

   The LRMC of market purchases of $84.94/MWh was derived from the BC Wholesale Market Energy Curve developed by Midgard Consulting for the 2012 Long Term Resource Plan[11]. Section 5.1 of the Energy & Capacity Market Assessment describes the development of the BC Wholesale Market Energy Curve[12]. To summarize, Midgard selected the "mid gas price/mid carbon price scenario" from the BC Hydro 2011 draft IRP activities as its starting point from which the 2011 BC Wholesale Market Forecast

[11] FortisBC 2012 Long Term Resource Plan, Appendix B: Energy & Capacity Market Assessment dated May 26, 2011, Section 5.1.3, Table 5.1.3.3-A: British Columbia Wholesale Market Energy Curve, Page 26 of 54.

[12] FortisBC 2012 Long Term Resource Plan, Appendix B: Energy & Capacity Market Assessment dated May 26, 2011, Section 5.1: BC Wholesale Market Energy Analysis, Pages 20- 26 (of 54).

price curve was derived, adding the cost of transmitting power from Mid-C to FBC territory, and then converting the resulting price into Canadian dollars.

2. Subsequent to the filing of the 2012 Resource Plan, natural gas prices fell significantly and the expectations on the development of carbon compliance markets changed. In 2013, FBC commissioned Midgard Consulting to update its BC Wholesale Market Energy Curve, which led to the LRMC of market purchases of $56.61/MWh used in this Application. Since there was no public update of the BC Hydro Mid-C forecasts available, Midgard developed its own Mid-C forecast based on a forecast of the price of natural gas. A description of the methodology was provided as part of the Application.[13] In summary, Midgard started with a Henry Hub gas price forecast, it used historic data to derive the heat rate between Henry hub and Mid-C, and used this to convert the gas price forecast to a Mid-C electric price curve. It then included a carbon adder and added the cost of transmitting power from Mid-C to FBC territory, and converted the resulting price into Canadian dollars. In order to be consistent with the gas price forecast used by FortisBC gas in regulatory proceedings, Midgard was directed by FBC to utilize the GLJ gas price forecast and exchange rate. The GHG adder was based on the work of Black & Veatch for BC Hydro.

3. This new method of calculating TRC based on the current regulation did not require the proposed 2012/2013 portfolio to be changed, since the average LRMC did not change dramatically.

98.2 Please state where in the Commission's 2012 FBC RRA and ISP Decision FBC's proposal to use a Mid-C market proxy as the avoided cost of DSM was discussed and approved.

Response:

The $84.94/MWh market-based LRMC was implicitly approved in two sections of the Decision:

1. Section 6.2.1.1, Adequacy and Cost Effectiveness - Commission Panel Determination:

> *"The Commission Panel finds that FortisBC's 2012 Long-Term DSM Plan is adequate and cost-effective as per subsection 44.1(8)(c) of the Act. No evidence*

[13] Exhibit B-1-1, Attachment H-4, Midgard Memorandum dated June 15, 2013, Derivation of the British Columbia Electricity Price Forecast 2014 to 2043.

was raised in the hearing to dispute FortisBC's position. The Commission Panel assesses the cost-effectiveness of FortisBC's DSM Plan on a portfolio basis and accepts FortisBC's calculation."[14] [underlining emphasis added]

2. Section 6.3.1 The Commission's Review of the DSM Expenditure Request:

"The Commission Panel accepts the cost effectiveness calculations put forward by FortisBC and thus ***finds FortisBC's 2012-2013 DSM Expenditure Schedule to be cost effective in accordance with the Demand-Side Measures Regulation (Ministerial Order No. 271) and the Amendments to the Demand-Side Measures Regulation (Ministerial Order No. 335)****."*[15]

98.3 Is use of a short-run market price estimate for long-term planning and acquisitions considered 'utility best practice'? If so, please justify with examples.

Response:

No, in FBC's view the use of a short run avoided cost for long term planning would not be considered 'utility best practice'. However, FBC's LRMC of market purchases is not a short-run market price estimate. It is based on a 30 year forecast of market prices delivered to B.C.

As BC Hydro states in its 2013 RIB Re-Pricing Application:

"A long-term view of the cost of new supply for a period of 10 years is appropriate for designing rates because there is a need for some rate stability in those rates. A short-run cost of new supply (short-run is defined as the three-year F2014 to F2016 period) would be a variable confusing price signal"[16]

It goes on to state:

"Subsection 6(2) of the CEA provides that BC Hydro must be self-sufficient by F2017 and each year after that by "holding the rights to an amount of electricity that meets the energy supply obligations solely from electricity generating facilities within the Province" [emphasis added]. Thus BC Hydro cannot plan to rely on the spot market to meet its

[14] BCUC Decision In the Matter of FortisBC Inc. 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan, Section 6.2.1.1 - Adequacy and Cost Effectiveness, Commission Panel Determination, Page 129.

[15] BCUC Decision In the Matter of FortisBC Inc. 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan, Section 6.3.1 - The Commission's Review of the DSM Expenditure Request, Page 136.

[16] BC Hydro 2013 Residential Inclining Block Rate Re-Pricing Application, page 1-13, lines 12-15.

customers' forecasted demand. BC Hydro's LRMC must be based on the cost to acquire new B.C.-based DSM and/or supply-side resources."[17]

This statement suggests that BC Hydro may have considered the costs of market purchases in the development of its LRMC if the *Clean Energy Act* did not require BC Hydro to achieve self-sufficiency by 2017. As discussed in BCUC IR 2.98.4, FBC can consider market purchases to meet its customers demand since its self-sufficiency obligations under the *CEA* are less prescriptive than BC Hydro's in terms of timing.

98.4 What is the basis by which BC Hydro calculates its LMRC? How does this differ, if any, from FBC?

Response:

BC Hydro defines LRMC as "…the change in the long-run total cost resulting in a change of the quantity of output produced. In short, LRMC represents the price of the most cost-effective ways of satisfying incremental customer demand where existing resources are insufficient to meet that demand."[18]

For ratemaking purposes, BC Hydro has up until now utilized the weighted average plant gate price of broadly-based power calls as a proxy for its energy LRMC. BC Hydro's 2008 RIB application and its current Industrial RS 1823 used the F2006 Open Call for Power, grossed up for line losses, as the basis of its LRMC. BC Hydro's 2010 Residential Inclining Block Rate Design Re-pricing Application used the 2009 Clean Power Call as a proxy for BC Hydro's LRMC (with an adjustment for transmission losses and inflation), as does BC Hydro's current RS3808 application. At the time of the calls, BC Hydro had a significant projected need for new resources, and greenfield clean or renewable IPPs were the marginal resource. "Greenfield clean or renewable IPPs were the marginal resource since there were insufficient cost-effective alternative resources available to provide needed supply for customers that met the requirements of the *CEA*."[19]

On August 3, 2013 BC Hydro submitted to government a draft Integrated Resource Plan (IRP). The IRP forecasted that BC Hydro would be in a surplus energy position until F2017. Beginning in F2017, there would be a need for new B.C.-based resources to meet expected future needs. However, it forecasted that B.C Hydro currently has sufficient alternative cost effective B.C.

[17] BC Hydro 2013 Residential Inclining Block Rate Re-Pricing Application, page 1-13, lines 26-29 to page 1-14, lines 1-3.
[18] BC Hydro 2013 Residential Inclining Block Rate Re-Pricing Application, page 1-12, lines 22-25.
[19] BC Hydro Draft Integrated Resource Plan, August 3, 2013, Chapter 8, Section 8.2.11.2, page 8-48, lines 25-27.

based resources to meet expected future needs, including DSM, IPP EPA renewals, Resource Smart, Site C and equipment efficiency and loss valuations. The next greenfield IPP clean or renewable energy acquisition is not expected within the planning horizon unless LNG needs exceed the 3,000 GWh/year expected amount.[20]

The IRP forecasts that DSM and IPP EPA renewals are marginal resources up to F2033, after which BC Hydro would again require greenfield clean or renewable IPPs. Because of this, and the other B.C. based resources available to it identified in the paragraph above, BC Hydro is no longer relying on broadly based power calls to establish its proxy for LRMC, and indicated that it plans to reduce its proxy for LRMC from $135/MWh to $100/MWh in future conservation rate applications. It has stated its LRMC may be further reduced to as low as $85/MW depending on the amount of LNG load that BC Hydro ultimately serves and whether non-LNG load growth occurs as expected.[21] Given this change in LRMC, BC Hydro is in the process of revisiting the stepped rate pricing signals starting with the Residential Inclining Block (RIB) rate.[22]

BC Hydro's recent 2013 Residential Inclining Block Re-Pricing Application provides further insight on BC Hydro's proxy for LRMC. It states:

> *"… there is a need for new B.C.-based energy resources starting in F2017. Subsection 6(2) of the CEA provides that BC Hydro must be self-sufficient by F2017 and each year after that by "holding the rights to an amount of electricity that meets the electricity supply obligations solely from electricity generation facilities within the Province". <u>Thus BC Hydro cannot plan to rely on the spot market to meet its customers' forecasted energy demand</u>. BC Hydro's LRMC must be based on the cost to acquire new B.C.-based DSM and/or supply-side resources."*[23]

In contrast, FBC's marginal resources in the short to medium term are market purchases, BC Hydro RS3808 (Tranche 1 energy)), and DSM. FBC has utilized the LRMC of market purchases, delivered to the FBC service territory, as its proxy for avoided cost. FBC's can consider market purchases since its self-sufficiency obligations under the CEA are less prescriptive that BC Hydro's in terms of timing. Section 6.4 of the *CEA* states:

> *6(4) A public utility, in planning in accordance with section 44.1 of the* Utilities Commission Act *for*
>
> *(a) the construction or extension of generation facilities, and*

[20] BC Hydro Draft Integrated Resource Plan, August 3, 2013, Chapter 8, Section 8.2.11.2, page 8-49, lines 3-11.
[21] BC Hydro Draft Integrated Resource Plan, August 3, 2013, Chapter 8, Section 8.2.11.2, page 8-50, lines 3-12.
[22] BC Hydro Draft Integrated Resource Plan, August 3, 2013, Chapter 8, Section 8.2.1.1, page 8-10, lines 16-19 to page 8-11, line 1.
[23] BC Hydro 2013 Residential Inclining Block Rate Re-Pricing Application, page 1-13, lines 25-29 to page 1-14, lines 1-3.

> *(b) energy purchases,*
>
> *must consider British Columbia's energy objective to achieve electricity self-sufficiency.*

However, FBC must still consider British Columbia's self-sufficiency objectives in acquiring power. FBC's long-term resource plan acknowledges this as it plans for building or contracting new BC based clean resources in the long-term. Long term planning must take into account the difference between the BC Hydro system and the FBC system, which results in fewer resource options in that FBC does not have access to the storage capabilities that BC Hydro does and therefore freshet energy cannot be stored for later use over the coming year. The resource options, timing and cost of achieving self-sufficiency will be further evaluated in the resource options and portfolio analysis of future resource plans.

99.0 Reference: FBC 2012-2013 RRA and ISP, Exhibit B-4, BCUC 1.273.1, Exhibit B-8, BCUC 2.3.1, FBC Final Submission, pp. 182–183

Consistency with ISP: Risk of increased reliance on Mid-C

FBC states in its 2012-2013 RR & ISP Application: "... based on past buying practices, the Company believes that historically there would be a high correlation between market purchases used to meet peak demand and wholesale market price spikes" (FBC 2012-2013 RR & ISP, Exhibit B-4, BCUC 1.273.1).

"It is the Company's position that the forecast of Power Purchase Expense should be on the basis of the firm resources that it holds to meet its firm load requirements" (FBC 2012-2013 RR & ISP, Exhibit B-8, BCUC 2.3.1).

"The factors making the reliance on the market increasingly risky include increasing installed intermittent generation, decreasing regional capacity margins..." (FBC 2012-2013 RRA and ISP, FBC Final Submission, p. 182).

FBC describes in its 2012-2013 RRA and ISP (Exhibit B-8, BCUC 2.3.1 and FBC's Final Submission, pp. 182–183) risks arising from increased reliance on the market.

99.1 Given FBC's responses/submissions in its 2012-2013 RRA and ISP regarding the risks arising from increased reliance on the market, please explain why FBC considers that the 2012–2013 RRA and ISP Decision approved using Mid-C hourly market estimates as the avoided cost of DSM. In your response, please specifically address if each of the concerns raised by FBC on pages 182 to 183 of its Final Submission are also a concern for DSM. If not, why not.

Response:

The response to BCUC IR 2.98.2 discusses the Commission acceptance in the 2012–2013 RRA and ISP Decision of using the LRMC calculated from the Mid-C annual average market forecast of energy as the avoided cost of DSM.

The concerns raised by FBC on pages 182 to 183 of the Final Submission in the 2012–2013 RRA and ISP Application are in relation to Planning Reserve Margin (PRM) and the requirement for dispatchable capacity reserves. DSM may indirectly assist in some of these issues to the extent that it reduces peak capacity requirements that will reduce the overall customer peak load, however the capacity concerns cannot be specifically resolved by DSM since DSM in general does not provide a dispatchable capacity product.

The concerns identified on pages 182 to 183 of FBC's Final Submission regarding using the market for capacity are summarized as below:

a) ***Eroding regional capacity surplus*.**

If FBC planned to rely on the market to supply capacity for PRM, the impact of eroding regional capacity surpluses cannot be solved through DSM since in general DSM is an energy product and not a capacity resource. Eroding capacity surpluses does not affect FBC's opinion that the market is a reliable source of energy. Therefore this concern does not change FBC's position that market purchases are the avoided cost of DSM;

b) NERC is projecting negative capacity margins in the Canadian sub-region of the WECC by 2019.

Similar to the response above, if FBC planned to rely on the market to supply capacity for PRM, the impact of negative capacity margins cannot be solved through DSM since in general DSM is an energy product and not a capacity resource. Negative Canadian capacity margins do not affect FBC's opinion that the market is a reliable source of energy. Therefore this concern does not change FBC's position that market purchases are the avoided cost of DSM;

c) The one-time capacity surplus created by the Direct Service Industry load closing in the US has now been fully allocated.

The full allocation of the one-time capacity surplus creates a similar capacity concern as the two previous concerns, and a similar response. This is a capacity issue and cannot be solved by DSM, so having that surplus fully allocated elsewhere does not affect FBC's opinion that the market is a reliable source of energy. Therefore this concern does not change FBC's position that market purchases are the avoided cost of DSM;

d) Large dependence on regional DSM programs.

If the planned aggressive DSM programs do not achieve their reduction targets it will create an energy imbalance. As discussed, market purchases are a reliable source on energy and are an appropriate measure of the avoided cost of DSM;

e) Regional drought could impact the ability of regional generators to supply FBC load to meet capacity requirements.

Again, this is mainly a capacity issue. However, there is associated energy with this capacity and DSM would help meet FBC's energy requirement in this case;

f) Congested transmission can reduce FBC's access to the market during capacity shortages.

Although this impacts FBC's reliance on the market for capacity, it can also impact energy imports. It is true DSM can address energy issues related to congested transmission. However the FBC system has sufficient native and contracted capacity to meet its peak loads, so the timing of when the energy is received is not as important, and energy import curtailments during times of congestion can be made up later.

Therefore, in this case it is still true that market purchases are a reliable source on energy and is an appropriate measure of the avoided cost of DSM.

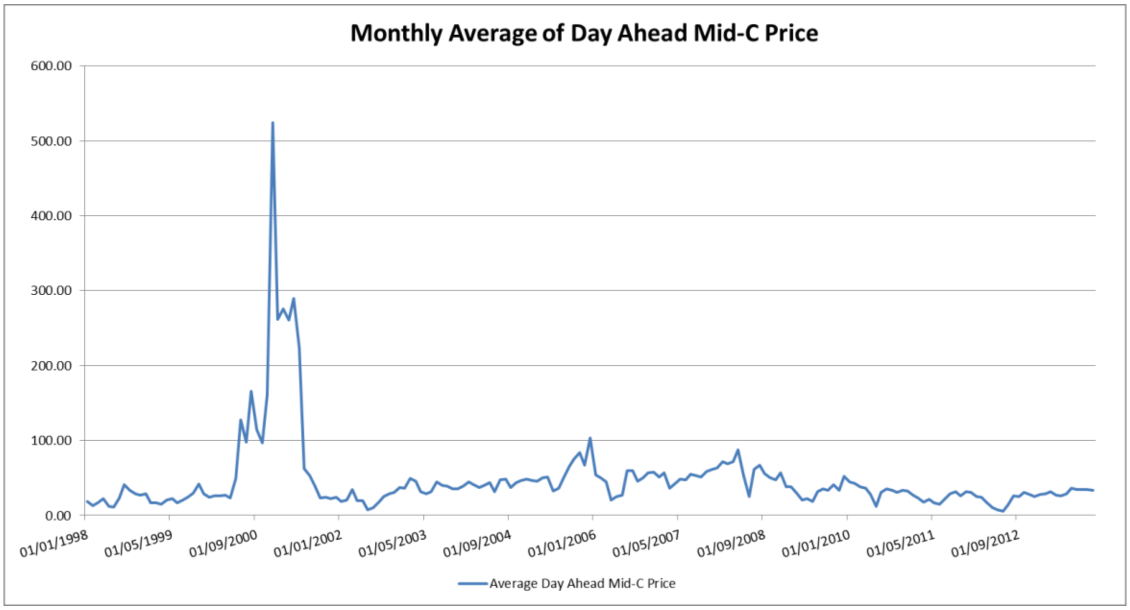
As discussed in BCSEA IR 1.8.2, FBC's main market requirement at this time is energy, not capacity. As discussed in the examples above, DSM provides a broad energy resource, but not capacity. FBC considers the market a reliable source of energy, and is an appropriate measure of the avoided cost of DSM. FBC will re-examine its resource options as part of the portfolio analysis in the 2016 Resource Plan.

99.2 Please provide a graph showing historical Mid-C prices for the past 15 years, and discuss whether reliance on Mid-C to meet long-term customer power needs would be appropriate in times such as during the 2000-2001 power price spikes. The graph can be expressed in monthly or daily prices.

Response:

As can be seen from the graph below, since 1998 the only period of extreme prices lasted a little under a year. If a utility were to rely on Mid-C to meet long-term customer power needs, it would be appropriate to have locked in deals at a fixed price covering several years in advance. This would allow customer needs to be met with only limited exposure to the extreme market prices that occurred. A power supply strategy that relied on nothing but the daily price would not be appropriate.

In FBC's case, almost all of the required supply of energy and capacity is available under long-term contracts or owned generation and is not at market risk. At this time FBC considers the market a reliable source of energy for the small amount of energy that is "at risk", but will re-examine the best resource options as part of the 2016 Resource Plan.


Monthly Average of Day Ahead Mid-C Price
600.00
500.00
400.00
300.00
200.00
100.00
0.00
01/01/1998
01/05/1999
01/09/2000
01/01/2002
01/05/2003
01/09/2004
01/01/2006
01/05/2007
01/09/2008
01/01/2010
01/05/2011
01/09/2012
Average Day Ahead Mid-C Price

100.0 Reference: FBC 2012-2013 RRA & ISP, Exhibit B-1, Capital Expenditure Plan (CEP), p. 116, Exhibit B-1-1, p. 10, FBC Final Submission, p, 196, FBC Reply Submission, p. 72; G-110-12, p. 133

Consistency with ISP: DSM funding expectations

FBC states in its 2012-2013 RRA and ISP Application: "[t]he 2012-13 DSM plan addresses the Policy Actions contained in the 2007 Energy Plan, in particular the following three: (1) to acquire 50 percent of… incremental resources needs through conservation by 2020" (FBC 2012-2013 RRA and ISP, Exhibit B-1, CEP, p. 116).

> "The specific energy objectives set out in the *Clean Energy Act* particularly relevant to FortisBC's DSM planning are: To take demand-side measures and to conserve energy, including the objective of the [BC Hydro (BCH)] reducing its expected increase in demand for electricity by the year 2020 by at least 66 percent .... FortisBC recognizes that while the 66 percent reduction target applies to BC Hydro, it is necessary for FortisBC to support provincial energy goals and principles." (FBC 2012-2013 RR & ISP, Exhibit B-1-1, p. 10)

"The Company believes that a long term, stable DSM offering gives the market time to respond most effectively to programs. The Company believes that the current DSM plan is reasonable and achievable" (FBC 2012-2013 RRA and ISP, FBC Final Submission, p. 196).

"FBC believes it has included all cost-effective DSM in its proposal ... FortisBC is of the opinion that it proposes to acquire all cost-effective DSM at an appropriate and prudent rate" (FBC 2012-2013 RR and ISP, FBC Reply Submission, p. 72).

The Commission's decision in the FBC 2012–13 RRA and ISP states: "...the Commission... does not accept that FortisBC should necessarily change its DSM target from one based on load growth to energy sales at this time." (FBC 2012–2013 RRA and ISP, Decision G-110-12, p. 133)

100.1 Does FBC agree that the Commission has endorsed FBC's approach of setting the DSM funding envelope at 50 percent of load growth? If no, please explain why not.

Response:

The 2012-13 RRA & ISP Decision and Order G-110-12 implicitly approved the FBC target of offsetting 50 percent of load growth through conservation (2012 DSM Plan excerpt) [24]:

> ***1.1 The 2007 Energy Plan and Clean Energy Act***
>
> *The 2007 BC Energy Plan highlighted the importance of DSM as a key component of future electricity supply, setting a target in Policy Action 1 to acquire 50 percent of BC Hydro's incremental resource needs through conservation by 2020. FortisBC has voluntarily adopted this target in its 2012 DSM Plan.*

However this is not necessarily the same as setting the DSM funding envelope at 50% of load growth, since some of the conservation effects are achieved through means (RCR, CIP etc.) outside of the 2014-18 DSM Plan.

For example, the first report on the Residential Conservation Rate (filed with the Commission on October 31, 2013), indicates energy savings of between 22.5 and 52.4 GWh. This is in addition to the annual program DSM program savings of approximately 13 GWh annually. The sum of these savings (of between 35.5 and 65.4 GWh) is considerably more than 50% of the before-savings annual average load growth forecast of 36 GWh between 2014 and 2018 (reference Exhibit B-1, Section E2, Table 1.1).

100.1.1 Please provide (for 2012 and 2013 (approved) and each year of the PBR period), a table which shows i) DSM approved/requested $ spend, ii) annual acquired DSM savings, iii) net load growth and iv) DSM savings as a percent of load growth. Please provide an explanation for any year where the percent is below 50 percent.

Response:

The following table shows i) DSM approved/plan $ spend, ii) annual acquired DSM savings, iii) net load growth and iv) DSM savings as a percent of load growth.

Over the PBR Period, DSM *program* savings offset 36% of load growth on average.

[24] 2012 Long-Term Demand Side Management Plan, Exhibit B-1-2 p. 2, LL 1-6, in the 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan Application

Item	**Approved**		**PBR Period**				
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
i) DSM approved/plan $ spend	$7,731	$7,878	$3,001	$3,087	$3,054	$3,100	$3,153
ii) annual acquired DSM savings (MWh)	31,587	31,506	12,800	12,887	12,823	12,823	12,823
iii) net load growth	18,488	87,591	46,566	33,376	32,892	30,121	36,940
iv) DSM savings as a percent of load growth	171%	36%	27%	39%	39%	43%	35%

Firstly it should be noted that due to the changes in the net load growth this metric fluctuates considerably, and thus is not a reliable measure on a year over year basis. The intent of the BC Energy Plan was that this metric was cumulative over the period ending in milestone year 2020.

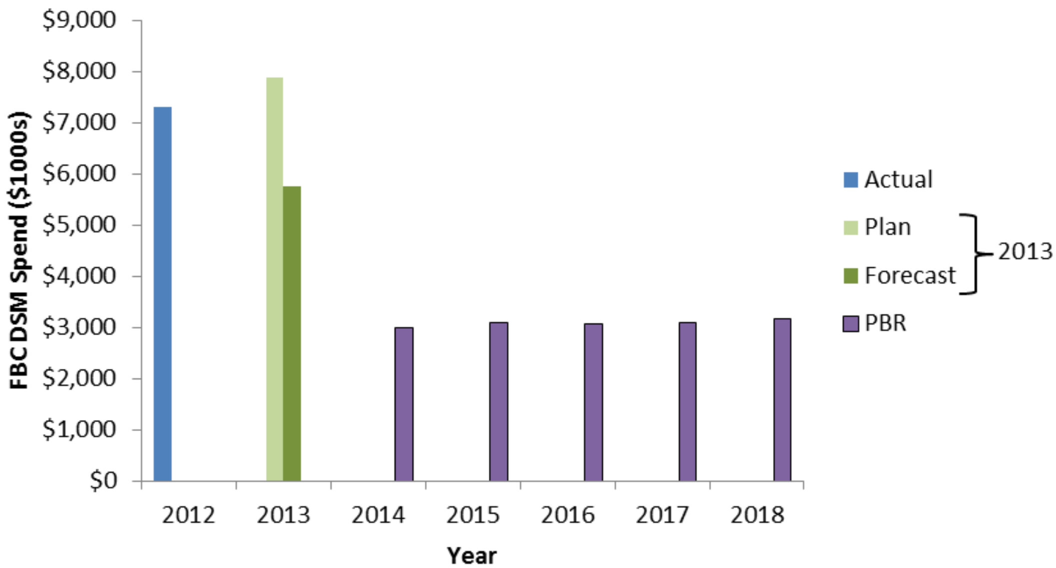
Secondly the FBC commitment to offsetting 50 percent of load growth through conservation includes the DSM program savings, plus other conservation initiatives such as RCR, CIP and AMI. The Company believes it will meet the 50 percent offset target through the aggregate of all such measures, not just DSM programs.

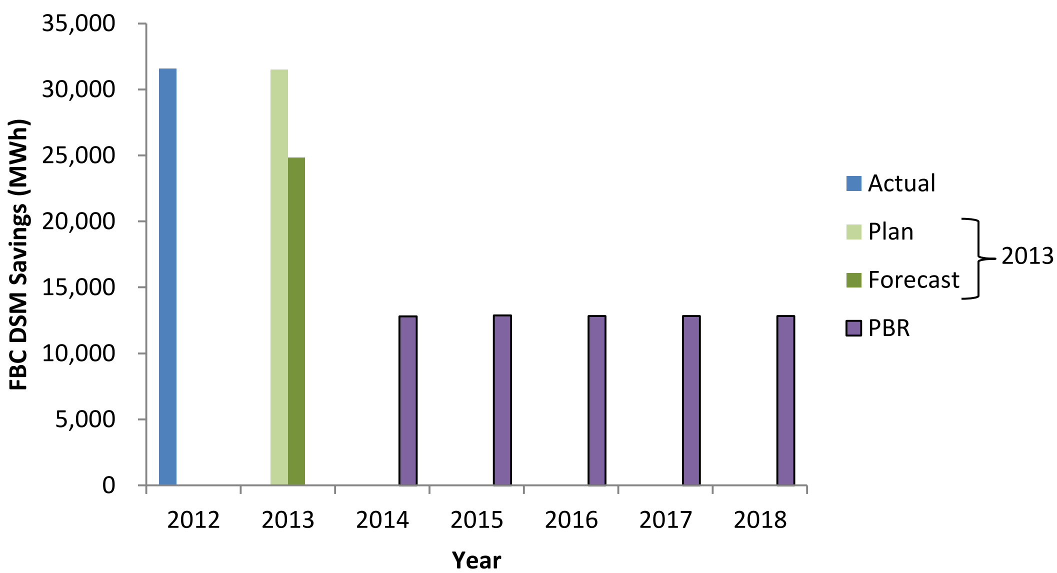
Please also refer to the response to BCUC IR 2.100.1.

100.2 Is it FBC's position that the DSM proposal for the PBR period continues to provide a 'long-term, stable DSM offering' compared to previous periods? Please include in your response a graph for 2012/2013 (approved) and forecast over the PBR period showing FBC i) DSM spend and ii) DSM energy savings.

Response:

The following two figures show the actual, plan, forecast, and proposed DSM spend and savings, as requested. While these figures indicate a reduction in DSM spend, FBC believes that the filed DSM plan continues to capture all cost-effective DSM. A combination of changed circumstances, including a reduction in the long run marginal cost of power and achievable DSM potential, lead FBC to conclude that the proposed 2014-18 DSM spend and savings continue to provide a long-term, stable DSM offering which is appropriate and prudent. FBC notes that the proposed expenditure level is not markedly different than DSM expenditures prior to 2011, and is in fact higher than the DSM expenditure in 2008 and earlier years.





100.2.1 Please provide a comparison of the DSM Savings Targets included in Table 15 (p. 126) of the FBC 2012–2013 RRA and ISP Decision with actual/forecast for 2012–13 and planned for the PBR period (please identify changes in GWh and percent terms). Please explain any significant differences.

Response:

FBC provides tables below that show the following: DSM Savings Targets included in Table 15 (p. 126) of the FBC 2012–2013 RRA; the Actual, Forecast, and 2014-2018 PBR MWh savings; as well as a comparison of the difference between these figures.

Table 15 – Savings Targets

Year	Residential	Commercial	Industrial	Proxy '17-31
	GWh			
2011	16.4	13.5	1.1	-
2012	16.1	12.2	1.7	-
2013	16.9	12.3	1.8	-
2014	19.5	11.9	1.8	-
2015	21.1	11.9	1.8	-
2016	22.6	9.9	1.9	-
2017-30	-	-	-	28

(Exhibit B-1-2, Volume 2, p. 15)

Year	2012-2013 RRA Savings Targets (Table 15), GWh				Actual, Planned and 2014-2018 PBR, GWh				Difference			
	Res.	Com.	Ind.	Tot.	Res.	Com.	Ind.	Tot.	Res.	Com.	Ind.	Tot.
2011a	16.4	13.5	1.1	**31.0**	11.4	24.2	0.8	**36.3**	-31%	79%	-28%	**17%**
2012a	16.1	12.2	1.7	**30.0**	12.8	17.9	0.9	**31.6**	-21%	47%	-45%	**5%**
2013f	16.9	12.3	1.8	**31.0**	12.1	11.9	0.9	**24.9**	-28%	-3%	-52%	**-20%**
2014p	19.5	11.9	1.8	**33.2**	5.8	6.2	0.8	**12.8**	-70%	-48%	-56%	**-61%**
2015p	21.1	11.9	1.8	**34.8**	5.8	6.3	0.8	**12.9**	-73%	-47%	-56%	**-63%**
2016p	22.6	9.9	1.9	**34.4**	5.6	6.4	0.8	**12.8**	-75%	-35%	-58%	**-63%**
2017p				**28.0**	5.5	6.5	0.8	**12.8**				**-54%**
2018p				**28.0**	5.4	6.6	0.8	**12.8**				**-54%**

a = Actual savings, f = Forecast savings, p = PBR period forecast savings

101.0 Reference: Exhibit B-7, Attachment to BCUC 1.248.2; Exhibit B-1-1, Table H1-1b

2013 Conservation and Demand Potential Review Report (CPR) Update

FBC filed an updated CPR dated September 19, 2013, as an attachment to BCUC 1.248.2.

101.1 Please describe any differences in the approach used to produce the 2010 CPR and the 2013 CPR with regards to the extent of the update. Please confirm, or explain otherwise, that the 2013 CPR update does not take the place of a full CPR update for ISP purposes.

Response:

The basic approach and model used for the 2013 CPR and the 2010 CPR are the same. The updates made in the 2013 CPR include the following:

- Baseline characteristics adjustments;
- Measure data;
- Load forecast; and
- Avoided costs updates.

A significant effort was made to develop the baseline for the 2010 CPR, including end-use surveys of residential and commercial customers. Minor adjustments were made to this baseline with program and other data readily available to FBC, but no new customer surveys were incorporated.

Third-party measure/product data sets were reviewed and updates were made to the measure list used in the 2013 CPR.

The load forecasts were updated based on the most recent forecast data provided by FBC.

The avoided costs used in the 2013 CPR are different than in the 2010 CPR.

101.2 Please identify the budget requested during the PBR period for a full CPR update, and also for any supporting analysis (for example, residential/commercial end use studies, market saturation study). Please describe how this budget was arrived at, proposed timing, and how it will be coordinated with other utilities (FEU, BCH). If no update is planned, please explain why, and how this aligns with the next FBC anticipated ISP update.

Response:

Please refer to the response to BCUC IR 1.248.2.1.

Due to the uncertainty as to the timing, budget cost and allocation of costs, FBC has not budgeted for the next CPR update, or any supporting analysis to support that CPR. Once the timing is known, likely as an integral part of FBC's next LTRP, the CPR budget costs will be submitted for approval via the anticipated Annual Review process using the existing DSM Study Costs deferral account.

101.2.1 Does FBC plan to update the next CPR for the recommended items identified on page 77 of the 2013 CPR? If no, please explain why not. If yes, please describe.

Response:

Yes, the RFP scope for the next CPR will include the recommended[25] items listed.

101.2.2 Please confirm that use of a market price forecast is not 'mandated' by the DSM Regulations (p. 34 of the 2013 CPR), and provide a correction as appropriate.

Response:

Confirmed. The sentence should read as follows:

FBC uses a market price forecast for the majority (90 percent) of its measures; and, as mandated by the British Columbia Ministry of Energy 2011 DSM Regulation, the provincial BC "clean" energy price for the remaining 10 percent of measures that require a lift through the prescribed modified TRC.

[25] …it is recommended that FortisBC continue to update the CDPR with customer characteristic data, forecasted loads, new measures or measure data, codes and standards, and historic achievement.

101.3 Please provide the data underlying Figures 27, 28 and 29 of the 2013 CPR in table form.

Response:

Scenario 1 ($56.61/MWh) Program Achievable Potential by Sector, MWh

	Residential	Commercial	Industrial	Irrigation	Behavioural	Total
2014	5,797	8,758	1,226	490	819	17,089
2015	5,713	8,747	1,277	490	805	17,031
2016	5,630	8,642	1,327	490	807	16,895
2017	5,597	8,489	1,378	490	809	16,763
2018	5,758	8,194	1,429	490	900	16,770
2019	5,771	8,003	1,464	490	1,120	16,848
2020	5,793	7,859	1,471	490	1,500	17,112
2021	5,814	7,620	1,435	490	2,170	17,528
2022	5,837	7,331	1,399	490	3,300	18,356
2023	5,851	7,042	1,326	490	4,420	19,129
2024	5,865	6,729	1,254	490	4,050	18,387
2025	5,878	6,489	1,181	490	3,300	17,338
2026	5,891	6,201	1,138	490	808	14,528
2027	5,899	6,107	1,094	490	807	14,396
2028	5,813	6,012	1,087	490	806	14,207
2029	5,449	4,289	1,080	490	805	12,112
2030	5,355	4,146	1,073	490	804	11,867
2031	5,355	4,051	1,051	490	803	11,749
2032	5,258	3,814	1,051	490	802	11,414
2033	5,258	3,576	1,051	490	801	11,176

Scenario 2 ($84.94/MWh) Program Achievable Potential by Sector, MWh

	Residential	Commercial	Industrial	Irrigation	Behavioural	Total
2014	10,453	12,912	1,488	490	819	26,161
2015	10,192	12,890	1,566	490	805	25,942
2016	9,931	12,734	1,644	490	807	25,606
2017	9,747	12,511	1,722	490	809	25,278
2018	9,563	12,086	1,799	490	900	24,838
2019	9,624	11,851	1,853	490	1,120	24,938
2020	9,722	11,676	1,861	490	1,500	25,248
2021	9,820	11,366	1,814	490	2,170	25,659
2022	9,924	11,004	1,767	490	3,300	26,484
2023	10,436	10,642	1,674	490	4,420	27,661
2024	10,497	10,242	1,580	490	4,050	26,858
2025	10,558	9,921	1,487	490	3,300	25,755
2026	10,619	9,533	1,432	490	808	22,882
2027	10,656	9,399	1,377	490	807	22,728
2028	10,482	9,265	1,369	490	806	22,411
2029	10,059	7,048	1,361	490	805	19,763
2030	10,281	6,847	1,353	490	804	19,774
2031	10,281	6,712	1,329	490	803	19,615
2032	10,281	6,376	1,329	490	802	19,278
2033	10,281	6,040	1,329	490	801	18,941

Scenario 3 ($128.80/MWh) Program Achievable Potential by Sector, MWh

	Residential	Commercial	Industrial	Irrigation	Behavioural	Total
2014	12,246	15,284	1,496	490	819	30,334
2015	12,099	15,218	1,579	490	805	30,190
2016	11,952	15,018	1,662	490	807	29,928
2017	11,874	14,751	1,745	490	809	29,669
2018	12,233	14,284	1,828	490	900	29,735
2019	12,506	13,960	1,885	490	1,120	29,961
2020	12,984	13,603	1,893	490	1,500	30,469
2021	13,461	13,113	1,847	490	2,170	31,080
2022	13,968	12,570	1,800	490	3,300	32,127
2023	14,296	12,027	1,706	490	4,420	32,939
2024	14,594	11,369	1,613	490	4,050	32,115
2025	14,892	11,050	1,519	490	3,300	31,250
2026	15,190	10,663	1,464	490	808	28,615
2027	15,369	10,530	1,409	490	807	28,605
2028	15,390	10,396	1,401	490	806	28,482
2029	15,106	8,162	1,393	490	805	25,955
2030	14,947	7,961	1,385	490	804	25,587
2031	14,947	7,828	1,361	490	803	25,429
2032	14,729	7,494	1,361	490	802	24,875
2033	14,729	7,160	1,361	490	801	24,540

101.4 Please comment on the sensitivity of the DSM portfolio spend in the 2013 CPR to changes in the avoided cost DSM estimate (for example, between which ranges of avoided cost estimates is the DSM funding estimate most sensitive to change).

Response:

The scenarios modeled in the 2013 CDPR have different assumptions for program administration costs and utility incentives, both expressed as a percentage of incremental costs. Also an achievability factor varied between scenarios. Table 6 from the 2013 CDPR report summarizes the assumptions used.

Table 6
Conservation Potential Scenario Parameters

	Scenario 1	Scenario 2	Scenario 3
Avoided Cost, Levelized $2013/MWh	$56.61	$84.94	$128.80
Program Administration Costs	30%	25%	25%
Utility Incentive	40%	40%	50%
Achievability Adjustment	90%	100%	100%

Table 101.4 below compares the estimated utility costs where only the avoided cost is changed across scenarios. The program administration costs are held constant at 25 percent of incremental measure costs and utility incentives held at 40 percent of incremental measure costs. The achievability adjustment in each of the three scenarios was set to 100 percent (i.e. no adjustment).

Table 101.4
Program Admin = 25%, Utility Incentives = 40%

	Scenario 1	Scenario 2	Scenario 3
Avoided Cost, Levelized $2013/MWh	$56.61	$84.94	$128.80
Estimated Utility Costs (Millions, $2013)	$58.9	$123.6	$189.0

The difference in utility costs between Scenarios 1 and 2 is $64.7m, which is quite similar to the difference between Scenarios 2 and 3 at $65.4m. However the difference in avoided cost between Scenarios 1 and 2 is $28.33/MWh whereas the difference between Scenarios 2 and 3 is considerably higher at $43.86/MWh.

102.0 Reference: Clean Energy Act, Sections 2 and 6; FBC 2012-2013 RRA and ISP; Exhibit B-4, BCUC 1.276.1

Consistency with BC Energy Objectives

The Clean Energy Act (CEA) includes the following BC energy objectives related to electricity self-sufficiency: 2(a); 2(b); and 2(n). In addition, Section 6 (4) of the CEA states “a public utility, in planning in accordance with section 44.1 of the [UCA] ...must consider BC’s energy objective to achieve electricity self-sufficiency.”

The CEA BC energy objectives related to the environment include: 2(b), 2(c); and 2(g). CEA 2(k) encourages economic development and the creation and retention of jobs.

FBC states in its 2012–13 FBC RRA and ISP:

> “Unlike electricity self-sufficiency, where section 6(4) of the Clean Energy Act specifically includes public utilities other than BC Hydro, the [Clean Energy Act] objectives listed above do not specifically direct other utilities to achieve them. However, these are important issues for British Columbia, and FortisBC believes it has a role to play in helping the Province achieve these objectives” (FBC 2012-2013 RR & ISP, Exhibit B-4, BCUC 1.276.1).

102.1 Please confirm that, while the 66 percent target included in CEA 2(b) applies only to BC Hydro, the first part of this objective (to take DSM measures and to conserve energy) applies to both FBC and BC Hydro, as do sections 2 (a) and 6 (4). If not confirmed, please explain why not.

<u>Response:</u>

Confirmed. Section 2(b) of the *Clean Energy Act (CEA)* states that the Province has an energy objective of taking demand-side measures conserving energy. Section 2(b) also has an objective that applies specifically to BC Hydro and requires BC Hydro to reduce its expected increase in demand for electricity by the year 2020 by at least 66 percent. Sections 6(4) of the *Clean Energy Act* indicates that a public utility, in planning in accordance with sections 44.1 of the *Utilities Commission Act* for the construction or extension of generation facilities and for energy purchases, must consider the provincial objective of achieving electricity self-sufficiency. Therefore, the first part of the *CEA* 2(b) applies to FBC in that FBC must consider the Province’s energy objectives.

103.0 Reference: California Standard Practice Manual, p. 23[26]; Exhibit B-1-1, Appendix H, p. 18;

Exhibit B-7, BCUC 1.243.1.1;

Exhibit A2-16,BC Hydro Integrated Resource Plan (IRP) 2013, pp. 4–2 and 5–46;

ACEEE, A National Survey of State Policies and Practices, 2012, pp. 36, 37[27]

Setting the DSM avoided cost: Attributes of DSM energy

The California Standard Practice Manual states on p. 23: "The benefits for the Program Administrator Cost Test are the avoided supply costs of energy and demand, the reduction in transmission, distribution, generation, and capacity valued at marginal costs *for the periods when there is a load reduction*." [emphasis added]

FBC states in the Application that the weighted average DSM measure life is 15.9 years (Exhibit B-1-1, Appendix H, p. 18). FBC states that, on a planning basis, FBC will experience its first energy shortage in 2019 (Exhibit B-7, BCUC 1.243.1.1). BC Hydro, in their August 2013 IRP, expect energy and capacity gaps by F2017 (Exhibit A2-16, p. 4-2).

BC Hydro states in its August 2013 IRP: "[c]urrent transmission lines are fully subscribed by firm transmission rights holders. Furthermore the availability of non-firm transmission capacity has been dwindling due to increasing competition from power producers" (Exhibit A2-16, p. 5-46).

A 2012 ACEEE report titled A National Survey of State Policies and Practices of the Evaluation of Ratepayer-Funded Energy Efficiency Programs states on page 37: "There is some risk ... that the use of a short-run perspective ... will undervalue the true avoided capacity cost benefits of energy efficiency over the lifetime of the energy efficiency effects. Ideally, states could use a 10 year (or more) integrated resource planning perspective."

103.1 Please confirm that, assuming an average measure life of 15 years, DSM investments made in the PBR period will on average be producing energy savings up to 2029 (for investments made in 2014) and 2033 (for investments made in 2018). If unable to confirm, please explain why.

[26] http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF
[27] http://www.aceee.org/sites/default/files/publications/researchreports/u122.pdf

Response:

Confirmed.

103.2 Please confirm that the avoided cost of energy for the mTRC ($112/MWh) includes the Deferred Capital Expenditure factor of $35.60/kW-year. If unable to confirm, please explain why not and whether FBC's approach is consistent with the California standard Practice Manual.

Response:

As per BCUC IR 1.244.1, FBC uses $111.96 per MWh as the marginal cost of power to calculate the mTRC. FBC did *not* include the Deferred Capital Expenditure (DCE) factor of $35.60/kW-year in the mRTC calculation – i.e. FBC did not add $35.60/kW-year to the $111.96 per MWh used to calculate mTRC. This omission was an oversight. The DCE factor is included in the TRC calculation and also should have been included in the mTRC calculation.

Note that including the DCE factor results in a total portfolio level mTRC of 1.42 compared to the mTRC of 1.39 as filed without the DCE. There is no resulting change in the proposed DSM portfolio.

FBC does follow the practices laid out in the California Standard Practice Manual. The economic analysis of FBC's DSM programs is consistent with these methods.

103.3 Please describe how FBC plans to hedge against Mid-C i) price spikes, ii) transmission constraint risk and iii) exchange rate risk, and if the costs of these hedges are included in FBC's Mid-C forecast.

Response:

FBC has a number of existing contracts including the CPA, PPA, Brilliant and WAX CAPA, as well as shorter term capacity and energy blocks that firm up and supplement FBC's owned resources. Combined with FBC's storage, these resources meet well over 99 percent of current expected load through 2018 and gives FBC flexibility to manage price risk.

103.4 Does FBC agree with the 2012 ACEEE report referenced above that the use of a short-run perspective could undervalue the true avoided capacity benefits of energy efficiency over its lifetime? Please explain.

Response:

FBC agrees that a short-run perspective could undervalue the true avoided capacity benefits over its lifetime. Energy efficiency investments are distributed throughout the service territory and the resulting impact on peak demand in any local or regional area is generally much smaller than normal variances in load due to confounding factors such as weather variations and economic and demographic changes. In other words, the localized demand reduction associated with an energy efficiency initiative can easily be swamped by greater than forecast load due to extreme temperatures (either high or low) or higher than forecast economic growth. This uncertainty worsens the further one looks into the future.

104.0 Reference: Exhibit B-7, BCUC 1.240.1 and 1.240.3.1; BCH IRP, August 2013, Chapter 8

Setting the DSM avoided cost: Mid-C as a proxy for BC market price

FBC states: "Mid-C was established by the regional balancing authorities as a platform for trading surplus energy..." (Exhibit B-7, BCUC 1.240.1). FBC state that Mid-C market prices for the past 10 years would not have supported full cost recovery of a merchant plant selling into the Mid-C spot market (Exhibit B-7, BCUC 1.240.3.1).

104.1 Please confirm that, if actual gas prices are the same as that forecast by FBC over the PBR period, a generator receiving the Mid-C forward market prices forecast by FBC would not receive any contribution towards their fixed costs. If not confirmed, please explain why.

Response:

Not confirmed.

FBC has not conducted a revenue and cost analysis of every existing or potential new generator which can sell into the Mid-C spot market, so cannot provide a definitive answer.

BCUC IR 1.240.3.1 asked about new generation and full recovery of its fixed and variable costs through selling into the Mid-C spot market. For reasons explained in its response, FBC believes a new generator would not be able to fully recover its fixed and variable costs through the Mid-C market sales alone.

Gas prices and Mid-C prices have historically had a high correlation because, as explained in BCUC IR 1.240.3.1, during the winter and shoulder seasons gas generators are typically the marginal producer. FBC's Mid-C forecast takes the historical relationship between gas prices and Mid-C electric prices, and using a gas price forecast, converts that into an electricity price forecast. Also, the Mid-C forecast is an annual average, and prices will vary throughout the year.

FBC believes that generators selling into the Mid-C spot market using the Midgard Mid-C forecast (and exposed to the underlying gas prices) would likely make a partial contribution to their fixed costs. Theoretically, a generator selling into the Mid-C market will generate energy anytime the Mid-C energy price is over their variable costs, and stop generating at times when the energy price does not cover their variable costs. As long as they are receiving more than their variable cost, they will receive some contribution toward their fixed costs.

The ability to receive a contribution to their fixed costs would be different for each individual plant. The cost structure of generation plants is not homogeneous, and even plants using the same generation technologies can have a wide range of costs. For example, property taxes can be a large component of a generator's cost structure, and can vary widely depending on where it is located. But if a generator cannot cover its variable costs through the Mid-C spot price, it would likely not be selling energy into the Mid-C market.

In addition, many generators will receive other sources of revenues or cost reductions which can help offset its variable costs, such as government grants, subsidies or in the case of wind and solar, tax incentives. Clean generators may also have REC sales. These can impact the generating economics.

104.2 Please confirm that, in their August 2013 IRP, BC Hydro estimated its LRMC (from F2017 to 2030) as $85/MWh to $100/MWh for energy and $50-$55 kW-year for capacity (BCH IRP, p. 8-50).

Response:

Confirmed.

104.2.1 Is there any reason why FBC's avoided cost of energy should be different from BC Hydro's avoided cost of energy (other than price differences due to network losses)? If yes, please describe and to the extent practicable, quantify the impact.

Response:

Please refer to the response to BCUC IR 2.98.4 for a discussion of how BC Hydro calculates LRMC and how this differs from FBC. FBC has not undertaken a study to quantify each individual difference but taken together the Company believes the utilized approach of taking the LRMC of market purchases, delivered to the FBC service territory, is reasonable for FBC at this time.

105.0 Reference: Exhibit B-7, Attachment to BCUC 1.248.2

Setting the funding envelope – Identifying cost effective DSM

FBC includes an updated 2013 CPR as an attachment to BCUC 1.248.2 (Exhibit B-7, BCUC 1.248.2).

105.1 Please confirm that the 2013 FBC CPR has not been adjusted downward to reflect i) an inability of the utility to scale up operations beyond that consistent with typical program ramp up rates, or ii) as a result of rate impact concerns. If unable to confirm, please provide a revised 2013 CPR Figure 29 updated to remove this constraint.

Response:

Confirmed. The 2013 FBC CPR has not been adjusted downward for either atypical ramp rate or rate impact concerns. In all scenarios (figures 27 – 29), the ramp rates are relatively aggressive as evidenced by the significant drop off in potential in the later years of the plan (see the last 5-8 years).

The overall difference in magnitude (total 20-year potential) of the different scenarios is predominantly a function of the avoided cost. Rate impact concerns were not a factor in developing this CPR.

105.2 Please confirm that the key constraint preventing FBC from expanding its cost-effective (from a utility perspective) DSM is the TRC test. If unable to confirm, please explain why.

Response:

Yes, the primary reason for the proposed DSM expenditure reduction is the TRC test. However, other factors also played a role, including (at the portfolio level) rate impact and (at a measure level), market maturity, administrative complexity and new codes and standards.

106.0 Reference: Exhibit A2-16, BC Hydro IRP 2013, pp. 8–16; Exhibit B-7, BCUC 1.236.3.1 and 1.248.2; Exhibit B-15, ICG 1.46.1; FBC 2012–2013 RRA and ISP, FBC Final Submission, p. 196; ACEEE, A National Survey of State Policies and Practices, 2012, pp. 36–37

Setting the funding envelope — Adjustments

BC Hydro, in its 2013 IRP, has developed five DSM principles to address a short-term energy surplus situation (Exhibit A2-16, pp. 8–16).

FBC provides a breakdown of DSM spend between customer classes in BCUC 1.260.1. FBC states in BCUC 1.236.3.1 that it applies the Rate Impact Measure (RIM) test at the portfolio level.

A 2012 ACEEE report titled A National Survey of State Policies and Practices of the Evaluation of Ratepayer-Funded Energy Efficiency Programs states on page 36 and 37: "[w]e find that the [Ratepayer Impact Measure] test has been largely abandoned by leading energy efficiency states... The flaws with the RIM test have been well documented...we recommend that the RIM test not be used.."

106.1 Does FBC agree that, once the level of cost effective DSM (from a societal and utility perspective) has been established, the portfolio size and/or content could be adjusted for various factors, including: i) energy security/environmental considerations; ii) ability of the utility to scale DSM up/down each year; iii) equity in access to DSM programs by customer class; iv) prescribed programs; v) short-term energy surplus/shortage; and vi) short-term rate impact considerations. Please explain why/why not, and identify any other categories which could result in an adjustment to the DSM funding envelope.

<u>Response:</u>

FBC generally agrees. However, FBC does not believe that adjusting portfolio size to "short-term" influences is prudent since investments in DSM are expected to last for an average of 15 years. Specifically, FBC does not believe it has changed the portfolio size based on "short-term" rate impact considerations or a "short-term" energy surplus or shortage.

Other important considerations not referenced are:

- Economic DSM potential identified in the Conservation Potential Review; and
- Market response, (customer take-up), which requires addressing market barriers including, but not limited to, the customers' hurdle rates.

106.1.1 Assuming FBC is required to meet long-term firm load growth with long-term firm clean BC energy, and to meet 50 percent of load growth through DSM, does FBC consider that DSM portfolio (CPR Scenario 3) meets FBC's energy security and environmental considerations? Please explain why/why not.

Response:

FBC is not required to meet long-term firm load growth with long-term firm clean BC energy, and to meet 50 percent of load growth through DSM. FBC assumes that these theoretical requirements constitute what the question refers to as "energy security and environmental considerations". On that assumption, the answer is that the FBC DSM portfolio has not been designed to meet the theoretical security and environmental considerations stated in the question because it is not required to do so.

The proposed DSM plan is consistent with actual FBC energy security and environmental considerations. Energy security is met over the PBR period as defined in the power purchase section of this Application, and on a long-term basis as defined in the Resource Plan. FBC's environmental considerations are broad, but with respect to DSM, FBC considers that the combination of the proposed DSM plan and the RCR conservation rates results in an offset of more than 50 percent of load growth.

106.1.2 For each year of the PBR period, please provide forecast DSM GWh savings for each customer class as a percentage of total GWh sold for i) DSM budget as filed, and ii) DSM budget assuming using avoided cost of $111.96/MWh (before losses).

Response:

The following table contains a forecast of DSM GWh savings for each customer class as a percentage of total GWh sold for the i) DSM budget as filed, and ii) a DSM budget assuming using avoided cost of $111.96/MWh (before losses).

Year	i) DSM budget as filed Using avoided cost of $56.61/MWh				ii) DSM budget using avoided cost of $111.96/MWh
	Residential	*Commercial*	*Industrial*	*Total*	*Total*
2014	0.18%	0.19%	0.02%	0.39%	0.68%
2015	0.17%	0.19%	0.02%	0.39%	0.68%
2016	0.17%	0.19%	0.02%	0.38%	0.67%
2017	0.16%	0.19%	0.02%	0.38%	0.66%
2018	0.16%	0.19%	0.02%	0.38%	0.66%

As per BCUC IR 1.244.1, FBC only developed a high level DSM budget assuming an avoided cost of $111.96/MWh thus is unable to provide customer class detail for this scenario.

106.1.3 What level of assurance can FBC provide that it will not significantly under-spend the Industrial DSM budget over the PBR period (Please refer to Exhibit B-15, ICG 1.46.1).

Response:

FBC cannot guarantee the industrial budget spending as it is dependent on participation by a relatively small number of customers. The small number and large size of industrial projects means that costs and benefits are more variable.

FBC encourages industrial customer program participation primarily through direct customer contact by PowerSense staff. The Sampson report indicated frequent contact took place between the FBC Technical Advisors and eligible customers.

106.2 Please evaluate the 2013 CPR Scenario 3 portfolio against each of the BC Hydro five principles described in the preamble above (BCH 2013 IRP, p. 8-16). Please also provide FBC's opinion on whether each of these principles is relevant to FBC.

Response:

Since the BCH principles address a short-term energy surplus, they do not apply to FBC which does not face a similar circumstance.

106.3 Has FBC reduced the level of cost-effective DSM spending out of concern for customer rate impacts? If yes, please describe and quantify the effect on the proposed DSM budget over the PBR period.

Response:

The reduction of DSM expenditures as compared to 2012/2013 results primarily from the application of the cost-effectiveness test prescribed by regulation. Other factors, such as the 2013 DSM forecast shortfall and the rate impact benefit support the expenditure reduction.

106.3.1 Please explain why FBC considers it appropriate to apply the RIM test at the portfolio level, what criteria FBC used to determine the acceptable customer rate impact, and whether it consulted with the DSM Advisory Committee on this issue (if yes, what was the response, and if not, why not?)

Response:

FBC did not use the RIM test per se and did not establish a threshold that it considers an “acceptable” rate impact.

FBC considered the three scenarios presented in the 2013 CPR Update and ultimately choose the one it believes had the appropriate LRMC, with the lowest expenditure level and hence least rate impact. The three CPR scenarios were presented to the DSMAC for discussion purposes, but the FBC decision wasn’t taken until a later date.

106.4 Does FBC consider that customer rate impact concern could be better addressed by ensuring i) an equitable level of DSM spending between customer classes, ii) that each key customer segment has reasonable access to DSM programs and iii) if appropriate, rate design changes? Please explain why/why not.

Response:

FBC believes its 2014-18 DSM Plan (i) provides appropriate levels of DSM spending in each customer class, and (ii) that its programs address major end-uses in key customer segments.

Rate design changes (such as Residential Conservation Rate, and Two-Stepped Rate) are also in place or being considered in other regulatory processes.

107.0 Reference: Exhibit A2-16, BC Hydro IRP 2013, Appendix 4D, Tables 8-3 and 8-6;

Exhibit A2-15, ACEE Saving Energy Cost-Effectively 2009 Report, pp. 5–7

Setting the funding envelope — Benchmarking

BC Hydro provides a DSM Jurisdiction Review Comparison of DSM Achievements as Appendix 4D to its August 2013 IRP, an analysis of TRC and UCT by program at Table 8-6, and DSM cost by customer class in Table 8-3 (Exhibit A2-16, Appendix 4D, Table 8-3, Table 8-6).

An ACEEE study titled *Saving Energy Cost-Effectively: A National Review of the Cost of Energy Saved Through Utility-Sector Energy Efficiency Programs*, September 2009, includes on Table 1 and Figure 1 a comparison of average State program costs of saved electricity (Exhibit A2-15, pp. 5–7).

107.1 Please reproduce Table 1 and Figure 2 of the ACEEE September 2009 study referenced above, updated to also show FBC average cost of saved electricity for i) 2012 and ii) forecast over the PBR period, and iii) forecast over the PBR period if DSM budget was increased to reflect an avoided cost of DSM at $111.96/MWh (before losses).

<u>Response:</u>

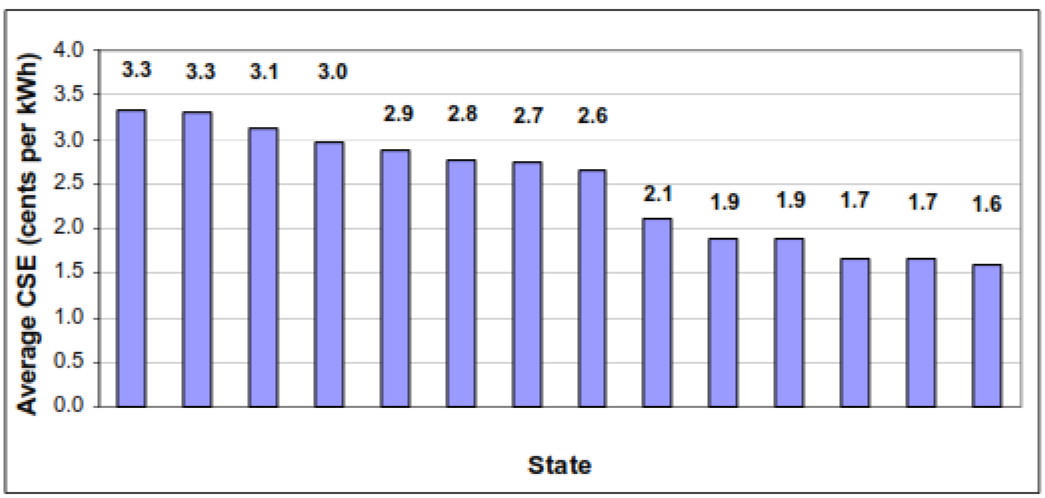
The following tables and figures compare Table 1 and Figure 2 from the ACEEE study titled *Saving Energy Cost-Effectively: A National Review of the Cost of Energy Saved Through Utility-Sector Energy Efficiency Programs*, September 2009 to the levelized cost presented in Table 14 of *Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 Volume 2 – Appendices Attachment H2*: Semi-annual DSM report year ended December 31, 2012 as well as the other scenarios identified in BCUC IR 2.107.1.

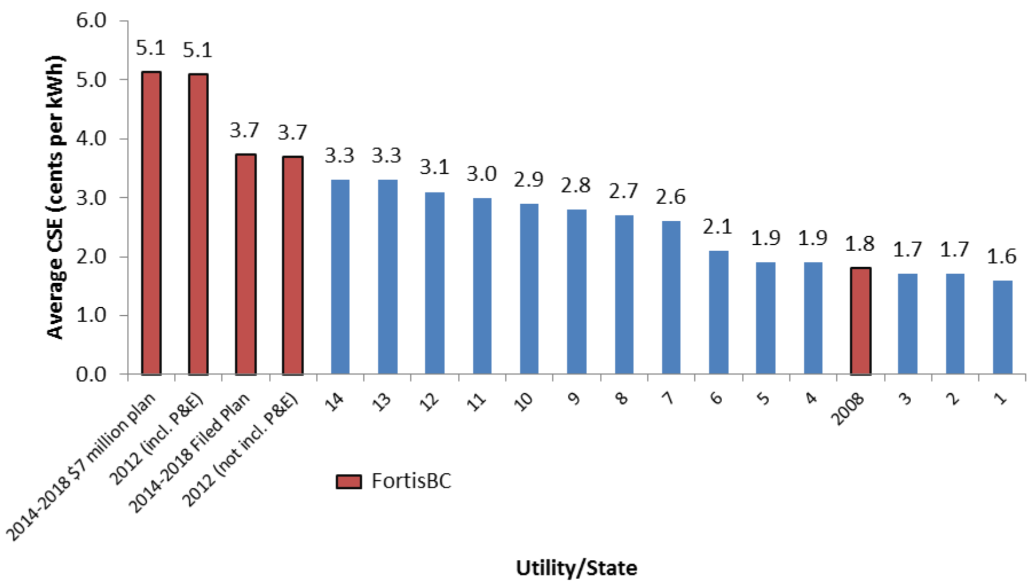
Table 1. Average Program Costs of Saved Energy Reported or Calculated by ACEEE for Electricity Efficiency Programs

State	CSE ($/kWh)	Sources and Notes
California	$0.029	Reported: average of figures in 2006 and 2007 Annual Reports for investor-owned utilities (IOUs): SCE, PGE, and SDGE (CPUC 2007a-d)
Connecticut	$0.028	Calculated with data from the Energy Conservation Management Board (ECMB) annual reports on the Connecticut Energy Efficiency Fund (ECMB 2006, 2007, 2008, 2009). Data include limited-income programs. The CSE estimate is the average of program years 2005–2008. Average measure lifetime is 13 years, based on lifetime and annual energy savings estimates from reports.
Iowa	$0.017	Calculated annual estimates for 2001 through 2007-year IOU programs in the state (IUB 2009). This is the average of those, using the program estimate of a 15-year average measure lifetime for energy efficiency measures (IUB 2009).
Massachusetts	$0.031	Average of figures in MA DER (2007) for program years 2003–2005 (reported) and for program years 2006 and 2007 (calculated) with data from MA DER (2009). Low-Income programs are included. Savings are net and average lifetime is about 13 years (MA DER 2007).
Minnesota	$0.021	Calculated annual estimates for 2006- and 2007-year electric utility energy efficiency and conservation programs, assuming the average 13-year measure lifetime because state-specific data was not available (MN DOC 2009).
Nevada	$0.019	Calculated with data for the Nevada Power Company and Sierra Pacific Power Company, the two IOUs in the state that supply 88% of electricity used in the state (Geller & Schlegel 2008). This is the average for 2006–2008 program data, assuming an average 13-year measure lifetime.
New Jersey	$0.026	Calculated with data for NJ Clean Energy Program (NJ BPU 2004–2007; Ambrosio 2009). Includes costs for energy efficiency programs only (including low-income programs), not renewable energy programs. Energy savings are gross. This is the average we calculate for program results from 2003–2006, for which the range is $0.022–0.037 per kWh. The average measure lifetime is 14 years.
New Mexico	$0.033	Calculated with data for PNM, the state's largest electricity provider, for efficiency programs in 2008 (PNM 2009). Average lifetime assumed is 9 years, which is derived from the 2008 annual report, and savings are net.
New York	$0.019	Calculated with data from the 2008 NYSERDA annual report (NYSERDA 2008) for program years 2004, 2005, and 2006. Costs are for electricity efficiency programs, including low-income programs and excluding R&D costs. NYSERDA estimates electricity program costs at 85% of total efficiency costs, with 15% estimated for natural gas. This is the average we calculate for three program years, assuming a portfolio average efficiency measure life of 15 years based on NYSERDA estimates.
Oregon	$0.016	Reported: Average of figures reported in 2005–2008 annual reports by the Energy Trust of Oregon (ETO 2006–2009). Electricity savings are net savings and average lifetime estimate for electricity measures for the program is 12 years.
Rhode Island	$0.030	Calculated with cost and savings data from the *2007 DSM Year-End Report* for National Grid (National Grid 2008a). Average measure lifetime is 11 years, based on lifetime and annual electricity savings estimate from the report.
Texas	$0.017	Calculated with data for 2004–2007 efficiency programs run by IOUs in Texas (PUCT 2008). No estimate of measure lifetime is provided, so we assume a 13-year measure lifetime.
Vermont	$0.027	Calculated with annual costs and net savings data from Efficiency Vermont (EVT) annual reports (2003–2008). The CSE range for annual programs is $0.024–0.032. Assumes 10–15 year measure lifetime based on annual EVT program reporting.
Wisconsin	$0.033	Reported value for efficiency programs from June 2001 through July 2007 (PA Consulting 2007). Electricity savings estimates are net verified savings and average lifetime estimate is 12 years based on program data.
Mean	**$0.025**	Average of reported and calculated CSE state averages.
Median	**$0.027**	Median of reported and calculated CSE state averages.
Range	**$0.016–0.033**	

FBC DSM	Levelised Cost	Notes
2008	$0.018	This levelized cost does not include program planning, program development, and monitoring and evaluation. A 5% discount rate is used.
2012 (incl. P&E)	$0.051	This levelized cost is taken from Table 14 - App H2. This levelized cost includes program planning, program development, and monitoring and evaluation. An 8% discount rate is used.
2012 (not incl. P&E)	$0.037	This levelized cost is recalculated from Table 14 - App H2. This levelized cost does not include program planning, program development, and monitoring and evaluation. A 5% discount rate is used.
2014-2018 Filed Plan	$0.037	This levelized cost is derived from the figures provided for BCUC IR 1.20.1 which is the PBR DSM plan as filed. A 5% discount rate is used.
2014-2018 $7 million plan	$0.051	As per BCUC IR 1.244.1, FBC only developed a high level DSM budget for an avoided cost of $111.96/MWh thus is unable to provide a levelized cost for this scenario. However, a $7 million scenario which approximated a level of expenditure previously approved was prepared for BCSEA IR 1.21.1.1. The levelized cost shown in this table is derived from the figures provided for BCSEA IR 1.21.1.1 which serves as a proxy for a DSM expenditure that would be consistent with an avoided cost of DSM at $111.96/MWh. A 5% discount rate is used.

Figure 2. Average State Values for Utility Cost of Saved Energy — Electricity Programs





It should be noted that these figures may not be directly comparable since the ACEEE report has out-of-date data going back to 2001 that have not been inflated to current dollars. FBC has provided the 2008 data point for comparison since that is the base year before DSM began to expand in response to the BC Energy Plan policy direction. The ACEEE CSE figures may also differ as the report encompasses state-wide results that benefit from economies of scale and possibly include codes and standards savings – which the FBC figures do not. Finally the figures may exclude adequacy (low-income, rental & education) and/or specified DSM programs which are less cost-effective and thus pass only on a portfolio basis.

107.2 Please provide a table comparing, for 2012, BC Hydro (excluding from BC Hydro's DSM data $ spend or GWh attributable to codes and standards and rates) and FBC: i) annual DSM $ as a percentage of retail revenues, ii) annual DSM GWh savings as a percentage of GWh retail sales, iii) annual DSM spend for each customer class and iv) average spend per customer by customer class. Please provide supporting details and explain any significant differences.

Response:

Please refer to the following table.

Item	FBC	BC Hydro
	2012	F2013
i) annual DSM $ as a percentage of retail revenues	3.3%	4.2%
ii) annual DSM GWh program savings* as a percentage of GWh retail sales	1.4%	0.4%
iii) annual DSM spend for each customer class ($)**		
Residential	2,858,000	27,532,000
Commercial	3,432,000	49,900,000
Industrial	195,000	31,558,000
iv) average spend per customer by customer class ($/customer)		
Residential	29	16
Commercial	234	252
Industrial	5,000	187,845

Note: total GWH retail sales and total retail revenue reflect only residential, commercial and industrial customers, and exclude wholesale and trading data.
*includes program savings only; excludes load displacement, codes/standards and rates
**includes planning and evaluation; excludes supporting initiatives, load displacement, codes/standards and rates

The majority of these metrics are not dissimilar between FBC and BC Hydro. The average spend per customer is higher by FBC for the Residential sector, likely due to economies of scale, but is quite similar in the Commercial sector.

The Industrial sector differs significantly between the two utilities. Few jurisdictions have as high a percentage of large industrial load as BC Hydro. The average sales per customer is a factor of ten larger (78.5 versus 7.5 GWh/customer) higher than FBC. Those two factors skew the industrial spend because there are likewise much larger DSM opportunities with the BCH customers.

107.3 To the extent practicable, please identify DSM programs offered by BC Hydro but not forecast to be offered by FBC during the PBR period, and explain why FBC is not offering these or similar programs in its service territory. Please also indentify if these or similar programs would be offered if the avoided cost of DSM was set at $111.96/MWh (before losses).

<u>Response:</u>

FBC’s 2014-18 DSM Plan is compliant with governing legislation, including the DSM Regulation, and the Plan addresses major end-uses in all sectors through cost-effective DSM programming. Collaboration with other utilities, namely FEU and BC Hydro, is pursued wherever possible in mass markets (e.g. EnergyStar appliance program) to ensure equity of offers for FBC’s customers.

