Diane Roy
Director, Regulatory Affairs

FortisBC Energy
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
Email: diane.roy@fortisbc.com
www.fortisbc.com

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

November 27, 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 Energy Inc. (FEI)

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

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

On June 10, 2013, FEI filed the Application as referenced above. FEI respectfully submits the attached response to BCUC IR No. 2.

In consideration of the large volume of IR responses attached, FEI believes it would be helpful to highlight for the Commission some key responses that provide the Commission with an understanding of the issues raised in this set of questions:

- 272.2/276.6 Determining the Base for O&M
- 306.2 Determining the Base for Capital
- 284.1 Evolution of the ES&ER department O&M
- 313.1 Overview of costing and reporting for Biomethane, NGT, TES activities
- 356.1 Determining the overhead allocation to FAES
- 359.1 Separation of FAES employees

In addition, FEI notes that the responses to BCUC IR No. 2 questions 242 series, 259.2, 296.4 through 296.5.1, 298.4 through 298.7, 305.1, 305.2, 306.1, 306.2, 307 series, 338.20, and 341.1 through 341.4 relate to the PBR Methodology, and will be submitted with the PBR Methodology IR responses to assist with maintaining separate evidentiary records.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (e-mail only): Registered Parties

MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

FORECASTS FOR THE PBR PERIOD – DEMAND FORECAST

242.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 1.1, p. 86

PBR Annual Reviews – Energy Demand Forecast

Fortis Energy Inc. (FEI) states in the Application that it "is expecting to experience a slight increase in consumption over the PBR Period. FEI's forecast of demand for natural gas is based upon a methodology that is consistent with that used in prior years, and provides a reasonable estimate of future natural gas demand for 2014." (p. 86)

242.1 As it specifically relates to demand forecasting, please comment on whether it is FEI's opinion there are any incentive differences for achieving accurate forecasts between Performance Based Ratemaking (PBR) and rate-of-return regulation.

Response:

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

242.1.1 With respect to forecasting customer demand, what impact, if any, will the PBR process have on the approach that FEI takes on preparing demand forecasts?

Response:

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

242.2 For the current test period, are there any performance incentives that will have an impact on FEI's accuracy in forecasting customer demand and sales revenue?

Response:

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

242.2.1 Does FEI believe that the PBR process should provide incentives for achieving accurate demand forecast? For example, is a PBR forecasting incentive that takes into account certain adjustments (e.g. weather-related sales variations) a reasonable expectation for ratepayers to have? Please discuss why.

Response:

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

243.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.56.1, p. 119; Exhibit A-11, Attachment

PBR Annual Reviews – Industrial Rate Classes

FEI states in response to BCUC 1.56.1: "In Quarters three and four of 2014 FEI will administer its industrial survey. The survey will allow all Rate Schedule 22 customers (and all other industrial customers) to update their individual demand forecasts for 2015-2019. Survey results will be loaded into the FIS model and demand will be recalculated." (p. 119)

243.1 Please confirm that the results from annually updated industrial forecasts will have an impact on rates during the term of the PBR.

Response:

Yes, the annually updated industrial forecasts will have an impact on rates during the term of the PBR. FEI will update the industrial volumes and revenue forecasts annually based on the results of the Industrial Survey that will be carried out each fall.

As background, FEI provides industrial customers with a state-of-the-art web-based tool that shows their past consumption and the forecast consumption the customer provided the previous year. FEI does not adjust the forecasts provided by the customer. The survey results are simply amalgamated by rate class. This methodology has been in place for over a decade.

The annual updating of industrial volumes and revenues will have a rate impact that may go in either direction. If industrial customers provide survey forecasts that result in greater forecast industrial revenues than the previous year's forecast there will be a corresponding rate reduction, all else equal. Conversely, if industrial customers provide survey forecasts that result in lower forecast industrial revenues than the previous year's forecast there will be a corresponding rate increase, all else equal. Under the proposed PBR treatment, variances between actual and forecast industrial revenues each year will be subject to the 50/50 earnings sharing mechanism.

243.1.1 If the annual industrial survey conducted in Q4 of 2014 indicated that energy demand would be 5 percent less for Industrial rate class 22 in 2015, what impact would that have on rates? Please provide an electronic spreadsheet that includes a calculation of the impact.

Response:

Attachment 243.1.1 contains the requested electronic spreadsheet. As shown in the table below, the estimated impact on rates for 2015 if Rate Schedule 22 customers were to decrease their forecast demand by 5% would be to increase the average rate for all non-bypass customers by $0.005 / GJ, all else equal. The supporting analysis excludes Rate Schedule 22 bypass customers as any change in demand by bypass customers would not cause a change in revenues nor have any impact on the average rate change calculation requested.

	Evidentiary Update Sept. 6, '13 Appendix G-1 Formula Schedule 3		
2015 Deficiency From Revenue @ 2013 Existing Rates	$	15,396	(1)
Less: 2014 Revenue Deficiency		(8,920)	(2)
2015 Net Revenue Deficiency	$	6,476	
Add: 2015 Rate 22 Reduced Revenue		770	
2015 Adjusted Revenue Deficiency	$	7,246	
2015 Forecast Non-Bypass Sales & T-service Energy (TJ)		172,101.7	(3)
Less: Rate 22 Volume Reduction		(1,456.5)	
Adjusted 2015 Non-Bypass Sales & T-Service Energy (TJ)		170,645.2	
Average Increase Prior to Rate 22 Adjusted Energy $ / GJ	$	0.038	
Less: Average Increase After Rate 22 Adjusted Energy $ / GJ	$	0.042	
Estimated Average Rate Impact $ / GJ	$	0.005	

Notes:

(1)	Appendix G-1, Formula, Schedule 3, Row 22, Column 4.		
(2)	Section E, Schedule 4, Row 22, Column 4.		
(3)	Appendix G-1, Schedule 3 Row 4.	Non-Bypass Demand (TJ)	172,102
		Bypass Demand (TJ)	42,042
		Total Demand (TJ)	214,144

243.1.2 Please update the following table with the most recent data available for 2012 and 2013. Also see the Exhibit A-11, Attachment.

Industrial Rate Class RS22

Year	Forecast (GJ)	Actual (GJ)	Variance from Forecast (GJ)	Variance from Forecast (%)
2004	25,823,891	24,938,882	885,009	3.4%
2005	24,736,568	25,501,393	(764,825)	(3.1)%
2006	25,254,831	24,029,093	1,225,738	4.9%
2007	24,206,537	23,508,062	698,475	2.9%
2008	20,967,980	22,487,971	(1,519,991)	(7.2)%
2009	18,166,574	19,745,960	(1,579,386)	(8.7)%
2010	19,183,662	22,494,945	(3,311,283)	(17.3)%
2011	16,757,447	25,133,369	(8,375,922)	(50.0)%
2012	23,233,216	28,807,092	(5,573,876)	(24.0)%
2013				
Total			**(18,316,061)**	**(11.0)%**

Data: F2014-F2018 RRA, Exhibit B-11, p.150

Response:

Actual annual volumes for 2013 are not available until after the end of the year. Therefore, there is no update available.

243.1.2.1 Based on historical results from 2004 to 2013, please comment whether there should be any concern that a forecast bias exists for RS22.

Response:

Please refer to the response to BCUC IR 2.243.1.2.3.

243.1.2.2 For the period 2004 to 2013, please calculate the total financial cost to rate payers and financial benefits to FEI shareholders resulting from RS22 forecast variances.

Response:

The question as posed is not correct, since there can be no financial cost to ratepayers resulting from variances in demand that arise subsequent to when rates have been approved by the Commission from a revenue requirement or rate design proceeding. Rate Schedule 22 customers have to pay for the services they receive at the Commission approved rates. The revenue variance of actual to forecast is not a generic cost or benefit to all rate payers.

However, if there is some form of revenue or earnings variance sharing, such as there was in the 2004 – 2009 period, variances can lead to rate adjustments in a subsequent year. As can be seen in the table below, during the last PBR period (2004 – 2009), the cumulative variance from the Rate Schedule 22 customers has benefitted ratepayers by $3.8 million in the Earnings Sharing Mechanism rate rider from what otherwise would have been if Rate Schedule 22 actual revenues had equaled forecasted revenues.

The benefit to FEI's investors, both debt and equity, for each year is in the column "Earnings Post Sharing". Dollar amounts in the table below are in thousands.

Rate Schedule 22

	Revenue										
Year	Decision	Actual	Variance	Tax Rate	Income Tax	Earnings Impact Ater Tax Pre-Sharing	ESM 50%	Earnings Post Sharing	Tax Rate Less Surtax Rate	Customers' Share of Surplus Pretax	Cumulative Customers' Share of Surplus
2004	$30,155	$30,326	$ 171	35.62%	$ (61)	$ 110	$ (55)	$ 55	34.50%	$ 84	$ 84
2005	$29,424	$31,066	$ 1,642	34.87%	$ (573)	$ 1,069	$ (535)	$ 535	33.75%	$ 807	$ 891
2006	$30,461	$30,743	$ 282	34.12%	$ (96)	$ 186	$ (93)	$ 93	33.00%	$ 139	$ 1,030
2007	$29,114	$29,388	$ 274	33.00%	$ (90)	$ 184	$ (92)	$ 92	33.00%	$ 137	$ 1,167
2008	$26,321	$30,081	$ 3,760	31.50%	$(1,184)	$ 2,576	$(1,288)	$ 1,288	31.50%	$ 1,880	$ 3,047
2009	$25,674	$27,153	$ 1,479	30.00%	$ (444)	$ 1,035	$ (518)	$ 518	30.00%	$ 740	$ 3,786
2010	$26,457	$28,932	$ 2,475	28.50%	$ (705)	$ 1,770	N / A	$ 1,770	N / A	N / A	
2011	$26,748	$29,218	$ 2,470	26.50%	$ (655)	$ 1,815	N / A	$ 1,815	N / A	N / A	
2012	$30,733	$33,697	$ 2,964	25.00%	$ (741)	$ 2,223	N / A	$ 2,223	N / A	N / A	

Most of the Rate Schedule 22 customers located in the Lower Mainland are 100 percent interruptible for which revenue variances are directionally related to variances in interruptible volumes. Negative volume variances generate negative revenue variances and vice versa. However, the Rate Schedule 22 volumes (included in response to BCUC IR 2.243.1.2) and revenues in the above table are comprised of all of the following Rate Schedules: 22, 22A, 22B and bypass customers.

Rate Schedules 22A, 22B and bypass customers have fixed firm revenues from demand charges that do not vary with volumes. These types of customers will not have a proportional relationship between volume and revenue variances, where volume variances may have little to no effect on revenue.

Therefore, in aggregate for all Rate Schedule 22 customers, it does not necessarily follow that volume variances and revenue variances will directionally have the same sign. This is evident from the table above where, in 2004, 2006 and 2007 the revenues received were still slightly higher than forecast even though the volumes, as shown in the response to BCUC IR 2.243.1.2, were lower than forecast.

FEI has not included data for 2013 as there are no actuals available to compare the Decision amount against.

243.1.2.3 Does FEI have any recommendations that could potentially lead to more accurate forecasts for Rate Class RS22?

Response:

No, not at this time.

FEI provides the tools for industrial customers to upload their own forecasts. FEI does not do any forecasting for RS22 customers or make any adjustments to forecasts that are submitted to it. As a result, any improvement in forecast accuracy needs to come from Rate Schedule 22 customers.

The industrial survey used to develop the forecasts in this Application used the latest version of FEI's industrial survey tool. This tool is web based and allows each customer to easily review both their historic consumption levels as well as the survey data they sent FEI the previous year. Once the customer's response is complete they can download both their actual consumption and forecast values in electronic format.

At this time the Company believes there are no additional improvements that could be added to the survey tool to allow our Rate Schedule 22 customers to provide a better forecast.

244.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-15, Evidentiary Update, Appendix G-2, Forecast Schedule 6, Line 15

Order G-88-13

Rate 16 Volume Forecast

In Appendix G-2, Schedule 16 of the Evidentiary Update, FEI has reduced previously forecasted energy demand for Schedule 16 customers by approximately 73 percent, from 1,341.3 TJ to 356.0 TJ. (Exhibit B-15, Appendix G-2, Schedule 6, Line 15)

244.1 Please confirm that this reduction is a consequence of Order G-88-13.

Response:

Confirmed. FEI received indications from potential customers that were contemplating switching their fleets from diesel to LNG that the determinations in Order G-88-13 caused them to reduce or abandon their plans to switch fuels.

As stated in Appendix H on page 9 from line 30 to line 33 of FEI's Evidentiary Update, filed on July 16, 2013, "The 53% increase in the delivery charge has resulted in a number of potential and prospective customers who were considering contracting under Rate Schedule 16 to either delay adoption of LNG, cancel adoption plans altogether or to significantly reduce vehicle additions from initial forecasts."

Further, in Appendix H on page 10 from line 14 to 16 of the Evidentiary Update, "Overall, the price increase and regulatory uncertainty with respect to rates and charges has affected market confidence in LNG supply, which is expected to limit the market potential of LNG adoption as a transportation fuel."

A combination of these two resulted in FEI lowering the forecast of LNG adoption as a transport fuel.

244.1.1 Please provide details of how the revised forecast was determined.

Response:

For clarity the energy demand referenced in the preamble to this question for Rate Schedule 16 customers is only for 2014. Further, the correct reference for the original forecast amount should be 1,371.3 TJ instead of 1,341.3 TJ, which equates to a reduction in the revised forecast of about 74% for 2014.

The price increase in the delivery charge as a result of BCUC Order G-88-13 combined with regulatory uncertainty has caused fleet operators to either defer their decision on the adoption of LNG fuel or cancel plans altogether, which caused a reduction in 2014. Several applicants who were awarded under the 2012 Vehicle Incentive Program decided not to proceed, since LNG was either no longer sufficiently economically attractive for them or there was uncertainty with respect to the costs of adopting LNG as a fuel choice for their fleets.

In addition, FEI also received feedback from potential customers who decided not to move forward due to the rate impact. Based on the feedback, FEI reduced the number of expected class 8 tractors that will move forward with their award under the Vehicle Incentive Program in 2013 to 60 vehicles. Of those 60 vehicles, and based on the best information from the applicants at that time, FEI assumed that 20% of the vehicles (12 vehicles) would be operational in 2014 and the remaining 80% (48 vehicles) would be operational in 2015.

There is generally a delay in taking volumes from the time an applicant signs the contribution agreement due to the amount of time it takes to order trucks and make arrangements for fueling. FEI plans to have at least one incentive call every year and for the years 2014 through 2016. FEI expects to have 60, 60, and 30 vehicles committed to LNG respectively as a result of these incentive calls. FEI has assumed 30% of the vehicles that commit in 2014 will be operational in 2015 and the balance will be operational in 2016. For the 2015 incentive call, FEI has assumed 50% of customers will be operational in 2016 as the market matures and fueling stations are constructed. Lastly, FEI assumes that 100% of the customers from the 2016 incentive call will be in operation in 2017. FEI will update these forecasts each year as part of the Annual Review process.

The tables below summarize and compare FEI's forecasts of vehicle additions, for the period 2014 to 2017, between what was originally filed in the Application on June 10, 2013, and the Evidentiary Update, which was filed on July 16, 2013.

Table 1: Comparison of Vehicle Addition Forecasts

Evidentiary Update

Vehicle Additions (FEI)	2014F	2015F	2016F	2017F	Total for Period	% Change from RRA
Vocational trucks	33	103	84	68	324	-16%
Buses	-	47	10	4	63	-35%
Class 8 tractors	12	66	72	60	241	-48%
Marine	-	1	1	1	3	0%
Total NGT Fleet	**45**	**217**	**167**	**133**	**631**	**-33%**

Initial 2014-2018 RRA Forecast (June 10, 2013)

Vehicle Additions (FEI)	2014F	2015F	2016F	2017F	Total for Period
Vocational trucks	153	63	56	56	386
Buses	36	21	19	19	97
Class 8 tractors	202	72	77	67	460
Marine	0	1	1	1	3
Total NGT Fleet	**391**	**157**	**153**	**143**	**946**

In the Evidentiary Update, FEI forecasted that class 8 tractor adoption will be 48% lower than what was originally filed in the Application over the remainder of the prescribed undertaking period (460 class 8 tractors compared to 241 class 8 tractors).

FEI then applied average annual consumption by vehicle type to the above forecast of vehicle additions to derive the annual addition of load to FEI's system. The following average annual consumption figures were applied to each vehicle type to derive average annual consumption by vehicle type:

- Vocational Trucks: 1,000 GJ per year
- Buses: 1,000 GJ per year
- Class 8 Tractor: 4,500 GJ per year
- Marine: 150,000 GJ per year

The forecast of average annual consumption by vehicle type, as summarized above, is based on FEI's experience with its existing CNG customers (BFI and Waste Management for vocational trucks and Kelowna School District #23 for buses) and LNG customer (Vedder Transport).

As a result, the table below summarizes the forecast of load additions to FEI's system based on the original forecast of vehicle additions and the revised forecast of vehicle additions. Note that the figures presented are cumulative; therefore the figures for 2014F are the sum of consumptions from 2010 to 2013 inclusive for each vehicle type.

1 **Table 2: Comparison of Consumption Forecasts**

Evidentiary Update

Load Addition (Cumulative)	2014F	2015F	2016F	2017F	% Change from RRA
Vocational trucks (CNG)	142,000	245,000	329,000	397,000	-27%
Buses (CNG)	13,000	60,400	70,400	74,400	-43%
Class 8 tractors (LNG)	356,000	653,000	977,000	1,247,000	-44%
Marine (LNG)	0	150,000	300,000	450,000	0%
Total NGT Fleet	**511,000**	**1,108,400**	**1,676,400**	**2,168,400**	**-35%**

Initial 2014-2018 RRA Forecast (June 10, 2013)

Load Addition (Cumulative)	2014F	2015F	2016F	2017F
Vocational trucks	369,680	432,372	488,695	544,276
Buses	71,426	92,366	111,178	129,743
Class 8 tractors	1,371,319	1,658,349	1,967,326	2,235,744
Marine	0	150,000	250,000	450,000
Total NGT Fleet	**1,812,425**	**2,333,087**	**2,817,199**	**3,359,763**

2

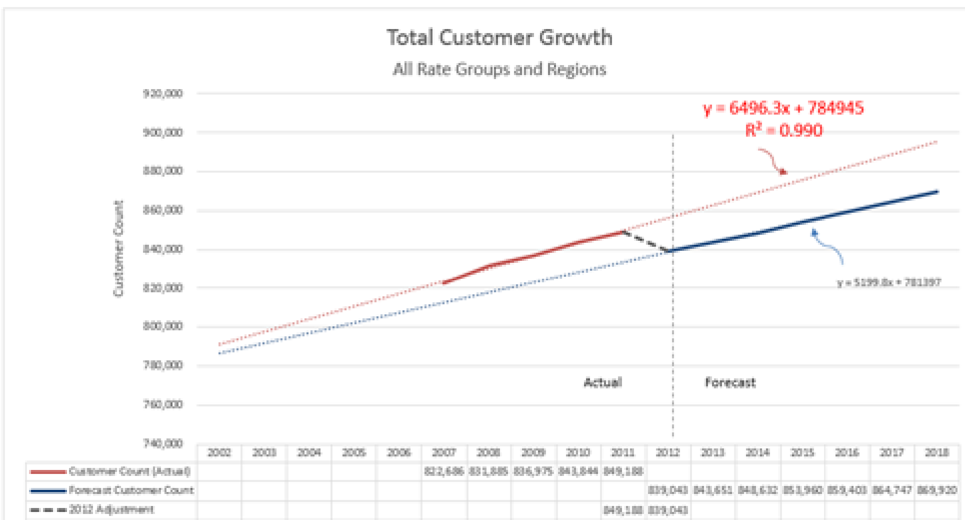
3

245.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 1.4.4, pp. 102-105; Exhibit A-11, Attachment

Customer Additions

The following graph compares the trend in the total number of customers between 2007 and 2011 to the forecasted trend in the current test period. What stands out is that prior to the 2012 CIS adjustment, the trend was essentially perfectly linear (R2=0.99) with an average annual increase of 6,496 customers. After the CIS adjustment, the trend remained linear, but at only 5,199 customer additions per year. During the test period, the difference in trend will result in approximately 19,038 fewer customers than would have otherwise been anticipated. Also see the Exhibit A-11, Attachment.



Data source: Exhibit B-4, FEI Data Model

245.1 Please confirm that the forecasted decrease in the rate of customer additions is not attributable to the one-time CIS adjustment that took place in 2012.

Response:

Confirmed that the forecasted decrease in the rate of customer additions is not attributable to the one-time adjustment that took place in 2012.

However, FEI does not agree with the analysis presented in the preamble to this question. FEI's understanding of the analysis described in this question is a time series regression model based on total customer count. Residential customer additions form a very small portion of the total customer count (about 0.6%) and year over year variation in the total due to new customer additions is minimal. As a result the fit of the model will always be good given the magnitude of additions relative to the total count. Therefore, the high R^2 value presented in the question is not an indication of the ability of the model to forecast customer additions.

The annual new customer additions do not depend on the total count of customers from prior years. Rather, as established by FEI, new additions are tied to external factors such as new housing starts. As a result, the residential additions methodology used by FEI for a decade is based on the CBOC housing starts forecast. Please refer to Figure C1-7 of the Application for the correlation analysis.

246.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Section C1, pp. 85-116; Exhibit Update B-1-3; Exhibit B-15

Impact of Evidentiary Updates on Section C1 of the Application

FEI filed Evidentiary Update B-1-3 on July 16, 2013, and Evidentiary Update B-15 on September 6, 2013. Both of these updates have impact the demand forecast data that FEI has summarized in the Application (Exhibit B-1, Section C1, pp. 85-116).

246.1 Please provide a restated version of Section C1 of the Application that includes updated tabular and graphical data found on pp. 85-116 inclusive.

Response:

FEI provided an updated Section C1 with its evidentiary update filed July 16, 2013 (Exhibit B-1-3, pages 110-114, 117 and 118). Exhibit B-1-3 included an update to the Natural Gas for Transportation (NGT) forecast volume and resulting changes to FEI's financial schedules.

FEI did not make any changes to the NGT forecast volume in its evidentiary update filed September 6, 2013, Exhibit B-15; consequentially, no changes to section C1 were required. FEI did, however, revise the approvals sought related to NGT on page 10 of Exhibit B-15. The update to the approvals sought was an outcome of responses to the first round of BCUC IRs where it was noted that FEI must update the approvals sought to include approvals for separate classes of service for its NGT classes.

247.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 1.4.3, pp. 99-102; Exhibit A-11, Attachment

Residential and Commercial Use Rates (UPC)

Commission staff could not reproduce the exact UPC data reported by FEI in Figures C1-11 to C1-14. It is believed that the results should be identical. Commission staff have ruled out rounding errors as an explanation for the difference. For example, the following table compares the weighted average UPC calculated by FEI to the weighted average UPC calculated by Commission staff for the Residential rate class.

Residential (RS1) UPC Weighted Average - All Regions				
Year	FEI Calculated UPC Weighted Average[1] (GJ/year)	BCUC Calculated UPC Weighted Average[2] (GJ/year)	UPC Difference (GJ/year)	% Difference
2002		106.8		
2003		105.8		
2004	102.6	103.8	-1.2	-1.1%
2005	97.2	98.2	-1.0	-1.0%
2006	96.8	97.8	-1.0	-1.0%
2007	96.0	97.1	-1.1	-1.1%
2008	92.5	93.8	-1.3	-1.4%
2009	93.3	93.9	-0.6	-0.6%
2010	92.6	93.9	-1.3	-1.4%
2011	90.4	91.6	-1.2	-1.3%
2012	92.2	93.2	-1.0	-1.1%
2013	91.4	92.5	-1.1	-1.2%
2014	90.7	91.7	-1.0	-1.1%
2015	90.0	91.0	-1.0	-1.1%
2016	89.4	90.3	-0.9	-1.0%
2017	88.7	89.6	-0.9	-1.0%
2018	88.0	88.9	-0.9	-1.0%

Note 1: source of data from Exhibit B-1, Section C, Figure C1-11, p.100
Note 2: Weighted average calculated from data contained in Exhibit B-4, Forecasting Model

247.1 Please provide an updated version of the table that includes revised data from Exhibit B-15, Evidentiary Update. See the Exhibit A-11, Attachment.

Response:

The FIS model performs calculations at the monthly level and then aggregates the results. To derive the annual UPC, the monthly UPC values for each region and rate are computed first.

Commission Staff could not reproduce the exact UPC data reported by FEI in figures C1-11 and C1-14 because they did not have all required information. The following tables demonstrate how FEI produced the annual UPC's in figures C1-11 and C1-14.

Monthly Use Per Customer 2004-2018F

Rate 1	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014F	2015F	2016F	2017F	2018F
January	15.3	15.1	15.8	14.6	14.0	14.0	14.6	13.9	14.1	14.3	14.2	14.1	14.0	13.9	13.8
February	13.7	12.1	12.3	12.8	12.6	12.0	12.1	11.6	11.9	11.8	11.7	11.6	11.5	11.4	11.3
March	11.7	11.6	11.3	11.7	10.7	10.7	10.9	11.0	10.2	10.9	10.8	10.7	10.6	10.6	10.5
April	7.3	8.0	7.4	7.7	7.3	7.4	7.5	7.2	7.5	7.3	7.2	7.2	7.1	7.0	7.0
May	4.8	4.9	4.8	4.7	4.8	5.0	4.5	4.4	4.7	4.6	4.5	4.5	4.5	4.4	4.4
June	3.6	3.3	3.4	3.5	3.7	3.3	3.0	2.7	3.1	3.3	3.2	3.2	3.2	3.2	3.1
July	3.5	2.9	3.2	2.8	2.9	3.2	2.6	2.1	2.4	2.8	2.8	2.8	2.8	2.8	2.7
August	2.9	2.7	2.5	2.4	2.7	2.6	2.6	2.5	2.7	2.4	2.4	2.4	2.3	2.3	2.3
September	3.7	3.7	3.5	3.7	3.7	3.4	3.2	3.5	3.0	3.4	3.4	3.4	3.4	3.3	3.3
October	7.8	7.5	7.1	7.5	7.2	7.0	6.8	6.8	6.7	7.0	6.9	6.9	6.8	6.7	6.7
November	11.7	10.9	10.8	11.0	10.9	10.8	10.6	10.5	11.3	10.3	10.2	10.2	10.1	10.0	9.9
December	16.6	14.6	14.6	13.7	12.0	13.9	14.3	14.2	14.5	13.4	13.3	13.2	13.1	13.0	12.9
Annual Rate 1 UPC	102.6	97.2	96.8	96.0	92.5	93.3	92.6	90.4	92.2	91.4	90.7	90.0	89.4	88.7	88.0

Rate 2	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014F	2015F	2016F	2017F	2018F
January	48.8	48.4	54.1	49.0	43.1	47.0	49.1	49.7	52.4	52.1	52.2	52.3	52.4	52.5	52.6
February	42.7	38.5	39.5	44.4	46.7	44.4	40.1	41.3	44.6	45.8	45.8	46.0	46.1	46.1	46.2
March	36.2	36.2	37.5	40.5	39.8	36.9	37.0	40.6	37.9	41.2	41.3	41.4	41.5	41.6	41.6
April	22.5	24.7	23.1	25.3	25.6	26.4	25.0	23.9	26.8	26.0	26.1	26.1	26.1	26.2	26.3
May	15.3	16.6	17.7	16.1	18.3	17.7	15.5	15.1	16.1	18.3	18.4	18.4	18.4	18.5	18.5
June	10.3	10.0	11.4	12.6	12.5	11.9	10.1	10.0	10.9	12.7	12.7	12.7	12.7	12.8	12.7
July	11.5	7.5	9.7	8.9	10.0	11.0	8.7	7.6	8.8	10.0	10.0	10.0	10.0	10.1	10.1
August	8.7	9.8	7.5	7.9	9.0	8.9	8.8	8.5	10.0	8.7	8.7	8.7	8.7	8.7	8.7
September	10.9	10.8	10.9	11.2	12.3	10.3	11.2	12.1	11.1	12.0	12.0	12.1	12.1	12.1	12.1
October	21.8	21.9	20.3	22.3	21.6	23.7	21.4	21.3	24.5	22.7	22.7	22.7	22.8	22.8	22.9
November	35.6	34.0	32.5	34.2	35.3	35.3	34.4	35.1	40.2	36.1	36.1	36.2	36.3	36.4	36.4
December	49.6	47.4	50.2	44.2	38.0	47.0	49.9	48.6	54.2	47.4	47.5	47.7	47.7	47.8	47.9
Annual Rate 2 UPC	313.8	305.8	314.3	316.5	312.2	320.6	311.3	313.7	337.6	333.0	333.6	334.3	334.9	335.6	336.2

Rate 23	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014F	2015F	2016F	2017F	2018F
January	691	676	674	677	687	706	667	717	729	775	797	820	844	869	895
February	629	542	563	591	577	551	570	593	643	661	680	700	721	742	764
March	607	584	564	591	549	583	562	659	609	651	669	689	709	730	752
April	444	437	406	472	397	445	424	456	474	487	502	517	532	548	564
May	294	301	299	246	298	284	277	321	315	322	332	341	351	362	373
June	234	184	190	180	186	200	190	203	219	211	217	223	229	236	243
July	198	144	144	148	143	170	138	159	161	164	169	174	178	183	188
August	172	145	132	142	132	160	105	177	175	154	159	163	168	173	177
September	212	193	192	199	182	231	261	237	222	217	223	229	236	242	249
October	455	381	346	376	348	391	371	401	414	407	418	431	443	456	469
November	501	496	542	521	513	537	574	548	608	599	616	634	652	671	690
December	675	631	633	635	687	628	711	667	668	743	764	786	809	832	856
Annual Rate 23 UPC	5,113	4,714	4,686	4,778	4,698	4,886	4,850	5,138	5,238	5,392	5,546	5,707	5,873	6,044	6,222

Rate 3	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014F	2015F	2016F	2017F	2018F
January	541	469	537	483	329	441	445	451	491	499	501	504	508	511	514
February	442	388	378	391	399	415	410	454	433	431	433	436	439	442	445
March	393	381	386	484	508	381	390	402	403	507	511	514	517	521	525
April	279	297	292	324	318	294	302	347	315	344	347	349	351	354	356
May	206	211	222	233	254	214	208	232	219	261	263	265	267	269	271
June	158	158	168	177	184	142	155	133	156	195	197	198	200	201	202
July	130	135	138	127	137	162	132	116	126	148	149	150	151	152	153
August	117	129	110	113	125	118	124	130	140	128	129	130	131	132	133
September	159	150	144	143	173	150	136	167	153	169	171	172	173	174	175
October	262	269	202	241	259	249	247	242	278	259	260	262	264	266	267
November	354	346	314	326	344	347	349	356	383	363	365	368	370	373	375
December	458	455	423	384	389	459	470	456	468	441	444	447	450	453	456
Annual Rate 3 UPC	3,501	3,388	3,314	3,426	3,420	3,372	3,370	3,484	3,566	3,746	3,769	3,795	3,821	3,847	3,873

Working Example to show how Monthly UPC's are derived
FEI: 2014F UPC

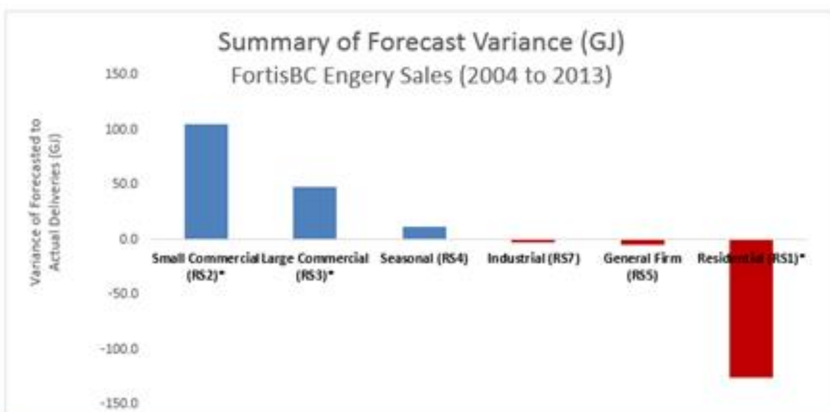
	2014F		
RATE1	Energy	Account	Monthly UPC
January	10,841,935	764,637	14.2
February	8,943,405	764,862	11.7
March	8,267,461	765,105	10.8
April	5,520,876	765,083	7.2
May	3,460,982	765,154	4.5
June	2,485,739	765,316	3.2
July	2,161,632	765,221	2.8
August	1,823,104	765,451	2.4
September	2,608,739	766,039	3.4
October	5,294,815	766,959	6.9
November	7,868,344	767,653	10.2
December	10,234,935	768,622	13.3
Annual Rate 1 UPC			90.7

247.1.1 Please reconcile the differences in the UPC calculation between FEI and Commission staff.

Response:

Please refer to the response to BCUC IR 2.247.1.

247.2 Please provide a tabular and graphical summary similar to the one provided below that illustrates the variance between forecasted and actual sales deliveries (GJ) segmented by rate class between 2004 and 2013. The following graph has been provided for illustrative purposes only. See the Exhibit A-11, Attachment.

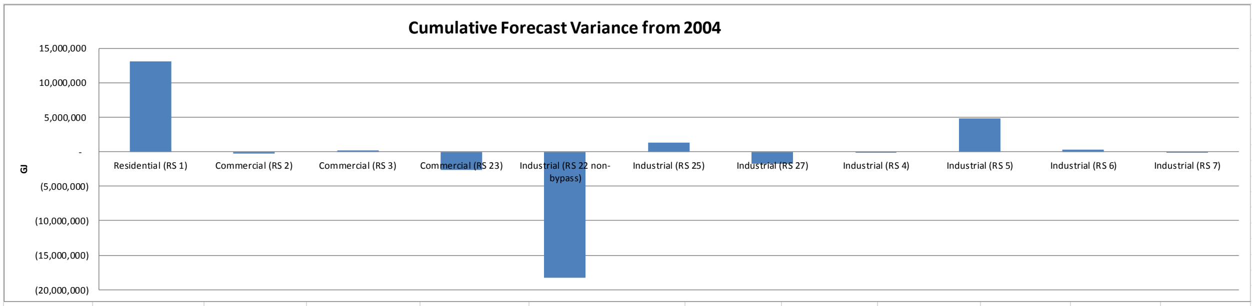


	Small Commercial (RS2)*	Large Commercial (RS3)*	Seasonal (RS4)	Industrial (RS7)	General Firm (RS5)	Residential (RS1)*
2004	730.1	482.3	4.6	2.4	63.8	1,926.5
2005	-665.4	-533.9	-4.8	-2.4	-68.2	-2,057.8
2006	-484.5	-324.4	-3.2	-1.7	-43.1	-1,344.8
2007	466.9	376.7	3.2	1.6	41.6	1,289.7
2008	-246.0	-169.3	-1.6	-0.8	-22.7	-600.8
2009	285.7	266.8	9.6	0.8	22.6	648.5
2010	-1,143.7	-861.9	-8.2	-4.3	-108.6	-3,335.5
2011	1,157.2	849.9	11.7	4.2	114.1	3,364.5
2012	-895.5	-687.5	-6.3	-5.4	-87.8	-2,493.6
2013	900.3	649.6	6.5	3.1	83.5	2,477.9
Total	105.1	48.4	11.5	-2.5	-4.8	-125.4

* Normalized

Response:

The tabular and graphical summary of forecast variance is provided below. Forecast variance is the forecast minus the actual for a given year on a normalized basis. The forecast variance for 2013 is not available as the year end actuals are not available at this time.

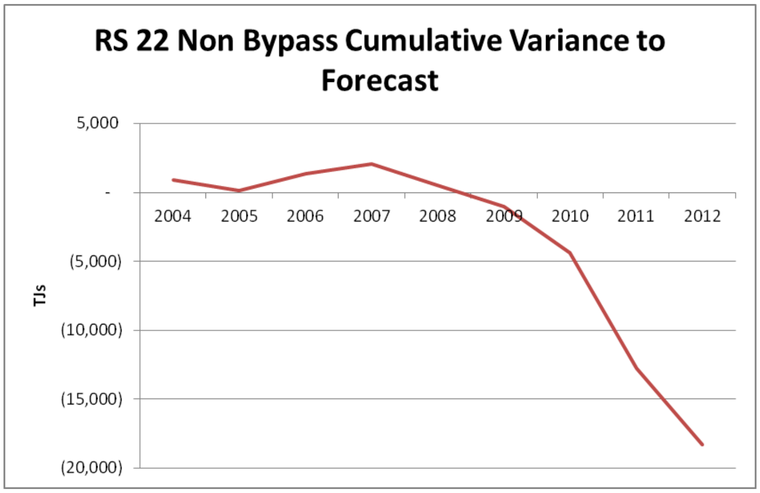


	Residential (RS 1)	Commercial (RS 2)	Commercial (RS 3)	Commercial (RS 23)	Industrial (RS 22 non-bypass)	Industrial (RS 25)	Industrial (RS 27)	Industrial (RS 4)	Industrial (RS 5)	Industrial (RS 6)	Industrial (RS 7)
2004	1,217,807	(1,014,884)	300,835	(412,021)	885,009	(1,941,132)	1,113,037	114,378	1,522,044	(19,091)	54,398
2005	4,287,901	377,343	1,208,200	(101,154)	(764,825)	(791,444)	(259,199)	(5,704)	485,982	141,702	15,006
2006	2,937,373	(609,102)	637,089	(330,317)	1,225,738	(165,422)	524,028	(58,436)	373,933	80,260	3,360
2007	2,927,163	(373,436)	(561,270)	(254,099)	698,475	686,825	71,185	(1,600)	325,291	49,053	4,757
2008	3,182,288	627,694	(836,646)	406,316	(1,519,991)	533,167	(128,146)	(29,726)	262,370	6,590	1,372
2009	2,298,636	95,200	(1,045,936)	391,379	(1,579,386)	2,179,664	(245,741)	(5,136)	562,545	17,113	(85,675)
2010	(2,211,863)	754,928	424,781	(495,758)	(3,311,284)	374,512	(798,210)	(555)	634,833	43,354	3,006
2011	(1,741,584)	720,402	290,981	(1,194,777)	(8,375,922)	(134,108)	(1,456,694)	(38,736)	526,794	34,418	(98,103)
2012	136,819	(880,137)	(274,728)	(650,642)	(5,573,876)	585,779	(573,976)	16,264	91,957	(5,776)	(75,845)
Cumulative Total	**13,034,541**	**(301,992)**	**143,306**	**(2,641,073)**	**(18,316,061)**	**1,327,842**	**(1,753,716)**	**(9,251)**	**4,785,750**	**347,623**	**(177,724)**

For Residential and Commercial customers, FEI's RSAM mechanism defers any variance in UPC, and consequently revenue, between forecast and actual. The revenue variance accumulates in the RSAM deferral account which is then given back to or collected from customers in subsequent years through the RSAM Rider.

The Company conducts an annual survey of industrial customers. The annual survey is delivered to each customer via a web application. The web site presents all the data available for each customer including their historic consumption and the forecast they provided in the previous survey. It is the responsibility of each industrial customer to complete the survey using a method of their choice. Any variance in Rate Schedule 22 volumes is a result of the forecasting performance from this group of customers and is not influenced by FEI.

The following chart shows the cumulative variance for Rate Schedule 22 (non bypass). The variance started to accumulate significantly following 2010. This correlates well with declining gas prices and it is likely that customers in this rate schedule consumed more than forecast as fuel prices dropped in comparison to their alternative.



247.2.1 Please comment on any significant trends in the positive or negative variances that in FEI's opinion may be indicative of a forecast bias to over or under forecast energy demand.

Response:

Please refer to the response to BCUC IR 2.247.2.

247.3 Please repeat the previous question for Transportation Services rate classes.

Response:

Please refer to the response to BCUC IR 2.247.2.

248.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 1.3.2, pp. 92-94

Residential and Commercial Average UPC Forecast Methodology

FEI states in the Application: "Since the Company's EEC programs have significant levels of funding, it is reasonable to assume that these programs will impact average UPC over the forecast period. In 2011 and 2012 the impact was estimated to be a 0.09 and 0.26 GJ decline respectively in residential average UPC. In 2013 the impact is forecast to be a 0.64 GJ decline in residential average UPC. While EEC savings are not a direct input into the forecast model, their effect is implicit in the declining UPC trends." (Exhibit B-1, p. 94)

248.1 As it relates to Residential and Commercial rate classes, FEI states that "EEC savings are not a direct input into the forecast model." However, the impact of EEC appears to be evident in the declining UPC trends, which FEI takes into consideration when formulating demand forecasts. Please confirm, or explain otherwise, that energy demand forecasts for the current test period are "after" EEC savings.

<u>Response:</u>

The energy demand forecast for the current test period are "after" EEC savings in the sense that the savings from the past EEC programs are embedded in the historical data used to prepare the forecast. The methodology to forecast the average use rate for residential and commercial rate classes is based on trending, which looks for a significant trend in historical consumption data. Residential and commercial consumption is subject to many factors, including the weather. To remove the weather impact the data is normalized. Once normalized, all other factors, including EEC savings, are assumed to be embedded in the data and their impacts are implicit in the resulting trend.

However, as noted in the IR, EEC savings are not a direct input into the forecast model. For example, FEI's forecast methodology does not include estimating the EEC savings in future years and then incorporating that as an input into the forecast.

248.1.1 If "after" EEC savings, please provide a tabular summary that indicates the annual EEC savings that have been applied to Residential RS1 and Commercial rate class RS2 and RS3 in the current test period.

Response:

Please refer to the response to BCUC IR 2.248.1.

248.1.2 For all rate classes other than RS1, RS2 and RS3, please provide a summary that clearly shows how EEC savings have been taken into consideration in developing FEI's energy demand forecasts for the current test period. Please segment by rate class and omit rates classes that are not impacted by EEC programs.

Response:

Please refer to the response to BCUC IR 2.248.1.

248.2 Segmented by rate class, please provide FEI's estimate for elasticity of demand. Please also indicate whether FEI includes the elasticity of demand as an input factor in forecasting energy demand and the rational for including or omitting it as an input into forecasts.

Response:

FEI's analysis indicates the price elasticity of demand coefficient for FEI residential customers is approximately -0.22 and for FEI commercial customers is approximately -0.19.

Although it is recognized that customers do change their short-term behavior when faced with sudden and significant commodity cost increases, long-term changes in use per customer rates for mature gas utilities are more a function of advances in heating technology and home construction techniques, both of which improve on an ongoing basis regardless of natural gas costs. Sudden increases in natural gas prices may accelerate the decision to purchase more efficient equipment, but once that purchase has been made the impact on consumption (related to the new equipment) is permanent regardless of whether prices later moderate. It is for this reason, and also the fact that it is difficult to isolate demand responses to only price, that FEI does not use price elasticity as a forecast input. Price elasticity is, however, captured because it is implicit in the historic consumption data used to develop future UPC forecasts.

FORECASTS FOR THE PBR PERIOD – OTHER REVENUE

FORECASTS FOR THE PBR PERIOD – LABOUR

249.0 Reference: LABOUR

Exhibit B-1-1, Appendix B2, p. 1

Full Time Equivalents (FTEs)

249.1 Using the format of the table below, show the growth in FTE's from 2007- 2013. Please indicate the years of the previous PBR regime, the Earning Sharing period from that PBR, and full Cost of Service period.

	2005	2006	2007	2008	2009	2010	2011	2012	2013
Change in FTE's		-30	25	40	41	76	186	144	
% Change		-2.8%	2.4%	3.7%	3.6%	6.5%	15.0%	10.1%	
Avg. Custs / FTE	727	758	753	735	715	676	592	531	

Response:

This response addresses BCUC IRs 2.249.1 and 2.249.2.

Two FTE tables are provided below. The first table shows the growth in FEI Total FTEs from 2007 – 2013. The 2007 – 2012 columns represent average FTE while the 2013 column represents actual FTE as of September 30, 2013. The FTE growth in 2013 is about 0.5% which is consistent with what was discussed in response to BCUC IR 1.77.1 and others, that the FTE levels for 2013 are expected to be at a similar level to 2012 on a total company basis.

The increase in FTEs after 2010 is due to the introduction of FEI's Customer Service team in 2011. The second table below shows Customer Service FTEs from 2007 to 2013 in a separate row.

The increases in 2010 and 2011 FTEs excluding Customer Service can be attributed to Codes and Regulations, Demographics, Service Standards and Reliability, IT support, and various initiatives such as EEC. For further details, refer to the response in BCUC IR 2.255.3 for change in NET O&M FTE for Distribution and Operations Engineering and PM and BCUC IR 2.254.3 for the reasons for the change in Net O&M FTE for ES&ER and ES&RD.

FEI Average Total Full time Equivalent

	2007	2008	2009	2010	2011	2012	2013
Average Full Time Equivalent (FTE)	1,084	1,124	1,165	1,241	1,427	1,571	1,579
Change in FTEs	25	40	40	76	186	144	8
% Change	2.4%	3.7%	3.6%	6.6%	15.0%	10.1%	0.5%
Avg Custs/FTE [1]	739	721	702	664	582	531	532

FEI Average Full time Equivalent without Customer Service

	2007	2008	2009	2010	2011	2012	2013
Average Full Time Equivalent (FTE)	1,084	1,124	1,165	1,241	1,427	1,571	1,579
Less: Customer Service Avg FTE	23	22	25	32	133	302	289
Avg FTE without Customer Service	1,061	1,102	1,140	1,209	1,294	1,269	1,291
Change in FTEs without Customer Service	21	41	38	69	86	-26	22
% Change without Customer Service	2.0%	3.8%	3.4%	6.0%	7.1%	-2.0%	1.7%
Avg Custs/FTE without Customer Service [1]	755	736	718	682	641	658	651

1 The average customers for 2007 - 2011 have been reduced by 14,892 to make it comparable to 2012 and 2013. The 14,892 represents the one time SAP customer count adjustment as discussed in Appendix E4 of the Application.

Of the years in this table, FEI was under PBR with Earnings Sharing from 2007 – 2009 and under Cost of Service from 2010 – 2013.

249.2 Please revise the above table to remove and put in a separate row the Customer Service FTE's.

Response:

Please refer to the response to BCUC IR 2.249.1.

249.3 Please provide a list of all job postings (filled or active) for the years 2011, 2012 and 2013 including the following information. Include the requested information in a fully functional spreadsheet.

	Job Title	Department / Group	Top 2 Projects / Initiatives supported	Compensation Range (A - <$50k B- $50k - $75k C - $75k - $100k D - $100k - $125k E - $125k - $150k F - $>150k	No. of Positions and Year filled
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
...					

Response:

Please refer to Attachment 249.3 for a spreadsheet showing all job postings for FEI for the years 2011, 2012, and 2013.

The data required to complete the attached spreadsheet was extracted by reviewing over 1,700 job postings. Information regarding the top two projects/initiatives supported is specific to the individual employee and is not contained in the job posting or job description. Therefore, this information has not been included, as it is not available.

Regarding compensation ranges, please note the following:

- Rates for IBEW positions are shown as hourly rates
- Charts showing the salary/band ranges for COPE, COPE Customer Service, and M&E positions in 2011, 2012 and 2013 are included in the spreadsheets as part of Attachment 249.3.

249.4 Please provide a list of all job retirements from FEI (including moves to affiliates not included in this PBR) for the years 2011, 2012 and 2013 including the following information. Include the requested information in a fully functional spreadsheet.

	Job Title	Department / Group	Top 2 Projects / Initiatives supported	Compensation Range (A - <$50k B- $50k - $75k C - $75k - $100k D - $100k - $125k E - $125k - $150k F - $>150k	No. of Positions and Year retired
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
...					

Response:

FEI job retirements and moves to affiliates for 2011, 2012 and 2013 year-to-date are listed in Attachment 249.4.

The data required to complete the attached spreadsheet was extracted by reviewing over 1,700 job postings. Information regarding the top two projects/initiatives supported is specific to the individual employee and is not contained in the job posting or job description. Therefore, this information has not been included, as it is not available.

With respect to Attachment 249.4, any dollar amounts shown represent an hourly wage.

With respect to other information shown in the "Compensation Range" column, please refer to Attachment 249.3, provided in the response to BCUC IR 2.249.3 for the M&E and COPE salary/band ranges in effect for positions in 2011, 2012 and 2013.

250.0 FORECASTS FOR THE PBR PERIOD – LABOUR

Exhibit B-1-1, Appendix B2, p. 1;

FEU 2012-13 RRA: Exhibit B-1, Appendix D-4 and Exhibit B-9-1, BCUC 1.46.1;

FTEs – Net O&M by Business Unit

FortisBC Energy Inc.
Mainland - Historic and Forecast FTE by Business Unit

Line no.	Business Unit	2006	2007	2008	2009	2010	Projected 2011	Forecast 2012	Forecast 2013
1	Energy Supply & Resource Development	37	36	36	38	40	45	46	47
2	Facilities	12	13	10	10	13	17	18	18
3	Operations Engineering	111	117	132	142	152	176	191	191
4	Operations Support	131	129	129	124	125	133	139	142
5	Customer Service	19	23	22	25	32	367	325	309
6	Human Resources	77	75	78	93	96	70	71	72
7	Environmental & Safety	8	8	8	10	11	14	14	14
8	Information Technology	44	47	49	54	63	65	74	75
9	Distribution	457	471	490	484	502	571	577	586
10	Energy Solution & External Relations	56	56	58	68	90	110	117	117
11	Finance and Regulatory	61	60	65	67	65	68	69	69
12	Transmission	44	46	44	49	51	55	59	60
13	Corporate	2	2	2	2	2	1	1	1
14									
15	Total FTE	1,059	1,084	1,124	1,165	1,241	1,692	1,701	1,701

(FEU 2012-13 RRA, Exhibit B-1, Appendix D-4)

Appendix B2 **Key Operating Facts**

FEI
Annual Report Statistics
2005-2012

	2005	2006	2007	2008	2009	2010	2011	2012
Headcount								
Average Full Time Equivalent (FTE)	1,089	1,059	1,084	1,124	1,165	1,241	1,427	1,571

(Exhibit B-1-1, Appendix B2)

SUMMARY
Total Employees

FEU	2009 Actual	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Capital	307	320	294	309	362	366	368
Capital/Deferral - Customer Service	0	7	7	7	336	15	13
Deferred - EEC	12	10	16	11	18	19	19
Deferred - Other	3	0	0	0	0	0	0
CMAE - Core Market Admin. Expense	19	21	20	21	22	22	22
NGV & Biomethane - O&M	0	0	0	0	1	1	1
Operating & Maintenance	925	1,053	1,090	1,090	1,082	1,405	1,406
Total	1,266	1,411	1,427	1,438	1,821	1,828	1,829
Dependant Contractors Excluded		23	15	23	3	3	3

Thermal Energy Services employees are not included in the 2012-2013 RRA Table 5.3-14

Operating & Maintenance	925	1053	1090	1090	1082	1405	1406
Customer Service						321	323
Net O&M FTEs	925	1053	1090	1090	1082	1084	1083

(FEU 2012-13 RRA, Exhibit B-9-1, BCUC 1.46.1)

250.1 Please provide an updated table for FEI, similar to that provided in Appendix D-4 in the FEU 2012-13 RRA shown above, of the historic and forecast Total FTE by business unit for 2006 Actual through 2013 Projected. Please identify any specific groups mentioned in this Application that are not included in the FTE numbers presented in the response. This table should provide the Total FTE actual amounts for 2006 through 2012 and the latest projection for 2013. If FEI does not have a current projected Total FTE for 2013, then use the actual FTE as of September 30, 2013 for responding to this IR. Include the requested information in a fully functional spreadsheet.

Response:

Please refer to Attachment 250.1 for the fully functioning electronic spreadsheet. The information reflects the actual average FTEs from 2006 to 2012 and the actual FTEs as of September 30, 2013 in a format similar to that provided in Appendix D-4 in the FEU 2012-2013 RRA.

250.2 Please explain the calculation for the Average FTE for 2011 and 2012 as presented in Appendix B2 of Exhibit B-1-1, including if these numbers are on the same basis as the FTE numbers presented at other locations in the Application. For example, please explain the difference in headcount in Appendix B2 of B-1-1 from the data provided in the FEU 2012-13 RRA, where the Approved Total FTE for FEI in 2011 was 1,311 and the projection was 1,692 which included 671 Capital/Deferred FTE, of which 336 was for the Customer Service project and capital.

Response:

The Average FTE count in Appendix B2 of Exhibit B-1-1 which includes 2011 and 2012 is calculated using the average monthly FTEs of the 12-month calendar period (January to December).

Monthly FTEs include all current (active) full-time regular (FTR), full-time temporary (FTT), part-time regular (PTR) and part-time temporary (PTT) employees at the end of the month. Monthly FTEs are calculated as follows:

- Each full-time employee is counted as 1 FTE if the employee meets the criteria of being an active employee at the end of the month.
- Total part-time hours for the month are calculated and converted into FTEs by dividing by the total annual full time hours, and then multiplying by 12.
- Part-time FTEs are added to the full-time employees counted to obtain the final FTE count.

The employee data provided in the FEU 2012-13 RRA, where the Approved Total FTE for FEI in 2011 was 1,311 and the projection was 1,692 which included 671 Capital/Deferred FTE (of which 336 was for the Customer Service project and capital) represents FTEs as at the end of December, 2011. Any forward looking FTE or employee information provided in the FEU 2012-13 Application would have pertained to the FTEs as at end of calendar year, whereas the historic information was referenced as average FTEs.

250.3 Please provide a series of tables, similar to the table from BCUC 1.46.1 of Exhibit B-9-1 from the FEU 2012-13 RRA, for FEI in total and for each Business Unit from 2006 Actual through 2013 Projected, which separates the Total FTE into the following categories:

(i) Capital, Deferred – EEC,

(ii) Deferred – GGRR,

(iii) Deferred – Other (specify),

(iv) Allocated to CMAE,
(v) Allocated to FAES,
(vi) Allocated to NGT,
(vii) Allocated to Biomethane,
(viii) Allocated to Other (specify), and
(ix) Net O&M FTE.

In many instances, it is anticipated the specific FEI Non-O&M allocation is related to a single Business Unit, such as for Core Market Administration Expense (CMAE). These tables will provide a view of the FTE to correspond to the work described in the Application. Please provide all of the tables resulting from this IR as working, unprotected Excel spreadsheets. If FEI does not have a current projected FTE for 2013, then use the actual FTE as of September 30, 2013 for responding to this IR.

Response:

Please refer to Attachment 250.3 in working Excel spreadsheet. The file is for FEI which includes a table for total FTE by Category and a separate table for each Business Unit by Category from 2006 Actual through 2013. The tables reflect the actual average full time equivalent employees for 2006 to 2012 and actual FTE as of September 30, 2013.

FEI has included as separate lines those employees that work on EEC and CMAE, and has made an estimate of the proportion of time employees devote to capital activities. Employees that work exclusively for TES are not included in the table but are included in a row at the bottom of the table.

FEI has not separated in the attachment those employees that charge part of their time to TES, NGT (GGRR or non-GGRR) and Biomethane/RNG. This is because these FTEs represent portions of employees' time that can vary from year to year. FEI provides the following information to assist in understanding the level of FTE devoted to these activities but included in the O&M FTE figures in the attachment.

As discussed in the BCUC 2.346 series regarding fueling station activities, FEI had estimated 2.15 equivalent employees are devoted to these activities. Additional staffing will vary to support administration of incentives, maintenance, facilities development and safety training for the GGRR, and will be managed within the approved level of funds.

FEI has the equivalent of one FTE managing the Biomethane Program.

Finally, in relation to TES activities, FEI recovers an overhead charge from the TESDA which was initially based on time allocated for a number of positions as described in the response to BCUC IR 2.353.1. No FTE equivalent was calculated to support the amount. Also, FEI employees charge directly to the TESDA or FAES for work on specific projects. Please also refer to the response to BCUC IR 2.359.3.

251.0 Reference: FORECASTS FOR THE PBR PERIOD – LABOUR

Exhibit B-1, Section C, Table C3-14; Exhibit B-11, BCUC 1.89.1;

FEU 2012-13 RRA: Exhibit B-1, Appendix D-4 and Exhibit B-9-1, BCUC 1.46.1

Customer Service Department - # of FTEs

Table C3-14: Customer Service Staffing Levels

	2010 Actual	2011 Actual	2012 Approved	2012 Actual	2013 Approved	2013 Forecast
O&M FTE	30	28	299	278	284	278
Project Temporary Employees	0	329	0	0	0	13
Capital FTE	7	7	10	10	10	10
Total	**37**	**363**	**309**	**288**	**294**	**301**

(Exhibit B-1, Section C, p. 145)

In response to BCUC 1.89.1, FEI states, "In the course of responding to this IR and reviewing evidence related to this matter, FEI has noted an error made in the Application by including nine temporary employees in the 2013 O&M Base (four of these employees were capital-related)." (Exhibit B-11, p. 230)

251.1 Please indicate which department(s) these nine temporary employees were recorded in.

Response:

As stated on page 146 of the Application, the temporary employees were recorded in the Customer Service department to support meter reading project transition to the new service provider.

251.2 Please indicate which department(s) the $373 thousand reduction in 2013 Base O&M has been recorded in and by how much each of these departments have been reduced.

Response:

The $373 thousand reduction has been recorded in the 2013 O&M Base for the Customer Service department. As indicated in the response to BCUC IR 1.89.1, FEI will update the record to adjust for $373 thousand in the 2013 O&M base for the Customer Service department when the financial schedules are filed to set the rates for 2014. Given that the rate impact has already been disclosed in the response to BCUC IR 1.89.1 and is not material, for the purposes of ease of regulatory review, FEI will provide an update to any impacted financial schedules at one time. FEI will provide an evidentiary update with actual 2013 O&M and capital amounts by the end of February 2014. At that time, FEI will also update the total 2013 O&M Base, if applicable.

251.3 Please provide the following revised tables to reflect the correction of the above-mentioned error: Table C3-1, C3-2, C3-14, C3-15 and C3-16.

Response:

FEI notes that the error with respect to the nine temporary employees only requires an update to 2013 O&M Base for the Customer Service department, and no updates are required for 2013 Approved or 2013 Projection. As such, the only tables that may be impacted are Table C3-2 and Table C3-16. FEI has not provided an updated Table C3-2 or C3-16 since this change may be offset by other changes. As stated in response to BCUC IR 2.251.2, FEI will provide an evidentiary update with actual 2013 O&M and capital amounts by the end of February 2014. At that time, FEI will also update the 2013 O&M Base and Table C3-2, if applicable.

251.4 Please provide a revised Appendix F6 to reflect the correction of this error in the O&M Expenses at the Resource View level.

Response:

As stated in response to BCUC IR 2.251.2, FEI will provide an evidentiary update with actual 2013 O&M and capital amounts by the end of February 2014. At that time, FEI will also update the 2013 O&M Base and Appendix F6, if applicable.

251.5 If the revised Table C3-14 still includes any "Project Temporary Employees" for the 2013 Forecast, please confirm or explain otherwise that the cost of these Project Temporary Employees has not been included in the 2013 O&M Base.

Response:

As indicated in the response to BCUC IR 2.251.3, this item did not affect the 2013 Forecast. As stated on page 146 of the Application, in 2013, on a temporary basis only, 13 additional FTEs were required to support meter reading transition to the new service provider. Given that these 13 FTEs are not required in 2014 onwards, the cost for these employees should not be reflected in the 2013 O&M Base for the Customer Service department. This is the adjustment that FEI has discussed in response to BCUC IR 1.89.1.

FortisBC Energy Inc.
Mainland - Historic and Forecast FTE by Business Unit

Line no.	Business Unit	2006	2007	2008	2009	2010	Projected 2011	Forecast 2012	Forecast 2013
5	Customer Service	19	23	22	25	32	367	325	309

(FEU 2012-2013 RRA, excerpt from Exhibit B-1, Appendix D-4)

FEU	2009 Actual	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Operating & Maintenance	925	1053	1090	1090	1082	1405	1406
Customer Service						321	323
Net O&M FTEs	925	1053	1090	1090	1082	1084	1083

(FEU 2012-2013 RRA, B-9-1, BCUC 1.46.1)

In reviewing the growth of Net O&M FTE over the period 2006 to 2013, the in-sourcing of Customer Services in 2011 creates a significant increase for 2012 Actual and 2013 Forecast.

251.6 Please provide an updated table, similar to that presented in the response to BCUC 1.46.1 in Exhibit B-9-1 from the FEU 2012-13 RRA as shown above, for just FEI over the period from 2006 to 2013. The resulting table should reflect the O&M share of the Total Customer Service FTE in a manner similar to the presentation in Appendix D-4 of Exhibit B-1 from the FEU 2012-13 RRA. Please comment on whether the response to BCUC 1.46.1 was meant to only show the incremental Customer Service FTE after the in-sourcing.

Response:

Please refer to Attachment 250.3 provided in the response to BCUC IR 2.250.3 for an updated table, similar to that presented in the response to BCUC IR 1.46.1 in Exhibit B-9-1 from the FEU 2012-2013 RRA but just for FEI from 2006 to 2013. The table in the response to BCUC IR 1.46.1 in the FEU 2012-2013 RRA was meant to show the Total Employees by Category and not meant to show only the incremental Customer Service FTE after the in-sourcing. The Customer Service FTEs in Exhibit B-1, Appendix D-4 for Customer Service represent the full time equivalent employees as at December 31st for each year which would have included both Capital and O&M activities.

Provided below is a table that shows the Total Net O&M FTE with and without Customer Service O&M FTE.

FortisBC Energy Inc.
Net O&M Employees

FEI	2006 Actual Avg FTE	2007 Actual Avg FTE	2008 Actual Avg FTE	2009 Actual Avg FTE	2010 Actual Avg FTE	2011 Actual Avg FTE	2012 Actual Avg FTE	Actual as of Sept, 30, 2013
Net O&M FTE with Customer Service	780	814	814	836	900	945	1,156	1,146
Less: Customer Service O&M	(14)	(14)	(14)	(18)	(21)	(21)	(282)	(271)
Net O&M FTE without Customer Service	766	800	801	819	879	925	874	875

251.7 Please confirm, or explain otherwise, that the "Project Temporary Employees" shown in Table C3-14 of the Application are Capital FTE.

Response:

As stated in the response to BCUC IR 1.89.1, four of the 13 project temporary employees were charged to capital.

251.8 Please estimate the number of O&M FTE which should be added to the Customer Services numbers, by year from 2006 to 2010, to normalize the Customer Services

Total FTE and O&M FTE to reflect the in-sourcing. For example, it would appear the adjustment for 2010 would be 248 FTE, and due to the changes in the number of customers, this adjusting figure would be lower in 2006.

Response:

The approach proposed in the question to normalize Customer Services Total FTE and O&M FTE is incorrect. It is also not clear how the adjustment of 248 FTEs for 2010 as stated in the question is derived.

Instead, please refer to the table provided in the response to BCUC IR 2.251.6 for the FEI Total NET O&M FTE with and without Customer Service, which normalizes the O&M FTE for Customer Service insourcing.

252.0 Reference: FORECASTS FOR THE PBR PERIOD – LABOUR

Exhibit B-1, Section C, Table C3-14; Exhibit B-11, BCUC 1.84.1, 1.98.1, 1.119.1;

2012-2013 FEU RRA, BCUC 1.46.1, BCUC 2.13.2;

Order G-44-12, 2012-13 FEU RRA Decision

FTEs – Net O&M for Base 2013 compared to 2012-13 RRA

FEU	2009 Actual	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Operating & Maintenance	925	1053	1090	1090	1082	1405	1406
Customer Service						321	323
Net O&M FTEs	925	1053	1090	1090	1082	1084	1083

(FEU 2012-2013 RRA, B-9-1, BCUC 1.46.1)

Table 5.3-14: Growing Employees to Support In-Sourced Customer Service and Enhanced Reliability

O&M Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	996	1,032	1,024	1,021	1,343	1,343

(FEU 2012-13 RRA, BCUC 2.13.2)

"A major consideration for the Commission Panel is whether in this Application, the FEU have demonstrated that they have optimized productivity levels. After consideration of the evidence, the Panel is not persuaded that the Companies have done all they can to optimize productivity and manage cost levels down. The Commission Panel has directed the FEU to reduce their O&M expenditures by $4 million in 2012 and 2013. Additionally, the Panel made further determinations with regard to new expenditure requests. These resulted in Departmental O&M reductions in Operations, (Energy) Supply and Resource Development, Energy Solutions and External Relations and Information Technology." (2012-13 FEU RRA Decision, p. 3)

"As discussed in Section C3.1, page 121 of the Application, the 2014 Forecast represents a high level forecast of future trends and upcoming challenges for FEI. As such, FEI did not develop detailed, zero based FTE levels for that year. The FTE levels for 2013 Projection are expected to be at a similar level to 2012 on a total company basis, and this trend is expected to continue throughout the PBR Period." (Exhibit B-11, BCUC 1.84.1)

"FEI does not have an approved number of FTEs for 2013. Although FEI did submit FTE forecasts for 2013 as part of its 2012-2013 RRA, Order G-44-12 removed a number of costs, including a $4 million productivity challenge, from the forecast O&M. Although FEI did receive approval for revised O&M and capital forecasts for 2013 that reflected Order G-44-12, FEI did not submit revised FTE forecasts. Therefore, FEI does not have an Approved 2013 FTE figure to provide." (Exhibit B-11, BCUC 1.98.1)

"As discussed in Section 3.1, page 121 of the Application, in the development of the 2013 projection and 2014 Forecast, individual department managers were challenged to maintain FTE levels, on a company wide basis that were similar to those of 2012 Actuals." (Exhibit B-11, BCUC 1.119.1)

Based on FEU's responses to BCUC 1.46.1 in Exhibit B-9-1 and to BCUC 2.13.2 in Exhibit B-17 of the FEU 2012-13 RRA, it appears that a significant thrust of the FEU 2012-13 RRA was that, not including the Customer Services in-sourcing, the Net O&M FTE for FEU and for FEI (Mainland) in 2013 was anticipated be lower than the actual Net O&M FTE in 2010.

From the response to BCUC 1.46.1 in Exhibit B-9-1 of the FEU 2012-13 RRA, it appears that FEU was expecting to have 323 O&M FTE in Customer Service in 2013; as no amounts are shown in prior years, these must all be the in-sourced group within FEI. From the response to BCUC 2.13.2 in Exhibit B-17 in the FEU 2012-13 RRA, it can be seen that the FEI (Mainland) Net O&M FTEs forecast for 2013 was to be 1,343 which, on comparison to the prior years, must include the 323 for Customer Services. From Table C3-14 in the Application, the O&M for Customer Services is to be 278 in 2013. Therefore, the Net O&M FTE for FEI in Base 2013 should be 1,343 less 323 plus 278 = 1,298 or 1,020 without Customer Services.

252.1 Please compare the latest projection for FEI 2013 Net O&M FTE to the 1,298 Net O&M FTE for FEI as suggested by the data from the FEU 2012-13 RRA process and this Application, and present the data in total and by Business Unit. If FEI does not have a current projection for 2013, use the actual as of September 30, 2013 as the 2013 projection for purposes of responding to this IR. Include the requested information in a fully functional spreadsheet.

Response:

This response addresses BCUC IRs 2.252.1 and 2.252.2.

The table and Attachment 252.1 below provide a comparison by department of the Actual Net O&M FTE at September 30, 2013 (1,146) with the 2013 Net O&M FTE listing provided in the 2012-2013 RRA (1,343). In order to make the comparison more meaningful, FEI has made a number of re-statements to the 2013 FTE listing provided in the 2012-2013 RRA. The result shows a total net reduction of 166 Net O&M FTE which becomes 156 Net O&M FTE after removing Customer Service. The O&M impact associated with this reduction of 156 Net O&M FTE can be summarized as follows:

- A significant portion of the $4 million 'productivity challenge' included in the 2013 Approved O&M was achieved by way of reduced FTE levels
- As discussed in Section C3.2 of the Application, FEI is projecting $9.4 million in sustainable labour savings, which are primarily driven by integration activities with FBC, savings in IBEW training through the use of new delivery models, refinement of the requirements for supporting capital activities, streamlining processes and the use of technology, and a shift to the use of contractors to allow more flexibility in staffing levels.

In relation to the 156 FTE variance, in all cases the number of FTEs is lower than what had been forecast as part of the 2012-2013 RRA. The inclusion of the $9.4 million sustainable labour savings in the 2013 Base O&M is a direct transfer of benefits to ratepayers for the duration of the PBR; as there is no increased headcount or costs, there is no requirement to substantiate the value to ratepayers as requested in BCUC IR 2.252.2.

FEI Net O&M FTE

Business Unit	Actual as of Sept 30, 2013	2013 Forecast as per 2012-2013 Application	Less: FTE Reduction as per Order G-44-12	Less: CMAE included in 2013 Forecast total of 1343	CSD O&M Allocation	Reorg Transfer	Revised 2013 Forecast as per 2012-2013 Application	Variance
Distribution	345	388	(1)		3	-13	377	(32)
Transmission	12	54				-33	21	(9)
Plant Operations	24					26	26	(2)
Customer Service	271	296			(15)		281	(10)
Energy Solutions & External Relations	88	100	(5)				95	(7)
Energy Supply & Resource Development	22	47	(2)	(22)		4	27	(5)
Information Systems	56	66			8		73	(17)
Engineering Services & PM	110	127	(1)			21	147	(37)
Operations Support	78	92				4	96	(18)
Facilities	17	18					18	(1)
Environment, Health, & Safety	10	14					14	(4)
Finance & Regulatory	56	69				-4	65	(9)
Human Resources	57	72			4	-5	71	(14)
Corporate	1	1					1	-
Total Net O&M FTE	**1,146**	**1,343**	**(9)**	**(22)**	**-**	**-**	**1,312**	**(166)**
Less: Customer Service	(271)	(296)	-	-	15	-	(281)	10
Total NET O&M FTE without Customer Servi	**875**	**1,047**	**(9)**	**(22)**	**15**	**-**	**1,031**	**(156)**

252.2 Please explain by specific Business Unit, where the current projected 2013 Net O&M FTE for FEI are different from the projected Net O&M FTE for FEI in the FEU 2012-13 RRA, the reasons for the differences, and the value to the Ratepayers. In all cases where there has been a change in O&M FTE, please attempt to quantify the dollar value to Ratepayers from the work done by these FTE as compared to the fully loaded cost of the FTE. If FEI does not have a current projection for 2013, use the actual as of September 30, 2013 as the 2013 projection for purposes of responding to this IR.

Response:

Please refer to the response to BCUC IR 2.252.1.

252.3 Please provide the Net O&M FTE proposed for the Base 2013 on which the PBR is to be calculated. Please explain, by Business Unit, the differences between the Projected 2013 Net O&M FTE and the proposed Base 2013 Net O&M FTE. If FEI does not have a current projection for 2013, use the actual as of September 30, 2013 as the 2013 projection for purposes of responding to this IR.

Response:

As stated in other responses, the FTE figures have historically been provided to demonstrate staffing levels of the Company. In FEI's view, the focus should be on the resulting costs and not on how FEI manages its costs between employees, contractors and shared or integrated services.

As such, FEI is not proposing a Net O&M FTE for the Base 2013. The 2013 Net O&M FTE by Business Unit as of September 30, 2013 has been provided in response to BCUC IR 2.250.3 and BCUC IR 2.252.1.

252.4 Please provide the number of FTE which, at an average direct cost, are represented by $4 million productivity challenge from Order G-44-12.

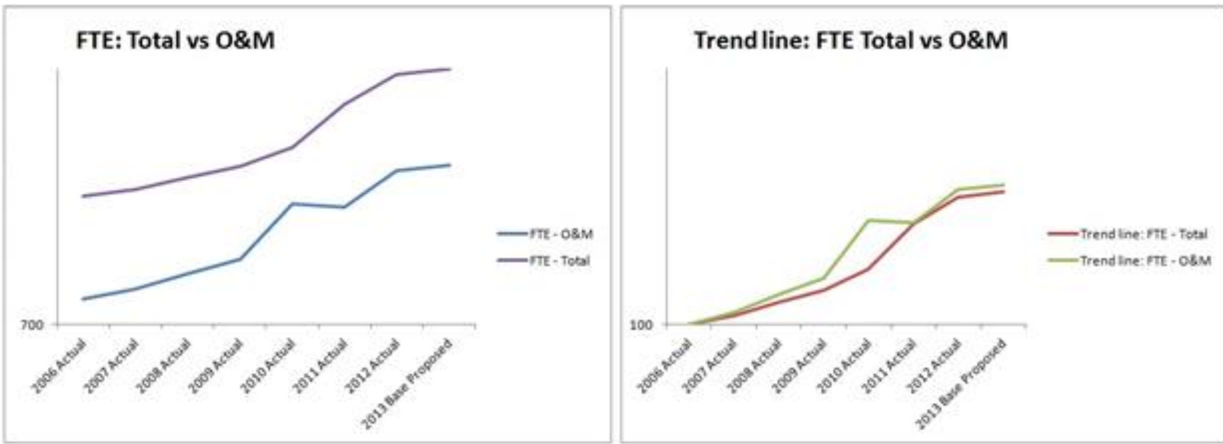
Response:

If the $4 million productivity challenge from Order G-44-12 was addressed solely through labour savings, it would equate to a reduction of approximately 42 FTEs, based on an average FTE labour cost for 2013 of $95,158 including salary and all benefits. However, as discussed in response to BCUC 2.252.1, the $4 million productivity challenge was not achieved solely by way of FTE reductions.