A side-by-side comparison is resource intensive, and unnecessary as per the FBC 2012-13 RRA decision (p. 139):

> *"As noted earlier, in the Panel's view, BC Hydro and FortisBC are different utilities, operating in different contexts. The Commission Panel is not prepared to direct FortisBC to implement the same DSM programs as BC Hydro, particularly in the industrial sector where the customer base is very different."*

107.4 Please reproduce Tables 1, 2 and 3 of the benchmarking data included in Appendix 4D to BC Hydro's August 2013 IRP, and update them to show the equivalent results for FBC i) 2012 (actual), ii) 2013 (forecast), iii) average forecast over the PBR period and iv) average over the PBR period if the avoided cost of DSM was set at $111.96/MWh (before losses). Please provide supporting analysis and explain any significant differences.

Response:

Table 1. Mandated Cumulative Energy Savings as a Percent of Retail Sales, 2010-2015

State	Energy Savings Target (% of Sales)					
	2010	2011	2012	2013	2014	2015
Delaware		2.0%				15.0%
Maryland						15.0%
New York						15%
Arizona		1.25%	3.0%	5.0%	7.25%	9.5%
Illinois	0.6%	1.4%	2.4%	3.8%	5.6%	7.6%
California* ^	1.4%	2.8%	4.1%	5.1%	6.1%	7.0%
Minnesota	1.0%	2.0%	3.0%	4.0%	5.0%	6.0%
Michigan	0.5%	1.25%	2.25%	3.25%	4.25%	5.25%
New Mexico					5.0%	
Ohio	0.5%	1.2%	2.0%	2.9%	3.9%	4.9%
Indiana	0.30%	0.80%	1.50%	2.40%	3.50%	4.80%
Pennsylvania	1.0%			3.0%		

* Includes investor-owned utilities, SCE, PG&E, and SDG&E. MWh savings goals converted to percent of sales.
^ Goals include savings from improved codes and standards.

	2012	2013	2014	2015	2016	2017	2018
	Energy Savings (% of sales), annual						
Actual, Forecast, and average PBR forecast	1.00%	0.77%	0.39%	0.39%	0.38%	0.38%	0.38%
Actual, Forecast, and avoided cost set at $111.96/MWh PBR forecast	1.00%	0.77%	0.68%	0.68%	0.67%	0.66%	0.66%

	2012	2013	2014	2015	2016	2017	2018
	Energy Savings (% of sales), cumulative						
Actual, Forecast, and average PBR forecast	1.00%	1.77%	2.16%	2.55%	2.93%	3.31%	3.69%
Actual, Forecast, and avoided cost set at $111.96/MWh PBR forecast	1.00%	1.77%	2.45%	3.13%	3.80%	4.47%	5.12%

Table 2. Summary of Utilities Included in DSM Achievement Review - 2009

		2009 Baseline Data						DSM Savings	
Organization	Jurisdictions(s)	Customers	Sales (GWh)	Revenues (Million $)	Average Retail Rate ($/kWh)	Summer Peak (MW)	Winter Peak (MW)	% of Energy Sales	% of Peak Demand
San Diego Gas & Electric	US - CA	1,370,621	16,994	2,929	0.17	4,482	3,691	2.89%	2.59%
Wisconsin Electric Power Co	US - MI, WI	1,115,500	25,818	2,459	0.10	5,751	4,758	2.42%	0.03%
Massachusetts Electric Co	US - MA	1,153,519	10,973	1,714	0.16	4,494	3,711	2.14%	0.87%
Southern California Edison Co	US - CA	4,855,071	77,983	10,973	0.14	21,786	15,262	2.14%	1.36%
Pacific Gas & Electric Co	US - CA	5,215,171	79,985	10,894	0.14	18,410	12,553	1.91%	1.48%
Nevada Power Co	US - NV	826,637	21,189	2,358	0.11	5,586	3,545	1.54%	0.86%
Vermont* ^	US - VT	356,132	5,621	710	0.13	1,103		1.51%	1.24%
Puget Sound Energy Inc	US - WA	1,072,811	21,866	2,021	0.09	3,508	4,906	1.47%	0.00%
Connecticut Light & Power Co	US - CT	1,077,735	12,090	2,349	0.19	4,873	4,016	1.32%	0.49%
Interstate Power and Light Co	US - IA, IL, MN	526,023	14,876	1,242	0.08	2,949	2,568	1.18%	1.12%
MidAmerican Energy Co	US - IA, IL, SD	723,178	20,184	1,210	0.06	4,299	3,522	1.08%	1.07%
Idaho Power Co	US - ID, OR	488,176	13,948	893	0.06	3,031	2,528	0.94%	0.59%
Energy Trust of Oregon*	US - OR	1,370,642	30,841	2,533	0.08			0.91%	
PacifiCorp**	US - CA, ID, UT, WA, WY	1,163,416	39,287	2,506	0.06			0.77%	
Arizona Public Service Co	US - AZ	1,117,199	28,173	2,962	0.11	7,218	4,086	0.74%	0.47%
Manitoba Hydro	Canada - MB	527,472	21,266	1,784	0.08			0.70%	
British Columbia Hydro	Canada - BC	1,801,328	50,771	4,269	0.08			0.69%	
Wisconsin Power & Light Co	US - WI	455,794	9,858	915	0.09	2,558	2,265	0.62%	0.35%
New Jersey Clean Energy*	US - NJ	3,892,544	79,130	12,686	0.16	18,189		0.58%	0.25%
Hydro Quebec	Canada - QC	3,300,000	165,300	12,055	0.07			0.55%	
Public Service Co of Colorado	US - CO	1,356,014	27,316	2,223	0.08	6,272	5,941	0.54%	2.66%
Kansas City Power & Light Co	US - KS, MO	510,296	14,681	1,134	0.08	3,448	2,631	0.27%	0.44%
Consolidated Edison Co-NY Inc	US - NY	2,672,296	23,477	5,038	0.21	5,329	3,849	0.18%	0.15%
NYSERDA*	US - NY	7,937,995	140,043	25,253	0.18	37,642		0.17%	
Florida Power & Light Co	US - FL	4,502,355	102,682	11,542	0.11	22,351	20,081	0.15%	0.33%
Ontario Power Authority*	Canada - ON		150,999						
Average Excluding BC Hydro								**1.11%**	**0.86%**

* Third-party implementer across multiple utility service territories.

** Excludes Oregon service territory where DSM is implemented by the Energy Trust of Oregon

^ Statewide, including Efficiency Vermont and Burlington Electric Department programs.

		2009 Baseline Data							DSM Savings
Organization	Jurisdiction	Customers Total	Energy Sold Total (GWh)	Revenues ($m)	Average retail rate ($/kWh)	Peak Demand (MW) - Summer	Peak Demand (MW) - Winter	% of Sales	% of Peak
FortisBC Inc.	Canada - BC	159,297	3,157	244.1	0.07732	561	714	0.90%	

Table 3. Summary of DSM Achievements – 2005 to 2009

Organization	Annual Energy Savings as Percent of Retail Sales					
	2005	2006	2007	2008	2009	Average
San Diego Gas & Electric		1.00%	2.13%	1.99%	2.89%	2.0%
Wisconsin Electric Power Co		0.20%	0.17%	0.27%	2.42%	0.8%
Massachusetts Electric Co	1.27%	1.94%	1.53%	0.92%	2.14%	1.6%
Southern California Edison Co	1.62%	0.99%	1.91%	1.98%	2.14%	1.7%
Pacific Gas & Electric Co	1.61%	1.00%	2.05%	3.35%	1.91%	2.0%
Nevada Power Co	0.34%	0.69%	0.82%	1.39%	1.54%	1.0%
Vermont	1.04%	1.06%	1.88%	2.51%	1.51%	1.6%
Puget Sound Energy Inc	0.83%	0.78%	1.02%	1.23%	1.47%	1.1%
Connecticut Light & Power Co	0.97%	1.18%	1.72%	1.95%	1.32%	1.4%
Interstate Power and Light Co	0.74%	0.83%	0.83%	0.80%	1.18%	0.9%
MidAmerican Energy Co	0.60%	0.78%	0.77%	0.83%	1.08%	0.8%
Idaho Power Co	0.31%	0.51%	0.62%	0.94%	0.94%	0.7%
Energy Trust of Oregon	1.10%	0.69%	0.96%	0.88%	0.91%	0.9%
PacifiCorp	0.41%	0.51%	0.44%	0.57%	0.77%	0.5%
Arizona Public Service Co		0.28%	0.93%	0.88%	0.74%	0.7%
Manitoba Hydro	0.51%	0.67%	1.13%	0.42%	0.70%	0.7%
British Columbia Hydro	1.09%	1.25%	1.09%	0.88%	0.69%	1.0%
Wisconsin Power & Light Co	0.57%	0.62%	0.65%	0.74%	0.62%	0.6%
New Jersey Clean Energy	0.47%	0.16%	0.27%	0.41%	0.58%	0.4%
Hydro Quebec					0.55%	0.5%
Public Service Co of Colorado	0.38%	0.17%	0.45%	0.63%	0.54%	0.4%
Kansas City Power & Light Co			0.09%	0.21%	0.27%	0.2%
Consolidated Edison Co-NY Inc	0.02%	0.16%	0.21%	0.38%	0.18%	0.2%
New York State Research and	0.36%	0.28%	0.48%	0.11%	0.17%	0.3%
Florida Power & Light Co	0.18%	0.19%	0.20%	0.16%	0.15%	0.2%
Ontario Power Authority			0.17%	0.25%		0.2%
Average Excluding BC Hydro	**0.70%**	**0.67%**	**0.89%**	**0.99%**	**1.11%**	**0.85%**

Organization	Annual Energy Savings as Percent of Retail Sales					
	2005	2006	2007	2008	2009	Average
FortisBC Inc.	0.80%	0.76%	0.90%	0.88%	0.90%	0.85%

108.0 Reference: Exhibit B-7, BCUC 1.247.2, 1.244.1 and 1.248.8.1; Exhibit B-1-1, Appendix H-1, p. 14; Exhibit A2-15, ACEE Saving Energy Cost-Effectively 2009 Report , p. 12

FBC proposed programs

FBC includes in BCUC 1.247.2 a list of proposed eliminated/scaled down DSM programs.

An ACEEE study titled *Saving Energy Cost-Effectively: A National Review of the Cost of Energy Saved Through Utility-Sector Energy Efficiency Programs*, September 2009 found an average of 76% of the DSM program budget was spent on incentive costs (Exhibit A2-15, p. 12).

108.1 Please provide an updated Table H1-7 to the 2014-2018 DSM Plan, by splitting the table in three separate tables for (i) Plan Savings, (ii) Plan Costs and (iii) Benefit/Cost ratios. Please include in each of these tables 2012 (Approved), 2012 (Actual) and 2013 (Approved) data. Where adjustments are required to ensure an 'apples to apples' comparison, please describe. Please explain any significant variances.

<u>**Response:**</u>

(i)	**Energy Savings (MWh/yr)**	**Actual 2012**	**Approved 2013**	**Plan Savings 2014**	**2015**	**2016**	**2017**	**2018**
3	**Programs by Sector**							-
4	Residential	12,758	16,946	5,800	5,783	5,615	5,511	5,407
5	General Service	17,892	11,980	6,200	6,304	6,408	6,512	6,616
6	Industrial	937	2,580	800	800	800	800	800
7	**Sub-total Programs:**	**31,587**	**31,506**	**12,800**	**12,887**	**12,823**	**12,823**	**12,823**
8	Supporting Initiatives							
9	Planning & Evaluation							
10	Total (incl. Portfolio):							
11	**Residential Programs**	-	-	-	-	-	-	-
12	Building Envelope	4,656	8,680	1,881	1,881	1,881	1,881	1,881
13	Heat Pumps	2,161	3,397	553	553	553	553	553
14	Lighting	2,599	2,467	2,136	2,067	1,997	1,928	1,859
15	Appliances	1,248	739					
16	New Home	1,040	93	98	98	98	98	98

(i)	**Energy Savings (MWh/yr)**	**Actual 2012**	**Approved 2013**	**Plan Savings 2014**	**2015**	**2016**	**2017**	**2018**
17	Water heating[1]	-	-	425	440	455	470	485
18	Low Income & Rental	1,054	1,570	707	744	631	581	531
19	Behavioural[1]	-	-	-	-	-	-	-
20	**Total**	**12,758**	**16,946**	**5,800**	**5,783**	**5,615**	**5,511**	**5,407**
21	**General Service Programs**	-	-	-	-	-	-	-
22	Lighting	14,256	7,140	3,359	3,463	3,567	3,671	3,775
23	BIP	1,959	3,730	2,641	2,641	2,641	2,641	2,641
24	Municipal (Water Handling)	1,677	1,110					
25	Irrigation[2]	-	-	200	200	200	200	200
26	**Total**	**17,892**	**11,980**	**6,200**	**6,304**	**6,408**	**6,512**	**6,616**
27	**Industrial Programs**							-
28		937	2,580	800	800	800	800	800
29	**Total**	**937**	**2,580**	**800**	**800**	**800**	**800**	**800**

[1] These programs were included in Home Improvements Program in 2012/2013

[2] Irrigation was included in Municipal (Water Handling) in 2012/2013

(ii)	**Program Costs ($000s)**	**Actual 2012**	**Approved 2013**	**Plan Costs 2014**	**2015**	**2016**	**2017**	**2018**
3	**Programs by Sector**	-	-	-	-	-	-	-
4	Residential	2,564	3,944	1,037	1,081	1,008	1,015	1,024
5	General Service	3,019	2,085	1,134	1,166	1,195	1,223	1,256
6	Industrial	173	364	148	150	152	154	156
7	**Sub-total Programs:**	**5,756**	**6,393**	**2,319**	**2,397**	**2,355**	**2,392**	**2,436**
8	Supporting Initiatives	816	725	190	190	190	190	190
9	Planning & Evaluation	728	760	492	500	509	518	527
10	Total (incl. Portfolio):	**7,300**	**7,878**	**3,001**	**3,087**	**3,054**	**3,100**	**3,153**
11	**Residential Programs**	-	-	-	-	-	-	-
12	Building Envelope	637	1,961	295	299	301	305	308
13	Heat Pumps	636	698	158	159	161	163	164
14	Lighting	337	313	176	171	164	158	153
15	Appliances	332	267					

(ii)	Program Costs ($000s)	Actual 2012	Approved 2013	Plan Costs 2014	2015	2016	2017	2018
16	New Home	314	45	67	68	68	69	70
17	Water heating[1]	-	-	99	103	108	112	119
18	Low Income & Rental	308	660	242	281	206	208	210
19	Behavioural[1]	-	-	-	-	-	-	-
20	**Total**	**$ 2,564**	**$ 3,944**	**$ 1,037**	**$ 1,081**	**$ 1,008**	**$ 1,015**	**$ 1,024**
21	**General Service Programs**	-	-	-	-	-	-	-
22	Lighting	2,152	1,170	510	535	557	579	603
23	BIP	612	738	592	598	605	611	619
24	Municipal (Water Handling)	255	177					
25	Irrigation[2]	-	-	32	33	33	33	34
26	**Total**	**$ 3,019**	**$ 2,085**	**$ 1,134**	**$ 1,166**	**$ 1,195**	**$ 1,223**	**$ 1,256**
27	**Industrial Programs**			-	-	-	-	-
28		173	364	148	150	152	154	156
29	**Total**	**173**	**364**	**$ 148**	**$ 150**	**$ 152**	**$ 154**	**$ 156**

[1] These programs were included in Home Improvements Program in 2012/2013

[2] Irrigation was included in Municipal (Water Handling) in 2012/2013

(iii)	Benefit/Cost Ratios	TRC	mTRC	Utility	Participant	RIM
3	**Programs by Sector**	-	-	-	-	-
4	Residential	1.2	1.3	3.5	5.5	0.5
5	General Service	1.4	1.7	3.3	5.2	0.6
6	Industrial	2.8	2.8	5.7	13.	0.7
7	**Sub-total Programs:**	**1.4**	**1.5**	**3.9**	**5.6**	**0.6**
8	Supporting Initiatives					
9	Planning & Evaluation					
10	Total (incl. Portfolio):	**1.2**	**1.4**	**3.7**		**0.6**
11	**Residential Programs**	-	-	-	-	-
12	Building Envelope	1.1	1.3	4.8	5.0	0.5

(iii)	**Benefit/Cost Ratios**	**TRC**	**mTRC**	**Utility**	**Participant**	**RIM**
13	Heat Pumps	1.1	1.1	2.4	5.7	0.5
14	Lighting	1.4	1.4	5.9	4.9	0.5
15	New Home	0.6	1.2	1.2	5.3	0.4
16	Water heating	1.6	1.9	2.1	18	0.4
17	Low Income & Rental	0.8	1.4	1.0	-	0.4
18	Behavioural	-	-	-	-	-
19	**Total**	**1.2**	**1.3**	**3.5**	**5.5**	**0.5**
20	**General Service Programs**	-	-	-	-	-
21	Lighting	1.7	2.0	3.4	9.2	0.6
22	BIP	1.1	1.5	3.1	4.0	0.6
23	Irrigation	2.1	2.1	7.3	6.3	0.6
24	**Total**	**1.4**	**1.7**	**3.3**	**5.2**	**0.6**
25	**Industrial Programs**	-	-	-	-	-
26		2.8	2.8	5.7	13	0.7
27	**Total**	**2.8**	**2.8**	**5.7**	**13**	**0.7**

Note: the 2012 Plan figures were omitted due to space limitations; however, they are more or less similar to the 2013 approved figures shown. Likewise due to space limitation the TRC Benefit/Cost ratios shown are limited to the 2014-18 Plan under scrutiny. The 2012 Actual benefit/cost ratios can be found in Appendix H2 of the filing, and the 2013 results are expected to be similar.

There is simply too much data presented in the above tables to try to identify or explain “significant variances”.

108.2 Please explain why the programs listed in BCUC 1.247.2 are proposed to be eliminated or scaled down when all programs (except appliances) pass both the TRC and UCT.

Response:

The programs classified as scaled down have had uneconomic measures removed from them, and the TRC/UCT ratios shown are for the remaining cost-effective measures. If the eliminated measures were restored the program TRC would fail and/or the mTRC budget amount would exceed the 10 percent cap.

Please refer to the responses to BCUC IRs 1.248.8.1 and 2.108.6 for specific reasons why programs, with a positive benefit/cost ratio, are being eliminated.

108.3 Please provide, to the extent possible, supporting details for the $7.9 million annual DSM budget estimate provided by FBC in response to BCUC 1.244.1. Please include in your response how the reduced/eliminated programs identified in BCUC 1.247.2 would be affected.

Response:

No further details are available as the $7.9 million estimate was a “high-level” DSM budget estimate. The reduced/eliminated measures and programs would be reviewed and potentially restored, if there was an appropriate case and the resources to do so.

108.4 Does FBC have, or is FBC intended to start, a codes and standards program? If not, why not? If yes, please provide budget over the PBR period and compare to BC Hydro’s budget request over the same period (weighting FBC budget to reflect FBC’s smaller retail sales compared to BC Hydro). Please explain any significant differences.

Response:

FBC does not have, and has no current intention to start, a codes and standards program. The PowerSense DSM program and staffing is relatively small (even at the 2012/2013 expenditure levels) and therefore FBC chooses to focus its DSM efforts elsewhere.

FBC does participate in discussions regarding codes, standards and regulations in a limited manner (for example, with CSA International). The $10 thousand budget item for codes and standards is for this work.

108.5 Please provide the Energy Diet budget for the PBR period, describe the program, and identify any increases in funding if the DSM avoided cost increased to $111.96/MWh (before losses).

Response:

As of the end of 2013, the entire FBC service area will have been exposed to a first wave of Energy Diet campaigns. There is no budget to continue the Energy Diet campaigns in the proposed 2014-18 DSM Plan. A second and perhaps third wave of Energy Diets would be implemented in the test period, if the higher avoided cost enabled a DSM spend that approximated the prior years' approved expenditures.

108.6 In BCUC 1.248.8.1, FBC states behavioural programs have been discontinued due to a lack of certainty in the savings. Does FBC consider that this could be a case of 'perfect being the enemy of the good'? Could FBC instead develop a range of probable savings, and determine the probability that the program will be cost effective? Please explain why/why not.

Response:

FBC has successfully propagated behavioural programs in the past, notably clotheslines, and found they work best with an actual measure or device that provides a substitution for the conventional behaviour (clothes dryers) that use a substantial amount of energy. Behavioural programs require a considerable amount of resources ranging from purchasing the devices, events to give-away the measure, promotion of those events, prompts (dryer magnets) and follow-up messaging to reinforce the behavioural change sought. FBC even persuaded local governments to pass clothesline friendly bylaws.

In absence of any obvious behavioural measures, such as clotheslines, to pursue and with more limited resources in the proposed plan the Company elected to discontinue behavioural programs in favour of "hard-wired" measures with more certainty in regards to the measure energy savings.

108.7 Please identify, describe, and provide the business case for any new DSM programs proposed during the PBR period, or that would be proposed if the DSM avoided cost increased to $111.96/MWh (before losses).

Response:

At the higher avoided cost shown, and presumably an expenditure that approximates the previously approved level of DSM spend, the Company would review the list of programs and measures (see BCUC IR 1.247.2) that were scaled back or eliminated to determine if any could be restored. As stated in the response to BCUC IR 2.108.5, FBC would consider adding additional waves of community Energy Diet programs. Conceptually FBC could pursue New Technologies or measures, as allowed under the DSM Regulation, for pilot programs. Otherwise there are no “new” programs in the wings.

108.8 For each year of the Plan (2014–2018), please provide a table showing the following amounts for each program for all sectors: total plan (i.e., utility) budget, budget for customer incentives and incentive spending as a percentage of total cost.

Response:

The following table shows the FBC DSM budget as filed and presents incentive spending as a percentage of program costs. Program costs were chosen as the denominator in order to present the FBC figures on a comparable basis to the ACEEE reference.

Budget	**2014**	**2015**	**2016**	**2017**	**2018**	**Total**
Incentives	1,462	1,477	1,436	1,443	1,452	**7,270**
Program Administration	857	920	919	949	984	**4,629**
Program Costs	*2,319*	*2,397*	*2,355*	*2,392*	*2,436*	***11,899***
% Incentives	**63%**	**62%**	**61%**	**60%**	**60%**	**61%**
Total Cost (incl. Portfolio components):	*3,001*	*3,087*	*3,054*	*3,100*	*3,153*	***15,396***

108.8.1 Please explain any significant difference between the FBC percentage of DSM program budget spent on incentive costs, and the results of the ACEEE September 2009 study referenced above (76 percent spent on incentive costs).

Response:

The FBC incentive ratio was 74 percent of program budget in 2012, which is quite similar to the study reference provided. The 2014 plan ratio is 63 percent which reflects the higher overhead costs associated with a smaller scale program.

109.0 Reference: Exhibit A2-17, Navigant Review of the Efficiency Main Trust Plan, pp. 27–29, p. 34; Exhibit B-11, BCPSO 1.61.1; FEU 2012/13 RR and Rates Decision, G-44-12, p. 173

Five year funding request — uncertainty

Navigant undertook a 2010 review of the Efficiency Main Trust Plan (Exhibit A2-17, pp. 27–29, 34). FBC states: "DSM savings are difficult to predict and are subject to influences outside of the Company's control" (Exhibit B-11, BCPSO 1.61.1).

The Commission states in the FEU 2012-2013 RR and Rates Decision (G-44-12, p. 173): "[t]he Commission believes that...the transfer of funds to new programs...will require prior Commission approval."

109.1 Please confirm (or provide evidence otherwise) that DSM spending approval periods in other jurisdictions are: i) One year: Rhode Island, Texas; ii) Two year: Hawaii, New Hampshire, New Mexico; iii) Three year: California, Colorado, Connecticut, Indiana, Massachusetts, Maryland, New York, Ohio, Pennsylvania, Vermont, Ontario and iv) Five year: Iowa.

Response:

There is no specific reference(s) provided for the data that the Commission presents in the question and FBC was unable to confirm or refute the DSM spending approval period claims for other jurisdictions.

109.1.1 Please confirm (or calculate otherwise) that the average number of years DSM spending is approved for based on the sample above is 2.7 years.

Response:

Please refer to the response to BCUC IR 2.109.1. The Commission has not provided adequate references for the data presented and FBC was unable to confirm or refute the calculation.

109.1.2 Has FBC consulted with the DSM Advisory Committee on the proposal to request an EEC funding envelope for a five year period (rather than, say, two or three years)? If yes, please describe the feedback received. If no, please explain why not.

Response:

No, DSMAC members were not consulted on the length of the DSM proposal.

109.2 Given that the Commission has a fundamental obligation to ensure DSM costs passed along to ratepayers are just and reasonable and were prudently incurred, please explain how the Commission can support a five year funding request for new programs when FBC has not yet developed a business case and program plan.

Response:

FBC has not proposed any new programs over the PBR filing period. It is likely that new measures will materialize over the period and can be added to existing programs where there is a suitable fit.

Whether new measures are to be added, or a new program instigated, FBC will work within the existing DSM constraints (i.e. authorized expenditure level, prescribed cost-effective tests, subject to EM&V processes and - albeit unlikely - the 25 percent budget transfer restriction).

FBC proposes to review any new programs at the PBR Annual Review.

109.3 Please explain why FBC should be allowed to transfer DSM approved funds to new programs given that such a request was previously rejected for FEU in the 2012/13 RR and Rates Decision.

Response:

FBC never put forth a request to transfer DSM approved funds to new programs in the 2012-13 RRA, and thus, such a request has never been rejected. FBC has now asked for this flexibility for the 2014-18 filing period.

Please refer to the response to BCUC IR 2.209.2 for FBC’s proposal on how to govern new programs that may be proposed in the filing period.

109.3.1 Does FEU agree that a business plan for a new DSM project should address each of the key areas identified as weaknesses by the Navigant 2010 review of the Efficiency Main Trust plan (pp. 27–29, 34)? If no, please explain why not.

Response:

The Company assumes that this question is intended to be directed to FBC and not to FEU.

Business cases for DSM programs are documents created for the internal use of FBC. The Company is under no obligation, statutory or otherwise, to create business cases for DSM programs that contain particular elements and pieces of information. That said, the Company is satisfied that the business cases that are created for internal purposes for DSM programs are suited to those purposes.

Further, the Company is of the view that in the case of the Navigant report on the Efficiency Maine Trust Plan, a third-party review of a public agency's plan, established and operating in a completely different jurisdiction, with entirely different statutory requirements, has little relevance to the FBC's proposed 2014-2018 DSM Plan and associated expenditure schedule, which is the subject of this proceeding.

109.4 Please provide the date that the FBC ISP and CPR are next expected to be updated, and comment on the extent to which an update could affect the optimum level of FBC DSM funding and/or programs undertaken.

Response:

FBC assumes this question refers to the date the next LTRP is due – June 30, 2016, since no date has been established for the next ISP. A combined gas-electric, province-wide CPR is being discussed by FEU, BCH and FBC and is tentatively slated for 2016 completion.

Unless as of yet unknown slate of new cost-effective measures and/or programs materializes in time for the aforementioned CPR, it is unlikely that the new CPR could materially affect the 2014-18 DSM Plan program mix or the proposed expenditures. Its timing will inform and impact DSM Plan filings in the post-2018 period.

109.4.1 If it is determined that the CPR update should trigger the end of this DSM approval period, how many years should this DSM Application be approved for? Please explain.

Response:

Please refer to the response to BCUC IR 2.109.4.

This DSM application should remain, as filed, at the five year period, since a new CPR is not expected to affect the current application. Further, in the interests of regulatory efficiency the DSM application duration is kept the same length and concurrent with the RRA filing.

109.5 Please discuss the likelihood of significant changes in each of the following areas during the five year PBR period, and comment on whether they could affect the optimum level of FBC DSM funding and/or programs undertaken: i) changes to the forecast long-run marginal cost of electricity; ii) changes to codes and standards affecting baseline efficiency level assumptions; iii) Development of new technologies, and/or results from pilot programs; and iv) EM&V results.

Response:

Please refer to the table below.

The Company will be continue to file the DSM Annual Report over the test period, which will allow the Company to consider (with input from the DSM Advisory Committee) any significant changes to the DSM portfolio, should the DSM operating environment change significantly, as described above.

Element of Operating Environment	Likelihood of Change	Comments/Impact on EEC Funding or Programs
Significant change to long-run marginal cost of electricity	Moderate	An increase in the long-run marginal cost of electricity might make more measures in the CPR appear cost-effective and suitable for consideration for inclusion in an EEC program, resulting in an increase to the proposed DSM budget; a decrease would have the inverse effect
Signifcant change to BC Hydro Funding Levels	Moderate	While BC Hydro has filed their 2013 Integrated Resource Plan and associated DSM Options and Expenditure, no particular Option had been established at the time of writing. The Companies anticipate that DSM funding will decline somewhat at BC Hydro over the proposed 5 year test period, and it may decline precipitously if government becomes more concerned about electricity rate increases and if BC Hydro's capacity surplus is greater than anticipated. The only program area that would be significantly impacted by a moderate decline in BC Hydro DSM funding would be the ECAP program in the Low Income Program area. If BC Hydro was no longer able to partner on this particular program, which is not cost-effective even with the 30% low income adder allowed for in the DSM Regulation, the FBC's ability to continue with ECAP would be impeded.
Significant change to LiveSmart funding levels	Unknown	In the residential program area, the FEU, FBC and BC Hydro have the ability to operate a non-LiveSmart collaborative home retrofit program, so changes to LiveSmart funding would have a minimal effect on residential programs. Similarly, in the Commercial program area, LiveSmart funding level changes would not have a significant effect since LiveSmart funding for commercial customers, with the exception of funding for Energy Advisors, was cut some time ago.
Signficant changes to Codes and Standards	Unlikely	Typically governments signal code changes well in advance. All currently-known code changes are incorporated into the baselines for planning purposes. Thus the Company's view is that it is unlikely that codes and standards changes could affect DSM funding or programs.
Development of new technologies	Unknown	Disruptive technologies can arise at any time, and are very difficult to predict. However, the Company has established a framework for transitioning technologies that emerge from successful pilots into full-blown programs and this should help to reduce risks to DSM funding and programs from New Technologies.

109.6 Please further explain why a five year DSM budget should be approved when i) the FBC shareholder is incentivized on the basis of the DSM $ spend, rather than results achieved and ii) there is no EM&V approved framework or independent audit of the results.

Response:

The assertions implicit in these questions are without merit.

The nature of the financial treatment of DSM, and the return on FBC expenditures on DSM activity has been well-established in previous proceedings and subsequent approvals by the BCUC. As is provided for under Section 6(1)(b)(ii) of the *Utilities Commission Act*, the financial treatment of DSM for British Columbia's utilities is that the utilities in B.C. earn their regulated rate of return on DSM expenditures, as the Commission must have due regard to the setting of a rate that "provides to the public utility …a fair and reasonable return on any expenditure made by it to reduce energy demands".

The DSM budget should be approved because it is supported by the 2014-2018 DSM Plan being put forward, which is cost-effective under the conditions that have been established for utilities in British Columbia and because it conforms with the DSM Regulation. The "results" from the DSM activity undertaken are bound by the TRC and mTRC test, and have been extensively and transparently reported in the Company's DSM Semi-Annual Reports; FBC has met the conditions established in British Columbia for evaluating cost-effectiveness over the last number of years. Therefore, the Company is allowed a fair and reasonable return for operating a cost-effective portfolio of DSM activity, and are proposing to continue doing so over the 5 year test period.

FBC is not seeking approval of the EM&V framework as part of this Application as no approval is required, nor is there any requirement for independent audits of British Columbia utility energy savings reported. As discussed in detail in response to information requests (e.g. BCUC IR 2.110 series), the segregation of the FBC's EM&V activities, the EM&V framework and the use of independent contractors avoids any conflict of interest or bias. The EM&V framework and FBC's results from previous activities are before the Commission in the proceeding. To be clear, the UCA does not include a requirement for an approved EM&V framework or an independent audit of BC utility energy savings reports.

109.7 Please explain the treatment for i) over and ii) under-spend of the DSM budget in any year during the PBR period, and if it represents a change from the treatment previously approved.

Response:

DSM deferred charge balances under the 2014-2018 PBR term are proposed to be included as part of the Annual Review process, as outlined in Section B6 of the 2014-2018 PBR Application. Therefore, regardless of whether there is over-spending or under-spending in the program, the amount is reforecast as part of the following year's rate base.

Currently, as approved by Order G-110-12 for the 2012-2013 RRA, there is no Annual Review process since the expenditures and year-end balances have been approved.

109.7.1 Is FBC requesting that DSM funds can be shifted between years i) within the PBR period and ii) outside of the PBR period? Please explain the reasons for the proposed treatment and if it represents a change from the treatment approved for 2012/13.

Response:

No, the Company is not requesting approval to shift funds between years, either within the PBR period or outside the PBR period. The Company is not proposing any change from the financial treatment of DSM expenditures approved for 2012/2013, except for increasing the DSM amortization period to fifteen years.

109.7.2 Please describe the advantages/disadvantages of being able to shift DSM funds between years during the PBR period, and whether program funding transfers between years greater than a maximum amount (such as 15 percent) should be subject to Commission approval.

Response:

The Company is not proposing to shift funds between years. This concept has not been contemplated by FBC; however the advantage of having the opportunity to do so would potentially mean that should a particular program become a runaway success during any particular year, funds could be transferred from a future year for that program, rather than another program area in the current year. A number of questions around the design of such a mechanism would need to be answered before such a mechanism could be implemented. These include:

- Should a program have a requirement for additional funding, and if that funding is being advanced from future years, does that funding get advanced from that particular program's future budget?
- Or from that program's program area generally?
- Or from the overall PowerSense DSM budget?

- Are there any requirements for program cost-effectiveness beyond those already in place for a program to be eligible for a future-year funding transfer?
- Is there a maximum amount that should be subject to Commission approval? And is that maximum amount a percentage of the program budget, the program area budget, or the overall DSM budget for any given year?

The Company has not given these questions any consideration, as at the time of writing.

110.0 Reference: Exhibit A2-10, Aligning Utility Incentives with Investment in Energy Efficiency, pp. 4–5 and 4–9; Exhibit B-7, BCUC 1.231.4.2 and 1.233.2; ACEEE, A National Survey of State Policies and Practices, 2012, pp. 20, 29; CPUC Decision 05-01-055, 2005, p. 112–114

Utility incentives/EM&V independence

FBC states in BCUC 1.231.4.2 that it does not support a review of the existing DSM organizational structure and shareholder incentive mechanism, and in BCUC 1.233.2 that it does not consider there is a potential conflict of interest in a utility both undertaking DSM activities and being responsible for EM&V of those activities.

Exhibit A2-10 states:

> "Capitalization currently is not a common approach to energy efficiency program cost recovery ... With a very few exceptions, capitalization is no longer the method of choice for energy efficiency cost recovery...in several states capitalization was abandoned, in part because the total costs associated with recovery...were rising rapidly " (Exhibit A2-10, pp. 4-5).

> "...[Nevada Commission] staff argued that the current cost recovery mechanism...provided no incentive for effective program performance and in fact, simply encouraged additional spending with no consideration for the implementation outcome – an argument echoed by the Attorney General's Bureau of Consumer Protection. Staff recommended that the ideal solution is to tie incentives to program performance and to share program net benefits with ratepayers" (Exhibit A2-10, pp. 4 9).

A 2012 ACEEE report titled A National Survey of State Policies and Practices of the Evaluation of Ratepayer-Funded Energy Efficiency Programs states on page 29 and 30:

> "...at one end of the spectrum, commission and/or commission staff in 12 states (28%) directly manage the evaluations. At the other end, in 11 states (25%) the commission either has no role at all or only provides limited oversight without requiring formal approval. In the middle, the most common situation (20 states, 47%) is for the commission to exercise formal approval over evaluation plans/products managed by utilities or other entities. ...In 3 states (7%) the [evaluation] work is done by utility staff."

CPUC Decision 05-01-055 (2005) states on pages 112-114:

> "...the EM&V structure within the overall administrative framework must be free of conflicts of interest that could bias EM&V results. ... In our view, allowing the

entity that selects the programs and manages the portfolio (IOUs) or the program implementers (IOUs or non-IOUs) to manage or contract directly for EM&V of their own efforts could seriously undermine the independence of even the most conscientious EM&V consultants."

110.1 Does FBC agree that that capitalization is not currently a widely used DSM cost recovery method and the ideal solution is to instead tie incentives to program performance and to share program net benefits with ratepayers? If no, please explain why not.

Response:

Please refer to the response to BCUC IR 2.97.3 regarding capitalization of DSM expenditures.

The view of the Company is that the financial treatment for DSM expenditures is well-established and appropriate. Capitalization is certainly widely used in British Columbia, as it is the method currently used by all three British Columbia utilities currently engaged in DSM.

FBC had a shared savings (net benefits) DSM incentive mechanism in the previous PBR period that ended in 2011. The Company choose not to propose a similar mechanism because it believes the necessary regulatory structure, including DSM Regulation, is in place for it to plan and pursue the appropriate amount of cost-effective DSM savings.

110.2 Does FBC agree with the Commission's G-44-12 finding for FEU (p. 196) that, should a review of DSM organizational structure and shareholder incentive mechanisms occur, it should be explored in a separate review process? Please explain why or why not.

Response:

The Company is of the view that the financial treatment of DSM for utilities in British Columbia has been well established through numerous and recent time- and resource- consuming regulatory proceedings and decisions by Commission Panels. Should the Commission wish to revisit these recent decisions, it is free to do so. In the interests of fairness, should the Commission wish to re-open the matter of the financial treatment of DSM in British Columbia, such a review would need to encompass the three British Columbia utilities engaged in DSM: the FortisBC Energy Utilities, FortisBC, and BC Hydro.

Please also refer to the response to BCUC IR 1.231.4.2.

110.2.1 Has FBC consulted with the DSM Advisory Committee on the need for a review of the DSM organizational structure and shareholder incentive mechanisms? Please explain why or why not.

Response:

No, these two items have not been on the DSMAC meeting agendas recently.

Discussions regarding DSM/EEC integration have centred on integrating customer-facing materials, such as the on-line Commercial Energy Rebate portal.

Note that the DSM advisory committee was originally struck to manage the DSM Incentive mechanism in place until 2011. The DSM advisory committee was made aware of the change from the incentive approach to the current model.

110.2.2 Does excluding DSM from FBC's scorecard indicate that DSM is not a priority for FBC? Please explain why or why not, and if this is consistent with the BC Energy Plan objectives.

Response:

The fact that FBC has been actively promoting PowerSense programs continuously since 1989 provides a strong indication that DSM is a priority for the Company. The proposed DSM plan represents a significant expenditure and is in fact greater than the expenditure in 2008 and all prior years. The plan is consistent with BC Energy Plan objectives.

As discussed in the response to BCSEA IR 1.34.4, when evaluating performance measures to include on its Scorecard such as DSM performance, FBC seeks not only to select the appropriate success measures but also the optimal number of measures (i.e. how many). Additionally, as the scorecard is an important communication tool to improving organizational alignment, clarity and understanding of a measure, for employees and other stakeholders, is an important consideration. FBC currently does not have any specific success measures on its Scorecard related to DSM performance. Instead, DSM related key success measures are included in individual employee objectives and performance plans, where applicable. This serves to ensure DSM activities are carried out in support of the BC Energy Plan objectives.

FBC reviews the appropriateness of its scorecard measures periodically and makes adjustments as required. At this time, FBC believes the six scorecard measures used best represent the overall priorities for Company.

110.3 Please confirm that, based on the ACEEE report cited above, it is not common practice for the utility to undertake the DSM evaluation role without formal approval by the Commission.

Response:

Not confirmed.

While the ACEEE report does indicate that it is the practice in some states for the Commission to approve the EM&V plans/products managed by utilities, there is no indication in the report that formal Commission approval is required for the utility to take on the evaluation role.

Further, the jurisdiction and legislative/regulatory framework in BC does not require regulatory approval of an EM&V plan. The Commission's oversight for the FBC PowerSense DSM program is governed by both the *Utilities Commission Act* and the *Clean Energy Act*, neither of which speak directly to approval of an EM&V plan. Indirectly, under the UCA, rates are approved and it is within this context that the Commission must ensure that the utility is prudently spending customer's money. A combination of economic tests and M&E ensure that DSM dollars are spent prudently. FBC does not believe that there is any reason to suggest that the M&E plan is not doing what was intended.

Currently, FBC's evaluation plan is before the BCUC as part of the 2014-2018 PBR, consistent with the most frequently cited practice in the ACEEE report as referenced above.

110.3.1 Does FEU agree with the CPUC that allowing FBC to manage or contract directly for EM&V seriously undermines the independence of EM&V? If no, please explain why not.

Response:

No, FBC does not agree. Please refer to the response to BCUC IR 1.233.2 where FBC presented their independence of EM&V practice through the organizational separation by function

FBC interprets the CPUC Decision to reference those Utilities where the program implementers (i.e. Program Managers) directly manage or contract with the EM&V consultants for review of their programs. Further, the CPUC decision is relevant to that jurisdiction and therefore is not directly applicable to other jurisdictions, who are under different regulatory and legislative rules.

FBC agrees that having the program implementer (i.e. Program Manager) directly contract the EM&V consultant could undermine the independence of EM&V. Hence, FBC program implementers do not directly contract the EM&V consultants. FBC EM&V staff report to a different manager than the program implementers and have the full responsibility in retaining EM&V consultants for program evaluation. The role of the FBC EM&V staff is well defined and as a result ensures independence of EM&V activities. It is FBC's view that FBC's current practice and organizational structure address the concern cited by the CPUC in these excerpts.

FBC notes that other utilities in BC also have evaluation staff (separate from program implementers) who undertake contracting for EM&V activities, and that BC Hydro has an in-house evaluation department within the utility. Further, the CPUC decision is relevant to that jurisdiction and therefore is not directly applicable to other jurisdictions, that are under different regulatory and legislative rules.

110.3.2 Does FBC consider that stakeholder comfort over the FBC estimate of the cost-effectiveness of its DSM programs would be significantly enhanced if annual reported results were subject to an audit by an independent expert who could then report the finding to the Commission and the DSM Advisory Committee? Please explain why or why not.

Response:

No. To date, the FBC stakeholders, which also include the Commission, have not expressed any concern about the FBC's analysis of the cost-effectiveness of the DSM programs or portfolio. The Company has provided all assumptions that affect program cost-effectiveness in the DSM Plan. These are transparent and all Intervenors are able to review them and pose Information Requests should they have a question about a particular assumption. FBC staff participated and provided input in the development of the draft EM&V Framework.

Two key objectives in the EM&V Framework are:

- to provide assurance to both internal and external stakeholders for the continued support of DSM programs, and

- to ensure the Companies and ratepayers are obtaining value from their DSM investments.

Stakeholders may, however, have concerns about how the added costs of an additional layer of evaluation review could impact customers. This additional review is not necessary as FBC acts in accordance with the evaluation principle of providing transparency with respect to EM&V activities.

110.3.3 Using FBC's best judgment, please provide an estimate (or estimate range) of the cost of an independent expert review of i) FBC EM&V framework and ii) FBC annual results. If unable to provide, please explain what steps would be required to provide this estimate and why FBC is unable to undertake this analysis.

Response:

FBC does not believe that such a review is warranted or a good use of ratepayer funds.

FBC does not believe anything has been shown to warrant additional scrutiny with respect to EM&V activities and FBC believe its EM&V practices are reasonable and in line with other BC utilities and, as such, are prudent. Additionally, the DSMAC is aware of the EM&V activities of the Company and has not requested such a review. The suggestion in this line of questions by the BCUC presupposes that there is a problem with the EM&V activities, a suggestion to which FBC strongly objects. Additionally, no other intervenors in this proceeding have posed Information Requests suggesting that a third party review of the Companies EM&V framework or practices is required.

However, to be responsive to the question, the following answers are provided.

1. FBC does not have sufficient understanding of the scope of work intended by the Commission with regard to a review of the EM&V Framework to provide any more than a very rough estimate of the costs for such review.

2. FBC estimates that an independent review of the draft EM&V Framework could cost between $30 thousand to $500 thousand, or higher, depending on the scope of work intended by the Commission, not including FBC's internal costs for managing such an activity.

3. As noted above, FBC is concerned about the impact that such additional costs would have on customers and the value that such a review could offer to customers. FBC

does not believe it necessary to have an independent expert review the EM&V Framework. As noted in the Framework, FBC developed the Framework with input from the internal and external stakeholders, utility partners and industry best practice, guidelines, and protocols.

4. FBC is unsure if part ii) of this IR is referring to all of the results contained in the FBC's DSM Semi-Annual Reports or just the EM&V annual results. For the same reasons cited in Part i) of this IR response, FBC does not have sufficient information to provide a reasonable cost estimate for this work. Again, FBC is concerned about the impact that such additional costs would have on customers and the value that it could bring to customers.

If the Commission is interested in pursuing such a review, the most reasonable approach is for Commission staff to develop a comprehensive scope of work that would address a review of all BC utilities' (BC Hydro, FBC, FortisBC Utilities, in addition to all small utilities in British Columbia, e.g. PNG) evaluation practices, send it to government, Intervenors and the utilities for a formal consultation, after which a Commission led review/regulatory process could occur. If after this review was conducted the Commission determined that third-party review of EM&V activities was required for all utilities, a RFP for such a review could be issued.

However, the Company restates that it does not believe that this type of review is either necessary, or warranted, and believes that it would not be a wise use of funds.

Please also refer to the response to BCUC IR 1.233.2.

110.4 Please confirm that independent review of DSM evaluation results occur in the following states: Massachusetts, New York, California, Wisconsin, Rhode Island, Connecticut and Illinois.

<u>Response:</u>

FBC cannot confirm that independent review of EEC Evaluation results occurs in the states cited.

The FEU asked E Source, a leading industry expert on energy efficiency practices, to investigate and confirm whether the above states conduct independent review of completed EM&V results. E Source was able to gather direct feedback and documentations from all of these states, with the exception of Rhode Island. Based on the E Source research and comments from some of the states they received (i.e. the states of California and

Massachusetts), they were able to confirm that a majority of states do not conduct an independent evaluation review or review of third-party evaluations. The E Source review indicates that the states in question appear to conduct more formal reviews of evaluation plans, survey instruments, and methodologies, and less formal reviews of the evaluation results, which is consistent with the Companies' Evaluation plan review process put forth with the BCUC.

111.0 Reference: Exhibit B-1-1, Section 2.4.1, p. 5

Adequacy Pursuant to the DSM Regulation – Low Income Programs

FBC states "[t]he Low Income Program is specifically designed to meet the needs of the Company's low income customers, in collaboration with the FEU and BC Hydro and Power Authority, that are of no cost or low cost to low income participants" (Exhibit B-1-1, Section 2.4.1, p. 5).

111.1 What is FBC's definition of low income customers? Is this definition the same across BC utilities? If not, why not?

Response:

FBC uses the DSM Regulation definition, and believes that other BC utilities also do so. This definition is as follows:

"low-income household" means a household whose residents receive service from the public utility and who have, in a taxation year, a before-tax annual household income equal to or less than the low-income cut off established by Statistics Canada for that year for households of that type;

111.2 In the FBC 2012–2013 RRA Application[28], FBC listed the First Nations Residential Households Program as a current or planned program. Why has this program been discontinued for the next DSM Plan? Is FBC planning to reintroduce this program or a similar one within the next five years?

Response:

The First Nation Residential Households Program, now renamed First Nations Efficiency Conservation Assistance Program (FN ECAP), is a pilot project that commenced in September 2013 and is expected to be completed in April 2014. If the program implementation meets success criteria, the program will be expanded to the whole of the FBC service territory. The First Nations will continue to be eligible to participate.

Presently, FBC PowerSense has a Technical Advisor whose responsibilities is to work closely with First Nations and to provide personalized service and help the bands and/or their residents to access PowerSense programs. This position will continue.

[28] FBC 2012-2013 RRA & ISP, Exhibit B-1-2, Volume 2, p. 25

111.3 Please explain why the new Energy Conservation Assistance Program (ECAP) program is not included in the DSM Monitoring and Evaluation Plan. In particular, given that the ECAP program is not included in the proposed schedule for process and impact evaluations in Table 9 (Appendix H-3), what are FBC's plan and timelines to evaluate this program?

Response:

At the time that the 2013-2015 DSM Monitoring and Evaluation Plan (Appendix H-3) was written, the ECAP program was jointly offered by FEU and BCH, and did not include FBC. ECAP has been under redesign and FBC's participation is not yet finalized.

The revised ECAP program will likely be evaluated in collaboration with the utility partners involved (BC Hydro and FEU). The date of the evaluation will depend on the program launch date within the shared service territory and the evaluation schedules of the utility partners.

112.0 Reference: Exhibit B-7, BCUC 1.257.3 and BCUC 1.265.0; Exhibit B-1-1, Appendix H-3, Table 7, p. 17

Adequacy Pursuant to the DSM Regulation — Rental Accommodation Programs

In response to BCUC 1.257.3, FBC states "[a] pilot project to introduce free walk-through energy assessments and direct installation of household EE measures for market-based multi-unit rental housing was started in August 2013. If successful this initiative will be expanded to other parts of the FBC service area" (Emphasis added).

In response to BCUC 1.265.1, FBC states "[p]resently, FBC is piloting a multi-family rental direct install (in-suite) and common area energy assessment pilot project, which is proving to be very successful. Based on that success, the intent is to continue the program into 2014 and beyond" (Emphasis added).

112.1 Please describe the criteria and performance measures used by FBC to measure "success" for this rental pilot program.

Response:

The criteria for success for the rental program, like other programs, is the number of customers involved, the amount of energy savings achieved in comparison to the overall administrative and measure cost of the program (cost-effectiveness tests).

The MURB rental pilot project was launched in August 2013. The three-month results showed a significant uptake in the service provided: direct installation of household EEC measures (low-flow shower heads, tap aerators and CFLs) and weather proofing of windows and doors were completed in 388 rental units (apartments). In addition, 15 buildings received free walk-through audits of common areas. A further 1406 units have been approved for direct installation measures over the next six months. With the first three month data now confirmed, PowerSense considers this program successful and will continue to support it.

112.2 Please indicate whether the two approaches suggested in Table 7: Residential Impact Evaluation are appropriate to evaluate FBC's rental pilot program and if so why. Otherwise, please describe the approach FBC plans to use to perform an impact evaluation of this program.

Response:

FBC believes that the two approaches suggested in Table 7: Residential Impact Evaluation are appropriate to evaluate FBC's rental pilot program, as these approaches were recommended by the qualified M&E consultants contracted to completed the M&E plan. The suggested approaches are tailored to the measures included in the rental pilot program and should ensure that the program effects are quantified.

113.0 Reference: Exhibit B-1-1, Section 2.4.3, p. 5

Adequacy Pursuant to the DSM Regulation — Education Programs

FBC states that "[t]here are also a number of initiatives specifically targeting post-secondary students, encouraging them to learn and apply their knowledge of energy conservation through interactive and fun competitions" (Exhibit B-1-1, Section 2.4.3, p. 5).

113.1 Please describe the initiatives specifically targeting post-secondary students.

Response:

PowerSense has worked closely with the Okanagan and Selkirk Colleges and UBCO. FBC has provided funding for curriculum development and purchased equipment for energy efficiency components of environmental study and alternative energy programs. More recently, it has provided funding to UBCO for an on-campus behaviour-based program, the Power of You, which features a number of educational opportunities and challenges (i.e. the October 16 lights out event, asking staff and students to turn off their lights for an hour during the day and the November: bundle up event, encouraging staff to wear warmer clothing instead of using heaters, or to consider which type of heater they are using in their office (ceramic vs radiant)). PowerSense is also sponsoring the Do It in the Dark student-led energy efficiency programming (described below).

It is expected that these programs will continue beyond 2014, as well as be augmented with new activities that the colleges/university and/or their groups initiate.

Post - Secondary

Do it in the Dark

Format: Online contest
Delivered to: Post-secondary students
Delivered in: All regions
Sponsored Since: 2011

Total cost: $6,500
EEC budget: $5,525 **PS budget:** $975
Cost sharing: 85/15
Budget for: Program implementation/delivery

Other details: Students at participating post-secondary institutions across BC compete to see what residences can reduce the amount of energy they use. A baseline is first taken, and then over the course of a few weeks, students are asked to reduce their energy use and take-part in sustainability related challenges, which also garner them points for their residence.

Objectives program helps us meet:

- Our long term goal to have consistent programs in post-secondary areas

2013/2014 Strategy: Investigate if this program runs in other post-secondary institutions, in particular UBC Okanagan, Okanagan College and South Okanagan College.

Timing:
Aug/Sept: Solicit post-secondary schools participation
Oct/Nov: Launch

114.0 Reference: Exhibit B-1-1, Section 5.3, pp. 10-11

Plan Flexibility and Adjustment

FBC proposes that:

> "it be permitted to launch new programs without pre-approval from the Commission as follows: The transfer of funds within an approved Program Area from an existing program to a new program not previously put forth in a Revenue Requirements Application would be permitted if this new program meets with the DSM Regulation, benefit/cost test requirements, and has not been previously rejected by the Commission" (Exhibit B-1-1, Section 5.3, pp. 10-11) (Emphasis in original).

FBC states in the Application that the existing program funding transfer rules cap at 25 percent funding transfers from one approved Program Area to another approved Program Area without prior Commission approval.

114.1 Would FBC agree to a similar cap of 25 percent to transfer of funds within approved Program Areas from an existing program to a new program? Why or why not?

Response:

No. As has been the case for many years with respect to the PowerSense program, the Company requires the flexibility to respond to market (customer) demand and energy efficiency opportunities that may present. The current constraints, including approved budgets, cost-effectiveness tests, annual reporting and the 25 percent limit on transfers between program areas are more than sufficient to ensure that the Commission is aware of changes in the DSM portfolio.

114.1.1 If FBC agrees with a cap but disagree with the percentage, please indicate what percentage cap would be appropriate and why.

Response:

Please refer to the response to BCUC IR 2.114.1.

115.0 Reference: Exhibit B-1-1, Section 6.1.1, p. 12

Portfolio-Level Analysis

FBC maintains that portfolio-level analysis remains the appropriate level of cost-effectiveness testing.

115.1 Please elaborate on the reasons why portfolio-level analysis remains the appropriate level of cost-effectiveness testing.

Response:

This type of analysis is permitted under section 4(1.1) of the DSM Regulation, and was last approved for use in the 2012 RRA & ISP decision (p. 136):

"Regarding the cost effectiveness of the DSM programs, the Commission has previously assessed FortisBC's DSM programming at a portfolio level and will continue to do so in this case."

Portfolio level analysis allows the Company the flexibility to include important measures with below unity TRC benefit/cost test results, and/or supporting initiatives (such as public awareness).

115.2 Please provide a table comparing FBC's approved DSM mix of programs for 2012-2013 to FBC's proposed DSM mix of program for the period 2014-2018.

Response:

The DSM program mix is largely unchanged from the approved 2012-13, as stated in the application Appendix H s. 5.2 and illustrated in Table H-5 (reproduced below). Certain measures or programs that have been scaled back or eliminated are discussed in BCUC IR 1.248.8.1.

Table H-5: Programs Classified as Previously Approved or New

Program Area	DSM Plan 2014 - 2018 Programs	Approved for 2012-2013
Residential	Home Improvement (Building Envelope) Program	X
	Heat Pump Program	X
	ENERGY STAR® Water Heater Program	X
	Water Savers (Low-Flow Fixtures)	X
	ENERGY STAR® Residential Lighting	X
	New Home Program	X
	Financing Pilot	X
Commercial	Commercial Lighting Program	X
	Building & Process Improvement Program	X
	Product Rebate Program	X
	Commercial Energy Assessment Program	X
Industrial	Industrial Efficiency Program	X
Low Income	Energy Savings Kit	X
	Energy Conservation Assistance Program	X
	Direct Install Lighting	X
Conservation Education & Outreach	Public Awareness Program	X
	School Education Program	X

115.2.1 In the event of significant differences in the DSM program mix between the 2012-2013 and 2014-2018 periods, please explain why portfolio-level analysis remains appropriate for cost-effectiveness testing.

Response:

Please refer to the response to BCUC IR 2.115.2.

The 2014-18 DSM Plan, with the exception of adequacy requirements, contains only programs that pass the TRC test at the measure, program, sector and portfolio level.

116.0 Reference: Exhibit B-1-1, Section 6.2.1, p. 15; Exhibit B-7, BCUC 1.245.2 and Attachment 1.245.2; Table BCUC 1.260.2

Net-to-Gross Ratio: Spill-over and Free Riders

On page 15, FBC states that "FBC has included 'spill-over' effects, where known, in the NTG which is a recognized approach that is used by other utilities including BC Hydro.13"

Footnote 13 states: "2012-2013 RRA Exhibit B-9, BCUC IR 1.210.2."

Attachment BCUC 1.245.2, which provides a copy of the reference in Footnote 13, states that BC Hydro also incorporates spillover effects in NTG calculations.75

Footnote 75 states: "Source: http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/rev_reg/directive_66_summary_report.Par.0001.File.2008_04_11%20DSMMES%20/rpt.pdf"

116.1 Please provide a copy of the BC Hydro summary report referenced in Footnote 75 in Attachment BCUC 1.245.2 as the web link provided appears to be malfunctioning.

Response:

Please refer to Attachment 116.1 for a copy of the BC Hydro summary report referenced which is also available at the following link:

http://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/rev_req/directive_66_summary_report.pdf

FBC states:

"[f]or program planning purposes, estimates of free riders are based on experience from earlier evaluations of the program, experience in other jurisdictions with comparable DSM programs, expert opinion, and/or feedback from industry stakeholders. Evaluations are used to assess the estimate program free riders" (Exhibit B-7, BCUC 1.245.1).

FBC also states "[f]or DSM program planning purposes, estimates of spillover are based on experience from earlier evaluations of the program, evaluations of similar or comparable programs from other jurisdictions, expert opinion, and/or feedback from industry" (Exhibit B-7, BCUC 1.245.3).

116.2 Please elaborate on the pros and cons of relying on each of the methods outlined above to estimate free-ridership or spillover effects: a) experience from earlier evaluations of the program, b) evaluations of similar or comparable programs from other jurisdictions, c) expert opinion and d) feedback from industry.

Response:

Key objectives of the DSM planning process include minimizing risk and maximizing the likelihood of successful outcome. Preparing a DSM plan involves managing a number of sources of information, some of which will be more credible or applicable than others. This may involve one or more of past evaluation findings, evaluations from outside the utility, expert opinion, and industry feedback.

Expert Opinion

Advice from experienced practitioners or industry experts is generally considered highly in the planning process as it represents experienced-based knowledge about best practices in program design and/or the market.

The value of advice provided by practitioners and industry experts may be discounted if their knowledge is based on markets or jurisdictions that differ significantly from that of FBC's.

Experience from Past Evaluations

Recommendations and information from independent program evaluations are integral inputs for program planning. As most evaluations are ex-post in nature, changes in program design (e.g., eligibility criteria, qualifying technologies, incentive levels, etc.) and/or changes in market conditions may reduce the relevance of their estimates of free riders and spillover. Advice from industry experts may be used to adjust the estimates to better reflect program design changes or developments in the market place.

Net-to-gross estimates for DSM programs operating in other jurisdictions may also be considered during the planning process if program design, market conditions, and customer characteristics are similar to FBC's.

Industry Stakeholder Feedback

Feedback from industry stakeholders is considered an important source of information and opinion on current state of the market, market trends, market opportunities and market barriers. On the downside, not all industry stakeholders, particularly those with a vested interest in the outcome of the DSM planning process, will provide unbiased advice. Information provided by industry stakeholders is generally considered in concert with other information available to FBC planners.

In response to BCUC 1.262.2, FBC provided the following table:

2012 (Actual) Program	Free-rider %	Spillover %	Non-energy benefits (% of total MTRC benefits) *	Lifespan of asset	Persistence of savings assumed
Residential Programs					
Home Improvement	0	0	1%	20	
Low Income	0	0	23%**	5	
Residential Lighting	9	0	-	5	
Heat Pumps	43	0	13%	17	
New Home Program	0	0	-	30	
Residential Total	**N/A**	**N/A**	**5%**	**N/A**	**100%**
Commercial Programs					
Lighting	28	0	-	12	
Building and Process Improvement	23	4	-	20	
Water Handling Infrastructure	0	0	-	15	
Commercial Total	**N/A**	**N/A**	**-**	**N/A**	**100%**
Industrial Programs					
Industrial Efficiency	12	0	-	10	
Integrated EMIS	12	0	-	10	
Industrial Total	**N/A**	**N/A**	**-**	**N/A**	**100%**

116.3 For each of the programs with a positive free-rider or spillover rate, please explain how FBC determined the free-rider or spillover rate. How much did FBC rely on experience from earlier evaluations of the program, experience in other jurisdictions, expert opinion and feedback from industry stakeholders? Please explain why.

Response:

For each program with positive free-rider or spillover rates, FBC uses rates that are determined in evaluation reports, which are completed by qualified M&E consultants who, as specialists in their field, ensure the free-ridership and spill-over rates are determined through best practices. Generally free-rider and spillover rates are determined using the Self-Reporting and/or Enhanced Self-Reporting Methods as described in BCUC IR 2.116.4. They may use experience from earlier evaluations of the program, experience in other jurisdictions, expert opinion and feedback from industry stakeholders to provide background information and/or to compare with their calculated results.

In response to BCUC 1.245.5, FBC states "FBC agrees that all claims to spill-over be supported and justified through empirical evidence collected and analyzed using industry accepted methods and procedures (best practices)."

116.4 Please describe the industry's best practices to estimate spillover effects and provide supporting documentation.

Response:

Assessing the presence and amount of spillover from program participants typically requires determining (i) which actions are eligible for consideration as spill-over, (ii) the energy or demand savings represented by these actions and (iii) the degree to which these savings are attributable the influence of the utility and its ECM program. Spillover from non-participants requires the same steps, but requires determining who is eligible as a non-participant. While some of the evaluation techniques used to assess spillover, notably that of attribution, are similar to those used to estimate free ridership, the volume of literature dedicated to spillover evaluation methods is less than that devoted to free ridership.

Methodologies to assess spillover considered best practice include:

- Self-Reporting and Enhanced Self-Reporting Methods – a series of survey questions posed to representative samples of program participants. Participants are asked about equipment purchases, behaviour changes, or process improvements taken outside of the program that did not receive an incentive from the program. They are then asked to qualify the level of influence their participation in the program had on making these decisions. Information provided by program participants is sometimes contrasted with feedback provided by program trade allies (contractors, suppliers, etc.);Market Assessments – sales or shipments data pertaining to program qualifying technologies are compared to similar data for jurisdictions outside of the utility service area that are uninfluenced by the program. Similar to the use of a treatment and control groups in experimental design, differences in sales of the qualifying technology between the two regions, normalized for non-program related differences (effects), is used to derive an estimate of net program effect, which by definition, includes spillover among participants and non-participants; andEconometric Methods – A variety of econometric methods using samples of participants and nonparticipants, including discrete choice analysis, assess spillover in an indirect fashion, through the estimation of the program's overall net to gross ratio. Implicitly, this ratio includes the degree of both free ridership and spillover.

Please refer to the response to BCUC IR 1.245.8 in regards to supporting documentation.

In response to BCUC 1.245.5.1, FBC states "[t]he 2009 Commercial Lighting M&E report found a 9% spillover rate for custom lighting, however that report has been superseded by the 2012 Commercial Lighting M&E report which did not determine a spillover rate."

116.5 Given that within three years, the spillover rate estimate for the custom lighting went from 9 percent to zero percent, please explain why experience from earlier evaluations of a program could be useful to estimate current spillover effect.

Response:

The spillover rate for the custom lighting program did not necessarily go from 9 percent to zero percent within three years. The 2012 Commercial Lighting M&E report did not determine a spillover rate, so it is an unknown value. For the purpose of the 2012 reporting, spillover rate was not included in the NTG ratios used to determine reported savings for Commercial Lighting. Please refer to the response to BCUC IR 2.116.3.

In response to BCUC 1.245.5.1, FBC also states that "the 2011 BIP (Retrofit) M&E report found a 12% spillover rate for custom projects" and provides a table (Exhibit 1: Spillover Calculation) showing the spillover calculation. However, the table shows a spillover score of 24 percent.

116.6 Please explain how Exhibit 1 supports the 12 percent estimate of spillover for the 2011 BIP custom projects.

Response:

The following excerpt from the 2011 BIP (Retrofit) M&E report explains how the 12 percent estimate of spillover is supported by the table (Exhibit 1: Spillover Calculation):

> ### 6.2.3 Spillover Results – Additional Discussion
>
> Some evaluations incorporate spillover by using its incidence (in this case, 24%) to offset the incidence of free riders when calculating the net-to-gross (NTG) ratio (i.e., NTG = 1 – free rider % + spillover %). However, applying the spillover incidence in this fashion can be misleading as it suggests that spillover investments are comparable in savings and the persistence of savings to those incented by the program.
>
> While it was not possible to develop a reliable estimate of energy savings attributable to the program in the form of program spillover, the results of the survey corroborate comments provided to evaluators during the site visits. That is, advice and recommendations from FortisBC technical advisors led some participants in the Retro BIP program to undertake energy efficient investments that did not receive an incentive from FortisBC. Excluding spillover from the calculation of net-to-gross for the program would understate program energy savings, while including the spillover rate as calculated from the survey could overstate savings. As a compromise, the calculated spillover rate for the program was discounted by 50%, and the discounted rate applied to the net-to-gross calculation.

116.7 Please explain the sharp decline in the BIP program's estimated spillover rate from 12 per cent in 2011 to 4 percent in 2012 (per Table BCUC 1.262.2 shown above).

Response:

FBC assumes that BCUC refers to Table BCUC 1.260.2 in this question.

These two figures do not represent a "sharp decline" in estimated spillover rate from 2011 to 2012 for the BIP retrofit program.

Table BCUC 1.260.2 refers to 4 percent (not 24 percent as shown in the reference) spillover for the Building and Process Improvement program. This 4 percent spillover blends both the new and retrofit components of the BIP program, whereas the 12 percent spillover rate applies only to the retrofit portion of the program. A spillover rate was not determined in the New BIP evaluation report.

117.0 Reference: Exhibit B-1-1, Section 6.2.1, Footnote 12, p. 15; Exhibit B-7, BCUC 1.245.4

Method to Estimate Spillover Effects

FBC explains that "Spillover effects involve non-participants who acquired an energy conservation measure (ECM), and who did not receive an incentive, but were influenced by the operation of the utility's DSM program" (Appendix H, section 6.2.1, Footnote 12, p. 15) (Emphasis added).

FBC states that:

> "FBC program evaluations that have addressed spill-over have typically used an enhanced self reporting methodology using representative samples of participants to assess both the qualifying nature of any potential spillover and whether some or all of the spillover is attributable to the program. Depending upon the program, participants are asked about energy efficient equipment purchases or upgrades, changes in behaviours, etc. undertaken outside of program (i.e., without an incentive from FBC). They are then asked to qualify the level of influence their participation in FBC's program had on making these decisions. Information provided by program participants is contrasted with feedback provided by program delivery personnel and, where and when feasible, program trade allies (equipment suppliers, contractors, etc.)" (Exhibit B-7, BCUC 1.245.4) (emphasis added).

117.1 Please clarify how FBC is able to assess a program's spillover effects (which involves non-participants to the program) when interviewing the program's participants?

Response:

To clarify, FBC differentiates participant spillover from non-participant spillover. Participant spillover represents non-incented actions taken by program participants that can be attributed in whole or in part to their participation in the FBC program. Participant spillover is most typically assessed through surveys and interviews with participants and is sometimes supplemented with feedback from industry stakeholders and program trade allies.

Non-participant spillover occurs when comparable measures are adopted by non-participants and can be attributed, in whole or in part, to the indirect influence of the DSM program on the market or their decisions. Evaluation of non-participant spillover requires surveys or interviews with non-participants.

To date, FBC has not made claims to non-participant spillover from any of its DSM programs.

117.2 Using the example of the Building and Process Improvement program, which has an estimate spillover rate of 4 percent; please explain how FBC could derive this spillover rate by interviewing customers who have participated in the program.

<u>Response:</u>

Please refer to the response to BCUC IR 2.117.1. The spillover rate estimated for the Building and Process Improvement program relates to participant spillover only, which can be assessed by interviewing customers who have participated in the program.

117.2.1 Alternatively, please clarify the method by which FBC is able to identify the non-participant to a program who acquired an ECM but did not receive the incentive.

<u>Response:</u>

Please refer to the responses to BCUC IR 2.117.1 and BCUC IR 2.117.2.

Generally speaking, non-participants can be found by drawing a random sample of program eligible customers from the FBC customer billing system.

118.0 Reference: Exhibit B-7, BCUC 1.245.4.1

Spillover Estimates by Program for 2014-2018

FBC states "[f]or planning purposes the DSM Plan uses "net" unit measure savings, provided in the 2013 CPR Update, as these reflect the NTGR adjustments (inclusive of any spill-over and free-rider effects) in the measure lists of the referenced utilities" (Exhibit B-7, BCUC 1.245.4.1).

118.1 Please confirm that FBC has already included spillover effects into its Net-to-Gross Ratio, prior to the Commission approving the inclusion of spillover.

Response:

Confirmed. FBC is using best practices by incorporating spillover.

A 2012 ACEEE report titled "A National Survey of State Policies and Practices of the Evaluation of Ratepayer-Funded Energy Efficiency Programs" states on page 38: "... we recommend that if a state wants to estimate and report "net savings," their methodology should incorporate both free riders and free drivers/spillover."

118.2 Please remove spillover effects from the NTG ratio and highlight any differences for each of the year in the DSM 2014-2018 Plan.

Response:

FBC is unable to perform the analysis requested. The "net" unit savings are obtained from measure lists of the referenced utilities and said lists do not break out the constituent components, i.e. realization rates, free-rider or spillover ratios.

119.0 Reference: Exhibit B-1-1, Section 6.2.2, p. 15; Exhibit B-7, BCUC 1.63.0

Attribution of Savings from the Introduction of Regulation

FBC states that:

> "[p]ursuant to this element of the DSM Regulation, the Company intends to attribute the benefit of savings from the introduction of codes and standards on a program-by-program basis where such an attribution can be supported. FBC is seeking the Commission's endorsement of the concept for reporting purposes. It is the intent of FBC to incorporate savings from the introduction of codes and standards on a case-by-case basis and to report on and highlight this practice in the DSM Annual Report" (Exhibit B-1-1, Section 6.2.2, p. 15).

Muncaster *et al*. (2012)[29] states on page 8-215:

> "In the new BC regulation savings can be claimed for programs that are run after a standard is announced or enacted, but before it comes into effect. The BCUC is tasked with approving the attribution rate. Attribution of savings from codes and standards is considered a part of the TRC rather than modified TRC (MTRC), since it is concerned with energy benefits rather than non-energy or societal benefits" (Emphasis added).

In response to BCUC 1.263.2, FBC states that "[e]ndorsement of the concept by the Commission simply means agreeing that Codes & Standards attribution represents valid savings."

In response to BCUC 1.263.1, FBC states that "it does not contemplate claiming any savings from the introduction of codes and standards over the PBR period, this it has not developed any methodologies for calculating and attributing energy savings."

119.1 Please explain why FBC is seeking Commission endorsement of the concept at this time given that a) the concept of attribution of savings from the introduction of regulation is introduced in the new BC regulation, and b) FBC does not contemplate claiming any savings from the introduction of codes and standards for the duration of the PBR.

Response:

FBC believed it was prudent to obtain endorsement at this time in case it becomes important to attribute savings from the introduction of regulation during the PBR period.

---

[29] Muncaster, K., A. Pape-Salmon, S. Smith, M. Warren. *Adventures in Tweaking the TRC: Experiences from British Columbia*, 2012 ACEEE Summer Study on Energy Efficiency in Buildings

119.2 In the eventuality that FBC decided to claim savings from the introduction of codes and standards during the PBR term, please outline the steps and related timelines that FBC would take to develop the attribution rule(s) and have them reviewed and approved by the Commission.

Response:

If an opportunity arose to claim codes and standards savings, FBC would propose attribution rules and put them before the DSMAC (and/or EECAG) in the first instance, and then to the Commission and other stakeholders through the Annual Review process provided under the PBR regime.

119.3 Please confirm that codes and standards could have a very high TRC/UCT result? If not, please explain why not.

Response:

Codes and standards attribution could improve the TRC/UCT ratios, but FBC is not sure whether the increase could be characterized as “very high”.

119.3.1 If so, does FBC agree that attribution of savings from codes and standards should not be included in the overall portfolio results as it could be distortionary? If not, please explain why not.

Response:

No, FBC does not believe that the benefits of any DSM activity should be excluded from the portfolio level cost effectiveness analysis simply because it could result in a higher TRC/UCT result.

120.0 Reference: Exhibit B-1-1, Section 8.2, p. 19

Request for Change in DSM Reporting Period

FBC states that:

> "[it] currently files semi-annual reports on its DSM activities, a reporting schedule which is inconsistent with the reporting requirements for other BC utilities, including the FEU and BC Hydro, and which is administratively burdensome. FBC therefore proposes to submit DSM reports on an annual, year-end, basis, consistent with the FEU and BC Hydro" (Exhibit B-1-1, Section 8.2, p. 19).

120.1 Please confirm that FBC's proposed annual DSM report would contain the same information as in the semi-annual report, however on an annual basis. If not, please highlight any other differences that FBC proposes to make in its DSM report.

<u>Response:</u>

Confirmed.

121.0 Reference: Exhibit B-1-1, Section 7.2, p. 16; Exhibit B-7, BCUC 1.233.2

EM&V Framework

On page 16, FBC states:

> "[t]he FEU, in conjunction with FBC, developed an EM&V Framework in 2012 to formalize the background, objectives, principles and general practices that guide the Companies' approach, resources and timeframes for EM&V activities. The framework addresses the following Commission directive (to FEU Companies) in their 2012-2013 RRA Decision.
>
> > *'The Commission Panel sees benefit in the establishment of an EM&V Framework. The Commission Panel directs the FEU to develop an evaluation plan and to determine an appropriate measurement and verification protocol to be used by the FEU and third party contractors in the EM&V Framework. The Commission Panel further directs the FEU to present the EM&V Framework to the EEC Stakeholder Group and solicit member feedback prior to implementing the Framework.'" (Exhibit B-1-1, Section 7.2, p. 16)*
>
> "The EM&V framework was developed by reviewing industry guidelines and common practices for EM&V activities. One of the FBC"s evaluation principles contained in the Framework is that of providing transparency both internal and external to the FBC with respect to EM&V activities, e.g. the 3rd 21 party consultant's M&E reports are filed with the BCUC on request by the Commission and/or interveners." (Exhibit B-7, BCUC 1.233.2)

121.1 Please provide detailed information on the industry guidelines and common practices for EM&V activities that were reviewed by FBC in order to develop its own EM&V framework. Please also provide the supporting documentation.

Response:

As noted in the draft EM&V Framework, the following industry guidelines and common practices were reviewed in the development of the Framework:

- The California Evaluation Framework. June 2004 http://www.calmac.org/publications/California_Evaluation_Framework_June_2004.pdf
- International Performance Measurement and Verification Protocol (IPMVP). Concepts and Options for Determining Energy and Water Savings. Prepared by the Efficiency Valuation Organization. www.evo-world.org. January 2012.

- California Standard Practices Manual (SPM): Economic Analysis of Demand-Side Programs and Projects. http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/Cost-effectiveness.htm

121.2 Please provide a copy of the EM&V protocols used by BC Hydro, as well as in California and Vermont.

Response:

A copy of the BC Hydro "DSM Evaluation, Measurement and Verification" document was submitted to the BCUC as part of the BC Hydro F2012 to F2014 Revenue Requirements Application filing. California uses the "California Evaluation Framework" and Vermont refers to a Technical Solutions Manual, "Efficiency Vermont Technical Reference User Manual".

Due to the size of the documents, the web links to these documents are as follows:

- BC Hydro "Amended F2012 to F2014 Revenue Requirements Application: Amended New Appendix II, F12/F13 DSM Expenditures. Attachment 7: DSM Evaluation, Measurement and Verification". http://www.bchydro.com/about/planning_regulatory/regulatory_documents/revenue_requirements/revenue_requirements_2012_14/regulatory_documents.html
- The California Evaluation Framework. June 2004 http://www.calmac.org/publications/California_Evaluation_Framework_June_2004.pdf
- Vermont Energy Investment Corporation (VEIC) *Technical Reference Manual (TRM)* http://www.veic.org/documents/default-source/resources/reports/trm-user-manual-excerpts.pdf

122.0 Reference: Exhibit B-1-1, Appendix H2, Table 4, p. 6 and Table 9, p. 9

Residential Energy Savings and Costs

Commission staff compiled the following table from Tables 4 and 9 in Appendix H2:

RESIDENTIAL	% of Plan Savings Achieved	% of Plan Costs Achieved
Home Improvement Program	71%	49%
Low Income	59%	45%
Residential Lighting	103%	103%
Heat Pumps	64%	90%
New Home Program	1155%	731%
TOTAL	**79%**	**69%**

122.1 Please calculate the Total Resource Cost (TRC) test, the Participant Cost Test (PCT) and the Utility Cost Test (UCT) for each of the residential sector areas shown in Table above.

Response:

RESIDENTIAL	Total Resource Cost (TRC) test*	Participant Cost Test (PCT)	Utility Cost Test (UCT)*
Home Improvement Program	1.7	3.7	4.5
Low Income	1.0	15.8	1.1
Residential Lighting	1.8	7.6	2.7
Heat Pumps	1.0	2.5	2.6
New Home Program	1.4	3.4	3.3
TOTAL	**1.5**	**3.6**	**3.3**

* from Table 14, Appendix H-2

Note: The figures from Table 4 and 9 in Appendix H-2 contain program costs, excluding Planning and Evaluation costs. The TRC and UCT benefit costs tests in Table 14 of Appendix H-2 include Planning and Evaluation costs.

122.2 For the Heat Pumps program, please explain why FBC spent 90 percent of the planned costs but only achieved 64 percent of the planned savings. Please elaborate on the assumptions that varied from plan.

Response:

For the Heat Pump program, FBC spent 90 percent of the planned costs but only achieved 64 percent of the planned savings because of the NTG ratio including a free rider rate of 43 percent (please refer to the response to BCUC IR 1.260.2) that reduced the reportable savings.

122.3 Please discuss any lessons learned from the implementation of DSM programs in these residential sectors.

Response:

PROGRAM	LESSONS LEARNED
Home Improvement Program	• Collaboration with BC Hydro, FEU and the LiveSmart program is effective to build program continuity and to share research and program design resources • The LiveSmart BC program has many barriers for customer participation, which has impacted overall program participation • Stand-alone program options continue to be popular as there are fewer barriers to participation • Stream-lining application forms and processes and bundling program offers are effective
Low Income	• Program design and implementation are more complex and have greater health and safety risks than other programs • Generally, identification of eligible customers and marketing to those customers are more difficult (lower trust and levels of understanding). Working directly with and marketing through organizations that provide service to this market segment is more effective. • Partnering with provincial government agencies is effective, both from resource sharing and communication perspectives. • Direct installation of measures is the most cost-effective approach. • Program cost-effectiveness is more difficult to meet. • Programs design and implementation require greater levels of human resources.

PROGRAM	LESSONS LEARNED
Residential Lighting	• Although it is initially difficult to attain good working relationships with lighting and building supply retailers, particularly in small markets like FBC serves, once trust and communication processes are established, working with retailers is effective in reaching more customers at decision-making points (when making purchases). Marketing efforts are more cost-effective. • Lighting technology is changing rapidly. It is important to continually monitor cost effectiveness of specific measures and evaluate levels of market transformation, and to change program offers accordingly.
Heat Pumps	• Heat pumps continue to be a viable, cost-effective option for heating and cooling residents' homes in the FBC service area. Rebates and program promotion reinforce this. • Heat pump technology is changing rapidly, making heat pumps an even more viable heating system for customers living in colder geographic regions and with electricity heating. • Bundling heat pumps rebates into other program offers (i.e. Home Improvement, LiveSmart, New Home) enhances marketing and uptake efforts. • The heat pump maintenance program is popular and cost effective for both customers and the PowerSense program.
New Home Program	• Strong, long-term relationships with new home builders and effective target marketing ensures that this program continues to be well received. • Bundling individual rebate offers into one program package is more cost-effective. It also makes the application process easier for customers. • The construction and housing market is much stronger in the Okanagan than in most other areas of the province. • Promotion of "whole home" and home energy efficiency EnerGuide ratings are effective.

123.0 Reference: Exhibit B-1-1, Appendix H2, Table 5, p. 7 and Table 10, p. 10

Residential Energy Savings and Costs

Commission staff compiled the following table from Tables 5 and 10 in Appendix H2.

COMMERCIAL	% of Plan Savings Achieved	% of Plan Costs Achieved
Lighting	193%	186%
Building and Process Improvement	57%	93%
Water Handling and Infrastructure	65%	67%
TOTAL	**134%**	**137%**

123.1 Please calculate the TRC, PCT and UCT for each of the commercial sector areas shown in Table above.

Response:

COMMERCIAL	Total Resource Cost (TRC) test*	Participant Cost Test (PCT)	Utility Cost Test (UCT)*
Lighting	2.2	10.8	3.1
Building and Process Improvement	1.3	3.5	2.6
Water Handling and Infrastructure	2.6	6.3	4.9
TOTAL	**2.0**	**7.9**	**3.2**

** from Table 14, Appendix H-2*

Note: The figures from Table 5 and 10 in Appendix H-2 contain program costs, excluding Planning and Evaluation costs. The TRC and UCT benefit costs tests in Table 14 of Appendix H-2 include Planning and Evaluation costs.

123.2 For the Building and Process Improvement program, please explain why FBC spent 93 percent of the planned costs but only achieved 57 percent of the planned savings. Please elaborate on the assumptions that varied from plan.

Response:

For the Building and Process Improvement program, FBC spent 93 percent of the planned costs but only achieved 57 percent of the planned savings because of the NTG ratio including a free rider rate of 23 percent (please refer to the response to BCUC IR 1.260.2) which reduced the achieved savings.

123.3 Please discuss any lessons learned from the implementation of DSM programs in these commercial sectors.

Response:

PROGRAM	LESSONS LEARNED
Lighting	• Moving from a point of purchase rebate program offer to an on-line application process was/is very difficult. Customers find new on-line application process more complex and time-consuming. • Rebates significantly influence purchases of EE lighting. Sales of EE lighting fell sharply in all regions and at all service area lighting wholesalers' businesses when the new more-complex application process was implemented. (A simpler application process, which still addresses possible free ridership, is now being introduced.) • Lighting technology is changing rapidly. It is important to continually monitor cost effectiveness of specific measures and evaluate levels of market transformation, and to change program offers accordingly.
Building and Process Improvement	• Technology and building codes are continually changing, sometimes in dramatic ways. It is critical to adapt baselines and program offers to meet the changes in a timely and cost-effective manner. • While most large commercial and industrial customers recognize a need to upgrade for energy efficiency, many do not invest in the personnel/skill set to implement appropriate system and/or process upgrade. • Most commercial and industrial retro-fit upgrades are long-term projects which require continuing attention and customer service. • Expert, personalized and customized customer service is critical to meet the larger commercial and industrial customers' needs.
Water handling and infrastructure	• Municipal and governmental agencies responsible for these services are keenly aware of need to and/or are mandated to maximize energy efficiencies in all system up-grades. This potentially impacts free-ridership measurement. • Agricultural irrigation customers are a disparate group and difficult to reach with prescriptive or non-customized offers.

124.0 Reference: Exhibit B-1-1, Appendix H2, Table 6, p. 8 and Table 11 p. 10

Residential Energy Savings and Costs

Commission Staff compiled the following table from Tables 6 and 11 in Appendix H2.

INDUSTRIAL	% of Plan Savings Achieved	% of Plan Costs Achieved
Industrial Efficiency	41%	51%
Integrated EMIS	0%	36%
TOTAL	**38%**	**49%**

On page 10, FBC states that "Energy Management Information System (EMIS) software is a long-term program with up-front costs and savings that will be realized later in the process. In 2012 the Company committed to co-funding the EMIS software at an Okanagan lumber mill."

124.1 Please calculate the TRC, PCT and UCT for each of the industrial sector areas shown in Table above.

Response:

INDUSTRIAL	Total Resource Cost (TRC) test*	Participant Cost Test (PCT)	Utility Cost Test (UCT)*
Industrial Efficiency	2.0	6.4	2.9
Integrated EMIS	0.0	-	0.0
TOTAL	**1.9**	**6.4**	**2.8**

** from Table 14, Appendix H-2*

Note: The figures from Table 6 and 11 in Appendix H-2 contain program costs, excluding Planning and Evaluation costs. The TRC and UCT benefit costs tests in Table 14 of Appendix H-2 include Planning and Evaluation costs.

124.2 Please confirm that the entire 36 percent of planned costs spent on the Integrated EMIS software was related to the Okanagan lumber mill. If not, please elaborate.

Response:

No. The entire 36 percent of planned costs spent on the Integrated EMIS program was not related to the Okanagan lumber mill. The majority of the costs were labour costs incurred as the PowerSense staff promoted the EMIS program with industrial customers throughout the FBC territory, including the Okanagan lumber mill.

124.2.1 If so, please indicate when FBC anticipates achieving the savings related to the EMIS software at the Okanagan lumber mill.

Response:

FBC anticipates the installation and commissioning of the EMIS software, combined with a recent comprehensive plant energy assessment, will begin to yield energy savings for the customer in 2014.

124.3 Please discuss any lessons learned from the implementation of DSM programs in these industrial sectors.

Response:

The following outlines some of the key lessons learned for each program.

PROGRAM	LESSONS LEARNED
Industrial Efficiency	• Supporting facilities' managers with training is appreciated by customers and results in greater EE savings in long-term • Results can be "lumpy" because of long time-line for some project completions • Needs to be customized; every industry unique • Lots of interest in power factor correction, but little/no energy savings ensue
Integrated EMIS	• The equipment was installed over summer 2013, making it too early to understand all impacts of program • Customer is keen on program as it will make EE savings verifiable and can test real-time energy productivity per unit

Attachment 33.1

FortisBC Asset Management

Project Update and Next Steps Planning

Draft – For Discussion Purposes Only

June, 2013

SECOR KPMG

Vision & Principles

Director-Level Workshop and Interviews

Director Interviews Identified 4 AM Principles

1 Asset Management should improve our decision-making ability

- Condition-based assessment
- Managing outputs not assets

2 Asset Management should support consistent and defendable actions

- Combines process and expertise
- Single source of truth and means to prioritize

3 Asset management should enable accountability and "ownership" over assets

- Clarity to each person's role
- Ability to control key outcomes of assets
- Improved information

4 The function of Asset Management should be integrated across departments

- Partnership model
- Clear roles in the process
- Clear guidelines and goals

Draft – For Discussion Purposes Only

1 Principle 1: Optimized Decisions

Principle

- Optimized decisions that effectively balance risk, cost and performance tradeoff

Key Changes Envisioned to Achieve Principle

- Decisions are supported by better data increasing the ability of FBC to explain the impact of decisions on rates, reliability and safety
- Improved ability to make the best decisions available using systems and tools
- Ability to continually improve decision-making as information continues to build about FortisBC's assets
- Improved ability to prove decisions using data

Key Support Tool(s) Needed to Achieve Change

- Data, documented FBC leading practices and expertise are used to make optimized decisions which effectively balance cost, risk and performance
- Information management system, guidelines, risk approach, project prioritization approach, integrated planning process

Draft – For Discussion Purposes Only

2 Principle 2: Consistent Decision-Making Process

Principle

- Consistent and defendable decisions using a transparent process

Key Changes Envisioned to Achieve Principle

- Internal and external stakeholders can easily understand AM decisions since they are made in a consistent and transparent manner
- Decision makers and internal stakeholders from different disciplines and regions can have confidence that they are acting in the best interest of FortisBC, not only from experience but from tools and guidelines
- FBC can easily generate confidence with the BCUC and other external stakeholders that its asset management decisions are in the interests of customers

Key Support Tool(s) Needed to Achieve Change

- Common decision-making tools are used across departments and regions to support consistency and align decisions to best practice
  - E.g. Asset guidelines, single project ranking tool, common risk tool, integrated planning process

Draft – For Discussion Purposes Only

3 Principle 3: Accountability

Principle

- High accountability and ownership over assets

Key Changes Envisioned to Achieve Principle

- All employees feel a sense of ownership over assets since there is ability in each department to impact decision-making
- There is an effective feedback loop from the field to Planning by annual planning process, through regional engineers and via systems
- Consistent processes, guidelines and distributed tools allow regional experts to understand priorities
- All employees in network services, engineering and generation (Engineering and Operations), understand their role for managing assets and are accountable for it

Key Support Tool(s) Needed to Achieve Change

- <u>Organizational structure</u> increases accountability since each department knows their role in the process
- Integrated planning process

SECOR

Draft – For Discussion Purposes Only

KPMG

4 Principle 4: Integrated Partnership Model

Principle

- Integrated partnership model

Key Changes Envisioned to Achieve Principle

- AM / Planning works closely with other departments to develop plans balancing system needs, local concerns, and implementation considerations
- More information flows between Planning and other areas:
  - A set planning process provides departments with the opportunity to provide insight on plans;
  - regional engineers provide a conduit for information to flow between Planning and the field
- More programs are approved by Planning and executed by PMO / Operations
- Greater transparency & visibility of plans (ST & LT) to allow PMO/Ops to prepare for work execution

Key Support Tool(s) Needed to Achieve Change

- Integrated planning process
- Organizational structure changes

SECOR

Draft – For Discussion Purposes Only

KPMG

The AM Vision Statement was Revised to Incorporate Principles

Making sound and prudent decisions in the interest of our customers is at the heart of everything we do at FortisBC.

Through a transparent, robust, and integrated Asset Management practice, combined with our culture of accountability, we ensure that our team is equipped to consistently make defendable decisions which are optimized and in the best interest of our customers.

Under this model FortisBC can effectively and efficiently maintain our commitments to the public on safety, reliability, and managing lifecycle costs.

Draft – For Discussion Purposes Only

Resulting Vision and AM Roadmap

Asset Management Vision Statement

Making sound and prudent decisions in the interest of our customers is at the heart of everything we do at FortisBC.

Through a transparent, robust, and integrated Asset Management practice, combined with our culture of accountability, we ensure that our team is equipped to consistently make defendable decisions which are optimized and in the best interest of our customers.

Under this model FortisBC can effectively and efficiently maintain our commitments to the public on safety, reliability, and managing lifecycle costs.

Principles

- Optimized Decisions
- Consistent Defendable Decisions
- Accountability
- Integrated Partnership Model

Supporting Tools / Processes

- Integrated Planning Process
- Integrated AM IT System
- Organizational Structure
- Single Project Ranking Tool
- Common Risk Framework
- AM Guidelines by Class

Draft – For Discussion Purposes Only

AM/Planning Alignment

Manager-Level Workshop and Interviews

Managers were Aligned on Value of AM Strategy

The session began with some introductory questions:

- Why is it important to set an Asset Management Strategy?
- What elements do you want to make sure we get right?
- What do you want to get out of today?

The AM and Planning teams were interested and aligned on the need for an Asset Management Strategy

An Asset Management Strategy was seen as valuable because:

- Helps set best practice for FortisBC as it relates to our assets
- Allows better defense of decisions to BCUC
- Helps with a consistent approach across regions
- Would provide a better understanding of the Corporate view on risk and priorities

Draft – For Discussion Purposes Only

Key Issues were Confirmed; Risk and LT Planning were Top Issues for Team

FORTIS BC™

Key Issues as Identified by Current Assessment:

Strategy

- Are corporate priorities clear?
- How can relationships with the regulator be improved?

Decision-Making

- How can we improve long-term plans and have them feed short-term plans?
- How can Fortis more consistently prioritize projects?
- Is there an opportunity to use more quantitative analysis in decision-making**?**

Life-Cycle

- How can Fortis better align investment plan to resource plan?

Organization

- How can Fortis better distribute AM expertise?
- How can Fortis planning better distribute decision-making?

Knowledge Enablers

- Would it be valuable to integrate IT systems? Within divisions? Across?
- How can we get better data on assets?

Risk

- How can we more consistently measure risk?
- How can we more consistently make decisions based on risk?

Participant Comments:

- In cross-functional and cross-department teams of two each of these issues were discussed.
- There was alignment across the group that these were key issues
- Most popular concerns:
- Measuring risk / prioritizing projects
  - Participants felt that these were critical tools to help them
- Improving long-term planning
  - Participants felt that improved long-term planning would help resourcing and current 5-year application

SECOR

Draft – For Discussion Purposes Only

KPMG

AM Team Agreed with Vision and Principles; More Effort Required to Reinforce Change

Asset Management Vision Statement

Making sound and prudent decisions in the interest of our customers is at the heart of everything we do at FortisBC.

Through a transparent, robust, and integrated Asset Management practice, combined with our culture of accountability, we ensure that our team is equipped to consistently make defendable decisions which are optimized and in the best interest of our customers.

Under this model FortisBC can effectively and efficiently maintain our commitments to the public on safety, reliability, and managing lifecycle costs.

Principles

Optimized Decisions	Consistent Defendable Decisions	Accountability	Integrated Partnership Model

- Optimized Decisions and Consistent Decisions were easily accepted as core principles
- Accountability was seen as important; however some comments were around ensuring others were held accountable (e.g. operations being accountable for collecting good data)
- Integrated Partnership Model was accepted but some seemed to think it was only there to appease others → some did not make the connection between integration and execution success
- In general, the participants liked having a clear vision with principles for communication purposes

Draft – For Discussion Purposes Only

AM Team Voted on Projects; All Projects were Affirmed; Tools & Org Structure were Prioritized

FORTIS BC

The voting exercise help solidify the need for projects while identifying excitement and volunteers; votes indicate alignment with principles and general excitement

Opportunity	Excitement / Interest	Optimize	Consistent	Accountable	Integrated	Volunteers
★ Integrated Planning Process	3	6	7	10	3	• Brian • Betsy • Ryan • Jonathan
★ Single Project Ranking Tool	10	9	14	0	1	• Gary • Aram • Jonathan • Tim
Organizational Structure Improvements	9	1	0	20	13	• Gary • Ian • Dale
★ Common Framework for Quantifying Risk	13	8	11	0	8	Brian, Paul, Janet, Jonathan, Ian, Gord, Betsy
Define AM Guidelines by Asset Class	4	9	6	3	5	• Paul • Aram • Janet • Ryan
Integrated Asset Management Systems	0	6	1	2	5	• Gord • Ian • Betsy

SECOR

Draft – For Discussion Purposes Only

KPMG

Wrap Up Discussion Focused on Next Steps

- **Participants expressed that they thought the workshop was worthwhile**

- **Comments that they were happy that the vision is well articulated and that there are identified projects**

- **Comments that the team was aligned across Gas and Electric**

- **<u>Interest in moving ahead quickly on projects</u>**

Next Steps Planning

For Discussion

General Approach for Projects

1. **Move quickly to capitalize on momentum and reinforce importance**
2. **Focus on value creation, both internally and externally**
3. **High involvement from AM/Planning; input from operations and PMO**
   - Build teams from identified resources; leverage as experts, sponsors and managers
4. **Sequence projects to ensure early benefit and high interest from team**
5. **Ensure communication of results**

Opportunity #1: Integrated Planning Process

Opp #1

Clearly define and communicate the AM planning process in Gas and Electric to improve collaboration and alignment

Description

- Clearly define the AM process: activities, timing, and roles
- Major planning activities would be defined both on an annual basis and against the revenue application schedule, with a focus on aligning planning approaches and integrating planning.
- The new process would then be communicated and implemented in order to improve participation, buy-in, decision-making, and, ultimately, to reinforce the transformation.

Value Proposition

- The current asset management planning process is not aligned across Gas and Electric or well integrated with PMO, Operations, Corporate Development, Marketing, and others.
- These issues have led to a lack of alignment on priorities and planning difficulties at the PMO, which have led to challenges in spending budget
- A clearly defined planning process will ensure that the required parties can share information, arrive at the best decisions, and fast-track any steps that require early intervention; it will also improve alignment/integration

Next Steps

- Identify project team and parties who should provide input
- Develop plan for building new planning process (and buy-in)
  - Agree on goals for improving process and timeline
  - Define new process so to achieve goals and remain feasible
  - Test process with key individuals
  - Implement the new process

Risks & Implementation Considerations

- Goal is to improve collaboration and avoid communication issues between departments; ensure buy-in to process
- The planning process does not need to be onerous

Draft – For Discussion Purposes Only

Opportunity #2 & #4: Risk Framework and Project Prioritization

Opp #2 & #4

Develop a consistent, defendable method for measuring risk in order to prioritize investments across regions and departments

Description

- Develop a consistent and defendable framework for measuring risk which can be used by Asset Managers and others to consistently assess risks in a defendable way
- Use risk framework as a basis for developing a project ranking tool which can help ensure a consistent method for ranking projects which can be communicated to staff and stakeholders
- The method for assessing risk and prioritizing projects should ensure a level of accuracy to support decision-making while remaining flexible and feasible to rollout on a wide-basis

Value Proposition

- Risks and project prioritization is assessed according to management expertise and therefore is not consistent or easily defended
- A consistent, process-based means for assessing risks and projects will ensure no issues are overlooked due to a higher tolerance for risk in one area vs another
- The risk framework will also help spread knowledge on calculating risk and make it easier to communicate decisions
- Consistent process will improve alignment

Next Steps

- Identify small team to lead project

Risks & Implementation Considerations

- Consider leveraging Enterprise Risk Management model, in place at Fortis Inc.
- Consider leveraging Electric's project prioritization spreadsheet

Draft – For Discussion Purposes Only

Attachment 33.2

FortisBC Asset Management

Current State Assessment and Vision

Draft – For Discussion Purposes Only

December, 2012

Context of Project

- **Globally, integrated asset management is becoming more important for utilities**
  - Our sustaining capital requirements are expected to grow to address our aging infrastructure
  - Expectations on reliability and conservation are on the rise
  - Increasing regulatory & stakeholder expectations
  - Growing skills gap
- **Within BC, utilities are increasingly in support of Asset Management transformations**
  - BCUC has supported AM at FortisBC with initial funding
  - CGA has developed has developed guiding principles on Asset Management
  - BC Hydro has gone through a AM transformation
- **Within FortisBC, Asset management is integral to success**
  - Increasingly busy planning group managing a growing asset base
  - Could serve as a catalyst for integration between Gas and Electric

SECOR

Draft – For Discussion Purposes Only

KPMG

Project overview

Our project is designed to engage a broad group across Electric and Gas in order to agree on a high-level roadmap to achieve FortisBC's AM vision

i — Asset Management Current State Assessment

- ✓ Establish a baseline for current asset management practices to assess the ability & scope to move to future state
- ✓ Compare FortisBC's Asset Management program to BC Hydro

ii — Creating the Asset Management Vision

- ✓ Conceive goals & objectives for Asset Management future state at FortisBC.
- ✓ Establish guiding principles, timing, and decision criteria

iii — Future State Gap Analysis

- ✓ Assess the major gaps between the vision and the current state
- ✓ Determine which area to tackle first

iv — Building the Strategic Roadmap

- ✓ Develop portfolio of opportunities
- ✓ Develop prioritization criteria
- ✓ Agree on a Road Map
- ✓ Implement improvements to meet short term value creation priorities (i.e. RFP)

Phase 1 (i–iii)

Phase 2 *(not in scope)* (iv)

SECOR

Draft – For Discussion Purposes Only

KPMG

Use of AM Guidelines / Frameworks

Guidelines/Frameworks: PAS55 (global, non-industry specific); CGA Guiding Document on Asset Management (Canadian, gas specific)

- We have aligned our process with the PAS55 Standard and CGA's AM taskforce
- We have used these guidelines and frameworks as:
  - A guide to check that important areas are being addressed comprehensively, without the need to tick all the guideline checkboxes.
  - A tool to start the discussion if resistance arises against changes.
  - A means to define a vision tailored to FortisBC, rally around a single objective and create momentum.
  - To ensure we are in line with industry efforts already in place (gas)

PAS55/CGA Areas of Focus

A. AM Strategy and Planning

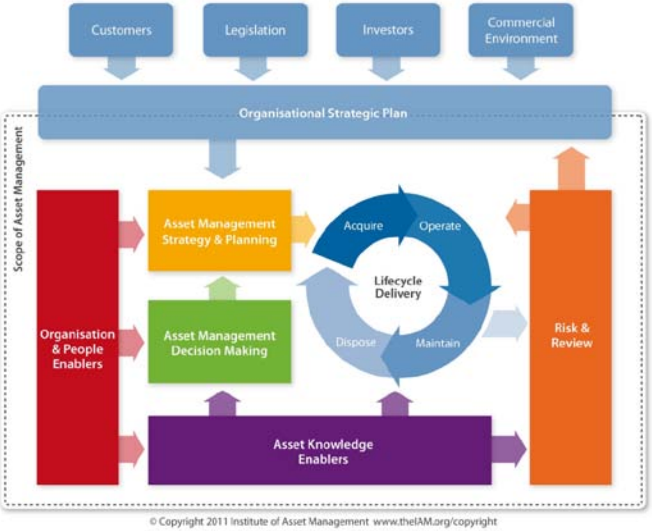
B. AM Decision Making

C. Lifecycle Delivery Activities

D. Asset Knowledge Enablers

E. Organization and People Enablers

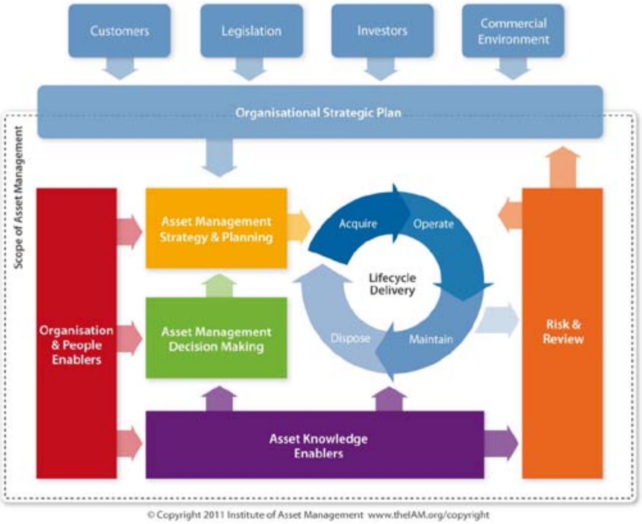
F. Risk and Review

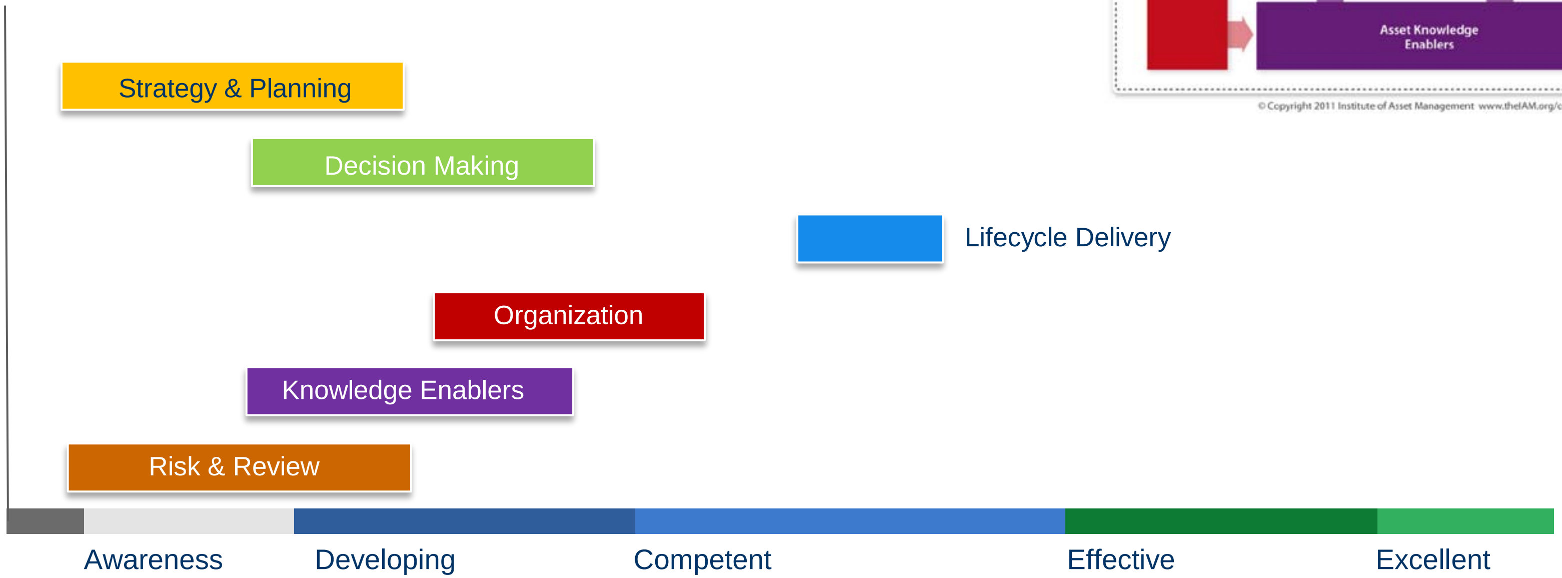


Asset Management Maturity Summary

FortisBC AM Maturity Summary

- We found a significant variance in maturity levels at FortisBC which reflects good AM decision-making and expertise but inconsistent documentation, a lack of formal processes and a lack of integration between AM domains (formal documentation, processes and integration are heavily weighted aspects of PAS55)
- A score of “Competent” = compliance with PAS55.
- The goal is for maturity bands to narrow over time to reflect more consistency across the organization and more documented processes to support decisions





SECOR

Draft – For Discussion Purposes Only

KPMG

Summary of Key Issues and Opportunities (1)

A. Strategy & Planning

1. Corporate Priorities for Assets
   - Issue: How to achieve corporate priorities with asset management by linking AM to corporate strategy
   - Opportunities: Exec-driven prioritization framework; developing an overarching AM Policy
2. Strategic Management of Regulatory Applications
   - Issue: Using asset management to fulfill strategy on regulatory approach
   - Opportunities: Improved budgeting and integration of AM and PMO/Operations; More quantitative means to justify plans

B. Decision Making

3. Developing Longer-Term Plans/Budgets
   - Issue: Be able to build better long-term plans based on asset needs
   - Opportunities: More integrated planning; more quantitative analysis
4. Project Prioritization Tool
   - Issue: Consistently prioritize projects using good criteria in a consistent, documented and defendable approach
   - Opportunities: Exec-driven prioritization framework; Leverage Electric project prioritization tool (and ensure scalability)
5. Quantitative Analysis
   - Issue: Use more quantitative analysis to make and defend decisions
   - Opportunities: Leverage lessons from gas GSA to Electric; Identify other analysis required to support RA's

Draft – For Discussion Purposes Only

Summary of Key Issues and Opportunities (2)

Lifecycle Delivery

6. Managing Budgets
   - Issue: Budgets are not being achieved in gas due to challenges around releasing/sharing SAP work orders, prioritizing projects, and providing information back from the field
   - Opportunities: Add more and earlier integrated planning sessions; provide information earlier; address planning issues with more transparent processes

Organization

7. AM Organizational Design
   - Issue: Are all elements of AM being resourced (e.g. innovation, performance improvement)? Is there too much duplication of responsibility (between Electric and Gas and within divisions)? Is there leadership in each area?
   - Opportunities: Add explicit AM responsibilities to new leaders, look for other areas to integrate (beyond PMO)

8. Siloed and High-Volume Decision-Making
   - Issue: Gas AM manages a high volume of SAP requests sourced from multiple areas; high volume makes it difficult to prioritize projects and share info with PMO
   - Opportunities: Developing process for providing and accepting more information from the field; Adding liaison roles to AM

SECOR

Draft – For Discussion Purposes Only

KPMG

Summary of Key Issues and Opportunities (3)

Knowledge Enablers

9. IT Landscape (Integration)
   - Issue: Electric and Gas are using a large number of systems, some at end of life; neither division has effectively communicated their needs, so IT cannot move forward
   - Opportunities: IT Roadmap for each business to feed into system selection decisions (already in progress)

10. Data Integrity
    - Issue: With multiple systems in place, duplicate and conflicting data is present impeding analysis and efficient work
    - Opportunities: Data integrity program; improve data collection process going forward; identify ways to use messy historical data

Risk & Review

11. Quantifying Risk
    - Issue: Both divisions have challenges quantifying and defending risk scores especially across different areas; ERM has methodology to compare apples and oranges but this is kept at corporate level
    - Opportunities: Leverage ERM heatmap methodology; build own risk scoring

12. Using Risk to Determine Investments
    - Issue: Both divisions have difficulty determining whether an investment is justified for this year rather than next since risk goals are not in place and implications cannot be quantified
    - Opportunities: Asset Health Registry with rules on investment (e.g. build out Cascade)

Potential AM Programs to Consider

- **Improved Capital Planning Process and Tools – new process for building capital plans, which includes:**
  - Capital Prioritization Framework
    - Prioritization framework which provides more clarity on acceptable risks and corporate priorities while generating more consistency across Electric and Gas
    - Roll-out of new framework and supporting vision to better link senior management goals with operations
  - Process Design and Organizational Changes
    - Process to align groups on how to identify priorities
    - Process and organizational changes to support better AM-PMO interactions to address inability to achieve budget in Gas (e.g. more integrated planning and new liaison roles)
  - Enhanced Quantitative Analysis
    - Identify what additional quantitative analysis is needed and is possible with existing and future systems
    - Build from gas GSA / 20 year plan project (for analysis) and records management project (for data integrity)

- **IT Roadmap / Architecture**
  - Define goal for integrated (or not integrated) IT architecture to support Asset Management
  - Business case to test cost-benefit

Draft – For Discussion Purposes Only

AM Quick Wins to Consider

- **Leveraging project prioritization tool from Electric to Gas**
  - Align project prioritization tool with ERM heat map methodology (e.g. apply likelihood and cost of risk to all projects)
- **Implement a planning session with PMO/Operations to collect input on year 2+ activities (e.g. plan for 2014 now)**
- **Add regional engineer liaison role to AM in gas**
- **Develop Asset Management philosophy document outlining how executive sees assets linking with strategy**
- **Have Gas GSA team provide instruction to Electric**
- **Leverage ERM heat map to broader set of risks (e.g. capital planning risks)**
- **Develop a spares strategy to reduce risk levels while minimizing carrying costs (e.g. transformers)**

SECOR

Draft – For Discussion Purposes Only

KPMG

Attachment 62.1

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 69.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 77.2.1

FILED CONFIDENTIALLY

Attachment 80.3

IN THE MATTER OF

FORTISBC INC.

2012-2013 Revenue Requirements
and
Review of 2012 Integrated System Plan

Decision

August 15, 2012

Before:

D.A. Cote, Commissioner/Panel Chair
A.A. Rhodes, Commissioner
N.E. MacMurchy, Commissioner

TABLE OF CONTENTS

Page No.

TABLE OF CONTENTS

Page No.

TABLE OF CONTENTS

Page No.

1.0 EXECUTIVE SUMMARY

On June 30, 2011, FortisBC Inc. filed its 2012-2013 Revenue Requirements (Application) and its 2012 Integrated System Plan for approval.

FortisBC sought across-the-board interim and permanent rate increases of 4.0 percent and 6.9 percent respectively for 2012 and 2013, pursuant to sections 59 to 61 and 89 of the *Utilities Commission Act* (*Act, UCA*). This was revised with the filing of its Evidentiary Update on November 4, 2011, and FortisBC now seeks a rate increase of 1.5 percent for 2012 and 6.5 percent for 2013. Pursuant to subsection 44.2 (1) of the *Act*, the Company has also filed its 2012-2013 Capital Expenditure Plan with proposed gross expenditures over the test period of $162.467 million as part of the Application.

A second part of the Application is the 2012 Integrated System Plan, which is made up of the 2012 Long Term Capital Plan, the 2012 Resource Plan and the 2012 Long Term Demand-Side Management Plan. FortisBC is seeking Commission acceptance that this is in the public interest pursuant to subsection 44.1(6) of the *Act*.

In reviewing this Application, the Commission Panel identified a number of overriding issues which have a direct impact on this proceeding and must be considered. These issues are as follows:

- The Magnitude of Rate Increase

  The rate increases being sought in this Application and the expected future rate increases through 2016 indicate a trend that is well in excess of inflation. Given the economic challenges faced by all British Columbians including those within the FortisBC service area, the Commission Panel will review this Application with a view to minimizing current and potential future rate increases.

- Relevance of BC Hydro/FortisBC Inc. Rate Disparity

  Considerable concern was raised in this proceeding with respect to the disparity in rates and practices of BC Hydro and FortisBC. The Commission Panel's notes that the two companies operate with a different set of supply resources and a different customer base in terms of geography, population density and the residential/commercial/industrial mix. Therefore the Panel is of the view that there is no mandate nor would it be appropriate to expect FortisBC to have programs and rates that mirror those of BC Hydro.

- Importance of Productivity Improvements

The Commission Panel places considerable importance on the need for creating what it has described as a ”productivity improvement culture” within utilities and, in the absence of evidence supporting its existence, to impose some form of productivity factor. The question facing the Panel is whether FortisBC has taken appropriate steps to demonstrate that it has processes in place to ensure productivity opportunities are explored.

These issues were not determinative in nature but did provide the Panel with a context to deal with specific issues as they arose within the proceeding.

Other key issue areas included:

- Power Purchase Management
- Departmental Operations and Maintenance (O&M) Expenses
- 2012-2013 Capital Expenditure Plan
- Deferral Accounts
- Demand-Side Management
- The Integrated System Plan

The Commission Panel has considered the views of all of the parties in making its determinations. We have not approved all of the FortisBC proposals nor have we agreed with all of the positions taken by the different Interveners. In the view of the Panel, the determinations made in this Decision are in the public interest and the resulting rates are just and reasonable as required under sections 59 and 60 of the *Act*.

A discussion of some of the highlights and key issues related to the Decision follows:

Power Purchase Management

A key function within FortisBC is the handling of power purchases through power purchase management. This Decision has examined a number of issues related to this function:

- A request for approval of increased power purchase expenses over the test period and a proposal to capture power purchase variances (both positive and negative) in a deferral account and flow them to customers in subsequent years.
- A proposal to increase power purchase management expenses (PPME) by 30 percent and include them as part of the estimate for power purchase expense.
- A proposal to implement a Planning Reserve Margin (PRM) late in the test period at an initial cost of $310,000.

The Commission Panel made the following determinations:

- Approval of the deferral account to capture power purchase expense variances was granted, however, the Panel directed FortisBC to reduce its Power Purchase Expense Forecasts by $1.5 million in consideration of previous forecast variances.
- PPME expenses were approved in a reduced amount and the proposal to move PPME from Operations and Maintenance and include it as part of power purchase expense was rejected.
- The proposal to implement a PRM and related expenses as part of the power purchase expense in this test period was rejected.

Departmental Operations and Maintenance Expenses

FortisBC has applied for O&M expenses of $55.4 million in 2012 and $56.8 million in 2013 (including PPME). A major consideration of the Commission Panel was whether FortisBC in this Application has demonstrated it has processes in place to ensure productivity opportunities are explored and implemented. The Commission Panel, while noting some concerns in specific departments, was not of the view that imposing an overall productivity factor as proposed by some of the Interveners was appropriate given the size of proposed increases and the evidence on this matter.

The Commission Panel directs FortisBC to reduce O&M expenditures for labour by $250,000 noting specific concerns in the Generation, Utility Operations and Community and Aboriginal Affairs departments. The Panel has made further determinations with respect to a reduction of proposed expenditures for the asset management program and non-labour related expenses in Customer Service and Community and Aboriginal Affairs.

2012-2013 Capital Expenditure Plan

FortisBC proposed capital expenditures totalling $162,467 million. The Interveners that commented on the 2012-2013 Capital Expenditure Plan were unanimous in calling for a reduction in expenditures. BCPSO notes that there has been a significant build-out in recent years resulting in increased reliability, safety and quality of service to ratepayers. The Industrial Customers Group (ICG) argues that capital expenditures being made on the basis of reliability improvements should not form part of the Plan.

The Commission Panel is of the view that safety, reliability and quality of service to ratepayers are at an acceptable level and a focus on identified problem areas is considered most appropriate at this time. The Panel has made specific determinations on projects which are inadequately supported or require additional work and has also made observations with regard to specific projects or project amounts we consider questionable given the evidence provided by the Company. The Commission Panel has rejected two projects totalling $10.5 million. While the Panel has identified possible overall reductions of $17.4 million, it has reduced that amount to $ 10.5 million to allow FortisBC to achieve the level of service it requires and have sufficient flexibility to manage its projects and workforce. The Commission Panel has accepted capital expenditures of $140,218 for the 2012-2013 test period.

Deferral Accounts

Important issues related to deferral account financing charges and the appropriate time period over which deferral accounts should be amortized have been examined. The Commission Panel has outlined the following guiding principles in making its determinations:

- A rate base rate of return applies only when a deferral balance has been transferred to become part of a capital project. Prior to this an interest rate of return based on the Weighted Average Cost of Debt (WACD) will apply.
- Deferred operating costs/current expenses are to attract an interest rate of return which varies based on the length of time they are deferred and the size of the amounts deferred.
- The length of amortization periods depends on a number of factors including the benefits of rate smoothing, the length of time where there is direct value related to the item being amortized, and the increased costs that longer amortization periods impose on the ratepayer.

These have been applied to the determinations on new and existing deferral accounts.

Demand-Side Management

FortisBC seeks approval of its 2012 Integrated System Plan which includes its 2012 Long-Term Demand-Side Management (DSM) Plan. In addition the Company has sought approval of DSM program expenditures of $7.73 million in 2012 and $7.88 million in 2013.

The Commission Panel has found that the 2012 Long-Term DSM Plan is adequate and cost effective. Citing the evidence of BCSEA’s expert witness, Mr. Plunkett, that FortisBC has achieved a ranking placing it in his second tier of jurisdictions with successful DSM programs, the Commission Panel approves the Company’s DSM expenditures as requested.

Integrated System Plan

In addition to the 2012 DSM Plan the 2012 ISP includes the 2012 Long Term Capital Plan (LTCP) and the 2012 Long Term Resource Plan (LTRP). Both of these plans address the medium and the long term and cover requirements through 2031 in the case of the 2012 LTCP and 2040 in the 2012 LTRP. Based on our review of the evidence, the Commission Panel finds that the 2012 LTCP to be in the public interest and the 2012 LTRP as meeting the requirements of the *Act with the* exception of the Planning Reserve Margin which was rejected. FortisBC has been directed to file its next Long Term Resource Plan no later than June 30, 2016.

2.0 INTRODUCTION

2.1 The Application and Approvals Sought

FortisBC Inc. is a vertically integrated electric utility operating in British Columbia and is regulated by the British Columbia Utilities Commission (Commission).

This is an application by FortisBC Inc. (FortisBC or the Company) for approval of its Revenue Requirements of $287.4 million for 2012 and $310.4 million for 2013 which, if approved, will result in general rate increases for its approximately 161,000 direct and indirect customers of 1.5 percent effective January 1, 2012 and 6.5 percent effective January 1, 2013. (Exhibit B-12, Table 1.0) This approval is sought pursuant to sections 59 to 61 of the *Utilities Commission Act* (the *Act*) RSBC 1996 c. 473.

FortisBC also applies for Commission acceptance of proposed capital expenditures in the gross amounts of $105.86 million for 2012 and $129.08 million in 2013 as being in the public interest under subsection 44.2(3) of the *Act*. These amounts include previously-approved capital expenditures of $7.92 million for 2012. They also include planned expenditures in the amounts of $10.52 million and $42.13 million for 2012 and 2013, respectively, for which the Company expects to file separate detailed applications for Certificates of Public Convenience and Necessity (CPCNs). (Exhibit B-1, Tab 6, p. 6, Table 1.1)

FortisBC has also filed its 2012 Integrated System Plan (ISP) which provides the long-term context for its 2012-2013 Revenue Requirements Application and 2012-2013 Capital Expenditure Plan. The Integrated System Plan outlines the long-term strategic direction of the Company in terms of capital, resource and energy conservation. The Integrated System Plan is made up of FortisBC's 2012 Long Term Capital Plan, its 2012 Resource Plan, and its 2012 Long Term Demand-Side Management Plan. FortisBC is seeking Commission acceptance that the Integrated System Plan is in the public interest pursuant to subsection 44.1(6) of the *Act*. (Exhibit B-1-1, Volume 1, pp. 1-2)

2.2 Legislative Framework

FortisBC is seeking approval of its proposed rate increases pursuant to sections 59 to 61 of the *Act.* Those sections basically require the Commission to have due regard to setting a rate that is not unjust or unreasonable in respect of the service provided by the utility. Subsection 59(5) provides that a rate is "unjust" or "unreasonable" if it is:

> "(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility,
>
> (b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or
>
> (c) unjust and unreasonable for any other reason".

The utility is required to file rate schedules with the Commission setting out its approved rates.

Sections 59 to 61 are set out in their entirety in Appendix A.

As noted above, the Company is seeking Commission acceptance of proposed capital expenditures for the 2012-2013 test period pursuant to subsection 44.2(3) of the *Act*. Section 44.2 deals with expenditure schedules and is set out in its entirety in Appendix B.

Subsection 44.2(1) provides that:

> "A public utility may file with the commission an expenditure schedule containing one or more of the following:
>
> (a) a statement of the expenditures on demand-side measures the public utility has made or anticipates making during the period addressed by the schedule;
>
> (b) a statement of capital expenditures the public utility has made or anticipates making during the period addressed by the schedule;
>
> (c) a statement of expenditures the public utility has made or anticipates making during the period addressed by the schedule to acquire energy from other persons.

Subsection 44.2(3), pursuant to which approval of the proposed capital expenditures for 2012-2013 is sought, states:

> ”After reviewing an expenditure schedule submitted under subsection (1), the commission, subject to subsections (5), (5.1) and (6) must
>
> > (a) accept the schedule, if the commission considers that making the expenditures referred to in the schedule would be in the public interest, or
> >
> > (b) reject the schedule”.

By subsection 44.2(4), the Commission may also accept or reject a part of a schedule.

Subsection 44.2(5) provides the factors which the Commission is required to consider in its review of an expenditure schedule filed by a public utility (other than the British Columbia Hydro and Power Authority) stating:

> (5) “In considering whether to accept an expenditure schedule...the commission must consider
>
> > (a) the applicable of British Columbia’s energy objectives,
> >
> > (b) the most recent long-term resource plan filed by the public utility under section 44.1, if any,
> >
> > (c) the extent to which the [expenditure] schedule is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act,*
> >
> > > [only section 6 of the *Clean Energy Act* is relevant to subsection 44.2(5)(c) and requires the public utility, in planning in accordance with section 44.1 of the *Utilities Commission Act* [which deals with long-term resource plans] to consider British Columbia’s energy objective to achieve electricity self-sufficiency in planning for the construction or extension of generation facilities and energy purchases, (by subsection 6(4))].
> >
> > (d) if the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any,
> >
> > > [Demand-Side Measures Regulation BC Reg 326/2008 as amended by BC Reg. 228/2011 is applicable]
> >
> > and

> (e) the interests of persons in British Columbia who receive or may receive service from the public utility".

Subsection 44.2(5.1) is not relevant to the Commission's review of the proposed capital expenditures in this case as that subsection applies only to British Columbia Hydro and Power Authority (BC Hydro).

Subsection 44.2(6) provides that:

> "[i]f the commission considers that an expenditure in an expenditure schedule was determined to be in the public interest in the course of determining that a long-term resource plan was in the public interest under section 44.1(6),
>
> (a) subsection 5 [which sets out the considerations for the commission's acceptance of an expenditure schedule as set out above] does not apply with respect to that expenditure, and
>
> (b) the commission must accept under subsection (3) the expenditure in the expenditure schedule".

British Columbia's energy objectives, the applicable of which the Commission is required to consider in its review of an expenditure schedule, exceed fifteen in number and are listed in section 2 of the *Clean Energy Act (CEA).* They relate in large measure to the use of clean or renewable resources, promotion of energy conservation and efficiency and the reduction of greenhouse gas emissions. Section 2 of the *CEA* is set out in Appendix C.

Also as noted above, FortisBC is seeking approval of its Integrated System Plan under section 44.1 of the *Act*, which relates to long-term resource and conservation planning.

Subsection 44.1(2) requires public utilities to file a long-term resource plan with the commission (in the form and at the times required by the commission) including all of:

> (a) an estimate of the demand for energy the utility would expect to serve absent new demand-side measures taken during the period addressed by the long-term resource plan;

(b) a plan of how to reduce that demand through cost-effective demand-side measures;

(c) the resulting net demand, after cost-effective demand-side measures are taken;

(d) a description of the facilities needed to be constructed or extended to serve the resulting net demand;

(e) information on energy purchases necessary to serve the resulting net demand;

(f) an explanation of why the resulting net demand which is to be served by the new facilities and energy purchases is not planned to be replaced by demand-side measures; and

(g) any other information that the commission requires.

By subsection 44.1(6), once the Commission has reviewed the long-term resource plan, it must either accept it, if it determines that carrying out the plan would be in the public interest, or reject it. The commission may also accept or reject part of a long-term resource plan pursuant to subsection 44.1(7).

Subsection 44.1(8) sets out the factors which the Commission is required to consider in determining whether to accept or reject a public utility's long-term resource plan. These factors are consistent with those the commission is required to consider when considering a public utility's expenditure schedule and comprise:

(a) the applicable of British Columbia's energy objectives;

(b) the extent to which the [long-term resource] plan is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*;

> [Again, only subsection 6(4) of the *Clean Energy Act* is relevant. As noted earlier, this subsection requires the public utility, in planning for the construction or extension of generation facilities and energy purchases in accordance with its long-term resource planning under section 44.1 of the *Act*, to consider British Columbia's energy objective to achieve electricity self-sufficiency.]

(c) whether the [long-term resource] plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures; and

(d) the interests of persons in British Columbia who receive or may receive service from the public utility.

The Demand-Side Measures Regulation

As noted above, BC Reg. 228/2011 amended the Demand-Side Measures Regulation, BC Reg. 326/2008.

The Demand-Side Measures Regulation applies to demand-side measures proposed in long-term resource plans filed under section 44.1 of the *Act* as well as those proposed in expenditure schedules filed under section 44.2 of the *Act*.

Among other things, the Demand-Side Measures Regulation defines the class composed of all demand-side measures proposed by a public utility in a long-term resource plan submitted under section 44.1 of the *Act* as a "plan portfolio". It defines the class composed of all demand-side measures proposed by a public utility in an expenditure schedule submitted under section 44.2 of the *Act* as an "expenditure portfolio".

Section 3 of the Demand-Side Measures Regulation sets out the criteria, all of which must be met (as long as the plan portfolio is submitted after June 1, 2009), for a utility's plan portfolio to be "adequate" for the purposes of subsection 44.1(8) (c) of the *Act*. To be adequate, the plan portfolio must include:

(a) a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption;

(b) a demand-side measure intended specifically to improve the energy efficiency of rental accommodations;

(c) an education program for students enrolled in schools within the public utility's service area;

(d) an education program for students enrolled in post-secondary institutions in the public utility's service area.

Section 4 of the Demand-Side Measures Regulation provides for the calculation of the cost effectiveness of demand-side measures. It also prescribes how the "cost-effectiveness" of a demand-side measure is to be determined for a demand-side measure proposed in an expenditure portfolio.

The calculation prescribed by the Regulation has been called the modified TRC (mTRC) to distinguish it from the more traditional Total Resource Cost test (TRC).

In essence, for any demand-side measure proposed in an expenditure portfolio (i.e. filed pursuant to section 44.2 of the *Act*) which is not directed at residents of low income households, and for which the benefit amount to be used in the TRC test has not already been increased in accordance with the utility's request, the Commission is required to increase the benefit of the demand-side measure by an amount that:

- increases the benefits of the entire expenditure portfolio of which the demand-side measure is a part by 15 percent, and
- is equal to the increase made for all other demand-side measures making up the expenditure portfolio.

Thus, each individual demand-side measure in an expenditure portfolio is subject to a minimum increase of 15 percent.

However, other than for "specified demand-side measures" (which are defined) and "public awareness programs" (which are also defined) there is basically a 10 percent cap on demand-side measures which need the 15 percent adder to be cost-effective, in the case of electric utilities. (Demand-SideMeasures Regulation, subsection 4(1.5))

The Commission also has the ability, in certain circumstances, to include other demand-side measures not included in the expenditure portfolio when determining cost-effectiveness and may, again in certain circumstances, and for certain demand-side measures, apply the utility cost test, as opposed to the modified Total Resource Cost test discussed above. (Demand-Side Measures Regulation, subsections 4(1.7), 4(1.8))

Demand-side measures which are required for a plan portfolio to be adequate, as set out above, are also subject to the Total Resource Cost test, but receive a 30 percent adder. (Demand-Side Measures Regulation, subsection 4(2))

2.3 Regulatory Process

FortisBC filed its Application on June 30, 2011. By Order G-111-11 of the same date, the Commission, among other things, established an Initial Regulatory Timetable and determined that the Company's Load Forecast would be reviewed by a Load Forecast Technical Committee, outside the Information Request (IR) process.

Ten Parties registered as Interveners, although not all participated in the regulatory hearing process. The Registered Interveners were:

- The British Columbia Municipal Electrical Utilities (BCMEU)
- British Columbia Hydro and Power Authority
- Mr. Alan Wait
- Mr. Norman Gabana
- British Columbia Pensioners' and Seniors' Organization *et al.* (BCPSO)
  (The British Columbia Old Age Pensioners' Organization *et al.* filed a Notice of Name Change on July 23, 2012.)
- The BC Sustainable Energy Association and the Sierra Club of British Columbia (BCSEA)
- The Regional District of Okanagan Similkameen
- Ms. Buryl Slack
- The Industrial Customers' Group (comprising: Zellstoff Celgar Limited Partnership, ATCO Wood Products Ltd. International Forest Products Limited, Kalesnikoff Lumber Co. Ltd., Porcupine Wood Products, Springer Creek Forest Products)
- The Irrigation Ratepayers Group.

Five other parties registered as "Interested Parties".

The review of the Application included two rounds of Information Requests.

On September 16, 2011, FortisBC provided a summary of required changes to its Application including, among other things, an expected reduction to its Power Purchase Expense resulting from the Provincial Government's review of BC Hydro's proposed rate increases and BC Hydro's announced intention to amend its Revenue Requirements Application to seek lower rate increases. The Company proposed to recalculate its Revenue Requirements and resulting rate impacts following the report of the Load Forecast Technical Committee which was at that time expected on October 28, 2011. (Exhibit B-6)

On September 28, 2011 FortisBC submitted responses to Information Requests from the Commission and from the BCPSO on system losses. (Exhibit B-7)

On October 4, 2011 the Commission issued Order G-167-11 which, among other things, established a Revised Preliminary Regulatory Timetable and set the date of November 22, 2011 for a Procedural Conference. (Exhibit A-7)

BCSEA filed Intervener evidence on October 31, 2011 on the issue of demand-side management. One round of Information Requests was held on that evidence.

On November 4, 2011, FortisBC filed an Evidentiary Update to its Application. The Evidentiary Update amended the Application to, among other things, incorporate actual results to September 30, 2011, expected reductions to BC Hydro's F2012-2014 rates and updated forecast market rates for electricity, as well as to make certain corrections. The net impact of the changes set out in the Evidentiary Update was to reduce the Revenue Requirements in each year of the test period, resulting in a revised rate increase request for 2012 from 4.0 percent to 1.5 percent and a revised rate increase request for 2013 from 6.9 percent to 6.5 percent. (Exhibit B-12)

A Procedural Conference was held in Kelowna, British Columbia on November 22, 2011.

On November 25, 2011, FortisBC filed its Load Forecast Technical Committee Report.

On November 30, 2011, by Order G-199-11, the Commission Panel determined that FortisBC's Revenue Requirements Application would be reviewed through an Oral Public Hearing process to be held in Kelowna, British Columbia, commencing on January 24, 2012. The Commission Panel also ordered that FortisBC's interim rates for 2011 were to be made permanent, and a deferral account to capture any difference as between the impact of BC Hydro's interim and final rates was approved. The Commission Panel also approved an increase to FortisBC's interim rates, effective January 1, 2012, in the amount of 1.5 percent. (Exhibit A-13)

On December 7, 2011, FortisBC requested an amendment to the Regulatory Timetable to reschedule the Oral Public Hearing from January 24, 2012 to March 5, 2012, or later, in part because key FortisBC personnel were unable to devote the time required to prepare for a hearing commencing in January.

On December 15, 2011, the Commission issued Order G-214-11 amending the Regulatory Timetable and establishing the date of March 5, 2012 for the commencement of the Oral Public Hearing.

The Oral Public Hearing proceeded for five days commencing on March 5, 2012. FortisBC filed its Final Submissions on April 5, 2012. Final Submissions were received from participating Interveners by April 23, 2012. FortisBC filed its Reply on May 3, 2012.

2.4 Approach to this Application

The Commission Panel is of the view that there are a number of broader issues raised in this Application, which are important. These include: the magnitude of rate increases for the current test period and beyond, the relevance of the rate disparity between BC Hydro and FortisBC, and the importance of establishing a productivity improvement culture. These issues are introduced in Section 3 and, while not determinative, provide the Commission Panel with context to deal with specific issues as they arise. This will be followed in Section 4 with a discussion of a number of specific issues of importance, some of which require Commission Panel determinations. Section 5 is a review of the 2012-2013 Application, its related issues and concerns and includes a discussion of operating and maintenance costs and various rate base issues in addition to the 2012-2013 capital plan. Following this is a review of Demand-Side Management in Section 6 and the Integrated System Plan in Section 7.

3.0 OVERRIDING ISSUES

3.1 Magnitude of Rate Increase

Prior to the Evidentiary Update filed on November 4, 2011, FortisBC was seeking rate increases of 4.0 percent and 6.9 percent for 2012 and 2013, respectively. As noted previously, the net impact of the changes set out in the Evidentiary Update resulted in a reduction in the requested rate increase to 1.5 percent in 2012 and 6.5 percent in 2013.

FortisBC attributes the need for rate increases primarily to:

(a) a growing rate base;

(b) an increase in the cost of financing the rate base;

(c) increased power purchase costs; and

(d) taxes.

(Exhibit B-1, Tab 1, p. 6)

A number of Interveners took issue with the proposed rate increases.

The ICG asserts that FortisBC "needs to make immediate changes to reduce costs" and that that will not happen "as long as the Commission continues to approve rate increases..." (ICG Final Submission, p. 47)

The BCPSO argues that "[t]he present economic climate requires the Commission to carefully examine any cost increases that exceed inflation and are not essential to providing service as significant increases will only exacerbate the problems of struggling families during difficult economic times." It submits that FortisBC's capital build-out has been aggressive and agrees that this has resulted in increased reliability, safety and quality of service but argues that "a balance needs to be struck between appropriate levels of safety, reliability, quality of service and reasonable customer rates." (BCPSO Final Submission, p. 3)

Similarly, the BCMEU, which represents the interests of FortisBC's five wholesale electricity customers which are municipal electrical utilities, encourages the Commission "to direct FortisBC to do better in terms of minimizing rate impacts on customers in this test period and beyond." The BCMEU adopts the position taken by the City of Penticton in its letter of comment (Exhibit D-4):

> "The last three years have been very tough at the City of Penticton. The City has had to take drastic steps. The road was not easy. The City faced organizational restructuring, staff layoffs and terminations, elimination of bonuses and no or very low salary increases. In addition, efficiencies were also found. In short, the City of Penticton has worked very hard to reign in expenses so that costs for our customers do not have to increase. In fact, for 2011 the Penticton residential tax rate was reduced by 0.5%.
>
> ...
>
> In closing I would ask that BCUC challenge FortisBC to also look internally to see what steps they can take to streamline their organization, increase efficiency and reduce costs in order that the proposed 2012 and 2013 rate increase can be reduced or eliminated."

(BCMEU Final Submission, pp. 2-3)

Mr. Norman Gabana also references the letter of comment from the City of Penticton as "what is happening in the real world" and asks the Commission to require FortisBC to produce operations plans that require no rate increases for 2012 and 2013. (Gabana Final Submission, pp. 1-2 referencing in part T2:84)

The Commission Panel acknowledges the position taken by the Interveners and agrees that the size of the proposed rate increases is significant, particularly in relation to inflation generally, and is therefore a very significant issue in these proceedings. The Commission Panel also views the main driver of this proposed increase as flowing from the increase in the size of rate base, as the other factors noted by FortisBC seem to be at or near historic lows. The Commission Panel also notes that rates are forecast to increase by a further 5.4 percent, 10.6 percent and 4.3 percent in 2014, 2015 and 2016, respectively. In the Commission Panel's view, these increases are also significant and likely to exceed inflationary increases for those years. (Exhibit B-12, Tab 7, p. 1) The Commission Panel acknowledges that electricity is a necessity and, while customers are encouraged to reduce their consumption somewhat, it will take time for Energy Efficiency and Conservation (EEC) measures to take hold and consumption is unlikely to be significantly reduced during the test period, or in the near future. The Commission Panel, bearing in mind the requirements of subsection 59(5) of the *Act*, is sensitive to the comments of Interveners and will therefore make its determinations in this proceeding with a view to minimizing the proposed current and potential future rate increases, where possible.

3.2 Relevance of BC Hydro/FortisBC Inc. Rate Disparity

A number of interveners expressed concern about the disparity between FortisBC rates and BC Hydro rates. FortisBC acknowledges the disparity and the resulting customer concern. The “Fortis Group of Companies of BC Communications & Public Affairs Plan 2010/2011” states: “FortisBC rates are currently considerably higher than BC Hydro’s (approximately 20 percent). Although the spread is anticipated to diminish within the next five years, having higher rates remains a concern as they impact customer satisfaction and the company’s competitive position.” (Exhibit C1-7, p. 26)

As was demonstrated in evidence, FortisBC has gone through a period of significant capital expenditures over the last number of years in order to upgrade its generation and transmission infrastructure to provide greater safety and reliability. The bulk of this investment has now been made. In BC Hydro’s case, FortisBC testified that significant costs will be incurred by BC Hydro in the areas of new generation and refurbishment of existing plants that, when reflected in rates, will lower the disparity between FortisBC and BC Hydro rates. (Exhibit B-1, p. 6-7; T2:116, 221)

FortisBC operates with a different set of supply resources and with a different customer base in terms of geography, population density and the residential/commercial/industrial mix it faces. The Commission Panel has no mandate, nor does it find it appropriate, to require FortisBC to manage its utility business to produce rates or programs identical to those of BC Hydro. The Commission Panel believes that FortisBC’s responsibility is to provide safe and reliable service in a cost-effective manner consistent with British Columbia’s energy objectives. To do so, FortisBC must design and manage its system based on the resources available to it and the needs of its customers. This, at times, may result in rates that are greater than those of BC Hydro and potentially times when they are less.