253.0 Reference: FORECASTS FOR THE PBR PERIOD – LABOUR

FEU 2012-13 RRA: Exhibit B-9-1, BCUC 1.46.1; Exhibit B-17, BCUC 2.13.2;

FTEs – Graphs of Total and O&M FTE and O&M Dollars



(Example graphs by staff)

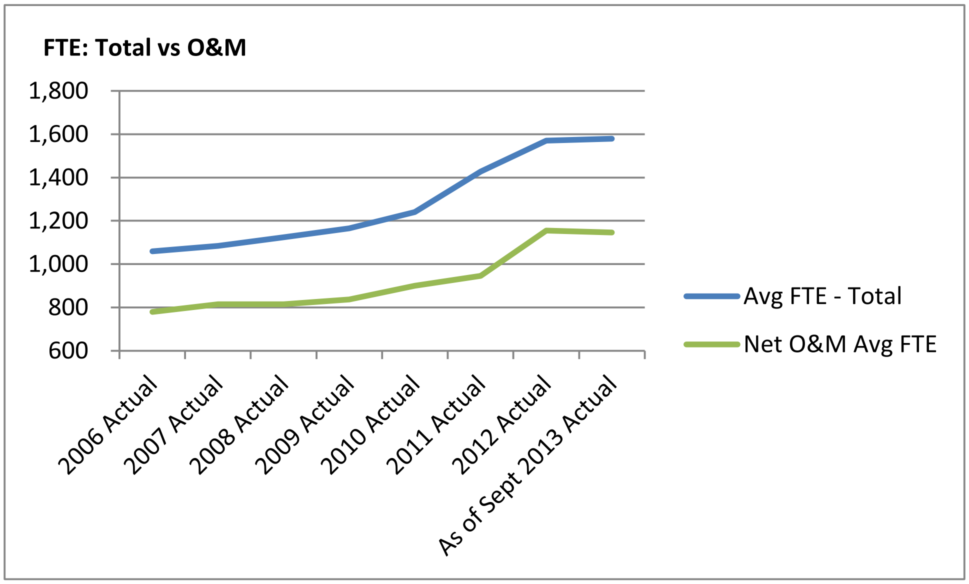
253.1 Please graph the FEI Total FTE from 2006 to 2013 compared to the FEI Net O&M FTE from 2006 to 2013, and provide the graph and data on paper and in working Excel format.

<u>Response:</u>

Please find the following data, graph and Attachment 253.1 showing the total average FTE for FEI from 2006 to 2013, compared to the net average O&M FTE for FEI for the same time period. FEI is using the actual FTE as at September 30, 2013 for 2013 for the purposes of responding to this IR.

There are a number of reasons why O&M FTE is not a straightforward calculation and should not be expected to tie directly to O&M labour costs. First, the O&M FTE is the remainder after removing an estimated allocation for employees working on capital, but includes employees that sometimes work on deferral items, since these charges vary from year to year. In addition, the O&M FTE will be influenced by the same accounting changes that influence O&M vs. capital activities. Finally, FEI's labour O&M costs are driven by changes in the mix of contractor utilization, variations from year to year in overtime requirements, increases in pension and OPEB costs that escalate faster than general labour inflation, and the extent to which shared and integrated services offset what otherwise would be changes in the number of employees and associated labour dollars.

	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	As of Sept 2013 Actual
Avg FTE - Total	1,059	1,084	1,124	1,165	1,241	1,427	1,571	1,579
Net O&M Avg FTE	780	814	814	836	900	945	1,156	1,146

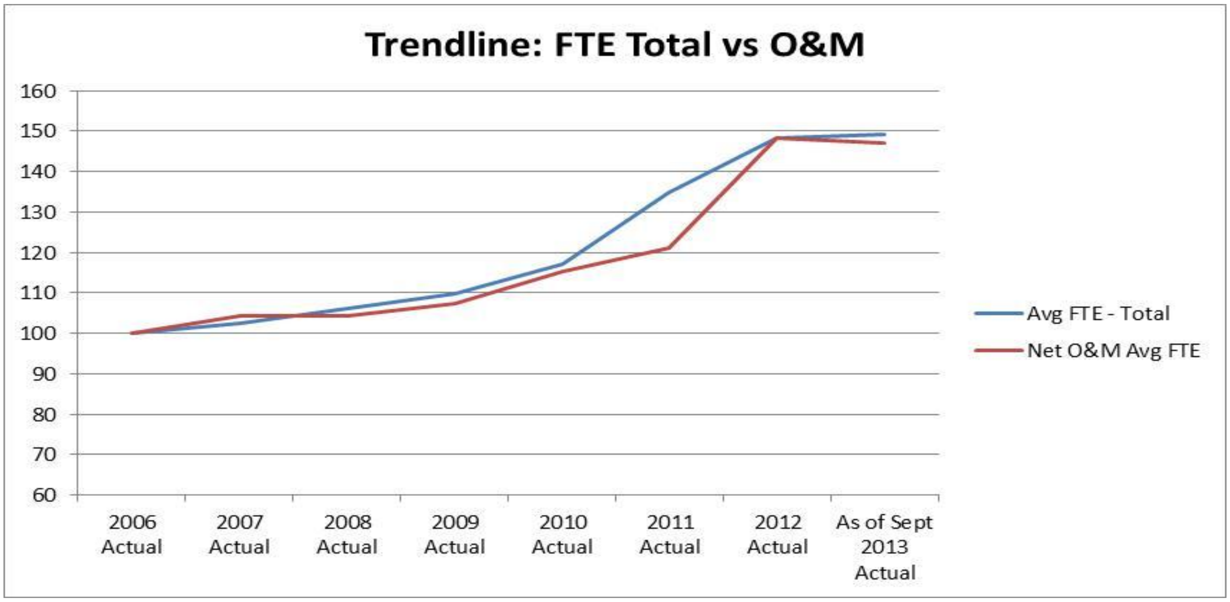


253.2 Please graph the trend line of the FEI Total FTE from 2006 to 2013 compared to the trend line of FEI Net O&M FTE from 2006 to 2013, and provide the graph and data on paper and in working Excel format.

Response:

Please find the following data and graph and Attachment 253.2 in a working Excel format for the FEI Total Average FTE from 2006 to 2013 compared to the FEI Net Average O&M FTE from 2006 to 2013. Please refer to the response to BCUC IR 2.253.1 to explain why FEI used 2013 Actual FTEs as of September 30, 2013 for 2013.

	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	As of Sept 2013 Actual
Avg FTE - Total	1,059	1,084	1,124	1,165	1,241	1,427	1,571	1,579
Net O&M Avg FTE	780	814	814	836	900	945	1,156	1,146



253.3 Please provide the fully loaded labour cost, and the direct labour cost, for the change in Net O&M FTE from 2010 Actual to 2013 Base.

<u>Response:</u>

Based on the context of this request, the response will address the fully loaded and direct labour cost from 2010 Actual to 2013 Projection, and therefore not consider the additional O&M impact in the transition from 2013 Projection to 2013 Base as discussed in Section B-6 of the Application.

In providing the response to this IR, FEI defines fully loaded labour cost as direct labour costs plus benefits (excluding retiree pension/OPEB). Direct labour cost includes base salary (regular earnings) only. Premium payments, overtime, timebank accrual and other salary adjustments are excluded from the direct labour costs as these costs fluctuate and vary year over year. The exclusion of these items, which are real cost pressures, will skew any extrapolation of the labour dollars calculated in this manner as compared to a change in total labour included in O&M over the same time period.

As discussed in the response to BCUC IR 2.252.3, FEI is not proposing a Net O&M FTE for the Base 2013. For this IR and other IRs asking for a 2013 Base Proposed FTE, FEI is using the actual FTE as of September 30, 2013.

The following table shows the change in Net O&M FTE with and without Customer Service from 2010-2012 Actual and as of September 2013 Actual for 2013.

	Change in 2011	Change in 2012	Change in 2013	Change from 2010-2013 Actual
Change in Net O&M FTE with Customer Service	46	210	(9)	247
Less: Change in Customer Service Net O&M FTE	(0)	261	(11)	250
Change in Net O&M FTE without Customer Service	46	(51)	2	(3)

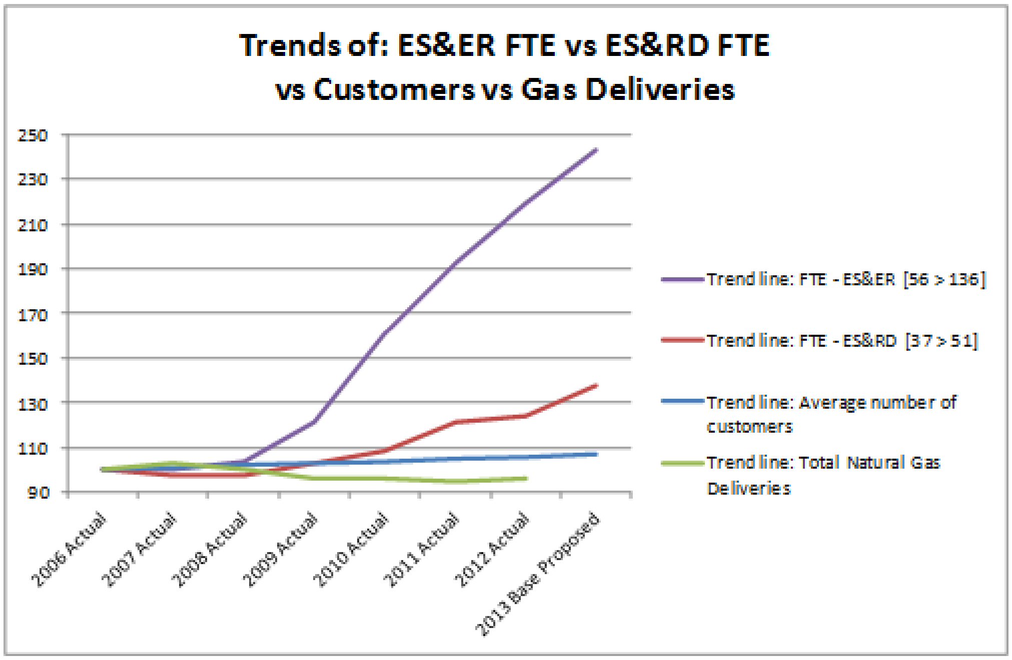
As the table shows, for all intents and purposes, the change in Net O&M FTE from 2010 to 2013 is due to Customer Service, and is approximately 250 FTE.

Using this 250 FTE, the average FTE direct and fully loaded labour cost from 2011 to 2013 is $47.1 thousand and $61.5 thousand respectively which would drive a direct and fully loaded labour cost increase of $11.8 million and $15.4 million respectively.

254.0 Reference: FORECASTS FOR THE PBR PERIOD – LABOUR

FEU 2012-13 RRA: Exhibit B-9-1, BCUC 1.46.1 and Exhibit B-17, IR 2.13.2

FTEs – Graph for ES&ER and ES&RD



(Example graph by staff)

Since the end of the last PBR period there has been a significant increase in the number of FTEs in the Energy Solutions & External Relations and the Energy Supply & Resource Development business units. The Application provides information on the total FTE but not the Net O&M FTE for the business units. The key focus of this Application is in setting the correct 2013 Base O&M for the 2014-18 PBR period. One key piece of information is understanding the driver behind any increases in the Base O&M; one major driver is any increase in O&M FTE.

254.1 Please provide the Total and Net O&M FTE for the Energy Solutions & External Relations and the Energy Supply & Resource Development business units, by year, from 2006 Actual through 2013 Base.

Response:

This response also addresses the response to BCUC IR 2.254.3.

Given the preamble to this IR, FEI understands this question to be interested in information from the end of FEI's last PBR period. FEI has therefore prepared the requested graph commencing from 2009, which marked the end of FEI's PBR period.

The suggested graph provided in the preamble to this question is a simplification of the activities of the ES&ER group over the period shown. The Company has staffed the ES&ER group size to meet the market needs; in addition, staff has been added as a result of Commission approvals for activities such as NGT (GGRR) and RNG. Further, as a relatively small group within the larger FEI company, each additional staff added results in a larger percentage increase than if a staff were added in the Operations group. Hence the graph is misleading and requires context to be a good comparator.

As per the response to BCUC IR 2.252.3, the proposed FTE levels for the 2013 Base is expected to be at a similar level to 2013 on a total company basis, and since FEI does not have a current 2013 Projection for FTEs, FEI is using the actual FTE as at September 30, 2013 for 2013 for purposes of responding to this IR.

Please find below the Total and Net O&M FTE for Energy Solutions & External Relations and the Energy Supply & Resource Development business units by year, from 2009 Actual through 2013 with 2013 as of September 30, 2013.

Business Unit	2009 Actual	2010 Actual	2011 Actual	2012 Actual	As of September 2013
ES & ER Total FTE	68	90	108	123	130
ES & ER Net O&M FTE	64	71	83	86	88
ES & RD Total FTE	32	34	40	42	40
ES & RD Net O&M FTE [1]	14	14	19	21	22

ES&ER

The overall change in Net O&M FTE for this period is due to additional staff required to implement the following activities to the benefit of natural gas customers:

- To implement the GGRR initiative. While staff working on GGRR activities charge their time to the GGRR deferral account, for such items as training, education and administration, these employees have not been excluded from the O&M FTE numbers provided here as these are not all full-time positions and could be a portion of an employee's time devoted to these activities and therefore difficult to segregate.
- Preparation of the LTRP – please refer to the response to BCUC IR 2.284.1.

- Development and implementation of the RNG service offering – please refer to the response to BCUC IR 2.284.1.
- Increased staffing to meet customer and company advocacy needs as it relates to operating agreement negotiations, greater engagement with First Nations and government policy analysis. Over this period there has been an increased volume of operating agreements that need to be reviewed with municipalities. Please refer to the response to BCUC IR 1.106.2 for more details. Greater First Nations engagement has been the result of provincial legislation to recognize aboriginal land title and the necessity to discuss with First Nations each time the company proposes to build a new infrastructure on Crown Lands or through First Nations Land. With the introduction of the 2007 BC Energy Plan and more recently the provincial Natural Gas Strategy, FEI's interaction with the Ministry of Energy, Mines and Natural Gas and various other government ministries has increased. In order to meet government objectives, FEI must be both aware of these objectives and understand the impact to the company and to its customers. An example of such an activity, which has been to the benefits of customers, is the development of the GGRR.
- Increase in staffing levels to support growth initiatives to advance the use of CNG and LNG; but not limited to NGT applications. .
- An increase in staffing levels in sales and account management to work closely with existing and potential customers to provide them with the services they require to meet their needs for gas energy solutions. These have become more complex as customers are often looking for ways to find efficiencies through integrated solutions whether it is with their existing systems or their new development. Further, small builder and developer groups make up a large proportion of the new customer additions and this shift requires an increased effort to engage a wider network of builders and developers along with other influencers of gas use in new homes, including architects, engineers, contractors, manufacturers, dealers as well as homeowners. FEI has seen encouraging signs in the Company's overall capture rate (for new homes with natural gas) as result of this work.

ES&RD

The overall change in Net O&M FTE shown in the table above for this period is due to the following:

- The main driver of the change in the ES&RD FTE from 2009 is that the Resource Development group was created after 2009 through the internal budget transfer of existing O&M labour resources.
- An additional 2 new business development specialist positions were added in 2011 as discussed in the 2012-2013 RRA (at page 188 of the 2012-2013 Application and in the response to 2012-2013 RRA BCUC IR 1.47.2).

254.2 Please graph the trend lines, starting at "100" in 2006, for the following:

(i) ES & ER Total FTE,
(ii) ES & ER Net O&M FTE,
(iii) ES & RD Total FTE,
(iv) ES & RD Net O&M FTE,
(v) Average Customers, and
(vi) Total Natural Gas Deliveries.

Please provide the graph and data on paper and in a working Excel file.

Response:

This response also addresses the response to BCUC IR 2.254.3.

Given the preamble to this IR, FEI understands this question to be interested in information from the end of FEI's last PBR period. FEI has therefore prepared the requested graph commencing from 2009, which marked the end of FEI's PBR period.

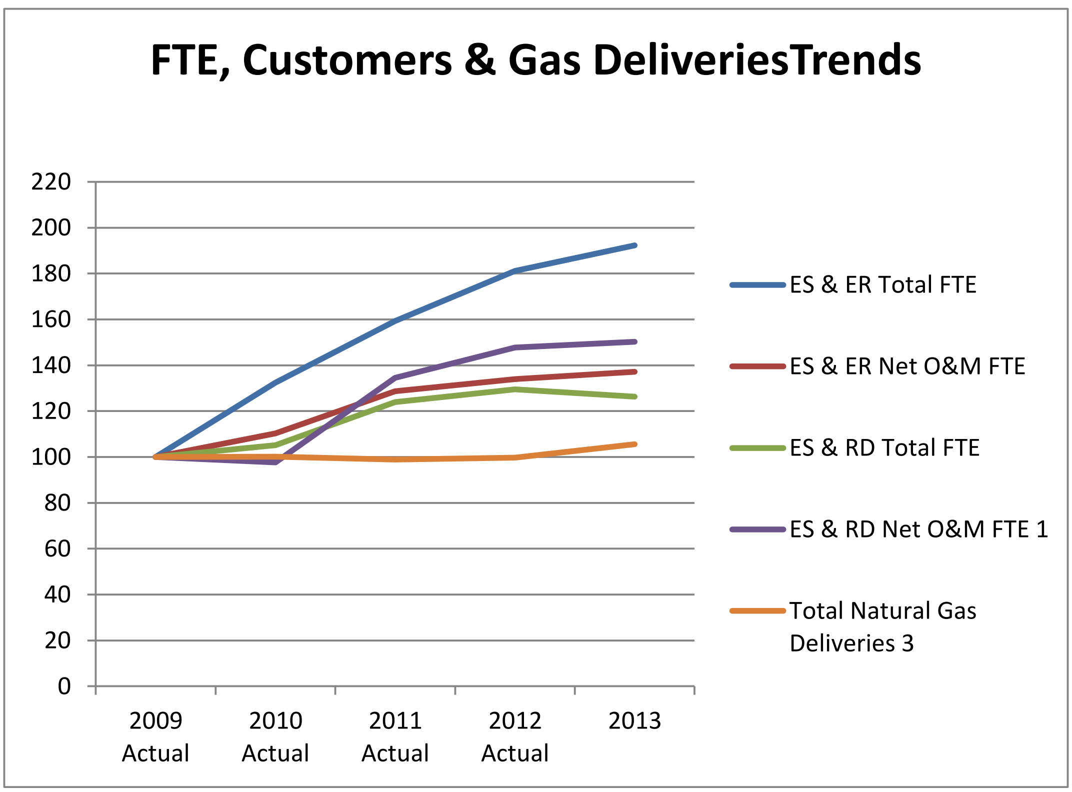
Please refer to the following data, graph and Attachment 254.2 for ES&ER and ES&RD. For purposes of responding to this IR, all data from 2009 to 2012 represents actual. For 2013, ES&ER and ES&RD are using FTE actual as of September 30, 2013 and 2013 Projection for average customers and gas deliveries.

Business Unit	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013
ES & ER Total FTE	68	90	108	123	130
ES & ER Net O&M FTE	64	71	83	86	88
ES & RD Total FTE	32	34	40	42	40
ES & RD Net O&M FTE [1]	14	14	19	21	22
Average Customers [2]	817,859	824,125	830,390	834,888	840,721
Total Natural Gas Deliveries [3]	200,822	201,111	198,497	200,388	211,876

1 Excludes FTE allocation for CMAE

2 The average customers for 2007 - 2011 have been reduced by 14,892 to make it comparable to 2012 and 2013. The 14,892 represents the one time SAP customer count adjustment as discussed in Appendix E4 of the Application.

3 Gas Deliveries in Normalized Actual



FEI has not separated in the attachment those employees that charge part of their time to NGT (GGRR or non-GGRR), TES/FAES and Biomethane. This is because these are not full positions, but only portions of employee's time that can vary from year to year. FEI provides the following information to assist in understanding the relationship between the level of "O&M FTE" and the customer count and natural gas deliveries.

This IR incorrectly suggests that there is a direct correlation between staffing levels and customer count or natural gas deliveries for each year. It is incorrect, however, to assume that costs incurred in a given year have a direct relationship with total customers and net customers added to the system in that same year. This assumption is flawed for the following reasons:

- The ES&ER group not only engages in activities to retain and attract customers but also on compliance activities including the LTRP and System Extension Test Filings. Please refer to BCUC IR 1.100.1 for a list of key activities for this group.
- There is often a time lag for benefits to accrue from an initiative. Activities undertaken in one period and often over a period of time will reap benefits in future periods. For example, the company began its efforts on the GGRR initiative in consultation with the government in a period before the first GGRR customer was added to the natural gas system.
- There are other external influences such as changes to codes, energy policy and regulation and the cost of gas appliances, for which FEI has limited influence, that significantly affect customer retention, additions and growth, and such changes in external factors cannot be "measured" in a such a graph.

Therefore, to base decisions on an evaluation of staffing levels against natural gas deliveries gives an inaccurate and incomplete picture of the business and the factors that affect it.

254.3 Please explain the reasons for the change in the Net O&M FTE from 2010 Actual through 2013 Base.

Response:

Please refer to responses to BCUC IRs 2.254.1 and 2.254.2.

254.4 Please provide the fully loaded labour cost, and direct labour cost, for the change in Net O&M FTE from 2010 Actual to 2013 Base.

Response:

Based on the context of this request, the response will address the fully loaded and direct labour cost from 2010 Actual to 2013 Projection, and therefore not consider the additional O&M impact in the transition from 2013 Projection to 2013 Base as discussed in Section B-6 of the Application.

In providing the response to this IR, FEI defines fully loaded labour cost as direct labour costs plus benefits (excluding retiree pension/OPEB). Direct labour cost includes base salary (regular earnings) only. Premium payments, overtime, timebank accrual and other salary adjustments are excluded from the direct labour costs as these costs fluctuate and vary year over year. The exclusion of these items, which are real cost pressures, will skew any extrapolation of the labour dollars calculated in this manner as compared to a change in total labour included in O&M over the same time period.

Please refer to the response in BCUC IR 2.254.2 for the table that shows the total Net O&M FTE from 2009 to 2013 for ES&ER and ES&RD. Provided below is a table that shows the total change in Net O&M FTE from 2010 to 2013 for ES&ER and ES&RD.

	Change in 2011	Change in 2012	Change in 2013	Total Change from 2010-2013 Actual
ES & ER - Change in Net O&M FTE	12	3	2	17
ES & RD - Change in Net O&M FTE	5	2	0	8

Please refer to the response in BCUC IR 2.254.1 for the reasons for the increase in Net O&M FTEs from 2010 Actual through 2013 for ES&ER and ES&RD.

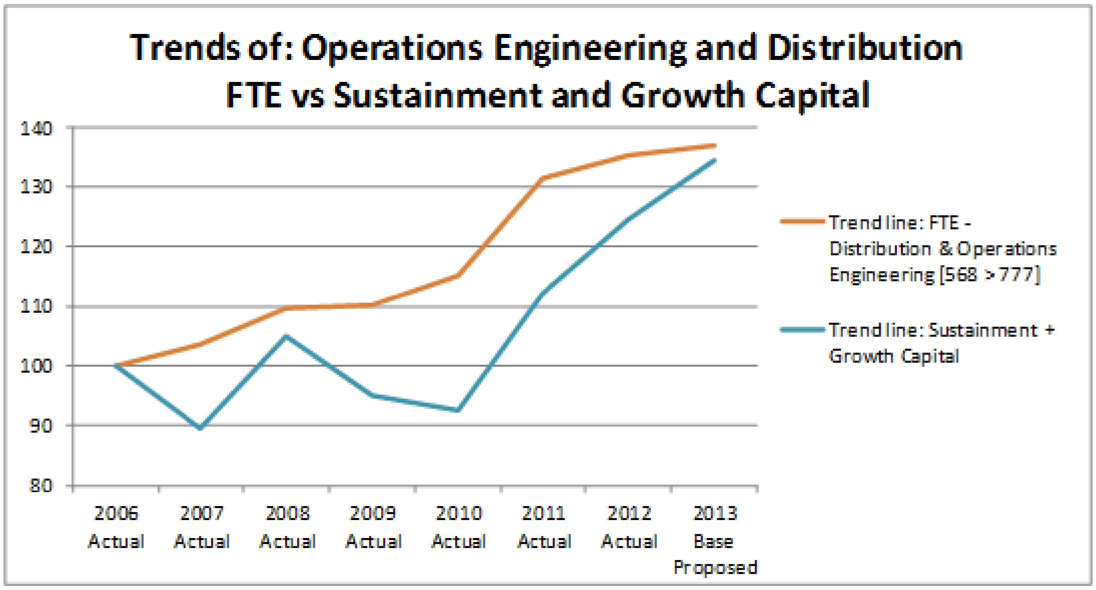
Average direct salary from 2011-2013 in ES&ER is approximately $85 thousand with fully loaded salary at approximately $117 thousand. Using this estimate, ES&ER's Net O&M FTE change from 2010 to 2013 is 17 or approximately $1.45 million in direct labour cost or $2 million in fully loaded labour cost.

Average direct salary from 2011-2013 in ES&RD is approximately $101 thousand with fully loaded salary at approximately $138 thousand. Using this estimate, ES&RD's Net O&M FTE change from 2010 to 2013 is 8 or approximately $800 thousand in direct labour cost or $1.1 million in fully loaded labour cost.

255.0 Reference: FORECASTS FOR THE PBR PERIOD – LABOUR

FEU 2012-13 RRA: Exhibits B-9-1, BCUC 1.46.1; Exhibit B-17, BCUC 2.13.2

FTEs – Graph for Operations Engineering and Distribution



(Example graph by staff)

Since the end of the last PBR period there has been a significant increase in the number of FTEs in the Operations Engineering and the Distribution business units. The Application provides information on the total FTE but not the Net O&M FTE for the business units. The key focus of this Application is in setting the correct 2013 Base O&M for the 2014-18 PBR period. One key piece of information is understanding the driver behind any increases in the Base O&M; one major driver is any increase in O&M FTE.

255.1 Please provide the Total and Net O&M FTE for the Operations Engineering and the Distribution business units, by year, from 2006 Actual through 2013 Base.

Response:

FEI notes that due to the varying levels of contractor usage over the years, and the non-labour pressures described in the responses to BCUC IRs 2.258.1 and 2.259.1, the O&M FTE does not bear a direct relationship to O&M dollars. Please find below the Total and Net O&M FTE for the Operations Engineering & PM and the Distribution business units by year, reflecting average actual FTE from 2006 through 2012 and actual FTE as of September 30, 2013 for 2013.

Business Unit	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual
Operations Engineering & PM Total FTE	120	118	132	140	152	159	163	170
Operations Engineering & PM Net O&M FTE	86	82	86	87	100	106	111	110
Distribution Total FTE	442	461	478	475	488	524	523	536
Distribution Net O&M FTE	296	326	320	310	327	344	332	345
The following group is not included in the Total FTE table above and in total FTE tables provided in Exhibit B-1, Appendix D-4 in the FEU 2012-2013 RRA and Exhibit B-1-1, Appendix B2 in the 2014 through 2018 Application.								
Dependant Contractors	23	23	23	23	18	5	3	4

The majority of Dependent Contractors (backhoe operators) in 2006-2010 were gradually converted to internal IBEW FTE Equipment Operators or terminated and replaced with internal IBEW FTE Equipment Operators.

255.2 Please graph the trend lines, starting at "100" in 2006, for the following:

(i) Operations Engineering Total FTE,
(ii) Operations Engineering Net O&M FTE,
(iii) Distribution Total FTE,
(iv) Distribution Net O&M FTE, and
(v) Sustainment and Growth Capital.

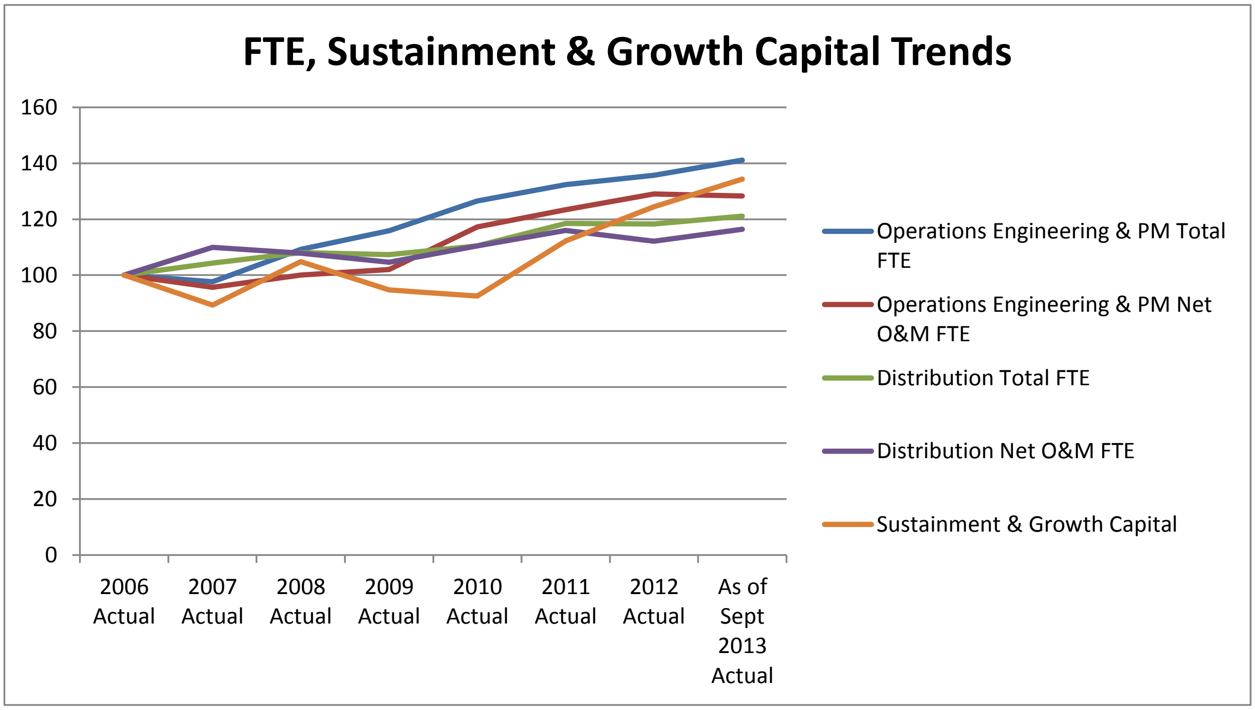
Please provide the graph and data on paper and in a working Excel file.

Response:

FEI has provided the information as requested. However, there should be no conclusion drawn based on the data below as it graphs two unrelated items - O&M FTE and capital dollars. Please refer to Attachment 255.2 in a working Excel file and the graph and data below.

Graph Data

	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	As of Sept 2013 Actual
Operations Engineering & PM Total FTE	100	98	109	116	126	132	136	141
Operations Engineering & PM Net O&M FTE	100	96	100	102	117	123	129	128
Distribution Total FTE	100	104	108	107	110	118	118	121
Distribution Net O&M FTE	100	110	108	105	110	116	112	116
Sustainment & Growth Capital	100	89	105	95	92	112	124	134



255.3 Please explain the reasons for the change in the Net O&M FTE from 2010 Actual through 2013 Base. Please provide the fully loaded labour cost, and direct labour cost, for the change in Net O&M FTE from 2010 Actual to 2013 Base.

Response:

Based on the context of this request, the response will address the fully loaded and direct labour cost from 2010 Actual to 2013 Projection, and therefore not consider the additional O&M impact in the transition from 2013 Projection to 2013 Base as discussed in Section B-6 of the Application.

Please refer to the response in BCUC IR 2.255.2 for the table that shows the total Net O&M FTE from 2006 to 2013 for Operations Engineering and PM and Distribution. Provided below is a table that shows the Total change in Net O&M FTE from 2010 – 2013.

	Change in 2011	Change in 2012	Change in 2013	Total Change from 2010 - 2013
Change in Net O&M FTE - Operations Engineering & PM	5	5	(1)	9
Change in Net O&M FTE - Distribution	17	(12)	13	18

The primary drivers for the increases, as discussed in further detail in the 2012-2013 RRA Application, include Codes and Regulations, Demographics, and Service Standards and Reliability.

Primary Codes and Standards contributors over this timeframe are the Integrity Management Program (as required by CSA Z662) and the BC Oil and Gas Activities Act (became law in October 2010).

Primary Demographics contributors over this timeframe are retirement transitions, distribution apprentices, planning and delivery of Operations training, and an expanded Engineer-In-Training program.

Primary Service Standards and Reliability contributors over this timeframe are increased maintenance and capital planning and programs and FEI's transition toward longer term asset sustainment planning horizons.

In providing the response to this IR, FEI defines fully loaded labour cost as direct labour costs plus benefits (excludes retiree pension/OPEB), while direct labour cost includes base salary (regular earnings) only. Premium payments, overtime, and other salary adjustments are excluded from the direct labour costs as these costs fluctuate and vary year over year. The exclusion of these items, which are real cost pressures, will skew any extrapolation of the labour dollars calculated in this manner as compared to a change in total labour included in O&M over the same time period.

Average direct salary from 2011-2013 for all affiliations in Distribution is approximately $67 thousand with fully loaded salary at approximately $89 thousand. Using this estimate, Distribution Net O&M FTE change from 2010 to 2013 year to date is 18 or $1.2 million in direct salaries or $1.6 million in fully loaded salaries.

The average direct salary from 2011–2013 in Operations Engineering is approximately $73 thousand with average fully loaded salary at approximately $100 thousand depending on affiliation. Using this estimate, Operations Engineering and PM Net O&M FTE change from 2010 to 2013 is 9 or $0.7 million in direct salaries or $0.9 million in fully loaded salaries.

256.0 Reference: LABOUR

Exhibit B-11, BCUC 1.77.1; Exhibit A2-11, Natural Gas Vehicle Infrastructure Brochure; Exhibit B-11-1, Attachment 75.1, pp. 1, 50

O&M – Executive Employee Expenses

"A further breakdown to the affiliation level is not available since FEI does not track employee expenses by affiliation." (Exhibit B-11, BCUC 1.77.1)

256.1 Given that FEI cannot provide employee expenses by affiliation, please provide the details of the Executive (Exhibit B-11-1, Attachment 75.1, p. 1) and Energy Solutions Directors' (Exhibit B-11-1, Attachment 75.1, p. 50) employee expenses by employee for the years 2007, 2010 and 2012-2013 by year, using the format below. Include the requested information in the form of a fully functioning electronic spreadsheet.

2013 EMPLOYEE EXPENSES - Executive Employees

	Description	**Date**	**Amount**	**Account Code**	**Line of Business***
D. Stout	NGV Infrastructure Canada Conference	Oct 1-2, 2013	$	310-11	GGRR
	Conference X	Nov. 6, 2013	$	310-11	Natural Gas
	Subtotal				
Executive B	NGV Infrastructure Canada Conference	Oct 1-2, 2013	$	310-11	GGRR
	Conference X	Nov. 6, 2013	$	310-11	TES/FAES
	Conference Y		$		
	Subtotal				
		Grand Total			

*Line of Business (i.e. natural gas, electric, EEC, TES/FAES, GGRR, non-GGRR, and Biomethane)

Response:

FEI was asked in BCUC IR 1.77.1 to provide a breakdown of employee expenses by employee "affiliation" (e.g. COPE, IBEW or M&E). This IR asks for expenses allocated to "lines of business" for select individuals. FEI can provide the expenses for the categories requested in the manner set out below. However, FEI is governed by the Personal Information Protection Act, which prohibits the disclosure of personal information of its employees. As a result, FEI is unable to provide the detailed list of employee expense items as requested in the question.

FEI is not organized under different lines of business as suggested in the question. EEC, Biomethane and NGT (GGRR and non-GGRR) are all part of the natural gas business. Please refer to BCUC IR 2.319.1 for a summary of the accounting and reporting for the various areas.

As employees incur expenses, they code these expenses to the relevant charge numbers (i.e. cost centres, internal orders, project numbers) in SAP. Employees undertake this coding in adherence to company procedures as they are the individuals who are able to best assess the nature of the expense. Each expense will be coded to a charge number, either the cost centre that the employee resides in or in certain situations, other cost centres, order numbers, or projects identifying a specific activity or project. The charge numbers are assigned to the appropriate cost category of O&M, capital or deferral (including EEC and the BVA) and to the appropriate entity or class of service.

FEI has provided its O&M employee expenses on a per FTE basis in response to BCUC IR 1.77.1 (approximately $3.7 thousand per employee in 2012). The employee expenses included in that response included all employee-related expenses, such as course fees, training, travel, meals, relocation, and hiring expenses. To be consistent, FEI has used the same definition in providing the information in this response.

In addition to these amounts included in O&M, there are employee expenses charged to the EEC deferral account which are provided below for the requested years, 2010, 2012 and 2013. The expansion of the EEC program did not occur until 2009 so no data is provided for 2007.

- $160 thousand for 2010
- $301 thousand for 2012
- $208 thousand YTD for 2013

No significant employee expense amounts have been charged to the Biomethane Variance Account (BVA) or the NGT fuelling station capital projects. The types of work done on these capital projects do not generally incur employee expenses. Also, the employee expenses per FTE provided in response to BCUC IR 1.77.1 do not include any expenses related to the electric business as those expenses are charged to FBC.

The employee expenses per FTE provided in response to BCUC IR 1.77.1 also do not include expenses charged to TES/FAES. The employees who currently reside in FEI but are focused on FAES projects (approximately 13 employees) incur expenses in support of FAES, and those expenses are allocated 100% to FAES, either the TESDA, FAES O&M, or specific FAES projects. As discussed below, the VP Energy Solutions and Director, Business Development also charges TES/FAES related expenses directly to TES/FAES.

FEI provides the total employee expenses charged to TES/FAES for 2010 through 2013 below. In 2007, the TESDA did not exist and there were no significant amounts charged directly to FAES.

- $101 thousand for 2010
- $116 thousand for 2011
- $76 thousand for 2012
- $75 thousand YTD for 2013

Given the IR's focus on the Executive and Energy Solutions Directors, FEI assumes that the IR is concerned about the allocation of employee expenses to TES/FAES.

The only Executive that spends any significant amount of time on TES/FAES matters is the VP Energy Solutions and External Relations. The President and CEO, VP Operations Support, General Counsel and Corporate Secretary and the VP Strategic Planning, Corporate Development and Regulatory Affairs spend approximately 1 percent to 2 percent of their time on TES/FAES and do not incur expenses related to TES/FAES. The VP Energy Solutions and External Relations is the only member of the Executive engaged in business development activities of the nature that gives rise to employee expenses related to TES/FAES.

For the Directors under the VP Energy Solutions and External Relations, the only Director now working on FAES/TES and anticipated to potentially work on FAES/TES in the future is the Director of Business Development.

The aggregate expenses of the VP Energy Solutions and External Relations and the Director of Business Development and the amount allocated to TES/FAES for the relevant years is as follows:

- $17 thousand for 2007, none of which was charged to TES
- $81 thousand for 2010, of which $18 thousand was charged to TES
- $94 thousand for 2012, of which $30 thousand was charged to TES
- $64 thousand YTD for 2013, of which $12 thousand was charged to TES

The coding of employee expenses to Natural Gas and TES/FAES is undertaken according to the primary purpose of the expense. For the VP Energy Solutions and External Relations, for instance, TES/FAES may be mentioned at a conference, but is rarely if ever the primary purpose of such an event. Further, even if a conference included some emphasis on TES/FAES, there is no practical or meaningful way to quantify how much of a particular expense is related to TES/FAES vs. natural gas. Accordingly, expenses incurred for the primary purpose of the natural gas business are charged to natural gas.

256.1.1 For cost not related to the natural gas or electric lines of business, please explain how employee expenses were allocated to the EEC, TES/FAES, non-GGRR, Biomethane or other lines of business.

Response:

Please refer to the response to BCUC IR 2.256.1.

FORECASTS FOR THE PBR PERIOD OPERATIONS AND MAINTENANCE EXPENSE

257.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.127.2, p. 316

FEU 2012-2013 Revenue Requirement and Rates Decision, p.36

O&M per customer

BCUC 1.127.2 requested actual and approved O&M per customer.

257.1 Please update the table below by adding columns for actual 2011 and 2012 and projected 2013. Include the requested information in a fully functional spreadsheet.

Historical and forecast O&M Expenses by Customer
(000)

	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
FEU Total Gross Nominal O&M Expenses	$206,371	$205,115	$213,167	$220,034	$237,938	$249,063	$261,127	$273,765
FEU Total Gross Real O&M Expenses	226,388	225,957	225,957	228,396	242,220	249,063	256,031	263,075
FEU Average Number of Customers	893	910	923	934	943	953	962	971
FEU Nominal O&M per Customer	**$231**	**$225**	**$231**	**$236**	**$252**	**$261**	**$272**	**$282**
FEU Real O&M per Customer	**$254**	**$243**	**$245**	**$245**	**$257**	**$261**	**$266**	**$271**

(Source: Exhibit B-1, Appendix D-2)

Table 6.2
Percentage Change in O&M expenses by Customer[1]

	2007	2008	2009	2010	2011	2012	2013
FEU Nominal O&M per Customer	**-2.6%**	**+2.6%**	**+2.2%**	**+6.8%**	**+3.6%**	**+4.2%**	**+3.7%**
FEU Real O&M per Customer	**-4.5%**	**+0.01%**	**0%**	**+4.9**	**+1.6%**	**+1.9%**	**+1.9%**

[1]The percentage is calculated by subtracting the O&M in the previous year from the O&M in the current year and then dividing the answer by the O&M in the previous year, and multiplying the result by 100.

(Source: Exhibit B-1, Appendix D-2)

Response:

Provided below is a table for FEI's Historical and Projected O&M Expenses by Customer from 2006 to 2013 as well as in excel format as Attachment 257.1. As discussed in FEI's 2010-2011 RRA, there were a number of changes to costs in 2010 driven by government policy, codes and regulations, customer/stakeholder expectations, demographics and service enhancements.

FEI HISTORICAL AND PROJECTED O&M EXPENSES BY CUSTOMER
(000)

	Actual							Projection
	2006	2007	2008	2009	2010	2011	2012	2013
Total Gross Nominal O&M Expenses [2]	$ 179,206	$ 178,973	$ 185,739	$ 191,946	$ 206,518	$ 213,606	$ 212,269	$ 221,333
Total Gross Real O&M Expenses (Real in 2013 $)	$ 201,692	$ 197,480	$ 200,534	$ 203,172	$ 215,578	$ 217,965	$ 214,244	$ 221,333
Average Number of Customers (restated) [1]	788	802	811	818	824	830	835	841
Nominal O&M per Customer	**$ 227**	**$ 223**	**$ 229**	**$ 235**	**$ 251**	**$ 257**	**$ 254**	**$ 263**
Real O&M per Customer	**$ 256**	**$ 246**	**$ 247**	**$ 248**	**$ 262**	**$ 262**	**$ 257**	**$ 263**

Percentage Change in O&M Expenses by Customer

Nominal O&M per Customer	**-1.8%**	**2.6%**	**2.5%**	**6.8%**	**2.7%**	**-1.2%**	**3.5%**
Real O&M per Customer	**-3.8%**	**0.4%**	**0.4%**	**5.3%**	**0.3%**	**-2.2%**	**2.6%**

1 The average customers for 2006 - 2011 have been reduced by 14,892 to make it comparable to 2012 and 2013. The 14,892 represents the one time SAP customer count adjustment as discussed in Appendix E4 of the Application.

2 Excludes deferred Customer Service O&M for 2012 Actual and 2013 Projection

258.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.127.3, p. 317

O&M per customer

FEI states that "For example, several accounting and operating code changes have occurred since 2007 which preclude using 2007 as a comparative base. IBEW training costs, prior to 2010 were included in loaded labour charge-out rates effectively allocating half of these types of costs to capital and billable work; since the accounting change, these costs are now 100% O&M. Similarly, a number of code and regulation changes were introduced in 2010/2011 particularly CSA Z662, Annex M&N which increased funding requirements around gas asset security and integrity management programs."

258.1 Even with the above qualification, is an increase of 52 percent over 6 years in O&M/customer a cause for concern, especially when O&M/customer was held flat during the PBR period from 2004 to 2007?

Response:

FEI interprets the question to refer specifically to the Operations Department O&M per customer as referenced in the response to BCUC IR 1.127.3 with the 52% increase representing the increase in 2013 Base compared to 2007 Actuals.

FEI offers the following comments to support this 52% increase and to dispel the validity of comparing 2013 Base to 2007 actuals:

- Please refer to response to BCUC IR 2.259.1 for discussion of O&M pressures in operations that occurred starting in 2008 and 2009;
- Please refer to response to BCUC IR 1.127.3 for examples of accounting and operating code changes that have occurred since 2007 which preclude using 2007 as a comparable base;
- The in-sourcing of Customer Service in 2012 required Operations to provide increased levels of support to customers as well as support new business processes, new systems and reporting, including additional meter to cash work that was absorbed by Operations that had previously been borne by Customer Service;
- In 2012, as discussed in Appendix E-4 of the Application, the customer count for FEI was reduced by 14, 892 customers, making the per customer comparison invalid;
- Please refer to response to BCUC IR 1.81.3 that shows total pension and OPEB in FEI increasing from $10.188 million in 2007 to $25.312 million in 2013 Base. By way of the labour loadings, a significant portion of this increase would have been allocated to Operations; and

- In Section D-3.1, page 265 of the Application, the accounting change with respect to the inclusion of retiree pension and OPEB in the labor loadings resulted in a shift of O&M from Corporate to Operations of $1.7 million effective with the 2013 Base.

Further, these historical changes were approved by the Commission. The Operations department O&M on a go forward basis will be managed as part of the Company's overall productivity challenge.

258.2 Does FEI agree that the appropriate comparison from 2007 should be to the 2013 Base cost since pension and OPEB adjustments back in 2007 were relatively minor compared to the large deferrals that have grown in recent years? If not, why not?

Response:

FEI interprets the question to refer specifically to the Operations Department O&M per customer as referenced in the response to BCUC IR 1.127.3 and the question is asking "is 2013 Base cost comparable to 2007, why or why not?" Please refer to the response to BCUC IR 2.258.1.

With regards to the comment in the question "relatively minor compared to the large deferrals that have grown in recent years", FEI interprets this comment to be referencing the increase in pension and OPEB expenses. These increases have been discussed on page 128 of Exhibit B-1 and in response to BCUC IR 2.258.1. To keep the numbers comparable from 2007 to 2013, any O&M impacts of the pension and OPEB increases (amounts not deferred) would need to be normalized from the historical figures to provide a comparison of the impacts over the years.

259.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.127.4, p. 318

O&M per customer

The table in the response to BCUC 1.127.4 shows that the O&M/ customer rose quickly at the end of the last PBR period.

259.1 What were the reasons for this large increase in each of 2008 and 2009?

Response:

FEI interprets the question to refer specifically to the Operations Department O&M per customer as referenced in the table in the response to BCUC IR 1.127.4.

As discussed in Section C – Tab 6, page 358 of the 2010-2011 RRA, "During the first four years of the PBR period, Distribution maintained the actual level of expenditures (expressed on a per customer basis) well below the level of the 2003 Decision. In 2008 and 2009, cost pressures began to cause substantial upward pressure on O&M per customer and those pressures will continue into 2010 and 2011".

Contributing to the cost pressures experienced were increased activities dedicated to mitigating operating risks and ensuring the safety and reliability of the transmission and distribution systems and plant operations. For the transmission system, these activities included vegetation management, pipeline corrosion control, and pipeline integrity programs such as cathodic protection. For the distribution system, activities included system inspections, leak surveys, and preventative and corrective maintenance of equipment, valves, stations, and meter sets.

The level of activities required was influenced by code and standard requirements (i.e. CSA), regulatory requirements, operating conditions, asset age, and the geographic footprint of the transmission and distribution systems.

259.2 In the theory of PBR, a utility is incented to achieve efficiencies and cost savings during a PBR period and those savings would be embedded for the benefit of customers thereafter. Some critics claim that a utility will increase their costs at the end of a PBR period to avoid seeing them embedded for the customers' benefit. Please discuss this with respect to the 2008 and 2009 O&M.

Response:

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

260.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, pp. 55, 121; FEU 2012-2013 RRA Decision, p.3

Development of Base 2013 O&M – Net Productivity (Sustainable Savings)

On page 121, FEI states that is has adjusted the 2013 O&M Projection to the 2013 O&M Base for PBR purposes.

260.1 How many months of actual data were used in the 2013 O&M Projection?

Response:

The 2013 O&M projection was based on the 2013 approved O&M reduced by sustainable savings realized in 2012 and 2013. Please refer to the response to BCUC IR 1.83.1.

In determining the sustainable savings for 2013, amongst other factors, 2013 actual data up to the end of April 2013 was taken into consideration.

260.2 What is the earliest date that FEI will be able to provide 2013 Actual O&M figures?

Response:

FEI will be able to provide the 2013 actual O&M figures in late February 2014.

260.3 In the Application, FEI reports that $14.67 million in “savings” is projected in 2013 for the future benefit of customers. (p. 55)

260.3.1 Please confirm what amount of this projected savings is collected in rates from customers in 2013 that will not be returned / refunded to customers.

Response:

Of the $14.67 million in projected 2013 savings, $10.285 million is expected to be recorded in the Customer Service Variance account and returned to customers through future amortization of the deferral account. Thus, the remaining $4.385 million in 2013 savings will not be directly returned to customers for that year. However, as these savings are used to reduce the 2013 Base O&M amount, they will benefit customers for the 2014-2018 proposed PBR period.

260.3.2 Is it appropriate to call the amounts that the utility has underspent compared to its approved forecast as savings and to say that this is the result of productivity improvements? Please explain.

Response:

Reductions in O&M that will continue in future years result in savings to customers, whether or not they were forecast at the beginning of the test period. From a customer perspective, lower O&M is beneficial if it results in lower rates without compromising customer service and system safety and reliability, which is what FEI has done.

Taking the 2013 Decision O&M as the starting point, the 2013 Base O&M incorporates $14.67 million of savings which will accrue for the benefit of customers for the duration of the PBR.

Of the $14.67 million in savings, $10.3 million was related to the Customer Service department as discussed on page 151 of Exhibit B-1. In the 2012-2013 RRA, FEI had recognized that certain costs within the Customer Service department were difficult to forecast and applied for deferral treatment accordingly. A large portion of these savings are due to FEI arranging a new meter reading agreement at a lower cost than forecast. Additionally, operational efficiencies were achieved which contributed to further savings. Other departments were also able to achieve savings of $4.385 million by reducing costs compared to that Approved.

By taking these actions, FEI has improved productivity which will result in lower O&M cost in future years to the benefit of customers.

260.3.3 Would it not be in the utility's (managers and shareholders) interest to forecast expenses and budgets conservatively so as to come under those budgets in practice?

Response:

FEI prepares realistic and appropriate budgets based on the information available at the time. As explained in the 2012-2013 RRA, this is accomplished through a comprehensive approach to budgeting that includes techniques such as zero-basing, trending, and analysis. Additionally, forecast expenses and budget are subject to rigorous review by management of the Company and the regulatory review process.

Under PBR, which is the focus of this Application, FEI's O&M will be determined by a formula, with the cost drivers in the PBR formula being re-forecast in annual reviews based on recent data.

260.3.4 Please provide FEI's applied for and approved O&M Expenses for 2012 and 2013.

2012 Applied For O&M	2012 Approved O&M	2013 Applied For O&M	2013 Approved O&M

Response:

Below is a summary of FEI's applied for and approved O&M expenses for 2012 and 2013 (before capitalized overhead).

Summary of Applied For and Approved O&M Expenses ($ thousands)

2012 Applied For O&M	2012 Approved O&M	2013 Applied For O&M	2013 Approved O&M
230,189	226,993	241,103	236,003

The FEU 2012 – 2013 RRA Decision on page 3 stated, "the Panel is not persuaded that the Companies have done all they can to optimize productivity and manage cost levels down. The Commission Panel has directed the FEU to reduce their O&M expenditures by $4 million in 2012 and 2013."

260.4 Please confirm whether the $14.67 million reported as savings projected for 2013 is on top of the $4 million reduction directed by the Panel in the 2013 approved amount.

Response:

Confirmed. The $14,67 million is on top of the $4 million reduction directed by the Panel in the 2013 Approved amount.

261.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.129.1, p. 321

Transmission O&M

The table in BCUC 1.129.1 shows the substantial increases in Transmission O&M since 2010.

261.1 What were the corresponding percentage increases in length of transmission pipe in those same years?

Response:

The assumption in the question that increases in Transmission O&M should correspond to percentage change in transmission pipe length is incorrect. Transmission O&M is not specifically tied to pipe length. Pipeline length is a factor in certain types of transmission activities, such as leak survey and line patrol. Other drivers for Transmission O&M are transmission integrity assessments and repairs, right of way activities such as vegetation management and inspections, and meeting depth of cover code compliance. Please refer to the response to BCUC IR 1.129.1 for the explanation of the increases in the Transmission O&M from 2010 to 2013.

Although changes to Transmission O&M do not correspond to changes in km of transmission pipe, the percentage increases in length of transmission pipe from 2010 to 2013 are presented in the table below:

	Transmission O&M ($000s)			
	2010 Actuals	**2011 Actuals**	**2012 Actuals**	**2013 Projection**
O&M ($000s)	$ 7,010	$ 8,209	$ 9,117	$ 9,369
Increase ($000s)	-	$ 1,199	$ 908	$ 252
Increase (%)	-	17.1%	11.1%	2.8%
Km of Transmission Pipe	2,324	2,569	2,332	2,332
% Change in Pipe Length	0%	10.5%	-9.2%	0.0%

Kilometers of transmission pipe fluctuate slightly year over year due to the up or down rating of system pressures (pipe moves into and out of the transmission category depending on pressure ratings), changes to how pipe is measured in geographical information systems (GIS) (i.e. two dimensional versus three dimensional which considers slope), and updates to GIS land bases (conflation).

262.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, p. 141; Exhibit B-1-1, Appendix B2, Key Operating Facts

Operations O&M

> **Operations Review Summary**
>
> In summary, the Projected Operations O&M is in line with the Approved O&M and the various groups within Operations are meeting their 2012 and 2013 commitments. Operations have delivered safe, reliable service to customers and will continue to look for productivity and efficiency opportunities to mitigate the impact of wage/salary inflation. The department has focused on increasing operating productivity, realizing sustainable cost savings, managing risk and workforce demographics and maintaining emergency response times. Emergency response times to all types of gas emergencies have been consistently maintained and continuous safe delivery of gas to customers speaks to the reliability of the FEI gas distribution network and the supporting Operations maintenance and operating programs.

(Exhibit B-1, p. 141)

262.1 Please describe any specific productivity measures and opportunities that the Operations department is focused on.

<u>Response:</u>

The Operations department continues to focus on productivity and efficiency initiatives in the following areas:

- Training programs and employee competencies – ensuring employees receive an appropriate level of training or testing to ensure they meet position qualifications; eliminating or minimizing the need to train employees on a regular cycle who can demonstrate a proficient skill level through an assessment rather than training.
- Minimizing day-time standby – ensure employees have ready access to other types of maintenance work when not actively engaged in customer or emergency work activities.
- Reviewing maintenance plans – asset condition and failure analysis to ensure appropriate maintenance programs are in place to strike a balance between cost and effective management of safety and reliability.
- Claims automation – improve field capture of data on system damage activities thereby eliminating duplicate data entry.
- Work Order management – use tracking systems for the management of maintenance orders to ensure work is completed within specific time constraint to ensure reliability/safety of assets while keeping costs down. Grouping work orders to maximize efficiency of travel time and minimize job start up durations.

- Multi-Unit meter exchanges – work in cooperation with large strata units to organize meter exchanges whereby all necessary exchanges are performed on a single day as compared to the traditional method of individual appointments over many months.
- Adopting new equipment technology – implementing electro-fusion technology to speed up the pipe joining times and improve the quality of every joint to maximize reliability and safety of the constructed gas systems. O&M cost to maintain the new equipment is lower (newer and less complex) and labour hours required to administer the equipment is lower due to a simplified technology (less parts).
- Maintenance order visibility – providing employees the ability to see all work required at a location to potentially complete while on-site thereby minimizing repeat visits to the same location.
- Alignment of Closing/AMFM Completions group to minimize duplication of record capture.
- Enhancements to GIS /mapping systems which will improve field capture of mapping information and reduce drafting/records input of records.
- Electronic forms – using technology to improve data capture.

262.2 Please discuss what is causing the increasing trend in Distribution Pipeline Leaks reported in Appendix B2 of Exhibit B-1-1 from a low of 57 in 2008 to a high of 169 in 2012 and specifically what FEI is doing to address this concerning trend.

Response:

The Distribution Pipeline Leaks reported in Appendix B2 tracks the number of leaks on distribution system mains as reported historically and defined under the current SQI/Directional Indicator framework.

The increased number of leaks in 2010, 2011 and 2012 (average of 158) relative to the low of 57 in 2008 reflects a change in process for reporting and correcting leaks. Commencing in 2006, with the implementation of new processes as part of the Order Fulfillment project, leaks were to be reported by creating an SAP internal document known as a “Notification”. It was discovered in 2009, however, that in many cases leak repair Work Orders were being raised to correct the leak without a corresponding Notification. The statistics for reporting Distribution Pipeline Leaks were generated based on Notifications raised. Due to a failure to consistently raise a Notification for a leak repair, the number of leaks reported for the Directional Indicator during the 2006 and 2009 period (and reported in Appendix B2) were understated. (Reference; 2012-2013 RRA, BCOAPO IR 1.8.3).

As an alternative to the leak repair notification reporting, the FEI internal budgeting process has accurately tracked the historical number of leak repair orders on distribution system mains (Reference; 2012-2013 RRA, BCUC IR 2.20.1) and based on this source for the activity levels, the Appendix B2 numbers are restated as follows:

- 2006: reported 71, restated 145
- 2007: reported 87, restated 88
- 2008: reported 57, restated 112
- 2009: reported 60, restated 122

Distribution system mains in residential areas are typically leak surveyed once every five years whereas similar mains in business districts and special use areas (hospitals, schools, care homes, etc) are surveyed annually. The number of leaks detected and repaired annually varies due to pipe condition, geographic location, age of pipe, pipe material, soil conditions, and corrosion propensity. The Company has a proactive pipe replacement program in place to address any areas where it is more prudent to replace than repair. The number of leaks on mains has been trending higher since 2007 and the Company has responded by establishing a Long Term Sustainment Plan (LTSP) methodology with a view to replacing pipe where needed in a timely manner.

262.3 How many leaks have been reported for 2013 up to end of September 2013?

Response:

105 leaks have been reported on distribution mains up to the end of September 2013.

262.4 Please discuss the statement "emergency response times to all types of gas emergencies have been consistently maintained" given that the information in Appendix B2 of Exhibit B-1-1 that shows Emergency Response times (minutes) increasing from a low of 20:36 in 2007 to a high of 23:48 in 2012.

Response:

The Emergency Response Time appearing in Appendix B2 of Exhibit B-1-1, which is the current SQI, measures average response time to hit line events only. These types of events are a subset of "all types" of emergency events and currently average 1,000 events per year.

"All types" of emergencies are defined internally as including hit lines, gas odour calls, fire calls, and carbon monoxide calls and represent approximately 24,000 emergency events per year. The percent of responses under one hour for all types of emergencies has consistently been in the 97.4% - 97.9% range and the average response time in minutes has improved from 21.4 minutes in 2010 to a consistent 19.7 minutes in both 2011 and 2012. This average response time metric includes regular business hours emergency calls as well as after business hours calls (evenings and weekends).

Table D7 , Appendix D7 (2014-2018 FEI Application, page 6), summarizes the historical response time, number of calls and percent of responses under one hour for the 2010-2012 time period for all types of emergencies.

262.5 What is the average response time for 2013 up to the end of September 2013?

Response:

The average response time for 2013 up to the end of September for hit line emergencies is 24.2 minutes.

The average response time for 2013 up to the end of September for all types of emergencies is 19.4 minutes and the percent of responses one hour or less for all types of emergencies is 97.5%.

262.6 Please list the specific performance metrics that the Operations group are accountable for in determining performance based wage/salary increases.

Response:

As discussed in response to BCUC IR 1.79.3, M&E compensation is made up of base pay and short-term incentive pay. Individual annual base pay adjustments are made within the appropriate salary range for the role based upon sustained long term performance together with the individual's contribution to company goals and allocated among positions while remaining within the overall corporate budget. Short-term incentive pay is performance-based, and is equally dependent on the achievement of individual and corporate objectives.

For the unionized groups, salary and wage increases are negotiated, and provided in accordance with the relevant collective agreement. Increases are not performance-based.

All groups, including Operations, contribute to the attainment of the corporate scorecard measures. Please refer to Attachment 120.2, provided in the response to BCUC IR 1.120.2 for copies of FEI's corporate scorecards and SQI results for the years 2008-2012.

Specific performance metrics that the Operations group are accountable for which impact short-term incentive pay are included in managers' personal objectives and tend to focus on financial management, customer service, leadership and safety, and departmental operations.

263.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.135.3, p. 345

Engineering Services and Project management

FEI states that "The appropriate comparison for 2012 Actual is to the 2012 Approved. 2012 Actual was 18% lower than approved. The 2012 Actual costs were lower than anticipated due to insourcing of LTSP development and challenges experienced by FEI associated with hiring technical staff from the current labour markets. Approximately half of this reduction is considered sustainable, and has been reflected in a lower 2013 Projection and Base to be included in rates in future years. The remainder is a timing difference primarily related to delayed hiring as described below."

263.1 BCUC 1.135.3 asked, "Why were the 2013 Approved costs 25 percent higher than Actual 2012 costs and the 2013 Projected costs 14 percent higher." Given the very large reductions in actual spending compared to approved levels, shouldn't the 2013 Base be reduced by the full variances?

Response:

The variances were for the reasons presented in the Application and discussed in the response to BCUC IR 1.135.3, including challenges associated with hiring technical staff from current labour markets and deferral of project assessments until project identification as a result of LTSP was completed. These delays resulted in the 2012 Actual being lower than what is sustainable on a go-forward basis. As explained in BCUC IR 1.135.3, the majority of the variance is related to delayed hiring, representing resources that FEI requires to plan and deliver required asset programs. Approximately half of the variance is considered to be sustainable.

263.2 Please provide the amount that was forecast for contracting the LTSP development for each of 2012 and 2013.

Response:

Although forecasts did not contain a specific dollar allocation for contracting LTSP development, FEI has estimated the 2012 and 2013 plans for LTSP-related contracting support at $1.2 million for each year.

263.2.1 Please provide an estimate of the amount saved by insourcing the LTSP development for each of 2012 and 2013.

Response:

Actual and forecast expenditures are not recorded such that variances due to insourcing alone can be identified. Key drivers of LTSP-related variances in 2012 and 2013 are due to insourcing as well as a decision to delay project assessments until improved project identification as a result of the LTSP was available.

As indicated in BCUC IR 2.263.2, the 2012 plan for LTSP contracting support has been estimated at $1.2 million. Contracting expenditures for 2012 were $0.2 million. The difference of $1 million is the amount FEI has attributed to variances due to both insourcing and delayed project assessments in 2012.

As indicated in BCUC IR 2.263.2, the 2013 plan for LTSP contracting support has also been estimated at $1.2 million. The current 2013 projection for LTSP contracting support is $0.9 million. The difference of $0.3 million is the amount FEI has attributed to variances due to both insourcing and delayed project assessments in 2013.

264.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, p. 175

Engineering Services and Project management

> FEI has improved productivity and decreased costs. For example, the BC One Call ticket processing automation reduced the cost of processing BC One Call tickets by $600 thousand. Productivity improvements and integration of Engineering Services and Project Management also reduced costs.

264.1 What date was the BC One Call ticket processing automation fully functional?

Response:

The BC One Call ticket processing automation was fully functional on April 30, 2012.

264.2 Please provide the labour and non-labour costs to develop the BC One Call ticket processing automation for each of 2012 and 2013.

Response:

	$000s	
	2012	**2013**
Labour costs (technology)	20	0
Non-labour costs (technology)	180	0

264.2.1 Please also indicate the relative amount of insourcing and outsourcing to develop the BC One Call ticket processing automation.

Response:

Ninety percent of the costs were incurred from outsourcing software development and ten percent of the costs were incurred from insourcing subject matter expertise, training, and testing.

265.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, p. 174

Engineering Services and Project management

- A common Director of Engineering Services for the electric and gas utilities has been appointed. Appropriate decision-making authority is being delegated to lower-level employees and is creating greater accountability for all employees;
- A common Manager, Project Management Office (PMO) for the electric and gas utilities has been appointed, delivering pipeline and above ground gas facility capital projects in a consistent, cost effective project management framework; and

265.1 When where the common Director and common Manager appointments made (month/yr)?

Response:

These appointments were effective January, 2013.

265.1.1 Did these two appointments result in a combined management cost reduction for the group? Please quantify.

Response:

The appointments of Director of Engineering Services and Manager, Project Management Office are the sole contributors to integration-related efficiencies realized to date in Engineering Services and Project Management. This reduction in O&M is included in the amounts shown in the Application on Table C3-2 and comprises a portion of the $1.5 million in productivity (Sustainable Savings) shown on the Engineering Services & PM line of the table.

The Director of Engineering Services position charges 50% of time plus associated expenses to FEI. The Manager, Project Management Office charges 60% of time plus associated expenses to FEI. As the appointments were both effective January, 2013, the 2013 savings prorated on a full year basis are:

- 50% of time less associated expenses for the Director of Engineering Services
- 40% of time less associated expenses for the Manager, Project Management Office

265.2 What is the expected combined labour and management savings from the integration of gas and electric engineering services and project management office expected for 2013 prorated on a full year basis?

Response:

Please refer to the response to BCUC IR 2.165.1.1.

266.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, pp. 178-180, Exhibit B-6, Attachment 1.17.1, p.2

Development of Base 2013 O&M – Operations Support

On page 179 of Exhibit B-1, FEI provides examples of various productivity enhancements within Operations Support including pursuing 3rd party revenue opportunities within Measurement Service, the Radio Network, ICS and Mechanical Service.

266.1 Please provide the actual and projected 3rd party revenues for 2010, 2011, 2012 and 2013.

Response:

The following table outlines the 3rd party revenue for Measurement Services, ICS and Mechanical Services and Radio Network from 2010 projected through to the end of 2013.

3rd Party Revenue	Amount
2010 Actual	$1,351,000
2011 Actual	$1,634,000
2012 Actual	$1,865,000
2013 Projected	$1,889,000

Only a portion of the revenues are based on fixed contracts; therefore there is variability in the revenues on a year over year basis.

267.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.137.2, p. 350

Development of Base 2013 O&M – Operations Support

FEI states that "The Operations Support Department actual 2008 O&M was $8,505 thousand."

267.1 In spite of the changes in accounting classifications and circumstances, isn't this 53 percent increase in 5 years not sustainable and shouldn't some reductions be made to the 2013 Base?

Response:

Operations Support is not forecasting an increase of 53 percent over the PBR Period. As shown in Table C3-26, the total anticipated increase is closer to 17 percent or approximately 2.3 percent annually on average. This demonstrates that the increase in costs that occurred over the past 5 years is indeed sustainable and is in fact expected to be sustained. The increases were driven by a number of items that were discussed in past RRAs, including maintaining the existing radio network repeater sites, additional gas detectors, pipeline emergency response equipment, electronic meters and meter sets. Further costs were incurred for additional AMR network fees, the introduction of Measurement Canada's mandatory sampling plan SS-06 and to support additional capital work to sustain the existing pipeline.

In 2013, Operations Support is projecting a cost savings of approximately $1.1 million as compared to the Approved O&M despite facing both labour and non-labour cost pressures related to government regulation, reliability standards and customer expectations. A contributing factor toward achieving these savings was the concerted effort to implement internal productivity enhancements throughout the department as outlined on page 179 of the Application. These cost savings are reflected in the 2013 Base and are forecasted to be sustained throughout the PBR Period to the benefit of customers. As such, the 2013 Base is reasonable and prudent.

268.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.137.2, p. 351

Facilities

FEI states that "The Facilities Department actual 2008 O&M was $5,890 thousand."

268.1 In spite of the changes in accounting classifications and circumstances, is a 57 percent increase in 5 years unsustainable and should some reductions be made to the 2013 Base? Please explain why, or why not.

Response:

The majority of the Facilities increase between 2008 and 2013 was a result of the addition of two facilities to support the two new contact centres brought into service as a result of the insourcing of the Customer Service function. The two new contact centres were approved through the CPCN Order G-23-10 and the 2012-2013 RRA Order G-44-12. After removing this impact, the remainder of the cost increase through this period amounted to 15 percent (approximately 3 percent per year on average) which was driven by external contracts, services and materials costs. As such, FEI believes the 2013 Base is reasonable and prudent.

269.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.138.2, 1.139.1, pp. 352-353

Facilities

FEI identifies that its average FTEs grew from 10 to 17 between 2008 and 2013 while the number of buildings increased from 65 to 72.

269.1 Please explain this 70 percent increase in FTEs for an 11 percent increase in number of buildings and why the 2013 Base shouldn't be reduced.

Response:

The actual FTE for the years 2008 through 2012 was not representative of the support work that Facilities performed in those years as it did not include contractor back fills. In addition, comparing Facilities FTEs to the number of buildings is not meaningful because Facilities staffing is based on the size and type of buildings and equipment required to support the building. These points are discussed below.

Facilities' required headcount was not attained over the 2008 to 2012 period due to job description re-writes, retirements and difficulty in finding skilled trade labour. As stated in the 2012-2013 RRA on page 243, "Facilities employee headcount for 2010 was not attained as a result of competency review and job description re-writes for the Maintenance roles which require a delay in hiring. During the years, vacancies were back filled by contractor services to ensure operations and maintenance were not impacted." Consistent with explanations provided in other responses, a focus on FTEs is misleading as there is not always a direct correlation between FTEs and costs, particularly in the short term. For the Facilities department specifically, the FTE statistic is misleading because contractor back-fill is not considered in the FTE count. The percent increase on a restated basis including work completed by contractors between the 2008 and 2013 period is 13 percent.

Furthermore, industry standards for Facilities staffing is not based on the number of buildings but rather size of building, type of building and required equipment to support the building. Facilities increased the building count by eleven percent between 2008 and 2013; however, the square footage increased by twenty five percent. The increase in square footage would be a better indicator for comparison to staffing additions.

As such, FEI believes the 2013 Base is reasonable and has been prudently managed, with the ratio of employees per square foot declining over the period.

269.2 Please explain the increase in FTEs and number of buildings in the context of relatively flat customer growth and declining total gas deliveries.

Response:

FEI does not agree that there should be a correlation between employees in the Facilities department and the level of gas deliveries. Please refer to the response to BCUC IR 2.269.1.

269.3 Does FEI plan to integrate some of these roles and facilities with the electric utility?

Response:

FEI has integrated the Facilities Manager role in late 2012 with the electric utility. This has resulted in a savings to FEI and FBC. FEI will continue to look for opportunities to integrate.

269.3.1 Has any progress been achieved in this area in 2012 or 2013?

Response:

Please refer to the response to BCUC IR 2.269.1.

270.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, pp. 187-189; Exhibit B-6, Attachment 1.17.1, p. 2

Development of Base 2013 O&M – Environment Health and Safety

> **3.12.5 Summary of EH&S Department**
>
> EH&S historical spending has been stable and FEI's high-level forecast is for incremental increases in the 2014-2018 period to cover inflation of labour and benefits for existing employees, and inflationary non-labour increases. EH&S expects that there may be additional regulatory requirements, the cost of which will need to be absorbed through productivity offsets.

(Exhibit B-1, p. 189)

270.1 Please reconcile the statement that EH&S historical spending has been stable with the following information below. Please complete the information for FTE's included. Include the requested information in a fully functional spreadsheet.

Particulars		Reference	2008	2009	2010	2011	2012	Projection 2013	Approved 2013	Base 2013
Environment Health & Safety Total		460	1,191	1,457	2,427	2,445	2,481	2,681	2,999	2,872
Percent Change				22.3%	66.5%	0.8%	1.4%	8.1%		
Average Annual Increase								25.0%		
FTE's - (FEI Gas)										
FTE's - (FBC Electric)										

> Many processes, programs, and operating standards in the gas and electric utilities have been aligned, and further program alignment will occur wherever appropriate. For example, the WHMIS (Workplace Hazardous Materials Information System) was aligned, the incident investigation process was synchronized, and the Emergency Planning program planning was aligned as was the selection of external consultants wherever operationally feasible, so as to take advantage of any economies of scale that exist. Certain roles were also aligned between the gas and electric divisions. In aligning the professional expertise of existing gas and electric division EH&S employees across all utility project works and especially during emergency response, the Company is enhancing internal cross-divisional operational support capabilities without increasing the current number of employees in the department. Ongoing reviews of opportunities for further process alignment will continue; however, varying regulatory and utility operational requirements may limit alignment in all program areas.

(Exhibit B-1, p.187)

<u>Response:</u>

FEI has provided the requested table below. FEI has not included the line "FTEs (FBC Electric)" as the total number of FTEs in FBC are not relevant to the discussion of FEI's O&M costs.

Particulars	Reference	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	Projection 2013	Approved 2013	Base 2013
EH&S Total ($000s)	460	1,191	1,457	2,427	2,445	2,481	2,681	2,999	2,872
Percent Change			22.30%	66.50%	0.80%	1.40%	8.10%		
Average Annual Increase							25%		
FTEs (FEI Gas)		8	10	11	12.5	11.5	12	12	12

A review of this table supports FEI's statement that EH&S' historical spending has been stable, when taking into consideration that the years being referenced were 2010 through 2013. (Historical spending was presented in the Application from 2010 through 2013.)

EH&S experienced a step increase in costs in 2010 to respond to changing codes and regulations in its area of responsibility. The increases that were approved consisted of a Public Safety Manager, an Emergency Planning Manager, and a number of other program-related costs that were listed in Table C-6-33 on page 398 of FEI's 2010-2011 RRA. The increase in 2013 as compared to 2012 actual was described on page 186 of this Application as "an increase in non-labour compared to 2012 Actual due to a delay in commencing some environmental-related consulting work that was expected to commence in 2012". Other than the associated FTE increases that occurred in 2010 and 2011, headcount has also been stable. FEI notes that FTEs cannot be tied directly by year to cost incurrence due to timing of when employees were hired, the use of external resources to temporarily fill roles, and cross-charging between gas and electric divisions. EH&S' 2013 Projection is still well below the 2013 Approved.

270.2 In what year(s) were the many processes, programs, operating standards and personnel roles alignments completed with the electric utility?

Response:

The alignment of the processes, programs, and operating standards is ongoing and has not yet been fully completed. The company, in 2011, implemented common overall management (through a cross charging arrangement) for the department, as well as a common Emergency Management and Public Safety function. The OHS and Environmental roles in the group continue to support the gas and electric operating divisions respectively, and are working to align all standards, as appropriate, where like regulatory requirements exist.

270.3 Have these efforts been accomplished with existing personnel?

Response:

Yes, these efforts have been accomplished with existing personnel.

270.4 Please provide the specific personnel roles that have been aligned.

Response:

The following roles have been aligned to provide support for the Company's EH&S programs:

1. Director, EH&S;
2. Manager, Emergency Planning and Business Continuity;
3. Operations Compliance Manager; and
4. Public Safety Manager.

270.5 Will these efforts result in specific productivity improvements in the following areas:

- Program maintenance and management labour
- Program (software, storage, printing, training, reporting etc) costs

Response:

Yes, these efforts have resulted in productivity improvements in the two areas listed, and this is expected to continue as integration activities continue; however, a reduction in resources and expenses will be highly unlikely.

270.6 What percent of the effort of the alignment or integration opportunities in this department are expected to be complete by the end of 2013?

Response:

FEI cannot provide the requested percentage as it is not known whether any further integration opportunities will be found by the end of 2013, and because integration opportunities depend on how the company's organizational structure will evolve.

270.7 Would it be reasonable to say the productivity benefits of the alignment efforts expended prior to the end of 2013 may largely be realized in the 2014 and beyond period?

Response:

Productivity benefits are being realized and will continue to be realized as alignment efforts are implemented, based on constraints that will be determined by operating and regulatory requirements. Any productivity benefits that are achieved will contribute towards FEI achieving its productivity factor under PBR.

> FEI is required to report on Greenhouse gas emissions in accordance with the requirements of the *Greenhouse Gas Reduction (Cap and Trade) Act*. The regulation sets out the requirements for the reporting of greenhouse gas emissions by FEI, as per the requirement for B.C. facilities emitting 10,000 tonnes or more of carbon dioxide equivalent emissions per year; this requirement began on January 1, 2010. Those reporting operations with emissions of 25,000 tonnes or greater are required to have emissions reports verified by a third party. As the regulation evolves, additional requirements are being reviewed with Regulators; and may result in additional measurement, reporting, and verification costs over time.

(Exhibit B-1, p. 188)

270.8 Please provide the operations Greenhouse gas (GHG) emissions for the years 2010, 2011, 2012 and projections for 2013 in total CO2 equivalent and on a per customer basis.

Response:

This response addresses BCUC IRs 2.270.8 through BCUC IR 2.270.8.2.

The primary drivers for the emissions' inventory for FEI operations are compressor and line heater fuel usage that is required to meet demand as related to process or industrial loads, new assets that are to be commissioned, cold weather conditions, or for maintenance that is required to efficiently and safely operate the natural gas system. Annual emissions fluctuate due to variations in operational requirements from year to year.

GHG emissions for the company (in total CO2 equivalent) for 2010 to 2012 have been provided below. The reported value for 2010 is not comparable to the reported values for 2011 and 2012 due to changes in calculation methodology, as directed by the provincial regulator, that occurred for reporting in 2011 and 2012.

- 2010: 74,414 tCO2e
- 2011: 88,865 tCO2e
- 2012: 88,465 tCO2e

FEI does not yet have the data compiled for 2013, and cannot provide a 2013 projection of total CO2 equivalent at this time. Reporting for 2013 is due by March 31, 2014.

FEI does not report GHG emissions levels on a per customer basis.

GHG emissions per customer is not an appropriate productivity metric as GHG system operations emissions covered by provincial reporting requirements for FEI are not directly related to the number of customers nor to the productivity of employees that work on the system. Rather, emissions vary annually depending on system operating requirements from year to year and are managed in order to minimize all releases into the natural environment.

270.8.1 What are the specific drivers of GHG emissions in FEI's operations?

Response:

Please refer to the response to BCUC IR 2.270.8.

270.8.2 Would GHG emission per customer be an appropriate productivity metric? (i.e. more efficient use of resources) Please explain.

Response:

Please refer to the response to BCUC IR 2.270.8.

271.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Tab D, Section 4.3.3-.4, p. 301-2; Exhibit B-11, BCUC 1.54.2

Development of Base 2013 O&M – Net Productivity (Sustainable Savings) - Gas Asset Records and BCOne Call Projects

"The completion of this project [Gas Asset Records Project] is expected to extend from 2015 to 2017." (Exhibit B-1, Tab D, Section 4.3.3, p. 301)

"The Technology Stream was completed on schedule and the Conflation Stream is on track to be completed in 2014 as planned. The completion of the Data Consistency Stream has been extended from 2014 to 2017…" (Exhibit B-1, Tab D, Section 4.3.4, p. 302)

271.1 Please provide the business cases for the Gas Asset Records and the BCOneCall Projects.

Response:

Both of these projects have already been reviewed and approved by the Commission in Order G-44-12 (pages 122 and 124) based on the evidence provided. The descriptions that were provided in the 2012-2013 RRA on pages 411 through 418 are summaries of the business cases for these two projects. Please refer to Attachment 271.1 for the extracted the pages from that application.

"Any savings from the Gas Assets Records project, and any incremental savings above the $600 thousand embedded in the 2013 Base O&M for the BCOneCall project, that are achieved during the PBR period will serve to close the gap between FEI's total forecast O&M costs and the formula O&M that is recovered from customers (estimated at over $12 million by the end of the PBR period) as well as offset other cost pressures that FEI has not forecast but that will inevitably arise." [Underlined for emphasis] (Exhibit B-11, BCUC 1.54.2)

271.2 Given that the Gas Asset Records and the BCOneCall projects were approved by Commission Order G-44-12, should the incremental savings above the $600 thousand embedded in the 2013 Base O&M for the BCOneCall project and the saving from the Gas Asset Records project be treated as a reduction to the Base Year O&M for 2014 – 2018? Please explain why, or why not.

<u>Response:</u>

No. Future incremental savings above $600 thousand should not be treated as a reduction to the 2013 Base O&M for the reasons explained in the responses to BCUC IRs 1.54.1 and 1.54.2.

Please also refer to the response to BCUC IR 2.272.2 for a discussion of the issue.

272.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.151.1

Development of Base 2013 O&M – Project Portfolio Benefits

272.1 In the same format as the table in BCUC 1.151.1, please provide the Financial Benefits Category per project for the 2010-2012 Business Technology Portfolios by year. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

As detailed in Exhibit B-1-1, Appendix C4, FEI developed the Benefits Management practice in response to Directive 42 from the 2012-2013 RRA Decision. As such, the tools and techniques developed in support of this practice including the Financial Benefits categorization have only been applied to the 2013 Business Technology Portfolio and for all subsequent years.

Business Technology projects from previous years including 2010 to 2012 do have supporting business cases but their respective benefits were not captured in the same format and approach as the new Benefits Management practice.

272.2 Given that the 2010-2013 Business Technology Portfolio costs were recovered in rates and review in previous applications should the saving from these projects be treated as a reduction to the Base Year O&M for 2013 – 2018? Please explain why, or why not.

Response:

No. The identified financial benefits from 2010 to 2012 Business Technology projects have already been incorporated in FEI's 2013 Base O&M. Since the identified financial benefits from 2010 to 2012 Business Technology projects have already been incorporated in FEI's 2013 Base O&M, this is effectively a rebasing of the benefits and there is no reason to make a further adjustment. Likewise, and as detailed in the response to BCUC IR 1.151.1, financial benefits captured in the newly introduced Benefits Management practice for 2013 and future years were considered in determining FEI's proposed productivity improvement factor for 2014 through 2018. This is one of the elements that has led to a decision to include a positive X-Factor as part of the Plan. By capturing these benefits as part of a rebasing, FEI could not propose a positive X-Factor. Rather, even including a stretch factor the proposed value of the X-Factor would become negative consistent with the negative trend for gas LDCs.

FEI's delivery rates for the PBR Period will be calculated using the PBR formula, not using the individual departments' high level forecasts that were included in Section C of the Application. FEI will be managing the achievement of any savings or incremental costs on a Company-wide basis as part of the overall challenge FEI has in meeting its O&M and capital targets under a PBR Plan that includes a large and significant X-Factor. This latter point is particularly important because of the number of years that FEI has operated under PBR. Empirical results show that the longer the utility operates under PBR the closer the X-Factor comes to the actual level of technical change across the industry. Put another way, the X-Factor is reduced over time.

The base year for a PBR is a starting point off of which future productivity is measured. The base should reflect the current level of required resources. If the Commission were to reduce the base for every potential productivity or savings that FEI is aware of, not only would this be asymmetrical, as there are many cost increases that FEI will encounter during the PBR period that it will be required to manage, but the result would be that FEI would have no opportunities remaining to achieve its significant productivity target during the PBR period, and would not have a reasonable opportunity to earn a fair return. This would be contrary to the intent of PBR, which is to incent the utility to find future productivity savings.

273.0 Reference: FORECASTS FOR THE PBR PERIOD – OPERATIONS AND MAINTENANCE EXPENSE

Exhibit B-11, BCUC 1.54.3; Exhibit B-11-1, BCUC 1.81.2

Benefits from specific IT projects approved in the 2012-13 RRA

Table 1: Updated Table from the 2010-2011 TGI RRA, BCUC 1.128.2

	2011 Actual	2012 Actual	2013 Projected	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Number of FTE Staff	20	18	17	17	16	16	17	17
Total Cost of FTE[1]	840	860	840	900	910	980	1,100	1,150
$ (thousands) per FTE			$49.4	$52.9	$58.9	$61.3	$64.7	$67.7
				7.1%	11.3%	5.6%	5.6%	4.6%

Increases at average 6.5% 2013-2018

(Excerpt from Exhibit B-11, BCUC 1.54.3)

273.1 Please confirm, or explain otherwise, the following observations which have been made based on the data in the above table and from BCUC 1.81.2 in Exhibit B-11-1:

(i) The data for the total cost of FTEs from 2013-2018 in Table 1 provided in the response to BCUC 1.54.3 increases at 6.5 percent per year, while the number of FTE remains almost constant over the same period.

(ii) The cost for 17 FTE in 2013 is the same as for 20 FTE in 2011.

(iii) Gross O&M increases from Base 2013 to Forecast 2018 by 3 percent per year in the response to BCUC 1.81.2 in B-11-1.

Response:

FEI responds to each observation below.

(i) Confirmed.

a. The total number of FTEs required to process BC One Call requests and meet the 2 day turnaround time is required by regulation. The FTE number is calculated by reviewing the average time it takes to process a BC One Call request and multiplying by the number of requests by month. The number of FTE staff varies by month and the FTE number shown in Table 1 is the staff required for the peak months from March through October.

b. The total FTE cost to process BC One Call requests includes forecast ticket volume growth and minor inflation. The cost number is calculated as the average cost to process a BC One Call request multiplied by the forecasted volume. Only the costs associated with the actual time spent processing tickets is included in the table.

c. The relationship observed indicates that each employee will increase productivity over the PBR period.

(ii) Confirmed. In 2011, FTE staff were mostly new hires paid at the minimum of their job grouping. With efficiency gains through automation FEI did not hire new staff and existing staff received increases (step increases and negotiated settlements) as per the COPE Collective Agreement. More FTE staff were required during peak BC One Call request times in 2011 than in 2013 because it took longer to process each ticket prior to this project. Benefits received in the Technology Stream of the BC One Call project allowed a reduction in the FTE required to process BC One Call requests. In 2013 FEI was able to redeploy/reduce more staff during non-peak times.

(iii) The O&M costs described in Table 1 (above) are a subset of the overall Engineering Services & Project Management costs described in BCUC 1.81.2 in B-11-1. Cost increases as calculated in this table would be offset by decreases in other areas.

273.2 Please explain why the labour cost for the BC OneCall staff would increase at 6.5 percent per year. For example, is this a result of a fixed step increase function for the union staff in addition to any annual labour inflation?

Response:

Please refer to the response to BCUC IR 2.273.1.

274.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.81.1; Exhibit B-1, Section 3.2, p. 123

Exhibit B-1-1, Appendix F6, p. 3, Line 27

Comparative O&M 2007 through 2018

On page 123 of the Application, FEI states, "Actual 2012 O&M was approximately $14.7 million lower than the approved amount, of which $7.4 million was captured in the Customer Service Variance deferral account and will be returned to customers." (Exhibit B-1, p. 123)

The Total Gross O&M Expenses for Actual 2012 provided in Appendix F6 is $219,704,000. (Exhibit B-1-1, Appendix F6, p, 3, Line 27)

In response to BCUC 1.81.1, FEI provides reconciliation between Actual 2012 O&M of $212,269,000 shown in Table C3-1 of the Application and Actual 2012 O&M of $220,619,000 shown in Appendix B2 of the Application. The main reconciling item is the $7.4 million Customer Service Deferral.

274.1 If the $7.4 million Customer Service Deferral relates to O&M costs **not** incurred, please explain why FEI would include the $7.4 million as part of Actual 2012 O&M in Appendix B2 and in Appendix F6.

<u>Response:</u>

The schedules provided in Appendix B2 and F6 reconcile to FEI's financial schedules provided in this RRA and also in the Company's Annual Reports filed with the BCUC. In those schedules, FEI recognizes the $7.4 million as an expense to the Company with an offsetting credit to the Customer Service Variance deferral account as demonstration that the customer is receiving the benefit of the $7.4 million savings in 2012, not the shareholder.

The credit for the reduced spending can only exist in one place on the financial schedules, either in O&M or in the deferral account, but not both. This treatment is consistent with the practice for other expense items that have a deferral to capture the variance in spending from approved. For example, the Property Tax Variance account uses this approach, and more recently the Depreciation Expense Variance account. Please refer to Section E, Schedule 3, lines 25 and 26, columns 3 and 4 which both show that the 2013 approved and actual expense are equal for Property Tax and Depreciation Expense, respectively. Also refer to Section E, Schedule 47, Line 20, Column 4 which shows the 2013 Property Tax Variance addition to the deferred charges and Schedule 48, Line 19, column 4 which shows the 2013 Depreciation Expense Variance addition to the deferred charges.

In comparison, the tables provided in the Application are net of the $7.4 million savings to demonstrate the true costs that have been incurred and to reflect the Customer Service savings that accrued in 2012 and 2013 as being passed on to the benefit of customers for the duration of the PBR.

275.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.82.1; Exhibit B-1, Tab C, Section 3.2, p. 123

Development of Base 2013 O&M – Analysis of 2012 Actual/Approved

In response to BCUC 1.82.1, FEI provided a table illustrating the 2012 Department O&M review of sustainable versus temporary savings.

2012 Department O&M Review ($ thousands)

	2012 Actual	Customer Service Deferral	2012 Sustainable Savings	2012 Temporary Savings	2012 Approved
Operations	59,806		(203)	(1,004)	58,599
Customer Service	40,737	7,435	342	601	49,115
Energy Solutions & External Relations	18,075		(859)	298	17,509
Energy Supply & Resource Dev	3,488		-	176	3,664
Information Technology	23,442		691	420	24,553
Engineering Services & PM	13,599		1,333	1,773	16,705
Operations Support	11,038		1,147	(53)	12,132
Facilities	9,563		10	(64)	9,509
Environment Health & Safety	2,481		211	57	2,749
Finance & Regulatory Services	12,149		265	715	13,129
Human Resources	8,610		53	320	8,983
Governance	7,366		-	236	7,602
Corporate	1,915		-	828	2,743
	212,269	7,435	2,989	4,299	226,993

(Exhibit B-11, BCUC 1.82.1, p. 218)

275.1 In the columns titled “Customer Service Deferral,” “2012 Sustainable Savings,” and “2012 Temporary Savings,” please confirm that a credit balance indicates incremental costs over the approved amounts for 2012, while a debit balance indicates savings.

Response:

Confirmed – a positive (debit) number indicates a savings, while a negative (credit) number indicates a cost. This is because the Actual is being reconciled to the Approved.

275.2 Please provide a breakdown of all the activities for each O&M department which would result in the over expenditure indicated in the above table. Please describe the nature of the incremental expenditures. Please also describe why each incremental expenditure was classified as either temporary or sustainable.

Response:

The nature of the major drivers of incremental expenditure and savings and the nature of any under or over expenditures have been outlined in Section C-3 of the Application and elaborated on in response to various information requests, as shown below:

	O&M Section	BCUC IR1	BCUC IR2
Operations	C3.4	127, 128, 129, 130 series	261.1, 258 series, 259.1
Customer Service	C3.5	88 through 97 series	251 and 278 series
ES&ER	C3.6	98 through 111 series	254 series, 279 to 288 series
ES&RD	C3.7	133 and 134 series	254 series
IT	C3.8	114 to 116 series	272 and 290 series
Engineering/PMO	C3.9	135 and 136 series	263 through 265 series
Operations Support	C3.10	135 series	266.1, 267.1
Facilities	C3.11	138 to 140 series	268 and 269 series
EH&S	C3.12	141 series, 142.1	270 series
Finance & Regulatory	C3.13	117 and 118 series	291 and 292 series
HR	C3.14	119.1, 120 series	
Governance	C3.15		
Corporate	C3.16	122.1, 182.1	329 series, 330.1, 352 series

FEI does not attempt to quantify individual activities that give rise to department O&M over-spend or savings at a total Company level. In assessing productivity, FEI compares department results at the highest and most beneficial level which is the total O&M spend with respect to allowed. If departments experience sustained savings with respect to their allowed O&M, this indicates departments have been successful in their efforts to realize productivity gains. If departments experienced sustained over-spend with respect to their Allowed O&M, this recognizes the development of unplanned pressures that over-rode departmental efforts to realize productivity gains.

As explained in the response to BCUC IR 1.82.1, sustainable savings have been interpreted as lasting through the term of the PBR. This means that any savings identified as lasting beyond 2013, by virtue of their inclusion in the 2013 Base O&M would qualify as sustainable savings.

As explained in response to BCUC IR 1.82.1, temporary savings include initiatives or hiring that was delayed pending the 2012-2013 RRA Decision, employee vacancies where recruiting was planned or underway, as well as any one-time events either positive or negative that were not forecast to re-occur.

FEI's department managers have developed a 2013 O&M Projection by department, that can be relied upon to establish a 2013 Base O&M as a meaningful starting point for the PBR. The 2013 Projection was compiled by adjusting the 2013 Budget a) to incorporate FTE levels and an extrapolation of annualized savings, based on those that were achieved in the first 4 months of 2013, and b) to recognize pressures and opportunities of a permanent nature identified for 2013. Comparing the 2013 O&M Projection to the 2013 Allowed O&M results in the assessment of sustainable savings.

The sustainable savings identified by comparing 2013 O&M Projection to 2013 Allowed O&M reflect the sustainable savings that have accumulated during 2012-2013. The 2013 Allowed O&M included a $4 million 'productivity challenge' that was allocated between departments. Department managers were tasked with using their knowledge of the business and a review of FTE levels, to allocate the net sustainable savings between 2012 and 2013. This then drove the split between 2012 sustainable and temporary savings, and as well the allocation of savings between labour and non-labour. Attempting to provide substantive definition to the allocation of savings between sustainable and temporary, or labour and non-labour would be a futile effort.

The 2013 O&M Projection is of key importance, and this is where FEI's efforts were concentrated.

275.3 Please provide a breakdown of all the activities for each O&M department which would result in the savings indicated in the above table. Please describe the nature of the savings. Please also describe why each savings was classified as either temporary or sustainable.

Response:

Please refer to the response to BCUC IR 2.275.2.

On page 123 of the Application, FEI states, "In total, FEI is projecting $9.4 million in sustainable labour savings and $5.3 million in sustainable non-labour savings. The labour savings arise primarily in the Operations, Information Technology, Engineering Services & Project Management, Operations Support, Human Resources and Finance/Regulatory departments." (Exhibit B-1, p. 123)

In response to BCUC 1.82.1, FEI states, "This review of savings did not entail an analysis of savings between labour and non-labour." (Exhibit B-11, BCUC1.82.1)

275.4 For the columns titled "2012 Sustainable Savings" and "2012 Temporary Savings" in the table provided in BCUC 1.82.1 (recreated above), please further separate the incremental costs/savings for each department into labour and non-labour.

Response:

As indicated in response to BCUC IR 2.275.2, FEI assesses department results at the highest and most beneficial level which is the total O&M spend with respect to Allowed. As stated in the response to BCUC IR 1.82.1 where FEI split the 2012 amounts between sustainable savings and temporary savings, this review of savings did not entail an analysis of savings between labour and non-labour.

FEI has provided the labour vs. non-labour changes by department in the tables included in Section C3, and the temporary vs. sustainable savings by department. FEI has also provided explanations of these savings in the Application and further details in response to IRs. FEI, however, does not have available a break down of each of the temporary and sustainable items into labour vs. non labour for the reasons explained in the response to BCUC IR 2.275.2.

In response to BCUC 1.82.1, FEI states, "Temporary savings include initiatives or hiring that was delayed pending the 2012-2013 RRA Decision, employee vacancies where recruiting was planned or underway, as well as any one time events either positive or negative that were not forecast to re-occur."

275.5 Please provide a list, by department, of O&M expenditures deferred from 2012 to 2013. For each department, please provide a description of the deferred expenditures and please indicate whether these deferred expenditures have been spent in 2013.

Response:

As discussed in the Application, the 2013 Projected O&M with adjustments forms the base level of O&M for the PBR Period. As indicated in the response to CEC IR 2.1.3, the basis for the 2013 O&M Projection was the 2013 O&M Budget which was built in the fall of 2012, utilizing FEI's approach of constructing detailed budgets that relied upon trending and analysis as well as zero-basing. This budget was constructed to encompass a full year of planned activity.

In this fashion, any planned expenditures that were not spent in 2012 were more correctly classified as 'temporary savings' that would not be expected to impact 2013

As discussed in response to BCUC IR 2.275.2, FEI does not maintain a comprehensive list of each of these items. Each department is responsible for their 2013 O&M Projection.

In response to BCUC 1.82.1, FEI states, "Sustainable savings have been interpreted as lasting through the term of the PBR." (Exhibit B-11, BCUC1.82.1)

275.6 Please explain why it is necessary that in order for a savings to be considered "sustainable" it must last through the entire term of the PBR.

Response:

To clarify, sustainable savings are those that have been identified as lasting beyond 2013, which are then included in the 2013 Base O&M as the starting point for the O&M Formula. Savings incorporated into the 2013 Base O&M therefore last throughout the term of the PBR from a ratepayers' perspective.

275.7 Please indicate if there are savings listed in the "temporary" column for 2012 that are expected to at least last beyond 2014.

Response:

There are no savings listed in the "temporary" column for 2012 that are expected to last beyond 2014. Please refer to the response to BCUC IR 2.275.6. Please also refer to the response to BCUC IR 1.82.1 where temporary savings in 2012 are described to include "initiatives or hiring that was delayed pending the 2012-2013 RRA Decision, employee vacancies where recruiting was planned or underway, as well as any one time events either positive or negative that were not forecast to re-occur."

275.7.1 If so, please provide a listing of the savings that meet this criterion.

Response:

Please refer to the response to BCUC IR 2.275.7.

276.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.83.1; Exhibit B-1, Tab C, Section 3.2, pp. 123-124

Development of Base 2013 O&M – Net Productivity (Sustainable Savings)

In response to BCUC 1.83.1, FEI provided a table illustrating the 2013 Approved and 2013 Projections for each O&M department. This table has been reproduced below for ease of reference.

2013 Department O&M Review ($ thousands)

	2013 Projection	Customer Service Deferral	2012 Sustainable Savings	2013 Sustainable Savings	2013 Approved
Operations	63,509		(208)	(117)	63,189
Customer Service [1]	41,825	10,285	342	-	52,452
Energy Solutions & External Relations	19,215		(859)	(175)	18,181
Energy Supply & Resource Dev	4,000		-	(262)	3,738
Information Technology	24,217		691	471	25,379
Engineering Services & PM	15,456		1,333	167	16,956
Operations Support	11,867		1,147	(24)	12,990
Facilities	9,249		10	-	9,259
Environment Health & Safety	2,681		211	108	2,999
Finance & Regulatory Services	13,279		265	641	14,184
Human Resources	8,458		53	-	8,511
Governance	7,935		-	-	7,935
Corporate	(358)		-	587	230
Total	221,333	10,285	2,990	1,396	236,004

(Exhibit B-11, BCUC 1.83.1, p. 220)

276.1 In the columns titled "Customer Service Deferral," "2012 Sustainable Savings," and "2013 Sustainable Savings," please confirm that a credit balance indicates incremental costs over the approved amounts for 2013, while a debit balance indicates savings.

Response:

Confirmed - a positive (debit) number indicates a savings, while a negative (credit) number indicates a cost. This is because the 2013 Projection is being reconciled to the 2013 Approved.

276.2 Please provide a breakdown of all the activities for each O&M department which would result in the over-expenditure indicated in the column titled "2013 Sustainable Savings." Please describe the nature of the incremental expenditures.

Response:

Please refer to the response to BCUC IR 2.275.2.

276.3 Please provide a breakdown of all the activities for each O&M department which would result in the savings indicated in the column titled "2013 Sustainable Savings." Please describe the nature of the incremental savings.

Response:

Please refer to the response to BCUC IR 2.275.2.

276.4 Please include an additional column to the above table which provides a breakdown of 2013 Temporary Savings or over-expenditures by department. Include the requested information in a fully functional spreadsheet.

Response:

As there are still 2 months of operational results remaining in the 2013 calendar year, FEI has not yet identified any 2013 temporary savings or temporary over-expenditures.

276.4.1 For each department, please provide a description of the activities which have resulted in either the over-expenditure or savings.

Response:

Please refer to the response to BCUC IR 2.276.4.

On page 123 of the Application, FEI states, "In total, FEI is projecting $9.4 million in sustainable labour savings and $5.3 million in sustainable non-labour savings. The labour savings arise primarily in the Operations, Information Technology, Engineering Services & Project Management, Operations Support, Human Resources and Finance/Regulatory departments." (Exhibit B-1, p. 123)

In response to BCUC 1.83.1, FEI states, "This review of savings did not entail an analysis of savings between labour and non-labour." (Exhibit B-11, BCUC 1.83.1)

276.5 Please explain why FEI was able to provide the description of labour and non-labour savings provided on pp. 123-124 of the Application, but unable to separate the sustainable incremental expenditures and savings for 2013 into labour and non-labour.

Response:

Please refer to the response to BCUC IR 2.275.4.

276.5.1 If FEI is able to provide this analysis, please further separate the 2013 Sustainable Savings/2013 Incremental Costs into labour and non-labour for each department.

Response:

Please refer to the response to BCUC IR 2.276.5.

276.6 Please explain why any over-expenditure from the 2012 and 2013 Approved budgets should be incorporated into the 2013 base.

Response:

The base year is set on cost of service principles. The sustainable savings represent a combination of the factors used to adjust the base period to a cost of service. Similarly, any over expenditure of the approved budget represents the actual cost of service because the budget is just a forecast of what costs are likely to be in the period.

The 2012 and 2013 Approved budgets prepared in 2011 as part of the 2012/2013 RRA were developed with the best information at the time. However, business conditions and requirements change over time affecting the level of funding and resources required. In order to reflect the current level of required resources, FEI's 2013 Base O&M reflects both increases and also decreases from the 2012 and 2013 Approved base. It would be asymmetrical to adjust for under-expenditures, but not to adjust also for the over-expenditures.

FEI's approach is consistent with historical practice where the Commission has accepted that it is FEI's role to manage the prioritization of its O&M funding and that changes amongst departments have traditionally formed the base for O&M going into a new test year.

In addition, not including expenditures above approved would understate the current resource requirements in the Base Year and potentially undermine the achievability of the PBR Plan. In filing a base year using updated cost of service as has been done with the various adjustments, the base year is a starting point from which future productivity is measured and should reflect the current level of required resources for the PBR Plan. FEI will be managing the achievement of any savings or incremental costs on a Company-wide basis as part of the overall challenge FEI has in meeting its O&M and capital targets under a PBR Plan that includes a large and significant X-Factor. This point is particularly important because of the number of years that FEI has operated under PBR. Empirical results show that the longer the utility operates under PBR the closer the X-Factor comes to the actual level of technical change across the industry. Put another way, the X-Factor is reduced over time. Since the base year is the basis by which future productivity is measured, the reasonableness of the X-factor depends in part on whether the base year reflects the current level of required resources. If the base year is underestimated, this in effect increases the X-Factor and potentially undermines the achievability of the PBR Plan.

276.7 Please explain how the Commission can determine whether any or all of the 2012 and 2013 over expenditures and savings are related to efficient operations or simply the result of non-expenditures of an already approved budget.

Response:

Please refer to page 123 of Exhibit B-1 for a description of the factors contributing to the savings realized. The labour savings are primarily driven by integration activities with FBC, savings in IBEW training through the use of new delivery models, refinement of the requirements for supporting capital activities, streamlining processes and the use of technology, and a shift to the use of contractors to allow more flexibility in staffing levels. Savings in non-labour resulted from the savings in meter reading and billing operations captured in the Customer Service Variance deferral account, offset by increases to support customer and code-driven requirements, and the increased use of contractors.

By reducing the O&M Base to account for these savings, the Company has committed to sustaining these savings over the PBR term. Regardless of how they have been achieved, the end result is that costs are lower, and are being sustained at a lower level.

Please also refer to the response to BCUC IR 2.338.20.

277.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Sections 3.2 and 3.3.5, pp. 123 and 129-130

Productivity and Integration with FortisBC Inc.

On page 123 of the Application, FEI states, "The labour savings are primarily driven by integration activities with FBC…" (Exhibit B-1, p. 123)

On page 129, FEI states, "In identifying O&M forecasts over the PBR Period, departments were encouraged to review processes and identify potential sustainable savings by streamlining processes, leveraging technology and optimizing opportunities for integration with the Electric business." [Emphasis added] (Exhibit B-1, p. 129)

On pages 129-130, FEI further states, "While no specific incremental savings have been identified, the productivity focus has served to manage the number of pressures put forward requiring incremental funding." (Exhibit B-1, pp. 129-130)

277.1 Please explain whether or not savings from integration with FBC have been incorporated into the 2013 Base O&M.

Response:

Savings from integration with FBC have been incorporated into the 2013 Base O&M. Please refer to Table B6-4 in Exhibit B-1 showing the 2013 Base O&M which incorporates $14.67 million of sustainable savings. As described on page 123 of Exhibit B-1, "the labour savings are primarily driven by integration activities with FBC, savings in IBEW training through the use of new delivery models, refinement of the requirements for supporting capital activities, streamlining processes and the use of technology, and a shift to the use of contractors to allow more flexibility in staffing levels."

277.1.1 If so, how much of the savings applied to the 2013 Base are related to integration with FBC and in what department(s) have these savings occurred.

Response:

As indicated in the response to CEC IR 1.12.1, given FEI's approach to ensuring accountability for productivity improvement, it has not required departments to specifically track savings benefits for each of the drivers including savings due to integration. As a result, FEI does not have a comprehensive list of savings benefits due to integration with the electric business at a total Company level.

FEI has provided a number of examples of integration initiatives in the Application. In Exhibit B-1 Section 3.1 Productivity Focus, starting on page 11, examples of integration initiatives are discussed. These included opportunities in the HR department where functions were integrated with FBC. Efficiencies were gained in the Communications and External Relations groups through sharing of resources across the two companies. Integration initiatives were also discussed on a departmental level in the O&M departmental review in Section C3. For example, in the EH&S department, several functions involved in the provision of gas and electric services were integrated. Service quality levels have been maintained with additional workload managed within existing budgets.

While FEI has not administratively tracked the specifics of the different integration initiatives for the reasons outlined in the response to BCUC IR 2.338.20, it is confident that integration initiatives have contributed to the $14.67 million sustainable O&M savings realized and that has been incorporated into the 2013 O&M Base for the PBR Plan.

Please refer to the responses to CEC IR 1.1.1 and BCUC IR 2.338.20 for FEI's approach to ensuring accountability for productivity improvement.

277.1.2 If not, please explain why not.

Response:

Please refer to the response to BCUC IR 2.277.1.

278.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.90; Exhibit B-1, Application, Tab C, Section 3.5.3, Table C3-15, p. 151; Exhibit B-1-1, Appendix F6

Customer Service Department – Customer Service Variance Deferral Account

In response to BCUC 1.90.1, FEI states, "The overall $10.6 million O&M savings includes both deferral and non-deferral savings, of which $10.285 million is reflected in the Customer Service Variance Deferral Account and thus not shown as a separate line item in Appendix F6 (which only shows amounts recorded as O&M)." ((Exhibit B-11, BCUC 1.90.1)

278.1 Please explain how FEI determined which savings are allocated to the Customer Service Variance Deferral Account and which savings are not.

Response:

Savings captured in the Customer Service Variance Deferral Account are those that were within the scope of the deferral account approved by the Commission.

In the 2012-2013 RRA, the FEU sought and received approval of the Customer Service Variance Deferral Account to defer the variances in forecast and actual costs resulting from the high degree of uncertainty arising from the new in-sourced delivery model. As discussed on page 404 of the 2012-2013 RRA, the Customer Service Variance Deferral Account captured meter reading costs and ongoing operating costs of in-sourced activities as listed in Table 5.3-32 on page 203 of the 2012-2013 RRA. Specific areas for deferral account treatment related to the ongoing operating costs of in-sourced activities were discussed on pages 203 and 204 of the 2012-2013 RRA and include the Burnaby and Prince George contact centres, revenue cycle and billing operations, and customer relations.

For the most part, these areas of business have individual cost centres and FEI captures these costs in the deferral account. Any previously in-sourced activities are not part of the deferral account. The Commission, on page 115 of the Decision (Order G-44-12) noted that "deferral account treatment is appropriate where certain costs are significant and beyond the control of the FEU and could result in windfall benefits or costs to ratepayers". The FEU's treatment of the O&M savings in the deferral account has been consistent with the Commission's determination.

278.2 What are the implications of allocating the majority of the O&M savings (i.e. $10.285 million) to the Customer Service Variance Deferral Account? Please discuss.

Response:

The O&M costs savings captured in the deferral account will be returned to customers, thereby providing a positive benefit to customers through lower rates over the period of amortization, as well as a lower base level of O&M for the PBR Period.

In response to BCUC 1.90.1, FEI states, "The difference between Approved 2013 and Projection 2013 as shown in Appendix F6 is $342 thousand, which is the non-deferred savings related to research studies and bad debt expense." (p. 232)

278.3 Please provide a more fulsome description of the $265 thousand savings in the Customer Operations activity group.

Response:

The $265 thousand O&M savings in Customer Operations activity category, as shown in Appendix F6, is mainly related to research studies. As explained in the response to BCUC IR 1.90.3:

> *The O&M savings from research studies is a result of the discontinuation of the historical Residential, Large Commercial, Small Commercial and Builder and Developer Customer Satisfaction Studies. The Residential and Small Commercial customer groups were already being surveyed as part of the natural gas Customer Satisfaction Index (CSI). Both the Large Commercial survey and the Builder and Developer survey were seen as no longer meeting the needs of the company and customer groups. Other ways of measuring their satisfaction will be considered going forward.*

FEI has no further information to add to this description.

In response to BCUC 1.90.3, FEI states, "Savings from the transfer of the Knowledge and Learning department were realized due to the Human Resources group being able to provide these services within existing budget levels." (p. 233)

278.4 Please describe the services provided by the Knowledge and Learning department and please provide a breakdown of the types of costs incurred to perform this activity.

Response:

The services provided by the Knowledge and Learning to the Customer Service group include:

- Providing instruction on a variety of core and/or technical training courses such as:
  - Customer moves, focusing on occupied premise-force move out, vacant premise, transfer from one home to another;
  - Meter exchange, focusing on introducing participants to the meter exchange program, scheduling appointments for residential and commercial customers, and rescheduling a meter exchange appointment; and
  - Service excellence, focusing on developing skills that will enable participants to deliver service to our customers and developing critical thinking skills that will help them resolve customer inquiries.
- Collections, focusing on the process of collecting of overdue balances;
- Developing and facilitating training for customer service departments as required;
- Liaising with subject matter experts, as required, throughout the design and development process;
- Analyzing training needs, designing and developing content, and defining measurement strategies using proven instructional design methodologies;
- Building effective relationships with business partners to ensure their business needs/objectives are being met/exceeded;
- Meeting project and program goals while keeping key stakeholders and management informed of progress;
- Writing, storyboarding and editing learning and performance support interventions;
- Directing the work of other members of the instructional design team;
- Managing the performance of large groups of individuals, in a training environment, up to and including termination; and
- Providing consultative advice to managers to support post training performance challenges

The costs associated with performing these activities are as follows:

- Labour costs;
- Travel expenses to and from various training locations;
- Materials expenses (flipchart paper, printing costs, etc.);
- Training development costs (video production, software licenses for eLearning, stock photo costs);
- Post-training costs (survey software to evaluate the effectiveness of learning); and
- Professional development fees and administrative costs.

279.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1-1, Appendix F6

Energy Solutions and External Relations

279.1 Please provide the Approved 2012 versus the Actual 2012 amounts at the activity view level for the ES & ER department.

Response:

This response also addresses BCUC IR 2.279.1.1.

BCUC Reference	Particulars	2012 Approved ($000's)	2012 Actual ($000's)	Difference	Explanation of Significant Differences	Temporary or Sustainable
310-11	ES&ER Supervision	622	614	8	-	-
310-12	Energy Solutions	5,040	5,134	(94)	-	n/a
310-13	Energy Efficiency	120	117	3	-	n/a
310-14	Communications & External Relations	6,441	7,212	(771)	Incremental spend due to natural gas customer education and awareness	Sustainable This activity has continued into 2013 at the same levels, and is critical in order to increase demand for natural gas end-use.
310-15	Forecasting, Market and Business Development	5,286	4,998	288	Lower spend due to short term vacancies which are not sustainable in the long run	Temporary
310-10	**Total ES&ER**	**$17,509**	**$18,075**	**(566)**		

279.1.1 For each variance, please distinguish which incremental costs/savings are temporary and which are sustainable, and discuss why.

Response:

Please refer to response to BCUC IR 2.279.1.

279.2 For each activity-level cost variance in the Projection 2013 compared to the Approved 2013 budget, please distinguish which incremental costs/savings are temporary and which are sustainable, and discuss why.

Response:

BCUC Reference	Particulars	2013 Approved* ($000's)	2013 projection ($000's)	Explanation of Significant Differences	Explanation of any Difference	Temporary or Sustainable
310-11	ES&ER Supervision	796	671	125	Offset in Energy Solutions	n/a
310-12	Energy Solutions	4991	5,117	(126)	Offset in ES&ER Supervision	n/a
310-13	Energy Efficiency	120	301	(181)	Increased spend in High Carbon Fuel Switching Program	Sustainable This program will continue at this level to influence customers to switch from high carbon fuels to natural gas
310-14	Communications & External Relations	6155	6,988	(833)	Increased spend in natural gas customer education and awareness program	Sustainable This activity is expected to continue throughout the five year period to increase customer awareness of the benefits of natural gas and in order to increase demand for natural gas end-use
310-15	Forecasting, Market and Business Development	6119	6,138	(19)	-	n/a
310-10	**Total ES&ER**	**$18,181**	**$19,215**	**($1,034)**		

279.3 Please explain why any over expenditures from the 2013 Approved budget should be incorporated into the 2013 Base.

Response:

Please refer to responses to BCUC IRs 2.287.2, 2.287.3 , 2.284.1 and 2.284.1 and specifically BCUC IR 2.276.6.

280.0 Reference: FORECASTS FOR THE PBR PERIOD

FEU 2012-2013 RRA, Exhibit B-1, Section 5.3.8, p. 206; Exhibit B-11, BCUC 1.98.1

Energy Solutions and External Relations

FEU states in the 2012-2013 RRA: "The implementation of a new Customer Information System and in-sourcing of Customer Service activities resulted in the creation of a new Customer Service department, which caused business activities between the two groups (ES&ER and Customer Service) to be realigned. Customer service and customer research activities were moved to the new Customer Service department, while customer information, education, energy solutions and business facilitation activities remain with the ES&ER department." (FEU 2012-2013 RRA, Exhibit B-1, p. 206)

In response to BCUC 1.98.1, FEU provided a table which shows that 2012 Actual FTEs have increased by 15 from 2011 Actual and are projected to increase by a further 13 FTEs for 2013. (Exhibit B-11, BCUC 1.98.1)

280.1 Please discuss whether FEI has recorded any cost savings in the ES&ER group due to the re-alignment of activities described above.

Response:

The following response addresses the responses to BCUC IRs 2.280.1, 2.280.1.1, 2.280.1.2 and 2.280.2.

The costs and FTE associated with these customer service and customer research activities have been retroactively moved from ES&ER to Customer Service, and for this reason there are no "cost savings" or "FTE reduction" to record in the ES&ER department. The amounts shown for the ES&ER department in the Activity View, Appendix G, Schedule 16 of the Application do not include these customer service and customer research activity costs for each of the years reported, and this also applies to the FTE count provided in response to BCUC IR 1.98.1. Such consistency in reporting provides for a basis for which to do a comparable year over year analysis for each of the departments, ES&ER and Customer Service. FEI understands comparability to be one of the goals the Commission has for FEI's reporting, and this is an example of how the Activity View is able to accomplish this.

280.1.1 If not, why not.

Response:

Please refer to the response to BCUC IR 2.280.1.

280.1.2 If yes, please indicate the amount and where these savings were recorded at the Activity View level.

Response:

Please refer to the response to BCUC IR 2.280.1.

280.2 Please explain why, if customer service and customer research activities were moved to the new Customer Service department upon the implementation of the new Customer Information System, there were zero reductions in FTEs in ES&ER in any of the functional groups (or in the overall total) provided in the table in BCUC 1.98.1.

Response:

Please refer to the response to BCUC IR 2.280.1.

280.3 Please further expand the table provided in BCUC 1.98.1 to include the years 2007 through 2009. Include the requested information in a fully functional spreadsheet.

Response:

Please refer to Attachment 280.3 where the requested years (2007 through 2009) have been provided.

The FTE count included in the attachment includes EEC Staffing who charge to the EEC deferral account. In response to BCUC IR 2.254.1, FEI has shown the NET O&M FTE view for the department along with an explanation of the changes.

281.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.98.1

Energy Solutions and External Relations

In response to BCUC 1.98.1, FEI states, "The increase in FTE in 2013 is primarily driven by the filling of vacancies, an increase in EEC staffing, and additional staffing required to support GGRR activity."

[Emphasis added]

281.1 Please indicate what the average FTE count was for 2013 which FEU applied for in its 2012-2013 RRA.

Response:

FEU did not apply for an FTE count in its 2012-2103 RRA.

281.1.1 Please provide an explanation for any variances between the 2013 average FTE budgeted in the 2012-2013 RRA and the 2013 Projection of 136 average FTE provided in response to BCUC 1.98.1.

Response:

The 2013 average FTE provided as supporting documentation in the 2012-13 RRA was 117.

Please see summary table below for a reconciliation:

Description	FTE as supplied in 2012/13 RRA**	2013 Projection**	Difference
Gross FTE	117	136	19 See EEC FTE
Less: EEC FTE	17	36	19*
Net FTE	100	100	0

**As indicated on Page 210 of the 2012/2013 RRA "the number of employees added to the EEC deferral account may vary as programs expand and customer activity increases."*

***The ES&ER department does not include in their FTE forecast seasonal staffing, such as the street team, as this FTE count can vary from period to period.*

281.2 Please provide the dates that vacancies were filled.

Response:

Please refer to response to BCUC IR 2.249.3 for a listing of all job postings filled by FEI for the years 2011, 2012 and 2013 (to date).

The vacant positions (new and existing) filled within the Energy Solutions and External Relations group in 2013, including effective dates, are listed in the table below.

Position Title	Effective Date
Account Manager (LNG & CNG)	9-Jul-2013
Business Development Manager	7-Oct-2013
Business Development Specialist	1-Mar-2013
Commercial Program Specialist (MBA Intern)	24-Jun-2013
Communications Coordinator (2)	26-Feb-2013 28-May-2013
Corporate Communications Advisor	15-May-2013
Designer, Communication Services	4-Mar-2013
Digital Communications Advisor	6-Aug-2013
DSM Tracking & Management Systems Analyst	17-Jun-2013
Employee Communications Writer	1-Oct-2013
Energy Utilization Manager	15-Apr-2013
Engineering Summer Student	3-Jun-2013
Events Specialist	4-Mar-2013
LNG & CNG Logistics Manager	12-Aug-2013
Marketing Co-ordinator (5)	2-Jan-2013 3-Jan-2013 7-Jan-2013 21-Aug-2013 28-Aug-2013
Mgr New Product Development	28-Oct-2013
New Product Development Coordinator (2)	1-May-2013 3-Sep-2013
New Product Development Coordinator	3-Sep-2013
NGV Account Manager	4-Mar-2013
Operations Manager - New Products (New Product Development Operations Coordinator)	26-Aug-2013
Project Assessment Manager (2)	18-Nov-2013
Relief Clerk	19-Mar-2013
Reporting & Consultation Analyst	30-Sep-2013
RNG Sales Mgr	2-Jul-2013

281.2.1 Please discuss if there are any sustainable cost savings in 2013 related to the vacancies that were filled. Specifically, please discuss if the incumbent employees were hired at a lower salary level.

Response:

The ES&ER department's labour budget requirements are represented in the 2013 Base amount. FEI has not identified any permanent savings as a result of the vacancies that were filled in 2013.

As can be seen from the list of vacancies filled in 2013, the department has experienced a fair amount of staff movement. In order to manage with this level of change, the labour budget and FTE count is managed as a whole and roles and responsibilities are shifted, with new positions created as necessary to fill resource gaps as staff come and go. For this reason, there is not a one-to-one relationship between the cost of an employee that has left and the cost of an employee that fills a vacancy (i.e. the roles and responsibility of the original employee may not match the roles and responsibilities of the new staff). Further, even if a new employee is hired at a lower salary level, there may be training expenses incurred which will offset savings that FEI may experience by hiring employees at a lower salary level, when that occurs.

282.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.99.1; FEU 2012-2013 RRA Final Submission, p. 67

Energy Solutions and External Relations - LTRP

In response to BCUC 1.99.1, FEI states, "The incremental spending that was approved to be included in rates for 2012/2013 related to the Long Term Resource Plan (LTRP) was reduced from what was requested, by $800 thousand in 2012 and by a further $100 thousand in 2013." (Exhibit B-11, BCUC 1.99.1)

282.1 How much incremental spending was approved for each of 2012 and 2013 for the LTRP?

Response:

The Commission approved an incremental $400 thousand in 2012 and a further incremental $200 thousand in 2013.

282.2 How much did FEI actually spend in 2012 related to the LTRP? Please break out the total spending in 2012 between labour and non-labour.

Response:

The labour and non-labour expenditures related to the LTRP form a part of the Market Development group budget area which is managed as a whole, and it is difficult to separate those costs strictly related to the LTRP. In order to maximize the skill set of the group, there are a number of individuals within the Market Development group who undertake activities related to the LTRP as either their primary activity or as part of a number of other activities they undertake through the course of a year. As such, time spent on the LTRP is not specifically tracked as it would result in additional administration with no added value since these costs are all borne by the natural gas ratepayers. For these reasons, FEI cannot provide the breakout of LTRP related spending as requested (please also refer to the response to BCUC IR 2.282.3).

282.3 How much does FEI project that it will spend on the LTRP for 2013? Please break out the total spending between labour and non-labour.

Response:

FEI does not track LTRP related costs separately and cannot provide a total sum that it expects to spend on LTRP activities in 2013. Although spending in 2013 may be lower than originally anticipated due to the filing of the LTRP being delayed as a result of the heavy regulatory burden, FEI expects to fully utilize the approved funding amount over the PBR Period.

282.4 Please describe the nature of the work performed on the LTRP in 2012 and 2013 and how many FTEs were used to perform this work.

Response:

FEI has utilized the increased funding in these two years to advance a number of the improvements it outlined in the 2012-2013 RRA proceeding, particularly in the areas of stakeholder engagement, analyzing the planning environment, future scenario development, long term annual demand forecasting, long term EEC analysis and alternative forecast impact analysis. However, given the reduced amount of funding for the LTRP activities from that requested in the 2012-2013 RRA, FEI has not been able to undertake all of the activities to improve the LTRP that were outlined by FEI at that time. Looking forward, FEI intends to use this increased funding to continue with the new tasks that have been undertaken for the LTRP currently under development and continue improving the LTRP process in other areas for future LTRPs.

Significant work performed through 2012 and 2013 on the LTRP includes (but is not limited to) the following high-level activity descriptions:

- An assessment of the impact of recent changes in the planning environment on the LTRP, future demand expectations and related analyses.
- Review of major issues impacting utilities and other planning organizations within BC and in neighbouring jurisdictions.
- Development of a range of future scenarios that could reasonably be expected to unfold over the planning horizon.
- Development of an end-use forecasting model based on the most recent Conservation Potential Review data and modeling.
- Determining the inputs into the end-use modeling that result from the future scenarios.
- Conducting quality assurance on end-use demand forecasting data.
- Development of long term scenarios for demand from NGT.

- Adaptation of the annual demand forecasting model to analyze long term outlook for demand reductions from EEC activities.
- Assessment of CO2e emissions from natural gas commodity sales and CO2e reductions from FEU initiatives including EEC and NGT.
- Incorporation of system sustainment planning work into the LTRP.
- Identification of system capacity constraints and timing, as well as reassessment of alternatives to address system capacity constraints.
- An update to the assessment of regional gas production and transmission planning and how that could impact the FEU and their customers.
- An assessment of the directional rate impacts of different future demand scenarios as well as the directional impact of EEC activities and NGT initiatives on rates.
- Community consultation activities throughout B.C. on the FEU's long term planning issues.
- Resource Planning Advisory Group engagement workshops to review long term planning issues and analysis with external stakeholders at various times throughout the LTRP process.
- Preparation of the first draft LTRP document and both internal and external professional review of same.

There are at least 3.5 FTE's within the Market Development group whose primary activities are related to the LTRP, but many more within and outside of the Market Development group who dedicate a portion of their activities to LTRP related work each year. As well, consultants were retained to undertake some LTRP related analytical activities. As a result, it is difficult to accurately determine the total number of FTE's involved in the above listed activities.

In response to BCUC 1.99.1, FEI states that it "expects to file the completed LTRP later this year and will continue such compliance throughout the 2014-2018 forecasted period with an updated LTRP to be filed during this five year period." (Exhibit B-11, BCUC 1.99.1)

FEU states in its Final Submission in the 2012-2013 FEU RRA: "The additional staffing will be employed to develop new end use forecasting methods, prepare and report on new forecasts, and compare new and traditional forecasting methods and processes." (FEU 2012-2013 RRA Final Submission, p. 67)

282.5 Does FEI agree that the purpose of at least a portion of the incremental LTRP spending approved in the 2012-2013 RRA was to “develop new end use forecasting methods” and other activities related to the set up/establishment of new processes?

Response:

This response addresses the responses to BCUC IRs 2.282.5 and 2.282.5.1

Yes, some of the work undertaken as part of the incremental LTRP related spending approved in the 2012 – 2013 RRA was to develop and implement a new annual demand forecasting methodology; however, the LTRP process is an ongoing one and the development of a new annual demand forecasting methodology is only the first step in a process of ongoing improvement in the LTRP. FEI has been working closely with a third party provider, ICF Marbek, to repurpose the model used to prepare the most recent Conservation Potential Review for the Companies – a project also completed by ICF Marbek. This solution has resulted in a very successful partnership in which FEI provides base customer data, ICF Marbek and FEI together develop other model inputs from future scenarios developed by FEI, ICF Marbek models future demand data, and FEI processes and analyzes the customer consumption outputs from the modeling process.

The repurposing and additional development work on the model is part of a process of ongoing improvement to the LTRP. Now that the model is in place, it will need to be duplicated and updated for future LTRPs, and the data that forms the base year inputs will continue to need careful management. In addition to undertaking all of the activities listed in response to BCUC IR 2.282.4 on an ongoing basis, new scenarios will be developed for future LTRPs based on changes to the planning environment in the intervening period. These will require the designing of new model inputs such as alternative costs of gas, carbon costs, long term price elasticity updates, commercial and industrial growth assumptions and as yet undetermined additional parameters that might be identified by FEI, the Commission or stakeholders for potential input into the model. While FEI believes that this new methodology is a very cost effective, yet significant advancement in the LTRP process, it is not just a one-time process or cost, but rather requires ongoing updating and improvement to the quality of the modeling inputs.

The LTRP process is an ongoing one. While FEI has undertaken many improvements to the LTRP currently being prepared as a result of the increased funding, there are still more improvements to make among those outlined in the 2012-2013 RRA proceeding in future LTRP’s, both in the area of energy demand forecasting and in other areas of LTRP analyses and reporting. As such, the current level of funding directed toward LTRP related activities remains appropriate.

282.5.1 If yes, why is it appropriate to include this portion of the incremental spending in the 2013 Base O&M, which essentially indicates that this spending is “sustainable”? If FEI does not agree, please explain why not.

Response:

The work undertaken with respect to the new end-use demand forecasting is expected to be largely ongoing activities. Please refer to response to BCUC IR 2.282.5.

282.6 Please distinguish between LTRP activities that are related to the establishment of new forecasting methods and other processes, and activities that relate to ongoing work in support of the LTRP.

Response:

There is no clear boundary between LTRP activities related to demand forecasting tasks and those related to other ongoing analyses since many activities inform the long term demand forecast and the long term demand forecast in turn becomes an input into many other analytical activities required as part of the LTRP. These interrelationships can be seen in the response to BCUC IR 2.282.4.

The repurposing of the ICF Marbek CPR model for end-use demand forecasting purposes was completed in a careful, step-wise process that saw the model development occur simultaneously with the model implementation. Any savings from efficiencies that might result now that the first iteration of the model is complete are expected to be small and will be utilized in the ongoing development of demand forecast modeling improvements and/or improvements to other areas of the LTRP process as discussed in response to BCUC IR 2.282.5.

283.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.99.1

Energy Solutions and External Relations

In response to BCUC 1.99.1, FEI states, "The 2012/13 approved incremental expenditure pertained primarily to three program areas – Safety Education Messaging, the LTRP and the Renewable Natural Gas (RNG) service offering." (p. 250)

283.1 Please indicate how much was approved for 2012 and for 2013 for Safety Education Messaging and for the RNG service offering.

Response:

The incremental amounts approved for inclusion in the ES&ER O&M for Safety Education Messaging and RNG service offering, as per Commission order G-44-12, are as follows:

Approved Item	2012	2013	Notes
Safety Education Messaging	$750,000	$850,000	Incremental amounts approved
RNG*	$418,384	$416,552	Reclassification from deferral account

**As per Exhibit B-1-0 2012/2013 Revenue Requirement Application Appendix J, Table J-2. These amounts exclude the budget for materials and supplies for interconnect facilities as these are captured in the Operations department budget.*

283.1.1 For these two program areas in 2012 and 2013, please indicate what was actually spent. Please describe the nature/cause of any variances between actual and approved for 2012 and 2013 amounts.

Response:

Please refer to the table below:

	2012			2013			
Approved Item ($000's)	**Approved**	**Actual**	**Explanation of Difference**	**Approved**	**Actual *As at Sept. 30***	**Year End Projection**	**Explanation of Difference**
Safety Education Messaging	$1,450	$1,549	Corporate reallocation of expenditure in order to ramp up efforts in this critical area.	$1,550	$825	$1,550	FEI anticipates spend for the year will be on budget. YTD underspend is low due to work completed but not invoiced by third parties.
RNG	$418	$406	Small variance largely due to the initial budgets developed based on preliminary estimates and before implementation of the RNG service offering.	$416	$160	$410	FEI anticipates that it will be underspent by $6 thousand due to savings in inbound call costs. YTD spend is not reflective of work done to date due to late invoicing from third parties.

Given that these two programs are expected to continue into the forecasted five year period and FEI will maintain a level of activities in these areas that is comparable to 2012/2013 levels, it is appropriate that these approved amounts be included in the 2013 Base O&M.

284.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.101.1; Exhibit B-1-1, Appendix F6

Energy Solutions and External Relations (ES & ER)

In response to BCUC 1.101.1, FEI states, "The department has evolved over the past five year period to meet the changes in business drivers, the evolving needs of customers, stakeholders and the requirements of the Commission and therefore a comparison over this five year horizon is not relevant or appropriate." (Exhibit B-11, BCUC 1.101.1)

Based on the Actual O&M costs provided in Appendix F6, the increase in Projected 2013 Total Gross O&M over the average of the past five years is 13.8 percent; whereas the increase in Projected 2013 O&M for the ES&ER department over the average past five years is 33.4 percent. (Calculated from Appendix F6)

284.1 Please specifically discuss the changes in business drivers and the evolving needs of customers and stakeholders which account for the difference between the percentage increase in O&M in the ES&ER department and the percentage increase in Total O&M for FEI.

Response:

This response also addresses BCUC IR 2.284.2

As referenced in the preamble to the question there has been an increase in O&M expenditure in the ES&ER department. The changes in business drivers were a subject of inquiry in both the 2010/2011 RRA and the 2012/13 RRA proceeding and have been discussed on pages 159 to 160 of the Application.

The O&M increase from 2008 to 2010 was driven by FEI's response to both changes in its business environment and its customers. During that time customers were moving more rapidly towards non-gas alternatives. The Company responded to many IR's in the 2010/2011 RRA pertaining to cost increases and the references are provided below:

- Exhibit B-4, BCUC IR 1.5.1,
- Exhibit B-4, BCUC IR 1.72.1
- Exhibit B-4, BCUC IR 1.83.1
- Exhibit B-4, BCUC IR 1.93 series
- Exhibit B-4, BCUC IR 1.95.1
- Exhibit B-4, BCUC IR 1.96.3
- Exhibit B-12, BCUC IR 2.16.1
- Exhibit B-12, BCUC IR 2.31.5

The majority of the increases in the ES&ER department have taken place over the four years from 2010 to 2013, over which time there was a 31 percent increase in O&M (or $4.6 million), and this amount represents 24 percent of the 2013 Projected O&M for the department and <u>less than 3 percent</u> of FEI's total 2013 Projected Base O&M. FEI has focused on this time period in preparing this response. A table summarizing the increase is provided below.

Item	**Amount ($millions)**
Safety Education Messaging	1.0
Renewable Natural Gas	0.4
Long Term Resource Plan	0.6
High Carbon Fuel Switching Program	0.3
Natural Gas Awareness	1.0
Increased staffing to support growth initiatives	0.4
Annual Labour & Non-Labour Inflation	0.9
Total	**$4.6**

The reasons for the increase, in the context of changes in FEI's business environment and in meeting the evolving needs of customer and stakeholders, and how they have benefited natural gas customers, are described below.

Safety Education Messaging

In compliance with the CSA Oil and Gas System Standard Z662-07, FEI has a responsibility to provide on-going and continuous education to the public about the risk associated with natural gas and propane products. Such education and messaging meets the requirements of the CSA Oil and Gas System Standard Z662-07, where it is identified as recommended practice for operating companies to develop safety and education programming as part of their safety and loss management and integrity systems. Public safety education programs can reduce risk to the public, the environment and property by third party damage. The benefit to customers of the safety education is that awareness has steadily increased. The number of survey respondents who felt that they were "very prepared" in knowing what to do when a gas odour was detected increased from 15 per cent in Spring 2010 to 29 per cent in Q3 2013. The number of "not at all prepared" decreased from 70 per cent to 50 per cent over the same period. The increased O&M over this period is $1 million, which was approved by the Commission in past proceedings (Order G-141-09 and G-44-12). Throughout 2014 to 2018, public safety education will continue to be an integral part of the company's integrity management system. Please refer to the responses to BCUC IRs 1.99.1 and 2.283.1 for more details.

Renewable Natural Gas (RNG)

Since the Clean Energy Act was introduced in 2010, the province has been focused on clean or renewable energy sources, energy conservation and energy sufficiency. In addition, the Clean Energy Act restricts BC Hydro from using natural gas for electricity generation. To address this provincial focus on renewable and clean energy and customer needs for a more sustainable energy solution, FEI introduced RNG in 2011. In 2012, the customer education costs of $0.4 million for this service offering were re-classed from deferral account to O&M as approved by Order G-44-12. Customers have shown an interest in this service offering with 6,093 residential and commercial customers enrolled as of the end of September 2013. Furthermore, RNG offers the advantage of being a carbon-neutral, renewable energy source and therefore furthers provincial climate and energy policy initiatives. Please refer to page 157 of the Application, and the responses to BCUC IRs 1.99.1, 2.283.1 and 2.347.1.

Long Term Resource Plan

As discussed in response to BCUC IR 1.99.1, pursuant to the directives in the Commission Decision on the 2010 LTRP (Order G-14-11), the Company was requested to include the development of a 20 year vision, engage in stakeholder consultation initiatives, address EEC impact and the impacts of new initiatives and to develop planning scenarios. Additional funding was sought in order to comply with these directives in the 2012/13 RRA. As such, FEI has ramped up its research, analytics, planning and consultation capabilities in response to meeting these expectations. The increase in LTRP expenditure over the 2010 to 2013 period to meet these directives was approved at $0.6 million by Order G-44-12, and provides for a more comprehensive LTRP for all stakeholders and the Commission. Please also refer to responses to BCUC IRs 1.99.1, 2.282.5 and 2.282.5.1.

High Carbon Fuel Switching Program

As noted on page 158 of the Application, the High Carbon Fuel Switching program provides incentives to customers to switch from higher carbon to lower carbon-emitting fuels through the installation of high efficient ENERGY STAR® natural gas heating systems. Prior to 2012 these costs were held in a deferral account but were reclassified to O&M, from 2012 onwards, as per Order G-44-12. In the decision accompanying that Order, the BCUC determined that this program should be distinguished from the load reducing EEC programs recorded in the EEC deferral accounts. The high carbon fuel switching program was successful in increasing customer attachment levels by 94 in 2011 and 98 in 2012. Furthermore, the addition of these customers resulted in a reduction of 573 tonnes and 598 tonnes of greenhouse gas (GHG) emissions in 2011 and 2012 respectively, as customers switched from propane or oil to natural gas for their space heating needs. The increase in O&M for this program over the 2010 to 2013 period is $0.3 million.

Natural Gas Awareness Initiatives

The natural gas awareness initiatives increase preferences and demand for natural gas products by way of creating awareness of the benefits of natural gas use, through customer education and outreach programs. This is being achieved by providing for increased channels of communication and tailored messaging based on customer segmentation. Please also refer to the responses to BCUC IRs 1.104.1 and 2.312.1. This accounts for $1 million of the increase in O&M, as described on pages 160 to 162 of the Application.

Growth Initiatives

In this period, there was an increase in staffing levels to support growth initiatives to advance the use of CNG and LNG; but not limited to NGT applications. These growth initiatives benefit customers by way of increased throughput on the gas distribution system; and in particular an increase in gas use for NGT applications provides for a year-round load on the system and furthers the provincial goals of GHG emission reductions. This accounts for $0.4 million of the increase over this period. Furthermore, FEI continues to pursue revenue growth opportunities in collaboration with industrial customers as described in the responses to CEC IRs 2.65.1, 2.65.2, 2.65.2.1, and 2.65.2.2.

Annual Inflation

The remaining significant increase of $0.9 million is for normal annual inflation for both labour and non-labour items.

Other Benefits of the ES&ER Department Activities

During the period 2010 to 2013, the department has continued to focus on rate mitigation efforts through initiatives designed to increase gas throughput, such as those described above, but also on process changes to improve productivity levels. Productivity enhancements have been in the form of improvements to existing processes which serve to assist in the retention of existing customers in providing them with increased value. Efficiencies were focused on developing more streamlined solutions for existing processes and providing increased value to customers. These improvements are discussed on pages 155 to 156 of the Application. They include reduced wait times by two weeks for customers waiting for a new gas service not requiring a permit, the development and launch of a new online home energy calculator for customers, development of a billed consumption data base, and development of an online survey for industrial customers. These types of activities and initiatives benefit customers both in the current period and in the future, and therefore will continue at such levels into the PBR period.

As it pertains specifically to initiatives undertaken to the benefit of customers by the Market Development group, which is part of ES&ER, including customer retention and attraction efforts, please refer to the response to BCUC IR 2.286.3.

The increase in ES&ER O&M over this period has ensured that FEI has retained and attached new customers in a challenging market place. As noted in the Generic Cost of Capital proceeding, customers have many more choices for energy, public policy (carbon tax for example) has made it more difficult to attach and retain customers, building code changes have increased the cost of natural gas equipment and customers do not understand the value (price) of natural gas compared to other energy choices. In addition, the sales process for customers has become more complex. Customers are often looking for ways to find efficiencies through integrated solutions, whether it is with their existing systems or their new development. Small builder and developer groups have in recent years made up a large proportion of the new customer additions and this shift requires an increased effort to engage a wider network of builders and developers along with other influencers of gas use in new homes, including architects, engineers, contractors, manufacturers, dealers as well as homeowners.

284.2 Please provide specific examples of how this large increase in O&M related to the ES&ER department since 2008 has benefited the average natural gas customer.

Response:

Please refer to the response to BCUC IR 2.284.1.

285.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.100.1

ES &ER – Communications Functional Group (Communications Group)

285.1 Please provide a schedule showing the gross ES&ER O&M, less allocation to FEVI through the FEI-FEVI Shared Services Agreement for Actual 2007-2013 by year. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Please refer to the response in BCUC IR 2.311.1 for the gross ES&ER O&M for the Communications group and to BCUC IR 1.100.1 for its major functions. For Communications O&M costs that are shareable with FEVI and FEW, FEI has estimated that an average of about three hundred thousand per year from 2007 – 2013 has been allocated to FEVI through the FEI-FEVI Shared Services Agreement for the Communications group. Any recoveries under the FEI-FEVI Shared Services Agreement would be reflected in the Corporate department.

285.2 Please provide a copy of the latest FEI/FEU Communications Plan.

Response:

Please refer to Attachment 285.2.

285.3 For Actual 2007- 2013, please provide the Communications Group O&M costs by year and resource, and the Communications Group O&M costs per customer and customer addition by year. Also, provide graphs of the Communications Group O&M cost per customer and customer addition by year for Actual 2007-2013. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Please refer to the response to BCUC IR 2.311.1.

286.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.98.1.1, 1.100.1

ES & ER – Forecasting and Market Development Functional Group (Forecast and Market Development Group)

"Development of new customer initiatives including rate offerings, customer retention and acquisition initiatives, small scale demonstration projects, and product development. For example development of the Home Energy Calculator." (Exhibit B-11, BCUC 1.100.1)

286.1 For 2007-2013, please provide a breakdown of the Forecasting and Market Development Group O&M by resource and between the Forecasting and Market Development areas. Include the requested information in the form of a fully functioning electronic spreadsheet.

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

Please refer to Attachment 286.1.

It appears from the line of questions that there is a misunderstanding regarding the nature of the Market Development group, which may be a result of how the information has been provided by FEI. This response and the responses to the rest of the BCUC IR 2.286 series provide information that will better explain the activities of this group.

The Market Development group as a whole is made up of five areas, which collectively make up the costs of this group and these are described below. Please refer to the response to BCUC IR 1.75.1 for an organizational chart of the Market Development Group. A breakdown of the Forecasting and Market Development group by development area is not possible as the group and costing is not structured or devised in the manner the Commission requests; instead the cost for the entire Forecasting and Market Development group is attached.

- Energy and Forecasting – which is responsible for energy forecasting and support of the long term resource plan. These roles are funded by O&M.
- Resource Planning and EEC reporting – which is responsible for the Long Term Resource Plan and EEC Reporting. The Long Term Resource Planning roles are funded by O&M and the EEC roles are funded by EEC Deferral.
- Business Performance and Technical Solutions – which is responsible for the business performance reporting of the ES&ER group, EEC technical support and Sales Technical support. EEC deferral funds the EEC roles with the remainder of the roles funded by O&M.
- Energy Products and Services – which is responsible for product and service changes and development in addition to administration, review and reporting of the System Extension

Test which is funded by O&M, and the administration of the Section 18 NGT incentive program, which is appropriately charged to the NGT Incentives deferral account.

- Market Development and Analysis – which provides financial analysis support to other parts of the ES&ER group as well as support to regulatory for ES&ER activities. This group also is the key contact for government initiatives and BC Hydro. This group is funded by O&M.

The increase in costs and staffing levels in 2011 were required to support those activities as indicated in the response to BCUC IR 2.286.3, which benefit natural gas customers including the system extension test review, the development of the home energy calculator, customer repatriation efforts, and wait time reduction for a new service line.

The increase in costs in 2012 was driven by the increased activities required for the preparation and compilation of a more comprehensive LTRP and the reclassification of costs for the RNG service offering from the deferral account to O& M. These costs were approved in the 2012/13 RRA.

As mentioned above, some of these staff work on GGRR and EEC activities and thereby charge their time to the appropriate deferral accounts, although their headcount is included here.

Please refer to response to BCUC IR 2.286.1.1 for discussion on O&M per customer.

286.1.1 For 2007-2013, please provide Market Development O&M cost per customer addition. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Please refer to Attachment 286.1 provided in response to BCUC IR 2.286.1 for the spreadsheet. Refer to the second tab.

To clarify, of the entire Market Development Group noted in response to BCUC IR 2.286.1, the majority of the group's activities are in support of either regulatory requirements (Resource Planning, Forecasting and Market Development and Analysis) or EEC. FEI submits that there is no direct correlation between costs and customer count or customer additions for these areas. This is because:

- The Market Development group not only engages in activities to retain and attract customers but also on activities that have no correlation with customer additions such as compliance activities including the LTRP and System Extension Test Filings. Please refer to the responses to BCUC IRs 2.286.1 and 2.286.3 for a list of key activities for this group.

- Even if there were a correlation, due to the nature of the service offering, there is often a time lag for benefits to accrue from an initiative. Activities undertaken in one period and often over a period of time will typically reap benefits in future periods.
- There are other external influences such as changes to codes, energy policy and regulation and the cost of gas appliances, for which FEI has limited influence, that significantly affect customer retention, additions and growth, and such changes in external factors cannot be "measured" in such a graph.

Therefore, to base decisions on an analysis of cost per customer or per customer addition in isolation of other factors may very likely inhibit and hamper the utility's ability to grow in future years.

286.2 For 2007-2013, please provide a breakdown of the Forecasting and Market Development Functional Group FTEs and between the Forecasting and Market Development areas. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Please refer to the response to BCUC IR 2.286.1.

286.3 For 2007-2013, please list the new customer initiatives including rate offerings, customer retention and acquisition initiatives, small scale demonstration projects, and product development activities by year. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

FEI has not provided a fully functioning spreadsheet as no numbers were requested in this IR. This response also addresses BCUC IR 2.286.4.

As noted in responses to BCUC IRs 2.286.1 and BCUC IR 2.286.1.1, there are only a small number of staff in the Market Development group that work on these customer initiatives.

To clarify, in the context of activities for this group, the reference to “the development of new initiatives and rate offerings....” pertains to natural gas service and offerings, including RNG and NGT and which benefit natural gas customers. These types of activities are ongoing in nature as the market and regulations continue to evolve.

In order to be provide a more appropriate and useful response to the question being asked, FEI has endeavoured to provide a sampling of these initiatives below (rather than an itemized list by year in an excel spreadsheet). Initiatives are ongoing and not confined to a specific year. The following response provides several illustrative examples demonstrating how the Market Development Group positively impacts natural gas customer satisfaction, the acquisition_of new customers and the retention of existing natural gas customers (collectively referred to as “Positive Impacts”). As discussed in the response to BCUC IR 1.100.1, ES&ER’s functional groups do not segregate O&M into specific initiatives and, as such, ES&ER cannot provide a comprehensive list of “new customer initiatives” attributable to the Market Development group. These initiatives were as a result of a market need or corporate direction.

Since 2007, the Market Development group has developed effective system extension policy and administration that helped facilitate the addition of tens of thousands of new, economic customers to our system. For example, the Market Development group led the revision of the system extension test in response to changing market conditions in order to achieve the following objectives referenced in the G-152-07 Decision:

- To signal better value for customers wishing to attach to the system;
- To ensure that the system extension test and policies measure the right factors, are simple to understand and administer with results that send the appropriate economic signal to the customer;
- To encourage energy conservation through the test and attachment policies; and
- To encourage the “right fuel” choice.

The revisions to the system extension included eliminating the service line installation fee, implementation of a service line cost allowance and the introduction of profitability indexes for individual main extensions and main extensions in aggregate.

The Market Development group has provided the Commission with extensive system extension reporting since 2007 that fulfills our compliance reporting requirements. The Market Development group also amended the general terms and conditions (GT&Cs) related to the definition of a service line (approved by Order No. G-6-08) in response to two market factors: 1) the changing British Columbian real estate market towards MFDs and away from single family dwellings and, 2) the relatively high up front capital costs associated with natural gas compared to electricity.

A more recent example of the Market Development group's Positive Impacts is the development of the online home energy calculator resulting in the retention of potential retrofit customers and the attraction of new customers such as those looking to convert from fuel oil to natural gas. Our research has shown that a significant percentage of our potential customer base were not aware of the operating cost and energy savings associated with the installation of energy efficient, natural gas appliances compared to those fuelled by other energy sources such as electricity or heating oil. Since going live early in 2013, the energy calculator has been an integral part of the education of customers as demonstrated by web analytics that show how customers actively use the tool.

The Market Development group also recently developed a mobile version of the system extension test that has traditionally only been available through our Customer Acquisition Front End (Café) platform. The tool makes it easier for our sales team to engage customers in discussions around reducing their potential contribution in aid of construction (CIAC) through the installation of energy efficient appliances.