3.3 Importance of Productivity Improvements

A considerable number of submissions were made with respect to the need for productivity improvements and the need to impose a productivity factor. The Commission Panel believes there is value in addressing this at the outset by stating our position with respect to productivity improvements and outlining our expectations as to how a utility should address this issue within its day-to-day operations. In doing so, we would hope to provide greater clarity and insight into relevant parts of the Decision which follow.

The Commission Panel is of the view that there is an ongoing need for utilities to manage their business in a manner that actively seeks out and creates efficiencies resulting in what might be described as a "productivity improvement culture". We believe this is in the interests of both the ratepayer and the shareholder. Put most simply, a productivity improvement culture is one where there is a demonstrated capability of a company to regularly undertake a review of the organization from both a macro and a micro point of view to examine what is being done, how it is being done and, where warranted, to make decisions to do things differently, or in some cases, not at all. When the Panel refers to the need for productivity measures we are not speaking of "cost cutting" but rather, "cost management". It is not a difficult task to cut costs in order to achieve a desired result over a short term period. It is however, a difficult task to manage costs downward on a sustained basis with greater or no loss of efficiency over the longer term. It is this latter result that the Commission Panel believes needs to be addressed more comprehensively within utilities and best describes what can be achieved in a productivity improvement culture.

FortisBC notes that in the recent FortisBC Energy Utilities 2012 Revenue Requirements and Rates Decision which was issued on April 12, 2012, the Commission made a cut to FEU's O&M budget and submits that such a reduction would not be appropriate in the context of the current proceeding. FortisBC states that imposing a percentage reduction as advocated by the BCMEU and BCPSO in this proceeding would not further the objective of subsection 60(1)(b)(iii) of the *Act* (which requires the

Commission to have due regard to setting a rate that encourages public utilities to increase efficiency, reduce costs and enhance performance) as the revenues as applied for by the utility accurately reflect the cost of service. The Company states that imposing a reduction would:

- Harm performance in the short term by denying access to necessary revenues it has forecast.
- Create an incentive for utilities to inflate revenues in a cost of service application in anticipation of such cuts; and
- Create regulatory inefficiency by undermining the process of review of the O&M part of a cost of service application.

(FortisBC Reply, pp. 24-25)

The Commission Panel agrees that imposing some form of productivity factor is not a decision to be taken lightly. However, there may be cases where a utility has been unable to satisfy the Commission that it has taken the necessary steps to ensure productivity and efficiency levels within the organization have been optimized. In these instances, some form of productivity adjustment to the O&M budgets of a utility are warranted. One purpose of examining productivity in greater detail in recent proceedings has been to encourage utilities to formalize processes to help create a productivity improvement culture and, where appropriate, to make the sometimes difficult decision to bring about change. These are difficult times for many ratepayers and the Commission Panel believes this is the least they can expect.

4.0 ISSUES OF IMPORTANCE

4.1 Load and Customer Forecast

FortisBC prepared a load forecast which was reviewed in detail by the Load Forecast Technical Committee (the Committee). This group was established by Order G-111-11. Members include representatives of FortisBC, BCUC staff, BCMEU, BC Hydro, and BCPSO and Ms. Buryl Slack Goodman.

The Committee met on various occasions and reviewed the load forecast, including the methodologies behind the forecast, for the 2012 and 2013 Revenue Requirements and for the Integrated System Plan. The review excluded assessment of the forecast of Demand-Side Management (DSM) savings, savings from rate structures or estimated system losses.

Committee members have accepted the load forecast and methodologies as put forward by FortisBC. Details of the forecast and the methodologies behind the forecast were filed by FortisBC on November 25, 2011. (Exhibit B-16)

The 2012 and 2013 Load Forecasts are summarized below:

Table 1

	2012 (GWh)	2013 (Gwh)
Residential	1,264	1,276
Commercial	696	709
Wholesale	926	935
Industrial	250	255
Lighting	14	14
Irrigation	44	43
Net	3,193	3,233
Loss	309	310
Gross	3,502	3,543
Winter Peak (MW)	721	731
Summer Peak (MW)	567	575

Source: Exhibit B-16, Appendix A, Attachment 1, Slide 5.

The customer count summary for 2012 and 2013 is summarized below:

Table 2

	2012		2013	
	Number	**% Change**	**Number**	**% Change**
Residential	101,320	1.9%	103,279	1.9%
General Service	11,837	2.3%	12,130	2.5%
Wholesale	7	0.0%	7	0.0%
Industrial	36	0.0%	36	0.0%
Lighting	1,830	0.0%	1,830	0.0%
Irrigation	1,075	0.0%	1,075	0.0%
Total Direct	116,105	1.9%	118,357	1.9%

Source: Exhibit B-16, Appendix A, Attachment 1, Slide 30.

One issue that was raised by interveners with respect to the forecasting process was the use of a 1 in 20 peak forecast. Under this methodology, seasonal peaks are recorded from actual demand in the previous twenty years. Net energy growth is calculated from actual sales over the same time period. The maximum peaks of the past twenty years are then projected forward using the historical net energy growth calculation.(Exhibit B-16, Appendix A, Attachment 1, Slide 28) For the current 1 in 20 year forecast, the base year winter peak was 1990 and the base year summer peak was 1998. (Exhibit B-10, BCUC 2.3.1 (Losses))

BCMEU is concerned with this methodology and submits that the more commonly used 1 in 10 peak forecast would be more appropriate. (Exhibit B-10, BCUC 2 3.3; BCMEU Final Submission, p. 9)

FortisBC responded to these concerns by pointing out that the 1 in 20 forecast is not used for the purpose of determining the need for power purchases or directly for capital planning. It is used for benchmarking against the existing distribution planning forecast to confirm that it can accommodate load increases that result from extreme weather variations. (Exhibit B-10, BCUC 2.3.1 (losses), p. 9) FortisBC states that all capital projects were driven by the distribution planning forecast and that no changes were made in terms of projects or timing as a result of the 1 in 20 forecast. (Exhibit B-10, BCUC 2.3.3)

Commission Panel Determination

The Commission Panel notes that in spite of the concerns raised by BCMEU concerning the use of a 1 in 20 peak forecast, all of the Committee members have accepted the Load Forecast. **The Panel further notes there was no evidence to suggest there were difficulties with the forecast or methodologies and therefore accepts the Load Forecast for the current test period.**

With respect to the use of the 1 in 20 forecast, the Commission Panel directs FortisBC in its next RRA to undertake both a 1 in 10 and a 1 in 20 peak forecast and provide evidence as to the relevant merits of each as a planning tool.

4.2 Capital Structure and ROE

In the Procedural Conference held in Kelowna on November 22, 2011, ICG questioned whether there was sufficient evidence for the Commission Panel to make a determination on FortisBC's capital structure and rate of return. ICG argued that the allowed capital structure of 60 percent debt and 40 percent equity and a risk premium of 40 basis points above the "benchmark" rate of return as approved by Order G-58-06 (Decision on an Application by FortisBC Inc. for Approval of its F2006 Revenue Requirement Application and Establishment of a Multi-Year Performance Based Regulation Mechanism (FBC 2006 RRA Decision)) could not be applied in this proceeding. In particular, ICG disputed the application of the benchmark rate of 9.5 percent as approved by Order G-158-09 (Decision on the Application by Terasen Gas Utilities for Return on Equity and Capital Structure (2009 ROE Decision)) considering its relationship to the automatic adjustment mechanism (AAM) which was eliminated by the same Order. (T1:27-38)

In the Reasons for Decision accompanying Order G-199-11 dated November 30, 2011, the Commission Panel addressed, among other things, the ICG's position on ROE and capital structure. The Panel noted that subsequent to the Procedural Conference on November 28, 2011, the Commission had issued a letter expressing its intent to conduct a Generic Cost of Capital (GCOC) Hearing designed to deal with capital structure and ROE with application to all utilities. In view of this, the Commission Panel concluded that there was little to be gained in terms of value or efficiency by considering the issue of capital structure and return on equity as part of this proceeding. The Panel's determination was as follows:

> "Accordingly, the Commission Panel has determined there is no need to expand this hearing to include a comprehensive review of FortisBC's capital structure and ROE. Therefore, the Commission Panel has determined that given the Commission announcement regarding a generic hearing process, it would be appropriate to maintain the current ROE and capital structure pending determinations made in the Generic Cost of Capital Hearing."

In its Final Submission, ICG argues that the cost of capital is "a significant component of a regulated utility's revenue requirements, and there should be no doubt that before rates are set the Commission Panel must determine the cost of capital for each year of the test period by applying the fair return standard". (ICG Final Submission, p. 45)

ICG refers to its submissions at the November 22, 2011 Procedural Conference where it argued that the Commission has never accepted any evidence other than expert evidence regarding the cost of capital and in the absence of such evidence, the Commission should not approve the rates applied for. (ICG Final Submission, pp. 45-46)

ICG submits that Recital D of Order G-20-12 in the GCOC proceeding, which includes a statement that there have been changes in the financial markets since the 2009 ROE Decision, prevents the Commission from relying upon the cost of capital as determined by the 2009 ROE Decision to determine fair and reasonable rates. (ICG Final Submission, p. 46)

ICG also submits that the elimination of the ROE AAM upon which the Commission had been able to rely to ensure the fair return standard is met, now means the Commission Panel must determine the fair return standard before it approves rates for the first year of a test period. (ICG Final Submission, p. 46)

ICG continues by noting that, for the period between the 2009 ROE Decision and the test period for this proceeding, the Commission relied upon negotiated settlements to ensure the fair return standard was met. ICG submits that, given Order G-47-12 dated April 18, 2012 in the GCOC proceeding, which states that the determination of the equity ratio and specific risk premiums for utilities will be no earlier than January 1, 2013, the Commission Panel has no other proceeding to rely on to ensure the fair return standard has been met for year one of the test period in this proceeding. (ICG Final Submission, p. 46)

ICG argues that subsection 58(1) of the *Act* requires a hearing before rates are set. It further submits that the onus is on the utility to justify all elements of its revenue requirement before the Commission sets rates. It submits there was no onus on the Interveners in this proceeding to file expert evidence on the cost of capital for the test period and, without expert evidence from the Company, the Application is deficient and cannot be approved. (ICG Final Submission, pp. 46-47)

ICG further submits that considerations of fairness require that there be an opportunity for the parties to challenge in a hearing, assertions of fact or opinion in dispute in order for a decision having an effect on rates to be made. Given Orders G-199-11 and G-47-12, it submits there will be no adjudicative process to determine FortisBC's cost of capital for the first year of the test period in this Application. ICG submits that this is a requirement before the Panel "can increase rates based on a return on equity of 9.9% and an equity ratio of 40%." (ICG Final Submission, p. 47)

The only other Interveners who comment on capital structure and ROE in their final submissions are the BCMEU and BCPSO. The BCMEU accepts that this issue will be addressed in the GCOC proceeding and, in particular, looks forward to the impact of the Commission's review on the Company's risk premium. BCMEU questions whether the existing risk premium is appropriate given FortisBC's proposal to further mitigate risks through the use of deferral accounts. (BCMEU Final Submission, p. 10)

BCPSO submits that it "will be seeking through the GCOC [proceeding], to reduce the Company's approved ROE to reflect current economic conditions." (BCPSO Final Submission, p. 4)

FortisBC notes that the ICG arguments to make a return on equity an issue in this proceeding have been made several times and are contrary to the determinations of the Commission in the November 30, 2011 Reasons for Decision for Order G-199-11 in this proceeding and the Commission's Reasons for Decision dated April 18, 2012 in the GCOC proceeding. Specifically, the Company notes that in the April 18, 2012 Reasons for Decision, the Commission reaffirmed that the current capital structure and ROE will be maintained pending GCOC proceeding determinations with specific determinations related to FortisBC to be made at a future proceeding following the generic hearing. (FortisBC Reply, p. 10)

Commission Panel Determination

The Commission Panel has reviewed the arguments of the parties and remains of the view that an examination of the ROE and capital structure for FortisBC is not a requirement in this proceeding and finds that the revenue requirements of FortisBC and resultant rate impacts can be adjudicated. Our reasons for this conclusion are as follows:

- FortisBC is not seeking a change to its capital structure or to its ROE in this proceeding. ICG submits that the onus was on FortisBC to file expert evidence on cost of capital in any event. FortisBC provided evidence that there had been no material change in its 40 point risk premium since the 2006 RRA Decision. In response to BCUC IR 2.31.1, FortisBC provides evidence with respect to maintaining the current ROE with a risk premium of 40 points over the benchmark in light of the Company's improved credit metrics. In its response, FortisBC states that it bases its business risk profile on the long-term perspective and continues to support a risk premium over the benchmark. The Company refers to the Moody's September 6, 2011 credit opinion which, among other things, states:

  "financial metrics remain weak compared to Baa-rate peers" and

FortisBC submits that any reduction in ROE would challenge the Company's credit metrics as well as available liquidity which could potentially result in a credit downgrade and cost of debt increase. In addition, FortisBC refers to the October 6, 2011 DBRS credit opinion which commented upon challenges related to relatively large anticipated capital expenditures and their contribution to large free cash flow deficits as well as challenges related to the execution of the capital expenditure program. In response to BCUC IR 1.31.1, the Company noted that a credit rating upgrade is not the sole determinant of a business risk premium and listed a significant number of other risk factors that it faced. Included among these were the relative size of the utility, major businesses served by FortisBC, population and economic growth, competition and technological changes which the Company asserts has influence on an entity's long-term risk profile and collectively do not support a reduction to the Company's risk premium. The Commission Panel agrees as the FortisBC evidence supports the view that there has not been a substantive change in risk. As noted below, none of the parties challenged this evidence. (Exhibit B-8, BCUC 2.31.1; Exhibit B-8, Appendix 31.2)

- While paragraph 9 of Order G-158-09 issued concurrently with the 2009 ROE Decision eliminates the AAM, paragraph 8 of that Order approves the continued use by FortisBC of the benchmark return on equity of 9.5 percent which was determined as appropriate for Terasen Gas Inc. for rate setting purposes. Paragraph 8 of that Order provides that: "The TGI ROE approved in paragraph 3 of this order can continue to serve as the Benchmark ROE for FortisBC and any other utility in British Columbia that uses a Benchmark ROE to set rates." In the view of the Commission Panel, this paragraph clearly establishes the Benchmark ROE for FortisBC for the purposes of this proceeding. In the Panel's further view, this approach is not substantially different in effect from what has been done in the recent past. In other words, in recent years, expert testimony on the cost of capital in a revenue requirements hearing has in fact been the exception, rather than the rule.

- The position of ICG is that for the period between the 2009 ROE Decision and the test period for this proceeding, the Commission could rely upon negotiated settlements to ensure the fair return standard was met. The last FortisBC RRA was completed on December 9, 2010 utilizing a negotiated settlement process (NSP) and resulted in a Commission approved Negotiated Settlement Agreement (NSA). The Commission Panel notes that the NSA which forms Appendix A to Order G-184-10 includes a list of issues and resolutions from the NSP. Neither ROE nor capital structure are referred to in the list of issues. Contrary to ICG's submission, the Panel's examination of the evidentiary record for that proceeding discloses that no expert evidence on capital structure or return on equity was filed by FortisBC or another party. Further, none of the parties raised this issue during the Information Request process. In their letters of support for the proposed NSA, none of the parties expressed any concern with the Commission approving the proposed NSA in the absence of expert evidence on capital structure or return on equity. While ICG was not a party to the NSA, Zellstoff-Celgar (a principal member of ICG) was a party, as were a number of the Interveners in this proceeding.

- The Revised Regulatory Timetable attached to Order G-167-11 provided for the filing of Intervener Evidence by October 31, 2011, after two completed rounds of information requests. Neither ICG nor any other Intervener filed evidence which challenged the FortisBC evidence that there had been no material change by that date or prior to the November 22, 2011 Procedural Conference. Consistent with the Commission Panel's determination in the Reasons for Decision accompanying Order G-199-11, no party sought to file such evidence after November 30, 2011.
- The ICG argues that the Commission must apply the "fair return standard" before it approves rates for the first year of the test period and that it is not able to do so in the absence of expert evidence, given the automatic adjustment mechanism was eliminated by Order G-158-09.

The Commission Panel disagrees.

The Utilities Commission Act governs the rate-setting jurisdiction of the Commission. By subsection 59(1), a utility is prohibited from making, demanding or receiving a rate that is "unjust, unreasonable, unduly discriminatory or unduly preferential" or a rate that otherwise contravenes the Utilities Commission Act, its regulations, Commission orders or any other law.

By subsection 59(5), a rate is "unjust" or "unreasonable" if it is:

(a) more than a fair or reasonable charge for service of the nature and quality provided by the utility, or
(b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or
(c) unjust or unreasonable for any other reason."

The fair return standard has been articulated in various regulatory decisions across North America including the Commission's August 26, 1999, Decision entitled "In the Matter of Return on Equity for a Benchmark Utility". The standard provides the regulated utility the opportunity to:

- Earn a return on investment which is commensurate with that of comparable risk enterprises.
- Maintain its financial integrity; and
- Attract capital on reasonable terms.

In the Commission Panel's view, the "fair return standard" is therefore intended to protect the utility. This is also apparent from the wording of subsection 59 (5)(b) that a rate is "unjust" or "unreasonable" if it is *insufficient* to yield a fair and reasonable compensation for the service provided by the utility or a fair and reasonable return on the appraised value of its property.

In the Panel's view, the rate for the first year of the test period is not insufficient to yield a fair and reasonable compensation to the utility for its service. This conclusion flows from the following:

- FortisBC has not sought to challenge the existing capital structure or ROE as yielding an insufficient return,
- The NSA for the previous test period arrived at rates which were approved by the Commission as not being "unjust" or "unreasonable". The rates for the first year of this test period are basically the same, when inflation is considered, and there has been no degradation in the nature and quality of the service provided as is indicated by the SAIDI and SAIFI statistics.

- The GCOC proceeding has been initiated to deal with the issues of ROE and capital structure for all utilities at the same time. This will ensure all of the utilities taking part in the GCOC proceeding are treated in a consistent manner. The Commission Panel considers this to be just and reasonable for both the utilities and the ratepayers.
- Reviewing cost of capital in a single process is an efficient and cost effective approach. The Commission Panel is of the view that holding a separate hearing process to examine cost of capital issues for FortisBC alone, for only one year in the test period, would result in significant additional costs which would be borne by FortisBC's ratepayers.

For these reasons **the Commission Panel reaffirms its Decision of November 30, 2011, to maintain the current ROE and capital structure pending determinations made in the GCOC proceeding.**

5.0 2012-2013 REVENUE REQUIREMENTS APPLICATION

5.1 Power Purchase Management

A key function within FortisBC is power purchase management. FortisBC has proposed a number of significant changes with respect to power purchase expense and the overall management of this important function. Additionally, the Company has proposed that the concept of a PRM be explored and put in place during the latter stages of this test period. In this section, the proposals put forth by FortisBC will be reviewed beginning with the handling of the Power Purchase Management group and related expenses, followed by a review of power purchase expense requirements and proposed changes in how these are handled and end with consideration of the PRM proposal.

5.1.1 Power Purchase Expense

FortisBC submits that the purpose of its resource acquisition policy is to allow customer load requirements to be met at the lowest reasonable cost with a minimum of environmental impacts. The Company can supply over 98 percent of its annual energy requirements from long-term, firm resources. In meeting its energy requirements, FortisBC uses a combination of Company-owned generation entitlements and firm supply which has been contracted, augmented by spot market purchases to deal with any capacity or energy deficits. FortisBC-owned generation entitlements include the Canal Plant Agreement (CPA) entitlements while examples of contracted firm supply include the Brilliant Power Purchase Agreement (BPPA) and the BC Hydro Rate Schedule (RS) 3808 Power Purchase Agreement (PPA). Other purchases include Independent Power Producers and market purchases made in advance, as well as those on the spot market. (Exhibit B-1, Tab 4, pp. 3-10)

FortisBC seeks approval for a power purchase expense forecast of $89.0 million in 2012 and $94.6 million in 2013 (Exhibit B-12).

As outlined in Table 3, FortisBC has consistently reported a power purchase expense under-expenditure variance. Over the period from 2007 through 2011 (actuals through 2010) the under-expenditure is expected to total in excess of $26 million:

Table 3

	2007	2008	2009	2010	2011A	Total
	Over / (Under) Approved					
Sales Load Variance (Gwh)	13	0	50	(153)	25*	
Power Purchase Expense Variance ($000s)	(5,631)	(2,528)	(168)	(8,444)	(9,693)	**(26,464)**

* 2011 is forecast
(Calculated from Exhibit B-1, Table 4.1.5-1 and Transcript 5, p. 849)

The Company explains that these power expense variances could result from a number of factors, including:

- Load variances related to variances in customer growth, usage or weather;
- Unit price variances from forecast (an example being BC Hydro rates which were not known at the time of application and were not finalized at the close of the evidentiary record);
- FortisBC's ability to displace contracted purchase with lower-cost market purchases;
- True-up of BPPA costs; and
- CPA operational factors affecting the Company's usage or timing of entitlements.

(Exhibit B-1, Tab 4, p. 23)

A Performance Based Regulation (PBR) Plan was in place over this period which allowed these variances to be shared equally between customers and shareholders through the ROE sharing mechanism.

In this Application, FortisBC has proposed a deferral account to capture variances in forecast and actual Power Purchase Expense. This is in part in response to a request from stakeholders in the 2011 Negotiated Settlement Agreement. FortisBC has requested that firm rates be set for the 2012-2013 test period and any accumulated variances be applied to rates in 2014. Thereafter, the Company proposes to flow through any variance in the Power Purchase Expense Variance Deferral Account to customers in the subsequent year. (Exhibit B-1, Tab 4, pp. 23-24)

None of the Interveners made specific submissions with respect to the proposed Power Purchase Expense Variance Deferral Account although it can be assumed that they support it given their request at the last NSP.

Commission Panel Determination

The Commission Panel finds that a deferral account to capture variances between forecast and actual power purchase expense represents a reasonable attempt to manage uncertainty and approves establishing the Power Purchase Expense Variance Deferral Account as proposed by FortisBC. The Panel understands the complexity of managing the number of variables affecting the power purchase process and is in agreement that any positive or negative variances are most appropriately borne by the customer. The establishment of a Power Purchase Expense Variance Deferral Account is the most effective way to manage this process with variances being handled in customer rates in subsequent periods.

Of concern to the Commission Panel however, is the level of accuracy of FortisBC's forecasts for power purchases over the past five years. As noted previously, the under-expenditure to forecast over this period has totalled more than $26 million or more than $5 million per year. Moreover, in only one of those five years has the under-expenditure been less than $2.5 million. This matter was pursued by Commission Counsel at the oral hearing phase of the proceeding. FortisBC, using 2010 as an example, pointed out that much of the under-expenditure was driven by a load variance. (T5:831-832) The Commission Panel accepts this reasoning for 2010 but notes that, based on the information presented in the above table, the favourable sales load variances in 2007 and 2009 also resulted in significant over-forecasting of the power purchase expense in those years.

The Commission Panel finds that based on the past five years, FortisBC has been overly conservative with its power purchase expense forecasts. As discussed in Section 3.1, there have been significant concerns raised with respect to the continued increase in rates given the economic challenges faced by all customer groups. The Commission Panel is of the view that reducing the power purchase forecast is both justified and will provide some relief to customer groups. The Panel understands that much of the customer risk associated with an under-expenditure has been eliminated by the approval of the Power Purchase Expense Variance Deferral Account but is of the view that this does not justify setting rates on the basis of overly conservative forecasts. **The Commission Panel directs FortisBC to reduce its Power Purchase Expense forecasts by $1.5 million in 2012 and 2013.** The Commission Panel notes that FortisBC forecasts its rate increases on the assumption that BC Hydro's rate increase, effective April 1, 2012, is 3.9 percent with a further 3.9 percent effective April 1, 2013. The Commission Panel notes that BC Hydro has recently adjusted its permanent rates for April 1, 2013 to 1.44 percent plus a 5 percent Deferral Account Rate Rider. **FortisBC is directed to adjust its power purchase expense forecast to reflect this change.**

5.1.2 Power Purchase Management Expense

FortisBC proposes a budget of $1.2 million in 2012 and $1.3 million in 2013 for PPME to be included in its Power Purchase Expense forecast. This represents an increase of $284,000 or 30 percent over the 2011 Forecast for this function which is primarily responsible for planning and securing power from a variety of sources (company-owned generating units, power supply contracts and market transactions) on a short, medium and long-term basis. The Company submits that its Power Supply group is facing a need to secure an increasing future load while dealing with a regional environment which is becoming more constrained and more tightly regulated. FortisBC further submits that the Application includes funding for incremental staff and funding for power supply which it believes to be necessary to manage the growing complexity of efficiently meeting an increasing load. The incremental costs for 2012 over the previous test period are made up of the following:

- $0.022 million for labour cost escalation.
- $0.143 million for the addition of one Full Time Equivalent (FTE) employee.

- $0.068 million for additional consulting resources.
- $0.050 million for inter company transfers from FortisBC Energy Inc. for services provided.

Costs in 2013 are planned to increase by $0.055 million reflecting inflationary changes affecting labour and some non-labour costs. Some examples of additional work requirements driving the increased costs over the test period include:

- The need for more in-depth analysis of power supply options
- The need to participate in outside organizations to cooperatively deal with common problems.
- Additional resource requirements with business continuity skills at the System Control Centre
- Requirement for more active management with dispatchers monitoring real-time resource load.

(Exhibit B-1, Tab 4, pp. 13-15; Exhibit B-8, BCUC 2.8.2)

A significant change that FortisBC has proposed for this test period is that the PPME be included in the estimate of Power Purchase Expense rather than maintaining it within the O&M budget as in the past. FortisBC submits that linking PPME directly to the Power Purchase Expense will help to ensure that there are sufficient resources to plan, implement and mitigate Power Purchase Expense. (Exhibit B-1, Tab 4, p. 13)

BCMEU is not supportive of increased staffing in order to purchase power supply. BCMEU expresses concern with the increase in PPME, given the longer term agreements being executed which it submits should provide stability in power purchase management. Additionally, BCMEU expresses concern that there is the potential for further efficiencies to be gained through the management of power purchase matters on a shared basis (i.e., with FortisBC Energy Inc.), which is not being pursued. BCMEU make no submission with regards to moving the PPME out of O&M. (BCMEU Final Submission, p. 17)

BCPSO expresses concerns similar to the BCMEU and points to the company's success in reducing power purchase costs over the PBR period. BCPSO suggests the Commission may wish to consider whether the additional power purchase costs are necessary and whether the benefits justify the additional cost. Like BCMEU, BCPSO makes no submission regarding the movement of the PPME out of O&M. (BCPSO Final Submission, p. 9)

FortisBC acknowledges the concerns of BCMEU and BCPSO and agrees that the current lower price environment has allowed it to realize power purchase cost savings against forecast through displacement of purchases under the BC Hydro RS 3808 PPA. However, FortisBC further notes that market conditions continue to change and submit that the Company must be proactive and responsive to these changes in order to maximize savings. FortisBC underlines this point with respect to the BCMEU comments regarding the apparent stability offered by long-term agreements. FortisBC notes that savings would be lost if it relied on existing agreements and did not take full advantage of opportunities to displace those purchases. In addition, FortisBC argues that the nature of long-term agreements continues to change and the yet-to-be negotiated BC Hydro RS 3808 PPA and the addition of Waneta Expansion capacity will not result in reduced workload. (FortisBC Reply, pp. 43-44)

Commission Panel Determination

The Commission Panel is in agreement with BCMEU and BCPSO with respect to the additional expenditures being proposed by FortisBC for PPME and is concerned as to whether there is a need for an increase of 30 percent of existing resources.

FortisBC has acknowledged that it has integrated its gas and power supply teams and has requested additional PPME funding for the services provided by the gas supply side as a means of creating greater efficiencies and leveraging off the experience of the two groups. (FortisBC Final Submission, p. 17) While the Commission Panel is disappointed that this integration has not led to some immediate savings, we do accept that there is potential benefit to utilizing some of the gas resources to maximize the productivity of existing PPME resources. However, we are not convinced that there has been a sufficient case made to justify the further FTE position that is proposed by FortisBC. As noted by

BCMEU in reference to the sizable under-forecast in power supply expense, favourable market transactions should continue to be achievable with existing staffing levels. (BCMEU Final Submission, p. 17) **The Commission Panel agrees with BCMEU and because FortisBC has not sufficiently justified the need for an additional FTE, denies the additional FTE and related costs of $142,000 in each of 2012 and 2013.**

The Commission Panel has an additional concern with the proposal to move PPME from O&M to become part of the estimate of Power Purchase expense. We are somewhat confused by how this movement will help ensure there are sufficient resources for planning, implementation and mitigation of power purchases as submitted by FortisBC. (FortisBC Final Submission, p. 77) The proposed move will result in no cost savings, nor will it have any impact on rates so it is difficult to determine where the benefits attached to this move actually lie. While there is a potential for less scrutiny of the activities, this will only serve to reduce transparency rather than increase efficiency and will only muddy the waters with respect to direct annual comparisons of metrics based on O&M expenditures. **Accordingly, the Commission Panel directs FortisBC to continue to maintain PPME as part of O&M expenses.**

5.1.3 Planning Reserve Margin

Following the Western Electricity Coordinating Council (WECC) recommendations, FortisBC is proposing to implement a PRM within the test period. FortisBC has included $310,000 in its Power Purchase Expense which is the forecast cost of holding an additional resource for the fourth quarter of 2013. FortisBC asserts that it is common practice to consider the level of capacity reserves required to handle long-term requirements and most neighbouring utilities carry PRM as a means to meet uncertain load requirements, provide operating flexibility and manage uncertainty in resource delivery. FortisBC states that while it is not mandatory, it believes it is prudent to carry an appropriate level of PRM. (T5:747, 748,763; T4:765; Exhibit B-8, BCUC 2.7.2)

FortisBC states there are three circumstances which have the potential to drive the need for PRM:

- Unavailability of supply due to unplanned generating unit or transmission outage,
- Unexpectedly high loads, typically due to extreme weather events, and
- A period of accelerated growth that outpaces the installation of new power supply resources. (Exhibit B-1-2, pp. 53-54)

FortisBC asserts that looking forward, a failure to carry a PRM will force the Company to rely on market purchases in order to meet future capacity shortfalls which, depending on the market, could become increasingly risky. Risk factors identified by FortisBC's consultant, Midgard Consulting, include increasing installed intermittent generation, decreasing regional capacity margins and the re-introduction of industrial load following an economic recovery, among others. (Exhibit B-1-2, Appendix D) FortisBC concludes that, given these risk factors, a failure to include PRM as part of its resource adequacy requirements exposes ratepayers to an unacceptable level of risk. (Exhibit B-8, BCUC 2.7.2)

With respect to quantification of the PRM requirement, FortisBC indicated that it has been doing further assessment. In testimony during the oral phase of the proceeding, Ms. Des Brisay, FortisBC Vice President of Energy Supply and Resource Development, stated that the formula-driven approach to determining PRM proposed in the Application may overstate PRM requirements. Ms. Des Brisay further stated that a detailed assessment is being undertaken and the Company is now taking a probabilistic approach to PRM and hopes to have an analysis completed by the end of the third quarter of the current year. (T5:766) Earlier, Ms. Des Brisay commented on that analysis by stating that "what is very clear is that it's not clear." In her testimony she continued by stating that there is a bit of art and science in determining an appropriate PRM and that it is very utility-specific. (T4:741)

ICG notes FortisBC's acknowledgement that its initial approach to PRM was not supported by evidence. ICG submits that the new approach to Planning Reserve Margin is not acceptable because it has not been sufficiently developed to where it can be relied upon by the Commission to determine fair and reasonable rates. ICG also points out that one of the underlying concerns leading to a need for PRM is risk associated with capacity shortfalls. ICG questions the submissions of FortisBC with regard to capacity constraints and submits that before the Commission Panel can approve PRM for ratemaking purposes, it needs to agree that this region has become tight from a capacity perspective. In addition, ICG points out that FortisBC's RS 3808 PPA contract negotiations with BC Hydro have not been completed and FortisBC does not know whether it will include excess capacity provisions to allow the forecast load requirement to be met without a PRM. Accordingly, ICG concludes that a PRM should not be approved at this time as the RS 3808 PPA contract negotiations with BC Hydro have yet to be concluded and further development of the methodology to identify the appropriate PRM is required. (ICG Final Submission, pp. 29-34)

BCPSO submits that a key factor in FortisBC's need for PRM is capacity constraints. BCPSO agrees with ICG that FortisBC may not be facing the capacity constraints which it has predicted. BCPSO concludes that the Commission should be satisfied that capacity constraints actually exist before allowing PRM requirements into rates. (BCPSO Final Submission, p. 16)

FortisBC notes that the Midgard Planning Reserve Margin Report identifies six factors which are aligned with a potential increase in capacity resource market costs within the WECC-Canada and WECC –Northwest Regions. Each of these is described by the Midgard Report as a risk factor and none is a justification in itself. FortisBC points out that the Midgard Report lists three potential circumstances which drive the need for PRM (listed above in this Section). FortisBC argues that there is, therefore, no basis for the ICG assertion that the Commission needs to agree that the region is becoming increasingly tight for capacity before approving rates based on PRM requirements.

FortisBC acknowledges that it is adopting a different approach to assessing PRM than was originally proposed but argues that consideration of PRM in assessing the adequacy of its resource portfolio is prudent and should be accepted by the Commission. The Company proposes to complete its PRM study and recommendations by the end of the third quarter of 2012 and file these with the Commission at that time for review and approval of related power purchase costs required to meet the appropriate resource adequacy standard. (FortisBC Reply, pp. 64-68)

Commission Panel Determination

It is clear from the evidence that there is a significant amount of work to be completed with respect to development of a methodology to determine an appropriate PRM, a point with which neither the Applicant nor the Interveners seem to disagree. **The Commission Panel also agrees with this assessment and therefore denies the proposal to implement a PRM at this time and the proposed additional $310,000 in planned Power Purchase Expense for 2013.**

The Commission Panel agrees with FortisBC's suggestion to complete its PRM methodology study and file it with the Commission along with its proposed recommendations later in 2012. Hopefully, by that time, the Company will have completed its BC Hydro RS 3808 PPA negotiations and any implications of the new agreement can be taken into consideration when reviewing the new proposal. The approval of the Power Purchase Expense Variance Deferral Account (PPEVDA) will allow any approved expenses incurred during the test period to be deferred to 2014.

5.1.4 Water Fees

FortisBC's power supply costs include not only power purchases but also water fees. (Exhibit B-1, Tab 1, p. 7) Water fees are assessed by the Province based on FortisBC's generation in the previous year and the rate is indexed to the BC Consumer Price Index (CPI). (Exhibit B-1, Tab 4, p. 28) Variance in water fees could be a result of either volume variances in FortisBC's generation in the prior year or from rate variances due to differences in water rental rates.

Water fees were $9.3 million in 2010 and $9.0 million forecast in 2011. FortisBC forecasts water fees to increase to $9.7 million in 2012 and to $9.8 million in 2013 due to increased plant entitlement use in 2011 and 2012, respectively, as well as the increase in water fee rates from 2011 levels based on the Company's forecast of BC CPI. (Exhibit B-1, Tab 4, p. 28; Exhibit B-12)

Although FortisBC has not proposed to include variances in water fees in the PPEVDA (Exhibit B-8, BCUC 1.22.1), during the oral hearing phase of the proceeding, Ms. Des Brisay stated that doing so would be consistent with the intent of the deferral account. (T5: 850)

Commission Panel Determination

The Panel agrees that water fees are solely related to the cost of generation. Given the intent of the Power Purchase Expense Variance Deferral Account, **the Panel directs FortisBC to include any variances related to water fees in that deferral account.**

5.2 Operations and Maintenance Expenses

5.2.1 Overriding Issues

The overriding issues pertaining to FortisBC's O&M budget are discussed in the following sections.

5.2.1.1 Demographic Challenges

FortisBC faces the challenge of having approximately half of its workforce eligible to retire in the next few years. Of these, 28 percent are eligible to retire with an unreduced pension. The Company states that it is difficult to predetermine the number of eligible employees that will retire but indicates that over a five year period beginning in 2006, 24 percent of those eligible to retire with an unreduced pension actually did so. Based on this past experience, this would indicate that roughly a quarter of those eligible to retire with unreduced benefits are likely to do so. FortisBC states that the biggest challenge departmentally is with Transmission and Distribution (T&D) with 33 of 72 employees eligible to retire in 2011 with an unreduced pension. Positions requiring focus are Power Line Technicians (PLTs) where there is a market shortage, Meter Technicians, Communication, Protection and Control Technicians and Power System Dispatchers. In addition, FortisBC notes that 30 percent of the management group in T&D are eligible to retire with unreduced pensions. (Exhibit B-1, pp. 35-39)

In addition to the retirement challenge is the risk of employee turnover. FortisBC states that voluntary turnover (not including retirements) was approximately 4.5 percent from 2008 through 2010. When viewed in relation to other companies, this turnover seems to compare favourably within the Transportation and Utilities sector and is well below the average of other comparable sectors. FortisBC has reported that 181 new employees were recruited from 2008 to 2010. It seems that many of these were not actually new employees but FortisBC employees moving to new positions within the organization. Such backfills often result in a cascading effect when filled with internal candidates. (Exhibit B-1, pp. 39-40)

Within the Application, FortisBC outlined a number of initiatives it has been undertaking as part of its workforce strategy to offset the combined effects of retirements and other turnover. Included among these are the following:

- A PLT apprentice program
- Sponsorship of the “Bright Futures” program to create interest in the industry within schools.
- Development and Execution of succession and workforce plans.
- Investment in Education.
- Offering Scholarships and participating in Co-op programs in conjunction with schools.
- Development of a Supervisory Skills program.

(Exhibit B-1, pp. 40-41)

Commission Panel Determination

The Commission Panel acknowledges the challenges faced by FortisBC with respect to planning for and dealing with the potential retirement of a significant number of employees in the near future. The Panel also acknowledges the work the Company has put into developing initiatives to mitigate or at least soften the impact of a large number of retirements if they were to occur. However, of concern to the Panel is the lack of clarity with respect to this problem beyond the current test period. During the oral phase of the proceeding, Ms. Drope, FortisBC's Chief Human Resources Officer, was asked to comment upon whether FortisBC, looking beyond the current test period, had forecasted the size of the problem, the costs, and when an end can be expected to the "bubble" of retirements moving through the system. Ms. Drope replied that an analysis had not been completed because of the number of variables at play but estimated that 10 years is a likely time horizon. Further, when asked whether a detailed plan or cost estimates for that 10 year period had been developed, Ms. Drope failed to confirm that a plan had been completed and was unable to respond to the cost implications "off the top of [her] head." (T3:581-582)

The Commission Panel is of the view that this issue is sufficiently important to warrant further analysis, including a comprehensive plan outlining the implications, activities and costs of dealing with this workforce challenge. **Therefore, FortisBC is directed to prepare a workforce action plan to address this issue covering, at a minimum, the next 5 year period and file it with the Commission no later than December 1, 2012.**

5.2.1.2 Productivity Factor

As noted previously in Section 3.3, there were a number of submissions regarding the need for productivity improvement. The BCMEU in its submissions expressed concern that FortisBC had not included a productivity factor in the preparation of the O&M budgets and urged the Commission to impose a productivity target of 1.5 percent for both 2012 and 2013. BCPSO agreed with BCMEU with both the concept of a productivity factor and the amount. For purposes of clarification, the Commission Panel interprets these submissions to mean that both parties are in agreement that an overall reduction of 1.5 percent of O&M budgets should be imposed by the Commission as a means of driving productivity improvement.

FortisBC advanced the position that productivity improvement factors are not appropriate if applied outside of PBR. The Commission Panel has addressed the need for productivity improvement factors in Section 3.3 of this Decision. The Panel will now address the issue of productivity improvement from the following perspectives:

- whether FortisBC has demonstrated that it has adequately addressed productivity improvement in this proceeding.
- whether there is evidence to justify imposing a productivity factor as suggested by BCMEU and BCPSO.

FortisBC states that it has achieved O&M efficiencies of 10.4 percent as a result of the negotiated productivity improvement factors during the PBR period. The Company acknowledges that there have been increases in O&M expenditures forecast for both 2012 and 2013 but submits that an increase in O&M expenditures is not inconsistent with performance during the PBR period. FortisBC further submits that there are factors other than a lack of productivity which could result in an increase in O&M costs regardless of how efficient the Company has been. These include items such as inflation, but also could involve the need to undertake new expenditures in certain areas or the need to reclassify an expense from capital to operating. In support of its management of O&M costs and resultant productivity, FortisBC states that "[a]fter factoring out the $3.78 million that was transferred from capital to O&M expense in 2011 as directed by Order G-195-10, concerning the Company's 2011 Capital Expenditure Plan, and those items referred to under the PBR mechanism as extraordinary O&M expense, the O&M expense per customer, on a real basis, has declined over the period 2007 to 2010". (FortisBC Reply, pp. 26-27)

Commission Panel Determination

The Commission Panel acknowledges that growth in O&M or O&M per customer are factors in determining whether an organization can be described as being efficient and productive. In the Panel's view the forecasted growth of O&M for the test period is not unreasonable (2.8 percent in 2012 and 2.6 percent in 2013), as it is generally in line with inflation. (Exhibit B-1, Tab 4, p. 31; Exhibit B-12, Tab 7, p. 1) We also accept that there are factors beyond the control of the Company which can affect growth of O&M and related measures. However, while O&M metrics must be considered, they do not directly address the question of whether FortisBC has demonstrated that it has addressed the issue of productivity improvement within this proceeding.

In his testimony, Mr. Walker, FortisBC's President and CEO, spoke to the issue of productivity and stated that he believed that a continuous focus of the Company was on productivity and how to be more efficient and that this commitment to finding efficiencies was well demonstrated within the Application. (T2:118-119) Moreover, throughout the O&M departmental review (Exhibit B-1, Tab 4), the Company outlined steps which had been recently undertaken or were planned to be undertaken in each of the departmental workgroups in a subsection entitled "Management of Cost Efficiency." Many of the initiatives undertaken were in recognition of the need to do things differently as a means of controlling costs and creating efficiencies and, in the view of the Commission Panel, provide an excellent example of the types of practices required to keep rates from rising unnecessarily. Further evidence of the Company's commitment to improving productivity is illustrated in answer to BCUC IR 1.28.2 which summarizes productivity improvement measures taken over the PBR period. The Panel notes that these examples would be more instructive if they were measured and quantified in dollar savings.

Given the evidence and the fact that the increases in O&M expenditures are within a reasonable range, the Commission Panel is not in agreement with BCMEU and BCPSO with regard to imposing a productivity improvement factor. However, this should not be interpreted to mean that the Commission Panel is satisfied with the need for all of the expenditures within the O&M area. O&M expenditures will be addressed in greater detail in Section 5.2.2.

5.2.1.3 Integration of FortisBC and FortisBC Energy Utilities

The level and speed of integration of common functions among the FortisBC group of companies was very much at issue in this proceeding. FortisBC states that the process is at an early stage as a number of key foundational elements (among these is the proposed amalgamation of the gas utilities) must be put in place. To date, the senior management teams of both organizations have been combined with the result that total executive costs in 2013 are projected to be only $13,000 higher than in 2007. Additionally, a Board of Directors has been shared by both organizations since in 2010, resulting in significant savings. FortisBC indicates that it is now about to start the process of looking for efficiencies through alignment of operational elements of the business. As noted by Mr. Walker under cross examination, the Company expects to see additional benefits by the latter part of 2013 and expects there to be filings to deal with integrated activities in 2014 and 2015. Further, Mr. Swanson, FortisBC's Director of Regulatory Affairs, noted that the process is just starting and there will be a period of time required for investigation and trying to determine whether there are potential savings. (Exhibit B-1, pp. 95, 100; FortisBC Final Submission, pp.16-17; T2:135, 267)

While acknowledging that some progress has been made, BCMEU expresses scepticism with the level of effort that FortisBC has applied in pursuing opportunities for integration to the benefit of ratepayers. BCMEU believes that additional savings can be attained (presumably in the short term) and states that it is frustrated that opportunities may not be identified earlier. (BCMEU Final Submission, p. 7)

FortisBC states that it is unrealistic to expect benefits beyond those embedded in the Application to be achieved before the end of the test period and argues that it would not be reasonable to reduce FortisBC's revenue requirements. FortisBC points out that while savings may be achieved at the higher level within the companies, this does not necessarily apply to lower levels of the two organizations. The reasons for this relate to the differences in commodities sold, different customers (in most cases) and embedded systems that work well for each organization. FortisBC concludes by stating that further synergies may be achieved following the Company's filing of a shared services model, which is unlikely to occur before the 2014 RRA application. (FortisBC Reply, pp. 16-18)

Commission Panel Determination

The Commission Panel, like BCMEU, would like to see the process of integration of common functions move forward more quickly. However, we accept that proceeding in this direction may not be a simple matter and must be done only after careful consideration. **Because of this, the Commission Panel is not prepared to be overly prescriptive at this time and will allow FortisBC to continue to proceed on the timeline it has proposed. However, we expect the issue to be fully explored and reflected in filings no later than 2014.**

5.2.1.4 Cost Allocations

FortisBC has stated that costs related to the Board of Directors' compensation and other expenses are shared amongst FortisBC and FEI utilizing a Massachusetts Formula which is applied to revenue, payroll and net tangible assets with a forecast allocation of 23.35 percent to FortisBC. The method for allocating the expenses of senior management between FortisBC and FEU differs significantly from this. In the case of senior management, FortisBC is charging FEI for those FortisBC executives who have responsibilities in FEI and is receiving charges for those FEI executives who have responsibilities at FortisBC based on estimated time spent.

ICG disagrees with the method of cost allocation for executives. ICG submits that the costs of executive officers should also be allocated to FortisBC on the basis of the Massachusetts Formula. (ICG Final Submission, p. 17) ICG provided no reasons as to why this was appropriate.

BCMEU concurs with the position of ICG and submits that, relative to other members of the FortisBC group of companies, FortisBC is potentially being overcharged by not using the Massachusetts Formula. (BCMEU Final Submission, p. 15)

FortisBC submits that the allocation of executive costs based on executive estimates of where time is spent is appropriate and there is no cross-subsidization between gas and electric customers. FortisBC continues by stating that the use of the Massachusetts Formula to allocate costs is currently being considered and once it has completed an examination of optional methodologies, the Company expects to bring the results before the Commission for review and approval. (FortisBC Reply, pp. 40-41)

On a related matter, FortisBC seeks to streamline the cross charges for executives to and from FortisBC Energy Inc. and base it on a fully loaded wage (excluding the current overhead charge) thereby mirroring the process approved in the 2012-2013 FortisBC Energy Utilities Revenue Requirements Decision. (Exhibit B-1, Tab 4, p. 100)

Commission Panel Determination

The Commission Panel concurs with the position which has been taken by FortisBC. There is value in exploring a variety of options for cost allocation and considering the implications of each. In the meantime, the Panel is satisfied that the allocation based on time estimates is reasonable and does not result in a significant variance from an appropriate amount. **The Commission Panel accepts FortisBC's proposal to continue to allocate costs for executive time based on the executives' estimates until such time as alternatives have been reviewed and a new proposal is put forward by the Applicant. The Commission Panel also approves the proposed handling of cross charges for executives based on a fully loaded wage only.**

5.2.2 Review of Operating and Maintenance Costs and Issues

5.2.2.1 Introduction

FortisBC's proposed O&M expenditures are approximately $55.4 million in 2012 and $56.8 million in 2013 which includes PPME as previously determined. This represents a 2.8 percent increase in 2012 and 2.6 percent increase in 2013. (Exhibit B-1, Tab 4, pp. 31-32; Exhibit B-12)

FortisBC submits that its 2012 and 2013 O&M Expense forecasts have been developed in support of the Company's business objectives, ensuring that O&M funding is appropriate and prioritized to meet the needs of customers. FortisBC states that its annual departmental O&M budgets are prepared by the department managers and incorporate both a trended and zero-based approach where appropriate. The budgets then go through a cycle of reviews and updates, and are eventually approved by the Company's Executive and Board of Directors. (Exhibit B-1, Tab 4, pp. 28-29)

FortisBC states that the costs for PPME have been excluded from these budgets but, if inclusion of the PPME costs in Power Purchase Expense is not approved by the Commission, the costs will be reclassified to O&M Expense. (Exhibit B-1, Tab 4, p. 29) A summary of the O&M expenses by department sought in this Application is provided in the table below:

Table 4

DEPARTMENTS	2012 Forecast	2013 Forecast
	($000s)	
Generation	2,287	2,497
Utility Operations	18,503	18,964
Mandatory Reliability Standards	1,179	1,187
Cominco Facility Charge	46	46
Brilliant Terminal Station	3,160	3,192
Internal Audit	396	393
Legal & Regulatory	1,520	1,548
Customer Service	6,737	6,806
Community & Aboriginal Affairs	674	689
Communications	923	952
Human Resources	1,840	1,874
Information Technology	2,841	2,846
Health, Safety & Environment	925	953
Facilities Management	3,685	3,466
Finance & Accounting	3,275	3,360
Transportation Services	573	593
Supply Chain Management	498	505
Corporate & Executive Management	5,112	5,674
TOTAL O&M EXPENDITURE	54,174	55,544
Power Purchase Management Expense	1,211	1,266
TOTAL O&M EXPENDITURES incl. PPME	55,383	56,810

(adapted from Exhibit B-1, Table 4.3.1 and Exhibit B-12, Tab 7, p. 1)

The Commission Panel has reviewed the relevant material pertaining to O&M. In what follows, we will separate the O&M budgets into Labour related costs and Non-Labour related costs and address the issues related to each in turn. Following this, the Panel will address any remaining issues not specifically related to either of these categories.

5.2.2.2 Labour Related costs

Based on the information in Table 4.3.4 of the Application (Exhibit B-1-6, Tab 4, p. 45), the number of FTEs has remained relatively stable over time. This trend continues into the current test period with 3 additional FTEs planned for 2012 and an additional 1 FTE planned for 2013. Labour costs are projected to increase by 1.5 percent in 2012 and 2 percent in 2013 which is a positive outcome given the size of labour adjustments contemplated in Table 4.3.2.1 which is discussed below.

i. Labour Inflation

FortisBC identifies the Company's three employee groups as unionized, exempt and executive employees. The Company states that its unionized employees are represented by either the Canadian Office and Professional Employees Union (COPE) or the International Brotherhood of Electrical Workers Union (IBEW).

FortisBC states that for each employee group, it targets a total compensation package which is at the median level of its peer group of companies and asserts that labour and benefits inflation are primarily non-discretionary cost increases. The Company affirms that given the demographic challenges, it must continually monitor and assess its total rewards framework and find a balance, allowing talented people to be attracted and retained. FortisBC states that the guiding principle is to have a total compensation program which is prudent, competitive, understandable and efficient to administer. Table 5 below outlines the labour adjustments which have been made from 2007 through to the present.

Table 5 – Labour Inflation (2007-2013)

	General Assumptions	2007A	2008A	2009A	2010A	2011F	2012F	2013F
2.0	**Pay Increases**							
2.1	COPE(1)	2.5%	2.5%	2.5%	3.5%	*	*	*
2.2	IBEW(2)	1.5%	3.0%	3.0%	3.0%	4.0%	5.0%	*
2.3	Exempt	3.0%	4.0%	3.5%	4.0%	3.0%	3.0%	3.0%

(Exhibit B-1, Tab 4, p. 34)

FortisBC states that for the unionized staff and, consistent with past practice, length of service-related step increases have been included in labour inflation. Presumably, we can infer from this data that this is not the case for Exempt employees. Wage increases for IBEW total 4 percent and 5 percent for 2011 and 2012, respectively. Increases for COPE over this period remain subject to negotiations.
(Exhibit B-1, Tab 4, pp. 32-34)

FortisBC submits that a key consideration with respect to the IBEW contract is that it covers PLTs. The Company states that it has had difficulty in finding and retaining PLTs due to the high demand for this workforce. FortisBC further submits that over the last number of years, 15 percent of PLTs have left the organization (a slightly higher number than have retired) to seek employment elsewhere. (FortisBC Final Submission, p. 39; Exhibit B-1, Tab 4, p. 51; T6:1023-1028)

During the oral phase of the proceeding, Counsel for FortisBC had Ms. Drope provide information concerning collective bargaining agreements in re-examining certain evidence provided by Mr. Walker in his testimony. Ms. Drope's evidence included the following:

- Recent research published by the Canadian Electricity Association in 2011 states that 45,000 workers will need to be recruited by utilities by the end of 2016 and utilities have gone on record stating that they intend to poach employees for many critical positions.
- The base hourly rate for FortisBC PLTs is $39.91.
- The Line Contractor Association base hourly rate is $44.97.
- BC Hydro's comparative rate is $37.96 for PLTs.
- The base rate for PLTs at Altalink in Alberta is $45.12.
- BC Hydro's compensation package for PLTs includes specific provisions not offered by FortisBC that make the rates comparable. These include 17 additional days off.
- FortisBC was able to negotiate some productivity offsets as part of the package.

(T3: 286-292, 294-295)

ICG asserts that the IBEW contract illustrates the FortisBC approach to cost control and prudent management which sends a message "...that FortisBC does not yet appreciate the need for fiscal restraint." ICG states that this is in sharp contrast to the provincial government message of restraint regarding wage increases. ICG further states that if FortisBC had focused on reducing costs with respect to the IBEW contract, the Company would have followed the 2010 Zero mandate or the more recent 2012 Cooperative Gains mandate.

The position taken by ICG is that FortisBC negotiated a contract with the IBEW that included percentage increases which were well beyond the norm and were not reflective of the downward pressure on wages which existed in 2010 (when the contract was negotiated). ICG has relied on information from:

- the BC Bargaining database (Exhibit C 9-9) which reported BC Hydro signed an agreement with the International Brotherhood of Electrical Workers, Local 258 for 0 percent for the period April 1, 2010 to May 31, 2012;
- the 2012/13 to 2014/15 Budget and Fiscal Plan (Exhibit C-9-10), outlining the British Columbia Government's public sector compensation mandate; and
- a MMK Consulting Report (Exhibit B-4, BCUC 1.179.1), which provided statements in support of a downward trend in contract settlements since 2008 as putting pressure on 2010 negotiations to settle at lower rates.

ICG argues that Ms. Drope was unable to answer tough questions with respect to the IBEW contract especially in support of "her conclusion that there has not been a downward trend in contract negotiations since 2008." ICG states that, in response to queries looking for particulars, her evidence amounted to vague references to newspaper articles and a memorandum of understanding. Further, ICG asserts that the affirmative response of Ms. Drope to a question posed by the Panel Chair as to whether FortisBC has a turnover problem puts an end to suggestions that turnover is a justification for the increases within the IBEW contract. (ICG Final Submission, pp. 14-16)

BCMEU expresses concern that ratepayers are paying a significant rate increase to extract "productivity gains" over the test period which may reduce O&M to the benefit of shareholders. BCMEU submits that the solution to ensure the ratepayer receives a share of the benefits for this investment is for the Commission to impose a productivity target. (BCMEU Final Submission, pp. 11-12)

BCPSO made no submissions with respect to this issue.

FortisBC argues that the position taken by ICG has no basis and is not supported by the evidence. The Company submits the following:

- with regard to ICG alleging that Ms. Drope was unable to comment on whether BC Hydro's PLTs would have settled for 0 percent over 2012 and 2013, FortisBC asserts that when the question was rephrased to ask whether BC Hydro PLTs settled for 0 percent over the two years, she answered "no."
- The part of the MMK Consulting Report focused on by ICG was construction labour which the Company argues is not at issue in this instance. Further, the report in question was prepared in May 2010 which was over a year past the conclusion of the IBEW negotiations.
- ICG's reliance on the statement that there was no turnover problem, while applicable to the company as a whole, did not apply to PLTs which were identified as a particular problem.
- Even if there was no percentage increase for BC Hydro PLTs over the test period, the differences in other aspects of the BC Hydro and FortisBC contracts result in greater absolute payments by BC Hydro.

FortisBC argues there is no basis to the BCMEU assertion that the contract may reduce O&M during the test period to the benefit of the shareholder only. The Company submits the contract negotiations were conducted several years ago and any implications of the contract can be readily forecast. (FortisBC Reply, pp. 31-34)

Commission Panel Determination

The Commission Panel agrees that on the surface the percentage increase offered to IBEW seems to be on the higher side of what might have been expected over the past few years. Moreover, the information provided through the BC Bargaining database suggests that in the time frame of the negotiations, other comparable negotiations in the Transportation, Communication and Other Utilities areas resulted in settlements which were significantly lower on a percentage basis than that reached by FortisBC. (Exhibit C9-11) However, what is not known are the issues and circumstances that were at play in the comparable negotiations and whether they are actually comparable. Because of this, the Panel believes the information in Exhibit C9-11 should be given only limited weight.

What is known with respect to the FortisBC settlement is that a significant number of employees in the bargaining group, the PLTs, were and are in high demand and short supply. Moreover, the role played by PLTs is an important one and their contribution to the operations of the company cannot be ignored. Finally, in the view of the Commission Panel, FortisBC has made the case that the risk of retirement and turnover with regard to PLTs is significant.

Nonetheless, the question remains as to whether these circumstances justify the size of wage increase which was awarded in the recent IBEW contract. In the view of the Panel, the evidence provided by Ms. Drope with respect to comparative salaries was most informative. As described, the base rate for PLTs is slightly higher with FortisBC than it is with BC Hydro. However, when the additional benefits that BC Hydro PLT employees receive are considered, the total compensation between the two companies becomes more comparable. When a comparison is made with Altalink in Alberta the base rate very much favours employees of Altalink. While perhaps not directly comparable, the fact remains that both companies compete for people in the same market. **For these reasons, the Commission Panel has determined that acceptance of the IBEW contract as it applies to rates is reasonable.** In making this determination, the Commission Panel understands that there is a significant part of the IBEW bargaining unit that is not in a PLT position. However, there was little evidence to suggest that the wages negotiated for the other employees were unreasonable.

ii. Executive Compensation

FortisBC's executive compensation program involves four main elements – base pay, short term incentives, long-term incentives and benefits. Collectively, these comprise what the Company describes as the "Total Rewards" package which, FortisBC asserts, supports customer needs and contributes to the support of both long and short term corporate objectives. FortisBC states that the compensation program is designed to provide competitive compensation and further its ability to attract and retain qualified and experienced executives. As a general policy, FortisBC has established its base program and related initiatives target for its executives to be compensated at the median level of a broad reference group of companies as established by Hay Management Consultants. This reference group is not weighted in favour of utilities. FortisBC submits that this is in keeping with its practice of hiring from a variety of other industries as well as energy and utilities. (Exhibit B-1, p. 44; Exhibit B-4, BCUC 1.34.4)

With respect to base salaries, FortisBC submits the normal range is between 80 and 110 percent, with the target amount being 100 percent. The Company further submits that an individual's placement within this range is determined after consideration of work experience and job performance. Short term incentives are related to the achievement of short term objectives and focus on key areas such as cost control, customer service, and safety and reliability and are tied to the achievement of specific targets. Long term incentives are intended to focus executives on sustained customer value creation through long-term strategies which provide a balance between long and short term company and customer interests. FortisBC has chosen to furnish its long-term incentives through participation in its stock option plan, the cost of which is funded by the shareholder. The Company submits that this would also be included in regulated expense but for Order G-52-05. To round out the executive compensation, the Company offers a Supplemental Employee Retirement Program (SERP) funded by the ratepayer which provides an accrual of 13 percent of all earnings in excess of the Canada Revenue Agency's RRSP limit. FortisBC states its consultant, Hay Management Consultants, advised that this is industry standard and the amount is reasonable and within the norm in Canada. (Exhibit B-8, BCUC 2.10.2; Exhibit B-4, BCUC 1.34.1, 1.34.5; T2:121; T3:439-440; FortisBC Final Submission, p. 48)

FortisBC argues the incentive portion of executive compensation is levered off of four broad categories, which make up the "scorecard", only one of which is earnings and directly benefits the shareholder. Additionally, the scorecard itself accounts for only 50 percent of the incentive pay with the remaining 50 percent being related to personal performance. FortisBC therefore concludes that Company earnings make up only a small component of the overall incentive plan. (FortisBC Final Submission, pp. 48-49)

BCMEU notes that over the test period, BC Hydro has a 0 percent increase in executive compensation. Further, BCMEU notes that in the oral phase of the hearing it was identified that FortisBC executive compensation was equal to or greater than that of the reference group. BCMEU submits that because the expansion of deferral accounts lowers the risk of operating a utility, it does not seem appropriate that FortisBC's executive compensation is so high and questions how this may affect the ability to negotiate settlements with the bargaining unit. Specifically, BCMEU also raises the following concerns:

- Executive base salaries are above the 100 percent target amount and the average compensation is above the average target median.
- Short term incentives are not sufficient to promote productivity improvements within the organization.
- The appearance is that FortisBC executives are getting the best of both worlds through base pay equal to or better than the reference group and further compensation through stock options.

BCMEU concludes by stating it would endorse an approach that would separate bonus elements of executive compensation from pensionable benefits. (BCMEU Final Submission, pp. 12-14)

BCPSO points out there is a need for benchmark information on FortisBC's executive long-term incentive plan (stock options) and submits the cost of these stock options should continue to be borne by the shareholder. (BCPSO Final Submission, pp. 6-7)

None of the other Interveners commented on this issue.

With respect to executive salaries, FortisBC states that prior to the job scope change in 2010, salaries were held flat and increases reflected the change in scope of executive positions and the roles executives play. Concerning a reduced level of risk for an executive operating a utility due to the expansion of deferral accounts, FortisBC responds that there is no basis to suggest reduced risk for the utility or the members of the executive and points out that Ms. Drope testified that if there was less risk, executive compensation would not necessarily be lower. Finally, with respect to concerns raised with regard to the ability to negotiate a reasonable settlement with the bargaining unit, the Company points out that the scope changes with respect to executive roles are not occurring at the bargaining unit level.

FortisBC responds to the remaining BCMEU concerns as follows:

- On the matter of incentives to find productivity improvements, FortisBC submits that the evidence is that the Company has cost control incentives through its incentive program for non-union employees.
- Base salary and short term incentives do not exhaust the total compensation paid at other companies. FortisBC points to Ms. Drope's testimony that a stock option program is common and market competitive.
- Excluding executive bonuses from pension benefits would depart from how the pension contribution is arrived at. FortisBC points to Ms. Drope's testimony that the pension contribution is derived from both base and incentive pay which is consistent for both the gas and electric non-union groups.

(FortisBC Reply, pp. 34-36)

Commission Panel Determination

While having some concerns, which are commented on below, the Commission Panel is of the view there is no need to change the FortisBC Executive Management base pay or the incentive program at this time. The Panel considers that there is a need for both a competitive base pay and an incentive package to attract and retain quality executives. Relying upon statements attributed to Hay Management Consultants by FortisBC, the Panel is satisfied that the compensation program offered by the Company is in the range of those in the reference group of companies and therefore competitive. However, like the BCPSO, we are of the view that the entire compensation package must be reviewed to determine whether it is appropriate. **Therefore, the Commission Panel directs FortisBC to provide benchmarking information on all elements of its executive compensation in the next RRA.** On a related matter, the Commission Panel would also like further information on the SERP program. Specifically, the Panel would like the benchmark study to address the following:

- whether the SERP is incentive-based or handled as a benefit; and
- how the 13 percent for SERP compares to amounts offered by comparable companies.

With respect to whether the incentive program should be included among pensionable benefits, the Commission Panel accepts that the incentive program is not levered solely off an earnings measure and therefore, there is some justification for the current practice of charging incentives in part to the ratepayer. What is less clear is the current practice in the labour marketplace with respect to allowing incentives to be included in pensionable benefits. We would like to see a more complete record on this matter in the future. **Accordingly, the Commission Panel directs FortisBC to include information as to current practice of their reference group of companies with regard to the inclusion of incentive payments in pensionable benefits for all groups of employees in its next RRA.**

iii. Departmental Labour Expense Issues

In spite of the lack of significant growth in FTEs and overall labour costs, the Commission Panel has with specific areas of concern with a number of O&M departments.

a) Generation

Labour costs in the Generation department are forecast to increase from $1.248 million in 2011 to $1.374 million in 2012 and $1.535 million in 2013 which represents an increase in excess of 10 percent in both years. FortisBC states that with the Upgrade and Life Extension program coming to a conclusion, the fluctuations in maintenance activities and costs of the past five years are expected to stabilize. The Company has explained that while it has managed to reduce planned routine repetitive maintenance costs, this has not fully offset the costs associated with the increase in working hours due to changes in legislation such as those relating to working alone and working in confined spaces. As a result, the Generation area is faced with an increase in planned maintenance costs of $0.24 million (Exhibit B-4, BCUC 1.38.1; Exhibit B-1-6, p. 48)

FortisBC states that it will continue to refine its maintenance program in 2012 and 2013 through development of a more condition-based maintenance approach which, over time, will allow the Company to conduct equipment maintenance based on actual need as opposed to a time-based interval. FortisBC submits that the expected benefits of this approach are increased intervals between shutdowns for maintenance and an increased capability to perform operations and plant diagnostics remotely.

Presumably the benefits of moving to a more condition-based maintenance approach as described by FortisBC will also result in cost savings. Given the size of increase in maintenance costs over the test period the Commission Panel has concerns with the speed with which the Company is refining its maintenance program. Because of this and the fact that monitoring equipment has begun to be installed, the Commission Panel is of the view that an opportunity exists for some savings to be realized over the 2012-2013 time period. (Exhibit B-1, p. 50)

b) Utility Operations

Forecast labour costs in Utility Operations have increased from $10.617 million in 2011 to $11.587 million (an increase of 9.1 percent) in 2012 and $11.974 M. (an increase of 3.3 percent) in 2013. This represents a corresponding increase of 11 FTEs in 2012 and a further 2 FTEs in 2013. FortisBC notes that it has had difficulty attracting and retaining skilled journeymen PLTs and system controllers because of the high demand for these positions. FortisBC reports there were 12 vacancies for PLT positions at the end of 2012. Given the demographic challenges outlined in Section 5.2.1.1 of this Decision, FortisBC states it will continue to actively recruit these positions and operational budgets will increase marginally over time.

FortisBC states that in response to the Commission's decision on the 2011 Capital Expenditure Plan, (Order G-195-10) capital expenditures for right-of-way reclamation, pine tree beetle hazard tree removal and hot tap connector replacements totalling $3.78 million were reclassified as operating expenditures. The Company advises that these have been included in the 2012-2013 budgets for this department.

FortisBC states that infrastructure expansion occurs at an average growth rate of 1.1 percent per year and submits that budget forecasts for 2012-2013 reflect this increase in line kilometres. FortisBC also states that right-of-way maintenance costs will also increase in 2011. Additionally, maintenance expenditures for substations are forecast to increase based on historical load and a task driven budget through the Computerized Maintenance Management System. (Exhibit B-1, pp. 52-54)

When questioned as to the size of increase from 2011 to 2012 for the whole department at the oral phase of the hearing, Mr. Sam, FortisBC's Vice President of Engineering and Generation, responded that the $1.1 million increase was made up of the following components:

- $500,000 for salary increases.
- $255,000 in incremental substation work.
- $230,000 for four additional PLT apprentices. Two of the existing apprentices will "top out" this year.
- The remaining $100,000 for various costs including the additional day in February and some additional training requirements.

(T6:1027-1029)

Of concern to the Commission Panel is whether there is sufficient justification for all of the additional expenses which have been forecast for 2012 and 2013. The Commission Panel accepts that the Company has faced challenges with respect to recruiting and retaining PLTs and acknowledges that steps have been taken to respond to this by establishing an apprentice program where there are currently four employees. The Company seeks to double the size of the program by hiring an additional four FTEs to this program during the current test period at an incremental cost of $230,000. While the Panel remains supportive of the efforts to develop future PLT resources in-house, we are not persuaded that there is a need to double the size of the program at this time. Increasing the program to 5 or 6 FTEs from the current 4 employees, in the view of the Commission Panel, would still allow the Company to continue to grow the program as it assesses the performance impact of those employees that have "topped out" or completed the program.

c) Community and Aboriginal Affairs

Overall labour costs for Community and Aboriginal Affairs have risen dramatically since 2010. FortisBC attributes the growth in budgeted costs to the increased complexity of relationships with local governments and consultation requirements for First Nations. Staffing levels were increased from 1 FTE to 3 FTEs in 2011. In addition to these labour costs, the Company has included a provision for external contractors at a cost of $36,000 for both 2012 and 2013.

FortisBC states it has worked to establish open and consultative relationships with First Nations and their communities which are important to enable decision making that incorporates the interests of the Company and its customers as well as those of First Nations. The Company submits that the development and maintenance of First Nation relationships is directly related to its ability to move initiatives forward in a timely fashion. FortisBC advises that increases in the departmental budget in recent years are a reflection of the increased cost of meeting First Nation consultation requirements due to the increasing complexity of these relationships. (Exhibit B-1, Tab 4, pp. 65-66; Exhibit B-9, Celgar 2.16.3.5)

FortisBC also argues that "under present case law FortisBC regards the Commission as having a duty to assess consultation...[so it has]... been doing its own consultation and summarizing that consultation to facilitate the Commission's ...[assessment]". (FortisBC Final Submission, pp. 51-52)

ICG maintains that while the complexity of First Nation relationships may have changed over the past 20 years, there has been no change with regard to there being a need to notify and consult with Aboriginal communities regarding facilities. The ICG notes that FortisBC has always had facilities located on First Nation lands, as it does today. Further, ICG argues the growth of costs in the past few years does not equate to the change in complexity of such relationships. (ICG Final Submission, p. 44-45)

The Commission Panel acknowledges the importance of the work that has been done with respect to building relationships with First Nations and Aboriginal communities. However, the point raised by ICG merits consideration. While building relationships and consulting with all stakeholders is undoubtedly a necessary part of doing business, and always has been, the formal "duty to consult" discussed in recent case law relates to a formal duty imposed upon the government and its agents and is grounded in the "honour of the Crown". The formal duty to consult is not a duty imposed by law upon FortisBC.