Another recent example of Positive Impacts is an initiative to repatriate former customers. Over recent months of 2013, the Company has been contacting former customers who still have meter and service line but are no longer consuming natural gas. The Market Development group has been working with the Customer Service group to train our customer service representatives to perform thousands of outbound calls in order to repatriate these former customers. Preliminary results have been positive with over 2,000 customers repatriated with no additional costs to customers.

The Market Development group also recently collaborated with the Operations group to reduce the time to attach a simple new service by approximately two weeks. Similar to the example above, the Positive Impact in this instance was achieved with no additional costs to customers.

The Market Development group has been pursuing a thermal metering pilot project to address the problem that the use of central hydronic systems is often discouraged by property managers and developers of MFDs in favour of electric baseboard heating to more easily allow for the individual metering and billing of heating costs. The Company has initiated a project through the Canadian Standards Association (CSA) and worked with them along with other participating utilities to successfully update the C900 standard for thermal meters.

The group works collaboratively with municipalities, associations and regulatory bodies to educate them on the potential impacts of gas-end use in proposed changes to codes and standards. This work is critical, because in some situations changes to appliance standards or building codes can make it prohibitive for customers to install gas appliances.

Market Development has recently been exploring ways to reverse the trend of a decline in the percentage of homes with natural gas service that have a natural gas hot water appliance, particularly multifamily dwellings (MFDs). Hot water represents a significant percentage of our residential load, second only to heat load. For example, the Company has been actively involved in a pilot project through the Canadian Gas Association's Emerging Technology Innovation Canada (ETIC) initiative to evaluate new technology aimed at meeting newly introduced, stringent government standards for natural gas hot water appliances. Work in this area will be critical to maintain the existing domestic hot water heating throughput which currently makes up 18 per cent of the residential load. Market Development has also been working on a variety of other technology related projects through ETIC and plans to continue this work through the PBR period

Market Development was instrumental in the development of an energy efficiency financing (EEF) program mandated by the provincial government. The research and design of the EEF was completed by Market Development which allowed FEI to be compliant with government legislation.

The Market Development group has led development of campaigns to create the awareness and commitment of RNG with both residential and commercial customers. For example, the use of Air Miles, My Planet has been an effective tool for securing RNG customer commitment. As of December 31, 2012, 4,693 residential and 75 commercial customers were enrolled in the program.

Similar initiatives and Positive Impacts can be expected from the Market Development group over the next five years, but these cannot be listed here as they are not yet known. Future initiatives will be in response to meeting the evolving needs of customers over the PBR period. One example of an area where the Company sees a future need is to better engage and educate our natural gas contractors, appliance distributors and equipment suppliers with better tools to sell and install natural gas appliances. As a result, the Market Development group is in the early stages of revamping our existing contractor program to better meet these needs.

Although not mentioned above as a new customer initiative resulting in Positive Impacts, the Market Development group also provides on-going services to our customers such as the development of our Long Term Resource plan, forecasting, assessment of EEC programs and the development and administration of the GGRR Section 18 NGT incentives.

286.4 For 2014-2018, please provide a list of new customer initiatives to be undertaken by the Market Development area and a clear and concise description of the methodology to allocate costs to the new customer initiatives.

Response:

Please refer to the response to BCUC IR 2.286.3.

286.4.1 If the FEI cannot provide a clear and concise description of the methodology to allocate costs to the new customer initiatives, would it be appropriate to exclude the cost of the Market Development area from the revenue requirements in the year that they were incurred and have FEI request recovery of the actual Market Development costs at the Annual Review, for recovery in following year (i.e. 2014 Market Development cost would be reviewed at the 2014 Annual Review and recovered in 2015 rates)? Please explain why, or why not.

Response:

FEI believes that it is necessary to provide clarification in terms of the new customer initiatives and rate offerings developed by the Market Development group, in that these are developed and implemented for the traditional base of natural gas customers and therefore benefit such customers. Examples of such initiatives are listed in the response to BCUC IR 2.286.3.

The Market Development group is responsible for, among other activities, short and long term energy forecasting, the preparation and compilation of the Long Term Resource Plan, preparation and filing of the System Extension Test, and EEC EM&V, EEC M&V and EEC Reporting. Please refer to the response to BCUC IR 2.286.1 for more details of the role of this group. These activities are to the benefit of the natural gas ratepayers. They require year over year continuity and it would not be appropriate to incur additional complexity in excluding the cost of the Market Development group from the revenue requirement in the year that they are incurred.

Furthermore, FEI does not believe it would be appropriate to adopt the treatment proposed in the question for the O&M costs of the Market Development area (i.e. exclusion of these costs from the formula-based O&M and a forecast amount put forward each year in the annual review process). The approach proposed in the question would run counter to some of the principles and goals of the PBR.

- The Market Development O&M costs fall into the category of costs that are controllable by the Company. A basic structural principle in the proposed PBR is to incorporate incentives into the cost of service elements that are controllable by the Company and treat non-controllable costs on a pass through basis. With respect to O&M expenses the items that are removed from the O&M formula are non-controllable cost items such as pension and insurance costs. Treating controllable cost items such Market Development O&M costs as proposed in the question would mark a departure from this principle.
- Another general principle of PBR is to adopt higher level formulas for setting rates or cost components in rates and to take the focus off line item cost management as is more a characteristic of cost-of-service regulation. The utility under PBR has more freedom to adapt and optimize its operations (within the constraints of meeting service quality requirements).

Removing Market Development O&M costs from the O&M formula and reforecasting them each year as proposed would be contrary to this aspect of PBR.

- Setting aside the Market Development O&M costs for special treatment would also run counter to the goal of streamlining the regulatory process under PBR. Regulatory burden would be added to review and approve this item on a yearly basis.
- Lastly, the inference in the question suggests that the activities of the group are not prudently incurred and as such should not be included in regular O&M. FEI does not agree with this inference. The Market Development group, and the activities they perform, has been part of the FEI O&M and activities through many RRA applications. It is not a new group or activity. To suggest that as part of a PBR application these activities should not be performed or if so, at risk to the shareholder until application is sought to recover costs is contrary to the regulatory compact.

In addition, FEI requires the stability in personnel and budget planning and the Market Development group should be treated no differently than other parts of the company that supports FEI's sustainment, growth and customer offerings, in other words all parts of the Company. FEI submits that there is no justification to treat the activities of the Market Development group in a different manner than any other department.

287.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.104.1; Exhibit B-1, Application, Tab C, Section 3.6.3, p. 158

Energy Solutions and External Relations

In response to BCUC 1.104.1, FEI states, “To be clear, FEI is not requesting incremental funding from the Commission for this initiative. FEI’s rates will include only the formula-driven O&M amounts under the PBR proposal, and as such any incremental amounts in 2014 for this program will be managed internally through savings achieved elsewhere in the organization. Neither is FEI requesting approval for this specific initiative in 2013 as it already had RRA approval to spend a total envelope of O&M dollars.”

(Exhibit B-11, BCUC 1.104.1)

In the Application, FEI states, “The 2013 projected expenditure shows an increase over the 2013 approved spend for the department. The initiatives currently underway which account for the increase in spend of $1 million are described below.” (Exhibit B-1, p. 158)

287.1 Please confirm, or explain otherwise, that the increase of $1 million between the 2013 Projected and the 2013 Approved O&M is incremental to the O&M amount approved in the 2012-2013 FEU RRA Decision for ES&ER.

Response:

The $1 million projected spend in 2013 is higher than FEI’s estimate of the ES&ER department’s allocation of the 2013 approved spend but the higher expenditure has been corporately managed and allocated through the savings achieved elsewhere in the organization. While there is an increase in O&M expenditure in 2013 for ES&ER, FEI’s overall 2013 projected O&M expenditure ($221,333 thousand) is less than the approved 2013 level ($236,003 thousand), as shown in Table C3-2, page 124 of the Application. Furthermore, in its 2013 Base O&M to be used in the O&M formula going forward, FEI has reduced the O&M base to reflect its corporate sustainable O&M savings of $14.67 million dollars (see Table B6-4 on page 55 of the Application).

Please also refer to the response to BCUC IR 2.276.6 which discusses why any expenditures over the 2012 and 2013 approved amounts should be included in the 2013 Base.

287.2 Please explain why the $1 million of additional O&M expenses for 2013 cannot be “managed internally through savings achieved elsewhere in the organization,” similar to how it plans to manage incremental costs during the PBR term.

Response:

Contrary to the suggestion in the question, the $1 million of additional O&M expense for 2013 for ESER is the result of "savings achieved elsewhere in the organization". Please refer to the response to BCUC IR 2.276.6.

287.3 Please explain why this over expenditures from the 2013 Approved budget for the ES&ER department should be incorporated into the 2013 Base.

Response:

Please refer to the response to BCUC IR 2.276.6.

Specifically with respect to these costs, these expenditures should be incorporated into the 2013 base O&M because they relate to activities that will continue and are critical to future growth. These include enhancing the high carbon fuel switching program to increase customer uptake and to accommodate customer participation rates, and increasing preferences and demand for natural gas products by way of creating awareness of the benefits of natural gas use, through comprehensive customer education and outreach programs. (See pages 158 to 162 of the Application)

These activities will serve to help FEI to respond to competitive threats through providing customers with monetary incentives to move from a high carbon fuel to natural gas and secondly educating customers so they are able to make more informed decisions with regards to their energy choice and how natural gas best serves their needs.

288.0 Reference: FORECASTS FOR THE PBR PERIOD
Exhibit B-11, BCUC 1.107.1-.2
ES &ER – Donations

"Note that pursuant to Commission Order GG-44-12, starting in 2012 only fifty percent of costs related to community involvement are allocated to the rate payer. The cost of the sponsorship is $15,000 plus the cost of the attendee gift distributed at the banquet which is referenced in response to BCUC IR 1.107.2."

288.1 Please provide copies of the invoices for the FEI sponsorship of the 2012 and 2013 Union of British Columbia Municipalities Conferences and the attendee gift distributed at the banquets.

Response:

Please refer to Attachment 288.1 for copies of the invoices for FEI sponsorship of the 2012 and 2013 UBCM conference. In 2013 FEI did not provide an attendee gift for the banquet.

289.0 Reference: FORECASTS FOR THE PBR PERIOD – OPERATIONS AND MAINTENANCE EXPENSE

Exhibit B-1, Application, Tab D, Section 4.1.1, p. 292; Exhibit A2-16

Development of Base 2013 O&M – Savings on Regulatory Process

In the Application, FEI states that it "will incur costs in 2013 and 2014 related to the current PBR Application. Costs incurred consist of legal fees, costs for expert witnesses and consultants, costs related to independent studies, intervener and participant funding costs, Commission costs, required public notifications, and miscellaneous facilities, stationery and supplies costs." (Exhibit B-1, p. 292)

"FortisBC saves approximately $57,000 per month on information request-related tasks thanks to the Information Request System. Along with an additional $100,000 in annual labour savings, 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." (Exhibit A2-16)

289.1 Please confirm, or explain otherwise, that the annual cost for internal staff to respond to RRA IRs is not included in the deferral account referenced in Section D4.1.1 but is part of the normal O&M.

Response:

Confirmed, the cost for internal staff is included as part of Base O&M costs; FEI Regulatory Department staffing levels have remained constant since 2008 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.

The IR System was installed in 2009. In 2011 the IR System was made available to FBC.

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 reached a total of approximately 6,025 IRs in 2012 – a 410 percent increase as compared to 2006. The FEU have surpassed the 2012 total in 2013, having received approximately 7,800 IRs year-to-date.

Had the FEU not implemented the IR System, then O&M cost increases would have been unavoidable for both FBC and the FEU in order to meet filing deadlines and to comply with the increasing regulatory process requirements.

289.2 Please confirm, or explain otherwise, the order of magnitude of the annual savings to FEI's regulatory process as a result of the IT system created by Habanero, as stated in the above-referenced article.

Response:

The productivity improvements and efficiencies gained by FEI since implementing the IR System in 2009 have allowed FEI to respond to a significantly increasing volume of IRs. Please also refer to the response to BCUC IR 2.289.1. It is important to note that FEI filed responses to this substantial increase in IRs without increasing staffing levels in the Regulatory Affairs department, and therefore, there was no increase in 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", the FEU (and FBC) 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.
- 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.

289.3 Please confirm, or explain otherwise, that FEI has not proposed to adjust the 2013 Base O&M for the annual savings from this new system.

Response:

It was not necessary for FEI to adjust the 2013 Base O&M because the "savings" since 2009 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 2.289.2.

289.4 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.

290.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.115.1; Exhibit B-1, Application, Tab C, Section 3.8.3, pp. 169-170

Information Technology (IT)

In response to BCUC 1.115.1, FEI states, "The $600 thousand increase in non-labour for consulting backfills is expected to continue over the PBR Term." (Exhibit B-11, BCUC 1.115.1)

290.1 Please indicate whether FEI utilized external resources for backfilling of internal resources and overtime work in previous years? If not, why not?

Response:

Please refer to the response to BCUC IR 1.115.1 for 2013. 2012 was similar to 2013 in that internal labour was assigned to various project work and external resources were used to backfill, as well as to provide support for non-recurring incremental support (overtime). Prior to 2012 external resources were used to backfill; however, requirements were less due to the outsourced Customer Care systems.

290.1.1 If yes, please discuss why FEI requires an additional $600 thousand for external consultants to provide these backfill functions.

Response:

FEI is not requesting approval for an additional $600 thousand for external consultants for the PBR period; rather it is forecasting that IT costs will remain consistent with the reduced 2013 base level as described on page 170 of the Application. FEI provided a discussion of the $600 thousand increase in consulting backfills as an offset to the $2 million decrease in labour, for a net overall decrease in O&M compared to the Approved.

FEI's total O&M will be set based on the formula-driven amount of O&M costs, and FEI will continue to manage its resources between internal labour and consultants depending on business requirements over the PBR Period. As stated in response to BCUC IR 1.115.1, it is often more cost effective to backfill resources assigned to projects or for overtime with external resources due to the flexibility that can be achieved.

290.2 Please provide the approved and actual (projected, in the case of 2013) cost of external resources for each of 2010, 2011, 2012 and 2013.

Response:

The following table shows the total IT department consulting costs for the years requested. Please also refer to the response to BCUC IR 2.290.1.1 for a discussion as to why a review of external consulting costs in isolation from the total O&M trends does not present a balanced view of FEI's productivity focus.

	$(000)			
	YR 2010	**YR 2011**	**YR 2012**	**YR 2013**
Approved	$6,100	$7,200	$9,500	$9,900
Actual/Projection	$6,500	$6,500	$9,800	$10,400

290.2.1 For each of 2012 and 2013, please provide a detailed explanation of the services that external resources were used for.

Response:

External resources were used for the following services:

- SAP ABAP support and development – SAP programming
- SAP Functional support and development – SAP configuration to support business requirements in areas such as HR, Finance and Supply Chain.
- SAP BASIS support and development – SAP database and security
- Database Administration (DBA) support and development – database configuration, tuning and programming
- Business Warehouse support and development – data warehouse configuration and programming
- JAVA support and development – JAVA programming for a number of systems
- Magic support and development – GE Smallworld GIS system programming

- SharePoint support and development – configuration and customization of SharePoint environments
- Web services support and development – HTML and other web programming
- Business Analyst – process reviews and development of requirements for technology initiatives for IT and business areas, including enhancement and transformational projects
- Project Management
- Infrastructure design and support – Wide Area Network (WAN) and Local Area Network (LAN) design and operations
- Help desk and technical support – first level telephone support and desk side support

290.2.2 For 2014, please discuss the services that FEI anticipates external resources will be used for.

Response:

FEI anticipates that external resources will be used for similar functions as those identified in response to BCUC IR 2.290.2.1. FEI will continue to manage its mix of internal and external resource according to its business requirements over the PBR Period.

FEI states in the Application: "A variance of approximately $700 thousand was due to some vacant positions that were not filled and the alignment of management between FEU and FBC." (Exhibit B-1,p. 169)

290.3 Please discuss whether the increase of $600 thousand for external consultants to backfill for overtime is linked to the fact that certain vacant positions were not filled in 2012.

Response:

The variance of $700 thousand identified in Exhibit B-1, p. 169, was for 2012. As stated on page 169 of the Application, this variance was due to the alignment of management in IT, and some vacant positions that were not filled. It was determined that the vacant positions were not required based on the needs of the organization. Permanent resourcing considers long term requirements, developments in technology and other factors that affect resourcing needs for IT.

There was no direct link between the $600 thousand for external consultants to backfill for projects and overtime in 2013, and the vacant positions that were not filled in 2012. As stated in response to BCUC IR 1.115.1, the external resources are used to backfill where necessary, not to continually backfill vacant positions. The vacant positions were not filled because it was determined they were not required.

290.4 Please discuss whether the decrease in Labour costs between 2013 Approved and 2013 Projection and the increase in non-labour costs between 2013 Approved and 2013 Projection is indicative of FEI increasing its use of external consultants and decreasing its number of FTEs.

Response:

The increase in non-labour costs and corresponding decrease in labour costs between 2013 Approved and 2013 Projection is indicative of FEI increasing its use of external consultants to backfill internal resources to allow the internal resources to be more involved in project work and for relief for overtime as described in response to BCUC IR 1.115.1. This approach is not intended to permanently replace FTEs with external consultants. Having internal resources involved in project work improves transition of support of delivered products upon completion of projects. It also ensures internal FEI technical requirements and standards are represented on projects for their duration. This strategy, as stated in the response to BCUC IR 2.290.1.1, decreased overall operating costs.

291.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.117.2; Exhibit B-1, Application, Tab C, Section 3.13, pp. 190-192

Finance and Regulatory Review

291.1 Please include an additional column to Table C3-31 provided in response to BCUC 1.117.2 which includes the 2012 Approved amounts. Include the requested information in a fully functional spreadsheet.

<u>Response:</u>

Please refer to Attachment 291.1 in a fully functioning spreadsheet for the updated Table C3-31 which includes the 2012 Approved Amounts.

In the Application, FEI states, "In 2012, this contributed to one-time labour savings realized as vacant positions were filled only after reviewing the need for the positions and evaluating how best to staff the positions." (Exhibit B-1, p. 190)

FEI also states, "Difficulties in filling these vacancies on a timely basis contributed to lower spending levels in the past." (Exhibit B-1, p. 191)

291.2 Please discuss the employee turnover in 2012. How many position(s) does this equate to?

<u>Response:</u>

Employee turnover resulted in the equivalent of approximately six full time equivalent positions not being filled during part of 2012. These included analysts and clerical union positions and management positions. During the year, vacancies occurred as the result of maternity leaves, employees leaving for other positions outside the organization and also for other positions within FEI.

291.3 How did FEI manage the vacancies during 2012? Why does FEI believe that its ability to manage with this lower level of staffing is not sustainable over the long-term?

Response:

FEI's Finance and Regulatory department managed the 2012 vacant positions primarily by having staff forgo vacation and management and exempt staff working more overtime than normal. This is not sustainable.

As indicated in the response to BCUC IR 1.118.2, FEI's Finance and Regulatory department will not be able to continue to operate at existing staffing levels for the next five years. The complexity and level of regulatory filings has increased which has resulted in a step change in requirements for regulatory applications from both the Finance and Regulatory departments. Also on the Finance side, the accuracy of accounting and forecasting, the application of accounting guidance, the interpretation of regulatory decisions and the maintenance over internal controls could be compromised, thus increasing financial risk.

291.4 Please discuss the difficulties FEI experienced in filling these vacancies and what the potential causes were of these difficulties.

Response:

As indicated in the response to BCUC IR 1.118.2, FEI was unable to hire employees to fill vacant positions in the past partly because of a reluctance to fill positions with full time staff given the potential for amalgamation and the adoption of postage stamp rates. The 2013 projection assumes no amalgamation which means positions can be offered on a full time basis, making them much more attractive to job applicants. Additionally, temporary vacancies caused by maternity leave affected the ability to fill positions.

FEI states, "In 2013, higher labour expenditures are expected due to inflation for labour and benefits, and the filling of existing vacant positions which were put on hold in part pending a decision on amalgamation of the gas utilities." (Exhibit B-1, p. 191)

291.5 Please indicate whether FEI has filled the existing vacant positions at this time. If not, why not?

Response:

At this time, four positions still remain vacant given the current proceeding for reconsideration of FEU's Application for Amalgamation of the Gas Utilities and normal staff turnover.

FEI states, "The increase in non-labour is due in part to inflation on financial services provided by FHI through the Corporate Services fee and also for additional taxation services being provided in 2013. Other contributors to the increase in 2013 are related to external audit fee, taxation consulting fees, SAP and systems support and miscellaneous support costs." (Exhibit B-1, p. 191)

291.6 Please describe the increased taxation services being provided in 2013.

Response:

Expenditures for taxation services are for specific tax matters for which specialized expertise is required. Specific tax matters in the past include future income tax (FIT), US GAAP FIN 48, commodity taxes, US tax compliance, and audit support, disputes and appeals. Spending on taxation services in a given year can vary depending upon the tax matter and the issues at hand. In 2013, the forecasted spending is estimated at $200 thousand, an increase of approximately $60 thousand compared to 2012 Actuals.

291.6.1 Please discuss why these increased taxation services are considered sustained costs versus temporary costs.

Response:

The 2013 forecast spending of $200 thousand for taxation services is representative of the baseline spending requirements. The scope and complexity of the tax services required annually will affect the overall costs. Taxes are increasingly complex, and when audits occur, tax authorities are increasingly aggressive. In addition, the return to two major commodity tax regimes (GST and PST) from a single regime (HST) is increasing recurring costs related to PST issues in particular.

291.7 Please discuss whether any of the other non-labour costs described by FEI above could be considered temporary costs for 2013. If not, why not?

Response:

The increases identified are required on a permanent basis. The items contributing to the increase include inflation; audit fees; maintenance fees in support of the Financial Consolidation software system; SAP consultant fees to support system enhancements and higher employee expenses and support costs. These expenditures are necessary to operate the department effectively.

FEI states, "the staffing level for the Finance department has remained stable in recent years at approximately 50 employees, and is forecast to remain relatively consistent over the forecast period." (Exhibit B-1, p. 189)

291.8 Please provide the number of management and exempt employees versus the number of COPE employees in the Finance department for the years 2007 through 2013 (projected for 2013).

Response:

Finance Department employees
Historical average full time equivalent

	2007	2008	2009	2010	2011	2012	As at Sep-13
M&E	11.5	11.1	12.2	13.1	12.1	11.1	11.0
COPE	31.7	34.5	33.8	32.9	33.3	30.7	30.9
Total	43.2	45.7	46.0	46.0	45.4	41.9	41.9

These numbers in the table reflect an adjustment for transfer out of Fleet Services employees which previously were included in the totals. With the inclusion of an average three Fleet Services employees during the period, the total FTE level would be approximately 50 as referenced on page 189 in the Application.

292.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.118.3

Finance and Regulatory Review

In response to BCUC 1.118.3, FEI states, "In the 2013 Projection, the regulatory department has included $122 thousand for internal labour and related costs to support the additional applications that will be required over the PBR Period and has also reflected the filling of one vacancy with permanent staff." (p. 301)

292.1 Has FEI included the budgeted cost to support this PBR Application as part of the 2013 Base O&M? If so, how much has been included in the 2013 Base O&M?

Response:

FEI has not included any incremental costs to support this PBR Application in the 2013 Base O&M. Only the ongoing continuing costs of the regulatory department's staff are included in 2013 Base O&M.

In any given year, the regulatory staff will work on a variety of applications and filings, some of which will be major applications. FEI considers major applications typically to be those relating to revenue requirements, rate design, cost of capital, amalgamation, and CPCNs. In 2013, one of the main areas of focus of the regulatory staff has been on this PBR Application. This focus will continue through the first quarter of 2014, at which time staff will shift to upcoming major CPCN applications, preparing studies in support of rate design applications, completing the required review of TPP/CoC, rolling out service offerings to other service areas (such as Vancouver Island and Whistler), continuing to file RRAs for the other three utilities, and preparing for and participating in the 2014 Annual Review for setting of 2015 delivery rates. With its anticipated workload over the PBR Period, FEI does not anticipate any reduction to its staffing complement, particularly in light of the increasing amount of process that has been experienced within the regulatory area generally.

292.2 What is FEI's estimated cost of a standard 2-year cost of service revenue requirement application? Please discuss all of the activities that are included in this estimate.

Response:

The incremental cost of FEI's most recent two year cost of service revenue requirement application, which included an oral public hearing, was $1.6 million (pre-tax) and was recorded in a deferral account (not in O&M) and allocated to each of the FEU. The types of costs incurred were third party fees and expert witness costs for studies and evidence supporting the application, legal costs, Commissioner costs, Intervener PACA, costs for Allwest reporting, media publication, and administrative costs such as courier expenses.

As far as internal staff time, the Regulatory department staff do not track their time to each of the hundreds of applications, compliance and tariff filings that they work on each year. There is a base level of O&M for regulatory staff to support these activities. FEI works to manage the timing of when applications are filed to accommodate the staffing resources available to it, and in so doing also attempts to manage the significant overtime requirements of the department. It is through this combination of unpaid overtime and managing the timing of filing of major applications that FEI has maintained its existing staffing complement despite increasing regulatory requirements.

292.3 Has FEI factored in the savings to the Finance & Regulatory department which will result from not having to prepare revenue requirement applications for FEI during the PBR period? If not, why not? If yes, how much has FEI estimated the savings to be?

Response:

FEI has taken into account the fact that FEI would not have to prepare revenue requirement applications during the PBR period; however, there are no forecast savings in the Regulatory department due to other significant regulatory applications and processes that are anticipated over the PBR period. If FEI were not under PBR, the forecasts for Finance and Regulatory department staff may be increasing rather than staying at existing levels. Please refer to the responses to BCUC IRs 2.292.1 and 2.292.2.

292.4 Does FEI expect to file a Rate Design application during the PBR? If yes, when?

Response:

Yes. FEI expects to file a Rate Design application during the term of the PBR. The timing of the Rate Design application is dependent on the outcome of the FEU's Reconsideration Application for amalgamation and the adoption of common rates.

As stated in the response to BCUC IR 1.58.1 in the FEU's Common Rates, Rate Design and Amalgamation proceeding:

> *"The earliest that FEI Amalco would be in a position to file a Rate Design Application with a scope that includes a review of cost allocation methodologies, customer segmentation and rate structure design would be towards the end of 2016. As discussed in Section 9.8 of the Application, the FEU believe that a two year period following the implementation of common rates is required to enable customer movement to occur. Following that two year period, analysis and application development activities would occur."*

Since that response was written, the implementation date for common rates has been changed from 2014 to 2015. As a result, in a common rates scenario, the FEU would not be in a position to file a rate design application until 2017.

If amalgamation and the adoption of common rates is denied, FEI will not have resources available to begin on the various rate design studies until after the oral hearing in this Application. Therefore, in that scenario, a rate design application could not be filed until sometime in 2016.

293.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Tab C, Section 1.4.7.2, p. 113; TGI 2010-2011 RRA, BCUC 1.70.0

FEU 2012-2013 RRA, BCUC 1.40.0-1.42.0; Letter L-40-11

Exhibit B-11, BCUC 1.131.3.1, 1.31.7-1.131.8; Sections 61(4), 61(5), 89 and 90 of UCA

Review of Core Market Administration Expense (CMAE)

In the Application, FEI states: "The cost of gas includes CMAE costs required to manage the FEI's natural gas and propane supply functions." (Exhibit B-1, p. 113)

In responses to BCUC 1.131.3.1 and BCUC 1.131.8, FEI states, "FEI submits that it is more appropriate to review the CMAE budget as part of the Fourth Quarter Gas Cost Reports as was the historical practice, since the CMAE expenses form part of the commodity and not the delivery rate. FEI only requested the approval of CMAE as part of its RRA for 2010-2011 because there were requests in that application related to moving items between O&M and CMAE and development of a shared services methodology for allocating some costs that were easier to review within the context of the company's overall O&M costs." [Emphasis added] (Exhibit B-11, BCUC 1.131.3.1)

"The CMAE consists of both labour-related expenses and non-labour expense. FEI agrees the labour expenses are largely controllable." (Exhibit B-11, BCUC 1.131. 7)

"While the CMAE budgets were approved in the 2010-11 and 2012-2013 RRAs, the CMAE costs from 2010 to 2013 have been treated as a flow-through as part of the cost of gas, with variance from budget flowing back to customers through the gas cost deferral accounts.

… although the labour-related costs within the CMAE are subject to the same inflationary components

as the labour in the Company's O&M budgets, the fact that the CMAE is a relatively small and distinct pool of costs severely restricts the Company's ability to generate ongoing productivity savings built into the PBR formula." (Exhibit B-11, BCUC 1.131.8)

Among other questions, the CMAE matters were previously canvassed in the following Exhibits:

- Terasen Gas Inc. 2010-2011 Revenue Requirements Application, Exhibit B-4, BCUC 1.70.0;

- FortisBC Energy Utilities 2012-2013 Revenue Requirements and Natural Gas Rates Application, Exhibit B-9, BCUC 1.40.0 through BCUC 1.42.0

293.1 Please specify what portion of the cost of gas is attributable to the CMAE costs. In the response, please express in terms of: (i) CMAE percentage of total gas costs, (ii) CMAE percentage of gas costs in the MCRA and CCRA, respectively and (iii) CMAE dollar amount in the MCRA and CCRA, respectively. Please provide this information for each year-end since 2010 as well as the current commodity charge in effect.

Response:

The table below provides the information requested.

FEI (1) CMAE

Amounts in $ Thousands

	2010 Actual (2)	2011 Actual (2)	2012 Actual (2)	2013 Projection (3)
CMAE in CCRA	$ 993	$ 1,070	$ 1,103	$ 1,091
CMAE in MCRA	2,317	2,549	2,709	2,545
Total	$ 3,310	$ 3,620	$ 3,812	$ 3,635

FEI (1) Gas Costs

Amounts in $ Thousands

	2010 Actual (2)	2011 Actual (2)	2012 Actual (2)	2013 Projection (3)
CCRA Gas Costs	$ 501,747	$ 441,391	$ 330,720	$ 348,131
MCRA Gas Costs	122,962	167,475	141,586	151,259
Total Gas Costs	$ 624,709	$ 608,866	$ 472,305	$ 499,390

FEI (1) CMAE as Percentage of Gas Costs

	2010 Actual	2011 Actual	2012 Actual	2013 Projection
Percentage of CCRA	0.2%	0.2%	0.3%	0.3%
Percentage of MCRA	1.9%	1.5%	1.9%	1.7%
Percentage of Total Gas Costs	0.5%	0.6%	0.8%	0.7%

Notes:

(1) Includes FortisBC Energy (Whistler) Inc. (FEW). Pursuant to Commission Order G-35-09, the FEI and FEW gas supply portfolios were amalgamated effective January 1, 2010.

(2) As filed in the FEI annual gas cost status reports.

(3) Based on actuals to October 2013 and forecasts for November-December 2013.

293.2 Please confirm that the purpose of quarterly gas cost reports is to make adjustments to the Commodity Cost Recovery Charge to reflect current market conditions which are non-controllable costs of FEI. If not confirmed, please explain.

Response:

The purpose of the quarterly gas cost reports is to review the appropriateness of the gas cost recovery rates based on the latest recorded activity and the forecast gas costs based on current forward prices of natural gas.

The Commission Guidelines for Setting Gas Recovery Rates and Managing the Gas Cost Reconciliation Account Balances (the Guidelines) established the quarterly review process related to gas costs and gas cost recovery rates. The Guidelines set out the conditions under which the Commission would generally expect the Company to file applications for changes to gas cost recovery rates.

The Commission noted that the Guidelines were intended as a general guide only. Nothing in the Guidelines precludes the Company from filing applications for rate changes at times other than those implied by the Guidelines; similarly, nothing in the Guidelines precludes the Commission from requesting rate applications at times other than those implied by the Guidelines.

Further, as stated in Commission Letter L-40-11, "*The Commission also agrees with FEI that the Guidelines should be applied in a flexible manner, considering the full circumstances prevailing at the time when a quarterly report is under review. The Commission intends to consider the full circumstances and other criteria in the review of the commodity and midstream cost recovery rates*".

293.3 Please confirm that adjustments to the Commodity Cost Recovery Charge and the Midstream Cost Recovery Charge are normally approved pursuant to section 61(4) of the UCA which states "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, <u>over which the utility has no effective control</u>, required to be paid by the public utility for its gas supplies, other energy supplied to it, or expenses and taxes …"[Emphasis added].

Response:

Confirmed. Please refer to Commission Orders G-147-13 and G-44-04 as examples of approvals of adjustments to the Commodity Cost Recovery Charges and Midstream Cost Recovery Charges under section 61(4) of the UCA. Please also refer to the response to BCUC IR 2.293.3.1.

293.3.1 In response to BCUC 1.131.7, FEI agrees that some components of the CMAE are largely controllable by FEI. In light of this, please explain whether changes to the CMAE can be approved under section 61(4) of the UCA.

Response:

Section 61(4) of the UCA has been applied most commonly and consistently by the Commission to flow through changes in gas costs. Please refer to the Commission Orders cited in the response to BCUC IR 2.293.3.

The flow-through-to-ratepayers practice permitted under section 61(4) remains applicable even if certain component of the CMAE, i.e. the labour expense, is controllable to some extent, for the following reasons:

- Providing safe, reliable, and cost effective gas supply resources that are required to meet core customers' load demands is the central purpose of CMAE activities. Thus, the CMAE is a necessary part of gas costs as it represents a utility's cost to secure gas supply resource.
- The controllable element that forms part of the total gas supply costs of FEI is a relatively small amount in consideration of the total gas cost required to serve the core customers and is thus less of a factor affecting the sales rates.
- The practice reflects the fact that the gas supply is purchased for customers who consume the commodity, that gas supply costs are outside the control of the utility and that the utility earns no return on gas supply costs.

As explained in the Application (at page 113), the CMAE forecasts that are included in the cost of gas for 2014 through 2018 will be submitted for Commission approval as part of FEI's routine gas cost reporting and rate setting process under section 61(4) of the UCA.

293.3.1.1 If not under section 61(4), under what section of the UCA could the CMAE changes be approved?

Response:

Please refer to the response to BCUC IR 2.293.3.1.

293.3.1.2 If section 61(1), could the Commission approve the requested Commodity Cost Recovery Charge either in part under section 89 or on an interim basis under section 90 of the UCA? Please explain.

Response:

Please refer to the response to BCUC IR 2.293.3.1.

293.4 The Commission by Letter L-40-11 in May 2011 revised the guidelines for the review of quarterly gas costs and rate setting mechanisms that were originally established by Letter L-5-01. Please confirm that the review of CMAE was not contemplated as part of the quarterly gas cost report review process. If not confirmed, please specify.

Response:

Not confirmed.

FEI believes that the Commission Guidelines for Setting Gas Recovery Rates and Managing the Gas Cost Reconciliation Balance (the Guidelines), originally established pursuant to Commission Letter L-5-01, contemplated the review of total gas costs, which implicitly includes all components of the gas costs, and the appropriateness of the existing recovery rates.

Commission Letter L-40-11, dated May 19, 2011, dealt with FEI's March 10, 2011 Report on the Commodity Cost Reconciliation Account (CCRA) and Midstream Cost Reconciliation Account (MCRA) Deferral Accounts and Rate Setting Mechanisms (the Report). The Report was completed pursuant to the Commission directing Commission staff to work with FEI to investigate the possibility of improving the MCRA forecasting capability, and to revalidate the methodology associated with the quarterly review of the CCRA costs and commodity rates. Commission staff and FEI held a number of discussions with respect to the CCRA and MCRA deferral accounts and rate setting mechanisms. As a result of those discussions, a few key areas were identified for FEI to conduct further analysis and review, and resulted in the Commission approving revisions to the Guidelines related to the following:

1. Natural Gas Commodity Price Forecasts;
2. CCRA Rate Adjustment Mechanism; and
3. MCRA Rate Adjustment Mechanism.

The Company believes it is appropriate to have the CMAE reviewed as part of the quarterly gas cost review, and that this is consistent with past practice when during most of the term of the previous PBR the CMAE was reviewed and approved as part of the Company's Fourth Quarter Gas Cost Report. In fact, the review of the gas costs conducted as part of the quarterly gas cost and recovery rate setting process includes a number of components comprising the gas costs. For example, CMAE and unaccounted for gas (UAF) are relatively insignificant cost components in comparison to the costs associated with the price of the natural gas commodity, and the third-party storage and transportation of the gas.

Gas cost rates are based on the prospective gas costs; variances between the actual gas costs incurred and the forecast gas costs embedded in recovery rates are captured in the gas cost deferral accounts and these variances are refunded to, or recovered from, customers as part of future rates. FEI does not benefit from any variances in the CMAE, or any of the other components of the gas costs. Further, at the end of each year the Company files its gas cost status report with the Commission which provides a summary of the variances between the forecast and actual gas costs and gas cost recoveries, and provides explanations for any material variances. For these reasons, the Company believes reviewing all components of the gas costs, including the CMAE forecasts, as part of the quarterly gas cost reports is appropriate and under normal circumstances a separate review process of the CMAE forecast is not required.

In summary, the Company believes the process followed during the previous PBR period and proposed for the 2014-2018 PBR period, to have the CMAE forecast reviewed as part of the quarterly gas cost review, remains appropriate and is administratively efficient and reduces regulatory burden.

293.5 Recognizing that past IRs examined CMAE matters (as referenced in the preamble) and that the quarterly gas cost reports are normally reviewed under an expedited process, is it reasonable to say that an appropriate review of the CMAE budget may require a separate review process?

Response:

Please refer to the response to BCUC IR 2.293.4.

293.5.1 If yes, please describe the appropriate separate review process and how it will take effect in the commodity charges.

Response:

Please refer to the response to BCUC IR 2.293.4.

293.5.1.1 Would it be reasonable to include review of the CMAE as part of the PBR Annual Review?

Response:

Please refer to the response to BCUC IR 2.293.4. The Company does not believe this would provide any regulatory efficiency.

293.5.1.2 If yes, describe the potential process.

Response:

Please refer to the response to BCUC 2.293.5.1.1.

293.5.1.3 If FEI does not believe in including the review of the CMAE in the PBR Annual Review, what would be an appropriate review process?

Response:

Please refer to the response to BCUC IR 2.293.4.

293.5.2 Is it reasonable to say that an appropriate review of the CMAE budget may require a separate review process, please explain why not.

Response:

Please refer to the response to BCUC IR 2.293.4.

The Company believes it would be administratively inefficient and create added regulatory burden to require a separate review process related to the CMAE forecast.

293.6 FEI requested approval of the CMAE as part of its 2012-2013 Revenue Requirements and Natural Gas Rates Application. Recognizing that the reallocation of costs between O&M and CMAE was reviewed by the Commission in the 2010-2011 Revenue Requirements Application, why did FEI request that the CMAE approval in the 2012-2013 Revenue Requirements and Natural Gas Rates Application and not in the Fourth Quarter Gas Cost Reports? Please explain.

Response:

The 2012-2013 Revenue Requirements Application and Natural Gas Rates Application (2012-2013 RRA) was filed on behalf of the FEU (FortisBC Energy Utilities comprising FEI, FortisBC Energy Inc. Fort Nelson Service Area, FortisBC Energy (Whistler) Inc., and FortisBC Energy (Vancouver Island) Inc.), and the FEU indicated in the 2012-2013 RRA that in the Fall of 2012 the Companies intended to seek the necessary approvals to amalgamate effective January 1, 2013 and to introduce harmonized rate structures effective on the same date. Under those circumstances, the Companies felt it was appropriate to include the request for approval of the 2012-2013 CMAE forecasts and allocation methodologies as part of the 2012-2013 RRA.

FEI notes, however, that the 2012 CMAE forecast was also utilized in the 2011 Fourth Quarter Gas Cost Report. The Commission approved the gas cost recovery rates effective January 1, 2012 pursuant to Order G-195-11 dated November 25, 2011 (the commodity rate remained unchanged but the midstream rates changed). The components of the midstream costs included the CMAE.

294.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Tab C, Section 1.4.7.2, p. 113

Exhibit B-11, BCUC 1.131.2, 1.133.2, 1.133.2.1

2012-2013 FEU RRA, Exhibit B-1, p. 142; Exhibit B-9, BCUC 1.40.1

CMAE

In the Application, FEI states, "The cost of gas includes CMAE costs required to manage the FEI's natural gas and propane supply functions. The gas supply function encompasses most elements of the merchant role, ensuring that there are reliable, secure and cost effective supplies of gas for core customers. These management activities are carried out by Gas Supply, which is an area within the Energy Supply and Resource Planning department." (Exhibit B-1, p. 113)

In response to BCUC 1.131.2, FEI states, "The approved CMAE budgets for 2012 and 2013 were $4,374 thousand and $4,519 thousand, respectively." (Exhibit B-11, BCUC 1.131.2)

On page 142 of Exhibit B-1 of the 2012-2013 FEU RRA, FEU provided the following:

Table 5.2-3: CMAE Forecast

Amounts in $ Thousands

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	$ 3,610	$ 3,309	$ 3,732	$ 3,732	$ 3,982	$ 4,112
Vancouver Island	$ 401	$ 368	$ 415	$ 415	$ 442	$ 457
Total	$ 4,011	$ 3,677	$ 4,147	$ 4,147	$ 4,424	$ 4,569

In the 2012-2013 FEU RRA, FEU also provided a further breakdown of the CMAE. (2012-2013 FEU RRA, Exhibit B-9, BCUC 1.40.1)

Table BCUC IR1.40.1 - CMAE Breakout

Amounts in $ Thousands

Cost Component	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
IT	279	249	282	320	485	502
Consulting & Legal	290	313	311	313	315	325
Sundries & Subscriptions	193	192	194	180	200	207
Training & Travel	210	134	214	232	172	176
Labour	1,809	2,235	1,871	2,534	2,703	2,799
Energy Management Services Revenue	(171)	(171)	(177)	(177)	(197)	(207)
Transfer from O&M	676	-	707	-	-	-
Shared Services	725	725	745	745	746	767
Total	**4,011**	**3,677**	**4,147**	**4,147**	**4,424**	**4,569**

294.1 Please reconcile the difference between the 2012 Forecast of $4,424 thousand and 2013 Forecast of $4,569 thousand against the information provided in BCUC 1.131.2 as referenced in the preamble.

Response:

Attached below is the reconciliation of the 2012 and 2013 Forecast amounts, as shown in the 2012-2013 FEU RRA, to the 2012 and 2013 Approved amounts.

CMAE Forecast as shown in Table 5.2-3

Amounts in $ Thousands

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	$ 3,610	$ 3,309	$ 3,732	$ 3,732	$ 3,982	$ 4,112
Vancouver Island	401	368	415	415	442	457
Total	$ 4,011	$ 3,677	$ 4,147	$ 4,147	$ 4,424	$ 4,569

Adjustment for EMS Recoveries From FBC Electric
as per the FEU 2012-2013 RRA Exhibit B-28

Amounts in $ Thousands

Utility/Region	2012 Adjustment	2013 Adjustment
Mainland	$ (45)	$ (45)
Vancouver Island	(5)	(5)
Total	$ (50)	$ (50)

Adjusted Total CMAE as shown in the BCUC IR 1.131.2

Amounts in $ Thousands

Utility/Region	2012 Approved	2013 Approved
Mainland	$ 3,937	$ 4,067
Vancouver Island	437	452
Total	$ 4,374	$ 4,519

294.2 Suppose the Commission determines that the CMAE should continue to be reviewed as part of a revenue requirements proceeding, please update the two tables as referenced in the preamble. For each of the two tables, please provide the 2010-2013 approved, 2010-2012 actual, 2013 projection, and 2014 forecast.

Response:

The attached tables provide the requested updated information.

CMAE Forecast
Amounts in $ Thousands

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Actual	2013 Approved	2013 Projection	2014 Forecast
Mainland	$ 3,610	$ 3,309	$ 3,732	$ 3,620	$ 3,937	$ 3,812	$ 4,067	$ 3,635	$ 4,205
Vancouver Island	401	368	415	396	437	408	452	404	467
Total	$ 4,011	$ 3,677	$ 4,147	$ 4,016	$ 4,374	$ 4,220	$ 4,519	$ 4,039	$ 4,672

CMAE Breakout
Amounts in $ Thousands

Cost Component	2010 Approved	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Actual	2013 Approved	2013 Projection	2014 Forecast
IT	279	249	282	246	485	245	502	402	300
Consulting & Legal	290	313	311	532	315	569	325	150	500
Sundries & Subscriptions	193	192	194	155	200	342	207	207	245
Training & Travel	210	134	214	125	172	124	176	176	170
Labour	1,809	2,235	1,871	2,319	2,703	2,383	2,799	2,449	2,721
Energy Management Services Revenue [1]	(171)	(171)	(177)	(181)	(247)	(188)	(257)	(112)	(51)
Transfer from O&M	676		707						
Shared Services	725	725	745	820	746	746	767	767	788
Total	4,011	3,677	4,147	4,016	4,374	4,220	4,519	4,039	4,672

Note (1) Includes the EMS recoveries from FBC Electric.

As discussed in the response to BCUC IR 2.293.4, the Company believes it is appropriate for the CMAE forecasts to be reviewed as part of the quarterly gas cost review. In fact, as the Commission will not render a decision in the 2014-2018 PBR proceeding until mid-2014, it further supports the Company's position that the 2014 CMAE forecast should be reviewed and approved as part of the 2013 Fourth Quarter Gas Cost Report process.

294.2.1 For any variances between approved and actual (or projection) greater than 10%, please explain why. For unfavourable variances, please explain in detail.

1
2 **Response:**

3 The attached tables provide the variances and explanations.

CMAE Breakout
Amounts in $ Thousands

Cost Component	2010 Approved	2010 Actual	Variance $	Variance %	Explanation
IT	279	249	(30)	(11%)	Entegrate (deal capture) system risk management package implementataion deferred
Consulting & Legal	290	313	23	8%	
Sundries & Subscriptions	193	192	(1)	(1%)	
Training & Travel	210	134	(76)	(36%)	Training and travel expenses lower than anticipated
Energy Management Services Revenue	(171)	(171)	-	0%	
Labour	1,809	2,235			
Add: Transfer from O&M	676				
Sub-total Labour	2,485	2,235	(250)	(10%)	Vacancies due to unplanned employee turnover (e.g. transfers / terminations, maternity leaves, etc.), and higher cross charge out
Shared Services	725	725	-	0%	
Total	4,011	3,677	(334)	(8%)	

Cost Component	2011 Approved	2011 Actual	Variance $	Variance %	Explanation
IT	282	245	(37)	(13%)	Entegrate (deal capture) system risk management package implementataion deferred
Consulting & Legal	311	392	81	26%	Unbudgeted consulting costs incurred due to GSMIP review
Sundries & Subscriptions	194	334	140	72%	Increased subscription costs (Platts), and assessment fees / advertising costs related to GSMIP and PRMP regulatory processes
Training & Travel	214	124	(90)	(42%)	Training and travel expenses lower than anticipated
Energy Management Services Revenue	(177)	(183)	(6)	3%	
Labour	1,871	2,359			
Add: Transfer from O&M	707				
Sub-total Labour	2,578	2,359	(219)	(8%)	
Shared Services	745	745	-	0%	
Total	4,147	4,016	(131)	(3%)	

Cost Component	2012 Approved	2012 Actual	Variance $	Variance %	Explanation
IT	485	245	(240)	(49%)	Entegrate (deal capture) system risk management package, and replacement gas cost forecasting application implementations deferred
Consulting & Legal	315	569	254	80%	Legal and consulting costs related to the participation in the NGTL Komie North Application regulatory process (see response to BCUC IR 2.294.3 for further details on the Komie North costs)
Sundries & Subscriptions	200	348	148	74%	Increased subscription costs and membership fees (NWGA fees), and stakeholder PACA cost awards related to GSMIP review
Training & Travel	172	124	(49)	(28%)	Training and travel expenses lower than anticipated
Energy Management Services Revenue	(247)	(188)	59	(24%)	PNG EMS contract rates lower than planned
Labour	2,703	2,377	(326)	(12%)	Vacancies due to unplanned employee turnover (e.g. transfers / terminations, maternity leaves, etc.)
Shared Services	746	746	(0)	(0%)	
Total	4,374	4,220	(154)	(4%)	

Cost Component	2013 Approved	2013 Projection	Variance $	Variance %	Explanation
IT	502	402	(100)	(20%)	Replacement gas cost forecasting application implementation deferred
Consulting & Legal	325	150	(175)	(54%)	Regulatory proceedings for Coastal Gas TBO and Montney deferred
Sundries & Subscriptions	207	207	-	0%	
Training & Travel	176	176	-	0%	
Energy Management Services Revenue	(257)	(112)	145	(56%)	PNG EMS contract expired in 2013 and not renewed
Labour	2,799	2,449	(350)	(13%)	Vacancies due to unplanned employee turnover (e.g. transfers / terminations, maternity leaves, etc.)
Shared Services	767	767	-	0%	
Total	4,519	4,039	(480)	(11%)	

4

In response to BCUC 1.133.2, FEI states that "FEI became increasingly involved in regulatory matters concerning TransCanada's Nova Gas Transmission Ltd. (NGTL) system as that system undertook expansion plans into northeast BC from Alberta beginning with the Groundbirch Pipeline in 2008." In response to BCUC 1.133.2.1, FEI also states that "… the cost would be significant given the importance of the issues Komie North raised and the need for third party expert witnesses."

294.3 For each year since 2008, please a breakdown of forecasted and actual costs of FEI's participation in the National Energy Board (NEB) proceedings, including the name of proceeding, consulting costs, external legal services, and travel expenses.

Response:

FEI has participated in NEB, as well as Alberta Utilities Commission (AUC) and its predecessor Alberta Energy and Utilities Board (EUB), proceedings both as a direct participant and as a member of the Western Export Group (WEG). Prior to FEI's substantive involvement in the Komie North proceeding, FEI did not track its resource utilization or costs incurred by proceeding. Thus, FEI can provide only a summary of the NEB and AUC/EUB proceedings it has participated in between 2008 and 2011. Due to the significant potential adverse cost impacts for FEI's core customers arising from the Komie North Application, FEI actively participated in that proceeding and tracked the costs of the external resources required. A summary of FEI's participation is provided below.

Year	Proceeding
2007/08	**Natural Gas Liquids Extraction Inquiry (EUB)** – participation through WEG (included IR, cross examination, participation on panel, and argument phases of proceeding)
2008	**North Central Corridor Pipeline Application (AUC)** – participation through WEG (included IR, cross examination, and argument phases of proceeding)
	TCPL Alberta System Facilities Hearing (NEB) – participation through WEG (included cross examination and argument phases of proceeding)
2010	**NGTL Toll Methodology and Integration Application (NEB)** – participation through WEG, and as FEI (included argument phase of proceeding)
	Horn River Project Hearing (NEB) – participation through WEG, and as FEI (included IR and argument phases of proceeding)
2011/12	**TCPL Application for Restructuring and Final Tolls for 2012-2013 (NEB)** – participation through WEG (included various phases of process)
2012	**Komie North (NEB)** – participation through WEG, and in a substantive role as FEI (additional details provided below)

Summary of 2012 Komie North Costs

	Costs Incurred *(in $ 000s)*
External Consultants	$248.0
External Legal	$153.3
Travel Expenses	$12.6
Total	**$413.9**

Notes: Costs include some minor amounts invoiced in early 2013.

295.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1-1, Appendix D7, Section 3.2.3, Table D5-8

Billing Service Quality Indicator

Table D5-8 sets out the billing sub-measure components for calculating the Billing Service Quality Indicator.

295.1 Please confirm that the proposed Billing Service Indicator includes all customers in the determination of one aggregate Billing Service Indicator.

Response:

Confirmed. The Billing Service Indicator includes all customers in the determination of one aggregate Billing Service Indicator.

295.1.1 Would it be appropriate to determine the Billing Service Indicator on a rate class basis rather than in aggregate, particularly where FEI has introduced a new service such as Biomethane? Please explain.

Response:

No. It would not be appropriate to determine the Billing Service Indicator on a rate class basis as our customer expectations related to Billing are consistent regardless of the rate classes.

Rate classes are not taken into consideration to determine Billing Service Index and therefore no information is available by rate class. Customers signed up for new service offerings such as Biomethane are processed and billed in the same manner as other accounts billing practices.

295.2 In the same format as Table D5-8, provide schedules showing the Billing Sub-measure for each of the following Biomethane customer classes for the period from January 1, 2012 through July 31, 2013:

295.2.1 Rate Schedule 1B;

Response:

The requested information is not available. Please refer to the response to BCUC IR 2.295.1.1.

295.2.2 Rate Schedule 2B;

Response:

The requested information is not available. Please refer to the response to BCUC IR 2.295.1.1.

295.2.3 Rate Schedule 3B;

Response:

The requested information is not available. Please refer to the response to BCUC IR 2.295.1.1.

295.2.4 Rate Schedule 11B;

Response:

The requested information is not available. Please refer to the response to BCUC IR 2.295.2.1.

FORECASTS FOR THE PBR PERIOD - CAPITAL

296.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Part C, Section 4.4.4, p. 218; Exhibit B-11, BCUC 1.143.1, p. 361,

BCUC 1.152.2, p.378, BCUC 1.152.5, p.380

Historical Capital

The table in BCUC 1.143.1 shows that total sustainment capital has risen from $34.6 million in 2007 to $75.1 million in 2013 Approved, for an increase of 117 percent in 6 years. Only Distribution System Reinforcements shows a reduced spending level while Transmission System Reinforcements has the largest increase of 380 percent.

296.1 Are these increases sustainable, and is it appropriate to use these amounts as a 2013 Base for the next PBR period?

Response:

Yes, the increases are sustainable as indicated in the Application showing the five year forecasts, and it is appropriate to use 2013 as a base for the next PBR period. However, the identification, analysis and planning of system sustainment is an ongoing function and, as influencing factors change (e.g. system condition, code requirements) the actual projects that will be required may change as compared to the high level forecasts provided, to ensure that the resources are invested in addressing the conditions with the highest risk. This dynamic analysis approach ensures that FEI will continue to operate safely and reliably while protecting customers from unwarranted costs and rate impacts.

296.2 Is the LTSP creating an expectation of ever increasing capital expenditures? Please explain how FEI proposes to mitigate capital expenditure increases due to the LTSP.

Response:

The high-level Sustainment capital forecast provided in the Application increases at an annual rate of approximately one percent over the five year term of the PBR, providing evidence that there is no expectation of “ever increasing capital expenditures”.

As stated in Appendix C3, Page 13, Paragraph 4 of the Application, "The LTSP enhances the FEU's Asset Management and capital planning processes and works in conjunction with the FEU's continuing Integrity Management Program (IMP)". The LTSP is not a standalone program, but rather a tool that has enabled FEI to gain an increased understanding of asset condition and future reliability of natural gas assets, and develop a sustainable methodology to identify and prioritize capital work over the long-term. Therefore, the LTSP in conjunction with the existing capital planning processes, have led to an enhanced view of the capital expenditures required over the long-term to ensure the continued safe and reliable operation and maintenance of FEI's natural gas delivery system. With this enhanced, longer-term view, FEI is then able to mitigate capital expenditure increases.

296.3 Is FEI's transition from a reactive approach to a proactive approach reasonable given the expected cost increases? Please provide statistics such as growth in leaks per km of transmission pipe over 50 years of age and leaks per km of distribution pipe over 40 years of age to demonstrate the need to sustain the current budgets into the PBR period.

Response:

Yes, FEI's transition from a reactive approach to a proactive approach is both reasonable and required.

As noted in previous applications and in this Application including in Appendix C-3, FEI has undertaken an initiative (the LTSP) to better understand asset condition and to plan required work in an effort to ensure all expenditures are appropriate and in the best interest of maintaining a safe and reliable natural gas delivery system.

Certain assets can be allowed to run to failure, depending on the consequences of that failure. Notably, where there is redundancy built into the system to ensure security of supply and where the failure will not result in an unsafe condition, run to failure may be acceptable. However, in instances where allowing an asset to fail will result in an uncontrolled release of natural gas with associated concerns for public safety or loss of supply and inconvenience to the customers, running an asset to failure is not acceptable. Correspondingly, a proactive approach is required to ensure continued safe, reliable delivery of natural gas to the customer.

The FEI transmission system installation was initiated in 1956; consequently in 2013, 33% of the transmission system is more than 50 years old with the oldest pipelines being in service for 56 years.

There has been one recorded leak on a transmission pressure pipeline more than 50 years old; this was as an equipment leak during routine maintenance.

Statistics specific to the leaks on distribution piping more than 40 years of age are not available; please refer to the responses to BCUC IRs 2.262 and 2.262.3 for the best information available specific to leak history on the distribution system.

As noted in Exhibit B-1-1, Appendix C3, Page 2, Long Term Sustainment Plan, age is not the determining factor in identifying the need to repair, replace or refurbish FEI assets and targeting a limited age range will provide skewed results (i.e. transmission pipelines more than 50 years old or distribution pipes more than 40 years old). For an accurate understanding of asset condition and the work required to maintain the system long into the future, it is necessary to examine many more factors. The LTSP provides that analysis and a more accurate means of identifying and assessing the required work.

FEI notes that focusing on those parts of the system that are more than a certain age, regardless of that age threshold, is contrary to the intent and the execution of the LTSP. Similarly, if leaks were used as the reason to initiate corrective action, FEI would be facing increasing capital costs due to the reactive nature of unplanned work and public safety would be compromised due to uncontrolled gas leaks. Customer disruption would be increased as response to the leaks would require more aggressive response to ensure safety than is possible by being proactive. The company needs to provide a safe and reliable system. Contrary to the apparent concern implied by the BCUC IR 2.262 and 2.341 series, the best way to minimize capital costs for system sustainment is to understand the assets and the reasons they fail, and then address any concerns before the pipelines begin to leak.

Please also refer to the response to BCUC IR 2.262.2.

296.4 Is there a concern that FEI could revert back to a low cost reactive approach during the PBR period and, if so, should base capital or some elements of base capital be removed from the PBR formula? Please discuss.

Response:

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

In response to BCUC 1.152.2 discussing the significant increase between 2010 and 2011 for Distribution Mains and Services expenditures, FEI states that "at least 37% of the increase was due to third party requests which FEI cannot control."

296.5 Should expenditures that FEI cannot control be included base capital or tracked outside the PBR base capital through a CPCN or capital tracker of some sort?

Response:

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

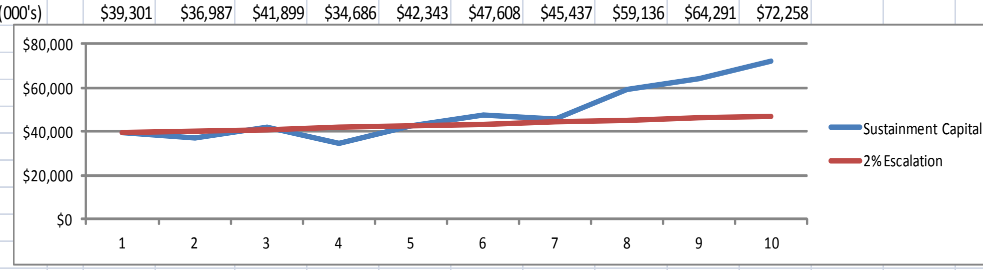
296.5.1 What should be the criteria for what is in base capital and what is in a capital tracker or Certificate of Public Convenience and Necessity (CPCN)?

Response:

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

296.6 Combining the data from the two Information Requests and adding a line representing a 2 percent escalation as a proxy for inflation over the period the following table and graph was prepared. Please confirm that the information is correct and the assumption of 2 percent average inflation is approximately reasonable for the period.

	Yr	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Sustainment Capital (000's)		$39,301	$36,987	$41,899	$34,686	$42,343	$47,608	$45,437	$59,136	$64,291	$72,258
2% Escalation		39,301	40,087	40,889	41,707	42,541	43,391	44,259	45,144	46,047	46,968



Response:

The Sustainment capital data illustrated in the graph accurately portrays the data provided in the subject Exhibits and IR responses. However, the 2% average inflation does not accurately reflect the requirements for sustainment capital during the period covered by the graph nor does it accurately reflect future requirements. As discussed in the response to BCUC IR 1.152.5, spending levels in sustainment capital expenditures from the last PBR is not directly relevant to the approvals sought in this Application; therefore, FEI does not agree that a 2% average inflation escalation based on actual capital expenditures from 2004 is reasonable during the illustrated period or necessarily during the PBR period.

As noted, FEI cannot control third-party requests and with increases in infrastructure replacement and development across the service area those requests have increased faster than 2% or inflation. Similarly, FEI has been forecasting the need to increase sustainment capital spending, both in this and previous applications. While this is currently planned to increase at less than 2% per year from the 2013 base FEI is also in a position of competing with similar companies across North America for limited technical resources. As proposed projects across the country and the province proceed it is fully expected that resource shortages will drive costs up at a rate far beyond the 2% illustrated without any increase in project scope.

As discussed in the Application at page 206:

> *"FEI's forecast capital expenditures over the PBR period have been prepared using a low inflation scenario, as noted in the sections that follow. However, as discussed below, there is the potential for a high inflation scenario which would impact the forecast capital expenditures."*

And also with reference to the potential high inflation scenario, FEI stated at page 77 of the Application:

"The proposed Mid-term Assessment Review will be held prior to the end of the third year (2016) of the term as part of the third Annual Review. Similar to the 2004 PBR Plan, the terms of reference of the Mid-term Assessment Review will be two-fold:

1. *If any one (or more) particular element of the PBR Plan appears to be inducing unintended outcomes or results in continuous material changes to service quality, then stakeholders will work to identify a change that can address that element and put it forward to the Commission.*
2. *If the results of operating under the PBR Plan have caused financial distress and, if so, to implement a change* ***(an example might be significant inflationary pressures on sustainment capital expenditures that are not reflected in the province-wide CPI or AWE measures)."*** [emphasis added]

296.6.1 From the data provided, is it reasonable to observe that during the previous PBR period of 2004 to 2007 FEI was able to manage sustainment capital below 2 percent escalation?

Response:

FEI's PBR Period was from 2004 to 2009. From the data provided and as interpreted in the graph it appears that FEI sustainment capital increased at a rate of less than 2% per year during the 2004 to 2009 PBR period; however, this observation has limited relevance to the 2014 through 2018 PBR period.

FEI provided written and oral evidence during the 2012-13 RRA process that work had been deferred during the 2004 through 2009 period to the benefit of the customers but that continued deferral of that work was not acceptable without resulting risk to safety and reliability of the natural gas delivery system. In other words, the limited expenditure on sustainment capital during the previous PBR is not sustainable.

As the evidence filed in the 2012-2013 RRA process and in the current Application shows, analysis of the asset condition and changes in operating conditions indicates the requirement to increase the expenditure of sustainment capital for the next several years. Efforts to manage the sustainment capital at historical levels will result in deferral of critical work with associated risks to public safety and security of supply.

Limiting the increase in sustainment capital over the long term is not sustainable and will result in an unacceptable decrease in system safety and reliability.

As the FEU previously stated in the 2012-2013 RRA proceeding, the savings during PBR were achieved through a number of means, including the Utilities Strategy Project (the adoption of combined utility management for the FEU), deferring activities and related costs where safe and prudent to do so, management of the meter to cash process resulting in the lowering of bad debts, centralized asset management in Distribution services, and department reorganization and streamlining. FEI continues to see lower costs in many areas from these initiatives which are permanent in nature. For example, FEI continues to benefit from the efficiencies of combined utility management first introduced by the Utilities Strategy Project. However, a number of the efficiencies that were realized during PBR can only be achieved once, or can only be sustained for a limited period of time before activities need to be resumed and costs need to be incurred. Savings have also been offset by new costs incurred to provide safe and reliable service to customers.

With the implementation of the LTSP methodology and the improved understanding of asset condition a number of programs and projects have been identified that are mandatory to maintain safe, reliable service of the natural gas delivery system. Identification of these projects and programs would not have been possible prior to the implementation of the LTSP and FEI would have been reactively dealing with asset failures that could not have been anticipated without the methodology. For example, an integrated analysis of supply to the Metro Vancouver area including the pending end of service life of the Coquitlam to Vancouver Intermediate Pressure pipeline has resulted in the identified need to implement a total of five major pipeline improvements (see Section 4.7.2, page 251 of the Application). Similarly, a central view of a variety of factors has resulted in the implementation of programs to replace isolated steel mains (see Section 4.4.7, Distribution Mains, Service Renewals and Alterations Capital, Page 224 of the Application).

296.6.2 Also, is it reasonable to observe that for the 3 years following the PBR (up to 2010) FEI was able to manage sustainment capital at or slightly above a 2 percent escalation line?

Response:

FEI notes that the assumption in the question is incorrect. FEI's last PBR ended in 2009. The three years following the PBR would be 2010 through 2013, and FEI has responded using this time period.

The rate of increase from 2010 to 2013 is consistent with the evidence filed by FEI specific to the need to increase spending to address the asset condition, and is consistent with the findings of the Long Term Sustainment Plan and the Commission's approval of those expenditures.

Please refer to the response to BCUC IR 2.296.6.1.

296.6.3 Is it accurate to say that over the period of 2004 to 2010 sustainment capital grew by an average of approximately 2 percent?

Response:

As illustrated by the graph provided as a part of this IR series and the data provided in the Application, sustainment capital grew by approximately 2 percent per year during the period of 2004 through 2010. However, FEI also notes that sustainment capital expenditures grew at a significantly higher rate from 2011 through 2013. The increase in the level of sustainment spending during this period has been previously approved by the Commission in the 2010/2011 and 2012/2013 RRAs and was fully justified in those proceedings.

A number of things changed during the period of 2011 through 2013 to cause the level of sustainment capital expenditures to grow. The factors that resulted in the increases in sustainment capital expenditures have been discussed in Appendix C3 of the current Application as well as in the FEU's 2012/13 RRA. The main factors include, but are not limited to:

- Increased development and infrastructure renewal throughout the province has resulted in increased costs in response to third-party requests.
- Work was deferred during the PBR period where it could be deferred safely. This benefitted customers by delaying the associated rate pressures. However, it is neither practical nor safe to continue to defer that work indefinitely; the increased spending during the 2011 through 2013 period reflected the need to address the work previously deferred.
- Work has been ongoing to develop an LTSP with improved identification, analysis and planning of sustainment requirements. Some of the less critical sustainment projects were deferred until the requirements could be better understood and confidence developed that the work and resulting costs were mandatory.
- With the implementation of the LTSP, FEI has a better understanding of the condition of the assets than at any time in the past and has identified significant projects that are required to ensure the ongoing safety and reliability of the gas delivery system.

The sustainment costs projected for the 2014 through 2018 period build on the LTSP results and are required to address a number of conditions that cannot be deferred without incurring an unacceptable level of risk.

The relationship between the previous PBR period and the proposed 2014 through 2018 period is limited. System condition, code requirements, and asset management expertise has changed;

sustainment requirements have also changed. The sustainment capital requested for the upcoming five years is necessary to ensure continued safety and reliability of the natural gas delivery system.

In summary, sustainment capital forecasted for the 2014-2018 period will increase at a rate less than 2% per year from the 2013 base and is consistent with the percentage increases seen over the 2004-2010 period.

296.6.4 Would FEI agree that the level of sustainment capital expenditures from 2004 to 2010 represented its true costs for its normal course of business in this area?

Response:

The sustainment capital expenditures during 2004 to 2010 accurately reflect the expenditures during that period. This is a limited period of time and does not accurately reflect a complete or realistic view of the sustainment requirements for the longer term based on the information known today and as described in the response to BCUC IR 2.296.6.3.

As described in this and previous applications, the amount of sustainment capital required has increased and is expected to increase in accordance with the costs projected in this Application.

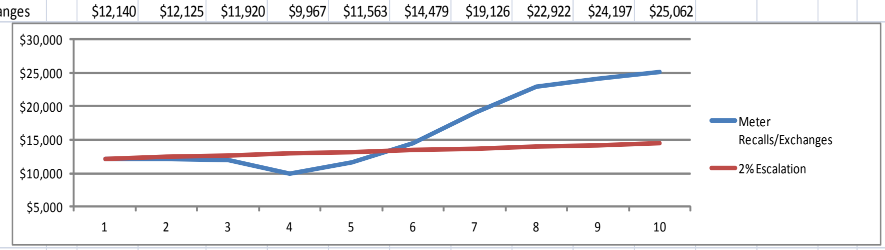
296.6.5 Would FEI agree that some thing or things changed in 2011, 2012 and 2013 to cause the level of sustainment capital expenditures to grow?

Response:

Please refer to the response to BCUC IR 2.296.6.3.

296.6.6 Combining the data from the two Information Requests and adding a line representing a 2 percent escalation as a proxy for inflation over the period the following table and graph was prepared for meter recalls and exchanges. Please confirm that the information is correct.

	Yr	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Sustainment Capital											
Meter Recalls/Exchanges		$12,140	$12,125	$11,920	$9,967	$11,563	$14,479	$19,126	$22,922	$24,197	$25,062
2% Escalation		12,140	12,383	12,630	12,883	13,141	13,404	13,672	13,945	14,224	14,508



Response:

Yes, the information and the graph are correct.

296.6.6.1 Is it reasonable to observe that FEI was able to manage these expenditures below 2 percent escalation over the previous PBR period (2004 – 2007)?

Response:

Please refer to the response to BCUC IR 296.6.6.2.

296.6.6.2 Would FEI agree that over the period of 2004 to 2009 these expenditures grew by an average of approximately 2 percent, but that in 2010 and onwards there was a significant change in the normal course of business?

Response:

The "Sustainment Capital- Meter Recalls/Exchanges" category includes all activities and expenditures required to exchange both meters and regulators.

Meter Exchanges

Within the period between 2004 to 2009 expenditures did grow by an average of approximately 2% per year. However, the period between 2004 to 2009 was unique because of a decision that was made by FEI to fundamentally change how meter replacement is managed.

Prior to 2006, the Company managed the residential meter fleet to a 28 year life span enabled by one maintenance and recondition operation at the midpoint of this 28 year life. This resulted in a meter recall frequency of 14 years. The Company's internal analysis combined with communications with both vendors and other utility representatives that sit on the Canadian Gas Association Measurement Committee, provided FEI the confidence to target a 20 year lifespan for the residential meter fleet without a mid-life recondition operation. This change in strategy allowed FEI to temporarily reduce the number of meter recalls between the period between 2006 and 2008. A reduction in the number of recalls was implemented to age the demographics of the meter fleet in line with a 20 year life expectancy and provided both customers and the shareholder with the cost benefits of previous investments in the meter fleet as described within the 2010-2011 RRA. Beginning in 2009, the number of meter exchanges began to increase as the compliance test results indicated a greater number of meters were reaching the end of service life. In addition, FEI also began a program of recalling meter families that had exhibited durability issues resulting in a shorter service life as discussed in BCUC 1.135.1 in the 2010-2011 RRA.

Regulator Evergreening:

A second impact to expenditures within this area was the increase in the regulator ever-greening program (described on page 216 of the Application). The customer service technicians, the primary resource for emergency first response and meter exchanges, were redeployed to outstanding regulator replacement activity as a result of having less annual meter exchanges. Subsequent to the Whistler gas conversion project in 2009, external resources also became available to assist with completion of the regulator ever-greening program. Please also refer to the response to BCUC IR 1.154.1

Regulator replacement is the activity of removing older and obsolete in-service gas regulators and replacing them with new regulators. The need for regulator replacements may be identified through routine operating activities such as meter exchanges, meter reading and leak surveys. These are generally low priority hazards that are batched together for completion and used to minimize standby time where technicians may otherwise not have enough customer driven work. Regulator exchanges are completed by both internal and external technician resources.

296.6.6.3 Please explain the cause of these increased expenditures with respect to the information provided in Table C4-8 of the Application (Exhibit B-1) reproduced here below and any other significant changes including unit cost and the number of meter recalls for the period prior to 2010.

Table C4-8: Historical Meter Exchange Activities & Expenditures ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Meter Recalls - Scheduled	58,403	57,511	62,141	58,900	58,900
Meter Recalls - Unscheduled	3,137	3,450	2,956	3,000	3,400
Total Meter Recall Activity	61,540	60,961	65,097	61,900	62,300
Unit Cost ($/meter)	274	303	297	308	304
Subtotal Meter Recall Expenditures	16,873	18,496	19,350	19,062	18,945
Incremental Recalls	-	-	-	-	-
Unit Cost ($/meter)	-	-	-	-	-
Subtotal Incremental Meter Recall Expenditures	-	-	-	-	-
Total Meter Recall Expenditures	16,873	18,496	19,350	19,062	18,945
Total Meter Recall Activity	61,540	60,961	65,097	61,900	62,300
Adjusted Unit Cost	$ 274	$ 303	$ 297	$ 308	$ 304

(Exhibit B-1, p. 218)

Response:

Please refer to the response to BCUC IR 2.296.6.6.2. The Meter Unit Cost which is an aggregate or blended meter unit cost is influenced by several variables including the number and type of meter exchanges, the timing of bulk meter purchases and meter upgrade activity. The meter unit cost fluctuates from year to year as the variables change.

297.0 Reference: CAPITAL

Exhibit B-1, pp. 61, 210, 217; Exhibit B-11, BCUC 1.153.1, 1.154.1, 1,156.1, 1.156.2

Capital Expenditures-Historical and Base for PBR

"For capital, there is no need to adjust the 2013 Approved for savings realized in 2012. This is because amounts that were not spent in 2012 are not considered sustainable, since they have been carried forward to the 2013 Projection. As described in Section C4 on Capital Expenditures, the total of the 2012 Actual and 2013 Projection amounts are very close to 2012-2013 RRA Approved amounts (approximately $2 million less), and in fact the 2013 Projection is $6.5 million higher than the 2013 Approved amount that is being used as a base for the PBR capital formula." (Exhibit B-1, p. 61)

Table C4-4 indicates that actual expenditures for Meter Recalls/Exchanges were significantly greater than the approved amounts in both 2012 and 2013. These numbers include regulator evergreening. Table C4-6 projects expenditures of $6,000 thousand for regulator evergreening in 2013 compared to an approved amount of $2,328 thousand, and indicates that the actual expenditure in 2012 was $4,847 thousand. (Exhibit B-1, pp. 210, 217)

297.1 What were the approved amounts for regulator evergreening in 2011 and 2012?

Response:

Of the total approved capital, $2,194 thousand in 2011 and $2,260 thousand in 2012 was initially forecast for the regulator ever-greening program.

297.2 Starting with an assumption that the approved expenditure for 2012 was the same as the amount of $2,328 thousand for 2013, does this indicate that FEI overspent the approved amounts for this category by an average of about $3,100 thousand per year in 2012 and 2013? Please use the approved amount for 2012 from the response to the previous question to calculate the correct amount of average overspending.

Response:

The $2,328 thousand in 2013 for regulator evergreening was a forecast, not a specific BCUC approval line item. FEI confirms that it was required to spend more in this category of capital than it had anticipated and forecast as part of its overall capital for 2012 and 2013. The 2012 and 2013 forecasts were developed in mid-2011, and as spending priorities and resource availability change it is FEI's responsibility to allocate capital as required to ensure the long term safety and reliability of the system and balance resource capacity to ensure capital and O&M programs are managed cost effectively.

Please refer to page 220 of the Application which discusses the reasons for increased spending on the regulator ever-greening program.

	$000's		$000's
2012 Actual	$ 4,847	**2013 Projection**	$ 6,000
2012 Forecast	$ 2,260	**2013 Forecast**	$ 2,328
Difference	$ 2,587	**Difference**	$ 3,672
Average Actual Less Forecast 2012-2013:			$ 3,130

Table C4-7 indicates an adjusted 2013 Base for regulator evergreening of $2,457 thousand, and provides forecasts of expenditures for 2014 through 2018.

297.3 Please confirm that the forecast expenditures for 2014 through 2018 average $2,291 thousand per year.

Response:

Confirmed, although there is significant variability from 2014 to 2018, with 2014 and 2015 having higher levels due to the work required to eliminate the backlog of outstanding identified regulator replacements.

297.4 If the objective was to establish an amount for regulator evergreening in a 2014 revenue requirements scenario, would $2,457 thousand or slightly less be an appropriate amount? If not, please explain.

Response:

No. If FEI were proposing a revenue requirement for 2014, it would be requesting approval of the $4,314 thousand included in the 2014 column in Table C 4-7.

FEI is instead proposing a PBR, and has set the 2013 Base amount for total Sustainment and Other Capital at $102,075 thousand (Table B6-8). Included in this total is $2,459 thousand for regulator evergreening.

> "If a need for a regulator replacement is identified, then there is a system-driven requirement to identify the address, type of replacement required and reason for replacement. These are generally lower priority hazards that are batched together for completion and used to minimize standby time where technicians or crews may otherwise not have enough customer driven work." (Exhibit B-1, p. 220)

297.5 Please confirm that the amount of expenditures on regulator evergreening in 2012 and 2013 was discretionary, within the control of FEI management and not in response to an immediate safety or reliability concern.

Response:

Please refer to the response to BCUC IR 1.156.1. Regulators are replaced under three different scenarios:

- at the time of a meter exchange;
- as follow-on work to a notification raised by a field resource; or
- as part of an emergency or repair call where the regulator replacement has been determined to be the corrective action necessary to resolve the call.

Replacement timing under the first two scenarios are in control of FEI management. While not an immediate safety or reliability concern as is the case with the third scenario, the regulator replacements under the first two scenarios are known hazards that are prudent to eliminate in a planned manner.

297.6 Does FEI's spending in excess of the approved amounts for regulator evergreening in 2012 and 2013 result in a higher total Base Capital for 2013 for PBR than would otherwise be the case? If not, please explain.

Response:

The 2013 Base for regulator evergreening was not set based on the 2012 actuals or the 2013 projection. It was set based on the portion of the 2013 Approved capital that was forecast to be spent on regulator evergreening. As a result, any increased spending levels in 2012 and 2013 do not result in a higher base capital for the PBR period.

297.7 Please discuss whether the total Base Capital for 2013 should be reduced to remove the effect on the PBR of this spending in excess of the approved amounts for regulator evergreening. Would an appropriate adjustment be the average difference between the approved and projected amounts for 2012 and 2013, or about $3,100 thousand?

Response:

The question is based on an incorrect assumption. The Base Capital for 2013 does not include any spending above approved for regulator evergreening. Please refer to the response to BCUC IR 2.297.6.

298.0 Reference: CAPITAL

Exhibit B-1, pp. 210-1, 221-3, 226, 250-3; Exhibit B-11, BCUC 1.153.1

Capital Expenditures-Sustainment Capital

Table C4-4 indicates that actual expenditures for Transmission System Reinforcements in 2012 and projected expenditures in 2013 are significantly greater than the expenditures in 2010 and 2011, but also significantly less than approved amounts for 2012 and 2013. (Exhibit B-1, p. 210)

"The Transmission-related capital expenditures included in Table C4-4 above include system capacity improvements to meet existing customer demand and forecast load, and expenditures related to ensuring safety, reliability and integrity of the transmission system, as well as to minimize the impact to the environment.

Between 2014 and 2018 projects that are forecast to cost greater than $1 million and that are included in the Transmission System Reinforcements line of Table D2-4 are discussed below and have been organized based on common issues." (Exhibit B-1, p. 221)

"Overall, sustainment capital expenditures are forecast to increase throughout the PBR period, from approximately $78 million in the base year 2013 to approximately $82 million forecast in 2018. This represents, on average, an increase of approximately 1.1 percent annually throughout the RRA period. Major transmission pipeline projects identified through the LTSP will be subject to further investigation by FEI's Engineering staff and potential projects will be filed separately as CPCNs." (Exhibit B-1, p. 226)

"Over the next five years FEI is considering a number of major projects to ensure the ongoing safety, integrity, and reliability of its gas system. Those projects will likely exceed the $5 million CPCN threshold, and therefore would be filed separately from this Application. These projects are typically identified through either integrity concerns being raised from a sustainment perspective, system improvements identified through hydraulic analyses, or through capacity concerns being raised due to demand growth as a result of specific customer additions. The following discusses those projects under consideration over the next five years for which FEI anticipates CPCNs will be required.

Cost estimates have not been updated at this time for the projects identified below,.." (Exhibit B-1, p. 250)

298.1 What was the cost of the work in past years to stabilize the Right of Way in the Burns Bog that is identified on page 251 of Exhibit B-1? Please respond with the expenditures by year from 2010 through 2013.

Response:

FEI has incurred costs to stabilize and strengthen the pipelines through Burns Bog dating back to 2001, with a total cost of approximately $8.4 million. It should be noted that much more than that has actually been spent but any additional costs have been recovered either from third party requesters (as in the case of the Ministry of Highways for the South Fraser Perimeter Road) or from insurance claims (as in the case of the repairs on the Delta Shake & Shingle, Alpha Manufacturing and the Dominion sites).

When the pipelines were originally installed in Burns Bog there was no development adjacent to the Right of Way nor was any development considered at the time of pipeline installations. This is evident by the standard width of the Right of Way. Subsequent development has been, and remains, outside the control of FEI. While FEI can, and does, conduct regular line patrols to identify potentially damaging activities and has cautioned adjacent property owners in the past, it remains that FEI's best option to ensure the ongoing reliability and protection of the pipelines is to strengthen and stabilize the Right of Way and pipelines. This is a multi-year project that requires:

- acquiring work space outside the Right of Way;
- installing temporary bypasses around the area to be stabilized;
- preloading the Right of Way for several months until the soil has been consolidated;
- removing the preload;
- reinstating the pipelines in their original alignment; and,
- removing the temporary bypasses.

Right of Way consolidation during the period of 2010 through 2013 has been limited to work in support of the construction of the South Fraser Perimeter Road and has been largely recovered from the Ministry of Highways. Those costs follow:

- 2010 $4,328 thousand
- 2011 $1,939 thousand
- 2012 $6,067 thousand
- 2013 $1,875 thousand (projected)

Despite the work that has been done, there remain a limited number of areas where the Right of Way has not been consolidated and these continue to be a potential source of damage and pipeline failure. There are more than 200,000 customers that could be affected by loss of the pipelines through Burns Bog. Addressing the potential risk to those areas of Right of Way identified as vulnerable is necessary.

298.2 Was this work in past years to stabilize the Right of Way in the Burns Bog carried out as part of Sustainment Capital? Please identify any of this work that was done under a CPCN.

Response:

Limited work has been completed in the past to consolidate and strengthen the soils along the FEI Right of Way in Burns Bog as part of sustainment capital. Over the life of the pipelines approximately $8.4 million has been spent that has not been recoverable from third parties or through insurance claims.

No work has been done to date to stabilize the Right of Way in Burns Bog under a CPCN.

Please also refer also to the response to BCUC IR 2.298.1.

298.3 Please identify the anticipated CPCN projects shown on pages 250 through 253 of Exhibit B-1 that are reinforcements of the Transmission System. If any are not reinforcements of the Transmission System, please briefly explain why.

Response:

FEI is unsure what exactly is meant by “reinforcement” of the transmission system, but offers the following response:

Sustainment capital as listed in Table C4-4 includes a number of projects and programs required to maintain the safety, reliability and compliance of the transmission system, these projects include, but are not limited to:

- Pipeline upgrades required to meet changes in class location as a result of development adjacent to the pipeline and as required by the CSA Z662, *Oil and Gas Pipeline Systems* standard;
- Valve replacements to ensure accessibility and to remove confined spaces;

- Installing remote control actuators on valves to improve emergency response in remote areas; and,
- Obsolete equipment replacement.

The CPCN projects identified in Exhibit B-1 are not included in the capital identified in Table C4-4.

Three of the CPCN projects identified in Exhibit B-1 could be considered transmission system reinforcements:

- Loop the 610 mm OD Nichol to Port Mann transmission pipeline;
- Loop the 610 mm OD Nichol to Roebuck transmission pipeline; and
- Loop the 508 mm OD Cape Horn to Coquitlam transmission pipeline.

These pipeline projects provide improved security of supply as well as increased capacity.

Replacement of the 508 mm OD Coquitlam to Vancouver intermediate pressure pipeline is not a part of the transmission system, but the proposed increase in size and operating pressure will provide reinforcement of the intermediate pressure system by increasing capacity.

Two of the CPCN projects identified in Exhibit B-1 are not transmission system reinforcements and are required to improve security of supply without increasing capacity:

- Huntingdon Station Bypass; and
- Preload and stabilize remaining right of way between Delta Station and Tilbury Station.

298.4 Are the reinforcements of the Transmission System that FEI anticipates will be CPCN projects different in some fundamental ways, other than with respect to the estimated cost of each project, from the Transmission System Reinforcements in Table C4-4? If yes, please explain with examples.

Response:

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

298.5 Please generate a table covering the period 2010 through 2018 with the headings shown in Tables C4-4 and C4-5 that includes Transmission System Reinforcements and anticipated CPCN projects that are reinforcements of the Transmission System. For the Transmission System Reinforcements, please identify each project involving an expenditure of $1 million or more, to the extent possible, and include a total amount for smaller projects that are not so identified. For the CPCN projects please use the most current timing and cost estimates available. Include the requested information in a fully functional spreadsheet.

Response:

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

298.6 Please discuss the pros and cons of including all reinforcements of the Transmission System in Base Capital for PBR, with the exception of very large projects like KORP.

Response:

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

298.7 Should some of the projects now identified as CPCNs be included in PBR Base Capital?

Response:

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

299.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, p. 218, 219

Sustainment Capital – Meter Recalls / Exchanges

299.1 In Table C4-8 FEI shows the 2013 Approved unit cost ($/meter) of $304. Why did FEI use a Unit Cost ($/meter) of $321 in C4-9 in the calculation of 2013 Base?

> Scheduled meter exchange activity levels are driven by factors related to Measurement Canada's mandatory standards and regulations. Measurement Canada allows utilities to operate their meter fleets by applying a compliance sampling plan to confirm meters used for billing customers are accurate. Compliance sampling is the process of randomly selecting a subset of meters from a group of installed meters, testing the samples and inferring the quality of the remaining installed meters in that group from the test results of the samples.

(Exhibit B-1, p. 219)

Response:

The difference between the 2013 Approved and 2013 Base Capital is summarized in Exhibit B-1, Section C4.3.2, specifically Table C4-2. The changes impacting Sustainment Capital are PST and pension adjustments. These adjustments flow through the Meter Recall/ Exchanges category and on a per unit basis are equal to a $17 increase or the difference between the 2013 approved unit cost and the 2013 base unit cost.

299.2 Please show why the number of meter exchanges (before the change to Measurement Canada S-S-06) is forecast at 58,900 in Table C4-9 other than this is what was approved for 2013.

Response:

The projected level of scheduled meter recall activity for 2013 is consistent with the approved level of scheduled meter recall activity for the same period as shown in Table C4-9 of the Application, Exhibit B-1. Meter recall activity levels are determined through the Measurement Canada mandated compliance sampling program which consists of annual testing and analysis of sample meters collected throughout the meter fleet. As FEI is confident that the 2013 projected level of meter recalls will be met, this projection provides an accurate reflection of the required level of meter recall activity necessary to remain compliant within existing Measurement Canada regulations. Furthermore, the 2013 Approved is a base that will provide a challenge to FEI in its transition from the current Sampling Plan LMB-EG-04 to Sampling Plan S-S-06, which takes effect on January 1, 2014, as mandated by Measurement Canada.

It is important to note that FEI is not requesting approval of the capital forecasts for 2014-2018 because the capital will be determined by formula.

299.2.1 Please show a calculation or other numerical derivation that supports this level of scheduled recalls based on the methodology and sampling required to be in compliance with Measurement Canada requirements.

Response:

At the end of each operating year, FEI analyzes the meter data to determine which meters will be required to be recalled for accuracy testing the following year in accordance with the Measurement Canada regulated compliance sampling program. FEI will further review its records for meters that have failed Measurement Canada defined accuracy requirements and for meters which have seals expiring and have proven through accuracy testing to be nearing end of service life. Finally, the company will review the meters identified with the potential for reliability and operating issues to assess the risk of failure. It is through this process that FEI works to manage the recall activities within its approved budget.

The Sampling standard SS06 is based on a series of requirements and tables contained within the document, there is no single calculation which could be presented which answers this question. Please see the following paragraph which is presented as a high level description of the requirement SS06.

The table that determines the number of samples is discussed in Annex B, Table 1, Nmin and Nmax (the bounds for the number of sample for a given group size) and Annex C, Table 2 , the Limiting Quality level, the sample number for a given groups size, the accuracy tolerances for acceptance (Type 1 (C1) >2% and Type 2 (C2) >2.9%)and found as well as Section 5.5.3. The number of permissible C1 and C2 meters is also identified in the Annex C, Table 2 where for example, a Lot Size of 1201 to 3200 under Limiting Quality of 3.15 with Nmin samples of 125 there would be allowable 1 only C1 and 1 only C2 (125,1,1). The limiting Quality column determines the maximum seal extension the group can obtain based on the C1's and C2's discovered in the samples recalled and tested. The permissible seal extension is further qualified by the "TT factor" (time on test) as indicated in Table 6 in Annex E. This is the measure of time the meters have been installed and in service. This prevents eligible sample meters from sitting on a shelf.

Please see below a link to the standard being discussed which is on the Measurement Canada web site at http://www.ic.gc.ca/eic/site/mc-mc.nsf/eng/lm04356.html.

299.2.2 Is the number of meters required to be exchanged / recalled under the control of FEI? Please explain in the context of Measurement Canada's mandatory standards.

Response:

The number of meter recalls that FEI performs each year is largely determined by Measurement Canada requirements. As such, where FEI has seal expiries or compliance sample recalls or failures of compliance sample groups, there is no provision for deferring the recalls. FEI has some discretion for managing the level of meter recall related to meter groups that through accuracy testing prove to be nearing end of life and therefore are granted only a short seal extension which is typically 2-3 years. In this situation, the Company has some ability to adjust the timing of removal for those meters. However, it should be noted that under the new Measurement Canada sampling plan SS-06, if FEI has knowledge that populations of meters are performing poorly, the Company will have a regulatory obligation to assess and potentially recall the meters early.

300.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.151.1, p. 375

Business Technology – 2013 Project Portfolio Benefits

The table in this IR response shows the forecast financial benefits of the 2013 Business Portfolio Benefits to augment table C4-1 in appendix C4 of the Application.

300.1 For projects that have been undertaken in the past has FEI regularly done post completion analyses to verify if the projected savings of each project were realized?

<u>Response:</u>

Prior to the introduction of the Benefits Management practice as detailed in Exhibit B-1-1, Appendix C4, FEI typically conducted post completion analyses to verify actual versus projected savings on CPCNs or large, transformational projects. Examples of these analyses can be found in Terasen Gas Inc. 2010-2011 RRA from page 134 to 141 and in the Application Exhibit B-1-1, page 143 to 146 and include the following projects:

- Distribution Mobile Solution;
- Nucleus Deal Capture Project for Gas Supply;
- Transmission AM/FM Project;
- Customer Attraction Front End Project;
- Service Delivery Enhancement Project;
- Commodity Unbundling Program; and
- Customer Care Enhancement Program.

300.2 Please explain how FEI evaluates past projects to assist it in determining if projected benefits from current projects are likely to be realized.

<u>Response:</u>

Past projects were evaluated based on the practices that were in place at the time. Experiences and analysis of past projects have been incorporated into the current benefits practice as detailed in Appendix C4 of the Application.

301.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.153.1, p. 381

Sustainment Capital

FEI provides three unforeseen circumstances that led to the large underspend in 2012.

301.1 The three examples provided seem to indicate that budgets for Transmission System reinforcement may be developed including all possible projects and maximum costing, and then some projects are not undertaken or deferred to future years. What budgeting cost control measures are in place to ensure this does not occur?

Response:

FEI is committed to ensuring that all expenditures are appropriate and in the best interest of customers and shareholders. This diligence requires that capital planning and expenditures be dynamically reviewed and managed to protect against unnecessary costs and that approach is reflected in the examples provided in response to BCUC IR 1.153.1.

Proceeding with the planned work at the LNG Plant could have resulted in stranded investments if the potential plant expansion made the requirements redundant. It was appropriate to defer the work and invest the funds in other required projects with less risk to the customers.

Transmission operations has traditionally retained funds to address major washouts and these funds have been approved in previous applications. Following the local freshets, if the funds were not required to repair washouts, they were diverted to complete other work. No similar contingency funding is included in this Application.

While FEI submits budgets based on the best information available at the time, the Company continues to strive to minimize costs with related impacts to our customers. The reduced costs of security upgrades at the Oliver Y Control Station are a reflection of ongoing diligence to minimize costs while continuing to complete the work appropriately.

As noted, FEI strives to provide budget plans and requests that are based on the best information available at the time; however, sustainment capital management remains dynamic. Priorities change and market conditions change. Continued diligence and internal review processes provide appropriate checks and balances to ensure all expenditures are required and made with the interests of customers in mind.

Specific measures in place to further ensure cost controls, both budgeting and execution, include:

- a cross-organizational team of senior managers that review and approve all submissions for capital funding and/or changes to previously approved funding that also monitor the impacts on the overall capital budget; and
- corporate approval processes that increase the level of approvals required for all capital projects based on estimated costs and/or increases to total costs.

Both of these initiatives ensure visibility and ongoing scrutiny of capital budgets and expenditures to ensure that, even with the dynamic and changing nature of the work, all costs are appropriate and that the customers and shareholders are protected.

As FEI has stated elsewhere, even when spending is less than originally approved due to prudent management decisions, it is in the ratepayers' best interests as the lower capital results in a lower rate base for the remaining useful life of the assets (up to 60 years).

302.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-11, BCUC 1.156.1, p. 386

Regulators

FEI states that "Unlike meters, regulators, being a relatively low dollar cost item, are not specifically tracked in FEI's maintenance information system. The number of regulators replaced in a given year is not currently available with existing reporting systems due in part to the number of different ways in which this type of activity is completed."

302.1 If FEI doesn't know how many regulators it has replaced since 2003, how does FEI know it has 70,000 yet to replace? Does FEI know how many it has replaced in aggregate?

Response:

There are approximately 70,000 outstanding hazard notifications logged in the FEI maintenance system. Notifications include both regulator and venting hazards, but do not differentiate between one or the other. In addition to these hazard notifications, based on experience, a further 10,000 to 20,000 regulator upgrades will occur annually through the meter exchange program. Technicians replace any obsolete regulators identified during the meter exchange process, some of which would have been previously identified and logged as part of the hazard notification process. For example, some addresses for the outstanding notifications will match the location of the meter exchange, so when the technician is on site to complete the meter exchange he will also complete the regulator replacement and eliminate an outstanding notification.

Since 2006, FEI has eliminated 72,000 of the regulator and venting hazard notifications which are generally indicative of a regulator replacement although not always. Prior to 2006, this type of record keeping was not available.

Since 2010, FEI has completed 71,100 regulator replacements while performing the meter exchange. Some portion of these replacements would also be included in the notifications eliminated above. Prior to 2010, this type of detailed record keeping was not available.

Regulator replacements as part of a response to an emergency or repair call have not been tracked.

The Company estimates the overall regulator replacement totals since 2006 to be between 100,000 and 140,000.

Please refer to the response to BCUC IR 1.156.1.

302.2 As an indication of need for this evergreening regulator project, please provide information on the failure mechanism, impact and frequency rate of residential regulators that are say 50 years old and the number of these regulators in the system.

Response:

In general, the failure mechanisms that are most likely to occur on residential regulators include: diaphragm stretches or ruptures due to deterioration over time, mechanical failure due to vibration or time effects, foreign material preventing full lock up, foreign material plugging orifice, foreign material blocking relief vent, and manufacturing defects.

The consequences of such failures can be measurement error, loss of service, leak to atmosphere, or over pressuring of the downstream piping. Both a leak to atmosphere and the over pressuring of the downstream piping have potential to create a hazard to public safety. The ever-greening program is designed to proactively remove aging regulators from the system in advance of predicted age-related mortality of the parts.

As explained in the response in BCUC IR 1.156.1, residential regulators are not specifically tracked in FEI's maintenance information system. In most cases the quantity, age, manufacturer, make, and model are unknown. Therefore FEI is unable to provide failure frequency rates for regulators that are 50 years of age or the number of them currently in the system.

303.0 Reference: Capital EXPENDITURES

Exhibit B-11, BCUC 1.158.1, p. 390

Transmission System Reinforcement

FEI states that "The pipeline across the Pitt River was installed in approximately 1958. An assessment of the pipeline and banks suggest that the crossing is susceptible to damage as a result of a seismic event having a return period of <500 (years)."

303.1 What richter scale equivalent level equates to a 500 year event?

Response:

For the Pitt River crossing specific site, a 500 year return period equates to a magnitude 7 on the Richter scale.

303.2 If that crossing was lost is there any other feed to the residents downstream of the crossing?

Response:

Yes. The Livingstone to Coquitlam pipeline which includes the Pitt River crossing is capable of flowing gas in both directions and, assuming no damage or maintenance is ongoing on any other part of the Coastal Transmission System, full service can be maintained to a 25 Degree Day design (DD). At weather conditions colder than 25 DD, it will be necessary to curtail interruptible customers.

304.0 Reference: Capital EXPENDITURES

Exhibit B-6, BCPSO 1.57.1 & 1.57.2, p. 113

Asset Management Strategy - PAS55 standard

FEI states that "To FEI‟s knowledge, PAS55 is not currently a regulated requirement for any Canadian gas distributors. However, the standard was reviewed by a committee of the Canadian Gas Association and formed the basis of the "Guiding Document on Asset Management" from the CGA Asset Management Task Force."

304.1 If the "Guiding Document on Asset Management" from the CGA Asset Management Task Force has not been entered into evidence, please provide it.

Response:

The CGA Standing Committee on Operations has approved the **confidential** filing of the CGA's "Guiding Document on Asset Management", and requests that this document be made available for viewing only by interested Interveners representing customer groups (i.e. BCPSO, as indicated by BCPSO IR 2.11.1) upon execution of an Undertaking of Confidentiality in this proceeding. This document, provided in Confidential Attachment 304.1, is not publicly available, and should not be distributed.

305.0 Reference: Capital EXPENDITURES

Exhibit B-1, p. 250

CPCNs

305.1 Should all CPCN applications submitted under PBR include an assessment and estimate of O&M savings or other capital expenditure savings?

Response:

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

305.2 How should savings identified by CPCN applications brought forward under PBR be accounted for in 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.

306.0 Reference: FORECASTS FOR THE PBR PERIOD – CAPITAL
Exhibit B-11, BCUC 1.148.2
Capital Forecast – Information Technology

In response to BCUC 1.148.2, FEI states, "If capital spending on any capital category that is subject to the formula is less than the formula driven amount, there is potential for FEI and ratepayers to equally benefit if FEI generates earnings above the Commission's approved ROE. Any earnings above or below the Commission's approved ROE will be subject to the 50/50 ESM during the PBR. Variances in capital (and O&M) spending from the formula-driven amount will also be included in the calculation of the Efficiency Carryover Mechanism in the years following the PBR Period." (p. 370)

306.1 Please confirm, or explain otherwise, that if the IT Capital set in the 2013 Base is too high, meaning that the amount can't be spent due to lack of business cases, then both FEI and the Ratepayers will share in the over earnings.

Response:

This response contains information relevant to PBR and non-PBR issues and will therefore be also submitted with the PBR Methodology IR responses.

It is a misnomer to identify a particular component of the 2013 Base capital as being "too high", or to single out a particular category of capital for different treatment. The main purpose behind setting a base level for overall capital spending to carry forward in a capital spending formula is to establish a suitable spending level that reflects reasonable spending requirements for capital as a whole going forward. Savings from the base spending level (plus I-X escalations) reflect savings that will be shared temporarily and then lead to lower future rates after rebasing occurs.

FEI refers to the response to BCUC IR 2.306.2 where it is confirmed that IT Capital is expected to be above the 2013 Base level.

306.2 Please explain why there is no provision to simply reduce the following year's IT Capital budget to re-set the base if FEI can't spend at the forecast base level.

Response:

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

307.0 Reference: FORECASTS FOR THE PBR PERIOD – CAPITAL

Exhibit B-11, BCUC 1.151.1

Business Technology – 2013 Project Portfolio Benefits

In response to BCUC 1.151.1, FEI states, "The financial benefits shown will include both O&M and capital components. The O&M and capital amounts included in the setting of delivery rates for 2014 through 2018 will be calculated using the PBR formula, not using the individual departments' forecasts that have been included in Section C of the Application. The forecasts of O&M and capital costs and any savings that have been provided in Section C of the Application are for reference purposes only. FEI will be managing the achievement of any savings or incremental costs on a Company-wide basis as part of the overall challenge FEI has in meeting its O&M and capital targets under PBR." (p. 374)

307.1 Please confirm, or explain otherwise, that O&M and capital savings from IT projects will be used to offset over spending by different Business Units to reach the overall PBR targets.

Response:

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

307.2 Please confirm, or explain otherwise, that under-spent IT capital that can't be used because of lack of business cases can be used by other Business Units for other types of capital spending.

Response:

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

FINANCING, TAXES, ACCOUNTING POLICIES AND DEFERRALS

308.0 Reference: FINANCING, TAXES, ACCOUNTING POLICIES AND DEFERRALS

Exhibit B-1, Tab C, Section 3.1.2, p. 122; Exhibit B-1-1, Appendix F6; Exhibit A2-13; Exhibit A2-14; Exhibit A2-15; BCUC Order G-44-12 and 2013-2013 FEU Decision dated April 12, 2012, pp. 140-142

BCUC UNIFORM SYSTEM OF ACCOUNTS (USoA)

308.1 Four basic options for recording and reporting of O&M expenses for management and for regulatory purposes are listed below; please provide a schedule that compares and contrasts the advantages and disadvantages, and material costs and benefits associated with each of these basic options, which are described as follows:

a. use only FEU's New Code of Accounts for recording and reporting of O&M expenses for both management and regulatory purposes.

b. use only the BCUC USoA for recording and reporting of O&M expenses for both management and regulatory purposes.

c. use only FEU's New Code of Accounts for recording and reporting of O&M expenses for management purposes. However, to enable regulatory reporting, create a "mapping relationship," which features permanent links, created at inauguration, between the BCUC USoA for O&M expenses and those in FEU's New Code of Accounts.

d. use two completely separate accounting systems, one which requires use of the BCUC USoA for O&M expenses, and one which uses the FEU New Code of Accounts for O&M expenses. The former is used for recording and reporting for regulatory purposes, whereas the latter is used for recording and reporting for management purposes.

Response:

As stated in the BCUC Uniform System of Accounts Report included in Exhibit A2-13 (the Report), the FEU continue to believe that their existing New Code of Accounts approach provides more meaningful and comparable information than the BCUC USoA, which has not been substantially updated since 1961, and at no additional cost to customers. In the Report, the FEU base this conclusion on the following:

1. Other than O&M accounts, the FEU are already meeting existing 1961 USoA requirements;

2. Full implementation of a new USoA would result in additional costs being borne by customers with no guaranteed improvement in understanding or comparability;

3. For O&M accounts, flexibility is required amongst the utilities in BC to determine a method that meets the objectives of comparability, transparency and understanding of results over time;

4. The FEU already have a fully reviewed and agreed-upon New Code of Accounts that meets those objectives; and

5. The FEU have reviewed the BCUC and other USoAs for O&M and have concluded that none of the ones reviewed would provide a measurable improvement over the existing New Code of Accounts.

The conclusion reached in the Report is also supported by the analysis provided in the following table that was prepared in response to this IR.

Option	Management	Regulatory	Advantages	Disadvantages
a	New COA	New COA	* No incremental conversion or ongoing cost * Meets business requirements * Provides more information than what would be provided by the BCUC USoA * Already reviewed and approved <u>Meets objectives:</u> * Comparability - provides consistent information to 2006 * Transparency - detailed questions can be answered through drilldown to source document * Transparency - totals agree to business unit totals included in RRA narratives and tables * Flexible - adapts to changes in structure & business * Flexible - allows for modifications to achieve additional granularity required by the BCUC * Understanding - assigns responsible owners for the information provided that aligns with how the business is managed	* None
b	BCUC USoA	BCUC USoA	* None - no evidence that more information would be provided by BCUC USoA	* FEU is not able to manage its costs using BCUC USoA; therefore this is not an option as BCUC cannot mandate this for the FEU for management purposes.

Option	Management	Regulatory	Advantages	Disadvantages
c	New COA	BCUC USoA (mapping)	* None - no evidence that more information would be provided by BCUC USoA	* No current 'mapping relationship' exists between BCUC UsoA for O&M and FEU New Code of Accounts – an undertaking would be required to create such a mapping * Adds ongoing costs for ratepayers * Adds no incremental information beyond what is achieved with current reporting * Requires all users in the company to add another coding block to the existing source document entry * Requires manual judgement to set up cost allocations * Historical information not available so no comparability over time * No "drill down" available * No issue of comparability with other utilities in BC so no requirement for a standardized USoA * Previously found unworkable
d	New COA	BCUC USoA (separate system)	* None - no evidence that more information would be provided by BCUC USoA	* Adds significant costs for ratepayers - both one time and ongoing * Requires all users in the company to enter data into two different systems * Adds no incremental information beyond what is achieved with current reporting * Requires manual judgement to set up cost allocations * Historical information not available so no comparability over time * No "drill down" available * No issue of comparability with other utilities in BC so no requirement for a standardized USoA * This would be an unacceptable solution

As stated in the Report, the FEU proposed to continue with the New Code of Accounts, and to undertake a project to implement a number of changes to respond to the Commission's concerns. The FEU restate here each one of these changes and what the status of each of them is.

1. Work with Commission staff to review and modify their New Code of Accounts to more fully address Commission's concerns with receiving information that is comparable, transparent, and understandable;

   Status: The FEU have met with Commission staff but did not receive any feedback on modifications to the New Code of Accounts to address their concerns. To date, the Commission staff has not articulated what concerns need to be addressed. The FEU are unable to address the concerns since there has been no communication about what additional information the BCUC USoA is expected to provide as compared to the existing

New Code of Accounts. However, the FEU remain committed to modifying the New Code of Accounts to meet those requirements once they have been communicated.

2. Provide the Commission with an updated description of the Activity View of the New Code of Accounts prior to filing its next RRA;

   Status: The FEU have provided the Commission staff with an updated description of the New Code of Accounts in February 2013, April 2013 and again in May 2013, just prior to filing this Application.

3. Implement the required revisions to the New Code of Accounts (Activity View and Resource View) into the SAP accounting system with no incremental cost to customers;

   Status: The FEU have implemented the changes into their SAP accounting system to create the current versions of the New Code of Accounts with no incremental cost to customers.

4. Provide test year information and 5 year historical information in future Revenue Requirement filings that includes the modified New Code of Accounts;

   Status: The FEU have provided the 2014-2018 and 5 year historical information in this Application using both the Resource View and the Activity View of the modified New Code of Accounts in Appendix F6 of the Application.

5. Provide tables in its written descriptions of the forecast and historical O&M changes in future Revenue Requirement filings that reconcile to the Activity View of the New Code of Accounts;

   Status: The tables provided in Section C-3 of this Application reconcile to the totals provided in Appendix F6.

6. Provide ongoing updates to the Activity View of the New Code of Accounts to the Commission as required; and

   Status: There have been no changes required to the Activity View of the New Code of Accounts since the last version provided to Commission staff.

7. Continue to report using the Activity View and Resource View of the New Code of Accounts (in combination with the 1961 USoA for the remaining accounts) in its BCUC Annual Reports.

Status: FEU will provide this information in BCUC Annual Reports starting with 2013.

In Exhibit A2-13, section 4.3, page 12, FEI states, "…the FEU have met with Commission staff and other major utilities in BC regarding this issue." (Exhibit A2-13, p. 12)

In Exhibit A2-13, section 4.1, page 8, FEI states, "…each cost centre in the FEU's SAP system has a responsible cost centre owner, and cost centres are grouped under one account that has a common activity." (Exhibit A2-13, p. 8)

308.2 Please name the major utilities in BC that FEU met with "regarding this issue."

Response:

FEU met with FBC, BC Hydro and Pacific Northern Gas, and subsequently this same group of major utilities met with BCUC staff regarding this issue.

308.2.1 Are any of these named major utilities in BC using an SAP system similar to that used by FEU? If yes, please name them.

Response:

Both FBC and BC Hydro utilize the SAP system. However, SAP is not an "off the shelf" software package. Each installation is customized to the individual entity. So while there will be some commonality (such as the use of cost elements and cost centres), each company will have implemented different modules and designed their reporting in a different fashion. Some systems are extremely integrated while others may involve only certain modules of SAP and rely on other systems to feed data into the SAP system. Therefore, the fact that SAP is used by other entities does not result in the ability to perform the same task in the same manner or report on the same information in the same way.

308.2.2 In reference to the immediately preceding question, will/have any of the named major utilities in BC adopted the BCUC USoA (with or without customization) for the regulatory reporting of O&M expenses? If yes, please identify them and indicate if a customization of the BCUC USoA will be/was involved.

Response:

FBC reports its O&M Expenses using a customized version of the USoA in its Annual Report to the BCUC. The Company does not use the USoA for any other purpose.

BC Hydro reports its O&M Expenses using a customized version of the USoA in its Annual Report to the BCUC. BC Hydro also attached an appendix to its F12-14 RRA with the customized USoA view for O&M.

PNG complies with the USoA in its regulatory reporting of O&M expenses without customization, both in its Annual Report to the BCUC and its RRAs.

308.2.3 In reference to the immediately preceding question, is FEI able to comment specifically on how these identified major utilities in BC will/have achieved the adoption of the BCUC USoA for the regulatory reporting of O&M expenses (e.g. through a one-time mapping process), and the effort and the costs, which will be/were incurred as a result. If you are not able to comment, please explain why.

Response:

FBC performs the necessary mapping manually once a year in order to complete its Annual Report to the BCUC according to the USoA. FBC determined that the costs associated with the software mapping function did not add value to the corporate reporting requirements.

BC Hydro's SAP system facilitates the mapping to the USoA O&M accounts. BC Hydro was directed to implement the USoA in its F09/F10 RRA Decision. As BC Hydro implemented its SAP system, it incorporated the USoA using the SAP financial systems as well as manual procedures.

PNG's financial system was originally set up to accommodate the BCUC USoA and no amendments have been made.

As the effort and cost associated with reporting using the USoA for O&M accounts will vary depending on the management structure of the utility, the size of the utility, whether the implementation is incorporated in the original design of a system, and the level of detail available, among other factors, no conclusion should be drawn on the appropriate cost to implement. This is supported by the wide range of costs reported by the various utilities in Alberta as summarized in response to BCUC IR 2.308.3.

308.2.4 If any of these above identified major utilities in BC developed a customized version of the BCUC USoA for regulatory reporting of O&M expenses, is FEI able to comment specifically on which aspects of the BCUC USoA were/will be customized and why. If you are not able to comment, please explain why.

Response:

The FEU provide comments on FBC and BC Hydro, as both of these utilities developed a customized version of the BCUC USoA for O&M for Annual Reporting to the BCUC.

FBC's amendments to the O&M accounts were required for the following reasons:

- Impracticality of separating "operation" from "maintenance" functions in the USoA;
- Inability to accurately assign supervision, administration and some engineering functions between transmission and distribution and between overhead and underground facilities; and
- Some amendments to more accurately reflect organizational structure.

BC Hydro adopted the BCUC USoA, with amendments to reflect BC Hydro's business circumstances. These were discussed with BCUC staff in the process of developing the customized USoA. The specific amendments made are as follows:

(i) Generally, BC Hydro is keeping costs that would otherwise require allocation to USoA functions in individual USoA general or administration operating accounts for reporting alignment purposes.

Specific items that are treated in this manner are support activity costs; e.g., information technology, materials management, fleet management, First Nations, properties management, environmental and safety support, construction services support and legal support, that are managed centrally and not associated with the specific core functions of generation or transmission; and other support costs that are not currently centralized; e.g., engineering support, finance and human resources.

Rationale: The support activity costs generally are managed centrally. For those areas that are not currently centralized, the support area is still subject to centralized oversight and common programs and strategies. BC Hydro believes that this structure provides for accountability for management of these activities and related costs.

(ii) Indirect work activities (that is, costs other than maintenance or operating work attributable to an asset) are classified as Supervision and Engineering within their appropriate functions, unless the function performed is directly aligned with an existing BC Hydro USoA account.

Rationale: BC Hydro believes that retaining these costs under one account provides for stronger accountability for the work. This is because the managers responsible for those activities continue to have accountability for those costs, whereas the accountability would be lost if the employees' time and costs are reallocated to other work activities.

(iii) Stations and load dispatch activities are centrally managed on a combined basis and the associated O&M expenses cannot easily be split between the transmission and distribution functions. For administrative simplicity and in accordance with the major use, BC Hydro is classifying stations and load dispatch activities as activities related solely to the transmission function.

Rationale: With the re-integration of activities that were previously managed by BCTC, it is administratively simpler not to distinguish between the transmission and distribution function of its station assets for cost distribution purposes. BC Hydro assigns a portion of these costs to the distribution function in the calculation of the OATT.

(iv) The costs of labour, inclusive of cash compensation, benefits, and time concessions are distributed to work. Current service employee benefits are not reported separately.

Rationale: BC Hydro believes that the labour cost associated with work should include all relevant direct costs, including benefits and time concessions. Reporting these employee benefits separately will result in understating the cost of work. This is particularly relevant where BC Hydro needs to determine whether it is beneficial to utilize contract labour. BC Hydro continues to be able to measure and report the total amount of employee benefits, if this is necessary.

(v) Costs related to external energy purchases and to the allocation of capital costs are shown separately, rather than being assigned to the appropriate USoA operating account.

Rationale: The costs of purchased energy are captured within an individual account. Historically, BC Hydro has separated the cost of energy from operating costs. Therefore, the BC Hydro USoA account for energy is not included in the operating cost schedule.

In reviewing these lists from FBC and BC Hydro, the FEU conclude these differences are very similar to the list of differences provided in Attachment 3 to its Report that was filed with the Commission.

308.2.5 Was there an opportunity to achieve "economies of scale" by having FEI work together with any of these above identified major utilities in BC on, for example, generic aspects of developing a BCUC USoA reporting view for O&M expenses. If not, why not?

Response:

FBC, BC Hydro and PNG's systems pre-date the FEI requirement.

The four utilities (FEU, BC Hydro, FBC and PNG) met with BCUC Staff on September 19, 2012 and discussed USoA reporting issues. The utilities were of the view that efficiencies were not applicable through economies of scale as the O&M section is unique to each utility and should reflect its requirements to manage the business effectively. In addition, the utilities use different bases of accounting. BC Hydro uses Prescribed Standards whereas the other utilities use US GAAP, so comparisons between the utilities would be misleading on this basis alone.

In Exhibit A2-13, section 4.3, page 12 (including footnotes 3 and 4), FEI states, " The FEU expect that the adoption of a "one size fits all" approach to O&M accounts will result in significant costs,[3] both one time and ongoing. This expectation is based on the adoption of a USoA for electric utilities in Alberta, which has resulted in both costs to make system changes,[4] and costs to support the provision of variance explanations for this alternate view of O&M.

Footnote 3: "…Cost estimates of fully adopting a USoA were provided by the affected utilities and ranged from a low of $300 thousand to a high of $17.8 million for implementation, and up to $2.8 million in annual operating costs."

Footnote 4: " An alternative adopted by some utilities in Alberta was to create an additional coding block in their accounting system, requiring employees in the field to complete additional fields to derive the information required on an ongoing basis."

"For example, to capture the amount of time spent by transmission managers on operating as opposed to maintenance activities, separate coding blocks would be added to the system…". "The FEU believe that this process would require and undue amount of the transmission managers' time and would not be cost effective."

308.3 Please name the above affected utilities in Alberta and indicate the method (e.g. a mapping process, separate accounting systems) each will/has used to develop a USoA reporting view for O&M expenses. In addition, please also provide the cost estimates for implementation and annual operating costs pertaining thereto.

Response:

Please refer to Attachment 308.3, which is Decision 2007-017 "EUB Proceeding - Implementation of the Uniform System of Accounts and Minimum Filing Requirements for Alberta's Electric Transmission and Distribution Utilities". This public document is the source for the FEU's information. The following table has been created from the information in that document (cost estimate data taken from Table 2 in Attachment 308.3).

			($ millions)	
Electric Utility	System	Method	Capital Costs	Annual Optg Costs
EPCOR	Oracle	Mapping	0.3	0.2
ENMAX	PeopleSoft	New Chart Field	6.7	0.5
ATCO	Oracle	Existing	0.4	0
AltaLink	SAP	Special Ledger	17.8	2.8
FortisAlberta	SAP	Profit Centre Acctg	15.6	1.6
			40.8	5.1

308.4 Please identify the above affected utilities in Alberta, if any, who are/will be using a SAP system similar to that used by FEU.

Response:

Please refer to the responses to BCUC IR 2.308.3 and 2.308.2.1.

308.5 Please identify the utilities in Alberta who adopted the alternative of creating an additional coding block in their accounting system.

Response:

From a review of the table provided in response to BCUC IR 2.308.3, the FEU conclude that Enmax and AltaLink would have required an additional coding block to achieve the method indicated. However, the FEU cannot confirm this.

FortisAlberta has created an additional ledger to accommodate the USoA for electric utilities in Alberta that requires additional coding to meet the USoA requirements.

308.5.1 What type of accounting system did these utilities utilize?

Response:

Please refer to the response to BCUC IR 2.308.3.

308.5.2 Is FEI able to comment on the reasons why these utilities took the steps to implement a process, which FEU judged “not to be cost effective”? If not, please explain.

Response:

The FEU understand that the adoption of the USoA was a result of a Board initiated process; it was the Board that concluded these costs would add value based on the evidence in that process. The Board's discussion of the anticipated benefits is summarized in section 3.2 of the Attachment 308.3 provided in response to BCUC IR 2.308.3. An excerpt from that section is provided below.

> *"The EUB believes that the adoption and use of an activity-based USA similar to that used by the United States Federal Energy Regulatory Commission will improve the ability to compare financial information from year to year for a utility and, to the extent possible, across utilities when testing the reasonableness of a utility's filings and budgets. The EUB and interveners will have greater confidence that the costs being considered are comparable. This increased confidence, combined with MFRs based on information from the USA, should result in more complete and comprehensive General Tariff Applications (GTAs), a more efficient interrogatory process, and reduced cross-examination time at hearings."*

The Board further stated in section 3.5:

> *"The Board has concluded that it cannot perform the usual quantitative analysis to compare the dollar costs of the implementation of the USA and MFR with the expected dollar savings associated with the benefits of having such a system. Therefore, the assessment must be done on a more qualitative basis.*
>
> *The Board is persuaded by the evidence that there are benefits to be gained through the implementation of the USA and MFR. Moreover, the Board is reassured that the interveners also consider there to be benefits to be achieved from the implementation of the USA and MFR as they would not otherwise have been willing to participate in the USA-MFR Committee or support this initiative in this proceeding. The Board also notes that although the implementation costs at this stage are uncertain, customer representatives are willing to pay the costs provided the implementation is done on a prudent basis."*

The FEU believe that there is more value to the adoption of a common USoA in Alberta than in BC. This is because:

1. The order in Alberta was related to the adoption of a full USoA. BC utilities are already compliant with all parts of the USoA except for O&M reporting, where three out of four of the major utilities have made modifications to address the issues with the O&M section of the USoA. This is because the O&M section of the BCUC USoA does not accommodate current management practices (for example changes in Information Technology) or accounting policies. Moreover, as the FEU have explained, the O&M section of the BCUC USoA does not provide any more meaningful or understandable information than the FEU's

New Code of Accounts. The FEU are already able to compare financial information from year to year and the BCUC USoA offers no improvements; the BCUC USoA will not improve the ability to compare financial information from year to year, which was one of the main benefits in the EUB's case.

2. There are many more utilities in Alberta than in BC. The EUB order was applicable to all electric transmission and distribution utilities that fall under the EUB jurisdiction. This includes not only the five electric utilities listed in response to BCUC IR 2.308.3 but also any smaller utilities such as the Cities of Lethbridge and Red Deer, and TransAlta unless they sought an exemption. These five major electric utilities contrast to only two major electric utilities in BC. Each utility manages its O&M differently in BC, and the adoption of the BCUC USoA is unlikely to improve the ability to compare financial information across utilities, which was one of the main benefits in the EUB's case.

3. In Alberta, there has been a history of the Board, and now the Alberta Utilities Commission, implementing standardized reporting requirements and processes across all the utilities it regulates. For example, it was the Board in Alberta that led the IFRS project. In BC it was the utilities that led the IFRS project. In addition, Alberta utilities follow a common code of conduct. Since the Board, and now the Alberta Utilities Commission, has required consistency of accounting and other policies by the utilities, a common method of reporting would be more consistent across utilities in Alberta than it would in BC and would therefore add more value.

4. The EUB also noted that customer representatives were willing to pay the costs in Alberta. Given that no customer groups have taken issue with the FEU's current reporting, the FEU do not believe this has been established to be true in BC.

Overall, the FEU believe that there are differences between the regulatory environments in Alberta and BC that makes the value proposition in BC significantly less.

308.5.3 How did the Alberta Energy and Utilities Board treat the implementation and the annual operating costs related to the adoption the USoA by affected utilities in Alberta?

Response:

The FEU understand these costs were recovered from ratepayers.

In Exhibit A2-13, section 4, page 7, FEI states, "Since the New Code of Accounts is based on how Terasen Utilities are currently internally planning, recording and reporting their costs, …"

In Exhibit A2-13, section 4.1, page 9, FEI states, "…since the adoption of the New Code of Accounts in 2006. The New Code of Accounts provides 50 different accounts in the Activity View and a further 12 accounts in the Resource View…"

308.6 Are the statements in section 4, page 7, and section 4.1, page 9, still current? In other words, does the information in the statements still apply in the present environment given that the name has changed from Terasen Utilities to FEU?

Response:

The change of name does not impact the reporting. However, over the years since the New Code of Accounts was developed, other changes in the business and reporting structure have resulted in changes to the Activity View of the New Code of Accounts.

The full text of the quoted excerpt from 2007 was "…Since the New Code of Accounts is based on how Terasen Utilities are currently internally planning, recording and reporting their costs, **the New Code of Accounts may in the future need to be adapted to meet changes in operational activities**. An example of potential future changes could be the reporting, coding and recording of CustomerWorks charges or Shared Services Agreement charges..." [emphasis added]

Consistent with this statement from 2007, the FEU, with their changes to the New Code of Accounts provided to the Commission staff and implemented in this Application, have specifically addressed the insourcing of the customer service function, among other items. This demonstrates the flexibility of the New Code of Accounts as compared to the BCUC USoA, which has not been substantially updated since 1961.

308.7 If the internal planning, recording and reporting of costs processes are still essentially the same, please provide a detailed description (also including graphical illustrations would enhance the value of the information provided) of same. In your detailed description, please include specific illustrative examples that demonstrate how transactions are processed/recorded, e.g. from the primary input data such as an invoice, and "rolling up" to the highest level of consolidation in an O&M account as per the New Code of Accounts.

Response:

FEI confirms that the internal planning, recording and reporting of costs and processes are essentially the same as referenced in Exhibit A2-13. FEI also adds that both the Resource and Activity view of reporting has been refreshed to reflect the most recent operational changes within the organization.

In providing a detailed description of the same, FEI will reference a presentation made to BCUC staff on February 5, 2013 titled 'BCUC Activity View Reporting', provided as Attachment 308.7.

In the presentation the FEU provide an overview of the New Code of Accounts which provides both an Activity view (the 'Why') and Resource view (the 'What') of O&M reporting.

As demonstrated in the slide titled 'Hierarchy of Activity View Reporting', departments across the organization are assigned activities such that the O&M summed for all activities within a department will total to the department O&M (this was a specific undertaking of FEU referenced in Exhibit A2-13, Section 5, Implementation Plan to Meet BCUC Objectives, page 13). Activities are then assigned to the various Cost Centers that operate in support of the Activity. The Cost Centre becomes the lowest level of hierarchal reporting within the organization. Cost Centers are assigned to Managers who are then charged with the planning, operational and reporting activities thereon. Within SAP, Activities are assigned Internal Orders for tracking purposes.

This contrasts with the Resource view of O&M reporting whereby Resources are assigned to Cost Elements in SAP with the objective of reporting costs by resource or cost type.

Within FEI, there exist approximately 275 Cost Centers. Collectively these roll up to 51 Activities in the BCUC Activity View which in turn rolls up to 13 Departments. From a resource aspect there are approximately 350 Cost Elements or expense types that roll up to 12 Resources in the BCUC Resource View.

Invoices are coded to a Cost Centre to assign operational responsibility, they are coded to an Internal Order to enable Activity View reporting, and are coded to a Cost Element to enable Resource View reporting.

For BCUC reporting, the Activity view reporting is done at an Activity level while the Resource view reporting is done at a company-wide level.

For internal management purposes however, this hierarchal view of reporting further enables management to provide Activity reporting at a Cost Center level, and to provide Resource reporting (including the expanded Cost Element view) at the Department level, Activity level, as well as Cost Center level.

FEI is of the view that the New Code of Accounts provides reporting that is more informative and better aligned to the operational management than what the original USoA is capable of providing.

308.8 If the internal planning, recording and reporting of costs processes are not essentially the same, please provide a full description of the changed processes in the same manner as requested in the immediately preceding question, and in addition, highlight the changes and provide explanations why the changes were necessary.

Response:

The internal planning, recording and reporting of cost processes are the same. However, there have been amendments to the New Code of Accounts to address changes in FEU's business, such as the insourcing of the customer service function. Please also refer to the responses to BCUC IRs 2.308.6 and 2.308.7.

In Exhibit A2-13, section 4, p. 6 and 7, FEI states, "The New Code of Accounts would allow reporting for both an activity-based view and a resource-based view and relationship mapping [emphasis added] to the Commission's Uniform System of Accounts."

In Exhibit A2-13, section 4.2.1, page 10, FEI states, "In Attachment 3 [Comparison of BCUC Uniform System of Accounts to Activity View], the FEU have provided a line by line comparison of the BCUC USoA for O&M Accounts to the New Code of Accounts. Based on this analysis, the FEU are able to conclude that there are no significant differences between the two in terms of the information provided."

308.9 Please describe in detail the relationship mapping process referred to above. Your description should provide very specific information about where the relational mapping "linkages" were established (e.g. primary or sub O&M expense accounts at individual cost center level). If an electronic model of the relational mapping process is available, please provide it.

Response:

This response addresses the responses to BCUC IRs 2.308.9 through 2.308.20. The questions posed in this series of IRs all relate to the “relationship mapping” referred to in the FEU’s Report and the time and cost required to implement the BCUC USoA view of O&M.

FEU has concluded from its review of this series of questions that the Commission has misunderstood what was intended by the use of the term “relationship mapping”. The referenced relationship mapping was provided by the FEU as Attachment 3 to its Report. The relationship mapping is nothing more than the creation of this excel file; it appears the Commission has misinterpreted the extent of mapping and concluded it is a relationship mapping that exists within SAP. It is not.

As such, there were no incremental costs incurred in developing Attachment 3. FEU estimate that internal staff spent approximately two weeks of time in developing the document. The document can be updated annually with a minimal investment of time.

The FEU do not believe that this relationship mapping could be fully implemented in FEU’s SAP system. This is because the USoA attempts to capture both the “what” (the resource) and the “why” (the activity) in one account. FEI’s SAP system is not designed to capture both the what and why in a single transaction. Instead, the resource view provides the what (the type of resource that was used) and the activity view provides the why (the reason the resource undertook the work). The issues with this are further described on a line item basis in the column “Differences noted from FEU compared to BCUC”.

Attachment 3 was prepared expressly to demonstrate to the Commission that there would be no more information provided through adopting the BCUC USoA or another USoA than what is being provided today through the Activity View and the Resource View. FEU was able to demonstrate that this is the case, and continues to believe there is no value to be gained from implementing a different USoA than what is currently in place.

If the Commission directed the FEU to follow the BCUC USoA for O&M despite any evidence of the benefits that would be obtained, then the FEU believe the Commission has a responsibility to first review and revise the USoA from 1961 to bring it more up to date and in line with the way utilities currently manage their business so that at least some value would be provided to ratepayers. FEU also expects that this exercise would result in a USoA that is more consistent with FEU’s New Code of Accounts than with the current BCUC USoA. Once this task was completed, the FEU would pursue one of two options:

1. Implement an excel-based manual process to allocate costs to the BCUC USoA accounts on an annual basis as is done by FBC. This could be accomplished utilizing internal resources. FEU believes it could undertake to complete this process within three months of

receiving a directive and a revised USoA from the Commission, depending on resource availability.

2. Implement a combination of SAP mapping and manual procedures to allocate costs to the BCUC USoA for BCUC Annual Report purposes as is done by BC Hydro. The work undertaken in SAP would involve reviewing all O&M cost centres and associated settlement rules, interviewing cost centre owners to provide allocation percentages for work that is undertaken, reviewing each SAP O&M report to determine if it would be impacted by the changes, implementing the changes and converting data, providing training, and undertaking an annual review and updating of the rules. Even with this work, FEI believes some customizations of the USoA will be required, similar to what was experienced by BC Hydro. FEI estimates this would consume approximately $500 thousand, primarily operating expenses, and take six months from receiving a directive and a revised USoA from the Commission, depending on resource availability. This estimate assumes this task can be accomplished solely by a review and update of the back end accounting processes.

As is the case with both FBC and BC Hydro, FEU would be unable to include this BCUC USoA view in the body of its RRAs since there would be no drilldown capability or specific management responsibility for the resulting line items.

The FEU restate that although the costs of implementing the BCUC USoA for O&M in this manner may not be significant in comparison to the overall revenue requirement, incurring any costs at all without a clear understanding of what benefits would be obtained would not be in ratepayers' best interests. FEU notes that no interveners representing customer groups have raised a concern with the availability of information or the use of the New Code of Accounts.

308.10 What costs (one-time and annual recurring), if any, were/are still associated with development and implementation of the "relationship mapping" process?

Response:

Please refer to the response to BCUC IR 2.308.9.

308.11 Is the "relationship mapping" process referred to above, presently incorporated (i.e. "hard wired"/programmed) in FEU's SAP system? If not, why not?

Response:

Please refer to the response to BCUC IR 2.308.9.

308.12 If the "relationship mapping " process is/were to be incorporated in FEU's SAP system would that then allow FEU to generate at any time, automatically or on demand, a view of O&M expenses, which very closely adheres to the requirements of the BCUC USoA? If not, why not?

Response:

Please refer to the response to BCUC IR 2.308.9.

308.13 Would FEI agree that the "relationship mapping" and more specifically, the associated "linkages" would need to be made permanent at their inauguration to ensure that consistency and comparability of information for regulatory reporting is maintained over time (e.g. any subsequent changes in FEI's organizational and/or responsibility reporting structure should not normally cause these "linkages" to be altered). If FEI does not agree, please explain why not? If FEI agrees, please confirm that the associated "linkages" were/will be made permanent at their inauguration.

Response:

Please refer to the response to BCUC IR 2.308.9.

308.14 Is Attachment 3 and the line-by-line comparison contained therein the result of the "relationship mapping" process referred to above? Please discuss.

Response:

Please refer to the response to BCUC IR 2.308.9.

308.15 With reference to Exhibit B-1-1, Appendix F6 - O&M Expenses – Activity View, is FEI able to convert this O&M Expenses - Activity View to a BCUC USoA View of O&M expenses, using the "relationship mapping" process illustrated in Attachment 3? If yes, please provide it. If not, why not?

Response:

Please refer to the response to BCUC IR 2.308.9.

308.16 If FEI is able to convert the O&M Expenses – Activity View in the manner requested in the immediately preceding question, i.e. to a BCUC USoA View, would it then still be possible to "drill down" to granular source data, e.g. invoices, when starting from the rolled-up information in the BCUC USoA View? If not, why not and what would need to be done to enable that "drill down" process?

Response:

Please refer to the response to BCUC IR 2.308.9.

308.17 What further refinements, if any, would still have be made to the "relationship mapping" process to bring the comparison shown in Attachment 3 into a total [Emphasis added] alignment with a BCUC USoA O&M expense reporting view. Please discuss.

Response:

Please refer to the response to BCUC IR 2.308.9.

308.18 How long would it take to complete such further refinements?

Response:

Please refer to the response to BCUC IR 2.308.9.

308.19 What would be the costs, if any, associated with such further refinements?

Response:

Please refer to the response to BCUC IR 2.308.9.

308.20 Please provide the estimated cost and timeline required for FEI to fully convert to the BCUC USoA.

Response:

Please refer to the response to BCUC IR 2.308.9.

309.0 Reference: FINANCING, TAXES, ACCOUNTING POLICIES AND DEFERRALS

2012-2013 FEU RRA Decision, p. 141; Exhibit B-11, BCUC 1.81.2, 1.101.1,

1.110.1, 1.127.3, 1, 1.129.1, 1.137.2, 1.138.2

BCUC USoA

"The Commission Panel believes that the use of the USoA for reporting purposes would require consistent and comparable information at an account level. We also note that if forecasting for a future RRA followed this same system of accounts, it would provide further clarity of forecast to actual results at an account level." (2012-2013 FEU Decision, p. 141)

"Finally, in years prior to 2010, some of the departments may not be strictly comparable due to organizational changes that FEI was not able to restate." (Exhibit B-11, BCUC 1.81.2)

"As such, information going back to 2010 provides for a trending which is more reflective of the current business environment. The 2010/2011 and 2012/2013 expenditures have also been examined in the two most recent RRA proceedings, and appropriate levels of expenditure have been set by the Commission. <u>While the information requested for 2007 to 2009 has been provided, this is not useful as a point of comparison</u>." (Exhibit B-11, BCUC 1.110.1)

309.1 Given that FEI was unable to provide 5-year comparable information in BCUC 1.81.2, 1.101.1, 1.110.1, 1.127.3, 1, 1.129.1, 1.137.2 1.138.2, and other IRs please explain why FEU should not be directed to comply with Directive 63 from the 2012-2013 FEU Decision requiring "FEU to fully adopt the USoA."

<u>Response:</u>

FEI did provide the information in the referenced IRs with the proviso that, in some cases, the information was not comparable. The reasons that it was not comparable included:

1. Customer Service department was insourced starting in 2012;
2. Accounting policies changed, resulting in items being classified differently between O&M and capital;
3. Organizational changes occurred at a lower level of reporting than was currently being captured in the system; and
4. The operating environment evolved over the intervening period including changes in energy policies, customer programs, codes and regulations.

Had FEI adopted the USoA for O&M, the information would not have been any more comparable than it currently is. A different method of grouping costs does not change the fact that accounting policies have changed to required capitalization differences, or that data that was previously captured at a higher level cannot be retroactively split to a lower level without considerable estimation which makes the data unreliable, or that there have been changes in the environment that drive costs and make O&M costs from 2007 not comparable to O&M costs from 2014.

FEI is concerned that there is a misunderstanding about what the outcome of adopting a different USoA would be, and that there is an expectation it will resolve all comparability problems. This is not the case.

In FEI's view, adopting the USoA provides no incremental value and will tie up the utility's resources in a project, potentially incur incremental external costs, and require a reconciliation process each year. FEI will not be able to provide accurate responses to questions on the resulting accounts since much of the data would be created through a judgement-based allocation process. Finally, the FEU does not believe that Directive 63 required the "FEU to fully adopt the USoA" as stated above. Instead Directive 63 stated:

> *"The Commission Panel directs the FEU to begin investigating the cost of fully converting to the USoA and to work with Commission staff to develop a plan that will allow the FEU to fully adopt the USoA prior to filing their next RRA with the Commission."*

The FEU submitted the Report contained in Exhibit A2-13 in compliance with that Directive and requested that "the Commission find that the FEU's proposal meets the objectives of the Commission's Directive or, in the alternative, provide further guidance to the FEU based on the contents of this Report."

The FEU received a letter (Log No. 41494 filed as Exhibit A2-14) from the Commission that stated:

> *"The Commission has reviewed FEU's proposed alternate approach and accepts it for the next Revenue Requirements Application (RRA) only. In the next RRA the Commission will assess whether FEU is required to either comply with Directive 63, continue with the alternate approach for further RRA's, or implement some other approach as the Commission finds appropriate at that time."*

Based on the original report and the analysis and discussion provided in response to the BCUC IR 2.308 series, the FEU submit that the Commission should determine that it is in customers' best interests that the FEU continue with its existing approach of the New Code of Accounts.

310.0 Reference: FINANCING, TAXES, ACCOUNTING POLICIES AND DEFERRALS Exhibit A2-10, June 2013 LGMA

BCUC USoA

"Energy solutions for every customer
FortisBC works hard to ensure the energy our customers rely on is there whenever they need it. From electricity and natural gas, including natural gas for transportation, to propane and thermal energy, we provide solutions for your community. Learn more **at fortisbc.com**." [Underlined for emphasis]

310.1 Please provide FEI's policy for allocating advertising costs when more than one line of business (i.e. natural gas, electric, EEC, TES/FAES, GGRR, non-GGRR, and Biomethane) is mentioned in an advertisement.

Response:

The following responds to BCUC IRs 2.310.1, 2.310.1.1 and 2.310.3.

Please refer to the response to BCUC IR 2.256.1 regarding the references to "lines of business".

Similar to how other costs are allocated in the Company, FEI's practice for allocating advertising costs to natural gas, electric or TES/FAES is based on the principle of cost-causality and which businesses benefit from the costs. In the case of advertising, costs are incurred primarily for the gas and electric businesses and the benefit of those customers served. Accordingly, our historical practice has been to allocate shared advertising costs based on the number of customers in the gas and electric utilities.

Please refer to the responses to BCUC IR 2.312.1 and COC IR 2.15.2 for specific examples of advertising cost allocations to the gas and electric businesses.

As it relates to FAES advertising, as discussed in the response to COC IR 2.15.2, FEI considers the mentioning of Thermal energy services (TES) in the common "tag line" as part of promoting the FortisBC brand name for which the Commission has provided approval in the AES Inquiry decision. Accordingly, no cost allocation is assigned to FAES. If FEI had applied a similar methodology in allocating costs to thermal energy customers (i.e., customer count), customer count would effectively allocate a negligible portion of costs to thermal energy customers as there are only a limited number of thermal energy customers.

FEI believes its practice of allocating advertising costs as discussed appropriately reflects the nature of the regulated utility businesses and is consistent with the requirements of the existing Code of Conduct and Transfer Pricing policies.

310.1.1 Does FEI's policy for allocating the cost of an advertisement to more than one line of business reflect the recommendations in the AES Report? Please explain why, or why not?

Response:

Please refer to the response to BCUC IR 2.310.1.

310.2 Please provide the allocation of the cost of the advertisement in Exhibit A2-10 by line of business (i.e. natural gas, electric, EEC, TES/FAES, GGRR, non-GGRR, and Biomethane), account and resource code.

Response:

The cost allocation for the referenced advertisement is based on the coverage of the gas and electric businesses. Therefore, the number of customers served by the gas and electric utilities was used to allocated costs; 85 percent to gas and 15 percent to electric.

Please refer to the response to BCUC IR 2.310.1.

310.3 Should the cost of an advertisements mentioning more than one line of business be shared equally between the lines of businesses mentioned in the advertisement? Please explain why, or why not?

Response:

Please refer to response to BCUC IR 2.310.1.

311.0 Reference: FINANCING, TAXES, ACCOUNTING POLICIES AND DEFERRALS Exhibit B-1-1, Appendix F6; Exhibit B-11, BCUC 1.188.3; Exhibit A2-12, 2010-2011 TGI RRA, BCUC 1.108.1; FortisBC Events, http://www.fortisbc.com/About/Events/Pages/default.aspx; Ad tiles and web banner, http://www.fortisbc.com/Rebates/ContractorProgram/AdTilesWebBanners/Pages/default.aspx

BCUC USoA - Distribution Sales Promotion – Operations

"FEI is unable to provide expenses by year for the original BCUC Uniform System of Accounts: 700, 701, 702, and 709." (Exhibit B-11, BCUC 1.188.3)

Given that, FEI is unable to provide expenses by year for the original BCUC Uniform System of Accounts: 700, 701, 702, and 709. The following questions will attempt to determine FEI's Distribution Sales Promotion – Operations expenses from 2007—2013.

311.1 For Actual 2007-2013 please provide a breakdown of account 310-14 between Corporate Communications and External Relations costs and the cost per customer by year. Also, graph the 2007-2013 Corporate Communications Costs and External Relations by year with years on the X-axis and costs on the Y-axis. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

The preamble to the question indicates that FEI has not been able to provide expenses by year in the BCUC Uniform System of Accounts (USoA) in response to the first round of IRs. Please refer to the responses to BCUC IR 2.308 and 2.309 series of IRs for the history and value of the New Code of Accounts as compared to the 1961 BCUC USoA.

As shown in the response to this question, FEI is able to provide the requested information when requested to do so but using current business descriptions, such as Corporate Communications and External Relations, as opposed to outdated departmental divisions which no longer exist, such as Distribution Sales Promotion – Operations.

This response also addresses BCUC IR 2.285.3.

Please refer to Attachment 311.1 for the information requested in the form of a fully functioning electronic spreadsheet. FEI submits that for these two groups, Communications and External Relations, the correlation of costs with customer count is not an appropriate measure. These groups manage and partake in activities, such as safety education, customer rate change education, media releases and responses, renewal of operating agreements and First Nations and public consultation, among other things, which have no direct correlation with the year over year change in customers.

Communications

Beginning in 2010, FEI undertook an annual natural gas public safety awareness campaign using digital, print and radio to raise awareness regarding gas odour detection and steps to be taken. Awareness has steadily increased over the past three years. The number of survey respondents who felt that they were "very prepared" in knowing what to do when a gas odour was detected, increased from 15 per cent in Spring 2010 to 29 per cent in Q3 2013. The number of "not at all prepared" decreased from 70 per cent to 50 per cent over the same timeframe.

Beginning in 2013, FEI undertook a media campaign (digital, print, radio) to increase British Columbian's Awareness regarding the value and environmental benefits of using natural gas. The objective of the campaign is to encourage British Columbians to request natural gas as an energy source in their homes to mitigate recent declining growth which if not reversed would be a pressure on delivery rates.

It is important to note that in addition to communicating with customers, FEI also has communications requirements for stakeholders, government officials, all British Columbians in the service territory, media and employees among others. Therefore a "cost per customer" is not an appropriate measure given there are other items that impacts costs for the group.

External Relations

External Relations costs are not related to "cost per customer" but rather a variety of external influences, including changes to government policy, an increasing need to engage with First Nations, negotiating operating agreements, and public consultation on new infrastructure investments. A number of these cost pressures were outlined in the response to BCUC IR 2.284.1.

311.2 Please update Exhibit A2-12 to include the actual Media monitoring and News wire services and the average news release cost (total Annual Media monitoring and News wire service costs/ number of news releases issued each year) for 2007-2012 and Approved and Projected 2013.

<u>Response:</u>

The updated table has been provided below.

	2007	2008	2009	2010	2011	2012	2013 Year End Projection
Media Monitoring	43,000	56,000	55,341	61,255	68,167	50,870	58,183
Newswire Services	8,000	23,000	25,665	26,246	23,331	19,353	26,759
	51,000	**79,000**	**81,006**	**87,501**	**91,498**	**70,223**	**84,941**

Please refer to the response to BCUC IR 2.311.3 for the average news release costs.

Since FEI does not have any specific approved amounts for these activities the table above includes actuals/projections only.

Both the ES&ER and Customer Service departments partake in these activities and the costs shown here are the aggregate of the costs for both departments.

From the 2011/12 period, FEI commenced with increasing the number of joint releases with such companies as BCHydo and also in sending key information direct to regional communities.

Media monitoring and news wire services will continue to be a critical activity in the 2014-2018 period to effectively manage communications to customers and stakeholders. FEI uses a newswire service to distribute its news releases to media outlets in its service territory of more than 125 communities. These news releases serve to acquire mass media coverage of information about safety, rates, energy efficiency, community involvement and other topics that are of value to our customers and the communities we serve. This release of information is either news (event-driven, such as a rate change) or to provide the public with awareness or education on key issues such as safety, energy efficiency, that are timely and are often triggered by a news event (such as a seasonal safety information supporting a weather-related event) or is new information and is therefore newsworthy.

311.3 For Actual 2007-2013, please provide please provide a breakdown of the Corporate Communications news releases and multimedia (YouTube, Flickr, Twitter, Instagram) costs. Use the format below and include the requested information in the form of a fully functioning electronic spreadsheet.

2007 Corporate Communications - new releases and multimedia costs*

Description	Date	Cost	Line of Business**	Cost Allocation
News release				
YouTube				
Flickr				

* Multimedia (YouTube, Flickr, Twitter, Instagram, Facebook)
**Line of Business (i.e. natural gas, electric, EEC, TES/FAES, GGRR, non-GGRR, and Biomethane)

<u>Response:</u>

Please refer to Attachment 311.3 for the requested information in a fully functional electronic spreadsheet.

Attachment 311.3 also shows the average cost per news release, as requested in BCUC IR 2.311.2.

Most news releases are issued using a news distribution service to reflect quarterly rate changes (minor variations are addressed via a bill message), the annual changes to midstream and delivery rates, key BCUC decisions that are of interest to customers and stakeholders, and topics such as safety and energy efficiency. This news distribution service sends these releases to newsrooms across British Columbia.

Cost per news release is not a good metric in this context as new releases are charged on a word count basis. In 2013, FEI has seen a change in the rate structure from the news service provider and is currently in discussions to explore a more cost effective option, including a fixed-term contract that would come with a rate discount.

As it pertains to multimedia costs, the company incurs costs to utilize those channels listed in the attachment. The use of other social media channels that the company utilizes, such as YouTube, is at no incremental cost to the company as these services are provided free of charge. The Communications Department may use and monitor such channels in the course of their day to day duties, but do not track their time or segregate the time they spend on such activities.

311.3.1 Please explain how new releases and multimedia costs are allocated to the different lines of business.

Response:

For news releases, as the work to prepare and disseminate the releases is handled by the respective gas and electric employees, the related costs are charged directly to the gas and electric businesses. On the rare occasion where there is a joint news release involving the gas and electric businesses, the related costs are allocated based on customer count.

For multi-media costs including web and social media, where there is shared content reaching gas and electric customers, customer count is an appropriate cost allocation driver, with 85 percent of the expenditures allocated to the natural gas utility and 15 percent to the electric utility. The number of TES customers is so small at this stage of FAES' development (under 100 TES customers, as compared to over 1 million gas and electric customers) that their costs have been too small to register in the allocation.

In the situation where the core content of the piece includes reference to the thermal energy business, the piece would be assessed to determine how much of the overall content is related to the thermal energy business, with the costs apportioned based on its share of content.

311.4 Please provide, in graph and table form, a comparison of FEI EEC annual spending (actual/projected) to FEI marketing spending from 2010 to 2018. Please explain if FEI is using EEC funding to support/replace any FEI marketing activities. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

The FEU are <u>not</u> using EEC funding to support or replace any FEU marketing activities. EEC expenditures are related to promoting the efficient use of natural gas, by way of educating customers on how gas is used, on opportunities to conserve gas, and in providing customers with incentives to assist with the purchase of more efficient appliances, so as to support customers in managing their energy bills, and government policy around cost-effective demand-side measures.

FEU's non-EEC marketing efforts serve a broader purpose. They pertain to communicating the benefits and value of using natural gas with the objective to attract new and retain existing customers. In doing so, FEI may promote energy efficiency as one of these benefits of using natural gas, as seen in the sample advertisement below. So the converse is true in that FEI's non-EEC marketing activities support and enhance the overall energy efficiency message which is at the heart of all of the company's EEC programs.

Regardless, all EEC program costs are recovered in FEI's delivery rates, as are the ES&ER expenditures that support the natural gas utility.

The information requested in the questions is presented in Attachment 311.4. FEI has interpreted this question as total costs for the department that plays a role in attracting and retaining customers, i.e. ES&ER. Therefore, in Attachment 311.4, FEI has shown the ES&ER department costs alongside the EEC annual spend for the period 2010 to 2018. Please refer to Attachment 311.4.