The Commission Panel notes that FortisBC is nearing the end of an aggressive capital build out and is moving toward greater emphasis on sustaining capital. (FortisBC Final Submission, p. 100) The Panel is of the view that while there will still be a need for consultation, it will be less intensive as the Facilities already exist. Therefore, we question whether there is a need for the proposed level of labour resources.

Given this and the fact that costs have risen dramatically and further increases continue to be forecast in the current test period, the Commission Panel is of the view there is an opportunity for cost reductions within the Community and Aboriginal Affairs area.

Commission Panel Determination

Taking these departmental labour expense concerns into consideration and, in addition the concerns raised as to whether there will be a need for all of the forecast requirements for Mandatory Reliability Standards discussed later in Section 5.2.2.4, the Commission Panel is of the view that a reduction in O&M expenditures for labour is warranted**. As a result, the Commission Panel directs FortisBC to reduce O&M expenditures for labour for each of 2012 and 2013 by $250,000. The Panel believes this reduction should be applied to the specific areas where concerns have been raised but will leave the decision as to where these costs are applied to the discretion of FortisBC.**

5.2.2.3 Non-Labour Costs

The following non-labour expenses in FortisBC's proposed O&M budgets are of concern to the Commission Panel and are individually addressed in the following sections. **Items not specifically addressed are approved by the Commission Panel.**

a) Asset Management Program

FortisBC proposes a staged approach to the development of an Asset Management strategy which it submits will require total expenditures of $0.8 million in 2012 and 2013. These expenditures are to accommodate the development of a project team made up of internal and external resources to examine current processes and map out an implementation plan for submission in a future capital expenditures plan application. (Exhibit B-1, Tab 5, p. 34; FortisBC Final Submission, p. 110) The project team will examine FortisBC's existing asset management process, review approved asset management models and strategies used by other utilities, investigate and evaluate available software, and provide a comprehensive report and project cost estimates with recommendations for changes.

FortisBC submits that this development work is incremental to the Company's existing workload. Without this project, FortisBC argues that it will continue to do a form of asset management, relying on professional judgment, which is consistent with other utilities. (T6:994-995)

The costs for the initial development phase of asset management are proposed to be captured in a rate base deferral account and to be dealt with in a future application. FortisBC submits that the asset management strategy would result in the development of processes and implementation of software that would provide benefits in subsequent years and, therefore, the project should be capitalized. (FortisBC Final Submission, pp. 111-112)

BCMEU argues that the expenditure on such a program may not be prudent if preliminary investigations have not been completed. (BCMEU Final Submission, p. 5) BCMEU sees no justification for the proposal and further urges the Commission to direct FortisBC to find more cost effective ways to come up with asset management processes. (BCMEU Final Submission, p. 19)

The Commission Panel notes that in 2010, FortisBC undertook a maintenance rationalization project in the Generation department which resulted in reducing routine maintenance by 10 percent and savings in labour costs of $110,000 per year. (Exhibit B-1, Tab 4, p. 50; Exhibit B-4, BCUC 1.39.4) The Panel expects these efforts and benefits from that project to continue into the test period. The Panel also notes that in 2011, additional monitoring equipment was installed at South Slocan which will assist in data collection and monitoring of equipment installed during the Upgrade and Life Extension (ULE) program. Over time, FortisBC claims that this monitoring will permit the company to further rationalize its maintenance activities by allowing maintenance on equipment to be conducted based on actual need rather than on a time based interval. The Panel notes that FortisBC's expected benefits of this approach are increased intervals between maintenance shutdowns and increased capability to perform remote operations and diagnosis of issues in the plants. (Exhibit B-1, Tab 4, p. 50) In light of the above, the Commission Panel acknowledges that FortisBC has made strides in improving asset maintenance activities and has realized benefits from these efforts.

The Commission Panel also notes the various systems that FortisBC currently has to review asset health and schedule maintenance such as GenJO, CMMS, Cascade, ArcFM and questions whether the full benefits of these existing systems have been exhausted. (Exhibit B-8, BCUC 2.15.1, 2.30.3)

Commission Panel Determination

The Panel understands that an asset management plan could provide system streamlining but the cost and benefits of such an undertaking have not been clearly presented in this proceeding. The Panel notes that there have been various asset management pursuits in the past so it is unknown whether this new proposal will create further additional cost savings or efficiencies to justify the incremental development costs. In addition, the Panel finds that, given the Company's adequate reliability performance, one of the goals of an asset management plan should be to identify and reduce non-essential maintenance to help control costs.

For these reasons, **the Panel denies the $0.8 million deferral account treatment sought by FortisBC in pursuit of the Asset Management Program.** The Panel believes that improving efficiencies and finding strategic solutions are a responsibility of corporate management and therefore should not be allowed as a deferred capital expense. **The Panel approves funds in the amount of $150,000 which may be required for external assistance over the test period. These funds may be included in the O&M budget.**

b) Community Investment (Corporate Sponsorships and Donations)

FortisBC states that expenses for Community Investment relate to the actual costs of donations and sponsorships the Company has undertaken to connect with customers and contribute to the communities that FortisBC serves. (Exhibit B-4, BCUC 1.52.3, 1.52.4) FortisBC indicates that some of these donations were made to political parties as well. (T3:315-316)

The amount of the non-labour expenses budgeted for event sponsorship and charitable donations for 2012 is $270,000 and for 2013 is $282,000. (T3:313-314)

FortisBC states that much of its work activities, including the siting of infrastructure, has an impact on communities and maintains that it is critical that the Company has a good relationship with the communities in which it operates. It argues that sponsorships and donations provided through the community investment program build such relationships and can reduce the expenses of these work activities. The Company argues that community investment is a requirement for successfully operating the utility for the benefit of ratepayers and should continue to be borne by ratepayers. (FortisBC Final Submission, pp. 52-53)

In taking the position that the cost of sponsorship and donations should be fully recovered from the ratepayer, FortisBC argues that the trend in British Columbia has been in the direction of allowing full recovery of donations made in rates if sufficient justification of customer benefit is provided. The Company further notes that this is a move away from an earlier pattern of sharing costs evenly between the ratepayer and the shareholder. The Company cites examples from recent decisions where the Commission allowed the utility to recover 100 percent of community expenditures in rates. In these cases, the Commission, in approving the expenditures, laid out expectations for further justification in future proceedings if the utility expected to continue with this practice. FortisBC argues that it has provided the justification required to support full recovery. (FortisBC Final Submission, pp. 54-56)

The Commission Panel notes the different treatment of these expenses in other jurisdictions in Canada, namely Alberta and Ontario, where donations and sponsorship costs are completely disallowed in revenue requirement applications. As noted previously, the treatment of donations and sponsorship costs in the recent past has been a 100 percent ratepayer expense until the 2012 FortisBC Energy Utilities RRA Decision (2012 FEU RRA Decision) in which community involvement spending was directed to be shared equally between the ratepayer and the shareholder. (Exhibits A2-7, A2-8, A2-9, A2-10, A2-11, A2-14; FEU 2012-2013 RRA Decision, p. 73)

ICG takes the position that all corporate sponsorships and donations should be borne 100 percent by the shareholder and not the ratepayer. ICG notes the testimony of Mr. Walker where he acknowledges that FortisBC determines the recipients of its corporate largesse and that its customers, whom FortisBC believes should continue to be responsible to pay 100 percent of these costs, may not share FortisBC's opinion as to the appropriate beneficiaries. (T2:181-182)

ICG argues that the line of reasoning set out in the March 17, 2006 decision of the Alberta Energy and Utilities Board (AEUB) in ATCO Electric Ltd.'s 2005-2006 General Tariff Application (ATCO Electric) on the issue of corporate donations, sponsorships and community relations expenses should be considered and followed. (ICG Final Submission, p. 43, citing excerpt from Decision-Exhibit A2-9) The ICG cites a quote from Decision 2004-067 of the Alberta Board which was noted and followed in the ATCO Electric:

> ...the Board considers that ***neither sponsorships nor donations*** (charitable or political) **should be included in a utility's revenue requirement.** The Board recognizes that ratepayers may not desire to support the same organizations that utility management or shareholders would support. **Therefore, the Board considers**

> **it inappropriate for ratepayers to bear such costs and *considers that all donations or sponsorships should remain as a shareholder expense.*** (Emphasis in original)

In ATCO Electric, the AEUB went on to determine that donations and sponsorships should not be included in ATCO's revenue requirement. The Board noted that "[c]ustomers have the right to support whichever charitable organizations or functions they choose through their own donation dollars and should not be expected to provide the funds to support the causes chosen by [ATCO] and for which [ATCO] receives the acknowledgement." (Exhibit A2-9, ATCO Decision, p. 68)

Furthermore, the Commission Panel notes that the Ontario Energy Board's current filing requirements clearly state that "[t]he recovery of charitable donations will not be allowed for the purpose of setting rates except for contributions to programs that provide assistance to the distributor's customers in paying their electricity bills and assistance to low income consumers" because "these expenses are not related to the provision of electricity distribution services and therefore do not appropriately form part of the revenue requirement." (Exhibits A2-10, A2-11)

BCMEU supports the sharing of expenditures on community and Aboriginal affairs on a 50/50 basis between the ratepayer and the shareholder, as being consistent with prior Commission decisions including the 2012 FEU RRA Decision. (BCMEU Final Submission, p. 14)

BCPSO submits that, at a minimum, the shareholder should pay 50 percent of the cost of sponsorships and donations, but urges the Commission to order the shareholder to pay 100 percent of such costs. BCPSO submits that the shareholder realizes significant benefits from these expenditures. (BCPSO Final Submission, p. 7)

In reply, FortisBC reiterates its interpretation of the 2012 FEU RRA Decision in that it did not exclude the possibility that ratepayers pay for donations and sponsorships in full in the appropriate circumstances. (FortisBC Reply, p. 38)

Commission Panel Determination

The Commission Panel is of the view that there are significant benefits that accrue to the shareholder from the Company's community sponsorship and donations spending. These include recognition of FortisBC as a good corporate citizen supporting the brand and improving goodwill. The Commission is also concerned that when all of the costs of Community Investment spending are borne by the ratepayer, the incentive for the Company to clearly focus on those activities that will help achieve its objectives is diminished. The Commission Panel agrees that customers may not wish to support the same causes as the Company and is also of the view that greater discipline will occur if the shareholder bears some of the community investment costs. **The Commission Panel finds that contributions to political parties should be solely for the account of the shareholder. Consistent with the 2012 FEU RRA Decision, the remaining budgeted amounts are to be shared equally between the shareholder and the ratepayer.**

c) Customer Service

FortisBC is forecasting customer growth of 1.8 percent and 1.9 percent in 2012 and 2013, respectively. However, there does not appear to be any evidence of the linkage between customer growth and the need for increased customer service. The Commission Panel is not persuaded that an incremental customer addition would necessarily result in a need for increased incremental customer service expenses.

FortisBC indicates that customer growth has created the need for customer service to find more efficient ways to handle current business while creating room to take on more customers. (Exhibit B-4, BCUC 1.29.3) When describing some of the efficiencies the Company has embarked on during the PBR period, FortisBC identifies numerous activities where Customer Service has mitigated potential cost increases through improving efficiencies. FortisBC provided a list of specific actions which have created efficiencies and states that "[t]hese efficiencies have created more time for existing staff to absorb the continual customer growth." (Exhibit B-1, Tab 4, p. 63; Exhibit B-4, BCUC 1.28.2)

The Panel commends FortisBC for its efficiencies gained in this area and expects these efficiencies to continue into the test period. Given that FortisBC indicates that there are "no significant changes in cost drivers" (Exhibit B-1, Tab 4, p. 63) the Panel is not persuaded that the non-labour costs increases of 9 percent in 2011 and an additional 8 percent increase in 2012 are needed. **As such, the Commission Panel will only approve an increase equal to the forecast BC CPI of 2.2 percent in 2012 and another 1.9 percent in 2013. (Exhibit B-1, Tab 4, p. 43) FortisBC is directed to reduce its non-labour expense forecast for this department by $113,000 in 2012 and $100,000 in 2013.**

5.2.2.4 Summary of Operating and Maintenance Cost Changes

In light of the above discussions, the Commission Panel summarizes the following reductions to O&M:

Table 6 – Adjustments to Operation and Maintenance Budgets

	Commission Panel Determinations:
Asset Management Program	$785,000 proposed in a rate base deferral account is denied. $150,000 for external consultant is allowed in O&M for the test period.
Community Investment (Event / Community Sponsorships and Donations)	Expenses shared 50/50 between ratepayer and shareholder: 2012 reduce by $135,000 2013 reduce by $141,000 Political contributions are 100% disallowed
Customer Service	2012 reduce by $113,000 2013 reduce by $100,000
Labour Related Expense Adjustment	2012 reduce by $250,000 2013 reduce by $250,000

5.2.2.5 Other Revenue Requirement Issues

i. Capitalized Overhead

FortisBC states that in its 2006 Revenue Requirements Application, it introduced a new mechanism for allocating overhead costs to capital expenditures which suggested that 25.2 percent of Gross O&M Expense should be allocated to capitalized overhead. As part of the 2006 NSA, the parties agreed that a capitalized overhead of 20 percent would be set for the term of the PBR. The Company states that this methodology was further updated based on 2010 actual results and suggests that a 23.9 percent capitalized overhead would be appropriate. In this Application, FortisBC submits that the 20 percent rate currently in place should be maintained for 2012 and 2013, noting that this will serve to mitigate variances to Net O&M Expense and related fluctuations in revenue requirements. (Exhibit B-1, Tab 4, pp. 101-103)

BCMEU submits that there is insufficient evidence on the record to support a change from that which has been proposed by FortisBC. BCMEU submits that FortisBC should be ordered to update its overhead capitalization survey in recognition of the Company's move away from capital intensive activity. (BCMEU Final Submission, pp. 18-19)

BCPSO takes no position on the capitalization rate but does suggest there is a need to distinguish between the capitalization rate of 20 percent and direct loading which is meant to capture T&D supervisory and administrative costs. (BCPSO Final Submission, pp. 12-13)

FortisBC submits that it has included an updated capitalization study in this Application and Ms. Leeners, FortisBC's Vice President of Finance and CFO, testified that this was a detailed analysis and she was not sure what more work could be done in addition to that provided. (FortisBC Reply, pp. 48-49)

Commission Panel Determination

The methodology employed by FortisBC to determine capitalized overhead is consistent with what has been used in recent revenue requirements and the 20 percent rate is also consistent with past NSAs. Further, as noted by BCMEU, there is no evidence on the record in this proceeding that would suggest a better methodology or capitalized overhead rate. While the Commission Panel does not fully agree with BCMEU, as stated below, we are of the view that further work is required in the future. **Therefore, the Commission Panel approves the requested capitalized overhead rate of 20 percent for the test period. For the next revenue requirements application, FortisBC is directed to provide an external audit opinion on the appropriateness of its capitalized overhead methodology. Further, if International Financial Reporting Standards (IFRS) is pursued in the next application, the Company is directed to perform a new study based on the accounting policy adopted at that time.** The Panel also acknowledges the concerns raised by BCPSO with respect to the need to differentiate between capitalized and direct loadings which will be addressed in the next section.

ii. Department and Corporate Overhead Loadings

A number of issues related to departmental and corporate overhead loadings were raised by the participants in this proceeding. Some of these issues were examined in detail and were the subject of IRs and questions during the oral phase of the proceeding. In some cases these questions resulted in FortisBC Undertakings which were completed following or during the oral hearing. The issues raised involve departmental and corporate overhead directly related to the following:

- the significant increase in overhead loading rates from 2008 to 2012; and
- whether direct overhead loading, as currently applied, is appropriate.

The Commission Panel will now address these issues separately.

- Increase in Overhead Loading Rates

FortisBC states that for several operating business units, where an activity supports multiple projects, costs are estimated during the budgeting process and a direct overhead loading rate is used to distribute those costs among the projects. These are in addition to the capitalized overhead costs discussed above and both are applied to capital projects. (Exhibit B-1, Tab 4, p. 102)

A concern of the Commission Panel is the significant growth in the percentage of both capitalized and direct overhead loading being applied to the various projects. Table 7 below summarizes the growth of overhead as a percentage of capital expenditures for 2008, 2010 and the forecast for 2012 for T&D projects. The Okanagan Transmission Reinforcement Project (OTR) (CPCN Application for the Okanagan Transmission Reinforcement Project) has been excluded from the calculations as it was subject to a separate loading rate pursuant to the Reasons for Decision for the OTR project. As outlined in response to Undertaking #20, the total overhead percentage applied to T&D projects is only slightly more than that applied to Generation projects. Although the gross dollars for direct overhead have remained relatively stable during the period of 2008 to 2012, the total overhead loadings for T&D have increased from 16 percent to 26 percent, as shown in the table below.

Table 7 - Capital and Direct Loading Summaries

		2008 Actual	2010 Actual	2012 Forecast
Unloaded Capital Expenditure Excluding OTR	A	93,883	77,339	74,369
Capitalized OH Excluding OTR	B	8,691	5,604	11,512
Capitalized OH (Excluding OTR) Percentage	C=B/A	9%	7%	15%
Unloaded T&D Capital Expenditure Excluding OTR	D	67,268	47,004	46,695
Direct OH	E	4,720	5,157	5,000
Direct OH (Excluding OTR) Percentage	F=E/D	7%	11%	11%
Total Loadings Applicable to T&D Sustaining Projects	G=C+F	**16%**	**18%**	**26%**

(Source: Exhibit B-8, BCUC 2.51.2)

FortisBC states that loading percentages are a function of four parameters which include, in addition to overheads, other adjustments and the Company's unloaded capital expenditure plan. By way of explanation, the Company advises that the loading rate is a calculation of the overhead amounts to be recovered, divided by the total unloaded capital expenditures. In this case, the numerator (or overhead to be capitalized) has continued to increase over the four year period while the capital expenditures have decreased. As a result, the overhead rate for both direct and capitalized overhead as a percentage of capital expenditures has increased. (Exhibit B-8, BCUC 2.51.2)

Of concern to the Commission Panel is that where capital expenditures may be reduced in any test period, the amounts being charged to capital through the capitalized overhead allocation continue to rise in both dollars and as a percentage. This appears to be counter-intuitive and indicates there may be a need to more closely align the capitalized overhead rate to the changing capital expenditures rather than to simply rely upon a percentage of operating costs as is currently the case.

An additional concern of the Commission Panel is the 2012 Forecast as outlined in FortisBC's response to BCUC IR 2.51.2. While we have been able to reconcile the figures shown in the above IR response for 2008 and 2010 to comparative figures shown in FortisBC's financial schedules and to its annual reports, the figures shown for forecast 2012 appear irreconcilable. The capitalized overhead figure of $10.834 million in Table 8 below, (which is 20 percent of gross O&M), is inconsistent with the figure of $11.512 million in the preceding table (an amount which excludes approximately $155 thousand for overhead attached to the OTR project). We can find no explanation for this discrepancy.

Table 8 – E-Operating and Maintenance Expense

	Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
	($000s)			
Total Operating and Maintenance Expense	46,148	53,885	54,172	55,794
Capitalized Overhead	(9,529)	(10,777)	(10,834)	(11,159)
Net Operating and Maintenance Expense	36,619	43,108	43,338	44,635

(Source: Exhibit B-1, Tab 7)

Commission Panel Determination

One of the concerns with using a point-in-time study to determine a capitalized overhead rate is that the amount of capital expenditures varies from year-to-year. Therefore, what may be appropriate at one point-in-time, may be above or below what should be considered appropriate in any given year. Therefore, the failure to consider the amount of capital being expended over a given period of time leads to the potential for inaccurate capitalized overhead estimates where a capitalized overhead study has not been prepared for that period. Because of this, the Commission Panel is of the view that some consideration as to the amount of forecast or actual capital expenditure is an important variable in determining an appropriate level of capitalized overhead. This may well become increasingly important as FortisBC enters a period which BCMEU describes as a move away from "the capital intense activity of Fortis in recent years to a sustaining capital approach." (BCMEU Final Submission, p. 19) **Accordingly, the Commission Panel directs FortisBC to meet with Commission staff following completion of the external audit opinion on its capitalized overhead methodology to review other options which may better reflect changes in the amount of capital being expended in a given year.** This will reduce the need to complete a comprehensive capitalized overhead study for each revenue requirement and allow capitalized overhead rates to vary annually in accordance with capital expenditure requirements.

The Commission Panel is also concerned with regard to the differing amounts of capitalized overhead reflected in Tables 7 and 8 above**. FortisBC is directed to prepare and file a report with the Commission by September 30, 2012, explaining this apparent inconsistency. If an amount greater than the 20 percent approved for capitalized overhead has been used in the calculation of rates, FortisBC is directed to adjust the capitalized overhead rates downward to reflect the approved amount for capitalized overhead.**

- Application of Direct Overhead

A second concern of the Commission Panel is whether FortisBC's current practice of charging a direct overhead loading to capital projects is appropriate. FortisBC distinguishes this from the 20 percent capitalized overhead rate applicable as well as from those cases where a person is working directly on a specific project and the time is charged directly to that project. According to FortisBC, direct overhead refers to the recovery of Transmission and Distribution supervisory and administrative costs that are not directly charged to specific projects. As noted in Table 7, the Direct Overhead is $5 million which, when added to the capitalized overhead of $10.834 million, totals $15.834 million or 29 percent of total forecast operations and maintenance costs. (Exhibit B-8, BCUC 2.25.4) This does not appear to include the Absorption Overhead applied to Generation projects, as shown in the table below, an Undertaking provided by FortisBC.

Table 9 - Overhead Loading By Category of Asset

Category of Assets		Approximate Overhead Load % by Asset Category							
		Absorption Overhead [1]		Capitalized Overhead [2]		Direct Overhead		AFUDC [3] (if applicable)	
		2012	2013	2012	2013	2012	2013	2012	2013
1	Generation	9%	9%	16%	15%	*Not applicable*		7%	7%
2	Transmission	*Not applicable*		16%	15%	11%	11%	7%	7%
3	Distribution			16%	15%	11%	11%	7%	7%
4	General Plant			16%	15%	*Not applicable*		7%	7%

Note-1: *Absorption Overhead for Generation is the equivalent of Direct Overhead for Transmission and Distribution*

Note-2: *Capitalized Overhead % also includes the ISP amortization of $677,000 per year.*

Note-3: *AFUDC is only applicable to specific projects that meet the AFUDC applicable criteria of >$100k and over 3 months in duration.*

(Source: Exhibit B-25, Undertaking #20)

Commission Panel Determination

The concerns of the Commission Panel are related to the lack of clarity as to how the amounts charged to direct overhead are calculated and whether there are some cases where costs which already form part of capitalized overhead are also charged as direct overhead, leading to duplication.

The Panel questions whether managerial and supervisory costs which are part of overall O&M expenses should be charged to capital projects. The Panel also notes that, in response to Undertaking 19, FortisBC has provided a list of departments that charge time to direct overhead loading. Among these are three Departments (Health and Safety, Finance and Procurement & Material) which are also included among those departments charged out through the capitalized overhead allocation. As noted above, our concern is that there is potential duplication in that the costs allocated through capitalized overhead are also being charged through direct overhead loading.

Recognizing there is a need for more granular information and a closer examination of the current methodology, the Commission Panel approves the application of direct overhead as proposed by FortisBC for the current test period only. The Commission Panel directs FortisBC to ensure the direct overhead loading methodology is commented upon as part of the external audit opinion which is directed in Section 5.2.2.5 (i) Capitalized Overhead. In addition, the Commission Panel directs FortisBC in the next RRA to provide a more fulsome explanation as to the appropriateness of the direct overhead loading methodology and to include a full reconciliation and justification. In preparing the material, the Company is encouraged to study the allocation methods of other comparable utilities and report on those findings.

iii. Mandatory Reliability Standards

On June 4, 2009, the Commission issued Order G-67-09 adopting certain Mandatory Reliability Standards (MRS). These standards are very similar to those developed by the North America Electric Reliability Corporation and the Western Electricity Coordinating Council and require affected BC entities to bring themselves into compliance with those standards that are applicable to them. Accordingly, FortisBC is responsible to ensure the Company is and remains compliant with all applicable standards. FortisBC states that it has reviewed the standards, filed mitigation plans to become compliant and submits that continued effort will be required to maintain compliance with all relevant standards and deal with changes to existing and new standards.

FortisBC has requested approval of O&M funds totalling $1.179 million in 2012 and $1.187 million in 2013 for Mandatory Reliability Standards in this Application. In addition, the Company seeks to amortize accumulated costs estimated at $0.7 million for this program over five years starting in 2012. The Company states that effort and costs going forward will focus on transitioning from capital expenditures to operating costs to maintain compliance. FortisBC states it has moved from 100 percent of the effort being directed to capital in 2010 to 100 percent of the effort being directed to operating in 2012 and 2013. This has resulted in an increase of $0.224 million in budget for 2012, with little additional requirements for 2013. (Exhibit B-1, Tab 4, pp. 54-55)

BCMEU has expressed concern with the program noting that the expenditures when compared to BC Hydro seem to be high.

FortisBC in response noted that in the oral phase of the proceeding, Mr. Chernikhowsky, FortisBC's Director of Engineering Services, testified that because BC Hydro has traditionally done business with the United States it has already implemented a number of the systems that support MRS. These standards had not been previously applicable to FortisBC because it was not trading across the border, nor did it have interconnections with other utilities. Given this context, FortisBC notes that its costs would understandably be proportionately higher than those of BC Hydro. (FortisBC Reply, p. 40)

Commission Panel Determination

The Commission Panel notes that the Company has built its forecast budget to cover the possibility that there will be changes to existing and the addition of new standards and there is no evidence to suggest that this is likely to occur in the future. However, the Panel acknowledges that the Mandatory Reliability Standards Program is an important program required by legislation. In addition, the Mandatory Reliability Standards program is still in the early stages of implementation and it is difficult to determine the exact costs which will be required to maintain compliance with all applicable standards. **Because of this, the Commission Panel is reluctant to take issue with the forecasts that have been prepared by FortisBC and approves the forecast expenditures, as requested.**

5.3 Financing Costs

FortisBC's financing costs are made up the cost of debt and the cost of equity. The Company's financing costs for cost of debt and cost of equity for the purposes of the Application are based on a deemed capital structure of 60 percent debt and 40 percent equity. The cost of debt is determined by the percentage of debt assumed to be included in the capital structure and the interest rate on that debt. The total percentage of debt discussed in the capital structure is determined by the Commission and the interest rate on the debt, by the banks, capital markets and the Company's credit ratings. The cost of equity is a function of the investment in rate base, the equity component in the capital structure and the rate of return on equity (ROE). (FortisBC Final Submission, p. 95)

Regarding the short-term and long-term interest rates, FortisBC submitted different forecasts at different points in time during the Proceeding. Tables 10 and 11 below summarize the Company's forecasts for short-term and long-term interest rates for the two-year test period. The first series of forecasts were used at the time of the Application, on June 30, 2011; the second, for the Evidentiary Update in early November 2011 and the third was presented during the oral phase of the proceeding, in March 2012.

Table 10 - Short-Term Interest Rate Forecasts for 2012 and 2013

			2012F[1]	2012F[2]	2012F[3]	2013F[1]	2013F[2]	2013F[3]
	A	Average Forecast Rate for Bankers' Acceptance Rates (3-month T-bill)	2.33%	1.13%		3.80%	1.95%	1.90%
+	B	Spread	0.30%	0.30%		0.10%	0.30%	0.30%
=	C	Sub Total Before Stamping Fee[4]	2.63%	1.43%		3.90%	2.25%	2.20%
	D	Rounded Up to Nearest 0.10%[5]	2.70%	1.50%		3.90%	2.30%	2.20%
+	E	Acceptance Fee Rate	1.25%	1.25%		1.25%	1.25%	1.25%
=	**F**	**Bankers' Acceptance Rate[6]**	**3.95%**	**2.75%**	**2.85%**	**5.15%**	**3.55%**	**3.45%**

[1] Exhibit B-4, Table BCUC 1.85.2a; Exhibit B-1, Table 4.7.1.2-1 p. 124
[2] Exhibit B-8, Table BCUC 2.35.2a; Exhibit B-8, Table BCUC 2.35.1
[3] T4:536
[4] Line C = Line A + Spread Line B
[5] Line D is Line C rounded up to the nearest 0.10 percent
[6] Bankers' Acceptance Rate (Line F) = Line D + Line E

Table 11 - Long-Term Interest Rate Forecast for 2013 Debt Issuance

	2013F[1]	**2013F[2]**	**2013F[3]**
Date of issuance	2013	2013	2013
Term (Years)	30	30	30
Average Forecast Rate for 30-year Government of Canada Bond	4.45%	3.55%	3.20%
Long-Term Debt Rate Spread	1.45%	1.70%	1.55%
All-in Borrowing Rate	5.90%	5.25%	4.75%

[1] Exhibit B-1, p. 122
[2] Exhibit B-8, BCUC 2.33.1.1
[3] T4:535

During the oral phase of the proceeding, FortisBC confirmed the Company's intention to use the interest rate forecasts presented in the Evidentiary Update, dated November 4, 2011. (T4:529-530) With respect to short-term debt, FortisBC argues that, because the Bankers' Acceptance Rate went up by 10 basis points in 2012 while it went down by 10 basis points in 2013, there is an offset that reduces the issue to a fairly immaterial impact on the revenue requirement model. (T4:536-537) With respect to long-term debt, FortisBC submits the impact of the change to the all-in borrowing rate from 5.25 percent to 4.75 percent on the revenue requirement model would be $100,000, in part because it is budgeted for the last part of 2013.

However, the BCMEU and BCPSO both support using the most current forecasts. The BCMEU submits that FortisBC has slightly overstated its financing costs and there should be an adjustment to recognize the lower interest rate environment that the entity is operating in. While the impacts are small and deferral accounts have been proposed, the BCMEU submits that the most current forecast should be used for financing costs in setting rates for the test period. (BCMEU Final Submission, p. 18) BCPSO also notes that the variances are small, but states that the use of more recent forecasts more accurately reflects current financial conditions. (BCPSO Final Submission, p. 11) Other Interveners did not take issue with the interest rate forecasts proposed by the Company.

In its Reply, FortisBC acknowledges the BCMEU and BCPSO's positions but emphasizes the need for a temporal cut-off point in establishing information for the test period. FortisBC also stresses that the difference is not material and the magnitude of the impact is not sufficient to depart from the need to have a temporal cut-off in preparing a revenue requirement application for a test period. In any case, the Company argues that any variances will go through a variance account for financing costs so that customers would only pay the actual costs. (FortisBC Reply, pp. 47-48)

Commission Panel Determination

The Panel agrees with the BCMEU and BCPSO that the use of more recent forecasts more accurately reflects current financial conditions. It also concurs with the BCMEU that FortisBC has slightly overstated its financing costs. For instance, the 2012 short-term principal that is financed at the

Banker's Acceptance rate is, on average, $44.702 million whereas the 2013 short-term principal that is financed at that rate is, on average, $69.442 million. (Exhibit B-8, Table, BCUC 2.35.1.1a) Therefore, when the Banker's Acceptance rate goes up by 10 basis points in 2012 (from 2.75 percent to 2.85 percent), the forecast interest expense should go up by $45,000. However, when the Banker's Acceptance rate goes down by 10 basis points in 2013 (from 3.55 percent to 3.45 percent), the forecast interest expense should go down by $69,000, which more than offsets the increase in interest expense the previous year. Even if the numbers are small, ratepayers benefit from using the most recent forecasts.

Regarding the 2013 long-term debt, the revised forecast saw a decrease in the all-in borrowing rate from 5.25 percent to 4.75 percent. The Panel notes that FortisBC has acknowledged this means a decrease in the revenue requirement for 2013 of about $100,000. Even if this variance is small, ratepayers again benefit from using the most recent forecasts. In addition, FortisBC indicated during the oral phase of the proceeding: "... we do agree at this point in time, based on future forecasts on 30-year underlying long Canada's that the rate likely will go down, based on today's information, in 2013." (T4:530) In light of this evidence, the Panel believes it is even more important to use the most up-to-date forecast long-term interest rates. This is particularly important given our determination not to approve FortisBC's proposed deferral account for financing costs, which is addressed in Section 5.4.3.

Therefore, the Panel directs FortisBC to use the most recent interest rate forecasts available at the time of the oral phase of the proceeding of 2.85 percent for short-term and 3.45 percent for long-term debt.

5.4 Rate Base

Rate Base is generally described as a utility's net investment in the assets it needs to provide service to its customers. The primary components of FortisBC's rate base are:

- Plant in Service
- Construction Work in Progress not subject to Allowance for Funds Used During Construction (AFUDC)
- Plant Acquisition Adjustment
- Deferred and Preliminary Charges
- Accumulated Depreciation and Amortization
- Contributions in Aid of Construction
- Allowance for Working Capital
- Adjustment for Capital Additions

(Exhibit B-1, Tab 5, p. 1)

FortisBC's mid-year Rate Base for 2010 to 2013 is set out below (in thousands of dollars):

Table 12

2010 (actual)	2011 (forecast)	2012 (forecast)	2013 (forecast)
$945,637	$1,070,756	$1,145,910	$1,215,357

(Exhibit B-12, Schedule 1)

As outlined in Table 12, Rate Base is forecast to increase 13 percent between 2010 and 2011, 7 percent between 2011 and 2012, and 6 percent between 2012 and 2013, representing an average increase of approximately 9 percent over the three year period.

As noted earlier in Section 3.1 of this Decision, the main driver of FortisBC' requested rate increases is the growth of its rate base. (Exhibit B-1, Tab 1, p. 6)

ICG argues that FortisBC's rate base has increased 142 percent since 2004 and that "this dramatic increase in rate base provides a very large benefit to shareholders." (ICG Final Submission, p. 4)

ICG further notes that FortisBC's sales in 2004 were 2,874 GWh with an associated revenue requirement in the neighbourhood of $170 million (or a revenue requirement of approximately $60,000 per GWh) as compared to forecast sales of 3,233 GWh for 2013 (an increase of approximately 13 percent) with an associated revenue requirement of $310 million, or $96,000 per GWh, an increase in the order of 60 percent, (37 percent on an inflation-adjusted basis). (ICG Final Submission, p. 10)

ICG further argues that the "distortion in rate base relative to sale [sic] growth needs to be addressed by the Commission Panel in this proceeding". (ICG Final Submission, p. 12)

The Commission Panel is of the view that the increase in the size of FortisBC's rate base is an issue given that it is the main driver of rate increases which have been and are predicted to be well in excess of inflation. However, as noted by FortisBC, many of its capital expenditures and rate base additions are the result of past approvals by the Commission. (FortisBC Reply, p. 2) As noted earlier, however, the Commission Panel is concerned with the magnitude of rate increases, which are forecast to continue beyond the test period, and is of the view that capital expenditures must be scrutinized carefully.

5.4.1 Plant In Service

Plant In Service makes up by far the largest component of rate base. It is made up of Property, Plant and Equipment used in the generation, transmission and distribution of electricity. Capital additions increase Property, Plant and Equipment while Retirements reduce the account. Rate Base is reduced by accumulated depreciation and amortization of capital expenditures.

5.4.2 Accumulated Depreciation and Cost of Removal

For 2010 to 2011, FortisBC was using a composite depreciation rate of 3.2 percent. FortisBC filed an updated depreciation study prepared by the depreciation consultancy firm Gannett Fleming (2011 Depreciation Study) as part of the Application. (Exhibit B-1, Appendix J as corrected in Exhibit B-12, Appendix J) FortisBC is requesting Commission approval to apply new depreciation rates flowing from the updated study, commencing in 2012. The combined updated depreciation schedules result in a virtually equivalent overall composite depreciation rate of approximately 3.2 percent. (Exhibit B-1, Tab 4, pp. 128, 131)

FortisBC is also seeking Commission approval to add $4.7 million into rate base for the net cost of asset removal for 2011, and $5.4 million and $4.0 million for removal costs for 2012 and 2013, respectively. (Exhibit B-1, Tab 5, p. 9)

In addition, FortisBC has requested Commission approval to continue its current accounting treatment of asset removal costs, which it charges against accumulated depreciation as they are incurred, as opposed to what has been referred to as the "traditional method" of pre-collecting estimated net negative salvage during the asset's estimated useful life.

Mr. Kennedy of the firm Gannett Fleming testified that both treatments of asset retirement costs are acceptable and "widely used." (T3:499-500) Ms. Leeners testified that adoption of the traditional method of collecting net negative salvage in advance would result in a rate increase of five percent. (T3:499)

In its Reply, FortisBC notes that should the Company adopt the traditional method of collecting net negative salvage in advance, "current and future customers will be paying for both the historical actual costs of removal already incurred, as well as the future costs of removal for existing assets." FortisBC suggests that if it were to adopt the traditional method for collection of net negative salvage, a transition period might be appropriate, given the otherwise immediate impact on customer rates. (FortisBC Reply, p. 43)

Commission Panel Determination

The Commission Panel notes the comments of Mr. Alan Wait concerning the erratic depreciation rates for certain particular classes of assets. However, as noted by the BCPSO, the overall effect on the composite depreciation rate for all classes is "relatively minor." The Commission Panel appreciates that establishing ongoing depreciation rates for various asset classes is not an exact science. The

Commission Panel finds that the variances in the depreciation rates were adequately explained during the oral phase of the proceeding and therefore approves the depreciation rates from the updated Depreciation Study and the corrected information provided in the Evidentiary Update of November 4, 2011.

The Panel also approves the inclusion of asset removal costs for 2011, 2012 and 2013 in rate base as requested in the Application. The Panel notes, however, that the inclusion of asset removal costs in rate base does increase the value of plant in service rate base by an amount that is actually being removed from plant in service. This concept may need to be reviewed in the future.

In any event, the Commission Panel approves FortisBC's continued use of recognizing actual asset removal costs as incurred, as requested. The Commission Panel acknowledges the view of the ICG that FortisBC "should not be permitted to delay the need to reduce costs by managing rates through accounting practices that do not follow the recommendations of the depreciation consultant", and we agree with the general premise. (ICG Final Submission, p. 43) However, the Panel finds that the evidence tendered at the oral phase of the proceeding, as noted above, supports FortisBC's current practice as being "widely used" and "acceptable." The Panel further notes the significant rate increase which would result from a change from the current method of accounting for asset removal costs to the traditional method of recognizing negative salvage value at the asset acquisition stage and is not prepared to direct a change in this accounting method at this time.

5.4.3 2012/2013 Capital Expenditure Plan

FortisBC seeks Commission acceptance under subsection 44.2(3) of the *Act* that the 2012-2013 Capital Expenditure Plan (2012-13 CEP) is in the public interest. FortisBC also requests the Commission to find that the 2012-13 CEP satisfies subsection 45(6) of the *Act* which requires a public utility to file with the Commission, at least once each year, a statement of the extensions to its facilities that it plans to construct. In considering whether to accept an expenditure schedule, the Commission Panel is required to consider subsection 44.2(5) of the *Act*. Section 44.2 is set out in its entirety in Appendix B of this Decision.

Table 13

Table 5.3.3.1 - Proposed 2012-13 Capital Expenditure Plan										
		2012	2013	Total	2012	2013	2012	2013	2012	2013
		Requested			Previously Approved		CPCN Application		Total	
		($000s)								
1	Generation	4,496	2,939	7,435	5,636	8	0	0	10,132	2,947
2	Transmission and Stations	33,028	29,036	62,064	2,219	0	0	3,720	35,247	32,756
3	Distribution	29,249	25,888	55,137	0	0	0	0	29,249	25,888
4	Telecom SCADA Protection and Control	2,329	3,682	6,011	0	0	0	0	2,329	3,682
5	General Plant	12,503	19,317	31,820	69	75	10,521	38,408	23,093	57,800
6	Total Plant and Equipment	81,605	80,862	162,467	7,924	83	10,521	42,128	100,050	123,073

(Exhibit B-1, Tab 6, p. 2, Table 1.1; Exhibit B-1-6, Errata 2, updated page 60, Table 3.3.2)

The amounts requested in this Application total $162.467 million in the current test period. In addition, FortisBC intends to submit applications for CPCNs in 2012 and 2013 for the following projects (Exhibit B-1, Tab 6, p. 6):

- Kelowna Bulk Transformer Capacity Addition project estimated at $25.6 million (exceeds the cost threshold);
- Advanced Metering Infrastructure (AMI) project estimated at $47.18 million (exceeds the cost threshold); and
- Kootenay Long Term Facilities Strategy estimated at $16.5 million (the project planning process falls between capital expenditure plan applications).

(Exhibit B-1, Tab 6, p. 6)

FortisBC has identified a number of key considerations that underpin the 2012-13 CEP, several of which are as follows:

- It has invested approximately $700 million in new or upgraded generation, transmission/distribution and general plant infrastructure since 2005 and is starting to move more into sustaining capital programs,
- It aims to level its annual capital spending where possible,
- It is not delaying expenditures for certain condition-based projects,

- The Company is making efforts to improve forecasting by narrowing the variance between approved and actual capital expenditures while increasing the accuracy of estimates by striving for, where possible, a Class 3 (Definition Phase) level of accuracy, and
- While committed to safety and reliability, FortisBC does not have the objective of attaining a gold “standard”.

(FortisBC Final Submission, pp. 100-106)

FortisBC states that for certain portions of the 2012-13 CEP where there is minimal forward looking information (such as unforeseen projects or new connects), the estimates tend to be based on historical information because the recent trend is the best information that FortisBC has available. However, the Company acknowledges that improvements could possibly be made and suggests asset management as a potential candidate. (FortisBC Final Submission, pp. 112-115)

BCPSO observes that FortisBC's capital program build-out since 2005 has been aggressive, and has resulted in increased reliability, safety and quality of service to ratepayers. It submits a balance needs to be struck between appropriate levels of safety, reliability, quality of service and customer rates. BCPSO further observes that while the costs of proposed transmission-related capital projects are declining, the costs for generation projects are not, which is a concern because of the rate impact to residential customers. In addition, it notes the Commission comments from the 2011 Capital Expenditure Plan Decision to the effect that estimates based primarily on historical average spending may not accurately address what is actually required in a given time period. BCPSO concludes by stating that in spite of having concerns with respect to specific capital projects, it requests the Commission Panel direct FortisBC to reduce the 2012-13 CEP by 15 percent, and leave FortisBC to determine which projects to cancel or postpone during the test period. (BCPSO Final Submission, pp. 3, 12-14)

BCMEU expresses concern as to whether FortisBC is implementing capital plans in the most prudent and cost effective manner and points to the Kettle Valley Project’s cost overruns as an example. BCMEU also expresses concern with the use of historical rolling averages for budgeting purposes and encourages a more active use of zero based budgeting for capital as an alternative. With respect to specific capital projects, BCMEU states it has ongoing concerns that the investments in fibre optic communications to service customers are above and beyond the necessary communication requirements for the area. Further, while not taking exception to any individual capital project, BCMEU recommends that a 10 percent reduction in capital expenditures is appropriate to implement discipline in the test period. (BCMEU Final Submission, pp. 9, 19-22)

ICG states that FortisBC has acknowledged that it is “approaching diminishing returns” from capital expenditures and submits that no capital expenditures which have been justified on the basis of reliability improvements should form part of the 2012-13 CEP. Furthermore, ICG recommends that until FortisBC develops alternate scenarios based on delaying capital expenditures as directed in the 2005 RRA Decision, only capital expenditures with ratings of 275 or higher (as shown on the project ranking scale submitted in Exhibit B-27, Undertaking 40), should be accepted. ICG has identified a few exceptions to this 275 threshold which include: Transmission Line Condition Assessment, Transmission Line Urgent Repairs, Transmission Line Right-of-Way Easements, Station Urgent Repairs, and Transmission Line Rehabilitation expenditures which it argues can be based on the average of the past five years of actual expenditures. (ICG Final Submission, pp. 40-42)

Mr. Gabana, in addition to comments concerning specific capital expenditures, recommends that the Commission Panel reject the Grand Forks Transformer Addition Project and that FortisBC confirm the estimates for all capital projects are accurate to within 3 percent. (Gabana Final Submission)

BCSEA and Mr. Wait had no comments with respect to the expenditures detailed in the 2012-13 CEP.

In reply, FortisBC states that any reduction to the capital expenditures would be arbitrary in light of the evidence it presented. FortisBC observes that in comparison to BCMEU and BCPSO’s proposed capital expenditure reductions of 10 percent and 15 percent respectively, the reductions ordered by the Commission in the 2011 Capital Expenditure Plan Decision amounted to 5.4 percent of the proposed expenditures in 2011 and 2012.

In response to ICG’s assertion that the Company should approve capital expenditures with a rating of 275 or greater, FortisBC argues that setting an arbitrary cut-off based on project rating, as suggested by ICG, would mean that capital investment would be reduced to a level where projects which are necessary are not undertaken. In the view of FortisBC, the ICG proposal seeks to reduce expenditures to unsustainable levels. FortisBC argues the proposed reduction is not supported by evidence.

FortisBC states it has also addressed the concerns raised by the Commission in the 2011 Capital Expenditure Plan Decision regarding the use of historical average expenditures for budgeting purposes by canvassing other utilities and finding similar examples of rolling averages being used for those purposes. In support of continuing to use this approach, FortisBC notes that, despite the concerns regarding the use of historical average expenditures for budgeting purposes, no party has suggested "a specific, reliable alternate solution." (FortisBC Reply, pp. 49-52)

Commission Panel Discussion

The Commission Panel notes that among the Interveners that commented on the 2012-13 CEP, the recommendations were unanimous for a reduction in expenditures. BCMEU and BCPSO call for general reductions of 10 percent and 15 percent respectively, while ICG is far more aggressive, calling for, by the Commission Panel's estimate, a reduction of approximately 55 percent spread across generation, transmission, stations, distribution and telecommunications, Supervisory Control and Data Acquisition (SCADA) and protection and control related expenditures.

In response to whether a slow-down in the capital building program should be anticipated as FortisBC shifts toward a sustaining program, Mr. Walker stated that this has been reflected in the capital plan. (T2:221) The Commission Panel observes the slow-down is not apparent when comparing the proposed 2012 /2013 capital expenditures with the 2011 Capital Expenditure Plan. Specifically, the approved 2011 Capital Expenditure Plan was for an expenditure of $103.3 million. (Decision accompanying Order G-195-10, p. 1) The current Application proposes additional expenditures (which include previously approved expenditures and expected CPCN applications) which bring the total capital expenditures to $100.0 million in 2012 and $129.1 million in 2013. (Exhibit B-1-6, Errata 2, Table 3.3.2)

A consideration in reviewing the 2012-13 CEP, is the level of reliability, safety and quality of service to ratepayers which is related to the recent capital expenditure program. The Commission Panel agrees with the comments of the BCPSO that it is important to strike a balance between safety, reliability, quality of service and achieving reasonable customer rates. The Commission Panel notes that System Average Interruption Frequency (SAIFI) and System Average Interruption Duration (SAIDI) are similar to or below Canadian Electricity Association average performance indexes. (Exhibit B-1-1, pp. 83-85) Within the oral hearing the issue was raised with Mr. Sam, the Vice President of Engineering and Generation, who was asked whether there was a need for further improvement in the SAIFI and SAIDI numbers with emphasis on the word "need". Mr. Sam replied that the Company did not see that there was a need to improve these numbers on average and agreed that the desire was to maintain them. (T6:1200) Taking this into consideration, the Commission Panel is of the view that safety, reliability and quality of service to ratepayers are at an acceptable level and a focus on identified problem areas is considered most appropriate at this time.

As noted above, subsection 44.2 (5) of the *Act* requires the Commission to consider certain matters in considering whether to accept an expenditure schedule.

Subsection 44.2(5) (a) of the *Act* requires the Commission to consider the applicable of British Columbia's energy objectives. With reference to this requirement, the Commission Panel is of the view that the following are the most relevant to this Application:

(a) To achieve electricity self sufficiency;
(b) To take demand-side measures and to conserve energy including the objective for the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66 percent;
(c) To generate at least 93 percent of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;... and
(d) To encourage communities to reduce greenhouse gas emissions and use energy efficiently.

The Commission Panel finds that the 2012-13 CEP is generally consistent with these objectives as the proposed expenditures will assist the province to achieve energy self sufficiency by prolonging the life of hydro-electric generation and transmission assets.

Subsections 44.2 (5)(b) and (d) also require the Commission Panel to consider the most recent long term resource plan filed by the utility under section441 and the cost effectiveness of any demand-side measures included in the expenditure schedule within the meaning prescribed by the Demand-Side Measures Regulation. Both of these have been filed with this Application. Demand-Side Measures are examined in Section 6 and the Long-Term Resource Plan is examined in Section 7 of this Decision.

Section 44.2 (5)(c) of the *Act* requires the Commission to consider the extent to which an expenditure is consistent with the applicable requirements under sections 6 and 19 of the CEA. Sections 6 and 19 of the *CEA* are primarily related to BC Hydro although section 6 does require a utility planning in accordance with section 44.1 of the *Act* to consider British Columbia's energy objective to achieve electricity self-sufficiency. Neither section applies to an expenditure schedule filed under section 44.2 of the *Act.*

The Commission Panel is also required under subsection 44.2 (5)(e) of the *Act* to consider the interests of persons in British Columbia who receive or may receive service from FortisBC. The Commission Panel finds that, except where an expenditure is reduced or rejected, the 2012-13 CEP is consistent with the interests of FortisBC's existing and potential customers.

The Commission Panel has reviewed the individual projects in the 2012-13 CEP in detail and in what follows will make specific determinations with respect to some projects which we have determined are inadequately supported or require additional work. In addition, the Commission Panel will make observations with regard to specific projects we consider to be questionable or program amounts which we consider to be unjustifiably high given the evidence provided by the Company. With this latter group of projects, the Commission Panel will not make specific determinations on individual programs, but will provide a determination directing FortisBC to reduce its overall expenditures by an amount we consider to be appropriate. The Panel will leave the final allocation of the approved capital expenditures for FortisBC to determine based on its objectives of providing reliable service and ensuring public and employee safety.

Generation

In the generation group of projects, the Commission Panel makes the following observations:

- Of the $1.2 million in expenditures in 2012 and 2013 for the "All Plants Concrete and Structural Rehabilitation" project, only $671,000 is related to public and worker safety which FortisBC has stated is a priority. (Exhibit B-4, BCUC 1.114.2)
- FortisBC has not sufficiently explained why all the windows in the Upper Bonnington, South Slocan and Corra Linn Powerhouses need to be opened on a daily or seasonal basis, especially with no noted ventilation deficiencies and the recent and proposed facility lighting upgrades. (Exhibit B-4, BCUC 1.115.3) The "Upper Bonnington, South Slocan and Corra Linn Powerhouse Windows" project estimate is $430,000. (Exhibit B-1, Tab 6, pp.12-13)
- With regard to the Corra Linn Unit 3 Completion project, FortisBC proposed expenditures related to the transformer and the acquisition of spare generator stator coils. However, FortisBC considers the risk of a transformer failure to be low and stated that individual stator winding coil failures could be bypassed to allow continued operation of the generation unit. This suggests that the need for both expenditures, estimated at $460,000 from a project total of $722,000, may be overstated. (Exhibit B-4, BCUC 1.116.2, 1.117.5)
- In the 2011 Capital Expenditure Plan Application, FortisBC stated that the "potential for refurbishment of the remaining four old units at Upper Bonnington is under review and will be addressed at a later date." (2011 Capital Expenditure Plan Application, Exhibit B-1, p. 13) The Panel finds that the proposed expenditures of $1.31 million (Exhibit B-1, Tab 6, Section 2.2.5, pp. 14-16) for the "Upper Bonnington Old Plant Various Unit Upgrades" project demonstrate a piecemeal approach to the disposition of the Upper Bonnington Old Plant units. The Panel considers that these may be better addressed as either maintenance expenditures or as part of a comprehensive project to address either overall rehabilitation or retirement.
- The incremental personnel safety that FortisBC claims as the driver for the $509,000 "Fire Panels at Lower Bonnington, Upper Bonnington and Corra Linn" project may be better addressed by improving personnel egress. (Exhibit B-1, Tab 6, pp. 16-17)
- Many of the projects in the category of "Generation All Plants Minor Sustainment Capital Projects" appear to be discretionary in nature, with no reliability or safety impacts associated with deferral of the proposed expenditures. For instance, the "All Plants Air System Upgrade" (Exhibit B-1, Tab 6, pp. 19-20) and the "All Plants Upgrade Telephone Communications" projects (Exhibit B-4, BCUC 1.122.1) are intended to upgrade systems that, although not modern, have not been shown to be under-performing or failing. Similarly, the need for upgrading the spillway gate hoists and controls and removing old wiring at Lower Bonnington, Upper Bonnington and Corra Linn is not supported by either

recent control system failures, electrical code requirements or reliability indicators. (Exhibit B-4, BCUC 1.123.1 to 1.123.6, inclusive) In total, these projects account for $1.034 million in the test period.

Overall, the Commission Panel observes the proposed spending in the 2011 Capital Expenditure Plan for generation projects was $2.513 million (December 17, 2010 Decision, Order G-195-10, p. 5, Table 1.1) compared with the request for approval of new expenditures in 2012 and 2013 of $4.495 million and $2.939 million respectively. This does not demonstrate a shift from a capital-intensive growth and rehabilitation oriented program to a sustainment oriented program. **From the preceding analysis, the Commission Panel is of the view that reductions of approximately $4 million in the proposed generation portfolio over the test period are possible.**

Transmission Growth

The Transmission Growth portfolio consists of four large projects that are individually discussed the section below.

1) The Okanagan Transmission Reinforcement Project, which was previously approved by Order C-5-08.
2) The Kelowna Bulk Transformer Capacity Addition Project, forecast at $3.72 million in 2013, and driven by the requirement to provide adequate transformation capacity to supply the Kelowna area load during single contingency (N-1) outage conditions, will be subject of a CPCN application in 2012. FortisBC states that this CPCN application will contain a detailed option analysis, information on the recommended solution and a revised project cost estimate and expenditure schedule. (Exhibit B-1, Tab 6, pp. 38-42)
3) Ellison to Sexsmith Transmission Tie project. FortisBC describes the Ellison to Sexsmith Transmission Tie project estimate as the equivalent of an “AACE Class 4” estimate. (Exhibit B-4, BCUC 1.126.2) FortisBC has updated this estimate to a class 3 estimate and notes that the remaining forecast costs are reduced by $0.283 million. (Exhibit B-28, Undertaking 51) The Commission Panel approves the project with the expectation that the capital request will be reduced by the amount stated.
4) The Grand Forks Transformer Addition project is forecasted to cost $7.205 million in 2013. FortisBC states that this project addresses two deficiencies in that it is intended to address transmission system reliability issues for the Grand Forks area as well as the gap between the Okanagan and Kootenay communications systems. (FortisBC Final Submission, p. 132) The project

> economics are aided by revenues with an NPV of approximately $2.5 million from a fibre leasing agreement (Exhibit B-4, BCUC 1.127.10), a redacted copy of which was provided by FortisBC. (Exhibit B-5, BCMEU 1.19, Appendix Q19) The proposed project has the highest NPV cost of the three options FortisBC analyzed for the project, one of which was the continued use of the existing 9L and 10L transmission lines. (Exhibit B-4, BCUC 1.127.1)

The Commission Panel notes that FortisBC was specifically directed to apply for a separate CPCN if it intended to proceed with the fibre installation portion of this project. (2011 CEP Decision) The filing of a CPCN application would allow the concerns expressed by the BCMEU regarding investments in fibre optic communications to be fully vetted. The Commission Panel notes the redacted fibre lease agreement contains a clause that requires the parties to negotiate in good faith to extend the agreement if the fibre is not in place by September 15, 2014. The Panel believes this to be more than sufficient time to accommodate a CPCN application and review.

In response to Mr. Gabana's comments regarding this project, FortisBC confirms that the transformer addition is not driven by capacity requirements, but is to maintain supply reliability in the Grand Forks area. (FortisBC Reply, p. 58) The Commission Panel notes that the customers served by the existing Grand Forks Terminal T1 have experienced better than average reliability in recent years. (Exhibit B-8, BCUC 2.46.2) Furthermore, the options reviewed by FortisBC, which include the continued use of 9L and 10L between Rossland and Christina Lake, have a lower NPV cost than the proposed project. (Exhibit B-4, BCUC 1.127.1) The removal of both the 9L and 10L transmission lines between Rossland and Christina Lake does not appear to be warranted at this time. **While the Commission Panel endorses the relocation of a spare transformer to the Grand Forks Terminal to reduce the downtime associated with a failure of the current transformer, we reject the proposed expenditure of $7.205 million for the Grand Forks Transformer Addition Project because the need for increased reliability is not apparent. In addition, the Panel notes that FortisBC was previously directed to apply for a CPCN for certain elements of the proposed project and failed to do so. If FortisBC intends to proceed with advancing either the fibre optic communications portion of the proposed project or the installation of the spare transformer at Grand Forks Terminal, it is directed to apply for a separate CPCN. In pursuing a CPCN for fibre optic communications, FortisBC is expected to diligently pursue the extension of the fibre leasing agreement to preserve the potential benefit to ratepayers.**

Transmission Sustainment

Approximately half of the capital expenditures proposed for Transmission Sustainment projects are driven by historical averages, and the other half are driven by specific transmission line condition issues. Rather than continuing to rely on simple rolling averages of historical expenditures, FortisBC was previously directed in the 2011 FortisBC Capital Plan Decision to investigate alternative means of developing capital budgets. As referenced earlier, this was also an issue of concern for some Interveners. FortisBC acknowledged that it has addressed the matter but it continues to use this method when there is a lack of better information. (T6:1124) FortisBC is encouraged to continue to investigate alternative methods of developing budgets for those project categories that were previously based on rolling averages of historical expenditures, with the caveat that the evaluation strategies and procedures be supported by direct linkage to fundamental objectives of reliability and safety. Absent direct linkage to direct reliability and safety effects, the Commission Panel is concerned that the cost of projects driven by specific condition issues may be inflated because the condition threshold may be set too high.

Furthermore, the Commission Panel notes that the true increase in the expenditures that underpin those budgets that are based on historic spending is made more difficult to determine because of the additive effects of both capitalized overhead loading rates and departmental direct overhead loading rates, both of which vary with the amount of overall capital expenditures. This will be considered in the discussion that follows. For transmission sustainment projects, the Commission Panel makes the following observations:

- For the “Transmission Line Condition Assessment” budget, the average of the last five years’ expenditures is approximately $403,000. (Exhibit B-1-1, p. 129) The test period expenditures are proposed to be $522,000 and $485,000 in 2012 and 2013 respectively. The Commission Panel notes that even with the increases of 6 percent in capitalized overhead and 4 percent in direct overhead in 2012 compared with 2008 (Exhibit B-8, BCUC 2.51.2), for a total 10 percent increase in overhead, and an additional 8 percent for inflation over the same period, the proposed average expenditures over the test period are more than 5 percent, or over $50,000, greater than the historical average.

- FortisBC states that the “Transmission Line Rehabilitation” budget is based on previous years’ transmission line condition assessment and explains the budget is also partially based on historical cost per pole expenditures because there is a delay in incorporating the condition assessment data from a given year into the next year’s rehabilitation budget. (Exhibit B-1-1, p. 129; Exhibit B-1, Tab 6, p. 45) The Commission Panel notes that forecast amounts have increased substantially over the test period for the “Transmission Line Rehabilitation” budget. The average of the last five years’ expenditures is approximately \$1.466 million, while over the test period expenditures are proposed to be \$3.372 million and \$2.621 million in 2012 and 2013 respectively. (Exhibit B-1-1, p. 129) As above, considering a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012, the proposed average expenditures over the test period are more than 70 percent, or over \$2.5 million greater than the historical average. FortisBC confirmed that the work required involved the rehabilitation of 2,191 poles in 2012 and 1,565 poles in 2013 which represents approximately 25 percent of the total number of transmission poles. (Exhibit B-4, BCUC 1.131.3) When asked about the causes for the large increase over the previous years during the oral hearing, Mr. Chernikhowsky indicated that there was some work that was rescheduled over the 2007 to 2011 period creating some backlog as well as work coming due on its cycle. (T6:1174-1175)

  The need for increased sustaining capital expenditures based on the current condition assessment is not immediately apparent given the level of reliability as indicated by SAIFI and SAIDI performance results. The Commission Panel is not suggesting delaying expenditures until reliability is seen to suffer but notes that large increases in sustaining capital expenditures over historical averages when reliability has been continually improving suggests that FortisBC’s methodology of identifying condition based expenditures may be too over-reaching. Therefore, the Panel is not persuaded that the amounts forecasted are actually required.

- For the “Transmission Line Urgent Repairs” budget, the average of the last five years’ expenditures is approximately \$476,000. (Exhibit B-1-1, p. 130) The test period expenditures are proposed to be \$594,000 and \$620,000 in 2012 and 2013 respectively. Considering a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012, the proposed average expenditures over the test period are more than 8 percent, or about \$90,000, greater than the historical average.

- For the “Transmission Line Right of Way Easements” budget, the average of the last five years’ expenditures is approximately \$215,000. (Exhibit B-1-1, p. 130) The test period expenditures are proposed to be \$400,000 in both 2012 and 2013. Considering a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012, the proposed average expenditures over the test period are more than 50 percent, or almost \$300,000, greater than the historical average. The Commission Panel notes that FortisBC provided justification for the increase in the rolling average based on the combination of transmission and distribution easements rather than solely for transmission. (Exhibit B-4, BCUC 1.133.4) With this proposed shift of distribution easement costs into the transmission category, the corresponding reduction in the distribution sustaining capital budget is not apparent.

A number of the remaining Transmission Line Sustainment projects are driven by the line condition assessments where the lines themselves have experienced relatively good reliability performance. The Commission Panel has previously commented on the relationship between increasing reliability and increasing sustaining capital expenditures, and questions whether the condition threshold has been set too high for the following projects:

- The “21-24 Line Rebuild” project with proposed expenditures of $2.219 million in 2012 does not appear to be driven by rapidly deteriorating line condition. Emergency expenditures in 2010 were less than 1 percent of the proposed capital project (Exhibit B-8, BCUC 1.55.2) and there is significant redundancy in the lines whereby no generation is lost for any single contingency (Exhibit B-4, BCUC 1.136.7)
- The “20 line Rebuild” project with proposed expenditures of $4.664 million in 2013 is required to maintain service reliability and alleviate safety concerns. (Exhibit B-1, Tab 6, Section 3.2.9, p. 53) These concerns are in two major areas, one being structural integrity of the poles and another being inadequate circuit-to-circuit spacing resulting in transmission to distribution contacts. (Exhibit B-4, BCUC 1.138.2) The Commission Panel notes that FortisBC stated that there were no transmission to distribution contacts on 27 line since 2007 (Exhibit B-8, BCUC 2.57.1) and although FortisBC does not provide the same information for 20 Line, the installation of station class arrestors is being considered to prevent overvoltage caused by transmission to distribution contacts from affecting customers. (Exhibit B-4, BCUC 1.138.3)

Overall, there appears to be some opportunity for reduction in the Transmission Line Sustainment capital budget. The review above suggests that a reduction of as much as $9.5 million over the test period is possible. FortisBC acknowledges that if approval is not granted for the these projects, it would still endeavour to mitigate risks associated with line failures. (T6:1048)

Station Sustainment

FortisBC has several station sustainment projects which involve the rehabilitation and ongoing upgrades to substation system. The Panel makes the following observations:

- The PCB Mitigation project, with $22.822 million in capital expenditures in the test period represent over three-quarters of the proposed capital expenditure of $28.395 million for Station Sustainment projects. (Exhibit B-1, Tab 6, p. 54, Table 3.3) The Commission Panel is concerned that the project estimate is an "AACE Class 4" estimate (where typical end usage is for study or feasibility) despite FortisBC's objective of submitting "AACE Class 3" estimates (where typical end usage is for budget authorization or control) for acceptance or approval. (Exhibit B-4, BCUC 1.140.1) Because of this, **the Commission Panel is concerned about the estimate quality and control of actual costs associated with the PCB Mitigation project, and directs FortisBC to file a comprehensive scope and schedule for this project by October 1, 2012 and semi-annual progress reports thereafter.**

- For the "Station Urgent Repairs" budget, the average of the last five years' expenditures is approximately $622,000. (Exhibit B-1-1, p. 130) The test period expenditures are proposed to be $818,000 and $907,000 in 2012 and 2013 respectively. Considering a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012, the proposed average expenditures over the test period are about 11 percent, or over $150,000, greater than the historical average.

- Although FortisBC does not endorse the approach (FortisBC Final Submission, p. 153), the Commission Panel notes the "Addition of Arc Flash Detection To Legacy Metal-Clad Switchgear" project goes beyond typical current practice in other utilities where mitigating procedures are used in place of switchgear modification. (Exhibit B-4, BCUC 1.143.3) This project is budgeted at $1.083 million in the test period.

- In the "Huth Low Voltage Breaker Replacement" project, scope creep is expanding the scope of the project beyond the strict current need. (Exhibit B-4, BCUC 1.144.3; Exhibit B-8, BCUC 2.60.1) In an environment where the capital program is moving away from growth and towards sustainment, discipline must be reinforced to avoid the temptation of adding scope simply because a project is being proposed at a certain time or location. This project is budgeted at $0.07 million in the test period.

Overall, the Commission Panel estimates there are possible reductions of $1.3 million in the Station Sustainment portfolio.

<u>Distribution</u>

The Commission Panel makes the following observations with respect to the Distribution Projects Portfolio:

- For those budgets that continue to be based on historic rolling averages ("New Connects System Wide", "Distribution Unplanned Growth", "Distribution Urgent Repairs", and "Forced Upgrades and Line Moves"), (Exhibit B-4, BCUC 1.145.2; Exhibit B-4, BCUC 1.149.2) the aggregate of FortisBC's proposed budgets are more than $2 million less than the average of the last five years' expenditures. Additionally, a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012 is applied to the five year historical average. (Exhibit B-1-1, p. 160; Exhibit B-1-1, p. 161; Exhibit B-1-1, pp. 171-172; Exhibit B-1-1, pp. 172-173) The Commission Panel notes spending in these categories is largely non-discretionary as it is driven by third parties, and if the proposed test period spending is under-forecast, the true size of the capital budget may be understated.

- For the "Distribution Line Condition Assessment" budget, which is based on a historical average of the cost per pole times the number of poles being assessed, the average of the last five years' expenditures is approximately $777,000. (Exhibit B-1-1, p. 170) The test period expenditures are proposed to be $1.410 million and $1.398 million in 2012 and 2013 respectively. Considering a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012, the proposed average expenditures over the test period are more than 50 percent or almost $1 million greater than the historical average.

- For the "Distribution Line Rehabilitation" budget, FortisBC acknowledges that at the time of the filing of the 2012-13 CEP, pole test results and condition reports were not available. Therefore, the Company has based its forecast expenditures on actual costs of previous years combined with the knowledge of the areas being assessed and equipment condition expectations. The Commission Panel notes that the average of the last five years' expenditures is approximately $2.757 million. (Exhibit B-1-1, pp. 170-171) The test period expenditures are proposed to be $5.298 million and $3.517 million in 2012 and 2013 respectively. As before, considering a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012, the proposed average expenditures over the test period are about 35 percent, or about $2.3 million, greater than the historical average.

- For the "Distribution Line Rebuilds" budget, the average of the last five years' expenditures is approximately $1.504 million. (Exhibit B-1-1, p. 171) The test period expenditures are proposed to be $1.679 million and $1.660 million in 2012 and 2013 respectively. Considering a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012, the proposed average expenditures over the test period are less than the historical average by more than $200,000.

- For the "Distribution Line Small Planned Capital" budget, the average of the last five years' expenditures is approximately $793,000. (Exhibit B-1-1, p. 173) The test period expenditures are proposed to be $726,000 and $826,000 in 2012 and 2013, respectively. Considering a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012, the proposed average expenditures over the test period are over the test period are less than the historical average by more than $300,000.

Given the review of the Distribution Projects portfolio, the Commission Panel is of the view that reductions of $2.5 million of proposed capital expenditures are possible. This is an amount which is lower than the combined potential savings of $3.3 million and is reflective of there being a number of projects where FortisBC has forecasted budgeted amounts to be lower than the five year average.