While FEI has supplied the graph requested, FEI believes that the graph only serves to demonstrate that after receiving Commission approval for increased EEC Program expenditure in 2009, FEI has ramped up its spending on EEC Programs since that date. Furthermore, the graph does not provide for a good comparator as EEC program expenditure is inclusive of incentives paid out to customers.

311.5 For Actual 2007-2013, please provide please provide a breakdown of the Events Manager/FortisBC Street Team costs by resource and year. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

This response also addresses BCUC IR 2.311.5.1

Please refer to Attachment 311.5 for the fully functional electronic spreadsheet.

The spreadsheet outlines the Events Manager/FortisBC Street Team labour charges. While these staff members also incur non-labour expenses, these are directly charged to the activity they are supporting and due to SAP reporting limitations it is not possible to provide them in the aggregate view requested. Charges are expensed to the appropriate accounts within the natural gas or electric businesses, utilizing timesheets for labour charges and coding of expenses for non-labour charges.

311.5.1 Please explain how the Events Manager/FortisBC Street Team costs are allocated to the different lines of business.

Response:

Please refer to the response to BCUC IR 2.311.5.

311.6 For Actual 2007-2013, please list each of the events attended by FortisBC Street Team and the cost allocation by year. Use the format below and include the requested information in the form of a fully functioning electronic spreadsheet.

Description	Date	Cost	Line of Business*	Cost Allocation
2011 PNE	Aug. 20 - Sept. 5 2011		Electric	Gas/Electric

*Line of Business (i.e. natural gas, electric, EEC, TES/FAES, GGRR, non-GGRR, and Biomethane)

Response:

Please refer to Attachment 311.6 for the fully functional electronic spreadsheet.

The costs shown are those for event participation. Costs for some of these events are not available in the format requested as they are generally part of a longer term agreement which encompasses several other elements (e.g. sponsorship) and therefore not tied solely to one event listed. Prior to 2011, the Street team reported directly to the EEC group and worked on education and community outreach for energy conservation.

311.7 The link to the FortisBC Events web page shows the “FortisBC at events across British Columbia from home show exhibitions, community events to sporting attractions.” For Actual 2007-2013, please list each of the FortisBC at events across British Columbia and the cost allocation by year. Use the format below and include the requested information in the form of a fully functioning electronic spreadsheet.

Description	Date	Cost	Line of Business*	Cost Allocation
Power of You kick-off	October 1, 2013		Electric	

Response:

Please refer to Attachment 311.7 for the fully functional electronic spreadsheet.

The costs shown are those for event participation. The events listed in the attached spreadsheet relate to public events that were shown and listed on our website, and/or public events in our customers’ communities where they could attend.

Costs for some of these events are not available in the format requested as they are generally part of a longer term agreement which encompasses several other elements (e.g. sponsorship) and therefore not tied solely to one event listed. Prior to 2011, the Street team reported directly to the EEC group and worked on education and community outreach for energy conservation.

The FortisBC Ad tiles and web banner web page states, “FortisBC ad tiles and web banners can enhance your advertising and help your customers by highlighting our natural gas rebate programs. And for members of our Contractor Program, co-op advertising funds* for print advertisements help your marketing dollars go further.”

311.8 For 2007-2013, please provide the contractor co-op advertising expenditures by year, resource and account code. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Please refer to Attachment 311.8 for the fully functional electronic spreadsheet

From 2010 onwards, these expenditures are charged to the EEC deferral account as they fall within the EEC approved portfolio of spend, and specifically the Efficiency Partner's Program.

In 2011, FEU rolled out a revamped Contractor program and extended co-op advertising funding to Contractor program members province-wide.

312.0 Reference: ACCOUNTING POLICIES

The Vancouver Sun launches their new UDI/Fortis BC Housing Affordability Index

http://www.newswire.net/newsroom/pr/00070862-vancouver-real-estate-housing-affordability.html

BCUC USoA - Distribution Sales Promotion – Operations

312.1 Please provide the 2013-2018 cost of FEI's involvement in the UDI/Fortis BC Housing Affordability Index, the contracted/expected term of FEI's involvement in the UDI BC Housing Affordability Index.

Response:

This response also addresses BCUC IR 2.312.1.1

The total cost of the 2013 involvement is $86 thousand. In regards to future activity, at this time, the Vancouver Sun is undecided as whether they will continue with this activity beyond 2014. In the event that it is discontinued, FEI will seek to engage in a similar activity where broad market reach is offered in both print and digital formats to support delivery of information on natural gas. FEI found significant benefits in the UDI/Fortis BC Housing Affordability Index as it provided a direct channel to communicate to those involved or interested in the housing market, which is a key target audience for FEI. Engaging with such a group helps create further awareness of the benefits of natural gas with the end goal of increasing natural gas end use. One measure of the success of the UDI/Fortis BC Housing Affordability Index is that FEI saw an increase in the site visits for the home energy calculator during publication, as readers were directed to this site.

The cost of this activity is allocated to the natural gas business as FEI has sponsored those print and digital ads that support the natural gas message aimed at first time and second time homebuyers, customer homebuilders and downsizers. The natural gas end uses being targeted through these ads include natural gas for space and water heating, fireplaces and cooking in the home.

312.1.1 Please explain how the cost of FortisBC's involvement in the UDI/FortisBC Housing Affordability Index is allocated to the different lines of business (i.e. natural gas, electric, EEC, TES/FAES, GGRR, non-GGRR, and Biomethane).

Response:

Please refer to response to BCUC IR 2.312.1.

313.0 Reference: ACCOUNTING POLICIES

Exhibits B-1, Tab C, Section 3.6, p. 153, Section 3.7.1, p. 162

Section 3.16, p. 200, Tab D, Section 3.6, p. 278; B-11, BCUC 1.202.1

Development of Base 2013 O&M – Net O&M involving Services/Projects

FEI states, "Costs related to serving Alternative Energy Services (AES) customers and associated activities are not included here, and are captured in a separate company, FortisBC Alternative Energy Services Inc. (FAES)." (Exhibit B-1, Section C3.6, p. 153)

FEI further states, "While the majority of the expenditures for these programs are accounted for in the EEC deferral accounts, the expenditures for the high carbon fuel switching program, which is managed by this group, are included in O&M." (Exhibit B-1, Section C3.6, p. 153)

FEI also states, "The Corporate department contains a number of items that do not reside in any particular department. These are corporate-wide costs and recoveries, consisting primarily of… recoveries from FAES as described in Section D3.6… and shared service recoveries from… CMAE." (Exhibit B-1, Section C3.16, p. 200)

FEI also states, "As a result of these other ongoing processes, FEI has not addressed the **allocation of corporate and shared services** to the TES offerings in this Application, but has requested a deferral account to ensure that natural gas ratepayers are held whole." (Exhibit B-1, Section D3.6, p. 278) [Emphasis added]

"The Gas Supply group is funded from two main sources – the Core Market Administration Expense (CMAE) budget and an O&M budget. … **The other activities of the department including management oversight**, are required in support of all customers, and are **included** in the O&M amounts shown in the tables below." (Exhibit B-1, p. 162) [Emphasis added]

In response to BCUC 1.110.1, FEI states, "The increase in FTE in 2013 is largely driven by additional staffing required in 2013 to support the GGRR … These costs will be appropriately captured in the GGRR deferral account." (Exhibit B-11-1, BCUC 1.110.1)

In response to BCUC 1.121.2, FEI states, "The forecast cross-charge revenue from gas to electric from 2013 onward reduces the Labour portion of Table C3-33 and C3-34 referred to in BCUC IR 1.121.1 (as a recovery of Labour). Cross-charges from electric to gas are included in the Non-labour portion consistent with the treatment of other shared and corporate services expenses." (Exhibit B-11, BCUC 1.121.2)

In response to BCUC 1.202.1, FEI states, "FEI employees who work directly on TES projects continue to charge time to internal orders via timesheets as a method of tracking time and allocating costs to TES. Certain functions, like senior management, continue to be included in the overhead allocation of $854 thousand." (Exhibit B-11, BCUC 1.202.1)

313.1 Please explain the existing and/or proposed costing and reporting process for each of the following Services/Projects:

- Biomethane
- CMAE – Core Marketing Administration Expense
- FAES – FortisBC Alternative Energy Services Inc.
- GGRR CNG and LNG
- Non-GGRR CNG and LNG
- Inter-company work (FEI – FEVI)
- NGT – Natural Gas for Transportation
- RNG – Renewable Natural Gas
- Woodfibre LNG

Please include in the explanation how the costing affects the presentation of the O&M tables and references in the Application. The intent is to understand exactly what costs are in Net O&M, if there are recoveries in the non-Labour which offset Labour, if there are recoveries in other Business Units related to costs in a different Business Unit, and/or if there are recoveries in accounts such as Other Revenue which offset specific Service/Project costs in Business Units. For example, the response to BCUC 1.202.1 explains time is charged/tracked the internal orders but it does not explain how this affects the data presented in the Business Unit sections of the Application.

Response:

For clarification purposes, please note:

- There are no new or proposed cost allocation methodologies being proposed in this Application (other than the change from time estimate to Massachusetts model for charging executive time between FEI and FBC). FEI will continue with all existing cost allocation methodologies. If any changes in cost allocation to FAES arise as an outcome of the TPP /CoC review, then these will be reflected through an adjustment to the proposed TESDA Overhead Variance deferral account, which will keep natural gas and TES ratepayers whole.
- Biomethane and RNG are one and the same thing – these words are used interchangeably.
- CNG and LNG stations, both GGRR and Non-GGRR, are currently treated as a separate class of service, and not as a "line of business."
- Delivery of natural gas to CNG and LNG stations is through one of FEI's rate schedules.

The table below shows a summary of the initiatives listed in the question in relation to its inclusion in the Base O&M dollars, and if appropriate which business unit in the Company is affected. Please also refer to the response to BCUC IR 2.250.3 for a discussion of FTEs for the areas described.

Item	Included in O&M Dollars – Business Unit	Recovery in O&M	Recovery in Other Accounts	Notes
Biomethane / RNG	Yes **ES&ER -** Labour and Customer Education Costs $410K **Operations -** $84K – Interconnect O&M facilities (both BCUC IR 2.347.1)	No	No	Those costs that are specific to RNG customers, such as the cost of the renewal gas, RNG upgraders, are captured in the Biomethane Variance Account (BVA) and recovered from only RNG customers through the BERC rate.
NGT Fuelling Stations GGRR and Non-GGRR	Yes **ES&ER -** Costs related directly to fueling station activities estimated at $282K by FEI (BCUC 2.346.1.1)	No	Yes Other Revenue	As per Commission decision there is a $0.52/GJ Overhead and Marketing rate charged to NGT customers, which the Commission determined was appropriate to compensate the NG utility for these costs included in O&M; amounts vary by year depending on volumes (BCUC 2.346.2).
NGT - GGRR Specific Activities	No	No	Yes FSVA for net GGRR surplus/ deficiency	GGRR specific admin/marketing O&M of $240K for CNG and $250K for LNG (BCUC 2.345.2) per Section 18 direction are charged directly to the FSVA; Incentives and incentive admin costs are charged directly to the GGRR Incentive deferral account.
NGT - Non-GGRR Specific Activities	No	No	No	Fuelling Station O&M and capital removed to separate classes of service (BCUC 2.345.1).
Intercompany (FEI –FEVI/FEW)	Departments that provide service to FEVI/FEW have costs included in department's O&M (BCUC 2.328.1 for listing)	Yes **Corporate Department** In Non-Labour	No	As per FEI-FEVI/FEW shared service agreements (Section D3.36.1 of the Application).
FAES /TES	Exec, Finance, Regulatory, HR, IT, Facilities' costs are included in department's O&M (BCUC 2.353.1 for listing)	Yes **Corporate Department** in Non-Labour recovery of BCUC-determined $854K for these services	No	In addition to this overhead allocation, those employees who work directly on FAES/TES projects charge their time to TESDA as explained in BCUC 2.250.1 (to be transferred Jan 1, 2014 to FAES); other employees charge part of their time directly to the TESDA or FAES via timesheets. In either case, the costs do not exist in the O&M department because they are direct charged.
Deferral Projects – such as Woodfibre	No	No	No	These costs are charged directly to the appropriate project/deferral account and do not exist in O&M.
CMAE	No	No	No	These costs are recovered through gas cost recovery rate.

1

313.2 Please explain how costs related to staff in the various business units working on FAES projects are charged to FAES; the reference in Section D3.6 refers to recovery of corporate and shared services costs but not to the cost of staff in business units.

Response:

The staff who directly work on FAES projects either charge time (through timesheets) to the TESDA, or to capital of a specific project in FAES, or to operations and maintenance within FAES for those projects that are in-service in FAES; therefore, these costs are not reflected in this RRA for natural gas customers. In addition, certain oversight and support functions are captured in the overhead allocation. For the overhead allocation, while the costs are in various departments, there is a recovery in the Corporate department. The individuals who are involved in the support and oversight functions have a more limited role as compared to those who directly work on the development and operations of the thermal energy projects.

Also refer to the response to BCUC IR 2.313.1.

313.3 Please explain if the costs in ES&ER for the energy efficiency and conservation (EEC) high carbon fuel switching program are balanced by a recovery in ES&ER from the EEC deferral account.

Response:

Pursuant to the direction of the Commission in Order G-44-12, starting in 2012, the costs for the high carbon fuel switching (or Switch and Shrink) program are captured in O&M and there is no recovery from the EEC deferral account. The Commission's Decision on FEU's 2012-2013 RRA accompanying Order G-44-12, states in Section 8.5.1.ii., page 162:

> *"The Panel accepts the merits of this program and therefore approves FEU to recover the EEC funds forecast to be spent on the Switch and Shrink program as expenses in this RRA."*

313.4 Please explain what other costs, besides the non-CMAE costs, are included in the O&M amounts, or are all the costs, including CMAE included in the O&M amounts; please confirm the recovery from CMAE is in Corporate and not as an offset to ES&RD.

Response:

The direct CMAE costs are not included in O&M in any department. The reference above "These are corporate-wide costs and recoveries, consisting primarily of… recoveries from FAES as described in Section D3.6… and shared service recoveries from… CMAE" refers to the recovery of **shared services costs** from CMAE, not the direct costs of CMAE itself. Consistent with the treatment of all shared services amounts, the costs for the shared services reside in the individual departments, with the recovery of shared services ($767 thousand in 2013) in the Corporate department.

Also refer to the response to BCUC IR 2.318.1.

313.5 Please explain if the FTE labour costs for work on GGRR are included in the Labour in Table C3-19 for ES&RD with a credit included in the Non-Labour, or are the labour costs charged directly to the GGRR deferral account without affecting O&M and without being reported in Table C3-19..

Response:

The labour costs in this table are shown net of charges to the GGRR, and therefore represent O&M expenditure only for the natural gas for distribution class of service.

Also refer to the response to BCUC IR 2.313.1.

313.6 Please explain if business unit charges to Services/Projects show in the accounts, both budget and actual, to facilitate their tracking and reporting. Please explain, why or why not, it would be beneficial to be able to see this information to help demonstrate the correctness of the impact on the Ratepayers.

Response:

The preamble to the BCUC IR 2.313 series cites numerous instances where business units would charge a portion of their O&M to Services/Projects. In all instances, both on a budget and actual basis, it is possible to view the nature and extent of these charges in FEI's SAP system at a detailed level for the current and historical years.

There are thousands of projects and services that an employee can charge to in any given year. To capture this level of detail and provide it in any kind of meaningful way would not be possible.

313.7 Please explain the advantages and disadvantages of having a single methodology by which FEI records, tracks, and reports the transfer of costs from a business unit to a Service/Project. Please explain if there should be any difference in methodology for charges within the utility compared to outside of the utility compared to a deferral account designed to insulate the Ratepayers.

Response:

FEI does have a consistent and well-understood approach to record, track and report cost transfers. There are two variations only – direct charges and allocations. Direct charges are recorded via timesheets, with the cost calculated at fully loaded labour cost. Allocations are typically done in accordance with an existing BCUC approved agreement or a BCUC Order, where there is no necessity to track time since it is recovered through an agreed upon method or amounts, examples being corporate services, shared services, TESDA overhead allocation, NGT OH&M charge. This consistent approach is followed for charges between business units or to regulated deferrals or capital projects within the utility, charges between related utilities, as well as charges to NRB's outside of the utility.

The advantages of a single methodology for recording, tracking and transferring of costs are adaptability and ease of understanding and application. To the extent possible, FEI does employ a single methodology, although recognizing that direct charges and allocations are inherently different in nature and require a different methodology. The disadvantage of a single methodology would lie in identifying a methodology that can be applied uniformly across all nature of charges.

FEI believes that its existing approach is well understood by its employees; employees are not required to designate whether the particular order or project they charge their time to is regulated, non-regulated, capital, deferral, or another company. They only need to understand that their time needs to be properly captured by appropriate coding. A different approach depending on where the costs finally reside would be extremely difficult to communicate and enforce with employees.

313.8 Please explain how the amount of a cost allocation based on time sheets is calculated. For example, please explain how non-productive time, such as vacation time, training time, administrative function time, is reflected in the labour rate used in costing labour hours to a Service/Project. Please explain if any of the current charging processes favour Services/Projects at the expense of the Ratepayers, who will absorb all costs not charged outside of FEI.

Response:

As explained in the response to BCUC IR 2.313.7, cost allocations are typically done in accordance with a BCUC approved agreement.

The response below assumes the question pertains to a direct charge of labour time.

As explained in the response to BCUC IR 2.313.7, direct charges are at fully loaded labour rates which include benefits and concessions (i.e. paid time off). For IBEW employees, it also includes loadings for admin costs such as time/costs spent on other unproductive time (meetings/presentation, vehicle management, field support/admin, muster clean up), and other costs such as personal supplies and small tools/supplies. Employees are assigned labour rates based on the annualized cost of labour and benefits divided by annualized chargeable hours. Annual chargeable hours are determined by taking total work hours in a year (based on a five day work week of 37.5 hours) and deducting hours related to statutory holidays, annual vacation, paid days off, and an estimate of employee sick time.

Other time that is defined 'non-productive' in this question such as training time and administrative function time, if it relates directly to the project / entity, would be direct charged to the project or entity to which it pertains.

FEI's believes its cost allocation process based on time sheets is appropriate and well established and will lead to accurate and representative costs for services provided to the different Service/Projects and accordingly to FEI ratepayers. The system is designed to capture the necessary input from employees who are best able to assess where their time has been spent. Additionally, as described in the response to BCUC IR 2.313.7, FEI believes that its existing time sheet approach and the importance of costing information is well understood by its employees.

FEI's time sheet based allocation approach has been used successfully for a number of years in the Company. FEI believes the same approach will work in the future to ensure appropriate cost allocations between the different projects/services and entities.

Please also refer to the response to BCUC IR 2.354.1.

313.9 Please explain where and how it can be seen that all the charges to Services/Projects have been done to properly remove these costs from the 2013 Base.

Response:

As outlined in Sections B6.2.4 and C3.3.1 of Exhibit B-1, FEI has provided information and justification in support of the proposed 2013 O&M Base.

Additionally, FEI has processes to ensure costs are recorded appropriately.

Please refer to the response to BCUC IR 2.313.1 which shows in table format whether the service/projects that are the subject of this IR series have been included in O&M, charged to a separate account or separate class of service, or are recovered within O&M.

For items that are charged directly to an account, such as the Biomethane Variance Account, these amounts have never resided in O&M. These amounts are not included in the 2013 Base.

For intercompany service charges, including shared services with FEVI and FEW and FAES, FEI has shown the recoveries within the Corporate Services Department.

Please refer ot the response to BCUC IR 2.319.1.

314.0 Reference: ACCOUNTING POLICIES

Exhibit B-1, Application, Tab D, Section 3.1, p.263

US GAAP

In the Application, FEI states, "If the OSC does not agree to an extension then FEI, as part of the Fortis Group, will begin the process of becoming an SEC Issuer in order to continue preparing external financial statements in accordance with US GAAP for 2015 and beyond."

314.1 If FEI does decide to proceed with becoming an SEC Issuer, when and how would FEI anticipate filing for approval to become an SEC Issuer with the Commission? Would FEI file the request as part of the Annual Review process or as a separate application? Please discuss.

Response:

If FEI does proceed with becoming an SEC Issuer, FEI anticipates filing an application in 2014 for Commission approval to continue to use US GAAP for regulatory accounting purposes and recover any potential costs that may result from becoming an SEC Issuer effective January 1, 2015. This application will be provided as part of a stand-alone application to the BCUC made by the FBC Utilities.

Regardless of whether FEI proceeds with becoming an SEC Issuer, FEI will be applying to the Commission by September 1, 2014 for approval of its regulatory accounting standard effective January 1, 2015 as required by Order G-117-11.

315.0 Reference: ACCOUNTING POLICIES

Exhibit B-1, Application, Tab D, Section 3.1, pp.263-264

US GAAP vs IFRS

315.1 Please discuss whether or not FEI believes that US GAAP and IFRS are ultimately heading towards convergence.

Response:

At this point in time, the Financial Accounting Standards Board (FASB), who is the primary U.S. GAAP regulator, and the International Accounting Standards Board (IASB), who is the IFRS regulator, have been working together on the convergence of certain standards; however there are still many differences that remain between the two sets of standards.

While progress is being made towards convergence of certain standards, whether full adoption of IFRS in the United States will be achieved is currently undeterminable. As discussed in Section D3.3.1 of the Application, accounting for the effects of rate regulation is one of the main differences that remains, due to lack of formal guidance for accounting for rate-regulated activities under IFRS.

Since 2002, the FASB and IASB have been working together to both improve US GAAP and IFRS and eliminate or minimize the differences between them. The Boards have completed several major projects to converge accounting standards, including those on business combinations, non-controlling interests, and fair value measurement. The FASB has issued those standards as US GAAP and the IASB has issued the same standards as IFRS. Over time, the two sets of standards are expected to both improve in quality and become increasingly similar. Currently, the FASB and the IASB are completing their work on their remaining joint standard-setting projects initially undertaken under the 2006 Memorandum of Understanding, which include revenue recognition, financial instruments, leases, and insurance.

Moving forward the FASB has stated they will continue to work on global accounting issues with the IASB through its membership in the Accounting Standards Advisory Forum.

Furthermore, the Securities and Exchange Commission (SEC), who regulates financial markets in the United States, has directed the FASB to consider international convergence as it develops new accounting standards. In July 2012, the SEC staff issued its final staff report on the “Work Plan for Consideration of Incorporating International Financial Reporting Standards into the Financial Reporting System for US Issuers.” The report was the final phase of a work plan, initiated in February 2010, to consider specific issues relevant to the SEC’s determination as to where, when and how the current financial reporting system for US issuers should be transitioned to a system incorporating IFRS.

The 2012 staff report summarized the SEC staff’s findings regarding key issues surrounding the potential incorporation of IFRS into US financial reporting, but did not make any recommendation to the SEC. According to the report "additional analysis and consideration of this threshold policy question is necessary before any decision by the Commission concerning the incorporation of IFRS into the financial reporting system for the US issuers can occur". Also in the report, the SEC staff examined a number of unresolved issues relating to the potential incorporation of IFRS into the US financial reporting system. These issues include, among others, the diversity in how accounting standards are interpreted, applied and enforced; the potential cost to US issuers of adopting or incorporating IFRS; investor education; and governance.

In summary, while the FASB and IASB are working to improve US GAAP and IFRS through convergence of certain standards, the FASB has stated they have concerns with full adoption, including the impacts on the US investor community. Similarly, the IASB has a policy of publishing a single set of standards that are universally applied, therefore working towards aligning with specific accounting standards that exist under US GAAP (outside of the 2006 MOU projects) is not in the best interests of maintaining the IFRS brand globally. Therefore, there still remain significant barriers to full adoption of IFRS in the United States.

316.0 Reference: ACCOUNTING POLICIES

Exhibit B-1, Application, Tab D, Section 3.1, p. 264

US GAAP Reconciliation to Canadian GAAP

As part of the Application, FEI is requesting to discontinue the requirement that it provides an annual US GAAP to Canadian GAAP reconciliation.

316.1 How much time does FEI estimate that it takes to prepare this annual reconciliation?

Response:

FEI estimates approximately one week was spent preparing and reviewing the US GAAP to pre-changeover Canadian GAAP reconciliation for 2012. Another set of accounting records would have to be maintained to recreate pre-changeover 2011 Canadian GAAP onwards and the reconciliation for items such as pension and OPEB will magnify on a prospective basis. Therefore, continuing to prepare this reconciliation is expected to not only increase the future preparation and review time, but also increase the external actuarial costs.

FEI would be willing to file with the Commission any future accounting policy changes or any material impact from its interpretation of US GAAP that would have an impact on setting customer rates. While there are always changes and developments that are occurring with US GAAP, not all such changes in accounting policy will have an impact to FEI. As a result, FEI would agree to provide and communicate accounting policy changes as part of its Annual Review material, consistent with what was provided during the previous PBR term.

316.2 What is the estimated annual cost to prepare this reconciliation?

Response:

Since the 2012 reconciliation was primarily prepared by salaried management and exempt staff, who do not attract overtime costs, there were negligible incremental O&M costs incurred the first time that this specific reconciliation was prepared. However, on a prospective basis, it would be expected that there would be incremental annual costs in preparing the annual reconciliation.

As indicated in Section D3.3.1 of the 2014-2018 PBR Application, specific accounting records in compliance with pre-changeover Canadian GAAP are no longer maintained since they are not used for any other reporting purpose.

Therefore, for 2013 and beyond, there could be incremental costs expected to be incurred that are associated with maintaining another set of accounting records to recreate pre-changeover Canadian GAAP from 2011 onwards, overtime paid to unionized staff that assist with preparing the reconciliation in the timelines given the overlap with year-end external financial statement reporting, and 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.

Since FEI requested cessation of this reconciliation beginning with its 2013, Annual Report to the BCUC, FEI's 2014 to 2018 PBR Application did not take into account any increases in actuarial costs required to perform accounting valuations under pre-changeover Canadian GAAP, any potential increased O&M or any additional accounting system capital expenditures to complete the reconciliation on a prospective basis.

Note that continuing to prepare a reconciliation to pre-changeover Canadian GAAP could be misleading in identifying true differences that would exist if pre-changeover Canadian GAAP had continued to be a financial reporting option. As discussed in Section 2-Background of the FBC Utilities Application to Adopt US GAAP, beginning in 2012 pre-changeover Canadian GAAP was withdrawn by Canadian standard setters and ceased to exist as a financial reporting option. Therefore, to the extent that a difference from pre-changeover Canadian GAAP arises from a change in accounting guidance by US standard setters, it would be difficult to determine whether a similar accounting guidance change would have occurred under Canadian GAAP if this financial reporting option had continued to exist. Currently, many emerging issues that result in new accounting guidance are jointly issued by US standard setters and international standard setters (as part of International Financial Reporting Standards). If Canadian GAAP had continued to exist as its own set of standards, there would likely be convergence towards one of these sets of standards which means that a difference may not have existed.

316.3 If the Commission approved the request to discontinue the preparation of this reconciliation, would FEI consider it appropriate to include a sustainable cost saving from 2013 Projection to 2013 Base to reflect this reduction in regulatory work? If not, why not? If yes, please provide the amount.

Response:

No, for the reasons discussed in the response to BCUC IR 2.316.2, the 2013 Base includes negligible incremental costs for preparing the reconciliation, so there should be no cost savings adjustment between 2013 Projection and 2013 Base upon the removal of the requirement to prepare this reconciliation. Since the Application assumes the removal of the reconciliation, if the reconciliation continues to be required, then the increased O&M and capital expenditures described in the response to BCUC IR 2.316.2 would have to be included in the 2014-2018 forecasts.

317.0 Reference: ACCOUNTING POLICIES

Exhibit B-11: BCUC 1.164.1, 1.164.2

Allocation of Retiree Pension and OPEBs

In response to BCUC 1.164.1, FEI states, "As a result of further investigation into specific US GAAP guidance and further understanding of general industry practice, the Company believes that the full Net Benefit Cost… is the appropriate amount to be included in benefit loadings." (Exhibit B-11, BCUC 1.164.1)

317.1 Is this proposed treatment consistent with how FEI is recording pension and OPEBs for financial reporting purposes? If not, why not?

Response:

Currently for financial reporting purposes FEI is including only the current service portion of pension and OPEBs in benefit loadings consistent with the current approved regulatory treatment. FEI will be implementing the proposed treatment for financial reporting purposes once it has been approved for regulatory reporting, effective as of January 1, 2014.

The consistency of pension and OPEB treatment for both regulatory accounting and external financial reporting is one of the main reasons for adopting US GAAP as the regulator's actions and decisions will often drive the external financial reporting.

317.2 Has this change in accounting treatment been reviewed and signed off on by FEI's independent auditors? If not, why not?

Response:

No, this change in accounting treatment has not been reviewed and signed off on by FEI's independent auditors because the change has not been implemented by FEI for financial reporting purposes as explained in the response to BCUC IR 2.317.1. If the BCUC approves FEI recognizing the full net benefit cost of pension and OPEB in benefit loadings, FEI anticipates that the auditors will accept the change in accounting treatment since US GAAP, in many cases, allows for consistency with the economic substance of the regulator's actions.

Additionally, the auditors will be aware of the relevant US GAAP guidance that supports FEI's proposed accounting treatment as described in the response to BCUC IR 1.164.1 which stated:

"ASC 715-30-35-3, *Compensation-Retirement Benefits, Defined Benefit Plans-Pension*, refers to Net Benefit Cost (referred to specifically as net periodic pension cost in US GAAP below) as a "homogeneous amount." Although the components of Net Benefit Cost are measured separately, they should be reported together as a single pension expense on the face of the financial statements. Accordingly, it would not be appropriate to disaggregate the individual components of the pension cost (e.g., service, cost, interest cost, amortization of net gains and losses) and report them separately in the financial statements."

Further, FEI has the same auditors as those for its sister company, FBC, and the auditors have reviewed and accepted the accounting treatment for FBC to include the full net benefit cost in benefit loadings.

317.3 Is the proposed change in the allocation of retiree pension and OPEBs required under US GAAP, or is FEI's current method of accounting for retiree pension and OPEBs allowed under US GAAP? Please discuss.

Response:

The proposed change in the allocation of retiree pension and OPEBs is not explicitly required under US GAAP but it is one of the options allowed under US GAAP. As explained in BCUC IR 1.164.1 FEI believes the proposed treatment of including both the net benefit cost of pension and OPEBs in benefit loadings is more closely aligned with US GAAP.

In response to BCUC 1.164.2, FEI states that its "treatment of the allocation of Retiree Pension and OPEBs prior to 2010 was to include the full Net Benefit Cost as determined by the Company's third party actuary, not just the Current Service Cost component, in benefit loadings. This is consistent with FEI's proposed treatment." (Exhibit B-11, BCUC 1.164.2)

317.4 Is the proposed method that FEI is proposing, which is consistent with the method used prior to 2010, less volatile? Please discuss.

Response:

FEI interprets the question's reference to volatility in the context of revenue requirements and rate setting. The various components of pension and OPEB net benefit cost are subject to variance from forecast and would be captured in the pension and OPEB variance deferral account. However the components of net benefit cost, including interest cost and amortization of actuarial net gains and losses, which were previously expensed in O&M between 2010 and 2013 would now be partially capitalized pursuant to the benefit loading ratio, resulting in less O&M volatility. The primary intent of the proposed change in accounting treatment is to better align with the relevant US GAAP guidance, as discussed in the response to BCUC IR 1.164.1, and to obtain consistency in accounting policy with FBC, while the mitigation of volatility is an additional factor considered for ratemaking purposes.

317.4.1 Did the desire to decrease volatility factor into FEI's decision to change back to its prior accounting treatment for pensions? Why or why not?

Response:

No the desire to decrease volatility did not factor into FEI's decision to change back to its prior accounting treatment for pensions. Please refer to the response to BCUC IR 2.317.4.

317.4.2 If part of FEI's goal is to decrease volatility, what other alternative treatment methods would be available to FEI to address volatility issues?

Response:

It was not FEI's goal to decrease the volatility of benefit loadings to FEI. Please refer to the response to BCUC IR 2.317.4.

318.0 Reference: ACCOUNTING POLICIES

Exhibit B-11, BCUC 1.165.1, BCUC 1.165.5; Exhibit B-1, Application, Tab D, Section 3.1, p. 265

Capitalization of Annual Software Costs

318.1 Is FEI also adopting this change in capitalization methodology for financial reporting purposes? If not, why not?

Response:

FEI will be adopting this change in capitalization methodology for financial reporting purposes once it has been approved for regulatory reporting. FEI would expect to adopt this change effective January 1, 2014 which would be concurrent with the adoption of this treatment for regulatory purposes.

318.2 Has this change in capitalization methodology been reviewed and signed off on by FEI's external auditors? If not, why not?

Response:

No, this change in capitalization methodology has not been reviewed and signed off on by FEI's external auditors because the change has not been implemented by FEI for financial reporting purposes as explained in the response to BCUC IR 2.318.1. FEI does not anticipate the auditors will have an issue with the proposed change since it is consistent with the treatment employed by FBC.

In response to BCUC 1.165.1, FEI states that "the proposed change is consistent with US GAAP treatment." (Exhibit B-11, BCUC 1.165.1)

318.3 Is the proposed change in capitalization methodology required under US GAAP, or is FEI's current treatment of software allowed under US GAAP? Please discuss.

Response:

The proposed change in capitalization methodology is not required under US GAAP but it is one of the options allowed under US GAAP; FEI's current treatment of software is also not required under US GAAP but it is one of the options allowed under US GAAP. As discussed in the responses to BCUC IRs 1.165.1 and 1.165.1.1, US GAAP allows for costs associated with upgrades to be capitalized because the upgrades result in either enhanced functionality of the software or extensions to the useful life of the existing software.

FEI believes the proposed change in capitalization methodology is better aligned with US GAAP guidance as the upgrade costs to be capitalized result in either enhanced functionality of the software or extensions to the useful life of the existing software.

318.4 Please discuss how this proposed change benefits ratepayers.

Response:

The proposed change is intended to properly allocate costs for software. The impact to ratepayers in 2014 is a credit of approximately $1.8 million to revenue requirements and a 0.29% decrease in rates.

318.5 Please discuss what other purposes this change in methodology serves beyond shifting a portion of O&M to capital.

Response:

This change in methodology was proposed because it results in an allocation of O&M and capital that more accurately reflects the capital nature of Annual Software Costs and is better aligned with US GAAP.

In response to BCUC 1.165.5, FEI states, "It is estimated that at least 25 percent of annual costs paid to vendors include service packs and enhancements that extend the life and enhance the functionality of the software and should be considered capital costs." (Exhibit B-11, BCUC 1.165.5)

318.6 Please provide a specific example of a "service pack and enhancement," please specifically explain how it serves to extend to the useful life of the software, and please specifically describe how it enhances the functionality of the software.

Response:

An example of a service pack and enhancement is the upgrade from Version 3 to Version 4 of FEI's Customer Interactive Centre system in the Contact Centres (included in annual fees). This upgrade ensures the continued support for the software past that of Version 3 (which extends the life of the software), ensures compatibility with required operating system and supporting architecture upgrades and has provided the following new or enhanced features:

- Upgraded and enhanced Schedule Bidding for the Interaction Optimizer which improves the ability to schedule resources in the Contact Centre based on trends helping to optimize resourcing requirements.
- Improved phone number management which allows for the customer extension to be included in the phone number string for contacting customers. This reduces steps in the process and improves productivity.
- String operator support for Assigned Workgroup search attribute, which enables users to put more attributes in searches. This narrows results from searches improving end user productivity.
- Additional features in email playback controls and recordings, which improves the ability to interact with the customer and provides additional Quality Assurance capability.

Product improvements and enhancements are provided for all software products that have long term agreements associated with them. As described in Section D–3.1 of the Application, the annual costs of a software product include providing upgrades and enhancements that add functionality and extend the life of the affected software. Also, as stated in response to BCUC IR 1.165.5, it is estimated that 50 percent of the annual cost is associated with providing these enhancements and upgrades for software solutions, other than Microsoft.

In response to BCUC 1.165.5, FEI also states, “Microsoft identifies approximately 30 percent of the annual desktop software costs (operating system, Project, Visio, Office, etc) relate to software licensing and maintenance, and the remaining 70 percent is the upgrade value, which should be considered capital.” (Exhibit B-11, BCUC 1.165.5)

318.7 Please provide evidence of how updates to Microsoft products such as Visio and Office fundamentally changed the software so as to increase the life of the software asset. Please describe the types of changes that resulted from the updates to the software and how this enhanced the functionality of the software in a measurable way.

Response:

Microsoft Office is standard desktop software that is used by a majority of the organizations with which FEI conducts business. Microsoft Office products have been used by FEI since the early 1990s. Given the long-term use of the software, FEI entered into an Enterprise Support Agreement with Microsoft under which FEI receives access to new supported versions and any new functionality available in new versions of the Microsoft Office suite of applications. The agreement has enabled the continued use of the Microsoft Office suite of software over a period of nearly 20 years. If this agreement had not been entered into, the Microsoft Office products would need to be re-purchased each time an upgrade was required, which would be a 100 percent capital cost and more costly than FEI’s long term Enterprise Agreement.

Upgrades to Microsoft Office are required to maintain compatibility with other organizations providing the Company with Microsoft Office created files. FEI can also take advantage of new features and functionality available in new software releases. Some specific examples of new functionality and features made available through upgrade process are:

- Collaboration capabilities for MS Word and MS Excel enable more than one person to contribute to a file at a time. This improves productivity particularly in an organization like FEI with dispersed resources contributing to common initiatives.
- Improved resource management in MS Project enables scheduling and budgeting for union resources that could not be done in previous versions. This decreased manual project management processes.
- Enhanced data integration capabilities for MS Office enabled information from multiple office applications to be incorporated into single documents or files for improved and streamlined presentations and reporting.
- Improved security for MS Office decreased the need to secure files at the directory level, thus decreasing the need for Network Administrator support to manage security for specific files.

318.8 Please provide the total amount paid for annual software costs for 2013 and please indicate how much of that total is being proposed to be capitalized and how much remains as O&M.

Response:

$4.2 million is being paid for annual software costs for 2013. Assuming the same amount for 2014 when this policy would be implemented, then $1.8 million of that amount would be capitalized and $2.4 million would be O&M.

319.0 Reference: ACCOUNTING POLICIES

Exhibit B-11, BCUC 1.166; Exhibit B-1, Application, Tab D, Section 3.1, pp. 265-266

Purchases of Vehicles

In response to BCUC 1.166.2, FEI states that its “change from a lease to own approach for vehicle acquisition will align all the FortisBC companies and therefore reduce the administrative burden that currently exists within Fleet Management associated with using two distinct processes.” (p. 405)

319.1 Please quantify the additional administrative burden that currently exists for Fleet Management in both additional labour hours and additional cost.

Response:

It is not possible to quantify the additional time related to having different acquisition methods associated with vehicles as staff time is not tracked at that level of detail. The time spent would not be significant. However, moving to a uniform approach for the acquisition of vehicles for FEI would simplify and standardize administrative processes across the FortisBC utilities. In addition transitioning the vehicle fleet to an owned status has the lowest present value cost of service as discussed in BCUC IR 1.166.6.

319.2 If FEI is approved to transition to an owned fleet and the administrative burden is therefore reduced, should this reduction be included as a sustainable savings and thus create a reduction to FEI’s 2013 Base O&M? If not, why not? If yes, please quantify the amount of sustainable savings.

Response:

No. Please refer to the response to BCUC IR 2.319.1.

In response to BCUC 1.166.1, FEI states in that it “decided to then partner with PHH Arval (PHH) to assume the vehicle services that BC Hydro had previously provided including lease and maintenance services.” (p. 405)

319.3 When FEI acquires a vehicle from the third party lessor, how many years is it expected to use the vehicle before retiring the vehicle?

Response:

Whether vehicles are leased or owned, many factors are taken into consideration when an actual vehicle replacement decision is made. When vehicles are near the end of their planned life cycle, factors such as suitability, ability to maintain adequate safety, age, condition, and compliance with regulations are reviewed. Each replacement decision is evaluated on a unit-by-unit basis. Based on past experience, vehicles are expected to be in service on average for 8 years as described in BCUC IR 2.319.3.1.

319.3.1 What is the average frequency with which FEI trades in vehicles under the lease contract?

Response:

Whether vehicles are leased or owned, on average, vehicles are replaced after 8 years in service. Some vehicles are replaced sooner than the 8 years and some vehicles are utilized longer than 8 years based on the factors provided in response to BCUC IR 2.319.3.

319.4 Please describe the maintenance services provided under the lease contract. What is the frequency of the maintenance that FEI is required to perform on its leased vehicles and what is the nature of the required maintenance?

Response:

No maintenance services are included by the vendor under the lease contract. FEI sets its maintenance schedules based on the vehicle type taking into factors such as provincial Commercial Vehicle regulations and minimum Recommended Manufacturer Maintenance Intervals to ensure warranty compliance.

319.5 Please describe the maintenance plan that FEI proposes for the purchased vehicles. How is this plan different from the maintenance plan under the lease contract?

Response:

There will be no change in the maintenance plan for the purchased vehicles. The maintenance plan based on vehicle type is identical for leased vehicles (FEI) and purchased vehicles (FEVI and FEW).

In the Application, FEI states, "The vehicles that are being purchased are estimated to have an average 8 year service life, resulting in a depreciation rate of 12.5 percent for this asset class (484)." (p. 266)

In response to BCUC 1.66.11, FEI states, "In 2014, FEI anticipates retiring and replacing 45 vehicles. Over the PBR period, FEI anticipates retiring and replacing 48, 45, 47 and 43 vehicles in 2015, 2016, 2017 and 2018, respectively." (p. 412)

319.6 What is the current number of leased vehicles in FEI's fleet?

Response:

The current number of leased vehicles in FEI's fleet as of October 30, 2013 is 464 units.

319.7 If FEI continued to lease its vehicles instead of purchase vehicles during the PBR period, how many vehicles would it anticipate retiring and replacing in each of the years 2014, 2015, 2016, 2017 and 2018?

Response:

FEI would continue to replace the same number of vehicles if it continued to lease its vehicles instead of purchasing the vehicles. Vehicle replacement is based on a number of different factors as described within the response to BCUC IR 2.319.3 and is not dependent upon whether the vehicle is leased or purchased.

319.8 If FEI was approved to purchase its vehicles and some of these vehicles lasted less than the estimated useful life of 8 years, what impact would this have on FEI's O&M and Capital? Please discuss the impact on O&M and on Capital separately.

Response:

The impact to O&M is the same whether the vehicle is leased or owned; if maintenance is required on either a leased or owned vehicle, the maintenance costs are charged to the vehicle's cost center.

The capital treatment between leased and owned vehicles is also similar. If a vehicle is owned and it lasts less than its useful life, the vehicle is disposed of and the remaining book value (less disposition proceeds) is added to FEI's gain/loss on asset disposition account. If the vehicle is leased, and it lasts less than its useful life, the vehicle is disposed of and FEI pays to PHH Arval (PHH) the book value of the vehicle (less disposition proceeds). This payment to PHH is added to FEI's gain/loss on asset disposition account.

The book value that FEI would show on its balance sheet if the vehicle were owned should be equivalent to that on PHH's balance sheet for a leased vehicle because in both cases the depreciation is straight line and based on the expected useful life of the vehicle.

319.9 What are the risks to ratepayers if the purchased vehicles have shorter than projected useful lives? Please discuss.

Response:

Please refer to the response to BCUC IR 2.319.8.

320.0 Reference: ACCOUNTING POLICIES

Exhibit B-11, BCUC 1.167.1

Capitalized Overhead

320.1 Please provide the revised 2014 revenue requirements and the 2014 rate impact of changing to an overhead capitalization rate of 12 percent.

Response:

Changing the overhead capitalization rate to 12 percent would have the effect of increasing the Revenue Requirement Impact as a percent of Gross Margin by approximately 1.0 percent in 2014 and the Revenue Requirement Impact as a percent of Total Revenue by about 0.6 percent in 2014 as illustrated below. These amounts vary from the amounts shown in BCUC IR 1.167.1 due to the correction in the “Change in Overhead Timing Difference” which previously recognized 6/14ths of the new capitalized overhead amount as the timing difference rather than the new timing difference of 4/12ths which would be required with a change in overhead capitalization rates.

	2014 Forecast ($000s)
Total Gross O&M	235,241
Capitalized Overhead @ 14%	32,934
Capitalized Overhead @ 12%	28,229
Increase in Net O&M	4,705
Income Tax Calculation	
Change in Equity Earned Return (-$4,705/2 x 8.75% x 38.5%)	(79)
Change in Overhead Timing Difference ((-$28,229 x 4/12) - (-$32,934 x 6/14))	4,705
Change in Depreciation (assets depreciated following year)	-
Taxable Income after tax	4,626
Taxable Income before tax ($4,626 / (1 - 26% tax rate))	6,251
Change in Income Tax Expense ($6,251 x 26% tax rate)	1,625
Earned Return Calculation	
Change in Rate Base (-$4,705/2)	(2,353)
Forecasted Return on Rate Base (Section E, Schedule 60, Sept. 6th Evid Update)	7.31%
Change in Earned Return	(172)
Revenue Requirement Impact	
Change in Net O&M	4,705
Change in Income Tax Expense	1,625
Change in Earned Return	(172)
Incremental Revenue Requirement Impact	**6,158**
Forecasted Gross Margin (Section E, Schedule 2, Sept. 6th Evid Update)	628,101
Forecasted Total Revenue (Section E, Schedule 2, Sept. 6th Evid Update)	1,123,911
Impact on Revenue Requirement as a % of Gross Margin ($6,158 / $628,101)	**0.98%**
Impact on Revenue Requirement as a % of Total Revenue ($6,158 / $1,123,911)	**0.55%**

321.0 Reference: ACCOUNTING POLICIES

Exhibit B-1, Application, Tab D, Section 3.3, p. 267

Depreciation Rates and Methodology

In the Application, FEI states that it "proposes to return to the method of calculating depreciation expense that was approved as part of the 2004-2007 PBR (extended for 2008 and 2009), whereby depreciation expense commences at the beginning of the year following when the asset is placed into service (as compared to the current practice of depreciation commencing at the time the asset is placed into service)." (Exhibit B-1, p. 267)

321.1 Please explain why FEI believes this depreciation method is more appropriate than the method currently in place.

Response:

FEI believes this depreciation method is more appropriate than the method currently in place for a variety of reasons.

First and critical to the design of the PBR Plan, given the incentive to find efficiency savings in capital is a key component of this PBR plan, a depreciation variance deferral, as currently approved, would take away all the incentive related to capital savings with the exception of the small earned return component.

Second, as described on Pages 304-305 of the Application (Exhibit B-1), with depreciation commencing in the year following when the assets are placed into service, the variance in depreciation expense will be driven by the formula vs. actual capital spending from prior years, not potentially through the timing of when assets are placed into service in the current year.

Lastly, this proposed depreciation method is allowed under US GAAP. FEI made the change to the currently approved method in the 2010-2011 RRA to comply with International Financial Reporting Standards (IFRS) as the Company was anticipating adopting IFRS at the time of submitting the application in 2009. Subsequently, the Commission granted approval for FEI to adopt US GAAP which does not require the change in depreciation method. Please refer to the response to CEC IR 1.76.2 for further history on this change.

321.2 Please explain why FEI switched to the current depreciation method after the previous PBR term ended.

Response:

Please refer to the response to BCUC IR 2.321.1.

321.3 Please provide the forecast depreciation expense for the years 2014-2018 under both the current depreciation method and the proposed method.

Response:

The forecast depreciation expense for the years 2014-2018, under both the current depreciation method and the proposed method, are provided in the table below. The reduction in 2014 depreciation expense as a result of this change is approximately $3.3 million, which equates to a delivery rate decrease of approximately 0.7 percent in 2014.

2014-2018 Forecast Depreciation Expense ($000s)

(Includes CIAC amortization)

	Current Method[1]	Proposed Method[2]	Difference
2014	$ 121,674	$ 118,368	$ (3,306)
2015	128,324	124,836	$ (3,488)
2016	133,554	131,232	$ (2,322)
2017	138,894	135,810	$ (3,084)
2018	145,386	141,529	$ (3,857)
Total	**$ 667,832**	**$ 651,775**	

[1] Depreciation commences mid-year on a forecast basis

[2] Depreciation commences January 1st the year following inservice

322.0 Reference: ACCOUNTING POLICIES FINANCING, TAXES, ACCOUNTING POLICIES AND DEFERRALS

Exhibit B-1, Application, Tab C, Section 3.9.2, p. 172, Tab D, Section 3.3, p. 267

Depreciation Rates and Methodology

"The recently developed LTSP risk framework is refining our 20-year view of potential infrastructure requirements. Over the 2014-2018 planning horizon, FEI's transmission and distribution assets have been forecast to require more O&M analysis and increasing sustainment capital investment in order to proactively address increasing safety and reliability risks." (Exhibit B-1, p. 172)

322.1 Please explain how FEI expects/does not expect the recently developed LTSP risk framework to impact the updated depreciation study to be filed during the term of the PBR Period.

Response:

By the time FEI files its next depreciation study (timing discussed in the response to BCUC IR 2.323.5), FEI may have retirement data for assets retired as a result of projects identified by the LTSP. This retirement information will be incorporated into the depreciation study by the external depreciation consultant along with information gathered from operational interviews with FEI staff, which will include discussion of the LTSP framework and methodology. However, at this time and until a depreciation study is completed, the potential impacts of the recently developed LTSP risk framework on the overall estimated service life and depreciation rates of sustainment asset classes are unknown.

323.0 Reference: ACCOUNTING POLICIES FINANCING, TAXES, ACCOUNTING POLICIES AND DEFERRALS

Exhibit B-1, Application, Tab D, Section 3.3, p. 267, Section 3.5.2, pp. 271-2; 2012-2013 FEU Decision, p. 85

Gains and Losses on Asset Disposition (Gains/Loss on Disposition)

"The FEU note that at the end of 2009, the total asset retirement loss balance stood at approximately $149 million with the asset categories, Mains, Services, Regulator and Meter Installation, and Meters accounting for the majority of the losses. (Exhibit B-1, Appendix E-3)" (2012-2013 FEU RRA Decision, p. 85)

"However, like the BCOAPO, the Panel does not necessarily accept the rationale that the Utilities will likely experience gains at a future point in time. We are of the view that gains will only occur if assets last beyond their expected useful lives. In our view, these "gains" are better characterized as "deferred asset replacements" due to the continued use of assets after they have been fully depreciated." (2012-2013 FEU Decision, p. 88)

"Consistent with the Commission's direction on the appropriate accounting treatment, the forecast gains and losses are being transferred from the respective plant-in-service accounts to the Gain/Loss Deferral account and amortized over a 20 year period." (Exhibit B-1, p. 272)

323.1 Please provide a continuity schedule for the Gains/Losses on Disposition Deferral account for 2010-2013. Also, provide a graph showing the year-end balance for the Gains/Losses on Disposition Deferral account for 2010 -2013. Include the requested information in the form of a fully functioning electronic spreadsheet.

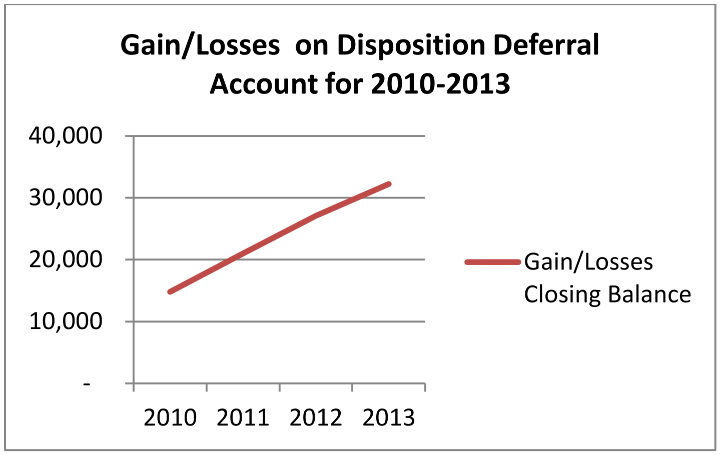
<u>Response:</u>

FEI notes that the balance is growing as anticipated, since FEI is adding a full year of losses each year, but only amortizing 5 percent of the opening balance. Please refer to Attachment 323.1 for the fully functional electronic spreadsheet.

Gain/Losses on Disposition Deferral Account for 2010-2013 (000's)*

Year	Opening Balance	Changes during years	Closing Balance
2010	-	14,817	14,817
2011	14,817	6,182	20,999
2012	20,999	6,091	27,090
2013	27,090	5,160	32,250

**Positive numbers represent Losses.*



"The following table [Table D3-3] shows the forecasted net losses by asset classes for 2013 and 2014 with 2014 considered a representative year of the expected gains and losses during the PBR Period." (Exhibit B-1, p. 272)

323.2 Given that FEI's annual asset losses for every year from 2003-2012 is greater than the $5.98 million of asset losses forecast in 2014, please explain why $5.98 million should be considered a representative of the expected gains and losses during the PBR Period.

Response:

The forecasted losses of $5.98 million are considered representative for 2014 and during the PBR period as they are based on the future planned retirement activities.

In addition, FEI notes the following two mitigating factors:

1. FEI will be updating the forecasts of losses at each Annual Review; and
2. The amount of asset losses forecast does not change the revenue requirement. These losses represent a transfer of the net book value of assets from plant in service to the deferral account. The amortization period of the deferral account is designed to equal the average service life of the affected asset classes. Therefore, there should be no impact on the revenue requirement from a change in the forecasted level of asset losses.

For the period 2003 – 2012, the recorded asset losses reflect the circumstances at the time and may include unusual losses. As discussed in the response to BCUC IR 2.323.3, 2012 reported losses include a catch-up adjustment. These exceptions distort the comparability of historical data.

323.3 Would the average gains and losses for the years 2011-2013 provide a better estimate of the expected gains and losses during the PBR Period? Please explain why, or why not. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Please refer to Attachment 323.3 for the fully functional electronic spreadsheet.

The average gains and losses for the years 2011-2013 would not provide a better estimate of the expected gains and losses during the PBR Period for the following reasons:

- Retirements for Distribution Services and Mains in 2012 included a catch-up adjustment to align reporting with the current year. Previously, the gains and losses with plant retirements for services and mains were calculated and reported the following year due to the timing of availability of data (i.e. 2011 gains and losses reported in 2012). By making changes to the reporting process, FEI is now able to align current year activities with the current reporting period. This adjustment was noted in FEI's 2012 Annual Report, Tab 19, Summary of FEI (3 Division) Net Negative Salvage schedule. Contributing to the increase noted also was higher service retirement activity due to Inactive Services program initiated by FEI (Application, page 274, line 15).
- 2012 also included other specific retirements from CPCN projects such as the Fraser River Crossing and Kootenay River Crossing projects that are not expected to occur during 2014.

The average gains and losses for 2011-2013 would be comparable to the 2014 projection of approximately $6 million if these unusual retirements as discussed are excluded. The 2014 projection is considered a representative year of the expected gains and losses during the PBR period.

However, the losses for 2015-2018 will be re-forecast as part of the annual rate setting process.

323.4 Please expand Table D3-3 to include the years 2010-2012. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Please refer to Attachment 323.4 for the fully functional electronic spreadsheet.

Table D3-3: Forecasted Net Losses for 2013 and 2014 ($ thousands) expanded to include 2010-2012 years

Particulars	2010 Cost	2010 Net Loss	2011 Cost	2011 Net Loss	2012 Cost	2012 Net Loss	2013 Cost	2013 Net Loss	2014 Cost	2014 Net Loss
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
INTANGIBLE PLANT										
461-00 Transmission Land Rights		(35)			-	-	-	-	-	-
402-01 Application Software - 12.5%	8,365		11,301	-	2,771	-	6,015	-	3,738	-
402-02 Application Software - 20%	2,527		91	-	1,899	-	2,997	-	2,317	-
	10,892	(35)	11,392	-	4,670	-	9,012	-	6,055	-
TRANSMISSION PLANT										
460-00 Land in Fee Simple	1	(39)			-	-	-	-	-	-
462-00 Compressor Structures					350	206	-	-	-	-
463-00 Measuring Structures			10	4	-	-	21	5	21	5
465-00 Mains	321	38	850	291	3,129	1,537	374	2	374	2
465-00 Mains - INSPECTION			138	-	-	-	1,268	-	368	-
466-00 Compressor Equipment	450	296	715	366	95	(4)	340	-	288	-
467-00 Measuring & Regulating Equipment	69	43	13	5	192	53	131	23	131	23
467-10 Telemetering			8	8	5	1	22	-	31	-
	841	338	1,734	673	3,770	1,793	2,157	30	1,213	30
DISTRIBUTION PLANT										
470-00 Land in Fee Simple		(63)								
472-00 Structures & Improvements	3	(5)	10	3	-	-	21	7	21	7
473-00 Services	2,956	2,023	3,765	2,507	9,356	5,945	3,185	2,053	3,185	2,053
474-00 House Regulators & Meter Installations	17,526	8,383	68	27	1,079	296	284	57	6	2
475-00 Mains	969	634	1,050	598	2,546	1,589	1,049	549	1,049	549
477-00 Measuring & Regulating Equipment	253	79	332	160	1,102	724	598	162	598	162
477-00 Telemetering	3	1	149	(40)	85	33	6	4	6	4
478-10 Meters	6,433	3,475	4,760	2,227	8,505	2,919	6,353	2,862	6,672	3,005
	28,143	14,529	10,134	5,481	22,672	11,506	11,496	5,693	11,538	5,782
GENERAL PLANT & EQUIPMENT										
482-00 Structures & Improvements			140	72	3	-	151	-	40	-
483-30 GP Office Equipment	1,077	-	146	25	392	82	303	58	92	24
483-40 GP Furniture			1,462	-	567	-	1,954	-	3,123	-
483-10 GP Computer Hardware	7,466	-			1,517	(2)	6,489	-	3,708	-
483-20 GP Computer Software	20	-	480	8	-	-	192	-	44	-
484-00 Vehicles	7	(15)	368	(3)	-	(3)	-	-	-	-
484-00 Vehicles - Leased	2,107	-	3,117	(122)	2,442	(100)	1,440	-	1,536	-
485-10 Heavy Work Equipment			-	-	42	25	-	-	-	-
485-20 Heavy Mobile Equipment			6	3	19	13	-	-	-	-
486-00 Small Tools & Equipment			1,854	1	884	(1)	963	-	2,003	-
488-00 Telephone	3,223	-	155	66	-	-	906	109	1,460	146
488-00 Radio			952	0	7	-	34	-	214	-
	13,900	(15)	8,680	50	5,874	14	12,432	167	12,221	169
TOTAL COST	$ 53,776		$ 31,940		$ 36,986		$ 35,097		$ 31,027	
TOTAL LOSS		$ 14,817		$ 6,205		$ 13,314		$ 5,890		$ 5,981

323.4.1 Please explain why the 2012 net losses gross additions of $13.23 million are 54 percent higher than 2013 net losses gross additions of $5.89.

Response:

The 2012 net losses gross additions of approximately $13 million are higher by approximately 56 percent compared to 2013 net losses gross additions of $5.89 million. The variance of $7.4 million is due to the following reasons:

- Transmission plant - The variance of $1.8 million is mainly due to retirement of CPCN project assets for the Fraser River South Arm Crossing project and the Kootenay River Crossing project. For the 2013 and 2014 forecast period, we are not expecting similar retirements.
- Distribution plant - The variance of $5.8 million is mainly due to a catch-up adjustment (Mains – $1 million, Services – $4 million) to align reporting with the current year. Previously, the gains and losses with plant retirements for services and mains were calculated and reported the following year due to the timing of availability of data (i.e. 2011 gains and losses reported in 2012). By making changes to the reporting process, FEI is now able to align current year activities with the current reporting period.

" 'In the design of any future PBR mechanism, the Commission Panel recommends that the parties take into account the potential impact of asset usage and deprecation.'

This recommendation has been addressed in two ways. First of all, consistent with the recommended approach to update depreciation rates every 3 to 5 years, FEI will provide an updated depreciation study during the term of the PBR Period and anticipates that, subject to Commission approval, any updated depreciation rates would be implemented during the term of the PBR. This will address concerns from the 2004 Plan regarding asset losses that accumulated as a result of the approved depreciation rates being lower than the asset lives for the duration of the previous PBR period. Second, FEI will continue to update its estimate of asset losses on an annual basis throughout the PBR Period for review by the Commission." (Exhibit B-1, p. 267)

323.5 In which year of the PBR Period FEI does expect to provide an updated depreciation study.

Response:

Consistent with the recommended approach to update depreciation rates every 3 to 5 years and given the last complete depreciation study was prepared in 2011 and filed in FEU's 2012 and 2013

Revenue Requirements and Rates Application (Appendix E-1 Gannett Fleming Depreciation Report), the earliest FEI expects to provide an updated depreciation report is in 2015. Subject to Commission approval, any updated depreciation rates would be effective in the year subsequent to when the study is filed.

324.0 Reference: ACCOUNTING POLICIES FINANCING, TAXES, ACCOUNTING POLICIES AND DEFERRALS

Exhibit B-1, Application, Tab D, Section 3.5.2, pp. 270-2; 2012-2013 FEU RRA, Appendix E3, Asset Loss Report, pp. 4-10

Asset Losses

324.1 Are exceptional retirements such as retirements due to customer initiated requests contemplated in FEI's depreciation studies. Please explain why, or why not.

Table E3-2: Most Services Retired Due to Customer Requests

Reasons for Retirement	2006		2007		2008		2009	
	Metres of Services Retired	Retirement Costs	Metres of Services Retired	Retirement Costs	Metres of Services Retired	Retirement Costs	Metres of Services Retired	Retirement Costs
Customer	76,958	$ 4,079,701	76,893	$ 4,235,239	68,959	$ 4,913,276	72,817	$ 4,906,138
Safety	11,303	$ 584,850	30,733	$ 311,291	45,852	$ 471,291	10,811	$ 499,975
Total	88,261	$ 4,664,551	107,626	$ 4,546,530	114,811	$ 5,384,566	83,628	$ 5,406,113

(2012-2013 FEU RRA, Appendix E3, p. 8)

<u>Response:</u>

FEI clarifies that the definition of customer initiated requests includes customer requests to retire services as a result of land development activities and those resulting from specific requirements of customers such as homeowners performing building modifications and landscaping activities. Under Section 10 of FEI's GT&C, customers are charged for the relocation or alteration of a service line which will be continuing in-service. However, Section 10 does not apply to retirement or abandonment of a pipeline that is removed from service.

Additionally, FEI's view is that the noted service retirements are not "exceptional" in nature. While the quantity of the service retirements may be unusual, in part caused by the increased demand for housing in the more densely populated regions (i.e. Lower Mainland) with existing housing and land being redeveloped, such service retirements are not unexpected as part of operating a distribution utility service. Over the life of an asset, many factors beyond FEI's control can influence an asset's life.

The recent study completed by Gannett Fleming and included in Appendix E1 of the 2012-2013 FEU RRA factors in such retirements. On pages II-28 and II-29 of the study, there is discussion of the early retirement trend in services.

> *The retirement rate analysis indicates a significant rate of retirement activity as plant reaches 20 years of age, with large retirement rates through to age 75. In order to better fit*

to this retirement pattern, Gannett Fleming has recommended the Iowa 50-R1 survivor curve to better reflect the trend toward increased retirement rates beyond age 40, as compared to the previous estimate of the Iowa 55-R2.5. This decrease in both the mode of the Iowa curve and the average service life expectation provides a reasonable interpretation of the original survivor curve, and falls within the range of typical service lives for this account and is, therefore recommended for this account.

The depreciation study factors in the impact of these customer initiated retirement requests as they are considered within ordinary course of business and expected to continue in the future.

324.2 Please update Tables E3-2, to include the retirement costs from 2006-2013, and the number of services retired each year.

Response:

Table E3-2: Services retirement costs and number of services retired from 2006-2013

Reasons for Retirement	2006		2007		2008		2009	
	Metres of Services Retired	Retirement Costs	Metres of Services Retired	Retirement Costs	Metres of Services Retired	Retirement Costs	Metres of Services Retired	Retirement Costs
Customer	76,958	$ 4,079,701	76,893	$ 4,235,239	68,959	$ 4,913,276	72,817	$ 4,906,138
Safety	11,303	$ 584,850	30,733	$ 311,291	45,852	$ 471,291	10,811	$ 499,975
Total	88,261	$ 4,664,551	107,626	$ 4,546,530	114,811	$ 5,384,567	83,628	$ 5,406,113

Reasons for Retirement	2010		2011		2012		Jan-Oct 2013	
	Metres of Services Retired	Retirement Costs	Metres of Services Retired	Retirement Costs	Metres of Services Retired	Retirement Costs	Metres of Services Retired	Retirement Costs
Customer	70,298	5,072,958	76,629	5,336,652	79,776	6,220,461	62,526	4,904,176
Safety	44,146	2,023,774	53,282	6,479,208	68,605	4,535,001	57,569	3,538,312
Total	114,444	7,096,732	129,911	11,815,859	148,381	10,755,462	120,095	8,442,488

FEI increased its service retirement program beginning in 2010 to remove inactive services. An inactive service to a premise is a live gas service or meter with no existing customer. These assets continue to attract regular maintenance such as leak survey and scheduled meter exchanges but are not presently used for gas delivery. Inactive services are often forgotten by the property owner and represent a significant risk of third party damage. Removal of inactive services initiated by FEI improves the safety of the public, the natural gas delivery system and its employees.

A retention program is also in place which reaches out to property owners for these inactive service addresses to find out why the service is not being used and to effectively attempt to reactivate the service with a customer, potentially adding a new customer and avoiding the retirement/removal cost.

"The data above indicates that the majority of retirements expressed in metres of pipe retired and the retirement costs incurred were the result of customer initiated requests.

…To mitigate the rate impact to all customers, FEI seeks to recover the retirement costs from the customer that initiates the work wherever possible." (2012-2013 FEU RRA, Appendix E3, p. 8)

Table E3-3: Most Mains Retired for Safety and Reliability Reasons

Reasons for Retirement	2006		2007		2008		2009	
	Metres of Main Retired	Retirement Costs	Metres of Main Retired	Retirement Costs	Metres of Main Retired	Retirement Costs	Metres of Main Retired	Retirement Costs
Customer	1,048	$ 22,981	-	$ 6,083	-	$ -	15	$ 535
Safety/Reliability	26,169	$ 513,060	54,548	$ 525,600	53,832	$ 474,834	21,107	$ 591,413
Total	27,217	$ 536,041	54,548	$ 531,683	53,832	$ 474,834	21,122	$ 591,948

(2012-2013 FEU RRA, Appendix E3, p. 9)

"Customer requests to relocate distribution mains may also lead to earlier retirement than expected. Highway construction, municipality activities and private industry development may result in FEI having to retire and relocate an existing main. To mitigate the rate impact to all customers, FEI seeks to recover the related costs wherever possible from the initiator of the request." (2012-2013 FEU RRA, Appendix E3, pp. 9-10)

324.3 Please provide the retirement costs recovered from customers initiating service line and distribution main retirement work by year from 2007-2013, and the accounting treatment of the cost recoveries. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

FEI does not recover retirement costs from customers initiating service line retirement work. Please refer to IR 324.4 for further explanation.

The table below provides the retirement costs recovered from customers initiating distribution main retirement work for the period 2010-2013.

Retirement costs recovered from customers initiating distribution main retirement

2010	2011	2012	Jan-Oct 2013
Recoveries	Recoveries	Recoveries	Recoveries
$ (316,851)	$ (384,097)	$ (446,847)	$ (307,350)

For the period 2007 to 2009, cost recoveries were netted against the retirement costs. As a result, comparable reporting of the amount of recoveries is not available for those years. Starting in 2010, recoveries were tracked separately from the retirement costs under the CIAC asset class.

Prior to 2012, recoveries were recorded as CIAC. Starting in 2012, as retirement costs are recorded in the Negative Salvage deferral account as per BCUC Order G-44-12, the recoveries of retirement costs are allocated to the same deferral account to provide an appropriate comparison to the estimated negative salvage provision which was also implemented starting 2012.

No electronic spreadsheet is provided as there is no additional information besides what is shown on the table.

324.4 Please explain why FEI does not/is unable to recover the service line and distribution main retirement costs from all customers initiating retirement work.

Response:

This response also addresses related questions in BCUC IRs 2.324.4.1, 2.324.6, 2.324.6.1 and 2.324.6.2.

The subject of the recovery of asset losses and negative salvage value (i.e. removal costs for abandonment/retirements) was discussed extensively as part of the 2012-2013 RRA proceedings. With respect to these two topics, FEI received and responded to over 150 IRs from the Commission, and a significant portion of the oral hearing was devoted to the topic. The Commission issued Order G-44-12, and discussed the evidence and its related findings on pages 79 to 88 of the attached decision. FEI refers to the evidence provided in that application, and below provides a summary of some the relevant discussion and to address the current information requests. FEI submits that there has been no material change in its operations; and no change in the approved accounting and depreciation methodologies employed that should result in a further review of this approved process less than two years after Order G-44-12 was issued.

In the response to BCUC IR 1.136.2 in the 2012-2013 RRA proceeding, FEU explained that a "loss" in the case of the FEU's assets, is defined as the difference between the remaining net book value of an asset and any salvage proceeds. As depreciation expense is recorded based on an estimated depreciation rate, a "loss" results primarily from the difference between the actual life of an asset and the estimated life on which the depreciation rate is based. Over the life of an asset, many factors beyond the FEU's control can influence an asset's life. A loss on retirement indicates that as a whole the assets in that class were not fully depreciated at the time of retirement. However, it does not indicate that they were retired before the end of their economic useful lives, but only that the historically approved depreciation rates were not adequate to recover their costs over the period of time that they were in service. These "losses" are appropriately included in rate base for future recovery from customers through rates. There is no basis for the losses to be determined unrecoverable as the ratepayers are responsible to pay for service received in the form of return of depreciation over time for the capital employed as plant and equipment.

In the response to BCUC IR 1.148.4 in the 2012-2013 RRA proceeding, the FEU discussed the issue of shareholder responsibility for the losses and cited six reasons why the losses should be recoverable from ratepayers, concluding with "There is no basis for the losses to be determined unrecoverable as the ratepayers are responsible to pay for service received in the form of return of depreciation to investors over time for the capital employed as plant and equipment."

Further, in the responses to BCUC IR 1.137.8, 1.137.9 and 1.155.2 in the same proceeding, FEU indicated that it considers removal costs incurred for abandonment and retirement activities as part of the ordinary course of business related to providing utility services. Therefore, the costs are recoverable from all customers through rates.

Regarding the recoverability of retirement costs for customer initiated work, as indicated in the response to BCUC IR 1.153.1 in the 2012-2013 RRA proceeding, the FEU confirmed that Section 10 of the GT&Cs applies to establishment or continuation of a Service Line, which may include choosing a route, site preparation, construction, connections, additions, and maintenance. As the wording of Section 10.13 indicates, subsections (a) and (b) specifically apply to "any change in the location of an existing service line," and do not apply to retirement or abandonment of a pipeline that is removed from service. In accordance with the GT&Cs, FEI charges a customer who wants to relocate or alter a Service Line which will be continuing in-service.

For retirement of services other than that provided for in the tariff, FEI does not recover retirement costs from customers initiating service line retirement work for safety reasons. Charging for the retirements costs may delay a customer request to disconnect a service line until absolutely necessary. During this delay, premises may be left vacant. Vandalism and theft of copper piping in such circumstances is not uncommon, and can easily lead to escaping gas emergencies. In the interests of safety to the public at large, it is current practice to perform this work without charging costs to encourage early requests for disconnection. These are typically not high dollar value activities, with many services being disconnected at the property line leaving a live 'stub' service. From a collections perspective, it also is unlikely that pursuing delinquent payments will be successful as customers requesting disconnections are at the end of their association with the company and will be closing their accounts. Some may become customers again in the future, but many will not for many and varied reasons. There would be some considerable proportion that would need to be written off to bad debt.

For retirement of mains, FEI recovers costs for customer requested gas main abandonments in the same manner as costs for customer requested main alterations. These are based on 'As Built' costs reported after construction and costs are collected on the basis of actual value of work performed. Please refer to the response to BCUC IR 2.324.3 for mains retirement costs and recoveries. Further, for highway construction and certain municipal activities where a pipeline is located on municipal/provincial land without a right of way, the municipality or provincial government has the right to request the removal of pipeline without compensation.

324.4.1 If FEI decides not to seek recovery of service line and distribution main retirement costs from customers initiating retirement work, should cost be recovered from the shareholder? Please explain why, or why not.

Response:

No. Please refer to the response to BCUC IR 2.324.4.

324.5 Please provide the gains/losses caused by service lines and distribution mains being retired due to customer requests, as a percentage of the gross additions to the Gains/Losses on Disposition Deferral account by year for 2007-2013. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Please refer to Attachment 324.5 for the requested information for the years 2007 to 2012. FEI does not have comparable data available for 2013.

324.6 Does FEI recover the gains/losses caused by service lines and distribution mains being retired due to customer requests? Please explain why, or why not.

Response:

Please refer to the response to BCUC IR 2.324.4.

324.6.1 Should FEI treat gains/losses caused by service lines and distribution mains being retired due to customer requests in the same manner as retirement costs (i.e. recover the costs from customers causing the service line retirement)? Please explain why, or why not.

Response:

Please refer to the response to BCUC IR 2.324.4.

324.6.2 If the Commission directs FEI to recover the losses caused by service lines and distribution mains being retired due to customer requests, and FEI decides not to seek recovery of the losses from customers responsible for the loss, should the losses be recovered from the shareholder? Please explain why, or why not.

Response:

Please refer to the response to BCUC IR 2.324.4.

324.7 In the same format as Table E3-3, provide schedules showing the 2007-2013retirements for Regulators and Meter Installations (Asset Class 474) and Meters (Asset Class 478). Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Please refer to Attachment 324.7 for the fully functioning electronic spreadsheet.

Regulators and Meter Installations (Asset class 474) & Meters (Asset class 478) Retirement Activity 2007 – 2013

Asset class	2007	2008	2009	2010	2011	2012	Jan-Oct 2013
	Retirement Costs	Retirement Costs	Retirement Costs	Retirement Costs	Retirement Costs	Retirement Costs	Retirement Costs
Asset class 474	$ 870,426	$ 900,663	$ 1,320,689	$ 2,219,397	$ 2,403,415	$ 2,606,126	$ 2,594,791
Asset class 478	$ (130,749)	$ (289,417)	$ 5,156	$ (3,935)	$ (117,023)	$ (66,592)	$ (193,367)
Total	**$ 739,676**	**$ 611,246**	**$ 1,325,846**	**$ 2,215,462**	**$ 2,286,392**	**$ 2,539,534**	**$ 2,401,424**

** The retirement costs for asset class 478 incorporate salvage proceeds from scrapping meters.*

For the asset classes 474 and 478, very few of the retirement activities are driven by customer requests and therefore this detail has not been included. Instead, the retirements occur primarily due to defects, various administrative recalls such as load changes, vacant premises / inactive accounts, etc.

325.0 Reference: ACCOUNTING POLICIES FINANCING, TAXES, ACCOUNTING POLICIES AND DEFERRALS

Exhibit A2-17, Summary of FEI Net Negative Salvage

Negative Salvage

325.1 Please explain the differences between the actual cost to salvage assets, as a percentage of the actual rate base value of the assets retired and the rate recommended in the prior depreciation study for the following accounts:

46500 TP Transmission Pipeline
46710 TP Meas/Reg Equipment
47300 DS Services
47500 DS Mains
47810 DS Meters

Response:

The negative salvage rates were determined by Gannett-Fleming in the previous depreciation study based on the then available information including statistical analysis of retirement data, discussions with management and operations staff and considerations of estimates made based on other peer natural gas utilities.

Over a period of one year, circumstances are likely to cause variations between the actuals and that provided for in the rates which are designed to be in place for a longer time period and are calculated over the entire life of the asset class.

The differences between the actual cost to salvage assets, as a percentage of the actual rate base value of the assets retired and the rate recommended in the prior depreciation study for the requested accounts is presented below:

Summary of FEI 2012 Net Negative Salvage

Asset Class	Annual Expenditures as % of Rate Base	Negative Salvage % per Depreciation Study
46500 TP Transmission Pipeline	-5%	-10%
46710 TP Meas/Reg Equipment	-17%	-5%
47300 DS Services	-118%	-50%
47500 DS Mains	-47%	-20%
47810 DS Meters	1%	-5%

Overall, no meaningful conclusions can be drawn from the figures above since they are a snapshot of one year as compared to a rate developed for the lives of the assets. Fluctuations from year to year are expected to normalize out over the 40 to 70 year lives of these asset classes. For the shorter asset life class, meters, salvage proceeds are contributing to the lower percentage.

FEI will continue to monitor the results and update the negative salvage rates as appropriate in the next depreciation study.

325.2 Should column 7 of the table be described as (7)=(4)/(6)?

Response:

That is correct. Column 7 of the Exhibit A2-17, Summary of FEI Net Negative Salvage should be described as (7)=(4)/(6).

326.0 Reference: ACCOUNTING POLICIES

Exhibit B-1, Tab D, Section 3.6.1, p. 278

Shared Services

In the Application, FEI states, "Since FEI completed a review of the Shared Services agreement and cost allocation approach as part of the 2010-2011 RRA with validation by KPMG, no changes in methodology have occurred since the time of the 2009 review that would warrant making any change to the Shared Service Agreement currently in place." (p. 278)

326.1 When does FEI anticipate it would be appropriate to perform the next review of its Shared Services agreement and cost allocation approach? Please discuss.

Response:

FEI does not anticipate performing a complete review of the Shared Services agreements and cost allocation approach during the term of the proposed PBR agreement unless there are material changes in the nature of the shared services agreement caused by changing business requirements affecting requirements for shared services.

If there are material changes during the term of the proposed PBR agreement, FEI will undertake a review of the shared services agreement and cost allocation approach. Depending on the significance of changes, a third party may be retained to perform an independent review of the shared services cost allocation methodology and the reasonability of the costs of the shared services.

If FEI were to perform a review of its shared services agreement and the cost allocation approach during the term of the PBR period, the review of the results would be included in the Annual Review.

326.2 If FEI were to perform a review of its Shared Services agreement and cost allocation approach during the term of the PBR Period, would that review be included in the Annual Review or would it likely be a separate proceeding?

Response:

Please refer to the response to BCUC IR 2.326.1.

FEI also states in the Application: "For this filing, FEI updated the approved model for changes in the department's forecast O&M numbers along with changes in the organization structure…" (p. 278)

326.3 Please describe the changes in the organization structure and how these changes have impacted/changed the approved shared services model. Please quantify the changes to the shared services model.

Response:

Organization structure changes necessitated an update to the Shared Services model but do not affect the appropriateness of the Shared Services model and the choice of the cost drivers for allocating the shared costs.

Changes to the organization included:

- Transfer of Asset Management group to Operations Engineering from Distribution and Transmission Operations;
- Transfer of Training resources from Human Resources to Distribution;
- Transfer of Knowledge and Learning facilitators from Customer Services to Human Resources;
- Transfer of Property Services from Operations Engineering to Operations Support

Costs and/or cost centres with the shared resources were transferred into different parts of the organization. The Shared Services model was then updated, remapping the shared resources and costs that were moved, using the same allocation basis as prior to the transfer of the resources.

327.0 Reference: ACCOUNTING POLICIES

Exhibit B-1, Tab D, Section 3.6.2, Table D3-4, p. 279

Shared Services

327.1 Please expand the comparative information provided in Table D3-4 to include the Actual shared service amounts for the years 2007 to 2012. Please also include an additional line item which shows the Direct Costs Retained by FEI for each of these years.

Response:

Below is a Shared Services table that includes the Actual shared service amounts for the years 2007 to 2012, and 2013 Approved, Projection and Base. The increase in the shared service amounts from 2013 Approved to 2013 Base has been discussed in Section D3.6.2 of the PBR Application.

('000s)	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Allocated to FEVI	5,104	5,477	5,793	7,255	7,550	8,439	8,995	9,399	9,630
One time adjustment						600			
Allocated to FEW	-	-	-	192	197	196	250	246	255
One time adjustment						16			
Allocated to FEI	45,470	47,754	50,289	65,187	67,900	76,000	77,863	83,713	86,547
One Time adjustment						(616)			
Total Costs Included in Shared Services Pool	50,574	53,231	56,082	72,634	75,647	84,635	87,108	93,358	96,432
Direct Costs Retained by FEI	133,503	137,985	141,657	141,331	145,706	144,282	158,140	147,905	144,438

327.2 Please provide a list of O&M items that are considered to be direct costs retained by FEI.

Response:

The following O&M costs are considered to be direct costs retained by FEI as these are excluded from the pool of costs allocated to FEVI and FEW because they are exclusive to FEI activities. The list below accounts for the majority of the retained costs:

- Dedicated Distribution field activities and Plant operations
- Dedicated Transmission and LNG field operations

- Dedicated Energy Solutions and External Relations costs
- Customer Care direct costs
- Bad Debt expense
- Insurance
- Dedicated Telecom & IT infrastructure & application support
- Corporate Services fees
- Dedicated Management and Operations back-office support
- External fees related to BCUC assessments, bank charges, bond ratings and auditors

328.0 Reference: ACCOUNTING POLICIES

Exhibit B-1, Tab D, Section 3.6.3, pp. 279-280; FEU 2012-2013 RRA, Exhibit B-9, BCUC 1.76.1

FEI and FEVI Shared Services

328.1 Please provide an updated table of the one provided in the FEU response to BCUC 1.76.1 as part of the FEU 2012-2013 RRA to reflect information for 2013. This table has been copied from BCUC 1.76.1 and provided below for your reference. Include the requested information in a fully functional spreadsheet.

Table 1: Shared Services Fee Breakdown by Department

	TOTAL SHARED SERVICES FEE				INCREMENTAL		TOTAL	
	2010		2011		2012		2012	
(in $000's)	FEVI	FEW	FEVI	FEW	FEVI	FEW	FEVI	FEW
Distribution	$ 1,573	$ 41	$ 1,659	$ 43	$ 269	$ 7	$ 1,927	$ 50
Transmission	109	3	115	4	122	3	237	7
Energy Supply & Resource Development	106	3	108	3	15	0	122	3
Customer Service	285	7	292	8	515	13	808	21
Energy Solutions & External Relations	872	36	886	38	207	5	1,093	43
Information Technology	1,042	27	1,136	28	186	5	1,322	33
Operations Engineering	703	19	746	20	19	0	765	20
Operations Support	466	12	475	13	6	0	482	13
Facilities	164	4	168	4	13	0	181	5
Human Resources	666	16	691	17	83	2	774	19
Environmental & Safety	245	7	251	7	33	1	284	8
Finance & Regulatory	852	22	880	23	49	1	929	24
Corporate	157	5	132	6	(18)	(0)	114	6
Total Incremental Shared Services	**$ 7,239**	**$ 202**	**$ 7,541**	**$ 212**	**$ 1,499**	**$ 39**	**$ 9,040**	**$ 251**

(FEU 2012-2013 RRA, Exhibit B-9, BCUC 1.76.1)

Response:

Please refer to Attachment 328.1 for the Projected 2013 Shared Services allocated to FEVI and FEW.

In the Application, FEI states, "Increased resources totaling to about $200 thousand per year are required in the dispatch centre to plan and coordinate field resource requirements." (Exhibit B-1, p. 279)

328.2 Please provide a breakdown of the $200 thousand and describe the types of activities performed in detail.

Response:

The increase of $200 thousand is attributed to resources from the Integrated Resource Management (IRM) and Pre-requisite departments within the Operations Centre performing dedicated work for FEVI and FEW. These resources perform dedicated work and resource planning and scheduling for install crews, providing locations of all foreign underground utilities. The activities being performed include:

- Dispatch of Operate and Installation field resources in Zone 6 North and Zone 6 South;
- Customer appointment setting for operate activities requiring customer premise access;
- Preparing work packages for field crews;
- Preparing survey packages for survey crews; and
- Obtaining permits from municipal, provincial and federal agencies.

FEI further states in the Application: "In determining FEVI's share of this reduction for 2013, estimates of the impact on the shared departments were originally used. With updated information available regarding the allocation by department, FEI is in a position to true-up the calculation." (Exhibit B-1, p. 279)

328.3 Please explain how the updated information on the allocation by department differed from FEI's original estimates and describe the reasons for these changes.

Response:

As part of the shared services review process, FEI's performs a true-up of the shared services costs allocated to FEVI and FEW based on actual O&M results.

The Commission directed the FEU as a whole to reduce their O&M expenditures by $4 million in 2012 and 2013 as per Order G-44-12. FEI submitted compliance filings for each of the utilities to reflect the decision but without detailed line by line information supporting the $4 million reduction. The most reasonable approach at the time was to allocate the $4 million reduction amongst the FEU using the shared services allocation percentages by including the $4 million reduction in the O&M subject to sharing, This approach resulted in a proportionate reduction of the 2013 Approved

O&M in FEVI. The FEU recently updated the shared services model using the 2013 Projected O&M costs which incorporates the $4 million reduction in specific departments, some of which are shared and some of which are not. This resulted in a different allocation to FEVI than had all departments been shared.

FEI further states in the Application: "… the remaining $200 thousand is to account for FEI's pension/OPEB and accounting related changes impact on shared services." (Exhibit B-1, p. 279)

328.4 Please indicate how much is related to pension/OPEB and how much is related to accounting changes. For the accounting changes, please break down the amounts by accounting change.

Response:

The breakdown of the $200 thousand impact on shared services is as follows:

Pension/OPEB true-up	$438 thousand increase
Accounting changes	
• Allocation of retiree pension/OPEB	$(38) thousand decrease
• Capitalization of annual software costs	$(200) thousand decrease
Total Impact:	**$200 thousand increase**

329.0 Reference: ACCOUNTING POLICIES

Exhibit B-15, Tab A, Section 2, p. 9; Exhibit B-1, Tab D, Section 3.6.5, p. 280

Approvals Sought – Sharing of Services with FBC

FEI states in the September 6, 2013 Evidentiary Update that it requests "approval to allocate Executive costs between FEI and FBC effective January 1, 2014 by way of applying the Massachusetts Formula as described in Section D3.6.5 of the Application." (Exhibit B-15, p. 9)

FEI states, "In this Application, sharing of resources between FEI and FBC, <u>except for the Executive Management team</u>, have continued with the approved cross charge process such that the cross charge includes a fully loaded wage including benefits and time away, with no overhead or facilities fees assigned. Executive Management time is being allocated on the basis of the Massachusetts Formula." (Exhibit B-1, p. 280) [Emphasis added]

FEI also states, "Since 2010, the FEU and FortisBC Inc. (FBC) have been sharing common resources starting with the sharing of the Executive Management team." (Exhibit B-1, p. 280)

329.1 Please confirm, or explain otherwise, that currently FEI utilizes the Massachusetts Formula to allocate corporate service costs between FHI, FI and the FEU.

<u>Response:</u>

FEI can confirm that the Massachusetts Formula is used to allocate costs between FHI and the FEU. However, Fortis Inc. costs are allocated to FHI using assets rather than the Massachusetts Formula.

329.2 Please confirm, or explain otherwise, that FEI does not currently utilize the Massachusetts Formula to allocate any costs between FEI and FBC.

<u>Response:</u>

As described in the preamble to this question, FEI and FBC do not currently use the Massachusetts formula to allocate costs between each other. However, FBC and FEI have prepared previously approved revenue requirement applications which have allocated Board of Directors' costs from FHI to FBC and FEI utilizing the Massachusetts Formula. Also as described above, FEI and FBC are applying in both the FEI and FBC 2014-2018 PBR applications to allocate executive costs using the

Massachusetts formula starting in 2014. Currently, executive costs are allocated using an estimate of the amount of time and effort spent by each executive.

329.3 Please explain if FEI is currently approved by the Commission to allocate Executive Management costs between FEI and FBC.

Response:

FEI is currently approved to allocate labour costs, including Executive labour costs, between FEI and FBC. The forecasted Executive costs included in FEI's 2012-2013 RRA, filed on May 4, 2011 and approved pursuant to G-44-12 on April 12, 2012, included the estimated time allocations between FEI and FBC. The 2012-2013 RRA described the allocation of Executive costs and methodology in at least two areas.

Included under "Sharing of Services with FortisBC Inc." on page 276 of Section 5 of the 2012-2013 RRA, it described the time estimate allocation of Executive costs between FEI and FBC as follows:

> *"In the summer of 2010, FEU and FortisBC Inc. ("FBC") began having a common, shared Executive Management team. The shared responsibilities between the entities facilitates the FEU and FBC cross charging each other for the time each Executive expects to spend with their new responsibilities. FEU are charging FBC for those Executives who are FEU employees and have responsibilities in FBC, and receiving charges for FBC Executives who have responsibilities at FEU."*

> *"In order to simplify this process between similar regulated entities, FEI is proposing to simplify the cross charges between FEU and FBC. In this Application, the FEU are requesting to allow for charges between these regulated entities to be based on a fully loaded benefits and concessions charge but not to include overheads or a facilities fee."*

Included under Section 5.3.18.4 Summary of Corporate and Shared Services. on page 278 of FEI's 2012-2013 RRA, it further mentioned the time estimate allocation of Executive costs between FEI and FBC as follows:

> *"Certain organizational changes as a result of a shared executive team have changed the relationship between the FEU and FBC. The shared executive team has resulted in cross charges between FEU and FBC for the portion of executive time spent on each others business."*

The Commission approval to allocate Executive costs between FEI and FBC is further corroborated on page 48 and 49 of Commission Order G-110-12, dated August 15, 2012, approving FBC's 2012-2013 RRA which stated the following:

> *"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."*

> *"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."*

The determination of fully loaded wage was further elaborated under FBC BCUC IR 1.144.7 as part of the FBC Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 – 2018 which states that:

> *"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."*

329.3.1 If yes, please describe the currently-approved methodology used to allocate the Executive Management costs.

<u>Response:</u>

Please refer to the response to BCUC IR 2.329.3.

329.3.2 If no, please explain why FEI now believes it is appropriate to allocate Executive Management costs between FEI and FBC.

Response:

Please refer to the response to BCUC IR 2.329.3.

329.4 Please explain why FEI believes that the Massachusetts Formula is the most appropriate method for allocating Executive Management costs between FEI and FBC.

Response:

The Massachusetts formula is the most appropriate method to allocate Executive Management costs between FEI and FBC as it is will result in an appropriate and accepted allocation, while allowing for increased cost effectiveness of the approach (i.e. reduced administrative effort). The Massachusetts formula is a cost sharing methodology that is well established and generally accepted in other regulatory jurisdictions.

The Massachusetts formula is generally utilized when there is substantial sharing of costs between entities. Prior to 2012, not all the executives for FBC and FEI had joint responsibilities in both companies and, as such, allocating Executive Management costs based on the Massachusetts formula would have been less relevant. However, with all the executives for FBC and FEI having joint responsibilities in both companies effective January 1, 2012 and for the term of the PBR it is now appropriate and relevant to apply.

FEI and FBC have also used the Massachusetts Formula to allocate costs in previously approved revenue requirement applications. Corporate costs have been allocated from FHI to the FEU using the Massachusetts Formula for many years. Board of Directors costs have also been allocated from FHI to FEI and FBC utilizing the Massachusetts Formula since 2010. Therefore applying this same cost allocation methodology to Executive Management costs allows for consistency and familiarity.

329.5 Please provide the total number of hours and the cost of the Executive Management time proposed to be allocated between FEI and FBC using the

Massachusetts formula in 2014. Please provide the detailed calculation of this allocation.

Response:

The response to FBC's 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 FBC 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 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. 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 it 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.

329.6 How much would the Executive Management cost allocation be for 2014 if it was based on the approved cross charge process used for the sharing of all other resources between FEI and FBC? Please provide explanations for any differences in the amount of the cost allocation under this method versus the Massachusetts Formula.

Response:

Please refer to the response to BCUC IR 2.329.5.

329.7 Please provide the total charged from FEI to FBC and from FBC to FEI from 2010 through 2012 and year-to-date in 2013. Please also provide the projected total 2013 charge.

Response:

The sharing of executive costs between FEI and FBC 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 FEI and FBC 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 FEI and FBC 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.

The following table shows the dollar value of Executive labour costs allocated using the Time Estimate Methodology, which is the method used to allocate actual costs for 2010 to 2013:

Time Estimate Allocation for Executive Labour

	2010 Actual	2011 Actual	2012 Actual	2013 YTD*	2013 Projection
			($000s)		
Executive Cross charges allocated from FBC to FEI	433	879	1,331	1,149	1,379
Executive Cross charges allocated from FEI to FBC	(252)	(428)	(469)	(325)	(390)
Net difference charged to FEI	181	451	862	824	989

**through to the end of October 2013*

As requested in the BCUC IR 329.7.1, the following table shows the dollar value 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 YTD*	2013 Projection
			($000s)		
Executive Cross charges allocated from FBC to FEI	450	943	1,461	1,262	1,514
Executive Cross charges allocated from FEI to FBC	(311)	(487)	(406)	(272)	(326)
Net difference charged to FEI	139	455	1,055	990	1,188

**through to the end of October 2013*

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 YTD*	2013 Projection
Increase (Decrease) in Executive Labour cross-charges to FEI from applying Massachusetts Formula instead of Time Estimate allocation	$ (42)	$ 5	$ 193	$ 165	$ 198

**through to the end of October 2013*

Note that the cross charges are representative of the fully loaded Executive regular base pay (net of time away). To clarify the concept of fully loaded costs, this would include regular base pay (net of time away) plus a general benefits loading. Since FEI and FBC 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 percent and 77 percent 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. 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.

329.7.1 Please perform the same analysis but this time using the Massachusetts Formula.

Response:

Please refer to the response to BCUC IR 2.329.7.

329.8 Has the cost allocation methodology for sharing of resources between FEI and FBC been reviewed by an independent third party since it was implemented in 2010? If yes, please indicate when. If not, why not?

Response:

The cost allocation methodology used to share Executive costs between FEI and FBC since 2010 is the time estimate methodology. The methodology has not been reviewed by an independent third party; however, the Commission approved this cost allocation methodology for Executive Management costs in 2012 as described in the response to BCUC IR 2.329.3. The time estimate methodology is a straightforward and acceptable methodology for allocating costs when there is not substantial sharing or complex intercompany transactions; therefore, an independent third party is not required to validate.

330.0 Reference: ACCOUNTING POLICIES

Exhibit B-1, Tab D, Section 3.6.6, pp. 280-286; Exhibit B-1-1, Appendix F2

Corporate Services

FEI states in the Application: "While there has been a limited amount of change since 2009 in the Corporate Services costs, FEI has engaged KPMG to review the corporate costs." (p. 280)

330.1 Given that FEI has stated that there has been a limited amount of change, what prompted FEI to engage KPMG to review the corporate costs at this time?

Response:

While there has been limited amount of change to the Corporate Service costs for 2014 as compared to 2009, FEI engaged KMPG to validate the results and support the appropriateness of the allocations in determining the 2014 base O&M expense for the PBR period. The last external review was conducted in 2009 and FEI believes that it is appropriate to have this corroboration every few years, particularly when setting base O&M for a PBR period.

331.0 Reference: DEFERRALS

Exhibit B-1, Application, Tab D, Section 4.2.1, p. 293

Midstream Cost Reconciliation Account (MCRA)

FEI states in the Application: "US GAAP defines an alternative revenue program as a program that adjusts "billings for the effects of weather abnormalities or broad external factors or to compensate the utility for demand-side management initiatives (for example, no-growth plans and similar conservation efforts.)" (p. 293)

331.1 Please provide the US GAAP section and wording which outlines this requirement.

Response:

The relevant US GAAP guidance on revenue recognition for regulated operations is discussed in section 980-605-25 Revenue Recognition (emphasis added):

Alternative Revenue Programs

25-1 Traditionally, regulated utilities whose rates are determined based on cost of service invoice their customers by applying approved base rates (designed to recover the utility's allowable costs including a return on shareholders' investment) to usage. Some regulators of utilities have also authorized the use of additional, alternative revenue programs. The major alternative revenue programs currently used can generally be segregated into two categories, Type A and Type B.

25-2 Type A programs adjust billings for the effects of weather abnormalities or broad external factors or to compensate the utility for demand-side management initiatives (for example, no-growth plans and similar conservation efforts). Type B programs provide for additional billings (incentive awards) if the utility achieves certain objectives, such as reducing costs, reaching specified milestones, or demonstratively improving customer service.

25-4 Once the specific events permitting billing of the additional revenues under Type A and Type B programs have been completed, the regulated utility shall recognize the additional revenues if all of the following conditions are met:

a. The program is established by an order from the utility's regulatory commission that allows for automatic adjustment of future rates. Verification of the adjustment to future rates by the regulator would not preclude the adjustment from being considered automatic.

b. The amount of additional revenues for the period is objectively determinable and is probable of recovery.

c. The additional revenues will be collected within 24 months following the end of the annual period in which they are recognized.

The FEI MCRA account would fall into Type A of the alternative revenue programs described in the US guidance above. The MCRA allows FEI to adjust rates in the future due to past events such as weather abnormalities. The MCRA account must meet the three criteria discussed under ASC 980-605-25-4 in order for FEI to recognize the incremental revenue requirement under US GAAP. The first two criteria are satisfied; however, the third criterion requires that the incremental revenue be collected within 24 months following the end of the annual period in which they are recognized. The MCRA account is currently approved to be refunded or recovered in rates over a three year period; therefore, FEI does not meet the third criterion. However, since the MCRA is currently in a payable (credit) position, incremental revenue is not being recognized and revenue is instead being refunded to customers, therefore FEI is compliant under US GAAP at the present time.

Should the MCRA change to a position where it requires incremental revenue to recover the shortfall from customers, and that revenue is not recognized within 24 months, then FEI would not be able to recognize the revenue for financial reporting purposes under US GAAP. FEI has consistently tried to align the accounting periods for both regulatory accounting and financial reporting. Accordingly, FEI has requested that the additional revenues be collected within 24 months following the end of the annual period in which they are recognized.

331.2 Does FEI currently have any other deferral accounts which could potentially be subject to this US GAAP requirement? If so, please describe these deferral accounts and why FEI believes they may, in the future, be impacted by this US GAAP requirement.

Response:

FEI has undertaken a review of its existing deferral accounts and has not found any other deferral accounts which could be subject to the guidance described in the response to BCUC IR 2.331.1. If any such potential instances are identified in the future, FEI would propose the appropriate accounting treatment under US GAAP as part of the Annual Review process during the term of the PBR.

As discussed in BCUC IR 1.189.1, while the existing SCP Mitigation Revenues Variance account is not directly subject to the US GAAP requirement to modify the recovery period of the account, FEI is amenable to changing the amortization period to two years to align the recovery period with the other margin related deferral accounts which may be impacted by the US GAAP requirement.

332.0 Reference: ACCOUNTING POLICIES

Exhibit B-1, Application Tab D, Section 4.2.11, p. 291

Deferral Accounts – Energy Policy

332.1 Please provide a schedule and graph showing the FEI Mid-Year Balances for Energy Policy Deferral accounts from 2007-2018. Include the requested information in the form of a fully functioning electronic spreadsheet.

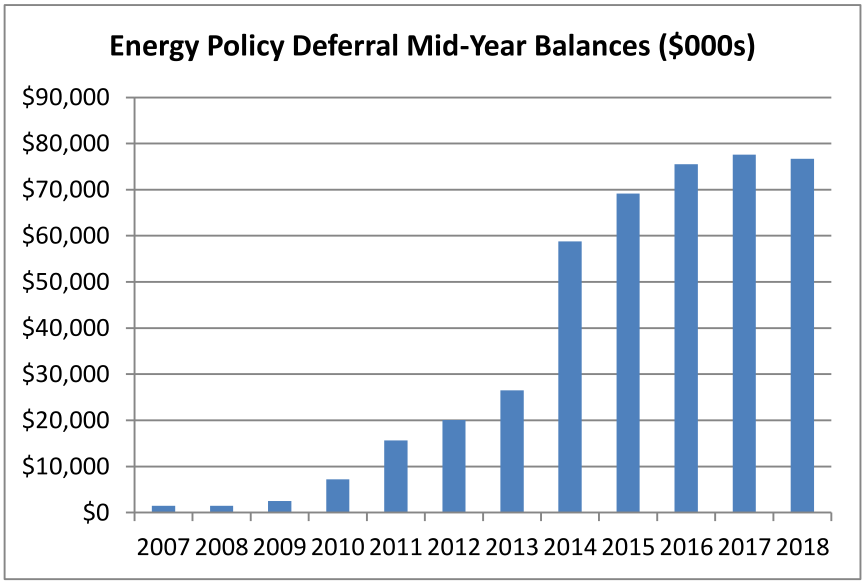
Response:

Please refer to the Attachment 332.1 for the fully functioning spreadsheet, which includes the 2007-2012 actual, 2013 projected and 2014-2018 forecasted FEI mid-year energy policy deferral account balances. The schedule and graph are also shown below.

FEI Energy Policy Deferral Accounts
Mid-Year Balances $000s (2007-2018)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	Actual	Actual	Actual	Actual	Actual	Actual	Projected	Forecast	Forecast	Forecast	Forecast	Forecast
Energy Efficiency and Conservation (EEC)	$1,331	$1,366	$2,375	$7,081	$12,639	$19,613	$26,078	$39,592	$45,182	$49,780	$53,391	$56,013
NGV Conversion Grants	$121	$111	$117	$101	$67	$39	$29	$20	$22	$28	$31	$37
NGT Incentives					$2,956	$0	$0	$18,860	$23,206	$25,083	$23,603	$20,188
Biomethane Program Costs						$420	$312	$150	$0	$0	$0	$0
2011 CNG and LNG Service Costs and Recoveries *						-$86	-$52	-$17	$0	$0	$0	$0
CNG and LNG Recoveries *						-$6	-$11	-$6	$0	$0	$0	$0
BFI Costs and Recoveries *						$74	$147	$0	$0	$0	$0	$0
Emissions Regulations						$0	$0	$0	$0	$0	$0	$0
On-Bill Financing Pilot Program							$0	$0	$512	$451	$390	$329
Fueling Stations Variance Account							$0	$228	$223	$213	$200	$125
Rate Schedule 16 Costs & Recoveries							-$26	-$26	$0	$0	$0	$0
Total Mid-Year Balances	$1,452	$1,477	$2,492	$7,182	$15,662	$20,054	$26,477	$58,801	$69,145	$75,555	$77,615	$76,692

* Classified as Residual Deferral accounts in 2014-2018 PBR



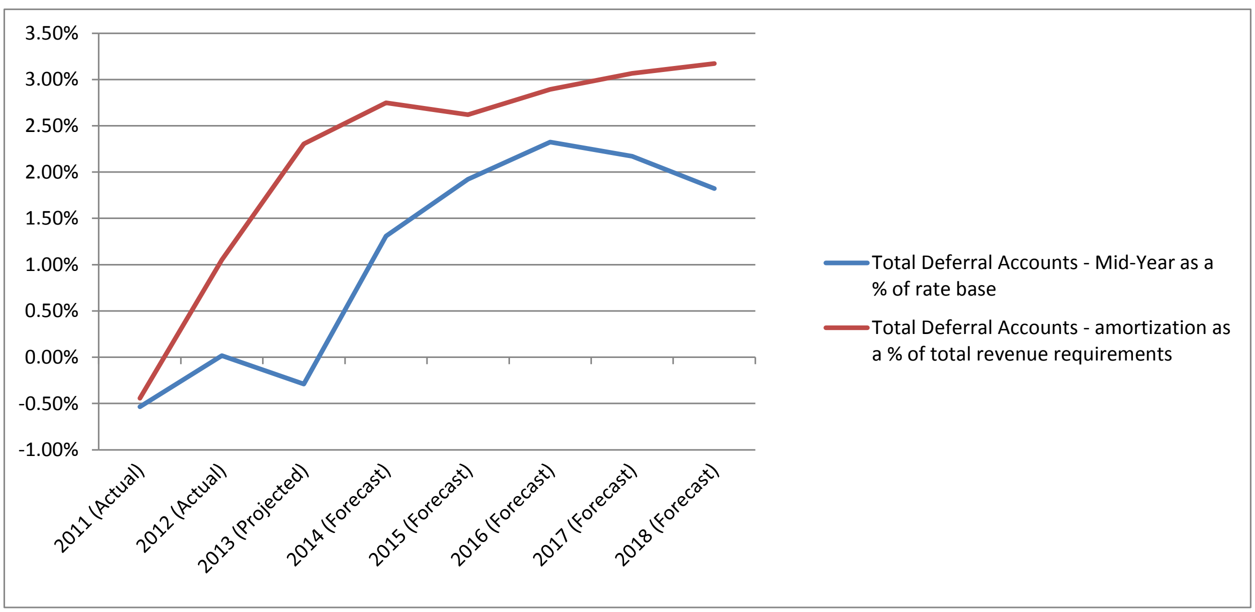
332.2 Using the same format as Exhibit B-1, Figure D4-1, p. 271, provide graphs of the Total Deferral Accounts - Mid-Year as a % of rate base (Table 2 of BCUC 1.170.1) and the Total Deferral Accounts – Amortization in (Table 4 of BCUC 1.170.1) . Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

FEI has provided updated versions of Tables 2 and 4 from BCUC IR 1.170.1 which include revised forecasts from the September 6th Evidentiary Update and show the rate base and revenue requirements lines separately. As well, FEI has provided a line graph showing the respective percentages of rate base and revenue requirements. Exhibit B-1, Figure D4-1 is a bar chart which shows total mid-year deferral balances by category and is not appropriate in this case considering two amounts are not being added together (i.e. mid-year deferrals should not be added to the entire rate base balance). Please also refer to Attachment 332.2 for the requested full functioning spreadsheet.

	2011 (Actual)	2012 (Actual)	2013 (Projected)	2014 (Forecast)	2015 (Forecast)	2016 (Forecast)	2017 (Forecast)	2018 (Forecast)
Total Deferral Accounts - MID YEAR ($000s)	$ (13,703)	$ 497	$ (7,813)	$ 36,486	$ 54,719	$ 67,336	$ 63,688	$ 53,986
Total Rate Base ($000s)	$2,563,640	$2,692,824	$2,702,240	$ 2,788,993	$ 2,845,893	$2,897,879	$2,933,369	$ 2,961,788
Total Deferral Accounts - Mid-Year as a % of rate base	-0.53%	0.02%	-0.29%	1.31%	1.92%	2.32%	2.17%	1.82%

	2011 (Actual)	2012 (Actual)	2013 (Projected)	2014 (Forecast)	2015 (Forecast)	2016 (Forecast)	2017 (Forecast)	2018 (Forecast)
Total Deferral Accounts - AMORTIZATION ($'000)	$ (5,269)	$ 11,847	$ 25,569	$ 30,632	$ 29,479	$ 33,136	$ 35,582	$ 37,473
Total Revenue($000s)	$1,190,447	$1,125,284	$1,108,844	$ 1,114,692	$ 1,124,853	$1,145,375	$1,160,147	$ 1,181,262
Total Deferral Accounts - amortization as a % of total revenue requirements	-0.44%	1.05%	2.31%	2.75%	2.62%	2.89%	3.07%	3.17%



333.0 Reference: ACCOUNTING POLICIES

Exhibit B-11, BCUC1.173.1

Deferral Accounts – Pension and OPEB Variance

333.1 Please provide the revised 2014 revenue requirements and the 2014 rate impact of using the currently approved 3-year amortization period versus the longer proposed 12-year period.

Response:

FEI includes below the response to BCUC IR 1.173.8 and further information on the revenue requirement impact.

> *"Compared to 2013 approved, the delivery rate increase for 2014 if the Pension and OPEB Variance deferral account continued to be amortized over three years would be 1.76 percent. However, by changing the amortization period to 12 years, the delivery rate impact has been reduced to 0.63 percent."*

Thus, using the currently approved 3-year amortization period would increase the 2014 delivery rate impact by 1.13 percent versus the longer proposed 12-year period. This equates to an additional $7.1 million in revenue requirement in 2014.

334.0 Reference: ACCOUNTING POLICIES

Exhibit B-1, Application Tab D, Section 4.2.11, p. 299

Deferral Accounts – Residual Delivery Rate Riders

"The consolidation of these deferral accounts into one account is consistent with the Commission's recognition in the 2012-2013 RRA Decision (at p.125) that 'combining three deferral accounts into a single Residual Delivery Rate Riders Deferral Account streamlines the account management of these deferral accounts.' "

334.1 To further streamline the management of deferral accounts, would it be appropriate to:

(a) 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:

FEI does not believe this approach is appropriate as FEI 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 FEI customers. If several deferral accounts all had debit balances of just under $1 million, the rate impact could potentially increase delivery rates up to 1.0 percent, depending on the existing approved amortization period for each account.

Lastly, FEI 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 FEI's control may serve to create rate fluctuations that are unnecessary and could more easily be managed under the existing policies.

(b) Eliminate deferral accounts for recurring non-controllable and using the average amortization for the past 5 years to determine the costs recoverable during the PBR? Please explain why, or why not. Also, provide a list of the recurring non-controllable deferral accounts.

Response:

FEI does not believe it would be appropriate to eliminate deferral accounts for recurring non-controllable amounts and use the average amortization for the past 5 years to determine the costs recoverable under the PBR.

There are several issues with this approach.

First, the amortization only returns to or recovers from customers variances between the amounts already embedded in revenue requirements and the actual amounts incurred. To simply include the average amortization of the deferral as the revenue requirement cost is incorrect as the forecast amount of the expense covered by the deferral account for each year would not be recovered, which is patently unfair. If the Commission's question is suggesting adding the average amortization to the expected forecast amounts for the category of expense pertaining to each deferral account, this would still not recover the actual costs incurred. The issue is the volatility in some of the existing deferral accounts. For example, FEI has seen pension costs increase substantially over the last several years. Given the risk associated with this forecast, it would be inappropriate to fix an increase to the pension costs based on the average amortization for the past 5 years, especially considering the volatility has created large additions to the account in the last two years which are not reflected in the amortization until 2014.

There is also an issue of fairness for both the customer and the utility. One of the reasons for establishing the deferral accounts is the recognition that these costs are beyond the control of the utility and therefore difficult to forecast accurately. Eliminating these deferral accounts would make variances from forecast a windfall to either the shareholder or customers. Maintaining deferral accounts for these non-controllable items serves to ensure for both parties that only the actual costs incurred are recoverable, and forecast risk is minimized.

If the approach proposed in the question was adopted, more regulatory process would be required and there would be more controversy related to establishing the appropriate forecast level of the expense category for each deferral account. Gains made in streamlining the management of deferral accounts would be lost to the additional regulatory process required to set forecast expense amounts and review the additional items that may now be viewed as potential exogenous factors.

The existing non-controllable deferral accounts are:

- Property Tax variances;
- Insurance variances;

- Pension & OPEB variances;
- BCUC Levies variances;
- Interest variances;
- Tax variances;
- Customer Service variances;
- Pension & OPEB Funding; and
- US GAAP Pension and OPEB Funded Status.

335.0 Reference: DEFERRALS

Exhibit B-1, Application, Tab D, Section 4.4.4, p. 306

CNG and LNG Recoveries

In the Application, FEI states, "The CNG and LNG Recoveries Deferral Account, approved by BCUC Order G-128-11, captured the incremental CNG and LNG fueling station recoveries received from fueling station volumes in excess of the minimum contract demand amounts embedded in the 2012 and 2013 revenue requirements. Effective January 1, 2014, given all stations are accounted for in a separate class of service, excess recoveries will be captured in the NGT classes of service and this account will be discontinued." (p. 306)

335.1 Please confirm, or explain otherwise, that the only deferral account to be discontinued is the Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG) Recoveries Deferral Account.

Response:

In reference to Section D4-4.4, FEI confirms that this is the only account to be discontinued.

However, as shown in Table D4-5 and discussed in sections D4.4.5 and 4.4.6 of the Application, FEI is also requesting to discontinue other NGT related deferral accounts. Specifically, the BFI Costs and Recoveries account, the Overhead and Marketing Recoveries from NGT Class of Service account and the 2011 CNG and LNG Service Costs and Recoveries account.

335.2 Please confirm, or explain otherwise, that this change in accounting results in the elimination of regular ratepayer risk for any costs, including for capital assets and property taxes.

Response:

The request to discontinue the CNG and LNG Recoveries Deferral Account is reflective of FEI's request to create separate classes of service for CNG and LNG stations. If the separate classes of service are approved, rate payers for other classes of service will not bear the cost risks, including capital assets and property taxes for fueling stations accounted for in the Non-GGRR CNG and Non-GGRR LNG Classes of service. In addition, the benefits of excess revenues of these stations (captured in the CNG and LNG Recoveries deferral account) will not flow to ratepayers for other classes of service.

As stated in Section 60.1 of the Utilities Commission Act:

> *"(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."*

To comply with this requirement, FEI has segregated all revenues and all costs to the separate classes of service for CNG and LNG stations.

335.3 Please confirm, or explain otherwise, that the prior years' additions to this deferral account include those recoveries of volumes in excess of the minimum contract demand amounts related to the Kelowna School District CNG service.

Response:

Pursuant to Order G-158-13, FEI will capture Kelowna School District revenue in excess of the minimum contract demand amounts from the year 2013 only in this account. Discontinuation of this account commencing January 1, 2014 as outlined in section D4.4.4 in the Application would be the proper treatment. Please refer to the response to BCUC IR 2.335.2 for further discussion.

BALANCED SCORECARD BENCHMARKING

336.0 Reference: BALANCED SCORECARD BENCHMARKING
Exhibit B-11, BCUC 1.191.1, p. 479
Financial Key Performance Indicators

FEI states that "FEI reviews the appropriateness of its scorecard measures periodically and makes adjustments as required. In evaluating potential changes to the scorecard categories and measures such as adding O&M per customer, Debt/Equity ratio and EBITDA to the financial KPIs, the Company seeks not only to select the appropriate success measures but also the optimal number of measures (i.e. how many). While the three referenced financial KPIs are not included in the overall Company scorecard, they are reflected in the financial category which is measured by Net Earnings. This measure for the financial category has been used consistently in previous versions of the FEU scorecard over the past number of years."

336.1 Does the use of net earnings alone result in the Company focusing primarily on profits whereas O&M/ customer focuses on both customer and shareholder interests? Please discuss.

Response:

The Net Earnings measure recognizes both the interests of customers and shareholder. As indicated in the response to BCUC IR 1.191.1, while an O&M per customer measure is not specifically included in the overall Company scorecard, it is reflected in the Net Earnings measure. To achieve the Net Earnings target, management takes action to ensure the approved controllable O&M costs that contribute to Net Earnings are appropriately managed. Under the proposed multi-year PBR agreement, O&M savings above the amount embedded in rates are shared equally between the Company and customers, leading to Net Earnings for the Company and helping to manage rates for the benefit of customers.

337.0 Reference: BALANCED SCORECARD BENCHMARKING

Exhibit B-11, BCUC 1.192.1, p. 480

Financial Key Performance Indicators

FEI states that "From 2000 to 2012, FEI conducted a Large Commercial Customer Satisfaction Study which surveyed Rate Schedule 3, 5 and 23 customers. The survey was discontinued due to declining participation rates especially among the Rate Schedule 5 customers. FEI has been working with a research vendor to design a replacement survey tool to obtain feedback from Industrial and Large Commercial customers about our energy efficient programs and general satisfaction with service."

337.1 Please provide the cost of and the date when the "survey tool" will be available and put into use.

Response:

FEI has spoken with several research vendors to understand how best to obtain feedback from Industrial and Large Commercial customers which is both measurable and actionable. FEI expects to issue a request for proposal before year-end with the tool anticipated to be available for use in the first quarter of 2014. FEI estimates the cost will be approximately $30,000, which will be managed within FEI's overall allowed formula-driven O&M.

338.0 Reference: BALANCED SCORECARD BENCHMARKING

Exhibit B-1, Section 3.1, Productivity Focus, pp. 11-13

Productivity Measures

> In 2012, the Company was able to achieve a number of efficiency successes. These included significant annual savings of approximately $9 million related to implementing a new manual meter reading contract. Starting in 2013, the new arrangement provides improved meter reading service at a lower cost than the previous arrangement.

(Exhibit B-1, p. 11)

338.1 Would **cost per meter read** be an appropriate productivity measure?

Response:

In response to the BCUC 2.338 series of questions, FEI's view is that the inclusion of a productivity improvement factor in FEI's PBR Plan provides a comprehensive productivity measurement that will require each department to consider continuous improvement, which is preferred to measurement of individual activity.

No, cost per meter read would not be an appropriate productivity measure because the cost per read is negotiated within the contract as a fixed transactional price and is set for the duration of the contract. As stated on page 150 of the Application, the new meter reading contract has already realized productivity gains by providing higher quality of service at a lower cost.

338.1.1 Please provide cost per meter read for 2011 (actual), 2012 (actual)

Response:

FEI does not have the cost per meter read for 2011. The agreement covering 2011 was based on a per customer per year basis rather than a per read basis. The average cost per meter read for 2012 was $1.8588.

338.2 What would be an appropriate productivity measure for improved meter reading service?

Response:

As this is an outsourcing arrangement, the most relevant measures of productivity are completion and accuracy. These are negotiated service metrics within the agreement.

> Streamlining and enhancement of processes contributed to increased productivity and provided increased service to customers. FEI reduced the customer wait time for installation of a new gas service not requiring a permit by implementing process changes. An on-line self-help Home

(Exhibit B-1, p.11)

338.3 Would **average wait time for new gas service** be an appropriate productivity measure?

Response:

Average wait time for a new gas service would not be an appropriate productivity measure. Customers and builders requiring new gas service may contact FEI a few days before the service is needed or several months before the service is needed. Generally speaking, FEI and the service requestor are able to mutually agree to the install commitment date that meets the needs of the customer and optimizes scheduling of either external or internal installation resources. The wait time could vary from a few days to a few months depending on the mutually agreed commitment date.

The wait time is not currently tracked at FEI for all services; however, the Company made process changes in 2013 to reduce the turnaround time for simple services not requiring permits so that it is possible to install a new service within ten days for customers who have not provided us with longer lead times. The average wait time for a new gas service is not considered a productivity measure but a customer service metric with considerable variability given the customer's requirements and the Company's installation resource considerations.

There is also variability in the wait time driven by geographical location and seasonality. Typically a crew will not be scheduled to one of the outlying towns such as Merritt until there is a sufficient number of new services to warrant the additional travel time from the main regional centres. In the Interior, there are also limitations and restrictions as to time of year when services can be safely and cost effectively installed given the weather and ground conditions. For example, in the Northern

Region, in areas such as Prince George and Quesnel, ground frost and snow usually prohibit service installations until the weather warms up.

338.4 Please provide the average wait time for new gas service for 2007-2013.

Response:

Please refer to the response in BCUC IR 2.338.3.

338.5 Would cost per new service addition by customer type and region be an appropriate productivity measure?

Response:

Inherent in FEI's proposed PBR formula and related productivity measure is "cost per addition" and as such there is little additional benefit gained from attempting to segregate this component from the broader PBR mechanism.

The difficulty with using a cost per new service addition by customer type and region is that there are a mix of service products having their own range of typical costs and over a hundred municipalities each having their own installation characteristics (permit and paving requirements, install conditions, distance from crew headquarters, etc.). Paving requirements and charges in Vancouver for example drive paving costs three times higher than Fraser Valley municipalities.

The preferred and internally used productivity metric for new service additions for internal crews is average install hours per service (refer page 236 of the Application, "Workforce Changes").

338.6 Please provide the cost per new service addition by customer type and region for 2007-2013.

Response:

The install cost for a new service addition by customer type (or rate class) for each region for 2007 to 2013 year-to-date is summarized in the table below:

	2007 Unit Costs	2008 Unit Costs	2009 Unit Costs	2010 Unit Costs	2011 Unit Costs	2012 Unit Costs	2013 Unit Costs
CENTRAL OKANAGAN AVERAGE	$ 787	$ 969	$ 1,336	$ 1,122	$ 1,277	$ 1,263	$ 1,129
RATE 1	$ 697	$ 850	$ 1,189	$ 1,022	$ 1,173	$ 1,161	$ 1,051
RATE 2	$ 3,270	$ 2,827	$ 2,637	$ 2,444	$ 2,780	$ 2,934	$ 2,421
RATE 3	$ 5,101	$ 6,306	$ 4,764	$ 7,599	$ 3,510		
RATE >3	$ 19,247						
EAST KOOTENAYS AVERAGE	$ 1,011	$ 1,061	$ 1,211	$ 1,293	$ 1,424	$ 1,798	$ 1,554
RATE 1	$ 984	$ 1,024	$ 1,137	$ 1,216	$ 1,404	$ 1,653	$ 1,450
RATE 2	$ 2,096	$ 1,460	$ 1,820	$ 2,661	$ 1,473	$ 3,412	$ 2,436
LOWER MAINLAND EAST AVERAGE	$ 1,170	$ 1,453	$ 1,481	$ 1,340	$ 1,583	$ 1,772	$ 1,996
RATE 1	$ 1,003	$ 1,213	$ 1,229	$ 1,219	$ 1,414	$ 1,516	$ 1,734
RATE 2	$ 5,334	$ 4,652	$ 5,044	$ 4,076	$ 4,825	$ 4,672	$ 5,043
RATE 3	$ 8,988	$ 12,077	$ 5,370	$ 8,725	$ 6,616	$ 4,480	$ 6,936
RATE >3	$ 26,834	$ 24,364	$ 22,598	$ 22,868	$ 8,161	$ 37,859	$ 28,575
LOWER MAINLAND WEST	$ 2,208	$ 2,361	$ 2,101	$ 1,965	$ 2,166	$ 2,371	$ 2,590
RATE 1	$ 1,832	$ 1,955	$ 1,762	$ 1,762	$ 1,954	$ 2,103	$ 2,337
RATE 2	$ 5,446	$ 4,263	$ 3,692	$ 3,979	$ 4,862	$ 4,836	$ 4,568
RATE 3	$ 5,813	$ 4,934	$ 6,027	$ 6,694	$ 4,927	$ 6,052	$ 5,437
RATE >3	$ 4,279	$ 7,230	$ -	$ 18,016	$ 9,457	$ 33,892	$ 79,736
NORTH OK Z4	$ 893	$ 963	$ 1,264	$ 1,658	$ 1,866	$ 1,911	$ 1,293
RATE 1	$ 844	$ 1,141	$ 1,079	$ 1,588	$ 1,496	$ 1,695	$ 1,200
RATE 2	$ 1,616	$ 260	$ 2,169	$ 2,814	$ 2,876	$ 2,811	$ 1,767
RATE 3	$ 3,111				$ 1,091		
NORTH OK Z5	$ 819	$ 1,030	$ 1,251	$ 1,067	$ 1,528	$ 1,371	$ 1,518
RATE 1	$ 761	$ 885	$ 1,126	$ 1,006	$ 1,331	$ 1,215	$ 1,423
RATE 2	$ 1,712	$ 2,953	$ 6,480	$ 1,570	$ 3,344	$ 2,422	$ 1,546
RATE 3	$ 1,776	$ 8,899	$ 2,307		$ 4,239		
RATE >3					$ 7,246	$ 4,114	
NORTHERN REGION	$ 1,528	$ 1,697	$ 1,869	$ 2,207	$ 2,141	$ 1,900	$ 2,064
RATE 1	$ 1,271	$ 1,378	$ 1,470	$ 1,650	$ 1,459	$ 1,759	$ 1,725
RATE 2	$ 2,690	$ 4,176	$ 4,003	$ 7,660	$ 11,068	$ 2,638	$ 3,040
RATE 3	$ 25,938	$ 4,822	$ 5,117				
RATE >3				$ 35,105			
SOUTH OKANAGAN	$ 1,386	$ 1,469	$ 1,749	$ 1,479	$ 2,007	$ 2,465	$ 2,232
RATE 1	$ 1,250	$ 1,228	$ 1,599	$ 1,293	$ 1,771	$ 2,273	$ 1,707
RATE 2	$ 2,369	$ 3,972	$ 2,816	$ 2,486	$ 2,441	$ 3,870	$ 4,130
RATE 3	$ 3,346	$ 6,100			$ 5,189		
THOMPSON	$ 1,096	$ 1,325	$ 1,646	$ 1,292	$ 1,529	$ 1,449	$ 1,441
RATE 1	$ 1,039	$ 1,227	$ 1,439	$ 1,168	$ 1,324	$ 1,341	$ 1,345
RATE 2	$ 2,401	$ 2,518	$ 2,839	$ 2,275	$ 3,595	$ 3,568	$ 2,370
RATE 3	$ 1,258		$ 3,646	$ 8,079			
WEST KOOTENAYS	$ 1,402	$ 1,499	$ 1,787	$ 2,078	$ 2,092	$ 2,447	$ 1,864
RATE 1	$ 1,305	$ 1,339	$ 1,670	$ 1,860	$ 1,916	$ 1,962	$ 1,609
RATE 2	$ 2,402	$ 7,915	$ 2,619	$ 5,506	$ 3,523	$ 4,959	$ 1,524
RATE 3			$ 3,325	$ 3,174			

Energy Calculator was introduced allowing residential customers the ability to compare energy costs of operating home appliances at the customers' convenience while reducing the amount of support required from customer service staff. The meter exchange process was improved using live-agent calls, in addition to letters, which led to increased customer satisfaction with the process as well as increased efficiency. Process enhancements in the GIS area have enabled

(Exhibit B-1, p. 11)

338.7 Would **number of support calls per customers** be an appropriate productivity measure?

Response:

No, FEI does not believe that the number of support calls per customer would be an appropriate productivity measure. In some cases, such as the example of the meter exchange process described in the excerpt above, productivity can be achieved by **increasing** the number of calls received from customers. FEI believes that an important part of customer satisfaction and an efficient operation is maintaining an open dialogue with customers and promoting availability of information through a choice of channels. For this reason, it is not a goal of FEI to reduce interactions with customers.

338.8 Please provide the **number of support calls per customers** for 2007-2013.

Response:

FEI has interpreted "number of support calls" to be the inbound calls received and the outbound calls made from FEI's contact center. The 2007 – 2011 data is from Accenture when the service was outsourced, while the 2012 and 2013 YTD data is related to FEI's new contact center operations. 2013 YTD includes calls up to the end of September.

Year	# Inbound and Outbound Calls
2007	1,153,231
2008	1,161,219
2009	1,012,568
2010	889,151
2011	977,578

Year	# Inbound and Outbound Calls
2012	1,499,294
2013 YTD	1,043,734

338.9 Would number of customer complaints per customer be an appropriate productivity measure?

Response:

Complaints are generally related to a real or perceived issue with service quality rather than operational inefficiency and as such the number of customer complaints per customer would not be an appropriate productivity measure.

338.10 Please provide the number of customer complaints per customer for 2007-2013.

Response:

FEI recognizes that the question asks for a breakdown of complaints per customer for this period of time; however FEI believes that due to the low number of complaints, a complaint per customer calculation would be meaningless. The information is best represented using total number of complaints.

Below is the number of formal complaints to the BCUC for the period from 2007 to 2013.

Performance Indicator	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Sep YTD
Number of Customer Complaints to BCUC	130	90	58	26	3	3	1

338.11 Would **cost or time per meter exchange** be an appropriate productivity measure?

Response:

Time per meter exchange is currently monitored internally. Cost per meter exchange is a financial measure and due to different labour and vehicle charge-out rates between regions does not lend itself as an appropriate productivity measure.

338.12 Please provide the **cost and time per meter exchange** for 2007-2013.

Response:

Two basic types of meter exchange are residential and industrial. Within the industrial category there are three different sub-types of exchanges (instrument drive sets, inches sets and PFM sets). Exchange times vary between types and the mix of industrial meters by sub types varies from year to year according to maintenance plans.

The following tables summarize the unit cost to complete the exchange and the labour duration or time to complete the exchange. The labour duration also includes the travel time to the job.

Industrial Meter Exchange		
Unit Cost & Duration		
2007 - 2013 Oct YTD		
Year	**Unit Cost $**	**Duration (Hrs)**
2007	296	3.10
2008	272	2.75
2009	269	2.87
2010	287	2.84
2011	269	2.86
2012	273	2.67
2013	269	2.65

Residential Meter Exchange		
Unit Cost & Duration		
2007 - 2013 Oct YTD		
Year	Unit Cost $	Duration (Hrs)
2007	67	0.88
2008	64	0.77
2009	76	0.90
2010	76	0.81
2011	81	0.94
2012	83	0.97
2013	89	1.01

process as well as increased efficiency. Process enhancements in the GIS area have enabled faster drawing production in support of distribution main expansions and alterations and more efficient use of resources. Simplification of various physical processes within Materials Services contributed to reduced cycle times.

(Exhibit B-1, p. 11)

338.13 What would an appropriate productivity measure be for distribution main extensions / alterations (i.e. to report on costs and/or time to complete)?

Response:

Cost per metre is currently used internally by the Company as an overall financial measure for new main extensions; however it is less relevant with main alterations as the latter type of work is not high volume repetitive type work. Even using the current cost per metre metric as a productivity metric for new mains work has limited value, as 80 percent of the work is completed by external contractors whose pricing is established through a regular competitive bid process.

Main extensions and alterations have a number of different attributes including location, diameter of pipe, length of extension or alteration, pressure, type of material, municipal requirements and installation workforce. FEI does not believe there are practical productivity measures for main extension or alteration work as the variables above limit the comparability of one project to another. Each project is unique and activity volumes are not generally high, particularly in some geographic areas which do not see a volume of consistent repetitive activity.

FEI believes the financial measure currently in place (dollar/metre) is the most suitable metric for this type of work particularly when most of the work is completed by an external workforce.

338.14 Please provide the distribution main extensions / alterations report on costs (forecast, actual and variance) and time to complete for 2007-2013.

Response:

Please refer to the annual Main Extension Summary Report submitted in Attachment 187.1 provided in response to BCUC IR 1.187.1 (Exhibit B-11-1).

There is no current reporting in place which summarizes "time to complete" mains work. Each mains project would have a different completion time ranging anywhere from one month to two years depending on the requestor, commitment date, phased installations, timing of parallel construction work, resource availability, weather conditions, and municipal restrictions.

> Productivity gains from leveraging technology include enhancements in support of the BC One Call process which resulted in significant productivity gains and provides the Company the ability to respond faster to customer inquiries. In the supply chain services, business processes were simplified using automation.

(Exhibit B-1, p. 11)

338.15 What would an appropriate productivity measure be for response times to customer inquiries on line locates and incident response times?

Response:

Line Locates:

As a general rule, FEI does not provide physical on-site line locates for requestors unless the requestor has gone through the BC One Call process, obtained the gas plant records information and has made an attempt at locating the pipe themselves or there is some confusion with the records provided by the Company as a result of the BC One Call request.

The requestor of the BC One Call service can then contact FEI to have a technician or qualified person attend the field site to assist with the line locate. Each request is unique and response time varies depending on time of day, location, urgency and resources available. Response times for these field site visits are generally same day but can range from 15 minutes to two days depending on the circumstances. There is no current reporting in place to track overall response times for these types of line locate verifications.

Incident Response Times:

For incident response times, which FEI has interpreted to mean emergency response times, please refer to Exhibit B-11-1, Appendix D7 of the Application, page 6 , Table D7-4 for a summary of average emergency response times (in minutes). The 2010-2012 average was 20.3 minutes. FEI does not consider this to be a productivity measure so much as a safety and customer service measure. It is, however, the most relevant metric for this category of work and is used internally to assess resource and emergency response capacity.

338.16 Please provide the response times to customer inquiries on line locates and incident response times for 2007-2013.

Response:

Please refer to the responses in BCUC IRs 2.338.15 and 2.341.9.

Integration with the electric business enabled certain efficiencies to be achieved. Integration driven opportunities involved a common management team, common processes and sharing of resources. Additionally, integration driven efficiencies were not only focused on lowering costs

(Exhibit B-1, p. 11)

338.17 Please provide total overhead including management cost for each of FBC and FEI before the integration and after. Have the integration and efficiency gains from this effort been completed?

Response:

Please refer to the following table.

$000s	2010 Actuals (2012 dollars)	2012 Actuals (2012 dollars)
FBC	22,729	22,487
FEI	84,896	84,604
Total	107,624	107,091

For the purpose of this response, overhead costs for each of FBC and FEI have been defined to include the following departments' O&M costs:

- Information Technology;
- Engineering Services & PM;
- Operations Support;
- Facilities;
- Environment Safety and Health;
- Finance and Regulatory;
- Human Resources;
- Governance; and
- Corporate.

Integration efforts have not been completed and are ongoing as described in Exhibit B-1 and the responses to CEC IRs 2.10.1 and 2.10.4.

Data for the years 2010 and 2012 have been provided for comparison as 2010 was the start of integration activities. For comparison, 2012 costs have been provided and the 2010 costs have been inflated to 2012 dollars to provide for consistent comparison of the two years. Overall, the combined overhead costs for FBC and FEI have declined from 2010, after adjusting for inflation, indicative of productivity efficiencies.

> but also on increasing the capacity of both the gas and electric businesses and providing employee growth and development opportunities.

(Exhibit B-1, p. 12)

338.18 Would employee turn-over rate be an appropriate measure of productivity? I.e. would a reducing employee turn-over indicate greater employee satisfaction and does employee satisfaction relate to productivity?

Response:

All of the elements mentioned here (i.e. employee turnover, employee satisfaction, and employee productivity) are impacted by many factors. It is difficult to identify one of these elements as being an appropriate measure over the other, because there are other variables that affect them as well. For example, while some employee turnover may be attributed to employee satisfaction, turnover is also impacted by employees' personal circumstances (e.g. a decision to return to school or a move to another city). Likewise, employee satisfaction may have some impact on productivity; however, factors such as workplace tools and processes and employee health may also play a role.

Please refer to the responses to CEC IR 1.1.1 and BCUC IR 2.338.20 where FEI provides further discussion on use of productivity metrics.

> For 2013, sharing of labour resources between the gas and electric businesses is forecasted at a net amount of approximately $0.5 million, with approximately $2.5 million being allocated from gas to electric and approximately $3 million from electric to gas. The forecasted labour dollars represent sharing of labour resources between the different gas and electric departments.

(Exhibit B-1, p. 12)

338.19 Does the above statement mean that by sharing labour resources between the gas and electric businesses there is a net increase of $0.5 million?

Response:

The sharing of labour resources does not mean there is a net increase of $0.5 million in gas utility costs and is not a contributor to the cost of service for gas customers. Instead, the $0.5 million represents just the net difference between the amounts of labour resources shared between gas and electric. While the gas utility may have received $3 million in costs from electric, this is offset in the gas business by a combination of items including the replacement of the use of consultant/contractor labour and existing vacant positions. The same type of offsets have occurred in the electric business in relation to the $2.5 million in costs received from gas. Overall, costs have decreased because of integration.

338.19.1 Assuming there are some savings (not increase) in costs of sharing labour resources what is the forecast amount of savings from this activity?

Response:

FEI does not have a forecast amount of savings from sharing of labour resources between the Gas and Electric businesses. Please refer to the responses to BCUC IRs 2.277.1, 2.277.1.1 and 2.277.2 for discussion on integration savings.

Please also refer to the response to BCUC IR 2.338.19.

338.19.2 Would total **labour expense per customer** be an appropriate productivity measure?

Response:

Total labour expense per customer would not be an appropriate productivity measure, as labour expenses are impacted by a variety of factors, including:

- Rate of pay of the employee performing the work, both in terms of wage rate and straight-time or overtime;

- Whether the work is easy to access;
- Number of employees performing work;
- Amount of time to complete the work;
- Geographic location of the work; and
- Variations in the use of contractors and shared/integrated services replacing direct labour costs.

Please also refer to the response to BCUC IR 2.338.18.

> Productivity gains and efficiency review activities will continue in the future, similar to the path followed in 2012, with the emphasis on managing costs and working more efficiently and effectively.

(Exhibit B-1, p. 13)

338.20 Would measuring and reporting on specific productivity measures allow the companies to monitor the effectiveness of its cost management and efficiency improvements into the future?

Response:

This response contains information relevant to PBR and non-PBR issues and will therefore be also submitted with the PBR Methodology IR responses.

FEI believes productivity 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. This is in compliance with Commission Order G-44-12 which stated at page 40: The Commission Panel further directs the FEU to file a Productivity Improvement Plan with their next revenue requirements application. **The Productivity Improvement Plan may take the form of a proposal for PBR** which places emphasis on both-short term activities as well as long term, sustainable improvements. [emphasis added]

In addition to this response where a recap of FEI's position on the subject of productivity is provided, FEI refers to the discussion on page 21 of Exhibit B-1 on the use of productivity metrics in the utility industry to provide further context on FEI's position on use of productivity metrics in the company.

In general, the research showed a wide disparity in the use of productivity metrics for performance measurement in the utility industry with a wide range of metrics used. Additionally, the research showed that "it is likely that most utilities are not measuring productivity across a large portion of their activities and costs. The productivity metrics are generally not benchmarked and regularly reported to regulators." The situation described summarizes the challenges of determining what and how many metrics to use to measure performance in a company. This challenge and disparity in choices is evidenced by the number of possible different metrics suggested in the information requests received to date regarding the company's Application.

FEI's use of productivity metrics is consistent with its industry peers. Some departments may use metrics to manage performance while others do not. What is common amongst all departments in FEI is that they are required to maintain or increase their outputs and activity levels while keeping cost increases to a minimum. To hold departments and managers accountable for this, they are asked to identify and reflect productivity gains in their budgets. Meeting budgets is an expectation of all departments and managers in the company. FEI believes this approach to ensuring a productivity focus is sustained throughout the company and will deliver the efficiencies that both the company and customers are looking for under the proposed PBR Plan. The focus should not necessarily be on how the efficiencies are achieved (i.e. monitored using metrics for different areas) and instead should be on ensuring that they are achieved with the respective savings benefiting customers and the company.

In addition, regardless of whether the efficiencies realized are short-term or sustained over the long-term, customers benefit in both scenarios under the proposed PBR Plan. There will be situations where the savings are short-term and justified. For example, to realize possible efficiencies, vacancies from staff turnover in the company are filled only after reviewing the positions and determining how best to staff the vacant positions. As a result, there may be some short-term savings in the delay in hiring. These actions taken by the company benefit customers by delivering short-term savings and ensuring over the longer term resources are managed effectively.

FEI's view is that the inclusion of a productivity improvement factor in FEI's PBR Plan provides a comprehensive productivity measurement that will require each department to consider continuous improvement, which is preferred to measurement of individual activity. Additionally, the need for detailed productivity metrics is lessened by the fact that FEI has put forward a realistic and appropriate 2013 Base O&M budget which reflects substantial productivity savings relative to previous years and yet still ensures safety standards and other service requirements are met.

FEI expects that the proposed 2013 Base O&M budget along with its proposed approach to productivity measurement, which is consistent with that successfully used in the past approved PBR Plan, will work to successfully deliver efficiencies and benefits for customers and the Company.

Please also refer to the responses to CEC IRs 1.1.1 and 1.1.5.

338.21 What if FEI had a project that would improve productivity and the cost to implement the project was greater than $5 million such as Advanced Meters. Would FEI apply for a CPCN (to have costs recovered outside the PBR while still sharing in the productivity benefits expected from the project)?

Response:

Please refer to the response to the BCUC IR 2.305.2.

338.22 Should any CPCN brought forward in the PBR include a detailed estimate of O&M or other savings that should be removed from the PBR formula? Please justify or provide evidence for the response.

Response:

Please refer to the response to the BCUC IR 2.305.1.

LONG TERM SUSTAINMENT PLAN (LTSP)

339.0 Reference: LONG TERM SUSTAINMENT PLAN (LTSP)

Exhibit B-1, p. 215

Development Costs

> The LTSP project team created a methodology to evaluate, for each asset, the relative probability and consequence of failure which together reflects the level of relative risk present in FEI's assets. The relative probability, consequence and risk are expressed by means of a numerical score calculated via customized criteria evaluating possible failure modes and causes. The LTSP analysis was made possible using Geo-Spatial Analysis (GSA) software developed by General Electric, and a custom Microsoft Access Database application. The GSA software is capable of extracting data from FEI's Geographical Information System in real-time, as well as data from other enterprise systems and records. The data input into the risk assessment is objective and represents the most current available information, supplemented by manual analysis where necessary. The team also undertook a validation process on the methodology, tools and results of the LTSP with operations and engineering staff. FEI believes that the results of the assessment are a reasonable representation of the current condition of FEI's system. Please refer to Appendix C3 for detailed information.

339.1 From the above, it would appear that the development of the LTSP (methodology, analysis, software, database, primary validation and assessment) is significantly complete. Please confirm or clarify the stage of completion of the development of the LTSP.

Response:

FEI confirms that the development of the first iteration of the LTSP (methodology, analysis, software, database, primary validation and assessment) is complete, has been implemented, and is currently being operationalized as an additional tool by the Asset Management department in the development of longer-term capital plans.

339.1.1 Please describe the planned ongoing LTSP improvements and expected frequency for re-running assessments.

Response:

FEI intends to re-run the risk assessments on an annual basis or as required, and implement improvements to the risk model as appropriate. Information regarding FEI's natural gas delivery system flows through the Asset Management department on a daily basis, and it is through analysis, research, and discussion of such information that improvements to the LTSP are derived. Therefore, the risk model will be updated with this information as appropriate. FEI considers the LTSP to be operating under a continuous improvement model, and improvements may be put forward at any time throughout the year.

339.2 What was the total cost for development of the LTSP including applications, software, FTE's etc. in 2012 and 2013 and show how this cost is allocated between departments and groups?

Response:

The total cost for development of the LTSP methodology, which was completed in 2012, including applications, software, FTE's etc., was $865 thousand. Within the Activity View of O&M, the costs have all been reflected as Systems Planning within Engineering Services & Project Management.

The initial development of the LTSP methodology and software has been completed. Further costs incurred will be consistent with those for other business processes including costs associated with the collection of incremental asset data to support risk assessment refinements, development of asset mitigation and project plans, and also implementation of continuous improvements to the LTSP methodology. Please refer to the response to BCUC IR 2.263.2.1.

339.3 Is it reasonable to expect that the costs and resources required in the ongoing implementation of the LTSP will be significantly less than the costs to develop the LTSP?

Response:

As discussed in Appendix C-3, Page 3 of the FEI 2014-18 PBR Application, as the long-term planning is operationalized the LTSP will cease to be a standalone initiative and simply be a part of the overall asset management program and ongoing system planning. Going forward, the overall budget for the LTSP is not expected to be significantly less than the costs to develop the LTSP, as resources will be re-allocated from development of the LTSP to other areas such as conducting condition assessments of assets, developing more detailed asset mitigation plans, and also implementing continuous improvements to the LTSP methodology.

339.3.1 Please provide a forecast of the expected operational savings from implementation of the LTSP methodology and access to the information to used undertake analyses.

Response:

FEI does not anticipate operational savings as a result of the implementation of the LTSP. The program was implemented to improve the understanding of asset condition and to provide decision making support for Asset Management personnel. It helps ensure that resources are invested appropriately and in the best interest of the customers and other stakeholders.

340.0 Reference: LONG TERM SUSTAINMENT PLAN (LTSP)

Exhibit B-1, Application, Tab C, Section, p. 267; Exhibit B-1-1, Appendix C3, p. 2; Exhibit B-11, BCUC 1.195.3 & 198.1, pp. 485 & 488

PE Pipe depreciation

In BCUC 1.195.3, FEI states that "In 2012, FEI amended its depreciation rate for Transmission Pipeline (account 465) from 60 years to 65 years.

Please refer to page 267 of Exhibit B-1 which states, "FEI will provide an updated depreciation study during the term of the PBR Period and anticipates that, subject to Commission approval, any updated depreciation rates would be implemented during the term of the PBR. This will address concerns from the 2004 Plan regarding asset losses that accumulated as a result of the approved depreciation rates being lower than the asset lives for the duration of the previous PBR period. Second, FEI will continue to update its estimate of asset losses on an annual basis throughout the PBR Period for review by the Commission." (Exhibit B-1, p. 267)

At the same time when the next depreciation study is undertaken, FEI will review the issue identified of potentially longer lives for both steel and PE pipe."

And "Polyethylene pipe (PE) was expected to last 35 to 40 years when it was first installed in the early 1980s. However, samples of PE of this age removed from service in 2011 were tested by an independent laboratory and showed no degradation in their performance." (Exhibit B-1-1, p. 2)

340.1 What is the current depreciation life for PE Pipe?

Response:

The estimated service lives and resulting depreciation rates are determined by asset classes such as Transmission Pipeline and Distribution Mains and not solely by the type of pipe (i.e. PE, steel). In determining the recommended service lives and depreciation rates of assets, Gannett Fleming, an external depreciation specialist who prepared the recent deprecation study for the FEU, performed a number of activities including reviewing the FEU's assets and retirement transactions, conducting operational interviews with the FEU staff and comparing the results to the FEU's industry peers.

Based on the recent depreciation study prepared by Gannett Fleming for the 2012-2013 RRA included as Appendix E1 to that application, the estimated service life of Transmission Pipeline (BCUC Account 465) and Distribution Mains (BCUC Account 475) is approximately 60 – 65 years. The types of pipe captured in these accounts include steel and PE.