Telecommunications, SCADA Protection and Control

The "Kelowna 138 kV Loop Fibre Installation" project ($3.761 million for both 2012 and 2013) accounts for more than half of the expenditures in the Telecommunications, SCADA, Protection and Control portfolio. The Commission Panel notes that FortisBC has filed this project for acceptance with a Class 4 estimate rather than the required Class 3 estimate. In addition, the Panel is not persuaded that there is sufficient justification to support moving forward with the most expensive Option F as proposed. Accordingly, **the Commission Panel rejects the expenditures for the Kelowna 138 kV Loop Fibre Installation project. FortisBC may provide Class 3 estimates for both Option E and Option F and additional justification for its recommendation in a future filing.**

The balance of the proposed 2012 and 2013 expenditures in the Telecommunications, SCADA, Protection and Control portfolio ($2.25 million) are for Communications Upgrades and SCADA Systems Sustainment, a portion of which address MRS issues. (Exhibit B-8, BCUC 2.64.1) Specifically, the Commission Panel questions the need for the "JungleMUX Laser Upgrade" expenditures ($144,000). FortisBC stated the JungleMUX equipment has been extremely reliable and it maintains a stock of spare equipment in both Trail and Kelowna. (Exhibit B-4, BCUC 1.157.3) The Commission Panel also questions the assignment of $163,000 of "MRS System Sustainment Internal Labour" cost as a capital expenditure and suggests such sustainment costs should be part of O&M expenditures. (Exhibit B-8, BCUC 2.64.1)

For the remaining projects, the Commission Panel estimates possible capital expenditure reductions of $300,000 in the Telecommunications, SCADA, Protection and Control portfolio.

General Plant

In the category of General Plant capital expenditures, the Commission Panel notes that the CPCN application for the Kootenay Long Term Facilities Strategy (Exhibit B-1, Tab 6, pp. 98-99) will be filed later this year and the Advanced Metering Infrastructure CPCN has been submitted to the Commission on July 26, 2012. Pursuant to the 2011 Revenue Requirements NSA, AMI costs are being collected in a non-rate base deferral account attracting AFUDC. FortisBC requests that the investigative funds be moved to a Rate Base deferral account in 2012 and, subject to the approval of the CPCN application, subsequently transfer the funds into the AMI capital project in 2012. (Exhibit B-1, Tab 5, p. 14) A determination on this issue is provided in Section 5.4.4.3 of this Decision.

Commission Panel Determination

The Commission Panel has rejected two projects, the Grand Forks Transformer Addition/High Capacity Communications Project and the Kelowna 138kV Fibre Loop Installation Project which result in a total reduction of $10.966 million in capital expenditures. These projects may be resubmitted over the current test period.

In addition, the Commission Panel has identified a number of areas where further reductions are possible. These total $17.6 million distributed as follows:

• Generation	$4 million
• Transmission Sustainment	$9.5 million
• Station Sustainment	$1.3 million
• Distribution Projects	$2.5 million
• Telecom/SCADA	<u>$0.3 million</u>
Total	**$17.6 million**

As outlined earlier in this Section, it is not the intention of the Commission Panel to make specific determinations on individual projects but to make an overall reduction to the capital expenditures portfolio and allow FortisBC to allocate the cost reductions as it deems appropriate. **Based on our review of the 2012-13 CEP the Commission Panel is of the view that an overall reduction to the CEP of $17.6 million over the test period is possible. However, the Panel believes imposing all of the reductions related to the $17.6 million may not provide FortisBC with sufficient flexibility to prioritize expenditures in a cost-effective fashion. By reducing the amount of $17.6 million to $10.5 million (which is approximately 60 percent), the Panel can be reasonably assured that FortisBC can achieve the level of service it requires and will still have sufficient flexibility to manage its projects and workforce. Accordingly, the Commission Panel directs FortisBC to reduce its capital expenditure budget by $10.5 million in addition to the two projects which have been specifically rejected above.** Collectively, these reductions and projects rejected result in a total reduction of $21.466 million from the $162.467 in additional capital expenditures requested over this test period. In addition to this there is a further reduction of $0.283 million as outlined in the undertaking on the Ellison to Sexsmith Transmission Tie Project. **Taking all of these reductions into account, the Commission Panel accepts additional capital expenditures totalling $140.218 million for the 2012-2013 test period.**

The Commission Panel confirms that FortisBC's 2012-13 CEP satisfies section 45(6) of the *Act*, which requires the utility to file a statement of the extensions to its facilities it plans to construct at least once each year.

5.4.4 Deferral Accounts

FortisBC is seeking a number of approvals relating to its existing and proposed new deferral accounts. These are summarized in Exhibit B-1, Tab 5, pp. 10-37.

In the view of the Commission Panel there are two important issues which must be considered in reaching a determination on whether to approve the deferral accounts as proposed by FortisBC. They are as follows:

1. Deferral Account Financing Costs

   This refers to the financing cost appropriate for various deferral accounts.

2. Determining an Appropriate Amortization Period

   This refers to the most appropriate time period over which specific deferral account groups should be amortized.

The Commission Panel believes that establishing principles to deal with these issues will be instrumental in helping provide a context for the determinations which follow. Accordingly, the Panel will address these two issues before undertaking to examine the specific deferral account approvals which are sought by FortisBC.

I. Deferral Account Financing Costs

FortisBC takes the position that all deferred expenditures or credits, other than notional or non-cash assets or liabilities should be included in rate base, which is financed at the Weighted Average Cost of Capital (WACC). It further submits that if a deferred expenditure is not included in rate base, then it should attract AFUDC. (FortisBC Final Submission, p. 81) The Commission Panel notes that these two rates are similar if not virtually the same.

The ICG argues that FortisBC's deferral accounts should be financed in the same way as those of BC Hydro, which is at the weighted average cost of debt, as opposed to the weighted average cost of debt and equity, as proposed by FortisBC.

In the alternative, the ICG argues that should the Commission Panel determine that some deferral accounts should attract the weighted average cost of debt and equity, then those should be limited to accounts where the balance is to be made part of a capital expenditure. (ICG Final Submission, pp. 39-40)

FortisBC argues in reply that BC Hydro is a Crown corporation with different access to resources. It argues that FortisBC, as an investor-owned utility, should properly earn an equity return on its rate base deferral balance to allow the shareholder an opportunity to earn a fair return on its invested capital. It argues that FortisBC's rate base, including deferral accounts, is financed as part of the total financing of the Company, and represents the actual cost being incurred by the Company. (FortisBC Reply, p. 47)

Commission Panel Determination

The Commission Panel agrees with the ICG that deferred expenditures or credits ought not to be included in rate base or attract a rate base rate of return. The Panel notes that deferral accounts are regulatory assets, not true capital assets. Capital assets which are recognized as such under standard accounting rules such as US GAAP do not require deferral account treatment. It is only amounts which would otherwise be required to be expensed under standard accounting principles for which deferral account treatment is needed. However, in the Panel's view, amounts which represent operating costs or other costs which would commonly be expensed as current period charges but which are deferred for rate-smoothing purposes do not become capital investments, simply by the fact of the deferral. Normally, a utility, whether a Crown corporation or shareholder-owned, is not entitled to receive a return on operating costs or current period charges but simply recovery of those amounts from its ratepayers, assuming recovery is otherwise justified. Current period charges are not "investments" which attract a capital return, they are deferred operating costs/current period expenses which, as noted above, in the Panel's view, should not attract rate base rate of return. **The Panel finds that a more appropriate financing cost is an interest return.** For expenditures which are amortized beyond one year, the Panel finds that the appropriate return is FortisBC's WACD. The Panel further finds that for true-up deferral accounts which are, by their very nature, a short term deferral, the appropriate interest return is FortisBC's short term interest cost.

The Commission Panel is also concerned about the proposed proliferation of smaller deferral accounts, all of which, as noted above, are proposed to be placed into rate base. The Commission Panel notes that deferral of current period expenses reduce the level of O&M expense recorded in a given period and, therefore, has the potential to distort true operating costs. We also note the dramatic forecast increase in rate base over the test period and are of the view that care must be taken to ensure that rate base items are properly so categorized.

II. Amortization Period

The Commission Panel also notes that deferral of expenses only serves to increase their ultimate cost by the amount of the financing charge and is of the view that amortization periods should be as short as possible, while continuing to serve the rate-smoothing function. The Commission Panel further notes that deferral of expenses only serves to increase their ultimate cost by the amount of the financing charge and is of the view that amortization periods should be as short as possible, while continuing to serve the rate-smoothing function. The length of amortization periods for a specific account depends on a number of factors including the benefits of rate smoothing, the length of time where there is direct value related to the item being amortized, and the increased costs that longer amortization periods impose on the ratepayer.

In the same vein, deferral accounts which continue for long periods without being amortized into rates also increase the eventual cost to the ratepayer. The Commission Panel is of the view that decisions as to whether to proceed with a particular project where there is an associated deferral account for preliminary and investigative charges ought generally to be made within three years. This time period should be more than sufficient to complete preparatory work for a project and placing a limit of three years ensures that preliminary and investigative charges are not deferred indefinitely. **The Commission Panel therefore directs that such deferral accounts, with costs accruing beyond a three year period and where no CPCN has been applied-for or expenditure schedule filed, be amortized into rates.** The amortization period to be used will depend upon the balance in the account. The amounts in these accounts, unless otherwise ordered, are to attract a return at FortisBC’s WACD until such time as they are properly added to an approved capital project. For greater clarity, costs incurred in relation to projects for which a CPCN is eventually sought, or an expenditure schedule filed, will become part of the capital project upon approval or acceptance as the case may be.

5.4.4.1 Existing Deferral Accounts

A. Preliminary and Investigative Charges – Pumped Storage Hydro

FortisBC accumulates costs to investigate potential capital projects in the "Preliminary and Investigative Charges" category of deferral account. The current treatment is that if a capital project in fact proceeds, the costs are transferred to the project. In the event a project does not proceed, costs are expensed at that time.

FortisBC has identified "pumped storage hydro" as a potential resource to meet its future capacity requirements. FortisBC advises that the lead times associated with development of facilities for this resource are lengthy. FortisBC's preliminary investigations have identified two possible sites at a cost of $0.227 million. FortisBC does not seek disposition of this account during the test period.

Commission Panel Determination

The pump storage account is an example of a deferral account for amounts which do not meet the capitalization criteria required by standard accounting principles and would be required to be expensed. In the Panel's view, this account should attract an interest return at FortisBC's WACD, and is not to be included in rate base. **FortisBC is directed to commence the amortization of this deferral account into rates in the next test period if the associated project has not commenced by that time.**

B. Deferred Regulatory Expenses

Expenses related to regulatory proceedings are deferred until approved by the Commission, at which time they are amortized into rates. Incentive amounts are also deferred and used to adjust rates in subsequent years. FortisBC has a number of this type of regulatory expense deferral account, some of which are being sought to be amortized into rates during the test period.

Commission Panel Determination

The Commission Panel approves the amortization in 2012, as requested, of the following regulatory expense deferral accounts into rates:

- **Implementation of new rate structures**
- **Residential Inclining Block Rate and Industrial Stepped Rate Applications**
- **2011 Revenue Requirements Application**

However, the Commission Panel takes issue with the proposed disposition of other regulatory deferral accounts sought in the Application and makes the following determinations.

- Shaw Application for Transmission Facility Access

FortisBC is requesting approval to amortize costs relating to Shaw's application to the Commission to continue to have access to FortisBC's transmission infrastructure in the amount of $0.2 million, ($0.3 million before tax) into rates in 2012. These costs were deferred pursuant to Commission Order G-184-10. These costs include:

- the cost of FortisBC disputing the Commission's jurisdiction to hear Shaw's application, which was addressed in Order G-24-10,
- subsequently seeking a Reconsideration of that Order, which was addressed in Order G-63-10, both with Reasons, and
- unsuccessfully appealing the Commission's ruling on its jurisdiction to hear Shaw's application to the British Columbia Court of Appeal, which loss resulted in an award of costs against FortisBC (FortisBC Inc. v. Shaw Cablesystems Limited, 2010 BCCA 552).

Commission Panel Determination

The Commission Panel rejects FortisBC's proposal to amortize this deferral account into rates. As noted by the Court of Appeal (at para. 60), "[a] plain reading of s. 70 reveals that the legislation enables the BCUC to make decisions regarding electricity transmission facilities. That power is not limited to particular uses. The BCUC properly took jurisdiction over the matter..."

In the Panel's view, FortisBC's continued pursuit of this issue, without success, was not reasonable. Shaw was at all times seeking to continue to use FortisBC's transmission infrastructure for a fee, which was the result obtained at the end of the day. In the Panel's view these costs were entirely avoidable and ought not to be borne by ratepayers.

FortisBC is seeking to amortize the following regulatory expense deferral account into rates in 2013:

- Irrigation Rate Payer Group Consultation and Load Research

FortisBC is seeking approval to fully amortize costs in the amount of $0.07 million ($0.1 million before tax) which relate to segmenting the irrigation class customers into sub-groups and installing interval metering for a sample of each sub-group in 2013.

Commission Panel Determination

The Commission Panel approves the full amortization of the research costs relating to Irrigation rate payers in 2013, as requested. However, any ongoing balances for 2012 are to attract a short term interest financing charge only and will be carried as a non-rate base deferral account.

FortisBC is seeking to amortize the following deferral accounts over a longer period.

- Renewal of BC Hydro Power Purchase Agreement

FortisBC advises that it has been in negotiations with BC Hydro over renewal of its Power Purchase Agreement which expires in 2013, since 2005. FortisBC seeks Commission approval to begin amortizing its expected costs of negotiations in the amount of $0.2 million ($0. 3 million before tax) over five years, commencing in 2012.

Commission Panel Determination

The Commission Panel is of the view that the costs relating to FortisBC's negotiations with BC Hydro, ongoing for a number of years, are more properly considered operating costs. **The Commission Panel approves amortization of these amounts over a shorter, two year period to reduce carrying costs.** This deferral account is to be removed from rate-base and is to attract a financing charge at FortisBC's WACD.

C. Other Deferred Charges and Credits

- Revenue Protection

FortisBC forecasts expenditures of $0.17 million ($0.23 million before tax) in 2011 on its revenue protection program, which it proposes to amortize into rates in 2012. Revenue protection includes conducting inspections to detect and remedy illegal power diversion activities and also involves rental of poles and possibly other electrical infrastructure to third parties. FortisBC will be including the costs of its revenue protection program in Operating and Maintenance Expenses-Customer Service department commencing in 2012.

Commission Panel Determination

The Commission Panel approves the amortization of 2011 Revenue Protection expenses into rates in 2012, as requested.

- Right-of-Way Encroachment Litigation

FortisBC expects to defer approximately $0.09 million ($0.12 million before tax) of legal costs incurred to the end of 2011 related to its ongoing litigation with a land developer who is encroaching on one of its Right–of-Ways in Kelowna. FortisBC advises that it will include any recovered costs following resolution of the dispute in the deferral account and amortize the balance in rates, in accordance with Commission Order G-193-08. This residual will not be available for amortization until 2014 as the dispute has not been settled.

Commission Panel Determination

The Commission Panel approves the continuation of the Right–of-Way litigation deferral account, with the inclusion of any recovered costs following resolution of the dispute, as a non-rate base deferral account, attracting an interest financing charge at FortisBC's WACD.

- US GAAP

FortisBC seeks approval to amortize its costs for conversion to US GAAP in the forecast amount of $0.6 million ($0.8 million before tax) over a two year period commencing in 2012. These costs relate to audit, legal, advisory, and actuarial fees.

Commission Panel Determination

The Commission Panel approves the amortization of costs relating to conversion to US GAAP over the test period. Any future costs are to be carried as a non-rate base account attracting interest at FortisBC's WACD.

- Mandatory Reliability Standards Project

FortisBC has deferred set up costs estimated at $0.7 million ($1.0 million before tax) by the end of 2011 to become and remain compliant with the new Mandatory Reliability Standards. FortisBC seeks approval to amortize these costs over 5 years commencing in 2012.

Commission Panel Determination

The Commission Panel approves deferral of the set up costs relating to Mandatory Reliability Standards in a Non-Rate Base Deferral Account attracting interest at FortisBC's WACD. However, in the Panel's view, the amortization period requested is too long. Therefore, the Commission Panel directs that these costs be amortized into rates over a three year period, as opposed to the five year period sought, to reduce the associated carrying costs.

5.4.4.2 Proposed Deferral Accounts

(i) <u>Preliminary and Investigative Charges</u>

The Commission Panel notes that "Preliminary and Investigative Charges" are not properly considered to be capital expenditures under US GAAP, which is why Commission approval is sought for deferral account treatment. The Commission Panel further notes that FortisBC charges operating costs associated with capital projects directly to those projects, in addition to charging a percentage of operating costs to capital projects as capitalized overhead. In the Panel's view, Preliminary and Investigative Charges can be separated into two groups:

- Those costs which at a future time may become capital projects.
- Those that contribute to the development of Plans which are a regulatory requirement but are not actual capital projects.

Those projects which may in the future become capital projects are more properly considered operating expenses as they are not yet part of an approved capital project. Therefore, **the Commission Panel directs that any approved deferral accounts for these costs attract a financing charge at FortisBC's WACD until such time as they become part of a specific capital project.** As noted previously, the decision to proceed with a capital project should generally be made within three years.

For those costs which contribute to the development of a required regulatory plan, the Panel is of the view that they are most appropriately handled as regulatory expenses and amortized over the period of time the plan is intended to cover. As a regulatory expense any deferral amounts will attract a financing charge at FortisBC's WACD.

- 2012 Integrated System Plan

FortisBC forecasts that it will have spent $3.4 million on the development of its Integrated System Plan which was filed contemporaneously with its 2012-2013 Revenue Requirements Application. The Integrated System Plan includes the Long-Term Capital, Resource and DSM Plans. FortisBC proposes to transfer these costs to approved capital projects over the five year period from 2012 to 2016.

Commission Panel Determination

The Integrated System Plan was prepared for regulatory purposes to cover a five year period commencing in 2012. **The Commission Panel considers this item to be a regulatory expense not a capital expense related to any specific project and therefore, directs that this account attract an interest financing charge at FortisBC's WACD and be amortized into rates over a five year period.**

- Plants 1-4 Capital Sustainment

This account is for investigative spending for project planning and engineering and includes "development of more investigation and development of detailed project scopes and cost estimates." FortisBC expects to spend $0.03 million in each of 2012 and 2013, which amounts it proposes will then be transferred to the associated projects, once construction begins. (Exhibit B-1, Tab 5, p. 13)

FortisBC argues that amounts in this account are not annual recurring O&M charges because the work relates to determining what capital programs are required in future years and the specific projects are different. (Exhibit B-8, BCUC 2.26.1)

Commission Panel Determination

The Commission Panel is of the view that the amounts at issue in this deferral account are small, in the order of $30,000 per year, and finds deferral to be unnecessary. The Commission Panel also finds that these costs are not sufficiently associated with a capital project to be considered capital in nature. Rather these costs are more properly considered current operating costs and should be expensed as incurred. **The Commission Panel therefore directs that these costs be expensed during the test period.**

- Kelowna Bulk Transformer Capacity Addition

FortisBC expects to spend $0.3 million in 2011 and 2012 for preliminary engineering involved in the preparation of an application for a CPCN for the Kelowna Bulk Transformer Capacity Addition. FortisBC plans to obtain approval for this project in 2013 and will transfer costs to the capital project at that time.

Commission Panel Determination

As discussed above in Section 5.4.4.1, the Commission Panel directs that any amount in this deferral account should be treated as a non-rate base item and attract a financing charge at FortisBC's WACD until such time as they are transferred to the capital project. As discussed above, this amount should be expensed if the project does not proceed within a three year period.

- 2014-2015 Capital Expenditure Plan

FortisBC expects to spend $0.8 million on preliminary investigation and engineering costs for its 2014-2015 Capital Plan. FortisBC proposes to include these costs in the capital projects for those years.

Commission Panel Determination

Because they relate directly to the preparation of a required regulatory plan, the Commission Panel views these expenditures as regulatory expenses. The Commission Panel directs that this deferral account attract an interest financing charge at FortisBC's WACD.

(ii) Non-Controllable Items Variances

FortisBC is proposing to create a number of variance deferral accounts for expenditures which it suggests are either beyond its control or it has limited ability to control and which it views as for the account of the customer. FortisBC advises that many of these items have been approved in the past as flow through or "Z-Factor" items eligible for deferral.

The forecast balances for 2012 and 2013 are nil.

Commission Panel Determination

The Commission Panel notes that these accounts for the most part represent variances in current period expenses which are proposed to be trued up in the short-term. In the Panel's view, the creation of these deferral accounts represents a reasonable attempt to manage the uncertainty and unpredictability associated with accounts which are largely uncontrollable in nature. **The Commission Panel therefore approves the following variance deferral accounts as non rate base deferral accounts attracting a short term interest financing charge.**

- **Power Purchase Expense Variance Deferral Account**
    - **any variance in this account is to be amortized in 2014**
- **Revenue Variance Deferral Account**
    - **any variance in this account is to be amortized in 2014**
- **HST Removal or Reform Variance Deferral Account**
- **Property Tax Asset Variance Deferral Account**
- **Pension and Other Post-Employment Expense Variance**

The Commission Panel declines to approve the following proposed non-controllable expense variance deferral accounts:

- Income Tax Variance Deferral Account

FortisBC is proposing to add a deferral account to capture and accumulate variances from forecast taxes, including federal and provincial income tax, sales tax and any other taxes. FortisBC proposes that the amortization period for this deferral account can be reviewed as part of its 2014 RRA.

FortisBC argues that it can face uncontrollable changes in tax laws or accepted assessing practices "at any time." FortisBC proposes to include as well any required compliance costs, including changes to information systems which are required in this account. FortisBC advises that income tax variances qualified as "Z factors" in the prior PBR period and so were treated in a similar manner for rate-setting purposes.

FortisBC considers this account to be "Primarily Non-controllable" as it may have some control over the costs to adapt information systems for new tax laws. (Exhibit B-8, BCUC 2.28.1)

Commission Panel Determination

The Commission Panel is of the view that it is not necessary to create a deferral account for possible variances in income taxes payable from those forecast. Taxes are a reality faced by all businesses and in the Panel's view are predictable with some certainty. Approval for this proposed deferral account is therefore denied. In the event that there is a significant change in the tax landscape it is always open to FortisBC to apply to the Commission for relief on an as-needed basis.

- Interest Expense Variance Deferral Account

FortisBC is proposing a new deferral account to capture any variances between actual and forecast interest expense – both long and short term, as well as financing fees. FortisBC proposes to address the amortization period for this account as part of its 2014 RRA.

FortisBC considers this account to be "Somewhat Controllable." (Exhibit B-8, BCUC 2.28.1)

Commission Panel Determination

The Commission Panel agrees with FortisBC that interest expense is at least "somewhat controllable" and also finds it to be somewhat predictable, in that numerous agencies publish opinions on future interest rates on a regular basis. Approval for this deferral account is denied on the basis that FortisBC should make its best effort to forecast and manage this cost as part of its day to day business operations.

- Insurance Expense Variance Deferral Account

FortisBC also proposes to capture the difference between forecast and actual insurance expenses in a new deferral account. FortisBC argues that global events can influence insurance costs and that such impacts cannot reasonably be incorporated into forecast expenses. FortisBC proposes to review the amortization period for this account as part of its 2014 RRA.

FortisBC considers this account to be "Somewhat Controllable." (Exhibit B-8, BCUC 2.28.1)

Commission Panel Determination

The Commission Panel is of the view that the need for the Insurance Expense Variance Deferral Account has not been established and denies it. The Commission Panel notes the evidence of FortisBC's Vice President of Finance and CFO, Ms. Leeners, that FortisBC has in fact been able to manage its insurance premiums to a large extent, in spite of extraordinary catastrophic events affecting the world such as Hurricane Katrina, and that FortisBC's geographical diversification, claims history and affiliation with a large company contribute to this ability. (T4:575-577)

- Extraordinary Costs (Z Factor) Variance Deferral Account

FortisBC proposes a further deferral account to capture variances from "steady state" operations due to unplanned events. FortisBC cites Commission directives and decisions, legislation, changes to GAAP and Force Majeure as examples of extraordinary events. FortisBC proposes to review the amortization period for this account as part of its 2014 RRA.

Commission Panel Determination

The Panel declines to approve this deferral account. As noted above, the Panel is concerned with the proliferation of proposed deferral accounts. The Panel agrees with the ICG that it is open to FortisBC to apply for a deferral account on a case by case basis for extraordinary events.

(iii) Deferred Regulatory Expenses

FortisBC is seeking deferral account treatment for certain regulatory expenses as set out below.

- 2014 Revenue Requirements Application

FortisBC is seeking approval to defer what it expects to be costs in the amount of $0.08 million ($0.1 million before tax) for its 2014 Revenue Requirements Application in 2013. FortisBC proposes to apply for disposition of these costs in a future application.

Commission Panel Determination

The Commission Panel is of the view that these regulatory expenses are operating costs and should be capable of being absorbed into rates without deferral. However, given that the treatment requested accords with what has been done in the past, the Panel is prepared to approve this item as a non-rate base deferral account for rate-smoothing purposes. This deferral account is to attract a financing charge at FortisBC's WACD.

- 2014-2015 Capital Expenditure Plan Regulatory Costs

FortisBC is seeking approval to defer costs related to the regulatory review of a 2014-2015 Capital Expenditure Plan which it expects to file, in the estimated amount of $0.08 million ($0.1 million before tax) in 2013. FortisBC intends to apply for disposition of these costs in a future application.

Commission Panel Determination

The Commission Panel is of the view that these regulatory expenses are operating costs and are capable of being absorbed into rates without deferral. However, given that the treatment requested accords with what has been done in the past, the Panel is also prepared to approve this item as a non-rate base deferral account for rate-smoothing purposes. This deferral account is to attract a financing charge at FortisBC's WACD.

- 2012 Integrated System Plan and 2012-2013 Revenue Requirements Application

FortisBC is seeking approval to amortize the costs of the 2012 -2013 Revenue Requirements Application and Integrated System plan which it expects to be approximately $2.4 million ($3.3 million before tax) in 2011 over a five year period, commencing in 2012.

Commission Panel Determination

The Commission Panel is of the view that the amortization period requested for these regulatory expenses is too long and that FortisBC's ratepayers will suffer from the associated increased carrying charges. The Commission Panel approves a non-rate base deferral account attracting interest at FortisBC's WACD, to be amortized over a period of two, as opposed to five years.

(iv) Other Deferred Charges and Credits

- Prepaid Pension Costs

FortisBC has recorded the difference between the actuarial valuation of the pension net benefit cost and the forecast Company contributions on a net of tax basis in a "prepaid pension deferral account" for 2011. This treatment accords with pre-changeover Canadian GAAP (which no longer exists), was approved by Commission Order G-184-10 and is consistent with prior years' treatment in revenue requirement applications over the PBR term. This treatment is also similar to that allowed by US GAAP.

FortisBC has now been approved to use US GAAP, which, unlike current IFRS, permits deferral accounting. (Exhibit B-1, Tab 5, p. 23)

The 2012 and 2013 prepaid pension cost consists of the net benefit cost, relating to the following pensions:

- IBEW (defined benefit) Pension Plan
- COPE (defined benefit) Pension Plan
- FortisBC (defined benefit) Retirement Income Plan
- Supplemental pension arrangements for current and former executives.

FortisBC is requesting approval to recognize total Prepaid Pension Costs as a Rate Base deferral account, on a net of tax basis, for 2012 and 2013. FortisBC forecasts a $0.7 million ($1.0 million before tax) and a $2.7 million ($3.6 million before tax) increase in this deferral account in 2012 and 2013, respectively.

Commission Panel Determination

In keeping with its earlier determinations, the Commission Panel approves this deferral account as a non-rate base deferral account attracting interest at FortisBC's WACD.

- US GAAP Pension Transitional Obligation Deferral Account

FortisBC also seeks approval to establish a "Pension Transitional Obligation Deferral Account" as a Rate Base deferral account, with an equal offset to the Prepaid Pension Costs Deferral Account, to separate these proposed rate base items. The Pension Transitional Obligation Deferral Account will recognize the difference between pension net benefit costs calculated under Canadian GAAP and US GAAP, as required by US GAAP. This amount is forecast to be $2.2 million as of January 01, 2012. It consists of unamortized net transition obligations determined pursuant to Canadian GAAP, which are required to be fully amortized under US GAAP, and the net benefit cost for a three month period resulting from the change in measurement date from September 30th to December 31st, as required by US GAAP.

FortisBC proposes that the balance in the US GAAP Transitional Obligation Deferral Account be amortized over an approximate twelve year period, to accord with the expected average remaining service life of the Company's pension plans. FortisBC forecasts a further addition of $1.6 million ($2.2 million before tax) to this account for 2012.

Commission Panel Determination

The Commission Panel approves the creation of this deferral account as a non-rate base deferral account attracting interest at FortisBC's WACD.

- Accumulated Other Comprehensive Income

FortisBC is also requesting regulatory recognition and acknowledgment of a non-rate base deferral account to record amounts representing accumulated unrecognized losses/gains and unrecognized prior service costs/credits which would otherwise be required to be recognized as "Accumulated Other Comprehensive Income" and offset against prepaid pension costs for external financial reporting purposes. (Exhibit B-1, Tab 5, p. 26, Appendix E)

Commission Panel Determination

The Commission Panel approves the creation of this non-rate base deferral account, attracting interest at FortisBC's WACD.

- Other Post-Employment Benefits Deferral Accounts

FortisBC also records the difference between the actuarially determined OPEB net benefit cost and actual payments to retirees in an OPEB Deferral Account on a net of tax basis. FortisBC forecasts a $2.1 million ($2.8 million before tax) addition to the OPEB Deferral Account for 2011. The 2011 accounting treatment is consistent with pre-changeover Canadian GAAP and was approved by Commission Order G-184-10. As of January 1, 2012, the Company has been relying on US GAAP.

FortisBC therefore now requests approval to recognize US GAAP OPEB Liability as a rate base deferral account, to which it expects to add $5.7 million ($7.7 million net of tax) in 2012 with a further $1.7 million ($2.2 million before tax) in 2013.

Commission Panel Determination

The Commission Panel approves the creation of a non rate-base deferral account attracting interest at FortisBC's WACD for Other Post-Employment Benefits.

- US GAAP OPEB Transitional Obligation Deferral Account

FortisBC is also requesting a further US GAAP OPEB Transitional Obligation Rate Base Deferral Account to record differences resulting from the calculation methodology for Other Post-Employment Benefits required under Canadian as opposed to US GAAP. (US GAAP would require all remaining unamortized net transition obligations determined under Canadian GAAP to be fully amortized). The proposed US GAAP OPEB Transitional Obligation Deferral Account would also include the net benefit cost for three months resulting from the change in the measurement date from September 30th to December 31st, which is required by US GAAP. These amounts are forecast to be $2.0 million, as of January 1, 2012. FortisBC proposes to recover this amount over 12 years.

FortisBC also proposes that a remaining transitional obligation in the amount of $3.5 million which resulted from a change from cash to accrual accounting for OPEB under Canadian GAPP in 2005 be recognized in the US GAAP OPEB Transitional Obligation Rate Base Deferral Account. It has been tracked to this time in a Non-Rate Base deferral account.

An amount equal to the US GAAP OPEB Transitional Obligation Deferral Account is proposed to be offset against the US GAAP OPEB Liability Deferral Account. FortisBC forecasts a $4.1 million ($5.5 million before tax) increase to this account in 2012.

As requested for the pension accounting treatment, FortisBC is also requesting regulatory recognition and acknowledgement of a Non Rate Base Deferral Account to accumulate unamortized gains (losses) and unrecognized prior service costs (credits) rather than flowing such amounts through Accumulated Other Comprehensive Income and back into OPEB.

Commission Panel Determination

The Commission Panel approves the creation of a US GAAP OPEB Transitional Obligation Deferral Account as a Non Rate Base Deferral account, attracting interest at FortisBC's WACD. The Commission

Panel also approves the inclusion of the remaining transitional obligation in this Non-Rate Base Deferral Account.

The Commission Panel approves the offset account and agrees to the deferral of unamortized gains (losses) and unrecognized prior service costs, again in a Non-Rate Base Deferral Account attracting interest at FortisBC's WACD.

- Asset Management

This proposed Deferral Account is rejected, as discussed in subsection 5.2.2.3 (a).

- Joint Pole Use Audit 2013

FortisBC advises that its various joint pole use agreements require that an audit be performed on the joint use pole contacts every five years. The last audit was in 2008. FortisBC is seeking approval "to defer funds of $0.2 million ($0.3 million before tax) and to begin amortization in 2013 over a five year period."

Commission Panel Determination

The Commission Panel approves the deferral of costs of audits for joint pole use contacts in a Non-Rate Base Deferral account attracting interest at FortisBC's WACD. In the Panel's view, these expenses should be recovered over a shorter period than five years, to reduce carrying charges. The Commission Panel therefore directs that these costs be recovered over a two year period.

- Deferred Debt Issue Costs

FortisBC advises that it expects to issue $120 million in unsecured debentures with a term of 30 years in 2013. FortisBC estimates that the total issue costs for the debt will be approximately $1.6 million.

FortisBC seeks approval to defer the issuance costs and to amortize them over the term of the debt, subject to approval of the debt issuance itself, which will be sought in a separate application.

Commission Panel Determination

The Commission Panel approves deferral of the debt issuance costs as a Non-Rate Base Deferral account to be amortized over the term of the debt and attracting interest at the same rate as the debt issuance. In the event that the debt issuance does not proceed, and subject to further Commission order, the related costs are to be expensed at that time.

5.4.4.3 Existing Deferral Accounts with Proposed Change in Treatment

- Advanced Metering Infrastructure

FortisBC advises that the forecast amount of $1.8 million is for the preparation of an application for a CPCN for advanced metering infrastructure which was to be filed in 2011. This amount is being held in a non-rate base deferral account, and includes AFUDC in the amount of $0.121 million. FortisBC is seeking to transfer these funds to a rate base deferral account, pending transfer to the AMI capital project in 2012. FortisBC advises that, although AFUDC is not generally applied to balances in Preliminary Investigative Deferral Accounts, AFUDC was accrued pursuant to a specific agreement made in the 2011 RRA NSA, which was approved by Commission Order G-184-10 on a without prejudice basis. (Exhibit B-1, Tab 5, p. 14; Exhibit B-8, BCUC 2.27.1)

Commission Panel Determination

As noted in Section 5.4.4.1, the Commission Panel is of the view that the costs incurred in respect of a CPCN Application should not form part of rate base until such time as the capital project is approved. Accordingly, FortisBC' request to make this a rate base deferral account is denied. This account is to attract an interest financing charge at FortisBC's WACD going forward, until such time as a determination on the CPCN Application is made.

6.0 DEMAND-SIDE MANAGEMENT

FortisBC is seeking two approvals regarding its Demand-Side Management (DSM) programming. The first is approval under subsection 44.1(6) of the *Act* that its 2012 ISP is in the public interest. FortisBC's ISP includes its 2012 Long-Term DSM Plan. The second approval sought is to spend $7.73 million in 2012 and $7.88 million in 2013 on demand-side measures, pursuant to section 44.2 of the *Act*. These two requests are addressed below.

6.1 Long-Term Demand-Side Management Plan

FortisBC's Long-Term DSM Plan includes the years 2012-2030. The Plan sets out the expected DSM programming, energy savings and spending for 2012-2016 as an extension of the spending and savings levels from the 2011 DSM Plan previously approved by the Commission. For the years 2017-2030, FortisBC has included a constant proxy figure of 28 GWh/year in energy savings. Overall, the Plan was designed to achieve electricity savings to offset 50 percent of FortisBC's load growth until 2030.
(Exhibit B-1-2, Volume 2, p. 1)

The expected energy savings for the 2012 DSM Plan are shown in the table below.

Table 15 – Savings Targets

Year	Residential	Commercial	Industrial	Proxy '17-31
	GWh			
2011	16.4	13.5	1.1	-
2012	16.1	12.2	1.7	-
2013	16.9	12.3	1.8	-
2014	19.5	11.9	1.8	-
2015	21.1	11.9	1.8	-
2016	22.6	9.9	1.9	-
2017-30	-	-	-	28

(Exhibit B-1-2, Volume 2, p. 15)

FortisBC plans to update its DSM Plan and the contributing studies (end-use studies and a Conservation Potential study) that are used in the development of the DSM Plan, every 5 years. (Exhibit B-1-2, Volume 2, p. 17)

6.2 Monitoring and Evaluation Plan

Included in the 2012 DSM Plan is FortisBC's Monitoring and Evaluation Plan (M&E Plan) for 2012-2014. The M&E Plan sets out the principles FortisBC will follow in evaluating its DSM programs and a schedule of programs that will be evaluated in 2012-2014.

As background on DSM evaluation, there are four major types of evaluation studies of DSM programs:

i. Process Studies

These studies review how efficiently and effectively a program is run and are typically done 6-18 months after a program is launched;

ii. Market Studies

These studies review how effective a DSM program is at increasing the market share of energy efficient technologies and are typically done 24-36 months after program launch and then every 2-3 years afterwards;

iii. Impact Studies

These studies review and determine the energy savings that are directly attributable to a DSM program and are typically done 24-36 months after program launch and then, every 2-3 years afterwards;

iv. Pilot Studies

These studies typically involve using a process study with some measurement and verification of energy savings and are usually completed during or immediately following a pilot program.

(Exhibit B-1-2, Volume 2, Appendix D, pp. 4-5, 7)

The M&E Plan proposes that each year FortisBC will conduct a Process, Market and Impact Study (what FortisBC terms a "Comprehensive Review") on two of its DSM programs and a Process Study and some M&E activities (what FortisBC terms a "Mini Review") on three of its programs. The Plan establishes a threshold to trigger evaluation, that is, when a DSM program is estimated to have achieved 10 GWh in energy savings, evaluation studies will be conducted. (Exhibit B-1-2, Volume 2, Appendix D, p. 11)

The proposed M&E plan would cost $385,000/year to implement which is approximately 5 percent of FortisBC's total requested annual DSM expenditure. (Exhibit B-1-2, Volume 2, Appendix D, p. 4)

6.2.1 The Commission's Review of the Long-Term DSM Plan

As discussed in Section 2.2 of this Decision, subsection 44.1(8) of the *Act* applies to the Commission's review of the ISP as a whole. The Long-Term DSM Plan, which is filed as part of the larger ISP, is appropriately assessed under subsection 44.1(8)(c) and (d) for adequacy, cost-effectiveness, and the public interest.

6.2.1.1 Adequacy and Cost Effectiveness

FortisBC currently runs and plans to continue running the four programs required for adequacy under the Demand-Side Measures Regulation which are:

Required DSM program for adequacy	**Current or planned FortisBC program(s)**
A program for low-income households	• Residential Energy Savings Kits • Residential Energy Conservation Assistance Program • First Nations Residential Households Program
A program for rental accommodation	• "Whole Home" financial incentives for landlords, property managers and rental agencies
An education program for students enrolled in schools in the utility's service area	• Financial sponsorship of educational events and programs • Designed Grade 11 curriculum-based course on energy and conservation
An education program for students enrolled in post-secondary institutions in the utility's service area	• Okanagan College "Home for Learning" energy efficiency training opportunities • Provide guest lecturers • Sponsorships and training for trades • Support energy management training workshops

(Exhibit B-1-2, Volume 2, pp. 24, 28-29)

FortisBC submits that the result of its mTRC test for its 2012-2013 DSM expenditure portfolio is 1.4 and that over the 2012 Long-Term DSM Plan the costs (avoided costs and measure costs) will change but that FortisBC will ensure the cost effectiveness of the portfolio will remain above one. (Exhibit B-27, Undertaking 31; Exhibit B-1-2, Volume 2, p. 14)

Commission Panel Determination

The Commission Panel finds that FortisBC's 2012 Long-Term DSM Plan is adequate and cost-effective as per subsection 44.1(8)(c) of the *Act*. No evidence was raised in the hearing to dispute FortisBC's position. The Commission Panel assesses the cost-effectiveness of FortisBC's DSM Plan on a portfolio basis and accepts FortisBC's calculation.

6.2.1.2 The Public Interest

Various issues were raised about FortisBC's Long-Term DSM Plan during the proceeding.

The first issue is whether the Plan is in fact a long-term plan or, more accurately, a five-year plan because a placeholder for energy savings has been used for 2017-2030. FortisBC's position is that detailed planning data is only valid for 5 years due to rapidly changing DSM technology and costs. (Exhibit B-8, BCUC 2.94.1.1)

The second issue is whether an increase in DSM spending is needed over the next five years, rather than FortisBC's Plan which proposes fairly flat DSM savings targets (and by extension, spending) for this period. FortisBC argues that it has increased DSM spending by almost 500 percent since 2000 and that further increased spending is not warranted at this time. (Exhibit B-8, BCUC 2.94.2)

The third issue is whether FortisBC's planning criteria of targeting 50 percent of load growth is appropriate. BCSEA argues that targeting DSM as a percentage of load growth does not aim to achieve all available energy savings and points out the following disadvantages of FortisBC's methodology: where there is no load growth, no DSM programs would be run; and when there is significant large load growth, all available energy savings may not be achieved. (T4: 620) BCSEA advocates the approach of targeting energy savings as a percentage of energy sales which FortisBC acknowledges is used in other jurisdictions. (T4: 621) In part as a result of consultation with its customers, FortisBC chose a “medium” DSM plan portfolio over a more costly “high” plan portfolio. BCSEA submits that FortisBC’s choice of a “medium” DSM scenario over a “high” scenario was flawed because FortisBC exaggerated the risk of DSM relative to new supply, failed to apply the same ranking criteria to DSM as new supply, and inappropriately considered rate impacts in its decision not to pursue more DSM activities. (BCSEA Final Submission, p. 14)

The issue of the rate impact of DSM programs and whether the rate impact should be used as a Plan selection criterion was also well-canvassed during the proceeding. BCSEA submits that rate impacts must be assessed in conjunction with bill impacts and that even if a higher level of DSM spending causes a rate increase, “the increase in average rates must be compared against the decrease in average bills.” (emphasis in original) (Exhibit C6-5, pp. 32-33) In other words, because DSM activities can help customers use less energy, their energy bills will decrease even if FortisBC’s increased spending on DSM causes an overall rate increase.

FortisBC cross-examined BCSEA’s expert witness, Mr. Plunkett, on his focus on bill impact versus rate impact suggesting that if only 10 percent or less of FortisBC’s customers participate in DSM programs, only that 10 percent will see bill savings from DSM, while the remainder of FortisBC ratepayers will see a rate (and bill) increase from the Company’s DSM activities. (T5: 941-944)

Mr. Plunkett agreed that, in the short term, bill savings will only be seen by ratepayers participating in DSM programs but postulated that bill savings will be obtained by most ratepayers over time. Mr. Plunkett testified that is “exactly how it works” because over time the Company will be in a position to avoid high cost new energy which will lower the total cost of service for everyone. (T5: 944)

BCSEA requests the Commission find that FortisBC’s Long-Term DSM Plan is not in the public interest because it does not show the utility’s intent to pursue all cost-effective demand-side measures. (BCSEA Final Submission, p. 28) It cites the evidence of Mr. Plunkett who recommends the Commission direct FortisBC to implement DSM programming by 2016 to target roughly 2 percent of annual sales, an increase from the current plan which targets approximately 0.85 percent of annual energy sales. BCSEA notes Mr. Plunkett's estimate that it would cost FortisBC approximately $33 million/year to achieve energy savings of 2 percent of energy sales. This yearly spending translates to roughly 5.5 cents/kWh which is less than the 10 cents/kWh FortisBC uses to estimate its avoided supply cost in its Long-Term DSM Plan. (BCSEA Final Submission, pp. 6-7)

BCSEA further recommends the Commission direct FortisBC to, among other things,

- Apply the same ranking criteria to DSM alternatives as it applies to generation alternatives;
- Take into account the ability to shape efficiency acquisitions to match energy and capacity requirements, in comparing DSM to generation alternatives;
- Address the timing of an updated Conservation Potential Review in its 2014 DSM expenditure schedule; and
- Revise its Long-Term Resource Plan if natural gas fired generation is added.

(BCSEA Final Submission, pp. 28-29)

6.2.1.2.1 Monitoring and Evaluation Plan

During the proceeding, FortisBC was questioned on the adequacy of its M&E Plan, especially given that the current plan and its 10 GWh savings threshold results in some DSM programs never being evaluated and others being evaluated very infrequently. (Exhibit B-4, BCUC 1.298.2) As noted, the proposed M&E Plan would cost FortisBC $385,000 per year to implement, which equates to 5 percent of its overall DSM budget. The 2004 California Evaluation Framework, a seminal document for DSM evaluation, references a spending range of 2-10 percent of overall DSM budget spending on DSM evaluation among utilities in North America, with the average spending being 4 percent. (Exhibit B-8, BCUC 2.98.7; Exhibit B-4, BCUC 1.297.1)

During the oral hearing, FortisBC referenced an evaluation study conducted by BC Hydro of the Energy Savings Kits program that FortisBC and BC Hydro both run. The study showed that of 700 kWh of possible energy savings in the kits, only 203 kWh in savings were realized if the kits were self-installed by the customer, whereas 350 kWh of savings were realized if maintenance personnel installed the kits. (T4:707-8)

FortisBC also testified as to the importance of conducting monitoring and evaluation studies on a regular basis to confirm that expected savings from a program are actually realized in the field. (T4:721-2) FortisBC agreed that administrative cost savings may be found when process studies are conducted on DSM programs and also stated that it intended to use M&E data from other utilities to supplement FortisBC studies. (T5: 873; FortisBC Final Submission, p. 215)

FortisBC outlined a possible alternative evaluation plan where every program undergoes evaluation according to the typical timing for the various evaluations described in Section 6.1.2 above. FortisBC estimates the alternative M&E plan would cost an additional $100,000 per year to implement. (Exhibit B-8, BCUC 2.98.7) This would represent just over 6 percent of the Company's total DSM budget.

FortisBC submits that its M&E plan, as proposed, is "robust." BCSEA submits it is generally satisfied with FortisBC's M&E plan for the 2012- 2014 period but notes that it is not best practice to never evaluate a program because "you'd eventually want to do some kind of evaluation of a program unless you had an awfully good reason not to." (T5: 884, 965; BCSEA Final Submission, p. 28)

Commission Panel Determination

The Commission Panel finds FortisBC's 2012 Long-Term DSM Plan to be in the interests of persons in British Columbia who receive or may receive service from FortisBC in accordance with subsection 44.1(8) (d) of the *Act.* Subject to the further findings relating to the M&E Plan and in accordance with subsection 44.1(7) of the *Act*, the Panel accepts the Plan under subsection 44.1(6) of the *Act*.

The Commission Panel recognizes that this acceptance means that FortisBC may simply maintain current levels of DSM spending over the next five years, subject to future DSM expenditure schedules filed for approval with the Commission. However, as discussed in relation to FortisBC's section 44.2 expenditure schedule request (below), FortisBC received approval to spend approximately twice the amount on DSM in 2011 over 2010 and was unable to spend to the higher approved level. As well, the Commission Panel acknowledges that the Company is implementing new programs that will take time to gain participants. The Panel is also persuaded that FortisBC can employ other best practises to achieve additional savings without adding to its budgeted spend.

The Commission Panel accepts FortisBC's proposal to submit a revised Plan and to update the contributing studies every 5 years.

The Commission Panel is also of the view that the rate impact from DSM spending is a relevant consideration for the public interest, at least in the short term, as increased participation in DSM programs may take some time.

With respect to BCSEA's proposals for the Company's next Long-Term DSM Plan, the Commission accepts that FortisBC may wish to apply the same ranking criteria to DSM as it applies to generation alternatives but does not accept that FortisBC should necessarily change its DSM target from one based on load growth to energy sales at this time. The Commission Panel is satisfied that FortisBC is taking a reasonable approach to setting targets for energy savings in the current environment.

Regarding FortisBC's proposed M&E Plan, the Commission Panel sees FortisBC's testimony concerning the Energy Savings Kits evaluation as highlighting the importance of the evaluation process. It would appear that if BC Hydro had not evaluated the kits, the utilities might assume savings of 700 kWh of energy savings per kit when in fact, the kits are producing savings of less than half of this amount. As stated by Mr. Warren, FortisBC's Director of Customer Service, M&E studies are done to ensure the savings claimed are actually occurring in the field. The Commission Panel expects that the energy savings estimates FortisBC puts before the Commission will actually occur because this represents the value of DSM to all ratepayers. An accurate account of energy savings cannot occur without M&E

studies conducted on programs. **The Commission Panel rejects FortisBC's proposed M&E Plan in its current form as it fails to ensure that all programs are evaluated.** Given that FortisBC's alternative M&E plan costs $100,000 more per year and that amount remains within the California Evaluation Framework range of common budget allocations to M&E**,** the Commission Panel recommends that FortisBC resubmit an alternative M&E schedule, such as that submitted in response to BCUC IR 2.98.7, that does not apply a 10 Gwh threshold to trigger evaluation and that follows the typical sequence of evaluations as laid out in the M&E Plan for acceptance by the Commission. Any additional funds for this alternative schedule should come from the currently proposed expenditure schedule and no additional funds above the requested amounts are approved. The Commission Panel encourages FortisBC to supplement its own studies with data from other utilities wherever appropriate and to conduct shared evaluations on integrated programs.

6.3 FortisBC's Expenditure Request for 2012-2013

As part of this Revenue Requirement Application, under section 44.2 of the *Act*, FortisBC is requesting approval to spend $7.73 m in 2012 and $7.88 m in 2013. The 2012-2013 DSM expenditure schedule is an extension of its previously approved 2011 DSM plan.

As background, in 2011 FortisBC was approved to spend $7.842m which is almost double the amount it was approved for in 2010. In 2011, FortisBC spent $5.917 million of the total $7.842 million approved. (Exhibit B-29, Undertaking 32)

The 2012-2013 proposed DSM expenditure schedule comprises DSM programs in the Residential, Commercial (or General Service) and Industrial sectors as well as funding for Supporting Initiatives and Planning and Evaluation.

Table 16

1		2011		2012		2013		TRC incl
2		Approved		Plan		Plan		MTRC
3		Savings	Cost	Savings	Cost	Savings	Cost	B/C
4	**Programs**	*MWh*	$(000s)	*MWh*	$(000s)	*MWh*	$(000s)	ratio
5	Residential	16,422	3,636	16,101	3,717	16,946	3,944	1.6
6	General Service	13,940	2,118	13,380	2,199	11,980	2,085	1.5
7	Industrial	9,360	613	2,480	350	2,580	364	3.3
8	**Sub-total Programs:**	**39,722**	**6,367**	**31,961**	**6,266**	**31,506**	**6,393**	**1.6**
9	Supporting Initiatives		725		725		$ 725	
10	Planning & Evaluation		750		740		760	
11	**Total (incl. Portfolio spend):**		7,842		7,731		7,878	**1.4**
12	Income Tax Impact		-2,078		-1,933		-1,969	
13	**Total deferred (net of tax)**		5,764		5,798		5,908	

(Exhibit B-27, Undertaking 31)

As shown in Table 16 above, FortisBC calculates that its proposed DSM portfolio has an mTRC of 1.4 and is thus cost effective.

6.3.1 The Commission's Review of the DSM Expenditure Request

As noted in Section 2.2 of this Decision, in considering whether to approve an expenditure schedule, the Commission must consider the following under subsection 44.2(5) of the *Act*:

(a) the applicable of British Columbia's energy objectives,

(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any,

(c) the extent to which the schedule is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*,

(d) if the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any, and

(e) the interests of persons in British Columbia who receive or may receive service from the public utility.

The Commission has considered the applicable of British Columbia's energy objectives in the context of FortisBC's proposed Capital Expenditure Plan. FortisBC's long-term resource plan is considered in Section 7 of this Decision. Sections 6 and 19 of the *CEA* are not applicable to DSM expenditures.

Regarding the cost effectiveness of the DSM programs, the Commission has previously assessed FortisBC's DSM programming at a portfolio level and will continue to do so in this case. The Commission Panel accepts the cost effectiveness calculations put forward by FortisBC and thus **finds FortisBC's 2012-2013 DSM Expenditure Schedule to be cost effective in accordance with the Demand-Side Measures Regulation (Ministerial Order No. 271) and the Amendments to the Demand-Side Measures Regulation (Ministerial Order No. 335).**

Given the assessment of the above items, the issue remaining for the Commission to consider is whether acceptance of the expenditure schedule is in the interests of persons in British Columbia who receive or may receive service from FortisBC. Of relevance to this issue is whether FortisBC's proposed spend is sufficient.

6.3.1.1 Sufficiency of DSM Spending Level

FortisBC is requesting approval to spend $7.73 million in 2012 and $7.88 million in 2013 on its DSM portfolio. As previously discussed in relation to FortisBC's Long-Term DSM Plan, BCSEA's position is that FortisBC is under spending on DSM and should ramp up spending to approximately $33 million per year.

FortisBC disagrees with BCSEA's position and counters that in 2011 they were approved for double the spend over 2010, that they have not yet been able to implement the increase, and that spending $33 million/year would result in a 6.4 percent rate increase between 2012 and 2016 which is significant. (T5: 869-70; Exhibit B-27, Undertaking 33, p. 26)

BCSEA's expert witness, Mr. Plunkett, provided testimony explaining his analysis of DSM programs in various jurisdictions across North America. Mr. Plunkett advised that he grouped the jurisdictions he reviewed into four tiers, based on energy sales avoided through DSM, with the first tier being the best. In Mr. Plunkett's analysis, only three jurisdictions were in Tier 1, California, Vermont and Connecticut. These jurisdictions were able to achieve one and one half per cent or more of energy sales being avoided through DSM. Mr. Plunkett placed FortisBC squarely in Tier 2, along with nine other jurisdictions which succeeded in achieving approximately one percent of energy sales being avoided through DSM. (T5:926-929)

Commission Panel Determination

Many of the issues related to FortisBC's 2012 Long-Term DSM Plan are the same as the issues related to the section 44.2 expenditure schedule request including spending level, rate impact and value for money.

Based on the conclusions the Panel has reached in relation to these issues for the Long-Term DSM Plan, and considering the testimony of Mr. Plunkett that FortisBC has achieved a ranking placing it in his second tier of jurisdictions with successful DSM programs, **the Commission Panel approves FortisBC's section 44.2 expenditure request for DSM in the amounts of $7.73 million in 2012 and $7.88 million in 2013**. The recovery of these expenditures is to continue in the manner previously approved for FortisBC.

6.3.1.2 FortisBC Industrial Incentives

An issue raised primarily by the Industrial Consumers Group is the difference in DSM incentive levels offered by BC Hydro and FortisBC and whether FortisBC's industrial incentives are sufficient. ICG requests the Commission direct FortisBC to enhance its industrial DSM programs to match BC Hydro's incentives and to implement an energy manager program, similar to that offered by BC Hydro to its industrial customers. (ICG Final Submission, p. 38)

FortisBC indicates a concern as to the persistence of savings from funding an energy manager position. (Exhibit B-5, Celgar 1.10.4)

BC Hydro's industrial DSM program offers incentives of 30.9 cents/kWh with no payback period limit and with 100 percent of the project cost being eligible for rebate for projects costing up to $1 million and 75 percent being eligible for projects costing more than $1 million. (Exhibit B-9, Celgar 2.12.1, 2.12.3)

FortisBC offers 10 cents/kWh with a two year payback period limit on the incentive amount. FortisBC compared the incentive it would offer an industrial customer under its DSM program to that which would be available to a BC Hydro customer. In the comparison, FortisBC would pay the industrial customer $1.5 million in incentives while BC Hydro would pay $4.635 million in incentives for the same project. (T4:732; T5:795)

FortisBC recognizes that there is significant difference in incentives offered by FortisBC and BC Hydro but takes the position that it does not have to offer the same programs as BC Hydro, although FortisBC does try to match BC Hydro's residential DSM incentives. (Exhibit B-9, Celgar 2.5.5, 2.10.3, 2.11.1; T5:801)

FortisBC was questioned during the oral phase of the proceeding about the difference in incentive levels, to which its witness responded:

> MR. WARREN: In this case I would have -- with a 1.0 benefit/cost ratio TRC, I would have -- I have some difficulty justifying paying the kind of numbers that B.C. Hydro pays, which is effectively 58 percent of the TRC value. For example, our air source heat pump customers, measured on the same benefit/cost ratio basis, have about a 1.0 TRC as well at $85, and we pay about 12 percent of the total cost of those upgrades.
>
> So it would be difficult to justify.
>
> (T5: 795-6)

ICG's position is that there is "simply no explanation" for the differences in BC Hydro and FortisBC industrial DSM programs and that at FortisBC's incentive levels, it is no surprise that Celgar, one of FortisBC's industrial customers, did not proceed with a planned DSM project. (ICG Final Submission, pp. 35-36)

BCSEA submits that the fact that FortisBC's commercial and industrial program incentives are capped at 10 percent of annual kWh savings with a two-year payback period limit discourages cost-effective energy savings. (BCSEA Final Submission, p. 12)

BCSEA advocates for consistent DSM programs across the province and requests the Commission to direct FortisBC to revise its DSM incentives to be better aligned with those offered by BC Hydro and to increase, wherever possible, standardization of common DSM program features across the Province, including marketing, financial incentives, and eligibility requirements. (BCSEA Final Submission, pp. 28-29)

FortisBC replies that increasing industrial incentives to match those of BC Hydro could result in millions of dollars in additional expenditures and argues that ICG did not file any evidence to explain why Celgar did not proceed with its planned DSM project. (FortisBC Reply, pp. 73-74) FortisBC also submits that the FortisBC and BC Hydro DSM programs which ICG references are comparable and that FortisBC takes a reasoned approach by preferring to have customer co-investment. (FortisBC Reply, pp. 75-77)

Commission Panel Determination

The Commission Panel does not accept ICG's request to direct FortisBC to match BC Hydro's industrial incentives or to implement an energy manager program. The Commission Panel acknowledges that BC Hydro does offer larger incentives to its industrial customers. However, we are not persuaded that BC Hydro's level of incentive is necessarily optimal and that FortisBC should move to that level.

As noted earlier, in the Panel's view, BC Hydro and FortisBC are different utilities, operating in different contexts. The Commission Panel is not prepared to direct FortisBC to implement the same DSM programs as BC Hydro, particularly in the industrial sector where the customer base is very different.

The Commission Panel also reiterates its view that FortisBC's DSM Program, as advanced, is reasonable.

6.3.1.3 Transfers of DSM Funding Among Programs

Currently FortisBC has no official policy in place for the transfer of funds between sectors such as residential and industrial but rather makes a judgment call to determine when transfers are appropriate. FortisBC agrees that customers might be concerned about a large transfer between sectors. FortisBC submits that it will seek concurrence of its DSM Advisory group in some cases prior to transferring funds. (Exhibit B-9, Celgar 2.2.2; T5:888-9)

FortisBC indicated in the oral phase of the Hearing that it was amenable to gaining Stakeholder Group approval and informing the Commission prior to making a transfer of funds between sectors where the proposed transfer would exceed a threshold of 30 percent of a sector's budget. (T5: 890-1)

Commission Panel Determination

The Commission Panel is of the view that a more formal policy regarding fund transfers among sectors/ program areas is appropriate at this time, given the substantial increase in the budget for DSM programs. The Commission Panel is also of the view that a threshold of 25 percent is most appropriate. **The Commission Panel therefore approves FortisBC's transfer of a maximum of 25 percent of the budget amount from one existing program area or sector to another existing program area or sector without prior approval of the Commission**. In cases where a proposed transfer into or out of an approved Sector is greater than 25 percent of that sector, prior Commission approval is required. The Commission Panel recommends that funding transfers of 25 percent or more requiring prior Commission approval, should, where feasible, be presented to FortisBC's DSM Advisory Committee for feedback before the approval request is made to the Commission.

6.3.1.4 Integration of DSM Programs Among BC Utilities

In its Final Submission BCSEA also recommends the Commission direct FortisBC to “provide evidence of concrete progress in terms of coordinating, integrating and standardizing DSM program design and delivery among FortisBC, BC Hydro and the FEU in FortisBC’s next DSM expenditure schedule filing.” (BCSEA Final Submission, pp. 28-29)

BCMEU requests the Commission direct FortisBC to “work more closely with Fortis Gas as well as BC Hydro to find efficiencies for investment in DSM which provides opportunities to ratepayers while reducing costs to ratepayers.” (BCMEU Final Submission, p. 90)

FortisBC submits that it has always collaborated with other BC utilities on DSM and that a direction in this regard is not necessary. (FortisBC Final Submission, p. 208; FortisBC Reply, pp. 72-73)

Commission Panel Determination

The Commission Panel agrees that every effort should be taken to integrate and collaborate among BC utilities to maximize the effectiveness and efficiency of DSM programs and minimize cost to ratepayers. **The Commission Panel directs FortisBC to include in its semi-annual DSM reports and in future DSM filings with the Commission, a short summary of progress on integration among utilities.**

7.0 INTEGRATED SYSTEM PLAN

7.1 Long-Term Capital Plan

FortisBC's Long-Term Capital Plan is the component of its Integrated System Plan that lays out the long-term strategic direction the company intends to follow to meet its infrastructure and asset needs. The overall capital plan has three components – the short term (2012-2013), dealt elsewhere in this Decision, the medium term (2014-2016) and the long term (2017 onwards). The Long-Term Capital Plan sets out projects that are expected to be developed over the next 20 years and, in the case of bulk transmission assets, projects expected over the next 30 years are also included.

The Company is not seeking approvals for any specific projects in its 2012 Long-Term Capital Plan, but does request Commission acceptance of its ISP, of which the LTCP is a component, as being in the public interest. (Exhibit B-1-1, p. 1)

The planning process to prepare a long-term capital plan has a number of key inputs, including load forecasts, cost estimation and capital-related accounting practices. FortisBC filed a detailed description of the processes utilized in developing the 2012 Long-Term Capital Plan. The filing includes details by types of projects (e.g. transmission infrastructure, generation infrastructure) and by region. Estimates for the medium term (2014 to 2016) are provided on an annual basis. For the longer term (2017-31) a single estimate is provided for the entire period. (Exhibit B-1-1, pp. 9-209)

While there was considerable focus on the 2012 -2013 capital expenditures in both the filed evidence and in information requests and cross-examination, parties to the proceeding generally did not express concerns with respect to details of the capital plan outside of the 2012-2013 period. A general concern explored in this proceeding was that, having gone through a major period of infrastructure renewal, FortisBC should be in a sustainment mode where its focus should be on cost containment. (ICG Final Submission, p. 5; BCMEU Final Submission, p. 2; BCPSO Final Submission, p. 3)

Commission Panel Determination

While the focus in this proceeding was largely on cost containment in the short term, the Commission Panel believes that the economic pressures many of FortisBC's customers are now facing and are likely to face in the foreseeable future, make this a long-term issue as well. The Commission Panel encourages FortisBC to pursue vigorously means to minimize costs in the long run while maintaining safe, reliable service. **The Commission Panel accepts the Long-Term Capital Plan (2014-2031) as being in the public interest.** Given the lack of detail in the long-term part (2017-31) and the limited information in the medium term part (2014-16) of the capital plan, the Commission Panel wishes to make it clear that acceptance of the LTCP for 2014-2031 is on that basis. In other words, capital programs based on limited information that may appear acceptable at a high level a number of years out, may be found not to be acceptable following a detailed review at a future time, when there is more detailed information and costs are carefully scrutinized or the context has changed significantly.

7.2 Long-Term Resource Plan

The Commission's mandate in assessing the resource plans of energy utilities is intended to assure the cost-effective delivery of secure and reliable energy services in a manner congruent with British Columbia's energy objectives. The Commission's Resource Planning Guidelines set out a comprehensive process to assist utilities in the development of their resource plans and provide a basis upon which to assess the LTRP. The Commission requires that any plan submitted under subsection 44.1(2) of the *Act* be prepared in accordance with these guidelines.

Under the guidelines, the utility is to prepare a range of gross (pre-DSM) demand forecasts structured in such a way that savings, load shifting or load building due to each DSM resource can be allocated to specific end-uses in the demand forecast. The plans should identify feasible supply and demand resources and measure each supply and demand resource against the objectives set out for the plan. The objectives include:

- provision of adequate and reliable service,

- economic efficiency,
- preservation of the financial integrity of the utility,
- equal consideration of DSM and supply resources,
- minimization of risks,
- compliance with government regulations and stated policies, and
- consideration of social and environmental impacts.

For each of the gross demand forecasts the utility should develop several plausible resource portfolios, each consisting of a combination of supply and demand resources needed to meet the gross demand forecasts. The process should lead to the selection of a set of preferred resource portfolios, each portfolio matching one of the gross demand forecasts. Out of this process should come an action plan setting out the detailed acquisition steps which would need to be initiated over the next four years in order to meet the most likely gross demand forecast.

On June 30, 2011 FortisBC filed its 2012 Long Term Resource Plan (2012 LTRP) as Volume 2 of its 2012 ISP. FortisBC states that its plan is consistent with the requirements under section 44.1 of the *Act* and with the Commission's Resource Planning Guidelines. (Exhibit B-1-2, p. 1) The Company states that it has also prepared its 2012 LTRP to be consistent with the objectives set out in the *CEA* which are believed to be relevant to the FortisBC resource planning process. (Exhibit B-1-2, p. 2)

7.2.1 <u>2012 Long-Term Resource Plan Summary</u>

The FortisBC LTRP sets out FortisBC's demand forecasts and supply requirements for the period 2012 to 2040. It summarizes FortisBC's objectives as: (1) providing cost-effective reliable power over the forecast term; (2) assessing the uncertainty and risks in its market purchase strategy and, over time, achieving 100 percent self sufficiency; and (3) balancing the provision of cost effective power against the applicable of British Columbia's energy objectives. (Exhibit B-1-2, p. 1) There are 16 energy objectives set out in Part 1, section 2, of the *CEA.* The objectives which FortisBC argues are applicable to it and which are addressed in the LTRP are:

- To achieve electricity self sufficiency;
- To generate at least 93 percent of the electricity in British Columbia from clean or renewable resources and to build infrastructure necessary to transmit that electricity;
- To ensure that BC Hydro's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the *BC Hydro Public Power Legacy and Heritage Contract* continue to accrue to the authority's ratepayers;
- To reduce BC greenhouse gas emissions;
- To reduce waste by encouraging the use of waste heat, biogas and biomass;
- To maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia; and
- To take demand-side measures and to conserve energy.

(*Clean Energy Act,* Section 2; Exhibit B-1-2, p. 2)

The Company has prepared high, low and expected forecasts of demand before DSM through to the year 2040. The Company is targeting to meet 50 percent of its load growth through DSM and sets out an expected forecast on this basis. Due to the uncertainties inherent in DSM resources, FortisBC treats DSM as contributing to a range of outcomes, rather than as a single pre-determined percentage component meeting the gross demand needs. (Exhibit B-1-2, p. 3)

As discussed earlier, FortisBC owns four hydroelectric generating plants providing about 30 percent of its current capacity needs and 45 percent of its current energy requirements. It also has long-term power purchase agreements with BC Hydro and with the Brilliant Power Corporation, and a five year capacity agreement with Powerex. These resources provide a total winter peak capacity of about 710 MW and a summer peak capacity of 524 MW. (Exhibit B-1-2, pp. 2-3)

Subsequent to this Hearing, FortisBC received approval to purchase capacity from the Waneta Expansion Project. This capacity purchase agreement (WAX CAPA) is expected to come into effect in early 2015 and will both replace the Powerex capacity agreement and meet FortisBC's forecast capacity needs through the period of the 2012 LTRP. FortisBC is currently negotiating to extend its

RS 3808 PPA with BC Hydro. In the LTRP, it is assumed the RS 3808 PPA will be renewed in 2013 with the same right to the capacity and all associated energy that FortisBC currently has under the existing agreement. Although existing resource arrangements are expected to meet most of FortisBC's energy requirements, the Company expects that, in the near term, there will be some energy gaps during the winter period due to the shape of the load. (Exhibit B-1-2, p. 7)

To address capacity and energy requirements in the near and longer term FortisBC looked at resource options characterized as "New Resources" (Build strategy), "Wholesale Market" (Buy Strategy) and a "Combined Strategy" incorporating elements of build and buy. These potential resource solutions were looked at from a short term (2011-2015), medium term (2016-2020) and long term (2021-2040) perspective. Potential resources in the build category were evaluated based on their ability to meet capacity gaps, their environmental impact and their relative economics. Detailed evaluation of a number of resource options was provided by Midgard Consulting Inc. in its "FortisBC – 2010 Resource Options Report." (Exhibit B-1-2, Appendix C) For the buy strategy, FortisBC assessed future market risk (price and availability) based on a further study (2011 FortisBC Electricity Market Assessment) provided by Midgard Consulting Inc. (Exhibit B-1-2, Appendix B)

With respect to capacity requirements, FortisBC's proposed solution is to rely on wholesale market purchases in the short and medium term (2012 to 2020) with the possibility of accelerating construction of new resources in the medium term (2016-2020), if necessary. For the longer term (2021-2040), new capacity resources are anticipated to be built by the mid-to-late 2020s, with additional resources in the 2030s. To meet energy needs FortisBC intends to rely on wholesale market purchases in the short and medium term (2012-2020) while continuing to assess new clean energy resources. No energy gap is anticipated until 2018. By 2020, an energy gap of 13 GWh is predicted. In the long-term (2021-2040), this gap is expected to increase by about 14 GWh/year, reaching 287 GWh by 2040. (Exhibit B-1-2, pp. 64, 86)

No planned capital expenditures for capacity resources are included in the LTRP. To meet energy needs, new clean energy resources and the Similkameen Hydroelectric Project are expected in the 2021 – 2040 period, but further evaluation will be required before any specific projects are selected.

FortisBC states that it cannot prioritize the preferred resource options that have been identified at this time. (Exhibit B-5, BCSEA 1.15.1)

ICG takes the position that the Commission should reject the Integrated System Plan (containing FortisBC's LTRP) on the basis that the ISP does not meet the requirements of the Commission's Resource Planning Guidelines. Specifically, ICG is concerned that FortisBC failed to include a portfolio analysis of resource options as set out in Guidelines 5 and 6. ICG quoted from the Commission's Decision on the BC Hydro 2006 Integrated Electricity Plan (IEP): "[t]he Commission Panel also agrees with BC Hydro that a portfolio analysis is a best practice for IEP or IRP analysis" (2006 IEP and LTAP Decision dated May 11, 2007, pp. 89-90) FortisBC testified that because its forecast energy gaps are small and its capacity gaps are being met for some time into the future, it did not do a full portfolio analysis for its LTRP. The Company characterized its resource plan work as a supply/demand resource gap analysis. (T5: 789-791; ICG Final Submission, pp. 17-26)

Commission Panel Determination

The Commission Panel agrees that portfolio analysis is a "best practice" for resource plan analysis. However, the Resource Planning Guidelines do not state that portfolio analysis "must" be done, but that it "should" be done. **The Panel accepts FortisBC's argument that, given there is no capacity gap forecast until sometime in the 2021 – 2040 period, the resource supply/demand analysis provided by FortisBC, supplemented with the Midgard "FortisBC – 2010 Resource Options Report" is sufficient to allow the Panel to accept the 2012 LTRP included in the ISP, subject to the findings in Section 5.1.3 in this Decision with respect to the Planning Reserve Margin. The Commission Panel directs FortisBC to include a full portfolio analysis in its next LTRP.**

7.2.2 Requirements under the Utilities Commission Act

As noted earlier, under section 44.1 of the *Act*, in determining whether to accept or reject a long-term resource plan (or a part thereof), the Commission must consider:

- The applicable of British Columbia's energy objectives;
- The extent to which the plan is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*;
- Whether the plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures, and
- The interests of persons in British Columbia who receive or may receive service from the public utility.

Section 7.2.1 of this Decision outlines those British Columbia energy objectives which FortisBC argue apply to its Long Term Resource Plan. Within the 2012 LTRP the Company has addressed these objectives and assert that these objectives have played an important role in shaping its analysis and decision-making. Specifically, FortisBC has identified resource options and related strategies to handle forecast capacity and energy deficits over the short, medium and longer term. The Commission Panel finds that the LTRP is generally consistent with the applicable British Columbia energy objectives as they are a key input in the evaluation of capacity and energy alternatives.

As noted in Section 5.4.3 of this Decision, sections 6 and 19 of the *CEA* are primarily related to BC Hydro. However, section 6 does have application when a public utility is planning in accordance with section 44.1 of the *Act*. The Commission Panel is of the view that the steps taken by FortisBC to identify and evaluate resource options and related strategies to handle forecast capacity and energy deficits as described in the 2012 LTRP, address the British Columbia energy objective to achieve self-sufficiency.

In Sections 6.2.1.1 and 6.2.1.2 of this Decision, the Commission Panel has found that the FortisBC 2012 Long Term DSM Plan is adequate and cost effective and in the public interest under subsection 44.1(8) of the *Act*.

The Commission Panel considers acceptance of the 2012 LTRP to be in the interests of British Columbians who receive or may receive service from FortisBC. In our view the 2012 LTRP has adequately met the provisions for considerations laid out in subsection 44.1 (8) of the *Act.*

Therefore, based on the Commission's Panel's review of the 2012 LTRP as described in this Decision, the Commission Panel finds that the LTRP meets the requirements of the *Act* with the exception of the proposed section of the plan dealing with the Planning Reserve Margin, which is rejected.

In reaching this conclusion, the Commission Panel notes that acceptance of the 2012 LTRP does not constitute approval of any of the potential initiatives addressed within this plan. The resource planning process by its nature is a high level exercise. Because of this, the Commission Panel would like to point out that in "accepting" the LTRP, the programs and initiatives outlined in the plan are not sufficiently "fleshed out" to finally determine whether they will pass careful scrutiny when a more detailed application is put forward.

7.2.3 Filing of the Next LTRP

FortisBC stated that its intention is to file its next long-term resource plan five years from the date the last plan was filed (June 30, 2011). The Company also stated that a revision to the current plan would be filed in the event of a material change such as the final RS 3808 PPA contract with BC Hydro having significantly different terms than those FortisBC is currently anticipating, a significant change in the marketplace (such as a marked increase in natural gas prices) or an unforeseen addition of major new loads onto the system. (T5:821-822)

The Commission Panel directs FortisBC to file its next Long Term Resource Plan by no later than June 30, 2016. The plan is to include a fulsome portfolio analysis as described in the Resource Planning Guidelines.

8.0 SUMMARY OF DIRECTIVES

This Summary is provided for the convenience of readers. In the event of any difference between the Directions in this Summary and those in the body of the Decision, the wording in the Decision shall prevail.

	Directive	**Page**
1.	With respect to the use of the 1 in 20 forecast, the Commission Panel directs FortisBC in its next RRA to undertake both a 1 in 10 and a 1 in 20 peak forecast and provide evidence as to the relevant merits of each as a planning tool.	25
2.	The Commission Panel reaffirms its Decision of November 30, 2011, to maintain the current ROE and capital structure pending determinations made in the GCOC proceeding.	32
3.	The Commission Panel finds that a deferral account to capture variances between forecast and actual power purchase expense represents a reasonable attempt to manage uncertainty and approves establishing the Power Purchase Expense Variance Deferral Account as proposed by FortisBC.	34
4.	The Commission Panel directs FortisBC to reduce its Power Purchase Expense forecasts by $1.5 million in 2012 and 2013.	35
5.	FortisBC is directed to adjust its power purchase expense forecast to reflect this change.	35
6.	The Commission Panel agrees with BCMEU and because FortisBC has not sufficiently justified the need for an additional FTE, denies the additional FTE and related costs of $142,000 in each of 2012 and 2013	38
7.	The Commission Panel directs FortisBC to continue to maintain PPME as part of O&M expenses.	38
8.	The Commission Panel also agrees with this assessment and therefore denies the proposal to implement a PRM at this time and the proposed additional $310,000 in planned Power Purchase Expense for 2013	41
9.	The Panel directs FortisBC to include any variances related to water fees in that deferral account.	42
10.	FortisBC is directed to prepare a workforce action plan to address this issue covering, at a minimum, the next 5 year period and file it with the Commission no later than December 1, 2012.	44

11.	The Commission Panel is not prepared to be overly prescriptive at this time and will allow FortisBC to continue to proceed on the timeline it has proposed. However, we expect the issue to be fully explored and reflected in filings no later than 2014.	47
12.	The Commission Panel accepts FortisBC's proposal to continue to allocate costs for executive time based on the executives' estimates until such time as alternatives have been reviewed and a new proposal is put forward by the Applicant. The Commission Panel also approves the proposed handling of cross charges for executives based on a fully loaded wage only.	49
13.	The Commission Panel has determined that acceptance of the IBEW contract as it applies to rates is reasonable.	55
14.	The Commission Panel directs FortisBC to provide benchmarking information on all elements of its executive compensation in the next RRA.	58
15.	The Commission Panel directs FortisBC to include information as to current practice of their reference group of companies with regard to the inclusion of incentive payments in pensionable benefits for all groups of employees in its next RRA.	59
16.	The Commission Panel directs FortisBC to reduce O&M expenditures for labour for each of 2012 and 2013 by $250,000. The Panel believes this reduction should be applied to the specific areas where concerns have been raised but will leave the decision as to where these costs are applied to the discretion of FortisBC.	63
17.	The Panel denies the $0.8 million deferral account treatment sought by FortisBC in pursuit of the Asset Management Program.	66
18.	The Panel approves funds in the amount of $150,000 which may be required for external assistance over the test period. These funds may be included in the O&M budget.	66
19.	The Commission Panel finds that contributions to political parties should be solely for the account of the shareholder. Consistent with the 2012 FEU RRA Decision, the remaining budgeted amounts are to be shared equally between the shareholder and the ratepayer.	69
20.	The Commission Panel will only approve an increase equal to the forecast BC CPI of 2.2 percent in 2012 and another 1.9 percent in 2013. (Exhibit B-1, Tab 4, p. 43) FortisBC is directed to reduce its non-labour expense forecast for this department by $113,000 in 2012 and $100,000 in 2013.	70

21.	The Commission Panel approves the requested capitalized overhead rate of 20 percent for the test period. For the next revenue requirements application, FortisBC is directed to provide an external audit opinion on the appropriateness of its capitalized overhead methodology. Further, if International Financial Reporting Standards (IFRS) is pursued in the next application, the Company is directed to perform a new study based on the accounting policy adopted at that time.	72
22.	The Commission Panel directs FortisBC to meet with Commission staff following completion of the external audit opinion on its capitalized overhead methodology to review other options which may better reflect changes in the amount of capital being expended in a given year.	75
23.	FortisBC is directed to prepare and file a report with the Commission by September 30, 2012, explaining this apparent inconsistency. If an amount greater than the 20 percent approved for capitalized overhead has been used in the calculation of rates, FortisBC is directed to adjust the capitalized overhead rates downward to reflect the approved amount for capitalized overhead.	75
24.	Recognizing there is a need for more granular information and a closer examination of the current methodology, the Commission Panel approves the application of direct overhead as proposed by FortisBC for the current test period only. The Commission Panel directs FortisBC to ensure the direct overhead loading methodology is commented upon as part of the external audit opinion which is directed in Section 5.2.2.5 (i) Capitalized Overhead. In addition, the Commission Panel directs FortisBC in the next RRA to provide a more fulsome explanation as to the appropriateness of the direct overhead loading methodology and to include a full reconciliation and justification.	77
25.	The Commission Panel is reluctant to take issue with the forecasts that have been prepared by FortisBC and approves the forecast expenditures, as requested.	78
26.	The Panel directs FortisBC to use the most recent interest rate forecasts available at the time of the oral phase of the proceeding of 2.85 percent for short-term and 3.45 percent for long-term debt.	82
27.	The Commission Panel approves FortisBC's continued use of recognizing actual asset removal costs as incurred, as requested.	86

28.	While the Commission Panel endorses the relocation of a spare transformer to the Grand Forks Terminal to reduce the downtime associated with a failure of the current transformer, we reject the proposed expenditure of $7.205 million for the Grand Forks Transformer Addition Project because the need for increased reliability is not apparent. In addition, the Panel notes that FortisBC was previously directed to apply for a CPCN for certain elements of the proposed project and failed to do so. If FortisBC intends to proceed with advancing either the fibre optic communications portion of the proposed project or the installation of the spare transformer at Grand Forks Terminal, it is directed to apply for a separate CPCN. In pursuing a CPCN for fibre optic communications, FortisBC is expected to diligently pursue the extension of the fibre leasing agreement to preserve the potential benefit to ratepayers.	95
29.	The Commission Panel is concerned about the estimate quality and control of actual costs associated with the PCB Mitigation project, and directs FortisBC to file a comprehensive scope and schedule for this project by October 1, 2012 and semi-annual progress reports thereafter.	99
30.	The Commission Panel rejects the expenditures for the Kelowna 138 kV Loop Fibre Installation project. FortisBC may provide Class 3 estimates for both Option E and Option F and additional justification for its recommendation in a future filing.	101
31.	Based on our review of the 2012-13 CEP the Commission Panel is of the view that an overall reduction to the CEP of $17.6 million over the test period is possible. However, the Panel believes imposing all of the reductions related to the $17.6 million may not provide FortisBC with sufficient flexibility to prioritize expenditures in a cost-effective fashion. By reducing the amount of $17.6 million to $10.5 million (which is approximately 60 percent), the Panel can be reasonably assured that FortisBC can achieve the level of service it requires and will still have sufficient flexibility to manage its projects and workforce. Accordingly, the Commission Panel directs FortisBC to reduce its capital expenditure budget by $10.5 million in addition to the two projects which have been specifically rejected above.	103
32.	The Commission Panel therefore directs that such deferral accounts, with costs accruing beyond a three year period and where no CPCN has been applied-for or expenditure schedule filed, be amortized into rates.	106
33.	FortisBC is directed to commence the amortization of this deferral account into rates in the next test period if the associated project has not commenced by that time.	107

34.	The Commission Panel approves the amortization in 2012, as requested, of the following regulatory expense deferral accounts into rates: • Implementation of new rate structures • Residential Inclining Block Rate and Industrial Stepped Rate Applications • 2011 Revenue Requirements Application	108
35.	The Commission Panel rejects FortisBC's proposal to amortize this deferral account into rates.	109
36.	The Commission Panel approves the full amortization of the research costs relating to Irrigation rate payers in 2013, as requested.	108
37.	The Commission Panel approves amortization of these amounts over a shorter, two year period to reduce carrying costs.	110
38.	The Commission Panel approves the amortization of 2011 Revenue Protection expenses into rates in 2012.	110
39.	The Commission Panel approves the continuation of the Right–of-Way litigation deferral account, with the inclusion of any recovered costs following resolution of the dispute, as a non-rate base deferral account, attracting an interest financing charge at FortisBC's WACD.	111
40.	The Commission Panel approves the amortization of costs relating to conversion to US GAAP over the test period.	111
41.	The Commission Panel approves deferral of the set up costs relating to Mandatory Reliability Standards in a Non-Rate Base Deferral Account attracting interest at FortisBC's WACD. However, in the Panel's view, the amortization period requested is too long. Therefore, the Commission Panel directs that these costs be amortized into rates over a three year period, as opposed to the five year period sought, to reduce the associated carrying costs.	112
42.	The Commission Panel directs that any approved deferral accounts for these costs attract a financing charge at FortisBC's WACD until such time as they become part of a specific capital project.	113
43.	The Commission Panel considers this item to be a regulatory expense not a capital expense related to any specific project and therefore, directs that this account attract an interest financing charge at FortisBC's WACD and be amortized into rates over a five year period.	113

44.	The Commission Panel therefore directs that these costs be expensed during the test period.	114
45.	Because they relate directly to the preparation of a required regulatory plan, the Commission Panel views these expenditures as regulatory expenses. The Commission Panel directs that this deferral account attract an interest financing charge at FortisBC's WACD.	115

46.	The Commission Panel therefore approves the following variance deferral accounts as non rate base deferral accounts attracting a short term interest financing charge.
	• Power Purchase Expense Variance Deferral Account
	    ○ any variance in this account is to be amortized in 2014
	• Revenue Variance Deferral Account
	    ○ any variance in this account is to be amortized in 2014
	• HST Removal or Reform Variance Deferral Account
	• Property Tax Asset Variance Deferral Account
	• Pension and Other Post-Employment Expense Variance
		115

47.	The Commission Panel rejects FortisBC's proposed M&E Plan in its current form as it fails to ensure that all programs are evaluated.	134
48.	The Commission Panel finds FortisBC's 2012-2013 DSM Expenditure Schedule to be cost effective in accordance with the Demand-Side Measures Regulation (Ministerial Order No. 271) and the Amendments to the Demand-Side Measures Regulation (Ministerial Order No. 335).	136
49.	The Commission Panel approves FortisBC's section 44.2 expenditure request for DSM in the amounts of $7.73 million in 2012 and $7.88 million in 2013.	137
50.	The Commission Panel therefore approves FortisBC's transfer of a maximum of 25 percent of the budget amount from one existing program area or sector to another existing program area or sector without prior approval of the Commission.	140
51.	The Commission Panel directs FortisBC to include in its semi-annual DSM reports and in future DSM filings with the Commission, a short summary of progress on integration among utilities.	141

52.	The Panel accepts FortisBC's argument that, given there is no capacity gap forecast until sometime in the 2021 – 2040 period, the resource supply/demand analysis provided by FortisBC, supplemented with the Midgard "FortisBC – 2010 Resource Options Report" is sufficient to allow the Panel to accept the 2012 LTRP included in the ISP, subject to the findings in Section 5.1.3 in this Decision with respect to the Planning Reserve Margin. The Commission Panel directs FortisBC to include a full portfolio analysis in its next LTRP.	147
53.	Based on the Commission's Panel's review of the 2012 LTRP as described in this Decision, the Commission Panel finds that the LTRP meets the requirements of the Act with the exception of the proposed section of the plan dealing with the Planning Reserve Margin, which is rejected.	149
54.	The Commission Panel directs FortisBC to file its next Long Term Resource Plan by no later than June 30, 2016. The plan is to include a fulsome portfolio analysis as described in the Resource Planning Guidelines.	149

Dated at the City of Vancouver, in the Province of British Columbia, this 15th day of August 2012.

D.A. Cote
Commissioner

A.A. Rhodes
Commissioner

N.E. MacMurchy
Commissioner

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-110-12

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Inc.
for Approval of 2012-2013 Revenue Requirements and
Review of 2012 Integrated System Plan

BEFORE: D.A. Cote, Commissioner
A.A. Rhodes, Commissioner
N.E. MacMurchy, Commissioner

August 15, 2012

O R D E R

WHEREAS:

A. On June 30, 2011, FortisBC Inc. (FortisBC or the Company) filed an application pursuant to sections 44.1, 44.2, 56 and 59 to 61 of the *Utilities Commission Act* (the Act) for approval of its 2012-2013 Revenue Requirements and the review of its 2012 Integrated System Plan (collectively referred to as the Application);

B. The Application contains two parts:

   1) FortisBC's 2012-2013 Revenue Requirements (including the Company's 2012-2013 Capital Expenditure Plan filed pursuant to section 44.2(1) of the Act),

   2) FortisBC's 2012 Integrated System Plan filed pursuant to section 44.1 of the Act, comprising its 2012 Long Term Capital Expenditure Plan, its 2012 Resource Plan, and its 2012 Long Term Demand-Side Management Plan;

C. FortisBC sought, among other things, approval of interim and permanent rate increases of 4.0 percent effective January 1, 2012, with any difference between interim and permanent rates to be refunded to or collected from customers by way of a general rate adjustment between the effective date of the permanent rates and December 31, 2012. FortisBC also sought a permanent rate increase of 6.9 percent effective January 1, 2013;

D. The Company requests a determination from the British Columbia Utilities Commission (the Commission) on whether the 2012-2013 Capital Expenditure Plan is in the public interest pursuant to section 44.2 (3)(a) and satisfies the requirements of section 45(6) of the Act;

E. The Company also requested a Commission determination on whether the 2012 Integrated System Plan, which is comprised of three components (the 2012-2013 Resource Plan, 2012 Long Term Capital Plan, and the 2012 Long Term Demand-Side Management Plan), is in the public interest pursuant to section 44.1 (6);

F. A Workshop to review the Application was held in Kelowna on July 22, 2011;

…/2

G. The Company filed an Evidentiary Update to the Application on November 4, 2011, which reduced the rate increase sought to 1.5 percent in 2012 and a 6.5 percent increase in 2013;

H. The 2011 Annual Review was held in Kelowna on November 22, 2011, to review the Company's performance for the 2011 year, followed by a Procedural Conference to hear submissions on procedural matters regarding the current Application;

I. By Order G-199-11, the Commission approved a 1.5 percent interim rate increase for FortisBC, effective January 1, 2012;

J. Pursuant to Order G-214-11, the Oral Public Hearing to review the Application took place between March 5 and March 9, 2012 in Kelowna;

K. Between April 5 and April 23, 2012, FortisBC and Interveners filed their Final Submissions. FortisBC filed its Reply Submission on May 3, 2012;

L. The Commission has considered the Application, the evidence and all the submissions as set forth in the Decision issued concurrently with this Order.

NOW THEREFORE the Commission, for the reasons stated in the Decision, orders as follows:

1. Pursuant to sections 59 to 61 of the *Act*:

   a. The requested permanent rate increase of 1.5 percent in 2012 and 6.5 percent in 2013 is not approved, as filed.

   b. Cross charges between FortisBC and its affiliates regulated by the Commission are approved to be based on fully loaded costs, not including overhead.

   c. The proposed Deferral Account for Power Purchase Expense variances from forecast is approved and is to be amortized into rates in 2014. The proposed Revenue Variance Deferral Account is also approved and is to be amortized into rates in 2014.

   d. Determinations for the new proposed Deferral Accounts and treatment for existing Deferral Accounts are set out in Section 5.4.4 of the Decision.

   e. Costs of Removal of $4.7 million for 2011, $5.4 million for 2012 and $4.0 million for 2013 are approved to be included in Rate Base as set out in Section 5.4.2 of the Decision.

2. Pursuant to section 44.2(3) of the *Act*, FortisBC's 2012-2013 Capital Expenditure Plan is approved subject to the determinations and reductions set out in Section 5.4.3 of the Decision.

3. The Commission Panel accepts FortisBC's Long Term Capital Plan is in the public interest and the Long Term Resource Plan meets the requirements of the Act except for the Planning Reserve Margin as set out in Section 7.0 of the Decision.

…/3

4. FortisBC is directed to resubmit its financial schedules incorporating all the adjustments as outlined in the Decision, within 30 days of this Order.

5. The Commission will accept, subject to timely filing, amended Tariff Rate Schedules which conform to the Decision. FortisBC is to provide all customers, by way of an information notice, of the change in rates.

6. If the 2012 permanent rates are less than the interim rates, FortisBC is to refund to customers the difference in revenue with interest at the average prime rate of the principal bank with which FortisBC conducts its business. If the 2012 permanent rates exceed the interim rates, FortisBC is to reflect this difference in customer rates over the balance of 2012.

7. FortisBC is directed to comply with all other directives in the Decision issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 15th day of August 2012.

BY ORDER

D.A.Cote
Commissioner

Sections 59 through 61 *Utilities Commission Act*

Discrimination in rates

59 (1) A public utility must not make, demand or receive

(a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia, or

(b) a rate that otherwise contravenes this Act, the regulations, orders of the commission or any other law.

(2) A public utility must not

(a) as to rate or service, subject any person or locality, or a particular description of traffic, to an undue prejudice or disadvantage, or

(b) extend to any person a form of agreement, a rule or a facility or privilege, unless the agreement, rule, facility or privilege is regularly and uniformly extended to all persons under substantially similar circumstances and conditions for service of the same description.

(3) The commission may, by regulation, declare the circumstances and conditions that are substantially similar for the purpose of subsection (2) (b).

(4) It is a question of fact, of which the commission is the sole judge,

(a) whether a rate is unjust or unreasonable,

(b) whether, in any case, there is undue discrimination, preference, prejudice or disadvantage in respect of a rate or service, or

(c) whether a service is offered or provided under substantially similar circumstances and conditions.

(5) In this section, a rate is "unjust" or "unreasonable" if the rate is

(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility,

(b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or

(c) unjust and unreasonable for any other reason.

Setting of rates

60 (1) In setting a rate under this Act

(a) the commission must consider all matters that it considers proper and relevant affecting the rate,

(b) the commission must have due regard to the setting of a rate that

(i) is not unjust or unreasonable within the meaning of section 59,

(ii) provides to the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demands, and

(iii) encourages public utilities to increase efficiency, reduce costs and enhance performance,

(b.1) the commission may use any mechanism, formula or other method of setting the rate that it considers advisable, and may order that the rate derived from such a mechanism, formula or other method is to remain in effect for a specified period, and

(c) if the public utility provides more than one class of service, the commission must

(i) segregate the various kinds of service into distinct classes of service,

(ii) in setting a rate to be charged for the particular service provided, consider each distinct class of service as a self contained unit, and

(iii) set a rate for each unit that it considers to be just and reasonable for that unit, without regard to the rates set for any other unit.

(2) In setting a rate under this Act, the commission may take into account a distinct or special area served by a public utility with a view to ensuring, so far as the commission considers it advisable, that the rate applicable in each area is adequate to yield a fair and reasonable return on the appraised value of the plant or system of the public utility used, or prudently and reasonably acquired, for the purpose of providing the service in that special area.

(3) If the commission takes a special area into account under subsection (2), it must have regard to the special considerations applicable to an area that is sparsely settled or has other distinctive characteristics.

(4) For this section, the commission must exclude from the appraised value of the property of the public utility any franchise, licence, permit or concession obtained or held by the utility from a municipal or other public authority beyond the money, if any, paid to the municipality or public authority as consideration for that franchise, licence, permit or concession, together with necessary and reasonable expenses in procuring the franchise, licence, permit or concession.

Rate schedules to be filed with commission

61 (1) A public utility must file with the commission, under rules the commission specifies and within the time and in the form required by the commission, schedules showing all rates established by it and collected, charged or enforced or to be collected or enforced.

(2) A schedule filed under subsection (1) must not be rescinded or amended without the commission's consent.

(3) The rates in schedules as filed and as amended in accordance with this Act and the regulations are the only lawful, enforceable and collectable rates of the public utility filing them, and no other rate may be collected, charged or enforced.

(4) A public utility may file with the commission a new schedule of rates that the utility considers to be made necessary by a rise in the price, over which the utility has no effective control, required to be paid by the public utility for its gas supplies, other energy supplied to it, or expenses and taxes, and the new schedule may be put into effect by the public utility on receiving the approval of the commission.

(5) Within 60 days after the date it approves a new schedule under subsection (4), the commission may,

(a) on complaint of a person whose interests are affected, or

(b) on its own motion,

direct an inquiry into the new schedule of rates having regard to the setting of a rate that is not unjust or unreasonable.

(6) After an inquiry under subsection (5), the commission may

(a) rescind or vary the increase and order a refund or customer credit by the utility of all or part of the money received by way of increase, or

(b) confirm the increase or part of it.

Section 44.2 *Utilities Commission Act*

Expenditure schedule

44.2 (1) A public utility may file with the commission an expenditure schedule containing one or more of the following:

(a) a statement of the expenditures on demand-side measures the public utility has made or anticipates making during the period addressed by the schedule;

(b) a statement of capital expenditures the public utility has made or anticipates making during the period addressed by the schedule;

(c) a statement of expenditures the public utility has made or anticipates making during the period addressed by the schedule to acquire energy from other persons.

(2) The commission may not consent under section 61 (2) to an amendment to or a rescission of a schedule filed under section 61 (1) to the extent that the amendment or the rescission is for the purpose of recovering expenditures referred to in subsection (1) (a) of this section, unless

(a) the expenditure is the subject of a schedule filed and accepted under this section, or

(b) the amendment or rescission is for the purpose of setting an interim rate.

(3) After reviewing an expenditure schedule submitted under subsection (1), the commission, subject to subsections (5), (5.1) and (6), must

(a) accept the schedule, if the commission considers that making the expenditures referred to in the schedule would be in the public interest, or

(b) reject the schedule.

(4) The commission may accept or reject, under subsection (3), a part of a schedule.

(5) In considering whether to accept an expenditure schedule filed by a public utility other than the authority, the commission must consider

(a) the applicable of British Columbia's energy objectives,

(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any,

(c) the extent to which the schedule is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*,

(d) if the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any, and

(e) the interests of persons in British Columbia who receive or may receive service from the public utility.

(5.1) In considering whether to accept an expenditure schedule filed by the authority, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider and be guided by

(a) British Columbia's energy objectives,

(b) an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*,

(c) the extent to which the schedule is consistent with the requirements under section 19 of the *Clean Energy Act*, and

(d) if the schedule includes expenditures on demand-side measures, the extent to which the demand-side measures are cost-effective within the meaning prescribed by regulation, if any.

(6) If the commission considers that an expenditure in an expenditure schedule was determined to be in the public interest in the course of determining that a long-term resource plan was in the public interest under section 44.1 (6),

(a) subsection (5) of this section does not apply with respect to that expenditure, and

(b) the commission must accept under subsection (3) the expenditure in the expenditure schedule.

Clean Energy Act – Section 2

British Columbia's energy objectives

2 The following comprise British Columbia's energy objectives:

(a) to achieve electricity self-sufficiency;

(b) to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%;

(c) to generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;

(d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;

(e) to ensure the authority's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the *BC Hydro Public Power Legacy and Heritage Contract Act* continue to accrue to the authority's ratepayers;

(f) to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America;

(g) to reduce BC greenhouse gas emissions

(i) by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007,

(ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,

(iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,

(iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and

(v) by such other amounts as determined under the *Greenhouse Gas Reduction Targets Act*;

(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;

(j) to reduce waste by encouraging the use of waste heat, biogas and biomass;

(k) to encourage economic development and the creation and retention of jobs;

(l) to foster the development of first nation and rural communities through the use and development of clean or renewable resources;

(m) to maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia;

(n) to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia;

(o) to achieve British Columbia's energy objectives without the use of nuclear power;

(p) to ensure the commission, under the *Utilities Commission Act*, continues to regulate the authority with respect to domestic rates but not with respect to expenditures for export, except as provided by this Act.

APPEARANCES

G.A. FULTON, Q.C.	Commission Counsel
G.A. MACINTOSH L. HERBST	FortisBC Inc.
C. WEAFER	British Columbia Municipal Electrical Utilities
R. HOBBS	Zellstoff Celgar Limited Partnership, Atco Wood Products Ltd., Kalisnikoff Lumber Company Ltd., Porcupine Wood Products, Springer Creek Forest Products, and International Forest Products Limited
S. KHAN	British Columbia Old Age Pensioners' Organization *et al.*
W. J. ANDREWS	B.C. Sustainable Energy Association, Sierra Club of Canada, British Columbia Chapter
A. WAIT	Self
N. GABANA	Self

LIST OF ACRONYMS

2012 LTRP	2012 Long Term Resource Plan
2012-13 CEP	2012-2013 Capital Expenditure Plan
AAM	automatic adjustment mechanism
AEUB	Alberta Energy and Utilities Board
AFUDC	Allowance for Funds Used During Construction
AMI	Advanced Metering Infrastructure
Atco Electric	ATCO Electric Ltd.
BC Hydro	British Columbia Hydro and Power Authority
BCMEU	The British Columbia Municipal Electrical Utilities
BCPSO	The British Columbia Pensioners' Organization *et al.*
BCSEA	The BC Sustainable Energy Association and the Sierra Club of British Columbia
BPPA	Brilliant Power Purchase Agreement
Commission	British Columbia Utilities Commission
COPE	Canadian Office and Professional Employees Union
CPA	Canal Plant Agreement
CPCN	Certificate of Public Convenience and Necessity
CPI	Consumer Price Index
DSM	Demand-Side Management
EEC	Energy Efficiency and Conservation
FEU	FortisBC Energy Utilities (FortisBC Energy Inc.; FortisBC Energy (Vancouver Island) Inc.; FortisBC Energy (Whistler) Inc.)
FortisBC or the Company	FortisBC Inc.
FTE	Full Time Equivalent

GCOC	Generic Cost of Capital
IBEW	International Brotherhood of Electrical Workers Union
IEP	Integrated Electricity Plan
IFRS	International Financial Reporting Standards
IR	Information Request
ISP	Integrated System Plan
LTCP	Long Term Capital Plan
LTRP	Long Term Resource Plan
M&E Plan	Monitoring and Evaluation Plan
MRS	Mandatory Reliability Standards
mTRC	Modified total resource cost
NSA	Negotiated Settlement Agreement
NSP	negotiated settlement process
O&M	operations and management
OTR	Okanagan Transmission Reinforcement Project
PBR	Performance Based Regulation
PLTs	Power Line Technicians
PPA	Power Purchase Agreement
PPA	Power Purchase Agreement
PPEVDA	Power Purchase Expense Variance Deferral Account
PPME	Power Purchase Management Expense
PRM	Planning Reserve Margin
ROE	return on equity
RS 3808 PPA	Rate Schedule 3808 Power Purchase Agreement

SAIDI	System Average Interruption Duration
SAIFI	System Average Interruption Frequency
SCADA	Supervisory Control and Data Acquisition
SERP	Supplemental Employee Retirement Program
T&D	Transmission and Distribution
the *Act*	*Utilities Commission Act*
the Committee	Load Forecast Technical Committee
TRC	total resource cost
ULE	Upgrade and Life Extension
WACC	Weighted Average Cost of Capital
WACD	Weighted Average Cost of Debt
WAX CAPA	Waneta Expansion Project capacity purchase agreement
WECC	Western Electricity Coordinating Council

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

FortisBC Inc.
2012 – 2013 Revenue Requirements and
Review of 2012 Integrated System Plan Application

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated June 30, 2011 and Order G-111-11 – Establishing an Initial Regulatory Timetable and Procedural Conference
A-2	Letter dated July 19, 2011 – Commission Appointment of Panel
A-3	Letter dated August 10, 2011 – Commission Information Request No. 1
A-4	Letter dated August 24, 2011 – Letter L-65-11 issuing Revised Initial Regulatory Timetable
A-5	Letter dated September 30, 2011 – Commission Information Request No. 2
A-6	**CONFIDENTIAL** Letter dated September 30, 2011 – CONFIDENTIAL Commission Information Request No. 2
A-7	Letter dated October 4, 2011 – Order G-167-11 and Revised Preliminary Regulatory Timetable
A-8	Letter dated October 7, 2010 – Commission Information Request No. 1 on Exhibit B-7
A-9	Letter dated November 2, 2011 – Notice of 2011 Annual Review and Procedural Conference
A-10	Letter dated November 10, 2011 – Commission Information Request No. 1 to BCSEA et al on Intervener Evidence
A-11	Letter dated November 10, 2011 – Procedural Conference Agenda
A-12	Letter dated November 18, 2011 – Letter to Participants Zellstoff/Celgar

Exhibit No.	Description
A-13	Letter dated November 30, 2011 – Order G-199-11 issuing Amended Regulatory Timetable with Reasons
A-14	Letter dated December 15, 2011 – Order G-214-11 issuing Amended Regulatory Timetable
A-15	Letter dated February 10, 2012 - Panel Letter to FBC
A-16	Letter dated February 10, 2012 – Oral Public Hearing Information
A-17	Letter dated March 23, 2012 – Request for Comments on FortisBC's Testimony Clarification
A-18	Letter dated April 19, 2012 – Response to FortisBC request for Filing Extension
A2-1	Submitted at Oral Hearing March 5, 2012 – Commission Staff Filing EXTRACT FROM "REPORT 8: OCTOBER 2011; BC HYDRO: THE EFFECTS OF RATE-REGULATED ACCOUNTING…OFFICE OF THE AUDITOR GENERAL OF BRITISH COLUMBIA"
A2-2	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing EXECUTIVE SUMMARY FROM 1994 BC GAS PHASE 1 REVENUE REQUIREMENT APPLICATION
A2-3	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing EXTRACT FROM BC GAS UTILITY LIMITED 2003 REVENUE REQUIREMENTS APPLICATION DECISION DATED FEBRUARY 4, 2003
A2-4	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing EXTRACT FROM THE BC GAS UTILITY LIMITED MULTI-YEAR PERFORMANCE-BASED RATE PLAN FOR 2004/2008 APPLICATION
A2-5	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing EXTRACT FROM THE FORTISBC ENERGY UTILITIES 2012-2013 REVENUE REQUIREMENTS AND NATURAL GAS RATES APPLICATION, EXHIBIT B-1
A2-6	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing DOCUMENT ENTITLED "BCUC STAFF WITNESS AID - SERP…"
A2-7	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing ORDER G-64-07 AND AN EXTRACT FROM THE ACCOMPANYING DECISION

Exhibit No.	Description
A2-8	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing COMMISSION DECISION DATED APRIL 3, 1992 ON A RATE APPLICATION OF PACIFIC NORTHERN GAS LIMITED
A2-9	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing EXTRACT FROM THE DECISION OF THE ALBERTA ENERGY UTILITY BOARD IN THE MATTER OF ATCO ELECTRIC LIMITED 2005/2006 GENERAL TARIFF APPLICATION DATED MARCH 17, 2006
A2-10	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing EXTRACT FROM ONTARIO ENERGY BOARD, CHAPTER 2 OF THE FILING REQUIREMENTS FOR TRANSMISSION AND DISTRIBUTION APPLICATIONS, JUNE 22, 2011
A2-11	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing EXTRACT FROM ONTARIO ENERGY BOARD, RP-2004-0188, 2006 ELECTRICITY DISTRIBUTION RATE HANDBOOK, REPORT OF THE BOARD, 2005 MAY 11
A2-12	Submitted at Oral Hearing March 7, 2012 – Commission Staff Filing "BCUC STAFF WITNESS AID: FINANCING COSTS, FORTISBC 2012-2013 RRA & ISP"
A2-13	Submitted at Oral Hearing March 7, 2012 – Commission Staff Filing "WITNESS AID - DEFERRAL ACCOUNTS"
A2-14	Submitted at Oral Hearing March 7, 2012 – Commission Staff Filing EXTRACT FROM BCUC DECISION "BRITISH COLUMBIA HYDRO AND POWER AUTHORITY AND F2009 AND F2010 REVENUE REQUIREMENTS DECISION, MARCH 13, 2009"
A2-15	Submitted at Oral Hearing March 8, 2012 – Commission Staff Filing STAFF "WITNESS AID, FORTISBC, DSM PANEL"
A2-16	Submitted at Oral Hearing March 8, 2012 – Commission Staff Filing LETTER FROM FORTISBC DATED SEPTEMBER 29, 2011, WITH ATTACHED EXCERPT OF "FORTISBC INC., SEMIANNUAL DSM REPORT, SIX MONTHS ENDED JUNE 30, 2011
A2-17	Submitted at Oral Hearing March 9, 2012 – Commission Staff Filing FORTISBC F2012-2013 RRA & ISP WITNESS AID - CAPITAL EXPENDITURES PLAN
A2-18	Submitted at Oral Hearing March 9, 2012 – Commission Staff Filing EXCERPT FROM BCUC "FORTISBC INC. 2011 CAPITAL EXPENDITURE PLAN DECISION", DATED DECEMBER 17, 2010

Exhibit No.	Description
APPLICANT DOCUMENTS FORTISBC INC	
B-1	**FORTISBC INC. (FBC)** Letter dated June 30, 2011 – 2012/13 Revenue Requirements and Review of 2012 Integrated System Plan Application
B-1-1	Letter dated June 30, 2011 – FBC Submitting 2012 Integrated System Plan Volume 1
B-1-2	Letter dated June 30, 2011 – FBC Submitting 2012 Integrated System Plan Volume 2
B-1-3	**CONFIDENTIAL** Letter dated June 30, 2011 – FBC Submitting Confidential Page 34 of Tab 4, Section 4.3.2.1 of the Application
B-1-4	Letter dated July 11, 2011 – FBC Submitting Addendum to Tab 7 (Financial Schedules) of the Application
B-1-5	Letter dated July 21, 2011 – FBC Submitting Errata 1 to the Application
B-1-6	Letter dated September 9, 2011 – FBC Errata 2 to Application
B-2	Letter dated July 22, 2011 – FBC Presentation submitted at July 22, 2011 Workshop
B-3	Letter dated July 25, 2011 – FBC Submitting Adoption of US Generally Accepted Accounting Principles and 2012/ 2012 Revenue Requirements Application Compliance Filing Order G-117-11
B-4	Letter dated September 9, 2011 - FBC Responses to IR No. 1 from BCUC
B-5	Letter dated September 9, 2011 - FBC Responses to IR No. 1 from Interveners BCOAPO, BCSE, Celgar, and Alan Wait
B-6	Letter dated September 16, 2011 – FBC Submitting comments regarding Material Updates to the Application
B-7	Letter dated September 16, 2011 – FBC Submitting responses to BCUC and BCOAPO System Losses Information Requests
B-8	Letter dated October 21, 2011 - FBC Submitting Responses to BCUC IR2
B-8-1	**CONFIDENTIAL** Letter dated October 21, 2011 - FBC Submitting Responses to BCUC CONFIDENTIAL IR2
B-8-2	Letter dated March 2, 2012 - FBC Submitting Errata to its Responses to Information Request No. 2 - Replacement pages

Exhibit No.	Description
B-9	Letter dated October 21, 2011 - FBC Submitting Responses to Intervener IR2
B-10	Letter dated October 21, 2011 - FBC Submitting Responses to FortisBC Responses to BCUC IR2 (Losses)
B-11	Letter dated October 21, 2011 - FBC Submitting Errata 3 to Application and IR1 Responses
B-12	Letter dated November 4, 2011 - FBC Submitting Evidentiary Update
B-13	Letter dated November 10, 2011 - FBC Submitting IR No. 1 to BCSEA
B-14	Letter dated November 17, 2011 - FBC Submitting comments on Reconsider Application of Order E-29-10 Exhibit C9-4
B-15	Letter dated November 22, 2011 - FBC Submitting Presentations from 2011 Annual Review
B-16	Letter dated November 25, 2011 - FBC Submitting Load Forecast Technical Committee Report
B-17	Letter dated December 7, 2011 – FBC Submitting Request for Amendment to Timetable
B-18	Letter dated February 1, 2012 – FBC Submitting Witnesses Anticipated Testimony
B-19	Letter dated March 1, 2012 - FBC Submitting Opening Statement
B-20	Letter dated March 2, 2012 - FBC Submitting Witness Panel
B-21	Letter dated March 2, 2012 - FBC Submitting Opening Statement of John Walker
B-22	Submitted at Oral Hearing March 7, 2012 – FBC Submitting DOCUMENT HEADED "2005 REVENUE REQUIREMENTS - REGULATORY POLICY/PERFORMANCE STANDARDS - TAB 10"
B-23	Submitted at Oral Hearing March 7, 2012 – FBC Submitting "FORTISBC 2012-2013 REVENUE REQUIREMENTS APPLICATION, ORAL HEARING UNDERTAKINGS FROM MARCH 6, 2012"
B-24	Submitted at Oral Hearing March 8, 2012 – EXTRACT FROM "IMPLEMENTING ENERGY EFFICIENCY: PROGRAM DELIVERY COMPARISON STUDY", IEE WHITEPAPER, MARCH 2010

Exhibit No.	Description
B-25	Submitted at Oral Hearing March 8, 2012 – FORTISBC 2012-13 REVENUE REQUIREMENTS APPLICATION, ORAL HEARING UNDERTAKINGS FROM MARCH 6, 2012"
B-26	Letter dated March 16, 2012 - FBC Submitting Clarifications to testimony at the 2012-13 RRA and ISP Oral Hearing
B-27	Letter dated March 16, 2012 - FBC Submitting Oral Hearing Undertakings
B-28	Letter dated March 23, 2012 - FBC Submitting Oral Hearing Undertaking 51
B-29	Letter dated March 30, 2012 - FBC Submitting Oral Hearing Undertaking 32
B-30	Letter dated April 3, 2012 – FBC Submitting Undertaking 50
B-31	Letter dated April 19, 2012 – FBC Request for Filing Extension

INTERVENER DOCUMENTS

C1-1	**BRITISH COLUMBIA MUNICIPAL ELECTRICAL UTILITIES (BCMEU)** Online Registration dated July 5, 2011 – Request for Intervener Status by Heather Grant
C1-2	Letter dated July 11, 2011 – Notice of Mr. C. Weafer, Owen Bird as counsel for BCMEU
C1-3	Letter dated August 10, 2011 – BCMEU Information Request No. 1
C1-4	Letter dated September 30, 2011 – BCMEU Information Request No. 2
C1-5	Submitted at Oral Hearing March 5, 2012 – BCMEU Filing REVIEW OF BC HYDRO, JUNE 2011
C1-6	Submitted at Oral Hearing March 5, 2012 – BCMEU Filing NEWS RELEASE FROM OFFICE OF THE PREMIER, MINISTRY OF ENERGY AND MINES, "CANADA STARTS HERE - THE BC JOBS PLAN", DATED FEBRUARY 3, 2012"
C1-7	Submitted at Oral Hearing March 5, 2012 – BCMEU Filing "FORTIS GROUP OF COMPANIES OF BC COMMUNICATIONS & PUBLIC AFFAIRS PLAN 2010/2011, 25 AUGUST 2010"
C1-8	Letter dated April 19, 2012 – BCMEU Submitting comments regarding Exhibit B-31 FBC Request for Filing Extension

Exhibit No.	Description
C2-1	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BCHYDRO)** Online Registration dated July 5, 2011 – Request for Intervener Status by Janet Fraser
C3-1	**WAIT, ALAN (WA)** – Online Registration dated July 6, 2011 – Request for Intervener Status
C3-2	Letter dated August 10, 2011 – WA Information Request No. 1
C4-1	**GABANA, NORMAN (GN)** – Email dated July 7, 2011 Request for Intervener Status
C4-2	Letter dated September 23, 2011 Via Email – GN Information Request No. 2
C4-3	Letter dated November 22, 2011 – GN comments regarding Order E-29-10 review
C5-1	**BRITISH COLUMBIA OLD AGE PENSIONERS' ORGANIZATION *ET AL.* (BCOAPO)** – Letter dated July 8, 2011 requesting Intervener Status by Ros Salvador
C5-2	Letter dated August 10, 2011 – BCOAPO Information Request No. 1
C5-3	Letter dated September 30, 2011 – BCOAPO Information Request No. 2
C5-4	Letter dated November 10, 2011 – BCOAPO Information Request No. 1 to BCSEA et al on Intervener Evidence
C5-5	Letter dated November 18, 2011 – BCOAPO Submitting change of counsel request
C5-6	Letter dated November 21, 2011 – BCOAPO Submitting clarification on counsel details
C5-7	Letter dated April 19, 2012 – BCOAPO Submitting comments regarding Exhibit B-31 FBC Request for Filing Extension
C6-1	**BC SUSTAINABLE ENERGY ASSOCIATION AND THE SIERRA CLUB OF BRITISH COLUMBIA (BCSEA ET AL.)** – Letter dated July 14, 2011 - Requesting Intervener Status by William J. Andrews
C6-2	Letter dated August 10, 2011 – BCSEA Information Request No. 1
C6-3	Letter dated September 30, 2011 – BCSEA Information Request No. 2
C6-4	Letter dated October 31, 2011 - BCSEA Submitting Evidence
C6-5	Letter dated November 24, 2011 - BCSEA Submitting Response to BCUC IR No. 1

Exhibit No.	Description
C6-5-1	Letter dated November 24, 2011 - BCSEA Submitting Errata
C6-6	Letter dated November 24, 2011 - BCSEA Submitting Response to FBC IR No. 1
C6-7	Letter dated November 24, 2011 - BCSEA Submitting Response to BCOAPO IR No. 1
C6-8	Letter dated February 20, 2012 – BCSEA Submitting Witness Panel Notification
C6-9	Submitted at Oral Hearing March 7, 2012 – BCSEA Submitting COPY OF UTILITIES COMMISSION ACT, DEMAND-SIDE MEASURES REGULATION
C6-10	Submitted at Oral Hearing March 8, 2012 – BCSEA Submitting "A STATISTICAL MODEL FOR PREDICTING FUTURE ELECTRIC ENERGY EFFICIENCY RESOURCES CLASSES (DRAFT)", MARCH 6, 2012
C6-11	Letter dated April 19, 2012 – BCSEA Submitting comments regarding Exhibit B-31 FBC Request for Filing Extension
C7-1	**REGIONAL DISTRICT OF OKANAGAN SIMILKAMEEN (RDOS) –** Online Registration dated July 15, 2011 – Requesting Intervener Status by Doug French
C8-1	**SLACK, BURYL –** Facsimile Registration dated July 15, 2011 – Requesting Intervener Status
C8-2	Letter dated November 10, 2011 by Fax – SB submitting comments
C9-1	**ZELLSTOFF CELGAR, ATCO WOOD PRODUCTS LTD., INTERNATIONAL FOREST PRODUCTS LIMITED (INTERFOR), KALESNIKOFF LUMBER CO. LTD., PORCUPINE WOOD PRODUCTS, AND SPRINGER CREEK FOREST PRODUCTS COLLECTIVELY, THE INDUSTRIAL CUSTOMERS GROUP (ICG)** – Letter dated July 20, 2011 requesting Intervener Status by Adrian Hay, Brian Merwin and Robert Hobbs
C9-2	Letter dated August 10, 2011 – Celgar Information Request No. 1
C9-3	Letter dated September 30, 2011 – Celgar Information Request No. 2
C9-4	Letter dated November 10, 2011 – Celgar Submitting comments regarding WAX CAPA
C9-5	Letter dated November 28, 2011 – Celgar Submitting additional Interveners Atco Wood Products Ltd., International Forest Products Limited (Interfor), Kalesnikoff Lumber Co. Ltd., Porcupine Wood Products, and Springer Creek Forest Products collectively, the **Industrial Customers Group (ICG)**

Exhibit No.	**Description**
C9-6	Letter dated November 25, 2011 – Celgar / ICG Submitting reply and comments
C9-7	Submitted at Oral Hearing March 5, 2012 – Celgar / ICG Filing EXCERPT "APPENDIX 1 TO ORDER NO. G-10-03, PAGE 7 OF 25"
C9-8	Submitted at Oral Hearing March 5, 2012 – Celgar / ICG Filing EXCERPT FROM "FORTISALBERTA IN 2010/2011 TARIFF APPLICATION", PAGES 2-27 AND 2-28
C9-9	Submitted at Oral Hearing March 5, 2012 – Celgar / ICG Filing DOCUMENT HEADED "BC BARGAINING DATABASE, VOL. 03, NO. 02-APRIL 2010, SETTLEMENT SUMMARIES (FEBRUARY 2010 TO APRIL 2010)"
C9-10	Submitted at Oral Hearing March 5, 2012 – Celgar / ICG Filing EXCERPT FROM DOCUMENT "BUDGET AND FISCAL PLAN, 2012/13 - 2014/15"
C9-11	Submitted at Oral Hearing March 5, 2012 – Celgar / ICG Filing DOCUMENT HEADED "BC BARGAINING DATABASE, VOL. 02, NO. 10 - OCTOBER 2009, SETTLEMENT SUMMARIES (AUGUST TO OCTOBER 2009)"
C9-12	Submitted at Oral Hearing March 5, 2012 – Celgar / ICG Filing DOCUMENT HEADED "BC BARGAINING DATABASE, VOL. 01, NO. 3 - JULY 2008, SETTLEMENT SUMMARIES (APRIL 2008 TO JUNE 2008)"
C9-13	Submitted at Oral Hearing March 6, 2012 – Celgar / ICG Filing "BC BARGAINING DATABASE, VOL. 05 NO. 01 - JANUARY 2012" QUARTERLY WAGE SETTLEMENTS IN BC (2005-2011)
C9-14	Submitted at Oral Hearing March 6, 2012 – Celgar / ICG Filing "F2012 TO F2014 REVENUE REQUIREMENTS APPLICATION, BC HYDRO, APPENSIC C-2, ORDER IN COUNCIL NO. 021, HERITAGE SPECIAL DIRECTION NO. HC2"
C9-15	Submitted at Oral Hearing March 7, 2012 – Celgar / ICG Filing "INITIATIVES FOR INDUSTRIAL CUSTOMERS - PROJECT INCENTIVES TRANSMISSION"
C9-16	Submitted at Oral Hearing March 7, 2012 – Celgar / ICG Filing "INTEGRATED RESOURCE PLAN - MEETING #2, JANUARY 27 & 28, 2011"
C9-17	Submitted at Oral Hearing March 7, 2012 – Celgar / ICG Filing EXCERPT FROM "NERC…2010 LONG-TERM RELIABILITY ASSESSMENT, OCTOBER 2010"
C9-18	Submitted at Oral Hearing March 7, 2012 – Celgar / ICG Filing "NERC…2011 LONG-TERM RELIABILITY ASSESSMENT, NOVEMBER 2011"

Exhibit No.	Description
C9-19	Submitted at Oral Hearing March 8, 2012 – Celgar / ICG Filing FERC "WINTER 2011-12 ENERGY MARKET ASSESSMENT…OCTOBER 20, 2011"
C9-20	Submitted at Oral Hearing March 8, 2012 – Celgar / ICG Filing DOCUMENT HEADED "PLANNING RESERVE MARGIN, PAGE 1 OF 1"
C9-21	Submitted at Oral Hearing March 8, 2012 – Celgar / ICG Filing "2005 REVENUE REQUIREMENTS, FORECASTS - POWER PURCHASE & WHEELING - TAB 7…NOVEMBER 26, 2004", PAGES 19, 20 AND 21
C9-22	Submitted at Oral Hearing March 8, 2012 – Celgar / ICG Filing "INTEGRATED RESOURCE PLANT, MEETING #2, JANUARY 27 & 28, 2011, 2011 IRP TECHNICAL ADVISORY COMMITTEE SUMMARY BRIEF"
C9-23	Letter dated April 19, 2012 – Celgar / ICG Filing Submitting comments regarding Exhibit B-31 FBC Request for Filing Extension
C10-1	**IRRIGATION RATEPAYERS GROUP (IRG)** – Letter dated July 20, 2011 requesting Intervener Status by Fred Weisberg
C11-1	**CITY OF TRAIL (CT)** – Letter dated July 20, 2011 requesting Intervener Status by Carolyn MacEachern
C11-2	Letter dated November 4, 2011 withdrawing Intervention

INTERESTED PARTY DOCUMENTS

D-1	**ACTIVE RENEWABLE (BC)** – Online Registration dated July 17, 2011 – Request for Interested Party Status by Bill Daly
D-2	**POWELL, JOHN O.** – Email Registration dated July 14, 2011 – Request for Interested Party Status
D-3	**KAROW, HANS (CORE)** – Email Registration dated November 22, 2011 – Request for Interested Party Status
D-4	**CITY OF PENTICTON (CP)** Letter dated December 21, 2011 – Submitting Letter of Comment
D-5	**FLYNN, JERRY** Online Registration dated January 5, 2011 – Request for Interested Party Status by Jerry Flynn

Exhibit No.	**Description**
D-5-1	January 25, 2010 **-** Registration of Interested Party Status withdrawn

LETTERS OF COMMENT

E-1	**KRISTIAN, BEN** – Letter of Comment dated July 20, 2011

Attachment 82.1

Hay Group Limited
121 King Street West
Suite 700
Toronto, ON M5H 3X7
Canada

tel +1.416.868.1371
fax +1.416.868.6871

www.haygroup.com/ca

November 11, 2013

Ms. Jody Drope
Chief Human Resources Officer
FortisBC Inc.
Suite 100, 1975 Springfield Road
Kelowna, BC
V1Y 7V7

Dear Jody,

Re: Response to Select Questions from BCUC Information Request (DRAFT)

Hay Group Limited ("Hay Group") was initially retained by FortisBC Inc. ("FBC") to conduct a review of its executive compensation as part of the response to a British Columbia Utilities Commission ("BCUC") Directive. A number of follow-up questions have been received from the BCUC, and Hay Group has been asked to assist with providing commentary.

In September, 2013, Hay Group assisted with drafting responses to a selection of questions, as requested by FBC, including the following:

219.8 Please create a list of companies that are comparable to FBC (measured by annual revenue) using the Commercial Industrial Comparator Group. (May refer to either Hay Group, Towers Watson, or other database to perform this task).

In response, a subset of the 2012 Commercial Industrial Market (n=275, see Attachment A) was provided, representing organizations with revenues between ½ and 2x the gross revenue ($293 million) of FBC (n=68, "Select FBC Revenue Cut"). Please see Attachment B for a full list of these organizations.

The BCUC has now requested follow-up analysis to this question, specifically:

82.1 Please recreate the Summary of Observations included in the Hay Group Executive Compensation Benchmarking using only those companies included in Attachment 219.8 of Exhibit B-7.

The following table (Fig 1, "2012 Select FBC Revenue Cut Table") contains this information for the 9 FBC executives included in the aforementioned 2012 Hay Group Executive Compensation Review, using methodology consistent with the original mandate.

Ms. Jody Drope
FortisBC Inc.

Fig 1: 2012 Select FBC Revenue Cut Table:

2012 Market Positioning - FBC Executives (n=9); Select FBC Revenue Cut

		Target Compensation				Actual Compensation			
Role	Actual Base Salary	STI (as % Base)	Target Total Cash	LTI (as % Base)	Target Total Direct	STI (as % Base)	Actual Total Cash	LTI (as % Base)	Actual Total Direct
President & CEO[1]	>P50	<P50	<P50	*	<P50	>P50	>P50	*	>P50
EVP HR, Customer & Corporate Services	P57	P37	P51	< P25	P49	P81	P75	< P25	P64
VP Engineering & Generation	P49	P37	P36	< P25	P38	P79	P62	< P25	P56
VP Energy Solutions & External Relations	P56	P43	P53	P33	P51	P80	P75	P33	P63
VP Energy Supply & Resource Development	P54	P46	P52	P33	P51	P79	P70	P34	P60
VP Finance & CFO	P48	P46	P47	P33	P45	P81	P66	P34	P57
VP Strat Plan, Corp Dev & Reg Affairs	P48	P46	P47	P33	P45	P81	P66	P34	P57
VP Gen. Counsel & Corp. Sec.	P43	P34	P36	P33	P40	P77	P56	P34	P52
VP Customer Service	P51	P26	P51	P19	P48	> P90	P77	P10	P59

* Insufficient data to display
1. Due to limited roles in the Select FBC Revenue Cut, only 50th percentile data is available

Jody, I trust this suggested response is of assistance to you. I will be happy to answer any questions that may arise.

Sincerely,
Hay Group Limited

Christopher A. Chen, LLB
National Director
Executive Compensation

cc: Kennedy Lee, Hay Group Limited

Attachment A – 2012 Commercial Industrial Market (n=275)

3M Canada Company
A&W Food Services of Canada Inc.
ALS Canada Ltd.
AMEC Inc.
ATCO I-Tek
Abbott Laboratories, Limited
Acuity Brands
Agfa Healthcare Canada
Agfa Inc.
Ainsworth Engineered Canada L. P.
Air Products Canada Ltd.
Akzo Nobel Canada Inc.
Alamos Gold Inc.
Alberta-Pacific Forest Industries Inc.
Alcon Canada Inc.
Aluminerie Alouette Inc.
Amgen Canada Inc.
Amway Canada Corporation
ArcelorMittal Canada
ArcelorMittal Canada Contrecoeur-Ouest Inc.
ArcelorMittal Canada Hamilton
ArcelorMittal Canada Saint-Patrick
ArcelorMittal Dofasco Inc.
ArcelorMittal Mines Canada
ArcelorMittal Tubular Products - Automotive Division
Arrow Transportation Systems Inc.
Astellas Pharma Canada Inc.
AstraZeneca Canada Inc.
Atlantic Packaging Products Ltd.
Atlantic Poultry Incorporated
Atotech Canada Ltd.
BASF Canada Inc.
BHP Billiton - Ekati Diamond Mines
BHP Billiton Canada Inc.
BIC Graphic Canada
Babcock & Wilcox Canada Ltd.
BakeMark Ingredients Canada Ltd.
Barilla
Barrick Gold Corporation
Basell Canada Inc.
Baxter Corporation
The Bay
Bayer Inc.
Bekaert Canada
Belden CDT (Canada) Inc.
Bericap North America Inc.
Blue Mountain Resorts Limited
Boehringer Ingelheim (Canada) Ltd.
Bombardier Transportation Canada Inc.
Brink's Canada Limited
Bristol-Myers Squibb Canada Co.
Broan-NuTone Canada Inc.
Bruce Power L.P.
CAE Inc.
CGGVeritas
CHEP Canada Inc.
CKF Inc.
CNH America, LLC.
Cabot Canada Ltd.
Campbell Company of Canada
Canadelle Inc.
Canadian Forest Products Ltd.
Canadian National Railway Company
Canadian Pacific Railway
Canexus Limited
Canfor Pulp Limited Partnership
CannAmm Occupational Testing Services
Canon Canada Inc.
Canpotex Limited
Cargill Limited
Catalyst Paper Corporation
Caterpillar Logistics Services Canada Limited
Caterpillar of Canada Corporation
Caterpillar Tunneling Canada Corporation
Centerra Gold Inc.
Christie Digital Systems Inc.
Chubb Edwards
The Churchill Corporation
Compass Group Canada
Co-op Atlantic
Coty Canada
Country Ribbon Inc.
DP World Canada
DSM Nutritional Products Canada Inc.
Danfoss Inc.
De Beers Canada Inc., Corporate Division
De Beers Canada Inc., Exploration Division
De Beers Canada Inc., Mining Division
Deeley Harley-Davidson Canada
Detour Gold Corporation
Direct Energy Marketing Ltd.
Dow Chemical Canada Inc.
Dr. Oetker Ltd.
Dynaplast Extruco Inc.
EFW Radiology
E.I. du Pont Canada Company
EMD Serono Canada Inc.
ERCO Worldwide
EWOS Canada Ltd.
Eli Lilly Canada Inc.
Elkem Métal Canada Inc.
Essar Steel Algoma Inc.
Finning Canada
Finning International

Attachment A – 2012 Commercial Industrial Market (n=275) (cont'd)

Fisher & Paykel Healthcare Inc.
G4S Cash Services (Canada) Ltd.
Gates Canada Inc.
General Kinetics Engineering Corporation
Gerdau Ameristeel
GlaxoSmithKline Inc.
Goldcorp Inc.
Golf Town
Graham & Brown
Grand & Toy
Griffith Laboratories Limited
Henkel Canada Corporation
Henry Schein Canada
Hilti (Canada) Ltd.
Hobart Food Equipment Services Canada
Hoffmann-La Roche Ltd.
Home Outfitters
HudBay Minerals Inc.
Hudson's Bay Company
HumanWare
Hunter Dickinson Inc.
Huntsman Polyurethane
INEOS Canada Partnership
INVISTA (Canada) Company
Ingersoll-Rand Canada Inc.
Innophos Canada Inc.
Janssen Inc.
John Deere Limited Canada
Johnson Matthey Ltd.
K+S Potash Canada
KGHM International Ltd.
K.I. Pembroke
KPMG MSLP
Kellogg Canada Inc.
Kemira Chemicals Canada Inc.
Kennametal Ltd.
Kimberly-Clark Corporation
Kinross Gold Corporation
Kongsberg Automotive
Kruger Products
LANXESS Inc.
Labatt Breweries of Canada
Lake Shore Gold Corp.
Lantic Inc.
Lantic Inc. - Rogers Sugar Division
Lego Systems, Inc.
Lehigh Hanson
Leo Pharma
LifeLabs
Linamar
Loblaw Companies Limited
Lotus Bakeries
Lowe's Companies, Inc.
Lundin Mining Corporation
MDA
MERSEN Canada Dn Ltd.
MERSEN Canada Toronto Inc.
Maidstone Bakeries Co.
Mainstream Canada Ltd.
McCoy Corporation
McElhanney Consulting Services Ltd.
The McElhanney Group Ltd.
McElhanney Land Surveys Ltd.
Merz Pharma Canada
Methanex Corporation
Michelin North America (Canada) Inc.
Minas Basin Pulp & Power Co. Ltd.
The Minto Group
Mitsubishi Canada Limited
Montship Inc.
Morneau Shepell Inc.
The Mosaic Company
Navtech Systems Support Inc.
North American Palladium Ltd.
North Atlantic Refining
Northern Pulp Nova Scotia Corp.
Novartis Pharmaceuticals Canada Inc.
Novo Nordisk Canada
Omicron
L'Oréal Canada Inc.
Otis Spunkmeyer Canada Limited
Outotec (Canada) Ltd.
OxyVinyls Canada Inc.
PPG Canada Inc.
PPG Canada Inc. - Fine Chemicals Division
PPG Canada Inc. - Industrial Coatings Division
PPG Canada Inc. - Performance Glazing Division
Pan American Silver Corporation
Penske Truck Leasing
PepsiCo Canada
Phantom Mfg. (Int'l) Ltd.
Pharmascience Inc.
Philips Electronics Ltd.
Pioneer Hi-Bred Limited
Potash Corporation of Saskatchewan Inc.
Praxair Canada Inc.
Procter & Gamble Inc.
Purdue Pharma
Randstad Canada
Richemont Canada Inc.
Rio Tinto - Diavik Diamond Mines
Rio Tinto Iron Ore
Ritchie Bros. Auctioneers (Canada) Ltd.
Rolls-Royce Canada Ltd.

Attachment A – 2012 Commercial Industrial Market (n=275) (cont'd)

Rothmans, Benson & Hedges Inc.
Runge Limited
Russel Metals Inc.
SABIC Innovative Plastics Canada Incorporated
SEMAFO inc.
SNC-Lavalin Group Inc.
Saint-Gobain Abrasives Canada Inc.
Saint-Gobain Ceramic Materials Canada/Abrasive Materials
sanofi-aventis
Saskatchewan Roughrider Football Club
Schneider Electric
Sears Canada Inc.
The Shaw Group Limited
Sherritt Coal
Shiseido (Canada) Inc.
Shore Gold Inc.
Siegwerk Canada Inc.
Sika Canada Inc.
Silver Standard Resources Inc.
Sleeman Breweries Ltd.
Société en Commandite Tafisa Canada Inc.
Sofina Foods Inc.
Sonoco Canada Corporation
Sultran Ltd.
Suncor Energy Inc.
Syncrude Canada Ltd.
TELUS Communications Inc.
TVI Pacific, Inc.
Tait Electronics Ltd.
Takeda Canada Inc.
Taro Pharmaceuticals Inc.
Teck Resources Limited
Teck Resources Limited - Highland Valley Copper
Teck Resources Limited - Trail Operation
Teekay Corporation
Tembec Inc.
Teranet Inc.
Tetley Canada Inc.
Teva Canada Limited
Thompson Creek Metals Company
TimberWest Forest Corp.
Tolko Industries Ltd.
TomTom International
Toromont CAT, A Division of Toromont Industries Ltd.
Toys "R" Us (Canada) Ltd.
Ultramar Ltée
uniPHARM Wholesale Drugs Ltd.
Uranium One Inc.
Vale Inco Limited
Vallourec Tubes Canada Inc.
VAM Canada
Viterra Inc.
Votorantim Cement North America
VPL Enterprises Ltd.
VWR International
W.E.T. Automotive Systems Ltd.
Wal-Mart Canada Corp.
WD-40 Products Canada Ltd.
Wescast Industries Inc.
West Fraser Timber Co. Ltd.
Winners Merchants International L.P.
Xstrata Copper Canada
Xstrata Nickel Canada
Xstrata Zinc Canada
Yara Belle Plaine Inc.
Yukon Zinc Corporation
Zellstoff Celgar Partnership Limited

Attachment B – FBC Comparators by Revenue

2012 Commercial Industrial Market companies: Annual revenues ½ to 2x the 2012 gross revenue of FBC ($293 million) (n=68)	
ATCO I-Tek	Morneau Shepell Inc.
Ainsworth Engineered Canada L. P.	North American Palladium Ltd.
Air Products Canada Ltd.	Northern Pulp Nova Scotia Corp.
Akzo Nobel Canada Inc.	Novo Nordisk Canada
Alamos Gold Inc.	OxyVinyls Canada Inc.
Alberta-Pacific Forest Industries Inc.	PPG Canada Inc.
Amgen Canada Inc.	PPG Canada Inc. - Fine Chemicals Division
BHP Billiton - Ekati Diamond Mines	PPG Canada Inc. - Industrial Coatings Division
Babcock & Wilcox Canada Ltd.	PPG Canada Inc. - Performance Glazing Division
Baxter Corporation	Penske Truck Leasing
Bayer Inc.	Philips Electronics Ltd.
Boehringer Ingelheim (Canada) Ltd.	Pioneer Hi-Bred Limited
Brink's Canada Limited	Rio Tinto - Diavik Diamond Mines
CAE Inc.	Ritchie Bros. Auctioneers (Canada) Ltd.
CHEP Canada Inc.	Rolls-Royce Canada Ltd.
CKF Inc.	SABIC Innovative Plastics Canada Incorporated
Canexus Limited	SEMAFO inc.
Christie Digital Systems Inc.	Saint-Gobain Abrasives Canada Inc.
Co-op Atlantic	Saint-Gobain Ceramic Materials Canada/Abrasive Materials
Coty Canada	Sanofi-aventis
De Beers Canada Inc., Corporate Division	Schneider Electric
Deeley Harley-Davidson Canada	The Shaw Group Limited
ERCO Worldwide	Sleeman Breweries Ltd.
Eli Lilly Canada Inc.	Sonoco Canada Corporation
G4S Cash Services (Canada) Ltd.	Teranet Inc.
Henkel Canada Corporation	Teva Canada Limited
Henry Schein Canada	TimberWest Forest Corp.
Hilti (Canada) Ltd.	uniPHARM Wholesale Drugs Ltd.
INEOS Canada Partnership	Uranium One Inc.
KGHM International Ltd.	VWR International
Kimberly-Clark Corporation	Wescast Industries Inc.
LifeLabs	Yara Belle Plaine Inc.
Maidstone Bakeries Co.	Yukon Zinc Corporation
McCoy Corporation	Zellstoff Celgar Partnership Limited

Attachment 89.2

	FortisBC Retirement Income Plan ("FRIP")		FortisBC IBEW Pension Plan	Pension Plan for Employees of FortisBC Holdings Inc. ("Holdings Plan")	COPE Pension Plan	Executive RRSP	Supplemental Employee Retirement Plan of FortisBC January 1, 2012 (TI Exec. SERP + FortisBC Electric SERP Consolidated)
Status	Closed as at January 1, 2002	Active	Active	Active	Active	Active	Active
Plan Type	Defined Benefit	Defined Contribution	Defined Benefit	Defined Benefit	Defined Benefit	Group RRSP	Notional Account
Membership/Participants	Exempt employees hired prior to January 1, 2002 who elected to remain in the DB plan rather than convert their entitlement to the DC Plan and union employees who retired prior to February 1, 1992 (17 former COPE members and 88 former IBEW employees)	Management and exempt employees hired after January 1, 2002 or hired prior to January 1, 2002 and who elected to convert their DB entitlements and earn future benefits under the DC Plan	All regular full-time employees affiliated with the IBEW; part-time employees are covered after meeting certain minimum criteria.	Gas M&E Employees - Jan 1, 2007 Gas COPE Customer Service Employees - October 1, 2010 Electric COPE Customer Service Employees effec February 1, 2012	All regular full-time employees affiliated with the COPE; part-time employees are covered after meeting certain minimum criteria	Executives in FortisBC as well as designated full-time employees.	All executives in FortisBC as well as designated full-time employees. (A transferred executive, under terms of plan we calculate interest on the FBC notional portion.)
Member Contributions	3% of earnings up to the YMPE + 4% of earnings above the YMPE	No required member contributions; voluntary member contributions permitted through Group RRSP program.	14.40% of earnings up to the YMPE, plus 18.00% of earnings above the YMPE	9.8% of pensionable earnings	7.344% of earnings up to the YMPE, plus 9.18% of earnings above the YMPE	6.5% of members' earnings	None
Company Contributions	10.26% of earnings for Normal Cost plus annual amoritzation payments noted below	7% of earnings (base salary+bonus)	15.24% of earnings up to the YMPE, plus 19.05% of earnings above the YMPE	9.8% of pensionable earnings	13.744% of earnings up to the YMPE, plus 17.18% of earnings above the YMPE	6.5% of members' earnings	The company contributes 13% to a notional account on Dec 31 of each Plan Year for earnings in excess of CRA maximum. This includes interest according to the Plan.
Legal Obligation (Pension)	Plan Document: 1.8.9	Plan Document: 3.2.1	C.A. : Article # 34.01 & 34.02 Plan Document: Article 4	LOU#2 Amendment #8 Plan Document: Article 6	C.A. Article #4.02 Plan Document: Article 4	N/A	N/A

Plan Document: Article1.8.9	**Plan Document: Article3.2**	**Plan Document: Article 4**	**Plan Document: Article 6**	**Plan Document: Article 4**
(a) Each Participating Employer shall make contributions pursuant to the recommendation of the Actuary which will provide funding sufficient to meet the ongoing funding requirements and tests for solvency prescribed by Applicable Pension Laws but, provided that such recommendations and tests are satisfied, each Participating Employer shall not be required to make contributions to the Plan. In the event the Plan is terminated, each Participating Employer shall contribute all such amounts as required under Applicable Pension Laws.	A Participating Employer shall contribute on behalf of each DC Member an amount equal to 7% of Basic Salary during each Plan Year or portion thereof.	4.01 In respect of each pay period commencing on or after January 1, 1998, the EMPLOYER and each MEMBER shall contribute a percentage of each MEMBER's PLAN EARNINGS, such percentage to be equal to the sum of the percentage determined under paragraph 4.02 and the percentage determined under paragraph 4.03. 4.02 (a) The EMPLOYER and each MEMBER shall contribute a percentage of PLAN EARNINGS which provides for (i) the cost of benefits expected to be accrued by the MEMBERS in respect of CREDITED SERVICE in that pay period, plus, (ii) the average per pay period expenses expected to be charged to the TRUST FUND in respect of the period from the effective date of the most recent actuarial valuation to the effective date of the next actuarial valuation. (b) The amounts described in sub-paragraph 4.02(a) shall be determined by the ACTUARY, based on Start Date: 01.01.2001 Employer % of Total: 50.0% Member % of Total: 50.0%	6.04 c) Subject to Section 6.06 and Section 6.07, the Member Contribution Rate and the Employer Contribution Rate shall, at all times, be identical and shall be equal to onehalf of the Total Contribution Rate. **Amendment 8** 3.0 Effective February 1, 2012, Section 3.26 to Section 3.64 are hereby renumbered Section 3.27 to Section 3.65 respectively, and a new Section 3.26 is hereby added: "3.26 "Customer Service Centre FortisBC Inc. Employee" means a FortisBC Inc.employee who is hired after February 1, 2012 and represented by Local 378 of the Canadian Office and Professional FortisBC Inc.'s Customer Service Centres."	4.02B Notwithstanding paragraph 4.02A, in respect of each period on or after January 1, 2008: (a) the EMPLOYEE REQUIRED CONTRIBUTIONS shall be determined as 50% of the excess of (i) over (ii), where: (i) equals the total required contribution rate revealed in the actuarial valuation with the most recent effective date, as determined under paragraph 4.02; and (ii) equals 8.0% of PLAN EARNINGS. Notwithstanding the above, if the contribution rate determined under this sub paragraph 4.02B(a) is negative, then the EMPLOYEE REQUIRED CONTRIBUTIONS shall be nil. (b) the EMPLOYER CONTRIBUTIONS shall be equal to (i) minus (ii), revealed in the actuarial valuation with the most recent effective date, as determined under paragraph 4.02;
		IBEW C.A. ARTICLE 34. PENSIONS	**LOU#2**	**COPE CA Article 31.02 & 31.03**
		34.01 Plan Earnings Best average plan earnings shall be a member's average annual plan earnings, in the 36 month period of service, in which the member's plan earnings are the highest. **34.02 Pension Contributions** (a) The employer and each member shall contribute a percentage of plan earnings which provides for: • The cost of benefits expected to be accrued by the members in respect of credited service in that pay period, plus, The average per pay period expenses expected to be charged to the trust fund, in the respect of the period from the effective date of the most recent actuarial valuation to the effective date of the next actuarial valuation. (b) The percentage in '(a)" above, shall be allocated between the employer and each member as follows:Feb 1, 2001 ER % of Total: 50% Member % of Total: 50%	All new hire CSC employees shall be subject to all the terms and conditions of the CSC collective agreement. This includes joining the "Pension Plan for Employees of FortisBC Energy Inc.", as it applies to employees of the CSC bargaining unit.	**31.02** Effective February 1, 1992 the provisions of the West Kootenay Power Staff Union Pension Plan for OPEIU Union Employees, 1992 shall come into effect. Effective February 1, 1995, the Company's contribution rate will be increased by 2.8% of base pay to provide for a reduction of the same amount in members' contributions. **31.03** Effective February 1, 2000 the definition of plan earnings in the OPEIU 1992 Pension Plan shall be amended to read: Effective February 1, 2001, Company contributions will rise by 0.7% and employee contributions will decrease by 0.7%. Effective February 1, 2002, Company contributions will rise by the remaining 0.7% and employee contributions will decrease by 0.7%.

Attachment 90.5

Multiple Fax Transmittal

Date: **Sept. 13/13**

Time: **9:25 am**

Pages: **11**
(including this one)

From: Susan Noble for
Ken Saunders, Vice-Chair and Registrar

LABOUR RELATIONS BOARD
Suite 600, Oceanic Plaza
1066 West Hastings Street
Vancouver BC **Phone: (604)660-1300**
V6E 3X1 **Fax: (604)660-1892**

RE: FortisBC Inc. -and- Local 213 of the International Brotherhood of Electrical Workers –and- Canadian Office and Professional Employees Union, Local 378
(Section 72 – Case No. 65369)

To:. FortisBC Inc. Attention: Doug Slater / Rita Ludwig	Fax No: 8 (866) 642-~~6~~7405
To: Fasken Martineau DuMoulin LLP Attention: C.G. Harrison/Stephanie Gutierrez	Fax No: (604) 631-3232
To: IBEW 213 Attention: Rod Russell	Fax No: (604) 571-6502
To:. Hastings Labour Law Office Attention: Chris Buchanan	Fax No: (604) 632-9611
To: COPE 378 Attention: Pat Junnila	Fax No: (604) 299-8211
To: COPE 378 Attention: James Quail	Fax No: (604) 299-8211

REMARKS: **BOARD DECISION ATTACHED – BCLRB No. B176/2013 – Hard copy to follow by mail.**

Please deliver immediately. Thank you.

****NOTE: FACSIMILE OPERATOR, PLEASE CONTACT THE ABOVE INTENDED RECEIVER AS SOON AS POSSIBLE. THANK-YOU.**

BRITISH COLUMBIA

LABOUR RELATIONS BOARD

"VIA FAX"

September 13, 2013

TO INTERESTED PARTIES:

Dear Sirs/Mesdames:

Re: FortisBC Inc. -and- Local 213 of the International Brotherhood of Electrical Workers -and- Canadian Office and Professional Employees Union, Local 378
(Section 72 – Case No. 65369/13)

Enclosed is a copy of the Board's decision (BCLRB No. B176/2013) rendered in connection with the above-noted matter.

Yours truly,

LABOUR RELATIONS BOARD

Susan Noble, Acting Sr. Executive Asst. to
Ken Saunders, Vice-Chair and Registrar

Interested Parties

FortisBC Inc.
1975 Springfield Road
Kelowna BC
V1Y 7V7
ATTENTION: Doug Slater/Rita Ludwig

Fasken Martineau DuMoulin LLP
2900 - 550 Burrard Street
Vancouver BC
V6C 0A3
ATTENTION: C.G. Harrison/Stephanie Gutierrez
(Counsel for FortisBC)

Local 213 of the International Brotherhood of Electrical Workers
1424 Broadway Street
Port Coquitlam BC
V3C 5W2
ATTENTION: Rod Russell

Hastings Labour Law Office LLP
3066 Arbutus Street
Vancouver BC
V6J 3Z2
ATTENTION: Chris Buchanan (Counsel for IBEW)

Canadian Office and Professional Employees Union,
Local 378
2nd Floor, 4595 Canada Way
Burnaby BC
V5G 1J9
ATTENTION: Pat Junnila

Canadian Office and Professional Employees Union,
Local 378
2nd Floor, 4595 Canada Way
Burnaby BC
V5G 1J9
ATTENTION: James Quail (Counsel for COPE)

BRITISH COLUMBIA BCLRB No. B176/2013

LABOUR RELATIONS BOARD

September 13, 2013

To Interested Parties:

Re: FortisBC Inc. -and- Local 213 of the International Brotherhood of Electrical Workers –and- Canadian Office and Professional Employees Union, Local 378
(Designation Re Essential Services)
(Section 72(1) Report - Case No.65360)
(Section 72(2) Order – Case No. 65369)

1. The Labour Relations Board hereby designates the following facilities, productions and services as necessary or essential to prevent immediate and serious danger to the health, safety or welfare of the residents of British Columbia:

(i) the continued production and supply of electricity to the residents of British Columbia serviced or supplied by FortisBC Inc. which includes:

(a) Emergency Response:

To make safe any electrical failures or damage to the electrical system components to protect the public, emergency personnel, FortisBC Inc. employees, and the environment.

(b) Operation of Electrical System:

General operation of the electrical system insofar as it is necessary to prevent immediate and serious danger to the health, safety or welfare of residents of British Columbia. This includes the generation of power where it cannot be supplied from the open market.

(c) Restoration of Services:

Restore electrical service to customers and address any environmental impacts.

In general, the order of priorities for restoring service should be:

- primary emergency facilities (hospitals, police, fire);

- local radio/television stations if they are required for distribution of emergency information;
- government/municipal services, schools, and other public facilities having a secondary role for emergency support;
- heavy industrial;
- residential; and
- commercial and light industrial.

(d) Restoration of System Integrity:

Restore system integrity (i.e., system damage that may have impaired system reliability), including generating capacity in situations where there is a reasonable probability that a single contingency event could occur and result in a disruption in service.

2. To ensure that the facilities, productions and services designated as necessary or essential are supplied, provided or maintained by the parties in full measure, the Labour Relations Board makes the following orders:

(i)

a. The Employer shall utilize the services of its management and excluded personnel who are qualified to the best extent possible. Management and excluded personnel utilized to perform essential service work pursuant to this Order shall work a minimum of 60 hours total per week unless otherwise agreed by the parties locally or otherwise ordered by the Board on application. Those personnel shall be placed on standby 24 hours a day, seven days per week. The Employer shall, if requested by the Unions, record the daily number of hours and locations worked by each manager and excluded employee and forward a written record of the hours and locations worked to the Unions every seven days.

b. The Employer shall not use replacement workers, including contractors or volunteers, to perform the "Bargaining Unit Work" of the IBEW Local 213 except where necessary for the performance of essential services functions. The Employer shall provide the Unions with a list of names of all volunteers who are expected to perform volunteer duties during the dispute, and where they usually perform their volunteer duties. The Employer will, if requested by the Unions, record the daily number of hours and locations worked by each volunteer and forward a written record of hours and locations worked to the Unions every seven days.

(ii)

a. Each Union shall schedule its members to work in accordance with the Essential Service Designations in the attached Schedules. The Unions shall provide the necessary information to the Employer for the preparation of payroll and, if possible, shall provide the schedule in advance. Where a shift is designated in the schedule, that shift shall not be split between employees unless otherwise agreed to by the parties. Members of the Unions scheduled to work as directed by this Order shall be the only members of the Unions who work. Members of the Union will not be required to work with excluded personnel unless there are insufficient bargaining unit members to perform essential services, in which case management and excluded or contractors will fill the gap (this provision does not alter the attached SCC schedule).

b. The Employer shall direct those scheduled employees to perform the duties of their employment that it determines to be necessary or essential to comply with this Order.

c. Each Union shall instruct its members to perform the work as directed by the Employer in (b) above.

d. Every employee shall perform the duties of his employment as directed by the Employer in (b) above.

e. Schedules, directions and instructions, in (a), (b) and (c) above shall be governed by the terms and conditions of the applicable collective agreement last in force between the Employer and the Unions except as altered by this Order.

f. The collective agreement shall be altered so that employees on standby during any job action will receive 5 hours pay for every 24 hour period of standby.

(iii)

a. The Unions are ordered to provide unrestricted access and egress for those persons covered by this Order, and any other person or delivery required for the continued operation of the facilities, productions and services designated by this Order.

b. The Unions may collectively select one person to be present to observe the loading or unloading of any delivery vehicle randomly selected once per day at the loading/unloading point at the facility. The observer shall not interfere with, or impede the loading or unloading process and shall not turn back any delivery. Observers may record their observations and if any activity contrary to this Order is observed, the Unions may apply to the Labour Relations Board for relief.

3. The Labour Relations Board retains jurisdiction to monitor the operation of the facilities, productions, and services of FortisBC Inc. during the dispute, and to make such change to the Order, as may be necessary for the continued supply, provision or maintenance of the facilities, productions and services which are necessary or essential to prevent immediate or serious danger to the health, safety or welfare of the residents of British Columbia.

4. Employees will be available in the event of any emergency or disaster situation. In the event of a dispute between the Employer and the Unions as to whether an emergency or disaster situation exists, the employees will perform the work in question. If such a dispute arises the Employer shall provide the Unions documentation and/or information in a reasonable period of time.

This Order reflects the current determination of the Labour Relations Board. The above designations may be increased by agreement of the parties or revised by successful application to the Labour Relations Board by the Employer or the Unions.

LABOUR RELATIONS BOARD

K. Saunders

KEN SAUNDERS
VICE-CHAIR AND REGISTRAR

<u>Interested Parties</u>

FortisBC Inc.
1975 Springfield Road
Kelowna, BC V1Y 7V7
ATTENTION: Doug Slater/Rita Ludwig
(Fax No. (866) 642-7405)

Fasken Martineau DuMoulin LLP
2900 – 550 Burrard Street
Vancouver, BC V6C 0A3
ATTENTION: C.G. Harrison/Stephanie Gutierrez
(Fax No: (604) 631-3232)

Local 213 of the International Brotherhood of Electrical Workers
1424 Broadway Street
Port Coquitlam, BC V3C 5W2
ATTENTION: Rod Russell
(Fax No: (604) 571-6502)

Hastings Labour Law Office
1100 – 675 West Hastings Street
Vancouver, BC V6B 1N2
ATTENTION: Chris Buchanan
(Fax No: (604) 632-9611)

Canadian Office and Professional Employees Union, Local 378
2nd Floor, 4595 Canada Way
Burnaby, BC V5G 1J9
ATTENTION: Pat Junnila
(Fax No: (604) 299-8211)

Canadian Office and Professional Employees Union, Local 378
2nd Floor, 4595 Canada Way
Burnaby, BC V5G 1J9
ATTENTION: James Quail
(Fax No: (604) 299-8211)

Schedule A

2013 Essential Services Summary

Department & Region	Position/Classification	Regular Shift	Standby Count
		1	20
[illegible]	[illegible]	[illegible]	[illegible]
South Okanagan including Princeton (13 PLT's, 3 apprentice and 1 pre- apprentice)	One crew of three (3) person (JM PLT) line, inc 1 CL		3
North Okanagan including Grand Forks (Kelowna (21 PLT's, 2 pre apprentice))	One crews of four (4) person (JM PLT) line, inc 1 CL		3
Okanagan (3 CPC technologists & 2 apprentice CPC technologists)	CPC Tech (senior fully qualified)		1
Okanagan (9 Electricians)	JM Electrician		1
[illegible]	[illegible]	[illegible]	[illegible]
Castlegar / Warfield / Surrounding Area (South Slocan (5 PLT's))	One crew of three (3) person (JM PLT) line, inc 1 CL		3
Kootenay Area stations (5 CPC techs)	CPC Tech (senior fully qualified)		1
Kootenay Area stations (8 Electricians)	JM Electrician		1
[illegible]	[illegible]	[illegible]	[illegible]
Trail Operations (11 Relief System Power Dispatchers and 7 System Power Dispatchers)	System Power Dispatch (1 T&D)*	1 (24-7)*	
[illegible]	[illegible]	[illegible]	[illegible]
(3 Electricians)	JM Electricians		1 (Site specific)
(2 Millwrights)	JM Millwrights		1 (Site specific)
[illegible]	[illegible]	[illegible]	[illegible]
(2 Electricians)	JM Electricians		1 (Site specific)
(2 Millwrights)	JM Millwrights		1 (Site specific)
[illegible]	[illegible]	[illegible]	[illegible]
FBC Plants (13 Electricians)	JM Electricians		1 (Site specific)
FBC Plants (7 Millwrights)	JM Millwrights		1 (Site specific)
[illegible]	[illegible]	[illegible]	[illegible]
All Plants (3 CPC Technologist plus 1 apprentice)	CPC Tech (senior fully qualified)		1 (Site specific)

* See Schedule A.2

BCLRB No. B176/2013

FortisBC
Page 7

SCHEDULE "A.2"

SHIFT SCHEDULE - TRANSMISSION DESK

11/09/2013

NAME	Sep 09 Mon	Sep 10 Tue	Sep 11 Wed	Sep 12 Thu	Sep 13 Fri	Sep 14 Sat	Sep 15 Sun	Sep 16 Mon	Sep 17 Tue	Sep 18 Wed	Sep 19 Thu	Sep 20 Fri	Sep 21 Sat	Sep 22 Sun	Sep 23 Mon	Sep 24 Tue	Sep 25 Wed	Sep 26 Thu	Sep 27 Fri	Sep 28 Sat	Sep 29 Sun
IBEW	DAY	DAY	DAY			DAY	DAY						DAY	DAY						DAY	DAY
IBEW	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT

NAME	Sep 30 Mon	Oct 01 Tue	Oct 02 Wed	Oct 03 Thu	Oct 04 Fri	Oct 05 Sat	Oct 06 Sun	Oct 07 Mon	Oct 08 Tue	Oct 09 Wed	Oct 10 Thu	Oct 11 Fri	Oct 12 Sat	Oct 13 Sun	Oct 14 Mon	Oct 15 Tue	Oct 16 Wed	Oct 17 Thu	Oct 18 Fri	Oct 19 Sat	Oct 20 Sun
IBEW						DAY	DAY						DAY	DAY						DAY	DAY
IBEW	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT

NAME	Oct 21 Mon	Oct 22 Tue	Oct 23 Wed	Oct 24 Thu	Oct 25 Fri	Oct 26 Sat	Oct 27 Sun	Oct 28 Mon	Oct 29 Tue	Oct 30 Wed	Oct 31 Thu	Nov 01 Fri	Nov 02 Sat	Nov 03 Sun	Nov 04 Mon	Nov 05 Tue	Nov 06 Wed	Nov 07 Thu	Nov 08 Fri	Nov 09 Sat	Nov 10 Sun
IBEW																					
IBEW	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT	NIGHT															

SCHEDULE "B"

SCHEDULE B – 2013 ESSENTIAL SERVICES SUMMARY – COPE 378

1. The Parties have agreed, and the Board so declares that the following Schedule is without prejudice or precedent to any current or future dispute or proceeding involving these or any other parties.

2. The following position is required for essential services:

Department & Region	Position / Classification Required	Regular Day Shift	24/7 Trouble Calls	Union
Kootenays (2 Analysts)	Systems Analyst – SCADA/SCC-MRS Support	2	1 (After hours only)	COPE 378

Attachment 116.1

BC hydro

Joanna Sofield
Chief Regulatory Officer
Phone: (604) 623-4046
Fax: (604) 623-4407
regulatory.group@bchydro.com

April 11, 2008

Ms. Erica M. Hamilton
Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

RE: British Columbia Utilities Commission (BCUC)
British Columbia Hydro and Power Authority (BC Hydro)
2004/05 to 2005/06 Revenue Requirements Application - Directive 66
Demand Side Management Evaluation Summary Report

BC Hydro is submitting its Demand Side Management Evaluation Summary Report (the Report), dated March 20, 2008 in compliance with Directive 66 (Page 197 of BCUC Decision dated October 29, 2004). Directive 66 directs BC Hydro to file the executive summaries of its milestone evaluation reports and full final evaluation reports for all its Power Smart programs. The Report summarizes the milestone evaluations carried out in F2008 on the following Power Smart programs:

- Product Incentive Program;
- Power Smart Partners Industrial Program;
- High Performance Buildings Program; and
- Residential CFL Program.

BC Hydro notes the Report has been prepared for the purpose of this compliance filing.

For further information please contact Lyle McClelland at 604-623-4306.

Yours sincerely,

J Sofield

Joanna Sofield
Chief Regulatory Officer

Enclosure (1)

Demand Side Management Milestone Evaluation Summary Report

March 20, 2008

Prepared by: Ken Tiedemann and Iris Sulyma
Power Smart Evaluation and Research

ABSTRACT

This report provides a summary of milestone evaluations completed by Power Smart Evaluation and Research during the Fiscal Year 2008. These studies are the impact evaluations for the Product Incentive Program, Power Smart Partners Industrial, High Performance Buildings, and Residential Compact Fluorescent Lighting.

ACKNOWLEDGEMENTS

Power Smart Evaluation and Research wishes to thank the members of the Evaluation Oversight Team for their assistance and for their support.

TABLE OF CONTENTS

MILESTONE EVALUATION REPORT - F2008

1.0 Introduction

BC Hydro evaluates its demand side management (DSM) programs to document their activities and impacts, to validate energy and peak savings, and to improve the design and operation of programs. The objective of BC Hydro's program evaluation function is to provide timely, credible, actionable and cost-effective evaluation studies. BC Hydro uses the California Evaluation Framework as a guide to undertaking program evaluations and related activities.

1.1 Background

BC Hydro resumed demand side management activity in 2002 and, since the resumption of Power Smart, undertaking evaluations of Power Smart programs has been a core activity. Program evaluation activities center on four main types of studies which are described below: baseline studies, process evaluations, market evaluations and impact studies. The basic objectives of program evaluations are to document program activities, assess program impacts, and identify opportunities for program improvement.

The BCUC Resource Planning Guidelines (RPG) note that "Because of measurement difficulties and uncertainty about consumer behaviour, DSM programs should be evaluated before and after implementation to determine their full impacts." Further in a Revenue Requirements Application decision, the BCUC directed that "BC Hydro file executive summaries of its milestone evaluation reports and the full final reports of all its Power Smart programs." The BCUC also suggested that "BC Hydro diversifies the composition of its evaluation oversight team with representatives from different lines of business and that the Chair of the team be designated from outside the Distribution line of business."

In response to these directives, BC Hydro determines the impact of its DSM programs in the following manner. First, a complete evaluation plan is prepared covering the scope, issues, timing and expected costs of the evaluation study(s). Second, process, market and impact evaluations are conducted at major milestones or at program completion. Third, evaluations are conducted, reviewed, and approved by a BC Hydro cross functional DSM Evaluation Oversight Team Committee chaired by a Senior Manager from BC Hydro's Engineering Services Business Unit. Fourth, BC Hydro has diversified the composition of the Evaluation Oversight Committee with members from all Lines of Business.

Executive summaries of the LED Traffic Light Program process and impact evaluation report and the Residential Lighting reconciliation report were filed with the BCUC on July 6, 2007. The present report provides the summaries for the remaining Evaluation Milestone Reports which were completed and approved by the Evaluation Oversight Committee during F2008. The following section outlines BC Hydro's approach to program evaluation.

1.2 Program Evaluation Principles and Approach

BC Hydro's approach to DSM program evaluation emphasizes four main principles**:**

- Undertaking baseline studies and periodic data collection to understand the nature and size of the pre-program market and changes in the market over time.

- Leveraging existing program, market and customer data to minimize program evaluation costs.
- Using multiple lines of evidence to increase the credibility, validity and reliability of evaluation findings.
- Reviewing and approving completed evaluation studies by the Evaluation oversight team, which represent key stakeholders.

DSM evaluations are often divided into four main categories: baseline studies; process evaluations; market evaluations; and impact evaluations. These four types of studies can be summarized as follows.

Baseline Studies. In baseline studies, the researcher describes the nature of the market, the roles of market actors and the market shares of more efficient and less efficient technologies. Key issues for baseline studies include the following. What are the sources of market data and how timely and reliable are they? What is the size of the market? What are the sales and market shares of more efficient and less efficient product? What are the prices of more efficient and less efficient product? Who are the key market actors? What are their roles? How can specific barriers to adoption of the technology be incorporated in program design?

Process Evaluations. In process evaluations, the researcher identifies and describes the program model or program logic, start-up procedures, implementation procedures and anticipated outcomes. Key issues for process evaluations may include the following. Are program goals clear, well defined, measurable and achievable? Are the goals clearly communicated through the organization? Is responsibility clearly defined? How efficient and effective are program processes? How can program processes be improved? What is the extent of stakeholder awareness of and participation in the program? How satisfied are the stakeholders with the program and its components?

Market Evaluations. In market evaluations, the researcher attempts to understand the impact of the program on the demand side and the supply side of the market. Key issues for market evaluations include the following. What is the size of the market? How much of the market has been captured? What is the remaining market potential? What are the barriers to market transformation? How successfully are the market barriers being addressed? What are the sales of more efficient and less efficient products? What are the prices of more efficient and less efficient products?

Impact Evaluations. In impact evaluations, the researcher evaluates program goals and objectives with respect to the program outcomes, whether intended or unintended. Key issues for impact evaluations include the following. What are the short-term impacts on clients or stakeholders? What are the long-term impacts on stakeholders? What the gross impacts of the program on energy and peak? What are the net impacts of the program on energy and peak?

2.0 Product Incentive Program Impact Evaluation

2.1 Introduction

The Power Smart Product Incentive Program (PIP) was launched in November 2003. The program utilizes financial incentives to encourage business customers to complete a variety of retrofit installations of energy efficient products, and it is administered primarily via the Internet through an online application site. Gross project savings are estimated automatically when the customer enters the project information into the online application using deemed savings algorithms for each technology type.

PIP is targeted at small and medium-sized commercial and institutional customers. However, customers in all sectors and tiers may participate in the program if they meet the eligibility requirements. PIP allows small and medium businesses to become more energy efficient through quick and easy retrofit projects. Larger businesses also benefit from the opportunity to undertake smaller projects that are not eligible for other Power Smart funding.

There have been two project phases to date. PIP I, which was launched in November 2003, focussed primarily on lighting technologies. PIP II, which was launched in November 2004, included an expanded product line. Process changes in March 2007 removed the pre-approval requirement, which changed the program structure to a more customer-friendly, rebate style model.

This report provides an evaluation of the Productive Incentive Program. The objectives for this evaluation are as follows.

- Provide a summary of program activity and customer characteristics.
- Determine customer program awareness, program satisfaction, non-participant energy conservation activities, free rider and spill over rates.
- Compare hours of use for program algorithms and logger data.
- Estimate gross energy and peak savings due to the program.
- Estimate net energy and peak savings due to the program.

2.2 Methodology

Updated data extracts containing information on all the PIP projects in the system were obtained in December 2006. The extract included a variety of information on PIP projects including project dates, application status, types and quantities of products installed, estimated energy savings and incentives awarded. This database was analyzed to provide an overview of program activity.

Telephone surveys were conducted with 62 program participants and 202 non-participants, from May 2006 through July 2006. Participant respondents were recruited from 229 PIP applications that were completed from February 9, 2004 to July 31, 2005. Non-participants were drawn mainly from a mailing list of customers who had received information about the program. This list was supplemented with strata dwelling customers who had also been contacted by the program. The surveys were used to collect information relevant to customer program awareness, customer satisfaction, program experience, free rider and spill over issues.

Gross and net energy savings were estimated for program activity for F2004, F2005 and F2006. The impact evaluation addressed program savings as follows. (1) The program's gross savings algorithms and parameter assumptions were adjusted using logger data on hours of use data by space type and building type. (2) These initial gross estimates were adjusted to compensate for space cooling cross effects. (3) Survey based free rider and spill over rates were used to calculate net program impacts. Evaluation issues, data sources and methods for this study are summarized in Table 2.1.

Table 2.1. Evaluation Issues, Data Sources and Methods

Issues	Main Data Sources	Method
Summarize program activity and customer characteristics	Program files Program interviews	File review Data base analysis
Determine customer program awareness, program satisfaction, non-participant energy conservation activities, free rider and spill over	Participant survey Non-participant survey	Cross tabulations
Compare hours of use for program algorithms and logger data	On-site logger data	Cross tabulations
Estimate gross energy and peak savings	Program data base Logger data on hours of use	Engineering algorithms
Estimate net energy and peak savings	Participant survey Non-participant survey	Free rider and spill over analysis

2.3 Results

Program Review. Program databases contain detailed information on applications and applicants, and this facilitated a detailed examination of program operations. This was supplemented with interviews with program marketing and delivery staff. Some key findings include the following.

- Tier 1 customers have completed the majority of PIP projects. The principal facility types are strata units and hotels, office building and elementary schools.
- These Tier 1 customers are also associated with projects which generate more than one-half of program savings, and PIP projects save an average of 50,000 kWh per year.
- T8 lighting products, CFLs and LED exit signs represent more than 96 per cent of all products installed under the program through December 31, 2005. T8 lighting products are the main technology followed by CFLs and LED exit signs.

Surveyed participants and non-participants were asked whether or not they had installed certain energy efficient equipment during the reference period. The selected products made up about 97 per cent of program savings for the period under review. Table 2.2 summarizes the results. The difference between the treatment and comparison group characteristics is examined using standard z-tests for difference of population proportions (z = 1.96 is the 95 per cent confidence threshold). The treatment group and the comparison group exhibit different behaviour for all four dimensions: treatment group are more likely to have purchased CFLs, energy saver T8s, standard T8s and LED exit signs over the reference period.

Table 2.2. Purchase of Energy Efficient Products

Product	Treatment (n = 62) (%)	Comparison (n = 202) (%)	Difference (%)	z-value
CFLs	51	34	17	2.47*
Energy saver T8s	23	6	17	3.85*
Standard T8s	35	9	26	4.96*
LED exit signs	65	17	48	7.21*

* indicates that the difference is significant at the 95 per cent level.

Survey Results. Participant and non-participant surveys were used to collect detailed information on program awareness, program satisfaction, non-participant energy conservation activities, free rider and spill over rates. Some key findings include the following.

- Some 53 per cent of non-participant survey respondents indicated that they were aware of BC Hydro's Product Incentive Program, and those who were aware of the initiative but had not participated cited needing more information, being too busy, perception that participation involved too much hassle and costs as the main reason for not participating.
- Participant satisfaction levels averaged over four out of five for all ten program dimensions examined, while non-participant satisfaction levels were substantially lower at between 2.9 and 3.6 for the five dimensions examined.
- About 70 per cent of participants would recommend the program to another customer.
- PIP qualifying products installed by non-participants in order of decreasing frequency included CFLs, LED exit signs, metal halide lights, T8 fluorescent tubes, high bay lighting, and occupancy sensors.
- Free rider rates were estimated at the technology level from participant survey data using a five-point scale rating for the organization PIP participation's importance in installing the rebated technology, where one is not at all important, and five is very important. Customers answering one, two or three were counted as free riders, and after aggregating results across technologies, this resulted in an estimated free rider rate of 19 per cent.
- Spill over rates were estimated by asking participants for each technology type if they had installed additional energy efficient products at the same site, and if the program had an influence on the install decisions. Again the results were aggregated across technologies, and this resulted in an estimated spill over rate for participants of 14 per cent.

Surveyed participants and non-participants were asked about their level of satisfaction with program elements, where one is very satisfied and five is very dissatisfied. Table 2.3 shows the top box score shares, or the percentages giving a four or five for that component. The difference between the treatment and comparison group characteristics is examined using standard z-tests for difference of population proportions (z = 1.96 is the 95 per cent confidence threshold). The treatment and comparison groups exhibit statistically different levels of satisfaction for five main program elements. Note also that the comparison group sample size is only 49 because many non-participants did not feel qualified to provide responses. For each program component, the treatment group had a higher satisfaction level than the comparison group.

Table 2.3. Satisfaction with Program Elements (% answering 4 or 5)

Dimension	Treatment (n = 62) (%)	Comparison (n = 49) (%)	Difference (%)	z-value
Program information by direct mail	85	42	43	4.63*
Program information by Internet	94	54	40	4.97*
Service by BC Hydro personnel	96	54	41	4.78*
Level of incentives	82	26	56	5.83*
Variety of eligible products	85	37	48	5.22*

* indicates that the difference is significant at the 95 per cent level.

Hours of Use. The main difference between the program energy savings algorithms and the evaluated results are due to differences in hours of use for lighting products. When compared to on-site measured hours of use, the hours of use assumptions used in the program algorithms appear to be high for many space types and building types. On-site monitoring data yielded a weighted average of 4,560 hours of use per year compared to program algorithm assumptions that yielded a weighted average of 5,886 hours of use per year.

Gross and Net Program Effects. Gross savings are estimated for program activity for the period from January 1, 2004 to March 1, 2006 using the revised hours of use estimates and an adjustment for space cooling cross effects. The space cooling adjustment is based on an engineering algorithm which is calibrated to the share of space that is cooled by building type.

Table 2.4 shows the program reported and evaluated savings. In the planning estimates, it was assumed that free riders and spill over were both five per cent, so that the gross and net savings were the same. Evaluated net energy savings are 18.7 GWh per year compared to reported net energy savings of 24.3 GWh per year. Evaluated peak savings are 2.6 MW compared to reported peak savings of 3.4 MW. The main difference between the reported gross energy savings and the evaluated gross energy savings is due to differences in the annual hours of use parameters employed as described just above. The combined effects of free riders and spill over rates yields a net to gross ratio for evaluated savings of 95 per cent, so that this is a relatively minor factor in determining the difference between program reported and evaluated energy savings estimates.

Table 2.4. Reported and Evaluated Energy Savings and Peak Savings

	Period	Energy Savings (GWh)		Peak Savings (MW)	
		Reported	Evaluated	Reported	Evaluated
Gross savings	F2004-06	NA	19.7	NA	2.7
Net savings	F2004-06	24.3	18.7	3.4	2.6

2.4 Conclusions

Program Design and Implementation. PIP has been successful in building a high level of product awareness and purchase behaviour for energy efficient lighting products in the commercial sector and institutional sector. The program has been gaining momentum, with increased customer applications for efficient lighting products leading to increased annual savings. It is worth noting that over 95 per cent of the program energy savings for the evaluated period of F2004 through F2006 are attributable to lighting products.

Energy and Peak Impacts. The program's engineering savings algorithms were modified to incorporate logger hours of use data and cooling system cross effects. This resulted in a gross savings realization rate of 81 per cent, with the main difference between reported and evaluated gross savings being driven by differences in hours of use estimates by space type and building type. PIP energy and peak impacts through F2006 are estimated at 18.7 GWh per year and 2.6 MW respectively. Since the estimated energy savings impact of 18.7 GWh per year is larger than the planned energy savings of 17.1 GWh per year for this period, the PIP program has successfully met its savings objective.

Program Monitoring. Applying BC Hydro's market transformation paradigm is enhanced when detailed information is collected on both supply side impacts and demand side impacts. Evaluation efforts to date have focussed on customer or purchaser behaviour with less attention paid to supply side considerations. For the next evaluation, it will be useful to interview supply side market actors to better understand their attitudes and roles and to determine how their activities can be leveraged to increase program impacts, particularly in the non-lighting products area.

2.5 Select Bibliography

BC Hydro Power Smart, (2006). Unpublished PIP survey data.

Habart and Associates (2006). Business Lighting Baseline Project Overview – Powerpoint Presentation to BC Hydro Power Smart, July 2006.

Intihar, C. (2004). Power Smart Product Incentive Program II Business Case, BC Hydro Power Smart Commercial Marketing, October 2004.

Longland, M. (2004). Process Evaluation of the Power Smart Product Incentive Program, BC Hydro Power Smart Evaluation, February 2005. .

Sampson Research (2004). BC Hydro PIP II Baseline Research, August 2004.

3.0 Power Smart Partners Industrial Program Process and Impact Evaluation

3.1 Introduction

The Power Smart Partner Industrial Program was launched in April 2002. The basic concept was that BC Hydro's largest business customers (who purchase at least $50,000 worth of electricity annually) have the most to gain from implementing long-term energy-saving strategies, not just one-time projects. BC Hydro partners with these companies, and it contributes matching funding and other resources to help them overcome barriers to realizing energy savings opportunities.

Requirements of the Power Smart Partners (PSP) program include: commitment to improve overall electrical energy efficiency: signing a Power Smart Partner Program agreement outlining their commitment, energy-efficiency target and the Energy Champion who will be responsible for carrying out the plan; and commitment to match dollars to identify and implement energy-saving opportunities.

BC Hydro in turn provides: energy savings opportunity identification: matching funds for businesses to identify electrical energy savings opportunities which may be used towards an energy manager, electrical energy audit, and building re-commissioning: education and training to help in developing the company's pool of energy management skills; e.Points bonus: an ongoing recognition program that rewards customers for the attainment of five per cent electrical efficiency targets with further financial incentives; a Fixed Incentive Fund for energy saving projects is available for customers with a distribution rate account; and a large project fund.

The purpose of this study is to conduct a process, market and impact study of the Power Smart Partners Program through March 2006. The objectives for the evaluation of the PSP Industrial program are as follows.

- Conduct process evaluation, including analysis of program awareness, customer decision making and program satisfaction.
- Conduct a market analysis, including determination of market penetration of standard and efficient technologies in participating and non-participating customers.
- Estimate realisation rates on the gross energy savings and peak savings.
- Estimate net program energy and peak savings.

3.2 Method

The main features of the approach used for the impact evaluation are as follows. The objectives for this evaluation are as follows.

- Data for the study was collected through interviews with program staff, review of program materials and processes, on-site inspections, end-use metering, and interviews with 42 participating firms.
- Based on program data, sample designs were developed for on-site data collection for the impact evaluation and for the telephone survey to collect decision-making information for net-to-gross analysis.
- Sample sizes were determined that would provide savings estimates for the program with ±10 precision at the 90 per cent confidence level.
- On-site visits were used to collect data for savings impacts calculations, while telephone surveys provided the information for the net-to-gross analysis and process evaluation.
- The on site visits at 59 participant and 65 on-participating sites were used to verify installations and to determine any changes to the operating parameters since the measures were first installed. Facility staff were interviewed to determine the operating hours of the installed system and to locate any additional benefits or shortcomings with the installed system.

- For some sites, monitoring of equipment was conducted to obtain more accurate information on hours of operation. The data collected on-site were used to estimate gross savings.
- Proven techniques, including engineering calculations using industry standards and computer simulations, were used to determine energy savings. Survey-based techniques for estimating free ridership in a program were applied to the data collected through a telephone survey of decision-makers.

Evaluation issues, data sources and methods for this study are summarized in Table 3.1.

Table 3.1. Evaluation Issues, Data Sources and Methods

Issues	Main Data Sources	Method
Conduct process evaluation, including determination of customer program awareness, decision making, program satisfaction	Participant survey	Cross tabulations
Conduct a market analysis, including determination penetration of efficient technologies	Participant and non-participant survey	Cross tabulations
Estimate gross energy and peak savings	Program files Site visits	On-site metering Engineering algorithms
Estimate net energy and peak savings	Participant survey	Free rider and spill over analysis

3.3 Results

Process Evaluation. The process evaluation used participant and non-participant surveys were used to collect detailed information on program awareness, program satisfaction, non-participant energy conservation activities, free rider and spill over rates. Some key findings include the following.

- The initial source of information on the program used by customers was the respective Key Account Manager, followed by calls to BC Hydro, with other sources much less important.
- The most important source of information on energy efficiency used by customers their BC Hydro representative, followed by an architect, engineer, or energy consultant, again with other sources much less important.
- Key determinants of energy efficient investments included BC Hydro financial incentives, cost savings, other benefits, recommendation from a BC Hydro study or report, and past experience with energy efficient equipment.

The following Table 3.2 shows customer satisfaction with key program components.

Table 3.2. Customer Satisfaction

Most Favourable	Mid-range	Least Favourable
Overall project result	Estimates of costs	Ease of understanding process
Operation of equipment	Estimates of savings	Actual process savings
Quality of installation work	Ease of completing paperwork	Post project inspection
Information from BC Hydro	Vendor or consultant support	Time to receive incentive
-	Amount of incentive	Amount of paperwork

Market Evaluation. The market evaluation focussed on key end uses, market penetration and opportunities, and participant versus non-participant shares of technologies. Some key factors include:

- The most important end uses in terms of consumption are: industrial processes including materials handling; pumps; fans; compressors; and lighting.
- The share of market captured by energy efficient technologies is generally high for industrial processes and pumps, but is somewhat lower for lighting, fans, pumps and compressors. Major opportunities include T8 lamps, electronic ballasts, premium efficiency motors, adjustable speed drives and appropriate sizing of key system components including motors, pumps and piping.
- Participants have higher shares of the energy efficiency technologies, and the program has been successful in encouraging energy efficient technology use.

Participants and non-participants were asked about the penetration of efficient technologies by end use as shown in Table 3.3.

Gross Savings Impacts. The gross savings impact analysis included first, re-estimating savings for sampled facilities and then, second, applying the realization rates to the total treated population. Expected saving for the sample facilities were determined by: (a) reviewing the documentation for the projects at a facility; (b) visiting the facilities to verify that the energy efficiency measures had been installed and the conditions under which the measures were operating; and (c) undertaking revised savings estimates as appropriate. Project documentation was collected and reviewed for each facility that was selected for the evaluation sample. For this review, a documentation checklist was used to record whether the following types of information had been provided: (a) documentation for equipment changed, including descriptions, schematics, performance data, and other supporting information; (b) documentation for new equipment installed, including descriptions, schematics, performance data, and other supporting information; and (c) information about the savings calculation methodology, including what methodology was used, specifications of assumptions and sources for these specifications, and correctness of calculations. This information was used to calculate a realization rate for sampled sites, and the realization rates were then used to calculate gross savings for each type of savings (incentive, consultative and both).

Table 3.3. Penetration of Energy Efficient Industrial Technologies (% penetration)

End Use	Technology	Treatment (n =59)	Comparison (n =65)	Difference	z-value
Lighting	T8	65.5	30.8	34.7	4.12*
Lighting	CFL	32.8	12.3	20.5	2.79*
Lighting	HPS	72.4	61.5	10.9	1.30
Lighting	Metal halide	72.4	72.3	1.2	0.01
Lighting	LED	29.3	10.8	18.5	2.62*
Lighting	Elect ballast	70.7	43.1	27.6	3.23*
Fan/blower	ASDs	27.1	6.2	20.9	3.21*
Fan/blower	Cog belts	35.6	6.2	29.4	4.25*
Fan/blower	Motor sizing	8.5	1.5	7.0	1.78
Fan/blower	EE motors	67.8	40.0	27.8	3.23*
Pumps	EE pumps	55.9	27.7	28.2	3.31*
Pumps	Pump sizing	69.5	38.5	31.0	3.64*
Pumps	Pipe sizing	69.5	40.0	29.5	3.46*
Pumps	ASDs	32.2	13.9	18.4	2.47*
Pumps	Motor sizing	8.5	1.5	7.0	1.78
Pumps	EE motors	67.8	40.0	27.8	3.23*
Compression	Low air temp	11.9	4.6	7.3	1.47
Compression	Controls	64.2	27.9	36.3	4.34*
Compression	Heat recovery	10.2	3.1	7.0	1.58
Compression	ASDs	27.1	6.2	27.8	3.21*
Compression	Motor sizing	8.5	1.5	37.6	1.78
Compression	EE motors	67.8	40.0	10.9	3.23*
Process	Motor sizing	8.5	1.5	7.0	1.78
Process	EE motors	84.8	61.5	27.8	3.23*
Process	PF correction	57.6	20.0	37.6	4.63*
Process	ASDs	67.8	56.9	10.9	1.26

* indicates that the difference is significant at the 95 per cent level.

Net Savings Effects. Net savings were defined as gross realized savings minus free rider effects plus spill over effects. Detailed survey information was used to calculate the free rider and spill over rates. Table 3.4 provides the results of this analysis for the period F2003-F2006. Evaluated energy savings were 469.3 GWh while evaluated peak savings were 64.5 MW.

Table 3.4. Reported and Evaluated Energy Savings and Peak Savings

	Period	Energy Savings (GWh)		Peak Savings (MW)	
		Reported	Evaluated	Reported	Evaluated
Gross savings	F2003-06	NA	513.4	NA	70.6
Net savings	F2003-06	497.3	469.3	68.3	64.5

3.4 Conclusions

Program Design and Implementation. The Industrial Power Smart Partners program has been successful in building a high level of knowledge of and interest in energy efficient technologies. Savings have been distributed across a wide range of end uses and technologies, suggesting that the program has effectively avoided cream skimming, which can sometimes be detrimental to longer term savings. Customer satisfaction with most of the program elements is high, and is in every case at least satisfactory.

Energy and Peak Impacts. Detailed on-site data collection combined with limited metering has been used to validate project savings estimates. For the period covered by the evaluation, net energy savings are estimated at 469.3 GWh per year while peak savings are estimated at 64.5 MW.

Program Monitoring. Monitoring and understanding changes in the industrial market for energy efficiency is complicated because the largest industrial customers use a variety of complicated and sometimes unique technologies. One consequence of this is that regression-based evaluation methods which are frequently applicable for the residential and commercial sectors may be difficult to apply. It would be useful to undertake a comprehensive baseline study to understand and update: (1) penetration information on energy efficient technologies: (2) end-use energy consumption; and (3) the scope for further energy efficiency improvements at the industrial site level.

3.5 Select Bibliography

ADM Associates (2007). Industrial Power Smart Partner Program Milestone Evaluation. Sacramento: ADM Associates.

Innovolgie (2006). Industrial Executives' Perspectives on the Past and Future of BC Hydro's Industrial Power Smart Partners Program, Rockville: Innovolgie.

Quantec (2005). Power Smart Partner Milestone Evaluation Report (2005). Portland: Quantec LLC.

Quantum Consulting (2004). National Energy Efficiency Best Practices Study, Volume NR5-Non-residential Large Comprehensive Best Practices Report, Berkeley: Quantum Consulting.

4.0 High Performance Buildings Program Impact and Process Evaluation

4.1 Introduction

The Power Smart High Performance Buildings (HPB) program was launched in July 2005. The objective of the HPB program was to accelerate the demand for and production of energy efficient new commercial and industrial buildings and industrial plants. HPB focuses on integrated design and whole building performance rather than selection and installation of individual energy efficient technologies.

The rationale for HPB is that by identifying and addressing barriers to energy efficiency during the design phase, new commercial buildings and industrial plants will capture energy efficiency opportunities. The program provides the following components to promote energy efficient design.

- Tools and financial incentives to address financial barriers.
- Education and training to address industry capacity constraint barriers.
- Promotional campaigns to address knowledge barriers.
- Recognition programs to address awareness barriers.

Minimum savings criteria apply, and projects are considered as qualified once certain guidelines have been met. The primary audience for the program includes: Building Owners; Building Developers; and Design Teams of new construction projects including architects, consultants and engineers. BC Hydro will assist the customer through two phases of the High-Performance Building Program: (1) BC Hydro will co-fund an energy study to develop a high-performance design that delivers energy savings, compared with conventional building design; (2) BC Hydro may provide incentives to help qualified projects implement the approved design, if the energy efficiency measures in the high-performance design involve added capital costs.

This report provides an evaluation of the High Performance Buildings program. The objectives for this evaluation are as follows.

- Review the rationale for the program.
- Assess the effectiveness of program activities.
- Characterize the new commercial construction market in British Columbia.
- Forecast the potential size of the new commercial construction market in British Columbia.
- Estimate energy savings and demand savings for the program.

4.2 Methodology

In this study we use a multiple lines of evidence approach, because no single line of evidence or method of analysis can provide information on all of the evaluation issues of interest. We use a combination of interviews with program staff and stakeholders; file review; literature review; on site-measurement of equipment run-time and loads; statistical forecasts and engineering analysis in this study. Evaluation issues, data sources and methods for this study are summarized in Table 4.1.

Table 4.1. Evaluation Issues, Data Sources and Methods

Issues	Main Data Sources	Method
Program rationale	Stakeholder and program staff interviews File and literature review	Logic framework analysis
Assess the effectiveness of program activities	Stakeholder and program staff interviews File and literature review	Logic framework analysis
Characterize the new commercial construction market	Stakeholder and program staff interviews B.C. Assessment Authority	Market analysis
Forecast the potential size of the new commercial construction market	Stakeholder and program staff interviews B.C. Assessment Authority	Market analysis
Estimate energy and demand savings	Six case studies	Engineering algorithms

4.3 Results

Program Rationale. The summary program logic model is shown in the following table. The program rationale is to address the four key market barriers (financial, capacity, knowledge and understanding, and awareness) to improve energy efficiency in new construction through four distinct but integrated strategies. These strategies are financial assistance, workshops and tools, promotional campaigns, and recognition programs. For each of the four strategies used, the program logic model shows the linkages between activities, outputs, program purpose and program goal. A review of the program logic reveals that the linkages are both reasonable and plausible, thus demonstrating that the underlying program logic is a valid one.

Figure 3.2.3. Program Logic Model

Market barrier	Financial barriers	Capacity constraints	Knowledge and understanding	Awareness
Activity	Financial assistance offered	Workshops and lunch and learn sessions held and tools developed	Promotional campaigns implemented	Recognition programs in place
Output	Building design costs and energy efficient equipment costs reduced	Construction and building design community capability increased	Knowledge and understanding of energy efficiency increased	Stakeholder awareness of energy efficiency importance increased
Purpose	Accelerate demand for and production of energy-efficient building and industrial facilities			
Goal	Reduce energy consumption and peak			

Program Effectiveness. Based on the file review, literature review, program interviews and stake holder interviews, a number of major finding emerged. First, incentive levels vary substantially across the new construction programs of various utilities, but many programs provide incentives equivalent to about 40 per cent to 60 per cent of incremental costs, which is about the share of incremental costs covered by BC Hydro for the case studies examined. Second, tiered incentives, where the incentive level is based on the level of energy efficiency improvement above the baseline, are successfully used by some utilities. Third, for many U.S. utilities, whole building baseline is determined through whole building simulations such as DOE 2.1 to establish the expected energy savings over the baseline. Fourth, program procedures are not viewed as particularly burdensome per se, but some concerns were raised about the length of time required for BC Hydro turn-around of documentation. Fifth, some interviewees felt that the effectiveness of program marketing could be improved, since program marketing depends heavily on Lunch and Learn sessions, which do not necessarily reach the key intended audiences including developers, owners and senior officials of architectural and engineering firms.

Market Characterization. Several key features of the new non-residential market in British Columbia stand out. (1) The construction industry is primarily cost driven by the underlying economics, with construction costs, operating costs, vacancy rates, revenues and return on investment being the key drivers. (2) Construction design typically focuses on visible building features, because they are what sell new commercial and industrial space. (3) Increased energy efficiency is a hard sell because triple net leasing means that the agent owning the building does not capture the gains from energy efficiency and because economic pay-back longer than five years is not viewed as attractive. (4) Energy efficiency is often an after thought, with relatively little attention paid to integrated design in the early stages of building design. (5) Three main end-use areas stand out as offering both broad savings potential and pay-back periods of five years or less - advanced lighting and controls, energy efficient chillers and mechanical systems including fans, pumps and compression.

Market Potential. New construction in British Columbia goes through fairly regular cycles in response to changes in the level of economic activity, interest rates, vacancy rates, the incremental stock currently under construction and forecasts of future economic conditions. Levels of new construction vary by segment in response to changes in rates of return and risk by segment. Construction activity is anticipated to increase through 2007 and 2008 and hit a short-term peak in 2009, and then fall back due to a reduction in major projects. The key non-residential construction segments are expected to be industrial, large and small offices, non-food retail, wholesale and warehouse, educational facilities and hotels and motels over the next three years. The program has a medium-term opportunity to significantly affect energy efficiency and capture lost opportunities on the order of at least 7 GWh in 2007, 13 GWh in 2008 and 15 GWh in 2009.

Energy and Demand Savings. The first six buildings participating in the High Performance Building program were the subject of detailed and comprehensive monitoring and verification. All six projects received post-completion monitoring and verification which involved metering of equipment run times and loads for periods up to twelve months to determine actual equipment loads combined with engineering modeling to determine energy savings. Since this is a new construction program, here were no pre-installation measurements available for comparison, so estimates of energy savings were based on engineering modelling calibrated to the measure loads. There was no evidence of free riders or spill over for these case studies.

Figure 3.2.1. High Performance Building Case Studies

Project	Project Summary	Analysis
Multiplex arena	Energy efficient lighting (T-8 lamps with electronic ballasts, CFLs, occupancy sensors, computerized, area specific time clock) and new ammonia refrigeration plant for 85,000 square foot complex (computer controls, larger evaporative cooler, supplementary 7.5 HP pony pump for low load conditions, VSD on 30 HP condenser fan, condenser fan)	22 lighting loggers installed for three months to capture lighting HOU, power loggers installed for seven months or more on fans, pumps, compressors
Refrigerated warehouse	New refrigeration system serving four blast freezers, two freezer storage rooms, one cooler and one loading dock with features including evaporative cooler with lower discharge pressure, multiple condenser fans, waste heat recovery, compressor oil cooling, defrost thicker insulation, VSDs on compressors (capacity increased from 140,000 to 318,000 lb/day)	Refrigeration system modeling using design refrigeration loads, run hours, and part load operating conditions, calibrated to metered load
Refrigerated warehouse	New refrigerated warehouse including a 92 ton refrigeration system serving food packaging and preparation areas at 30°F and a 137 ton refrigeration system serving a spiral freezer for storing product at -45°F with the following features: reduced condensing temperature, thermosyphon oil cooling, computer system controls, condenser fan and compressor VSDs	Savings based on measured operating hours on compressors and the condenser combined with on-site inspections to ensure proper system operation
Food processor	New refrigeration system serving two blast freezers, freezer storage room and cooler and production room with one-100 ton compressor, one-200 ton compressor with VSD, one-250 ton compressor with VSD, added insulation, waste heat recovery, defrost	Power meters were installed for one year on three compressors and actual and modeled consumption compared
Food processor	New refrigeration system using serving blast freezers and freezer storage room with ASDs on compressors	Power metering showed no savings
Residence	Space heating (plate frame heat exchanger with water at 375°F on primary side and 200°F on secondary side mixed to 120°F for radiant floor tubing with two 3 HP, four 1 Hp and two ¾ HP pumps), water heating (two 350 gallon storage tanks heated with two shell and tube heat exchangers, two small pumps), ventilation heating (two roof-mounted heat recovery ventilation units) by central steam plant for dormitory/dining hall	Heating water energy use calculated by measuring water flow and the temperature drop across the primary heat exchanger, using DDC package sensors with data collected for one year

The following table summarizes key impact results and compares these to initial reported estimates. Energy savings were estimated at 5.0 GWh per year and peak savings were estimated at 0.7 MW.

Table 2.2. Reported and Evaluated Energy Savings and Peak Savings

	Period	Energy Savings (GWh)		Peak Savings (MW)	
		Reported	Evaluated	Reported	Evaluated
Net savings	F2004-06	7.9	5.0	1.1	0.7

4.4 Conclusions

Program Design and Implementation. Energy efficiency in new commercial buildings is critical because once a building is constructed and occupied, the major building systems may be in place for ten years or more, leading to substantial lost opportunities. The High Performance Building program could address these lost opportunities through a prescriptive program offer that emphasizes energy efficient technology investments in: (1) advanced lighting technologies and lighting controls: (2) energy efficient chillers and HVAC controls: (3) energy efficient mechanical systems including fans, pump and compressors, which offer highly visible savings and rapid pay-back.

Building and System Baselines. There may be advantages in terms of stakeholder understanding and support by moving to a widely accepted and well understood baseline such as the ARSHAE/IESNA 90.1 standard. This may also increase program participation.

Design Assistance. Many commercial, institutional and industrial buildings are designed with limited attention paid to energy efficient systems and less attention is paid to integrated, energy efficient design. Energy efficiency considerations often enter the design process when the major mechanical and lighting systems are being designed, which is often too late for an integrated system to be sued. Support for early design assistance during the concept phase could help to overcome this barrier.

Energy and Peak Impacts. Energy savings were estimated at 5.0 GWh per year and peak savings were estimated at 0.7 MW.

4.5 Select Bibliography

ADM Associates (1996). Evaluation of the New Building Design Program, Sacramento: ADM Associates.

ADM Associates (2006). New Construction Baseline, Sacramento: ADM Associates.

BC Hydro (2005). BC Hydro Design Smart.

BC Hydro (2005). High Performance Buildings Business Case.

5.0 Residential CFL Program Impact and Market Evaluation

5.1 Introduction

The CFL residential lighting initiatives is an electricity acquisition and market transformation program aimed at motivating residential customers to obtain the best long-term value from their choice of household lighting and to shift customer behaviour and the lighting market so that efficient usage becomes a way of life. In the early stages of this program CFLs were purchased in bulk by Power Smart and then distributed free to BC Hydro utility customers through redeemable vouchers at partnering retail outlets. Vouchers were redeemable at Power Smart booths that rotated among participating retailers. The PS booths included knowledgeable staff and interactive displays to help educate customers on the benefits of CFL bulbs, how to choose the right bulb, and the best places to use them. Mail-in and point-of-sale rebate coupons were used in conjunction and in separate campaigns to stimulate the purchase of CFLs.

The 2006-07 CFL campaign involved the availability of $3 in-store instant rebate coupons for the purchase of Energy Star CFLs worth $9.90 or more. These coupons were distributed through Power Smart in-store promotions held with participating retailers throughout BC Hydro's service territory. The CFL coupon was a co-promotion with rebate coupons for Energy Star qualifying light fixtures. Users of the $3 CFL coupon were not required to provide contact information to redeem the coupon. For the purposes of follow-up market research, contact information for potential CFL coupon users came from contest entry forms for a one-year lease of a Toyota Prius automobile.

This report provides an evaluation of the Residential CFL Program for F2007. It also provides an update of the evaluation of the Residential CFL program for F2006, using final statistics on coupon redemptions that were not available at the time the evaluation of the F2006 program was undertaken. Issues for this study are as follows.

- Describe the recent supply-side developments in the British Columbia market for CFLs, including stocking behaviour, product variety and prices.
- Describe the recent demand-side developments in the British Columbia market for CFLs, including product awareness, purchase behaviour and purchases.
- Estimate program effects for both energy and peak savings due to the program for F2007.
- Revise the program effects for both energy and peak savings due to the program for F2006.

5.2 Methodology

Supply-side characteristics were determined primarily through the in-store shelf space study of 43 major retailers of CFLs across BC Hydro's four service regions. The shelf space survey collected information on CFL product availability, pricing and placement. Specific information collected included the overall shelf space devoted to lighting products, CFL share of the space, bulb styles, rated life, wattages, prices and presence of the Energy Star label on the package. Demand-side characteristics were determined mainly through three customer surveys conducted in March 2007 with 350 program participants, 600 BC Hydro customers and 512 comparison group households in North and South Dakota.

Table 6.1 compares the British Columbia and North and South Dakota customer samples on several key characteristics, which are believed to be drivers of CFL purchase and use. The difference between the treatment and comparison group characteristics is examined using standard z-tests for difference of population proportions (z = 1.96 is the 95 per cent confidence threshold). Since none of the differences are statistically significant, this comparison suggests that the treatment group and the comparison group are reasonably comparable, so that differences in CFL awareness, purchase or use are likely due to program activity rather than differences in the populations.

Table 6.1. Treatment and Comparison Group Characteristics

Dimension	Treatment (n = 600) (%)	Comparison (n =512) (%)	Difference (%)	z-value
Home ownership rate	85	85	0	0.018
Percentage of households with children under 19	32	31	1	0.338
Percentage with incomes under $40,000	34	38	-4	-1.416

* indicates the difference is significant at the 95 per cent level.

Energy savings were estimated for program activity (direct effects) and for market effects (indirect effects) for F2006 and F2007. The impact evaluation addressed program savings as follows. (1) Engineering algorithms were used to estimate the direct effects of the program using information on the number of coupons redeemed, the installation rate, the estimated free rider rate, hours of use and cross effects. (2) Total effects were estimated using information on incremental purchase rates for the treatment and comparison groups, the installation rate, hours of use and cross effects. (3) Market effects are defined as total effects minus direct effects. Issues, data sources and methods for this study are summarized in Table 6.2.

Table 6.2. Evaluation Issues, Data Sources and Methods

Issues	Main Data Sources	Method
Supply side analysis	Retail shelf space study	Cross tabulations
Demand side analysis	Consumer survey	Cross tabulations
Energy and peak savings for F2007	Participant, non-participant and consumer surveys Program data	Engineering algorithms
Energy and peak savings for F2006	Participant, non-participant and consumer surveys Program data	Engineering algorithms

5.3 Results

Supply-Side Analysis. The shelf space survey of major retailers operating in BC Hydro’s service territory assessed the supply-side developments in the availability, accessibility, and affordability of CFLs. Compared to the previous year’s study, the November 2006 shelf stock study found a modest increase in CFL availability and a significant decrease in CFL prices. Some key supply side findings include the following.

- Total shelf space allocated to screw-based CFLs by retailers increased to 13.8 per cent in November 2006 from 13.0 per cent in November 2005. CFLs accounted for 6.1 per cent of shelf space in the 2002 baseline survey.
- Spiral CFLs dominate the market, accounting for 75 per cent of all CFLs on store shelves in 2006. They are typically packaged in multiples of two or more, and offer the best value on a per-CFL bulb basis. Spiral CFLs accounted for only 22 per cent of all CFL product surveyed in the baseline year (2002).
- CFLs rated at 13 to 15 watts accounted for the majority (49 per cent) of CFL product surveyed in 2006. General merchandise and home improvement / hardware stores offer the greatest selection of CFLs in terms of wattages, brands, and models. Grocery stores continue to offer the least selection. In total, 190 different models of CFLs were observed across the four retail segments in 2006, down slightly from 196 models in 2005. Ninety (90) models were observed during the baseline year (2002).
- Share of CFLs rated at 10,000 hours continued to decline, accounting for 20 per cent of all CFL product in 2006, compared to 46 per cent in 2003. CFLs rated at 8,000 hours were most common, accounting for 37 per cent of all CFLs surveyed. The DOE Energy Star® logo was displayed on 79 per cent of all CFLs surveyed in 2006, unchanged from 2005.
- CFL prices continued their long-term decline in 2006 with 50 per cent of all CFLs priced at less than $4 each (adjusted for multi-packs), and 11 per cent of all CFLs priced at less than $2 each. On a weighted average basis, globe, circular, tube, and par/reflector style CFLs recorded price declines.
- Based on the current capital and operating costs of a typical 15 watt CFL versus a 60 watt incandescent bulb, the expected payback for a CFL based on average use of four hours a day is now nine (9) months, compared to 27 months in 2002.

Demand-Side Analysis. The general consumer survey of BC Hydro residential customers indicated that awareness of CFLs remains unchanged, but the incidence and penetration (saturation) has increased significantly since the last survey conducted in January 2006. A survey of BC Hydro customers who took advantage of the in-store instant rebate coupon for CFLs (participant survey) supplemented this information. Key findings from the consumer and participant surveys include:

- Ninety-one per cent (91 per cent) of BC Hydro residential customers are aware of CFLs, which is statistically unchanged from the previous three years (89 per cent to 90 per cent).
- Recall of information, advertising, or promotions from BC Hydro Power Smart regarding CFLs declined to 68 per cent from 73 per cent recorded during January 2006 survey.
- Seventy-three per cent (73 per cent of BC Hydro residential customers have at least one CFL in use (incidence) as of March 2007, up from 70 per cent in 2005, and 23 per cent in 2002. On average, these homes have 9.0 CFLs installed, up significantly from the 6.9 average recorded in January 2006. The average numbers of installed CFLs increased for both indoor and outdoor applications.
- Nearly six in every ten (58 per cent) BC Hydro residential customers purchased a CFL in 2006. On average, 7.4 CFLs were purchased per household, with or without using a Power Smart sponsored coupon.
- The average price paid for the most recent CFL purchase was $3.77 a CFL, down considerably from January 2006 when the average price paid was $5.00 per CFL.
- Seventeen per cent (17 per cent) of households reported using a Power Smart sponsored coupon in 2006. These households purchased an average of 10.1 CFLs,

8.2 CFLs during the last three months of the year. Households using a coupon purchased an average of 5.7 CFLs each using the discount coupon.

- The proportion of households with one or more CFLs in storage rose to 68 per cent in March 2007 from 57 per cent in January 2006. The average quantity of CFLs sitting unused also increased; rising to 2.1 CFLs per user-household from 1.8 CFLs in January 2006. The most commonly mentioned reasons why the CFLs are not in use include waiting for existing CFLs or incandescent bulbs to burn out (29 per cent and 13 per cent of responses, respectively), and that they didn't have a use for them (29 per cent).
- Overall, 81 per cent of CFLs purchased during calendar year 2006 were installed as of March 2007. This installation rate is down from the 87 per cent record high during the January 2006 survey, but consistent with higher average purchase quantities and the increase in CFLs in storage.
- Thirty-nine per cent (39 per cent) of user households replaced one or more CFLs in 2006. On average, these households replaced 2.9 CFLs each. Eight-two per cent (82 per cent) of these CFLs were replaced with another CFL.
- Of the households with at least one CFL currently in use, 91 per cent indicated they still have incandescent lights in use either indoors or outdoors. The most frequently mentioned reasons why CFLs are not used in these fixtures include frugalness (i.e., waiting for existing incandescent bulbs to burn out) (20 per cent of all responses), technical issues with using CFLs in the fixture (19 per cent), issues with the performance of CFLs (15 per cent), and cost of CFLs (11 per cent).

Table 6.3 compares the British Columbia and North and South Dakota customer samples on several CFL awareness and purchase characteristics. The difference between the treatment and comparison group characteristics is examined using standard z-tests for difference of population proportions (z = 1.96 is the 95 per cent confidence threshold). The treatment and comparison groups exhibit different behaviour for all four dimensions: BC Hydro customers are more likely to be aware of CFLs, to have at least one CFL installed in their home, to have purchased at least one CFL in the last year, and to have used a coupon to purchase a CFL.

Table 6.3. CFL Awareness and Purchase Behaviour

Dimension	Treatment (n = 600) (%)	Comparison (n = 512) (%)	Difference (%)	z-value
Aware of CFLs	91	81	10	4.74*
Have at least one CFL installed	73	36	37	12.41*
Purchased at least one in the last year	58	22	36	12.12*
Purchasers used coupon to buy CFL	21	7	14	6.58*

* indicates that the difference is significant at the 95 per cent level.

Energy and Peak Savings. Net savings for F2006 and F2007 are shown in Table 6.4. For F2006, evaluated net energy savings are 32.5 GWh per year compared to reported net energy savings of 29.0 GWh per year, and evaluated peak savings are 8.3 MW compared to reported peak savings of 9.0 MW. For F2007, evaluated net energy savings are 80.1 GWh per year compared to reported net energy savings of 11.8 GWh per year, and evaluated peak savings are 20.3 MW compared to reported peak savings of 3.0 MW.

Table 6.4. Reported and Evaluated Energy Savings and Peak Savings

	Period	Energy Savings (GWh)		Peak Savings (MW)	
		Reported	Evaluated	Reported	Evaluated
Net savings	F2006	29.0	32.5	9.0	8.3
Net savings	F2007	11.8	80.1	3.0	20.3

5.4 Conclusions

Program Design and Implementation. Power Smart's Residential CFL program has been successful in building a high level of product awareness and purchase behaviour for energy efficient lighting products in the residential sector. BC Hydro may have the highest residential CFL penetration and saturation rates of any major utility service territory in North America. The Residential CFL program has successfully made the transition from a give-away and incentive program to a market transformation program. Given the high level of residential use, it will be major challenge for the program to sustain momentum and further increase the residential saturation and penetration of CFLs.

Energy and Peak Impacts. We saw above that for F2006, evaluated net energy savings are 32.5 GWh per year compared to reported net energy savings of 29.0 GWh per year, and evaluated peak savings are 8.3 MW compared to reported peak savings of 9.0 MW. And for F2007, evaluated net energy savings are 80.1 GWh per year compared to reported net energy savings of 11.8 GWh per year, and evaluated peak savings are 20.3 MW compared to reported peak savings of 3.0 MW.

5.5 Select Bibliography

BC Hydro Power Smart, (2007). Unpublished customer survey data.

Sampson Research (2006). Direct and Market Effects of BC Hydro's 2005-2006 Compact Fluorescent Lamp Program, Sampson Research/BC Hydro.

Sampson Research (2007). Direct and Market Effects of BC Hydro's 2006-2007 Compact Fluorescent Lamp Program, Sampson Research/BC Hydro.

Sulyma, I., D. Fielding, J. Gin-Johnson, H. Haeri and A. Lee, (2003). "Buying Success: Bulk Purchase Programs as Agents of Market Transformation," Proceedings of the 1996 ACEEE Summer Study on Energy efficiency in Buildings, Seattle, Washington.

Vine, E. and D. Fielding, "An Evaluation of Residential CFL Hours-of-use Methodologies and Estimates: Recommendations for Evaluators and Program Managers," Energy and Buildings, Vol 38(12).