Please refer to the table below which was included as Table 5.4-1 in FEI's 2012-2013 RRA and shows the depreciation rates for asset classes 465 and 475:

Table 5.4-1: FEI - Impact of Implementing Recommended Depreciation Rates

Line #	Class	Description	Existing 2011 Rate	Recommended 2012 Rate	Depreciation Based on 2011 Rate	Depreciation Based on 2012 Rate	Increase +/ Decrease -
1	175-00	Unamortized Conversion Expense *	1.0%	1.0%	7,770	7,770	-
2	401-01	Franchises and Consents	19.76%	49.19%	19,609	48,814	29,205
3	402-01	Computer S/W-Applic 8 Year	12.50%	12.50%	5,052,518	5,052,518	-
4	402-02	Computer S/W-Applic 5 Year	20.00%	20.00%	3,375,631	3,375,631	-
5	402-03	Intangible Plant	2.14%	2.38%	14,714	16,364	1,650
6	402-11	Plant Acquisitions and Adjustments	23.66%	57.14%	14,777	35,688	20,910
7	432-00	Mfg. Gas Structures	3.28%	3.38%	15,203	15,667	464
8	433-00	Mfg. Gas Equipment	6.30%	6.63%	9,194	9,676	482
9	434-00	Mfg. Gas Holders	3.90%	2.35%	13,946	8,403	(5,543)
10	436-00	Mfg. Gas Compressor Equipement	4.96%	5.16%	2,644	2,751	107
11	437-00	Mfg. Gas Meas/Reg Equipment	19.50%	15.89%	60,342	49,171	(11,171)
12	442-00	LNG Gas Structures	3.65%	3.57%	181,020	177,053	(3,968)
13	443-00	LNG Gas Equipment	2.18%	1.93%	359,570	318,335	(41,235)
14	449-00	LNG Gas Other Equipment	3.36%	4.24%	896,611	1,131,438	234,827
15	462-00	TP Compressor Structures	3.84%	3.74%	565,585	550,856	(14,729)
16	463-00	TP Meas/Reg Structures	4.27%	3.80%	229,706	204,422	(25,284)
17	464-00	TP Other Structures	2.88%	2.83%	173,211	170,204	(3,007)
18	465-00	TP Transmission Pipeline	1.63%	1.44%	12,823,038	11,328,328	(1,494,710)
19	465-00	TP Mains - Inspection *	14.87%	14.87%	608,683	608,683	-
20	465-10	TP Mains - Byron Creek *	5.00%	5.00%	48,525	48,525	-
21	466-00	TP Compressor Equipment	3.18%	2.87%	3,516,218	3,173,442	(342,776)
22	466-00	TP Compressor Equipment - Overhauls *	4.47%	4.47%	102,160	102,160	-
23	467-10	TP Meas/Reg Equipment	7.19%	4.27%	2,073,508	1,231,416	(842,092)
24	467-02	TP Telemetry Equipment	1.33%	0.31%	87,493	20,393	(67,100)
25	467-20	TP Meas/Reg Equipment - Byron Creek *	4.01%	4.01%	1,553	1,553	-
26	468-00	TP Communications Equipment	5.32%	4.37%	18,401	15,115	(3,286)
27	472-00	DS Structures	3.60%	3.33%	572,054	529,150	(42,904)
28	472-10	DS Structures - Byron Creek *	5.00%	5.00%	5,362	5,362	-
29	473-00	DS Services	2.25%	2.29%	15,440,032	15,714,521	274,489
30	473-01	LILO DS Services	2.20%	5.91%	946,515	2,542,683	1,596,168
31	474-00	DS Meters/Regulators Installations	5.21%	7.44%	7,871,078	11,240,081	3,369,003
32	474-01	LILO DS Meters/Regulators Installations	2.19%	3.72%	351,936	597,809	245,873
33	474-02	DS Meters/Regulators Installations New	4.55%	4.55%	-	-	-
34	475-00	DS Mains	1.89%	1.48%	16,899,394	13,233,388	(3,666,006)
35	475-01	LILO DS Mains	2.00%	4.54%	794,352	1,803,178	1,008,826
36	476-00	DS NGV Fuel Equipment	25.04%	26.54%	256,993	272,388	15,395
37	477-00	DS Telemetering *	0.25%	0.25%	16,235	16,235	-
38	477-10	DS Meas/Reg Additions	5.72%	4.75%	5,037,554	4,183,284	(854,271)
39	477-30	DS Meas/Reg Equipment	0.00%	0.00%	-	-	-
40	478-01	DS Meters	5.31%	7.89%	10,611,070	15,766,731	5,155,661
41	478-11	LILO DS Meters	3.29%	5.23%	329,879	524,398	194,518
42	478-20	DS Instruments	4.03%	3.15%	463,480	362,273	(101,207)
43	472-00	Biogas - Structures and Improvements *	3.60%	3.60%	-	-	-
44	475-10	Biogas - Mains - Municipal Land *	1.48%	1.48%	-	-	-
45	475-20	Biogas - Mains - Private Land *	1.48%	1.48%	4,907	4,907	-
46	418-10	Biogas - Purication Overhaul *	13.33%	13.33%	62,354	62,354	-
47	418-20	Biogas - Purification Upgrader *	6.67%	6.67%	124,802	124,802	-
48	474-10	Biogas - Reg and Meter Installations *	5.21%	5.21%	34,546	34,546	-
49	478-30	Biogas - Meters *	5.31%	5.31%	23,710	23,710	-
50	476-10	NGV - Transport CNG Dispensing Equipment *	5.00%	5.00%	102,910	102,910	-
51	476-20	NGV - Transport LNG Dispensing Equipment *	5.00%	5.00%	87,615	87,615	-
52	476-30	NGV - Transport CNG Foundations *	5.00%	5.00%	22,720	22,720	-
53	476-40	NGV - Transport LNG Foundations *	5.00%	5.00%	19,305	19,305	-
54	476-50	NGV - Transport LNG Pumps *	10.00%	10.00%	83,160	83,160	-
55	476-50	NGV - CNG Dehydrator *	5.00%	5.00%	8,019	8,019	-
56	476-70	NGV - LNG Dehydrator *	5.00%	5.00%	-	-	-
57	482-10	GP (Frame) Structures	3.67%	4.82%	298,520	392,061	93,542
58	482-20	GP (Masonry) Structures	2.50%	2.23%	2,159,032	1,925,856	(233,175)
59	482-30	GP (Leased) Structures *	10.00%	10.00%	26,071	26,071	-
60	483-10	GP Computer Hardware	20.00%	20.00%	4,211,342	4,211,342	-
61	483-20	GP Computer Systems Software	12.50%	12.50%	243,739	243,739	-
62	482-21	GP Computer Systems Software	20.00%	20.00%	0	0	-
63	483-30	GP Office Equipment	6.67%	6.67%	239,110	239,110	-
64	483-40	GP Furniture	5.00%	5.00%	970,903	970,903	-
65	484-00	GP Vehicles	7.70%	5.16%	99,560	66,718	(32,842)
66	485-10	GP Heavy Work Equipment	6.64%	8.96%	18,148	24,489	6,341
67	485-20	GP Heavy Mobile Equipment	8.48%	18.06%	86,792	184,842	98,050
68	486-00	GP Small Tools/Equipment	5.00%	5.00%	2,039,639	2,039,639	-
69	487-20	GP NGV Cylinders	6.67%	6.67%	587	587	-
70	488-10	GP Telephone Equipment	6.67%	6.67%	520,793	520,793	-
71	488-20	GP Radio Equipment	6.67%	6.67%	303,246	303,246	-
72		Total Annual Depreciation			101,659,094	106,219,301	4,560,207
73							
74		Annual Composite Rate			3.0%	3.1%	
75							
	* Numbers above are in actual dollars with depreciation calculated using the January 1, 2012 gross asset values.						

340.2 Why wasn't the depreciation life of PE Pipe extended in 2012 when the Transmission pipe depreciation rate was adjusted?

Response:

The Gannett Fleming depreciation study prepared for the 2012-2013 RRA was based on plant additions, retirements, transfers and other activity from 1958 to 2009 (refer to page I-4 of study). Given that the samples of PE pipe removed from service occurred in 2011, they would not have been accounted for in the recent depreciation study.

340.3 Are these longer service lives an indication that the rapid rise in sustainment capital spending may have been excessive? Please discuss.

Response:

Longer than previously anticipated service life is not a result of excessive sustainment capital spending. In fact, excessive spending of sustainment capital would be likely to shorten the life expectancy of the assets as it would result in assets being replaced before it was necessary.

The data currently being gathered and analyzed is critical to understanding the failure causes and modes of the assets but is not adequate to suggest wholesale changes in life expectancy are required. For example, while the PE pipe examined shows no degradation in performance at approximately 30 years in service, the failure mode may simply be one of rapid onset after a certain period of time. It is possible that the PE will simply experience rapid degradation at some point as opposed to a gradual decline in asset performance. It should also be noted that the 30 years in service is considerably less than the depreciation rate and that PE pipe is not used in the transmission system.

As noted throughout Appendix C-3 of the Application, understanding the probability of failure of an asset is complex and requires examining a number of factors. The results of the PE pipe analysis are an example of where new information is being developed regularly and it is part of a complex process. To suggest that the entire system can be represented by this relatively limited data set would be inadvisable.

FEI will continue to learn and develop the LTSP methodology and tools to ensure that the sustainment capital initiated is appropriate and based on a complete view of the assets with the best analysis of the information available.

341.0 Reference: SERVICE QUALITY INDICATORS

Exhibit B-1, pp. 75-6, 214; Exhibit B-1-1, Appendix B2

Service Quality Indicators and System Leaks

"Service Quality Indicators (SQIs) are used in the context of PBR to ensure that the utility is encouraged to pursue efficiencies that do not sacrifice service quality." (Exhibit B-1, p.75)

341.1 In Table B6-9, the proposed SQIs that have Benchmarks all appear to be related to direct contact between the utility and customers. Why do the proposed SQIs not also include measures that reflect the condition of the gas delivery system, which will impact safety, reliability and cost experienced by customers now and in the future?

Response:

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

341.2 Does FEI agree that maintaining its system in satisfactory condition should be an objective of a PBR program?

Response:

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

341.3 What system condition-related SQIs did FEI consider, and why did it decide to exclude them?

Response:

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

341.4 What other possible system condition-related SQIs, and corresponding Benchmarks, can FEI identify?

Response:

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

"Aside from third party requests, mains renewal or replacement may be driven by the frequency of leaks occurring on a segment of main, the cost of addressing each successive leak, the Company's ability to prevent any further leaks and the potential consequences of future leaks occurring." (Exhibit B-1, p. 214)

341.5 Appendix B2 indicates that the number of Distribution Pipeline Leaks increased from an average of 68 per year in 2007 -2009, to 158 per year in 2010-2012. Please explain the reasons for this increase.

Response:

Please refer to the response in BCUC IR 2.262.2.

341.6 Does the increase in Distribution System leaks indicate a general deterioration in the condition of the distribution system?

Response:

This responds to BCUC IR 2.341.6 and BCUC IR 2.341.7.

The increase in leaks referred to in the IR above is specific to leaks on mains where FEI has seen a trend higher. Leaks on services, however, comprise the majority of distribution system leaks (approximately 80 percent) and the activity trend has been relatively flat and even decreasing in some areas particularly where polyethylene pipe has been used for the service installation.

An increase in the number of detected leaks on main does not necessarily indicate a deterioration of overall system conditions. It may simply indicate an increase in the number of leak detection surveys or a change in geographic location of such a survey in any given year. Each year approximately one fifth of the distribution system is surveyed for leaks. The number of leaks will vary from year to year more as a result of the condition of the pipe being surveyed in the given year than the quality of the maintenance program. Typically some of the new areas with a predominance of polyethylene piping (Fraser Valley) have a lower leak activity rate versus the older system infrastructure in municipalities where steel piping is a larger component of the mix. FEI should be encouraged to continue to find as many leaks as possible and an SQI such as detected leaks per kilometer of distribution mains is contrary to that objective.

341.7 Would the annual number of leaks be a useful SQI for the condition of the Distribution System? What would be an appropriate Benchmark for this SQI?

Response:

Please refer to the response to the BCUC IR 2.341.6.

341.8 Appendix B2 also indicates that average Emergency Response Time has increased from 21.06 minutes in 2007-2009 to 23.00 minutes in 2010-2012. Please explain the reasons for this increase. What Benchmark does FEI use for this measure?

Response:

The average emergency response time measures the average length of time after notification for a qualified company representative to arrive on the scene of a gas emergency where the gas line has been struck or pulled or gas is blowing. Many variables factor into the response time of an individual emergency event including the location of the event, time of day, day of week, traffic, road construction, proximity of available first responder, dispatcher’s ability to contact a technician, type of work first responder needs to withdraw from and overall emergency footprint complement on the day of the event. The overall weighted average response time is also impacted by the geographic distribution of the emergencies and the overall volume of activity.

As indicated the average emergency response time has increased from 21.06 minutes in 2007-2009 to 23.00 minutes in 2010-2012. The reasons for the increase in the 2010-2012 period are described in Section 3.3.1, Appendix D-7 of the Application:

"Changes to the geographical mix of emergency hit line events, a decreasing number of events and the different response times historically experienced in these areas are the main contributors to a higher overall weighted average response time … Firstly, the overall number of hit line events is on a declining trend with a 15% reduction in 2012 from 2011 levels. 2011 activity levels were down a similar percentage from 2010. Secondly, the geographical distribution of the decreasing number of events has shifted over time. The Lower Mainland has typically experienced a higher percentage of emergency events and has historically lower response times due to the size of the available emergency response workforce. The decrease in the number of events overall, together with generally lower response times than Interior locations, has contributed to a higher weighted average response time. Also, emergency response time to Fraser Valley hit line events, proportionally the area with the most number of events, has increased year over year by 1.5 minutes, primarily for day time events. Traffic congestion, roadwork, and resultant travel times have been the root cause of the increase. The Northern Region, Prince George and Quesnel primarily, in contrast to the rest of the Province, experienced a 20 percent increase in hit line emergency activity in 2012. The higher response time for this outlying area (26 minutes) and the higher weighting of this geographical area in the total mix contributed to the higher overall emergency response time observed."

FEI believes that its response time to gas emergencies is appropriate and no changes are required to the emergency response resources and emergency management. FEI is proposing to replace this indicator with a more appropriate indicator, "Percentage of emergency events responded to within one hour", and therefore no new benchmark is proposed for average emergency response time.

341.9 Did the proposed SQI for Emergency Calls Responded to Within One Hour show a similar deterioration in performance over the 2007 to 2012 period? If not, please explain.

Response:

The historical results for the proposed SQI for Emergency Calls Responded to Within One Hour are as follows:

- 2007: 98.8%
- 2008: 98.9%
- 2009: 97.7%

- 2010: 97.7%
- 2011: 97.9%
- 2012: 97.4%

The proposed SQI showed a slight deterioration in the percentage of emergency calls responded to within one hour over the 2007 to 2012 period, but has been consistent over the last 4 years.

The deterioration was due in part to the replacement of the emergency and work dispatching technology (software and hardware) in Q3, 2009 which changed the time stamping slightly for emergency jobs.

The response time percentage decrease in 2009 also corresponds to a return to higher levels of meter exchange activity in 2009 discussed in BCUC IR 2.296.6.6.2. First responders to emergency events are generally technicians whose main work activity is scheduled meter exchange and customer service activity. Technicians require a few minutes to pull off these types of jobs once started to be able to respond to the emergency.

341.10 Please explain why FEI considers Emergency Calls Responded to Within One Hour is a better SQI than Emergency Response Time.

Response:

The advantages of the Emergency Calls Responded to Within One Hour over the Emergency Response Time are explained in Exhibit B-1-1, Appendix D7, Section 3.3.1 of the Application and can be divided into two main items: stability of measure (related to the scope of emergencies included), and comparability with other gas utilities.

Stability of measure and scope of emergencies included in the measure

In general, inclusion of a broader scope of emergencies will measure the response time on a considerably higher number of events and mitigate the variability created by changes in the geographic mix that may happen in the case of narrowly defined emergency metrics.

As described in Exhibit B-1-1, Appendix D7, Section 3.3.1 of the Application, the current Emergency Response Time SQI is too narrow in that not all emergency events are considered in the response time (less than 1,000 hit line events annually) and therefore the overall weighted average response time is distorted by changes to activity levels in each geographical area. On the other hand, the proposed Emergency Calls Responded to Within One Hour SQI includes a broader scope of emergencies such as gas odour calls, carbon monoxide calls, house fires, hit lines, etc. (approximately 24,000 events annually for FEI), and therefore this considerably higher number of events would mitigate the variability created by changes in the geographic mix.

Comparability with other natural gas distributors

The current Emergency Response Time is not readily comparable to other Canadian Gas Association (CGA) member equivalent metrics while the new proposed metric more accurately reflects a performance metric comparable to other Canadian gas utilities.

342.0 Reference: LONG TERM SUSTAINMENT PLAN (LTSP)
Exhibit B-11, BCUC 1.197.1, p. 487
Poly-tape wrap

FEI states that “For example, during the 1960s through to the early 1970s, steel pipe with a factory applied vinyl tape coating known as poly-tape wrap was introduced to the industry. Experience over subsequent decades has shown that this type of coating is subject to disbondment, shielding the cathodic protection system and resulting in active corrosion underneath the coating. In such cases, piecemeal repairs may not eliminate the underlying threat to the entire segment and increasing cathodic protection may not be effective due to shielding. The most effective long-term solution is to replace the pipe segment.”

342.1 What length of poly-wrap pipe was installed in the 1960s and early 1970s and what length has been removed due to actual leaks?

Response:

FEI’s records indicate approximately 561 km of poly-wrap distribution mains were installed in the 1960s and early 1970s and are still in service as of December 2012. However, FEI is unable to report what length of poly-wrap pipe has been removed due to actual leaks.

It is important to note that different installation techniques, cathodic protection or soil conditions in different areas where this pipe was installed directly impact the coating effectiveness and not all of these distribution mains require replacement.

343.0 Reference: LONG TERM SUSTAINMENT PLAN (LTSP)

Exhibit B-11, BCUC 1.199.1, p. 489; Exhibit B-1-1, Appendix B2

2nd generation LTSP

FEI states that "Another consequence factor that FEI is considering is a customer retention metric. That is, a metric that provides a measure of the likelihood of either existing or potential customers switching from natural gas to another energy source as a result of a failure."

343.1 What is the rationale for including this consequence factor in the 2nd generation LTSP?

Response:

In an effort to develop a complete understanding of the risk associated with a failure, FEI is considering the inclusion of a customer retention metric as a consequence factor. At this point the customer retention metric has been provided only as an example, and there is no guarantee it will be incorporated into subsequent iterations of the LTSP. However, it is under consideration as FEI believes that one of the potential consequences of a failure is the potential loss of customers and the associated loss of load and, given a large enough volume loss, eventual rate increases for remaining customers.

343.2 Wouldn't such a factor simply lead to "gold plating" the pipeline system with little benefit to customers?

Response:

The customer retention factor has been considered and may be used as an input in the algorithm to help prioritize work, but would have a limited impact on the assessment of what assets need work or what action would be taken to address a particular issue. For example, if two segments of pipe were deemed equally risky on all factors other than customer retention, then the segment of pipe where the customer retention consequence was deemed greater would be prioritized ahead of the other segment, should replacement be determined to be the best form of mitigating action. The question of whether or not the main is to be replaced or another form of mitigating action is to be taken remains with the skilled worker. This is the purpose of the LTSP, to provide information to support skilled individuals in making informed decisions as to how best to sustain the natural gas delivery system. The possible inclusion of a customer retention based consequence factor would provide a better understanding of the impacts of an asset failure; it would not lead to "gold-plating" the pipeline system.

343.3 Are customers more interested in lower rates rather than precluding the remote possibility of a short outage?

Response:

The inclusion of the consequence risk factor referred to would help assess the relative risk of failure and would potentially help prioritize work, but it would not lead to higher rates. Refer to the BCUC IR 2.343.2.

FEI believes customers are interested in both low rates and safe, reliable natural gas service. FEI does not believe customers would respond uniformly if presented with the choice in the question. For many customers a gas outage is very significant if their business or institution is reliant on natural gas service to operate. For customers that use natural gas for heating purposes, an outage during the winter may also be very significant.

The purpose of the LTSP and the Asset Management philosophy is to address these factors on behalf of the customers to ensure that when FEI makes capital expenditures or seeks approval of its capital plans, it is for projects that are required in order to maintain the safety and reliability of the system in a cost effective manner.

343.4 For 2007-2013, please compare FEI and BC Hydro's:

- Outages cause by a Third Party
- System outages and customers affected

Include the requested information in a fully functional spreadsheet.

Response:

FEI does not believe a comparison to BC Hydro of outages caused by a third party or system outages and customers affected would provide a meaningful comparison.

The mechanisms of third party damage on an electrical system are substantially different than those on a gas system due to electrical being primarily above ground while gas is primarily below ground. Electricity can be turned on and off with a switch and the flow of the energy is instantaneously started or stopped; gas on the other hand continues to leak until the pipeline pressure drops to ambient. Once the gas system is repaired, relighting requires visiting each customer to shut off or turn on the meter set and relight all appliances. Momentary outages occur frequently in electric power systems, whereas there is no equivalent concept in a gas network. Outages on a gas system require significantly more effort to address than on an electric system. For example, an outage of 100 customers on an electrical grid could be ended instantly following completion of the repair to whatever caused the outage. Those same 100 customers on a gas grid would require between 30 and 45 person-hours to shut off and relight depending on whether it was an urban or rural environment and assuming access to the homes and appliances was readily available for relights. Due to the more involved recovery process, FEI strives to minimize the number of customers impacted wherever possible.

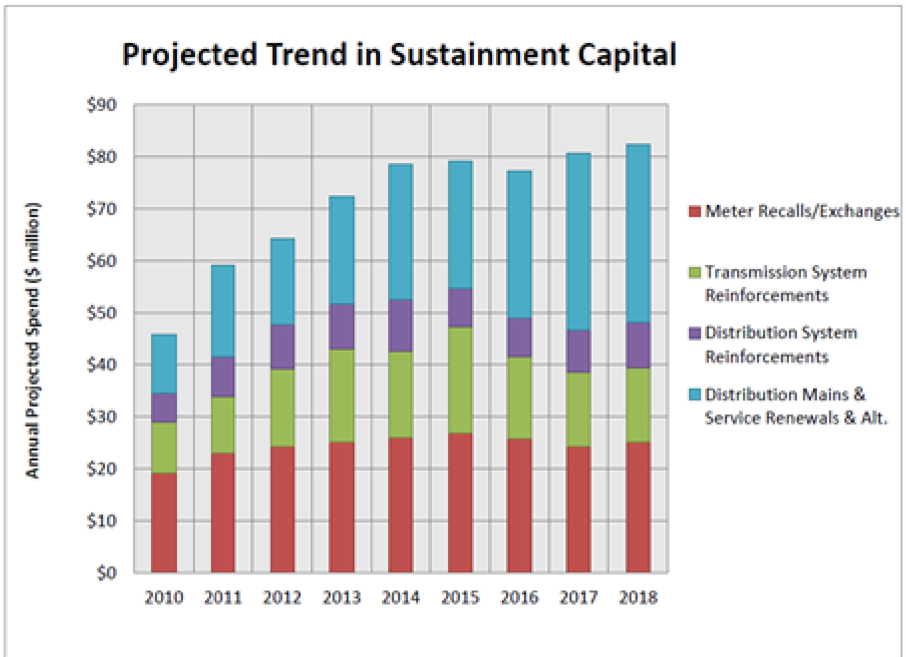
The basic requirements of the two energy sources are so technically different that there can be no meaningful comparison of system outages, regardless of the cause. A direct comparison is not possible.

344.0 Reference: LONG TERM SUSTAINMENT PLAN (LTSP)

Exhibit B-1-1, p. 14

Sustainment Capital Expenditures

Figure C3-3: Projected Annual Capital Spend (FEI: 2013-2018)



344.1 Please provide forecast (requested), approved and actual Sustainment Capital expenditures for the years 2009, 2010, 2011, 2012 and 2013. For 2013 for actual include a projected figure stating the number of months of actual and forecast expenditures.

<u>Response:</u>

Please refer to the table below for 2009-2013 forecast, approved and actual sustainment capital expenditures.

($000's)	2009 Actual	2010 Actual	2010 Requested	2010 Approved	2011 Actual	2011 Requested	2011 Approved
Total Sustainment Capital	47,852	45,437	46,684	45,684	59,137	44,778	43,778

	2012 Actual	2012 Requested	2012 Approved	2013 Actual**	2013 Requested	2013 Approved
Total Sustainment Capital	64,291	65,517	65,517	72,258	75,114	75,114

Notes
1) In 2009, FEI was under PBR formula whereby the formula was not calculated specifically for sustainment capital; therefore, a 2009 approved/requested sustainment figure is not provided above.
2) 2013 Actual - Based on actual expenditures as at 10/31 and forecast expenditures from 11/1 to 12/31

344.2 Please confirm the class of estimate and accuracy range as defined by AACE International Recommended Practice No. 10S-90 used in developing the forecasts for Sustainment Capital expenditures.

Response:

In instances where the work is well defined and FEI has recent experience with costs of completing that or similar types of work, estimates may be reasonably accurate. However, no AACE estimates are completed for routine or smaller projects.

In instances where costs are expected to be high or where FEI does not have recent experience with the work, Sustainment Capital estimates are completed to AACE International Recommended Practice Class 5 accuracy and could vary from -50% to +100% in accuracy or, occasionally, to Class 4 with an accuracy of -30% to +50%.

344.2.1 What amount of contingency (percentage) is applied in developing the capital cost estimates used in the forecast for Sustainment Capital expenditures?

Response:

As there are many projects and programs included in Sustainment Capital, it is not typically necessary to include a contingency in the estimates. Typically the nature of the requirement is well understood but multiple options are available for the solution. Once an optimal solution is selected and a project is released for execution, depending on how well the solution has been developed, a nominal contingency may be included. In those instances where a contingency is deemed appropriate and unless otherwise stated, the contingency is likely to be approximately 10%.

NATURAL GAS FOR TRANSPORTATION

345.0 Reference: NATURAL GAS TRANSPORTATION

Exhibit B-1-1, Appendix H, pp. 9, 16-17; Exhibit B-15, p. 10; 2012-2013 FEU RRA Decision, pp. 42, 60)

GGRR and Non-GGRR Classes of Service

"10. Approvals pursuant to sections 59-61 of the Act for the creation of separate classes of service to account for CNG and LNG Stations apart from the traditional natural gas for distribution class of service." (Exhibit B-15, p. 10)

"Accordingly, the cost of service for each of the NGT fueling station classes of service has been removed from the traditional natural gas ratepayer revenue requirement financial schedules within this Application unless otherwise approved and identified within this appendix." (Exhibit B-1-1, p. 7)

"The FEU have added a new area within Preventive Maintenance for the operation and maintenance of Biomethane and NGV assets. Requirements to support NGV (specifically, CNG and/or LNG stations) total $115 thousand for both 2012 and 2013. Biomethane assets will require a further $23 thousand in 2012 and $68 thousand in 2013 as the number of assets to be maintained increases." (2012-2013 FEU RRA Decision, p. 42)

"As a component of customer and stakeholder expectations, the FEU also request approval for an additional [Operations Support] employee to be added to support growth in the business including new NGV and Biomethane initiatives at an incremental cost of $52 thousand." (Underlined for emphasis) (2012-2013 FEU RRA Decision, p. 60)

345.1 Please provide a schedule showing the O&M cost/capital expenditures for each of the NGT fueling station classes that has been removed from the 2013 Base Year O&M and Capital by resource, Department, FTE (identify specific positions). Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

FEI confirms that there are no NGT fueling station capital expenditures in the 2013 Base for capital. The CNG and LNG stations reside in the CNG and LNG classes of service. These stations are listed in Table H-1 in Appendix H of the Application. FEI also removed the existing assets from Gross Plant and Accumulated Depreciation to ensure no impact to traditional rate payers.

In responding to this IR FEI has determined, in contradiction to what was stated in Appendix H, that $289,000 of maintenance costs remain in the 2013 Base O&M of the Distribution department relating to fueling stations. FEI will remove the $289,000 from 2013 Base O&M in its next evidentiary update. FEI uses contractors to perform the maintenance on its CNG and LNG stations. Consequently, the O&M estimates are not based on FTE's or specific positions.

The following table summarizes the gross plant value of the NGT assets that were removed from Plant and the amounts that will be removed from the 2013 Base O&M in the next evidentiary update.

Capital removed

Class of Service	Station	2013 Base
Non-GGRR CNG	Kelowna School District	$ 471,922
Non-GGRR CNG	BFI	$ 1,536,118
Non-GGRR CNG	Waste Management	$ 1,475,584
Non-GGRR CNG	Surrey Operations CNG Pump	$ 141,645
Non-GGRR CNG	Burnaby Operations CNG Pump	$ 141,645
Non-GGRR LNG	Vedder Transport	$ 51,295
Total		$ 3,818,208

O&M included

Class of Service	Station	2013 Base
Non-GGRR CNG	Kelowna School District	$ 15,000
Non-GGRR CNG	Surrey Operations Pump	$ 15,000
Non-GGRR CNG	Waste Management	$ 25,000
GGRR CNG		$ 17,000
Non-GGRR LNG	Vedder Transport	$ 82,000
GGRR LNG		$ 135,000
Total		$ 289,000

Please refer to Attachment 345.1 for the fully functioning electronic spreadsheet.

345.2 For Table H-11: FSVA Gross Addition Forecast, please provide a breakdown by revenue surplus/deficiency, application costs, administrative, marketing, training allowances provided in the Prescribed Undertakings.

Response:

FEI does not distinguish between revenue surplus/deficiency and application costs within the forecast additions to the FSVA. FEI forecasted CNG and LNG stations to come into service over the term of the GGRR and each of the fueling stations included application costs of $25,000. These application costs are forecast to be recovered from the station customer over 5 years. A levelized rate was calculated for each of the stations which included, among other things, recovery of capital, O&M, earned return and application costs. The expected revenue (levelized rate multiplied by expected volume) was deducted from the annual cost of service to derive the FSVA addition. Therefore, implicit in the revenue surplus/deficiency addition to the FSVA is recovery of the station application costs.

The table below shows the Surplus/Deficiency (including application costs) and Admin and Marketing being added to (removed from) the FSVA.

FSVA ($000)

Line	Paticulars	Reference	2014	2015	2016	2017	2018
1	CNG - GGRR						
2	Surplus/Deficiency (including application costs)		33	(17)	(21)	(48)	(37)
3	Admin and Marketing		48	48	48	48	-
4	Total	Line 2 + Line 3	81	31	27	0	(37)
5							
6	LNG - GGRR						
7	Surplus/Deficiency (including application costs)		107	(20)	(6)	(36)	(100)
8	Admin and Marketing		50	50	50	50	-
9	Total	Line 7 + Line 8	157	30	44	14	(100)
10							
11	Total	Line 4 + Line 9	238	61	71	14	(137)

When the 2013 amounts for the Admin and Marketing costs are included, the totals agree to the GGRR approved amounts ($240 thousand for CNG and $250 thousand for LNG).

345.3 If FEI's proposal to create classes of service for CNG and LNG Stations apart from the traditional natural gas for distribution class of service is approved, should the Administration, Marketing, Training & Education allocated to traditional natural gas for distribution class of service for CNG and LNG Stations be limited to the amounts approved in the GGRR. Please explain why, or why not.

Response:

No, these activities should not be limited to the amounts approved in the GGRR.

Pursuant to Order G-78-13, FEI will be charging all NGT Customers (GGRR and Non-GGRR CNG/LNG) an OH&M Charge of $0.52 per GJ. The Commission decision was that this charge is adequate to recover the overhead and marketing costs that FEI incurs in support of the NGT business. To this end, distribution ratepayers' rates are not impacted by the marketing and overhead activities for NGT.

The GGRR allows FEI to charge its distribution rate payers for a portion of these costs. The amount allowed in the prescribed undertaking equals $490,000 ($240,000 for CNG and $250,000 for LNG) by way of additions and amortization of the FSVA.

In summary, FEI distribution rate payers will only pay $490,000 for overhead (administration) and marketing of all the NGT stations over the term of the GGRR.

Training and education amounts are already limited to those specified in the prescribed undertaking.

345.4 Provide methodology for allocating corporate and shared service costs to the CNG/LNG GGRR and CNG/LNG non-GGRR classes of service.

Response:

No corporate or shared services costs are allocated to the CNG/LNG GGRR and CNG/LNG non-GGRR classes of service in this Application, under the approved arrangements between FEI and FEVI/FEW for shared services and between FHI and FEI for corporate services.

Instead, the stations include an Overhead and Marketing recovery charge (Order G-78-13) which is an alternative method of recovering the costs of shared resources. FEI employees directly involved in providing shared services are included in the Overhead and Marketing rate charged to CNG/LNG customers. For corporate services such as legal and corporate accounting services, any incremental costs incurred to support GGRR activity are charged to the GGRR deferral account.

> "Pursuant to the AES Inquiry Report (Order G-201-12), the Commission has recommended that FEI **undertake CNG and LNG activities outside of the prescribed undertaking in a non-regulated business**. In the spirit of complying with G-201-12, FEI has pursued an approach for existing CNG and LNG stations that segregates them into separate classes of service, which removes their cost of service from FEI's traditional natural gas rate payer's revenue requirement in this Application." (underlined for emphasis) (Exhibit B-11, BCUC 1.201.3)

345.5 Please explain why FEI has not undertaken CNG and LNG activities outside of the prescribed undertaking in a non-regulated business.

Response:

FEI has explained its approach to creating the non-GGRR CNG and LNG classes of service in Exhibit B-1-1, Appendix H. As indicated there, based on previous Commission decisions and the directives and recommendations of the AES Inquiry Report, FEI has determined that four NGT classes of service are required to account for CNG and LNG stations constructed in compliance with either the GGRR requirements or GT&C 12B.

The AES Inquiry Report states that it is a forward looking report and not meant to change previous decisions. Moreover, the AES Inquiry Report specifically contemplated CNG and LNG activities continuing in separate classes of service as ordered for the BFI CNG station and suggested that the Waste Management CNG Station be within the CNG class of service. The AES Inquiry Report states at p. 54:

> *"The Panel notes that the BFI CNG station is ordered to be in a Separate Class of Service. The Waste Management CNG Station was approved within the existing natural gas class of service, subject to the conditions contained in its approval. While the Panel believes it would be appropriate to have the Waste Management CNG Station within the CNG Class of Service, this report is a forward looking document and does not apply to previous decisions, unless specific issues were referred to this Inquiry. The Panel does not see this report as directing any change to the BFI or Waste Management Decisions."*

With this in mind, and as stated in Appendix H of the Application, the need for four separate classes of services arises from two orders in particular:

- BCUC Order C-6-12 regarding the BFI CPCN, item 3 of which directed FEI to establish two new classes of service, one for CNG Service and one for LNG Service, and
- The AES Inquiry Report (Order G-201-12) which determined that "CNG activities done under the Prescribed Undertaking should be structured as a separate Class of Service with the costs to be recovered from the traditional gas utility ratepayers, to the prescribed limit."

Please refer to Appendix H of the Application for further details.

As stated in the response to BCUC IR 1.201.6:

> FEI's rationale for including existing Non-GGRR CNG and LNG stations in a separate class of service is a result of the Commission's directive to account for BFI's fueling station in a separate class of service. In principle, the same treatment should be applied to all of FEI's Non-GGRR CNG and LNG stations as they are similar in purpose and rate design as the BFI fueling station, and FEI is endeavoring to act in the spirit of the Commission's orders. There is also some administrative efficiency, simplicity and transparency accorded by accounting for all of the non-GGRR stations in the same fashion.

FEI will be focusing its limited resources on the prescribed undertaking business opportunities and sees no reason to set up a non-regulated business for CNG and LNG related activities at this time. Whether the activities are in a non-regulated business or a separate class of service, they do not impact the delivery rates that are the subject of this Application.

345.6 Please provide the reduction in 2013 Base O&M, if FEI is directed to undertake CNG and LNG activities outside of the prescribed undertaking in a non-regulated business.

Response:

To clarify, FEI's Rate Schedule 26 does provide a natural gas vehicle transportation service rate for customers with consumption of greater than 2,000 GJ annually that will only use gas to fuel vehicles. This is an approved rate and a regulated service that is not segregated into a separate class of service

Within this Application, the assets and O&M costs[1] for CNG and LNG activities have already been segregated from traditional natural gas rate payers into separate classes of service. Therefore, if

[1] Please refer to the response to BCUC IR 2.345.1 for discussion of the 2013 Base O&M.

directed to undertake CNG and LNG activities in a non-regulated business, no adjustment to 2013 Base O&M is required.

BCUC Order G-78-13 directed FEI to collect $0.52 per GJ from all CNG and LNG Customers. Given this direction, FEI is not required to additionally calculate and charge an amount using the TPP guidelines.

"Burnaby Operation's CNG Pump is for company use only and does not have a dispensing rate in place at this time." (B-1-1, Appendix H, p. 17)

"Surrey Operation's CNG Pump, Commencing January 1, 2014 FEI will account for this recovery in the Non-GGRR CNG Class of Service as an offset to the cost of service for this pump. A portion of the recoveries come from CNG sales to the public and a portion from CNG sales to FEI's fleet servicing Core ratepayers. The recovery from FEI fleet will show as a debit in the Application, Section C2 - Other Revenues." (Exhibit B-1-1, Appendix H, p. 17)

345.7 Please provide a breakdown of the 2010-2013 sales for the Burnaby and Surrey Operation's CNG pumps t o the public and FEI's fleet.

Response:

The following table has sales and consumption data for the Surrey Operations pump.

Year	3rd Party Monthly Purchase Total	3rd Party Consumption (GJ)	FEI Fleet Monthly Purchase Total	FEI Fleet Consumption (GJ)	Total Consumption (GJ)	Note
2010	$13,259	738			738	1
2010				886	886	2
2011				846	846	3
Jan - Mar 2012				292	292	4
Apr - Dec 2012	$12,668	753	$17,083	1,003	1,756	
2013	$16,188	926	$16,310	932	1,859	5

Notes:

1. Estimates provided in "Application for Approval of a Compression Rate Schedule, Compression & Dispensing Rate Calculation and Resulting Effective Rate to Provide for Public Natural Gas Vehicle ("NGV") Refueling at FEI Surrey Operations Centre" filed July 8, 2011.
2. Total CNG consumed in 2010 was 1,624 GJ of which 738 was to the public (See note 1). The balance is assumed to be consumed by FEI Fleet.
3. The CNG Pump at Surrey Operations was closed to the public during 2011
4. The CNG Pump at Surrey Operations was closed to the public during Jan - Mar 2012.
5. Includes data to August 31, 2013

The Burnaby Operations pump has been used exclusively to fuel FEI Fleet vehicles. The following table provides FEI's consumption data.

Year	FEI Fleet Consumption (GJ)	Note
2010	765	
2011	953	
2012	1,338	
2013	730	1

Notes

1. Includes data to August 31, 2013

345.7.1 Please explain why the sales to FEI are not considered "Own Use Gas".

Response:

Historically, FEI has included these costs as a vehicle fuel expense and not as Own Use Gas, which is the same treatment for FEI vehicles fueling with other types of energy such as gasoline or diesel regardless of where FEI fuels its vehicles. FEI believes this consistent treatment is appropriate. Own use gas has a specific meaning and does not include gas or other fuels used to operate company vehicles.

To be transparent in the Application, FEI included the amounts in Other Revenue (as a cost).

346.0 Reference: NATURAL GAS TRANSPORTATION

Exhibit B-1-1, Appendix H; Order G-44-13; Order G-150-12 Compliance Filing, pp. 8, 10; Order G-150-12 Compliance Filing, IR No. 1; Application for Approval for Approval of Rate Treatment of Expenditures under the Greenhouse Gas Reductions (Clean Energy) Regulation and Prudency Review of Incentives under the 2010 – 2011 Commercial NGV Demonstration Program (GGRR Application), p. 26

Cost Allocation to FEVI

Table 2: Forecast staff resource cost related to fueling station activities 2012-2017

Title	Fueling Station Time Allocation	2012	2013	2014	2015	2016	2017
Senior Manager, BD	15%	24,848	25,151	25,906	26,683	27,483	28,308
BD Manager	50%	59,000	59,373	61,154	62,988	64,878	66,824
BD Specialist	15%	15,450	15,660	16,130	16,614	17,112	17,625
Manager, NGT Solutions	50%	71,750	75,110	77,363	79,684	82,075	84,537
NGT Account Manager	25%	25,500	25,750	26,523	27,318	28,138	28,982
Manager, NPD	60%	81,000	81,540	83,986	86,506	89,101	91,774
Total		**277,548**	**282,584**	**291,061**	**299,793**	**308,787**	**318,051**
Total FTE:	2.15						

(Order G-150-12 Compliance Filing, p. 8)

346.1 Please revise Table 2: Forecast staff resource cost related to fueling station activities 2012-2017 to show the full cost of each position. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Title	Full Cost Allocation		2012	2013	2014	2015	2016	2017
Senior Manager, BD	100%		165,653	167,673	172,707	177,887	183,220	188,720
BD Manager	100%		118,000	118,746	122,308	125,976	129,756	133,648
BD Specialist	100%		103,000	104,400	107,533	110,760	114,080	117,500
Manager, NGT Solutions	100%		143,500	150,220	154,726	159,368	164,150	169,074
NGT Account Manager	100%		102,000	103,000	106,092	109,272	112,552	115,928
Manager, New Product Dev.	100%		135,000	135,900	139,977	144,177	148,502	152,957
Total			**767,153**	**779,939**	**803,343**	**827,439**	**852,260**	**877,827**
Total FTE:	6.00							

The costs above represent fully loaded labour costs, including benefits and time off.

Please refer to Attachment 346.1 for a fully functioning electronic spreadsheet.

346.1.1 Please provide the staff resource cost related to fueling station activities included in the 2013 Base Year O&M. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Pursuant to Commission Order G-78-13, the Commission determined that the appropriate time allocations should be as shown in the third column of the table below (while FEI's estimates are shown in the second column).

Table 1: BCUC Allocation of Cost Resources by Position (per Order G-78-13)

Position	FEI Allocation	Panel Allocation	Fully Loaded Salary (2012)	Allocated Salary (2012)
Senior Manager, BD	15%	67%	$ 165,653	$ 110,435
BD Manager	50%	50%	$ 118,000	$ 59,000
BD Specialist	15%	67%	$ 103,000	$ 68,667
Manager, NGT Sol.	50%	100%	$ 143,500	$ 143,500
NGT Account Manager	25%	100%	$ 102,000	$ 102,000
Manager, New Product Dev.	60%	60%	$ 135,000	$ 81,000
TOTAL				**$ 564,602**

Using the time allocations as determined by the Panel in Order G-78-13 and the total staff resources costs provided in response to BCUC IR 2.346.1, the allocated staff resource costs for 2013 are provided in the table below.

Table 2: BCUC Allocation of Cost Resources by Position for 2013

Position	Panel Allocation	FEI Allocation	Fully Loaded Salary (2013)	Allocated Salary (2013)	FEI Calculated Allocated Salary (2013)
Senior Manager, BD	67%	15%	$ 167,673	$ 111,782	$ 25,151
BD Manager	50%	50%	$ 118,746	$ 59,373	$ 59,373
BD Specialist	67%	15%	$ 104,400	$ 69,600	$ 15,660
Manager, NGT Sol.	100%	50%	$ 150,220	$ 150,220	$ 75,110
NGT Account Manager	100%	25%	$ 103,000	$ 103,000	$ 25,750
Manager, New Product Dev.	60%	60%	$ 135,900	$ 81,540	$ 81,540
TOTAL				**$ 575,515**	**$ 282,584**

Based on the Commission's time allocation $575 thousand is the estimate of 2013 base O&M that should be allocated to NGT fueling station activities pursuant to Order G-78-13. From this the Commission derived a $0.52/GJ OH&M charge. However, FEI continues to believe that the allocation as presented in the table, labeled as "FEI Allocation" is more representative of the time these staff members spend on the fuelling station activities and more accurately reflects overhead and marketing costs supporting NGT activities that are included in the 2013 O&M.

Please refer to Attachment 346.1.1 for the fully functional electronic spreadsheet.

346.2 In the same format as Table 2, please provide a breakdown of the staff resource cost related to fueling station activities between FEI GGRR, FEVI GGRR and non-GGRR fueling stations for 2013-2018. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

The 2014 to 2018 amounts in the same format as Table 2 would equal the 2013 amounts shown in response to BCUC IR 2.346.1.1 escalated by labour and benefits inflation (for the high level forecast) or by the formula driven inflation net of productivity (for customer rates).

However, as directed by the Commission in Order G-78-13, FEI is not charging these amounts to the GGRR and non-GGRR fuelling stations. Instead, FEI is charging the OH&M rate of $0.52/GJ. This results in the following amounts that are forecast to be charged to each of the GGRR and the non-GGRR classes of service for each of 2013 to 2018. These amounts will be re-forecast each year as part of FEI's Annual Review process. The following table shows the OH&M forecast to be collected from FEI and FEVI GGRR and Non-GGRR Classes of Service from 2013 to 2018.

	2013	2014	2015	2016	2017	2018
Volume (GJ)						
FEI						
Non-GGRR CNG	65,000	65,000	65,000	65,000	65,000	65,000
Non-GGRR LNG	140,000	140,000	140,000	140,000	140,000	140,000
GGRR CNG	6,626	53,550	105,550	141,799	193,700	193,700
GGRR LNG	27,263	96,750	245,250	407,694	542,250	542,250
Total	238,889	355,300	555,800	754,493	940,950	940,950
FEVI						
Non-GGRR CNG	-	-	-	-	-	-
Non-GGRR LNG	-	-	-	-	-	-
GGRR CNG	10,000	40,000	77,100	100,100	118,100	118,100
GGRR LNG	-	-	-	-	-	-
Total	10,000	40,000	77,100	100,100	118,100	118,100

OH&M Rate ($/GJ) $0.52

	2013	2014	2015	2016	2017	2018
OH&M Collected from Non-GGRR and GGRR Classes of Service ($000)						
FEI						
Non-GGRR CNG	34	34	34	34	34	34
Non-GGRR LNG	73	73	73	73	73	73
GGRR CNG	3	28	55	74	101	101
GGRR LNG	14	50	128	212	282	282
Total	$ 124	$ 185	$ 289	$ 392	$ 489	$ 489
FEVI						
Non-GGRR CNG	-	-	-	-	-	-
Non-GGRR LNG	-	-	-	-	-	-
GGRR CNG	5	21	40	52	61	61
GGRR LNG	-	-	-	-	-	-
Total	$ 5	$ 21	$ 40	$ 52	$ 61	$ 61

Please note that the FEI totals will not match exactly the amounts in Appendix H, Table H-9. In the Appendix FEI escalated the OH&M charge of $0.52 per GJ by CPI each year. However, G-113-13 directed FEI to not escalate the OH&M charge by CPI each. Therefore, the amounts in the above table differ slightly from Appendix H, Table H-9. FEI will reflect this direction (which does not affect 2014) in the material filed as part of its annual rate setting process for 2015.

Table 3: Forecast overhead and marketing costs related to fueling station activities 2012-2017

Item	2012	2013	2014	2015	2016	2017	TOTAL
Staff resource cost	277,548	282,584	291,061	299,793	308,787	318,051	1,777,823
Customer Education	70,000	75,000	80,000	90,000	70,000	60,000	445,000
Total fueling station overhead costs	$ 347,548	$ 357,584	$ 371,061	$ 389,793	$ 378,787	$ 378,051	$ 2,222,823

(Order G-150-12 Compliance Filing, p. 10)

346.3 In the same format as Table 3, please provide a breakdown between FEI and FEVI of the overhead and marketing costs related to fueling station activities included in the 2013 Base Year O&M and forecast 2014-2017 O&M. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Please refer to the response to BCUC IR 2.346.1.1 for FEI's estimate of staff resource costs related to fueling station activities as part of the 2013 O&M. Table 3 above provides the Customer Education amounts under the Forecast. Under the proposed PBR methodology, these amounts will be escalated by the O&M formula for each of 2014 to 2018. The amounts recovered from the GGRR and non-GGRR classes of service, as estimated, have been included in the response to BCUC IR 2.346.2. The recovery amounts will be re-forecast each year as part of the Annual Review process.

346.4 Please explain why Customer Education costs are forecast to increase from $75,000 in 2013 to $90,000 in 2015.

Response:

Natural gas for transportation (NGT) is a relatively new initiative undertaken by FEI and customers are just beginning to realize the operational and financial benefits of adopting natural gas vehicles. Technology is continuing to develop for both CNG and LNG vehicles. Therefore, FEI believes that ongoing customer education is required as the NGT market grows to a point of critical mass and adoption of natural gas as a transport fuel continues to gain in popularity. FEI foresees the NGT market growing to a point in which ongoing customer education related to fueling station activities will provide diminishing returns, and therefore, beyond 2015, expenditures related to customer education will decline to $70,000 and $60,000 in 2016 and 2017, respectively.

346.5 Should Customer Education costs decrease from 2013 to 2017 in the same proportion as the forecast GGRR Administration, Education, Safety training expenditures? Please explain why, or why not.

Response:

Please refer to the response to BCUC IR 2.346.4. The customer education costs should not decrease in the same proportion as the forecast GGRR Administration, Education, Safety training expenditures (GGRR Safety Expenditures). GGRR Safety Expenditures are primarily related to Prescribed Undertaking 1 under the Greenhouse Gas Reductions (Clean Energy) Regulation (GGRR), in which FEI (and FEVI) provide grants and loans to upgrade facilities for eligible vehicles under FEI's NGT Vehicle Incentive Program and educate customers about the benefits of choosing natural gas for transportation.

The customer education amounts specified in Table 3 of FEI's Compliance Filing pursuant to Order G-150-12 are primarily related to costs to pursue sales channels directed at fueling station customers. These charges are unrelated to the charges as permitted under prescribed undertaking 1 of the GGRR.

FEI's Compliance Filing pursuant to Order G-150-12 was accepted via BCUC Order G-78-13 on May 14, 2013, which also included Commission acceptance of the customer education amounts as specified in Table 3 of the Compliance Filing. These charges are recovered from NGT customers through the $0.52 Overhead and Marketing charge.

346.5.1 Please provide a schedule showing the Customer Education costs decreasing in the same proportion as the forecast GGRR Administration, Education, Safety training expenditures. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Customer Education costs will not decrease in the same proportion as the forecasted GGGR Administration, Education, Safety training expenditures, as discussed in response to BCUC 2.346.5. Therefore, to prepare a schedule showing such a correlation is not a relevant reflection of such costs.

Table 6-1: Breakdown of Incentive Funding 2010/2011-2016

NGT Incentive Program Funding Summary	2010/2011	2012	2013	2014	2015	2016	Total
Incentive Funding by Category							
Trucks	$ 5.2	$ 6.3	$ 7.0	$ 6.4	$ 6.3	$ 6.8	$ 38.1
Buses	$ 0.4	$ 1.6	$ 1.0	$ 1.0	$ 1.0	$ 1.0	$ 5.8
Marine	$ -	$ -	$ 3.5	$ 3.0	$ 2.5	$ 2.0	$ 11.0
Safety and Maintenance	$ -	$ 0.2	$ 1.0	$ 1.0	$ 1.0	$ 1.0	$ 4.0
Administration, Marketing, Training & Education	$ -	$ 0.3	$ 1.0	$ 0.9	$ 0.6	$ 0.3	$ 3.1
Total	**$ 5.6**	**$ 8.3**	**$ 13.4**	**$ 12.3**	**$ 11.4**	**$ 11.0**	**$ 62.0**

(GGRR Application, p. 26)

346.6 In the same format as Table H-2, please provide a schedule showing a breakdown of the forecast GGRR incentive expenditures for FEI and FEVI for 2013-2017. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

FEI assumes that the Table H-2 referenced in the question refers to Appendix H of Exhibit B-1-3 Evidentiary Update as filed on July 16, 2013. Table H-2 provides a schedule for FEI and the table below illustrates the breakout of FEVI GGRR forecast incentive expenditure.

The FEU have not yet allocated administration, education and safety training to FEVI, however the FEU expect that there will be incentives issued to successful applicants to implement safety practices and upgrade shops, including training. These will not be incremental costs but as a part of the overall $7.1 million approved under the GGRR for this cost category, pursuant to Order G-101-13.

FEI will only record actual costs for FEI GGRR incentives in the NGT Incentives deferral account as part of Prescribed Undertaking 1 for recovery from FEI's Natural Gas for Distribution class of service, and the NGT Incentives deferral account balances and recoveries will be re-forecast each year as part of the Annual Review process.

Table 1: FEVI Incentive Forecast

Incentive Forecast	pre-2013	2013F	2014F	2015F	2016F	2017F
Total Vehicle Incentives	$ -	$ 2,326	$ 710	$ 429	$ 217	$ -
Marine	$ -	$ -	$ -	$ -	$ -	$ -
Admin, Education, Safety Training	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ -	$ 2,326	$ 710	$ 429	$ 217	$ -
Cumulative	$ -	$ 2,326	$ 3,036	$ 3,466	$ 3,683	$ 3,683

Please refer to Attachment 346.6 for the fully functioning electronic spreadsheet.

BIOMETHANE

347.0 Reference: FORECASTS FOR THE PBR PERIOD

2012 Biomethane Application, Appendix B1, Table J-2, p. 8

2012 Biomethane Application O&M

Table J-2: Biomethane O&M Costs Summary

FEI Biomethane O&M Costs	Approved Until December 31, 2011	Actual Until March 31, 2011	Projected Until December 31, 2011	Forecast 2012	Forecast 2013****
O&M Costs - All Customers					
Labour Costs	125,000	24,491	125,000	102,000	104,040
Computer Costs				10,000	
Customer Education	400,000	4,600	400,000	300,000	306,000
Internal Reporting Charges	3,200		3,200		
Inbound Calls	35,900		35,900	6,384	6,512
Rate Changes	4,000		4,000		
Application Support	165,600		165,600		
Interconnect Facilities*					
Materials & Supplies	49,500	1,163	49,500	22,500	90,000
Total O&M Costs - All Customers	**783,200**	**30,254**	**783,200**	**440,884**	**506,552**
O&M Costs - Biomethane Customers					
Upgrader Equipment**					
Materials & Supplies	70,000		70,000	123,000	237,000
Customer Related					
Energy Peace Application Support	23,280		23,280		
Enrollment Confirmations (mailings)	3,000		3,000	4,824	4,920
Customer Drops/Finalizations	10,455		10,455	32,080	32,722
Credits to Customers for Heat Content Adjustments	54,000	7,804	54,000		
Reporting & Adminnistration	4,963		4,963		
Process for Updating Premise Heat Zone in New CIS system***				20,000	
Total O&M Costs - Biomethane Customers	**165,698**	**7,804**	**165,698**	**179,904**	**274,642**

* O&M costs for interconnect facilities includes for Catalyst and CSRD and future projects under consideration

** O&M costs for upgrader includes for CSRD and future projects under consideration

*** One time adjustment cost

**** 2013 forecast has been adjusted by an inflation factor of 2% from the 2012 estimates

(2012 Biomethane Application, Appendix B1, p. 8)

347.1 Please provide the O&M costs to be recovered from all customers and from Biomethane customers included in the 2013 Base O&M and Forecast 2014-2018 O&M. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Please refer to Attachment 347.1 for the fully functioning electronic spreadsheet.

To clarify, costs recovered from biomethane customers have not been included in the base amount.

Costs recovered from all customers are shown on the spreadsheet which provides approved 2013 costs for O&M, projected costs for the year end 2013 and forecast costs for 2014 through 2018.

The 2014 to 2018 forecast has been provided for reference purposes only as FEI's approved envelope of spend will be managed at a total O&M level based on the PBR formula.

FEI expects the RNG program to continue into the forecasted five year period and will maintain or increase the level of activity compared to the 2012/2013 levels. FEI will continue to identify key customer segments for increased customer attachments in the five year period through customer education and awareness. FEI sees the commercial customer segment, for example customers like UBC, having potential in this regard. Additionally, ongoing program management, including supply and demand balance, will continue at 2013 levels. Therefore, it is appropriate that these amounts be included in the 2013 Base O&M.

For 2013, FEI expects to spend close to the budgeted amount for labor and customer education.

For the 2014-2018 forecasts, labor and customer education have been inflated by 2% annually from the 2013 Approved.

In the case of the interconnect facility costs for the 2014-2018 forecasts, these are based on the approved supply projects and the projected growth associated with an increase in the number of projects.

Given that FEI expects the RNG program to continue and to grow over the PBR period, the costs for the program have been included in the 2013 base O&M.

348.0 Reference: FORECASTS FOR THE PBR PERIOD

2012 Biomethane Application, FEI Final Argument, p. 56

2012 Biomethane Application

> **4.3 Communications Budget**
>
> 171. Commission information requests explored measures for setting a communications budget for the Biomethane Program and FEI has responded fully to those information requests.[174] However, the Commission has approved FEI's communications budget for 2012 and 2013 and FEI is not seeking approval for any communications budget in this proceeding. For the next five years, FEI has proposed a Performance Based Rate Plan which would encompass FEI's O&M spending over that time period and provide incentives for FEI to control and reduce costs. FEI therefore submits that setting a communications budget is outside the scope of this proceeding.

(2012 Biomethane Application, Final Argument, p. 56)

348.1 Please provide the 2013 Biomethane communications budget costs included in the 2013 Base O&M.

Response:

The Biomethane communications budget included in the 2013 base O&M is $306 thousand, the same amount included in the Approved O&M total.

348.2 Given that that FEI is proposing to include Biomethane O&M and capital costs in the proposed PBR Plan, should the evidence in the 2012 Biomethane Application be treated as evidence this Application? Please explain why, or why not.

Response:

FEI has proposed to include in the proposed PBR Plan the capital and O&M expenditures for Biomethane that are currently recovered from all customers. The capital and O&M expenditures that are currently recovered specifically from Biomethane customers through the Biomethane Energy Recovery Charge, including capital costs of Biomethane Upgrader Equipment, are excluded from the proposed PBR Plan.

FEI does not believe that the evidence from the 2012 Biomethane Application should be incorporated as part of the record or evidence of this Application. In this Application, FEI has provided sufficient information for the Commission's decision on the PBR Plan. For instance, FEI has provided not only information on the 2013 base relating to the Biomethane interconnection facilities but also historical capital expenditures data for the Biomethane interconnection. FEI has also provided discussion on the O&M forecast for the ES&ER Department for the 2013 base year and beyond.

As FEI has indicated in the Application, if there are any impacts on the Biomethane interconnection forecasts resulting from the 2012 Biomethane Application, FEI will adjust its filing if applicable.

349.0 Reference: FORECASTS FOR THE PBR PERIOD

2012 Biomethane Application, p. 62

2012 Biomethane Application

"FEI will open the **Biomethane tariff to FEVI customers from 2015 onwards** through the proposed rate amalgamation (application currently in front of BCUC). (2012 Biomethane Application, p. 62) [Emphasis added]

349.1 How does FEI propose to allocate Biomethane O&M costs to FEVI from 2015 onwards and how will the reduction in 2015 FEI Biomethane costs be reflected in the forecast 2015-2018 O&M and capital costs.

Response:

To clarify the context of the pre-amble to this question, in its 2012 Biomethane Application, FEI made the assumption that if the FEI and FEVI amalgamation were to be successful then the Biomethane service offering would be offered to FEVI customers in 2015.

The amounts of O&M and capital included in the 2013 base, from which the 2015 - 2018 formula amounts will be forecasted, are based on serving FEI customers. The addition of FEVI customers will require incremental O&M expenditure to educate and promote the service offering to the FEVI service region. As such at this time no allocation to FEVI is necessary.

350.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Tab C, Section 4.6.2, pp. 241-242

Exhibit B-11, BCUC 1.99.1

Biomethane Capital and O&M Costs

On pages 241 to 242 of the Application in section 4.6.2 "Biomethane Capital Expenditures," FEI notes that FEI filed its "Post Implementation Report and Application for Approval of the Continuation and Modification of the Biomethane Program on a Permanent Basis" (2012 Biomethane Application) on December 19, 2012 and that the projected Biomethane capital expenditures in this Application assume that the 2012 Biomethane Application is approved with a similar program structure to that approved in the original Biomethane Application filed in June 2010. FEI further states, "If there are any impacts on the Biomethane interconnection forecasts resulting from the current Biomethane application, <u>FEI will adjust its forecasts if applicable</u>." (Exhibit B-1, p. 242) [Emphasis added]

In Exhibit B-11 to this Application, in response to BCUC 1.99.1 regarding incremental O&M spending in 2012 and 2013 in the Energy Solutions and External Relations department for various initiatives FEI states, "The company requested that starting in 2012 the costs of making the RNG service offering available to customers, including program administration and customer education to all non-bypass customers, be included in O&M. Prior to 2012 these costs were recorded in a deferral account. FEI expects to continue providing this service offering to its customers, and thereby incur the associated expenditures, <u>subject to the Commission decision on FEI's Biomethane Service Offering</u> (Post Implementation Report and Application for Approval for the Continuation and Modification of the Biomethane Program on a Permanent Basis) application filed on December 19, 2012." (Exhibit B-11, BCUC 1.99.1) [Emphasis added]

350.1 In the event the Commission decision on the 2012 Biomethane Application impacts the assumptions relied on in this Application regarding the O&M and capital costs related to FEI's Biomethane Service Offering, please describe how FEI proposes to incorporate the necessary adjustments to the O&M and capital estimates into the evidence in this Application?

<u>Response:</u>

An appropriate adjustment to reflect the Biomethane Application decision would be made to the 2013 base O&M and/or base capital expenditure from which the PBR formula amounts are calculated. This adjustment, if necessary, would be included in an Evidentiary Update.

351.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Tab C, Section 4.6.2, p. 241

FEI Biomethane Purchase Agreement between FEI and Greater Vancouver Sewerage and Drainage District Streamlined Review Process (GVS&DD SRP), Exhibit B-8, Undertaking No.1

Biomethane Interconnection Costs

On page 241 of the Application in Section 4.6.2 Biomethane Capital Expenditures FEI states:

> "Biomethane interconnection expenditures in 2013 are based on approved projects through BCUC Order G-70-13. FEI is anticipating an increase of approximately $2.8 million in 2014 compared to 2013 with a return to lower levels in the following years. These forecasts are based on known projects that have been filed with the BCUC, as discussed below."

In the Streamlined Review Process for review of the FEI Biomethane Purchase Agreement between FEI and Greater Vancouver Sewerage and Drainage District (GVS&DD), FEI was asked

> "Were capital expenditure amounts for the GVS&DD interconnect facilities already included in the 2012-2013 RRA rates? If so, what amount was forecast and put into rates in that test period, and does including them in future rates cause double-counting?"

FEI provided the response in Undertaking No. 1 where FEI states:

> "With respect to what has actually been spent in 2012 and 2013, FEI has incurred the bulk of the expenditures for the Kelowna and Salmon Arm projects, and will be incurring a portion of the costs for Earth Renu, Dicklands, and Seabreeze, and this project (GVS&DD). In total, FEI is anticipating incurring the $2.03 million that was approved in FEI's 2012-2013 RRA."

351.1 Please complete the table below showing the actual or projected interconnect expenditure for each of the biomethane supply projects approved to-date on a project-by-project basis for each year from 2010 through 2018. Include the requested information in the form of a fully functioning electronic spreadsheet.

Biomethane Interconnect Facilities Capital Expenditures									
Biomethane Project	**2010 Actual**	**2011 Actual**	**2012 Actual**	**2013 Projected**	**2014 Projected**	**2015 Projected**	**2016 Projected**	**2017 Projected**	**2018 Projected**
Fraser Valley									
Salmon Arm									
Kelowna									
Earth Renu									
Seabreeze									
Dicklands									
GVS&DD									
Total									

Response:

Please refer to Attachment 351.1.

The actual and projected interconnect expenditures provided in this table are based on approved to-date projects as requested and do not include any prospective projects which have been anticipated in Table C4-3 of the Application.

In the course of responding to this IR and reviewing evidence related to this matter, FEI has noted an error made on page 205 of the Application, Table C4-1 related to historical costs for Biomethane interconnection expenditures. These corrections do not affect the financial schedules or delivery rate requests included in this Application. FEI will provide a corrected version of Table C4-1 when it files its next Evidentiary Update.

351.2 For each project in the previous question, please provide a schedule showing the forecast, actual and capital cost variance for each project. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

While the 2012-2013 RRA included an annual estimate of costs for biomethane interconnection expenditures, interconnection costs for individual projects were not included in the 2012-2013 RRA forecast or approved on a project basis by the Commission in Order G-44-12. Prior to 2012, biomethane interconnection expenditures were not included in the RRA forecast. Therefore, FEI is unable to provide the capital cost variance as compared to an approved amount for each individual project.

The amount of $2.03 million for biomethane interconnection was included in the total capital expenditures approved as part of the 2012-2013 RRA.

With regard to what has actually been spent in 2012 and 2013, FEI has incurred the bulk of the expenditures for the Kelowna and Salmon Arm projects, and will be incurring a portion of the costs for Earth Renu, Dicklands, and Seabreeze, and GVS&DD. In total, FEI is anticipating incurring the amount anticipated to be spent in its 2012-2013 RRA. Actual/forecast capital for the projects completed or in progress has been provided in response to BCUC IR 2.351.1.

351.2.1 If FEI's actual capital costs were lower than forecast, should the Biomethane capital costs included in the 2013 Base capital be reduced to reflect FEI's actual experience? Please explain why, or why not.

Response:

FEI is not anticipating that its interconnection capital costs will be lower than forecast.

In addition, as shown in Table C4-3, FEI is forecasting that Biomethane Interconnection spending will be above the 2013 Base level for each year of the PBR Period.

THERMAL ENERGY/FORTISBC ALTERNATIVE ENERGY SERVICES (FAES)

352.0 Reference: THERMAL ENERGY

Exhibit B-11, BCUC 1.205.1

Thermal Energy Services – O&M

In response to BCUC 1.205.1, FEI states, "Directive 25 of Order G-44-12 did not require that financial schedules be provided. The FEU have complied with the directive and have broken their activities into traditional gas operations and TES. TES activities are held in FAES, which is a separate legal entity and is not the subject of this Application. Traditional gas operations are included in the financial schedules filed with this Application."

352.1 Please confirm that directive 25 of the FEU 2012-2013 RRA Decision Order G-44-12 specifically directed FEU to update its corporate service and shared service agreements?

Response:

FEU confirms that, in compliance with directive 25, it has updated its corporate service and shared service agreements. These agreements were filed in 2011 along with the 2012-2013 RRA covering 2012 and 2013 and updated agreements were filed with this Application covering periods after 2013 as Appendices F1 and F2.

On page 278 of the Application, FEI indicated the following regarding the shared service agreements for gas operations between FEI and FEVI/FEW:

Since FEI completed a review of the Shared Services agreement and cost allocation approach as part of the 2010-2011 RRA with validation by KPMG, no changes in methodology have occurred since the time of the 2009 review that would warrant making any change to the Shared Service Agreement currently in place. For this filing, FEI updated the approved model for changes in the department's forecast O&M numbers along with changes in the organization structure, and has provided updated agreements in Appendix F1 in accordance with the Commission's direction. The cost allocation methodology and drivers used remain the same as that previously approved.

On pages 280 and 281 of the Application, FEI indicated the following regarding the corporate service agreement for gas operations between FEU and FHI:

While there has been a limited amount of change since 2009 in the Corporate Services costs, FEI has engaged KPMG to review the corporate costs. The report of KPMG is included in Appendix F2. While the costs of many of the various cost centres have changed *in relative proportion, the total 2013 projected fee to FEU is unchanged from what was approved.*

On pages 276 - 278 of the Application regarding sharing of services related to TES offerings between FEI and FAES, FEU indicated:

FEU also observes that there is insufficient time prior to filing the Upcoming RRA to address the directives in the AES Inquiry Report related to the scaled regulatory review of TES activities, the allocation and recovery of the Thermal Energy Services Deferral Account (TESDA) or the recommendation regarding the Code of Conduct and Transfer Pricing Policy (COC/TPP).

As a result of these other ongoing processes, FEI has not addressed the allocation of corporate and shared services to the TES offerings in this Application, but has requested a deferral account to ensure that natural gas ratepayers are held whole.

352.1.1 Has this been done? If so, please provide the updated agreements.

Response:

Yes. Please refer to the response to BCUC IR 2.352.1.

352.1.2 If not, based on this directive, is it fair to say that the Commission expected FEU to revisit its cost allocations for shared and corporate services? If you disagree, please comment on why FEI believes the Commission made this directive.

Response:

FEI did revisit its cost allocations for shared and corporate services. Please refer to the response to BCUC IR 2.352.1.

352.1.3 If the agreements have not been updated, is it fair to say that FEU is not in compliance with this directive at this time?

Response:

The agreements have been updated. Please refer to the response to BCUC IR 2.352.1.

352.2 Would FEI agree that based on Directive 25, the Commission expected: a) more rigor be put into assessing and identifying and b) more data to be provided on FAES cost within this Application?

Response:

Please refer to the response to BCUC IR 2.352.1. Although the Commission may have expected more rigor and data to be provided when Directive 25 was issued, neither the outcome nor timing of the AES Inquiry was known at that time. As discussed with Commission staff, the timing and further processes (CoC/TPP review) that resulted from the AES Inquiry made it impossible to complete a rigorous review of FAES cost allocation, and as a solution to address the concern, the TESDA Overhead Variance deferral account has been requested. Commission staff involved in those discussions agreed with FEU that timing, and availability of Commission staff resources, did not allow for a review of the CoC/TPP prior to the filing of this Application.

Regarding the allocation of corporate and shared services agreements on FAES costs within this Application, FEI believes that with the use of the requested deferral account, it has provided a solution that ensures natural gas ratepayers and thermal energy customers are held whole while the issues of the COC/TPP are reviewed and assessed. Any variance between those costs included in this Application and what is finally determined would be captured in the requested deferral account.

FEU representatives have met with Commission staff to develop a collaborative approach to establish a Code of Conduct and Transfer Pricing Policy. Initial consultation sessions with interested parties have started.

353.0 Reference: THERMAL ENERGY

Exhibit B-13, COC 1.4.5.1

Thermal Energy Services – Overhead Recoveries

In response to COC 1.4.5.1, FEI states, "The O&M costs are shown as net of what is directly charged to TESDA or an FAES capital project with the exception of the overhead recoveries that are recovered through the TESDA overhead allocation. For the TESDA-overhead related costs, the costs reside in the individual departments and the recovery resides in the Corporate department."

353.1 Please complete the following table for the Overhead recoveries applied to FAES' operations:

Description of Component of Overhead recovery allocation	Forecast Value of Component in 2013 ($)	Value of Component in 2012 ($)	Value of Component in 2011 ($)	Value of Component in 2010 ($)	Explain how this component is quantified. ie through invoices, timesheets, discussion with management, best estimate	Has this method of quantification changed since the 2012-2013 RRA? If so, please identify the changes.
Total						

<u>Response:</u>

FEI is unable to complete the chart as requested. In its 2012-2013 RRA, FEI had applied to allocate approximately $500 thousand of overhead from natural gas customers to thermal energy customers. As part of Order G-44-12, the Commission adjusted the amount to approximately $850 thousand.

FEI has evidentiary support for the $500 thousand calculation. The underlying support for how FEI had arrived at the approximately $500 thousand was provided in response to BCUC IR 1.78.1 in the 2012-2013 RRA and is included as Attachment 353.1.

353.2 Are FAES CPCN projects a cost driver of this Overhead recovery allocation?

Response:

No, most of the costs that are subject to the overhead recovery, like executive and support and back office functions, are not related to the amount of FAES capital projects. The overhead allocation covers things such as office space and IT support for employees dedicated to FAES. In contrast, capital costs for a CPCN project are directly allocated to the individual projects. In the event that CPCN projects increased to the point where more dedicated office space was required for FAES, for example, then the CPCN projects could indirectly drive overhead allocation. However, FEI notes that the current overhead allocation determined by the BCUC is much higher than FEI's cost based allocation; thus, even an indirect requirement for more office space would be well within the current allocation.

353.2.1 If not, please explain your response and provide alternative cost driver(s) that FEI considers is more appropriate.

Response:

Most of the items included in the overhead allocator are more general or supportive in nature and are not directly related to certain activities in FAES. The direct correlation is with time incurred related to TES activities. The TPP/CoC process will review the resource sharing between the regulated affiliates FEI and FAES (if any) and the appropriate cost structure.

353.3 What percentage is this overhead recovery allocation as a percentage of total FEI operating costs?

Response:

The overhead charged to the TESDA is approximately $854 thousand and the total FEI O&M costs are projected at $221,333 thousand in 2013 (Table C3-1), making the recovery 0.385 per cent. FEI also directly charges FAES for staff time associated with FAES work.

353.3.1 Why is this appropriate given the strategic importance of FAES activities?

Response:

The overhead allocation represent the time of those individuals who work on supporting the thermal energy business but who do not directly charge their time to either TESDA or FAES. These individuals provide support or strategic direction to the thermal energy business and the overhead allocation, as originally proposed by FEI at $500 thousand, represented the time they expected to spend supporting the FAES business. The $854 thousand amount in 2013 was determined by the Commission in Order G-44-12. The TPP/CoC process will review the resource sharing between the regulated affiliates FEI and FAES (if any) and the appropriate cost structure.

353.4 Does FAES benefit from the lending abilities of FEI? For example, can FAES lend money at a lower rate through its affiliation to FEI?

Response:

No, FAES does not benefit from lending abilities of FEI. FAES utilizes the credit facilities of FortisBC Holdings Inc.

353.4.1 If yes, please explain how this benefit has been quantified and allocated to FAES.

Response:

Please refer to the response to BCUC IR 2.353.4.

353.4.2 If no, please confirm that FAES maintains its own, independent credit facilities and provide the interest rates of FAES as compared to FEI.

Response:

Please refer to the response to BCUC IR 2.353.4. For rate making purposes, FAES utilizes, as directed by the Commission, a deemed interest rate for each project rather than an interest rate for FAES in aggregate as the question suggests.

354.0 Reference: THERMAL ENERGY

Exhibit B-11, BCUC 1.202.1

Thermal Energy Services –O&M

In response to BCUC 1.202.1, FEI states that "FEI employees who work directly on TES projects continue to charge time to internal orders timesheets as a method of tracking time and allocating costs to TES. Certain functions, senior management, continue to be included in the overhead allocation of $854 thousand."

354.1 If an employee of FEI who also works on FAES activities has any unused or low productive time, will any of this time be allocated to FAES? If so, please describe.

Response:

In accordance with the existing Transfer Pricing policy, all direct costs related to the FAES business have been charged to FAES using loaded labour rates (i.e. timesheets), plus through the overhead allocation of $854,000. The existing Transfer Pricing Policy already allows for time off including vacation and sick time in the labour charge-out rates.

354.2 What tools does FEI use to monitor utilization, productivity and effectiveness of employees?

Response:

FEI management is responsible for monitoring the productivity and effectiveness of its employees. Performance plans and personal objectives are developed, aligning the efforts of employees to the Company's priorities. Additionally, where appropriate and relevant, performance metrics are utilized.

354.3 Has FEI documented any formal policies for cost allocations for FAES activities that are distributed to all staff? If so, please provide copies of internal policies for FEI staff related to rules and procedures for allocating time or costs to FAES activities and note which date these policies were distributed to employees.

Response:

Where costs between FEI and FAES are directly charged, FEI follows the existing BCUC approved Code of Conduct and Transfer Pricing Policy. FEI employees are reminded annually of the Code of Conduct and Transfer Pricing Policy and their requirements. The last reminder was provided on August 2013 on the Company's intranet site, advising all employees to review and refresh their understanding of the Code of Conduct and the Transfer Pricing Policy.

354.4 What, if anything, has changed in FEI's cost allocation policies since the 2012-2013 FEU RRA? Please describe the changes in detail.

Response:

The cost allocation policies have not changed since the 2012-2013 FEU RRA as FEI is still following the existing Code of Conduct and Transfer Pricing Policy.

While the cost allocation policies have not yet changed, a number of events have happened around thermal energy that provide clarity regarding cost allocations.

- In March 2012, the Commission issued a decision on the CPCN application for provision of thermal energy services to the Delta School District that required assignment of the Delta School project to an affiliate company of FEI. The Delta School project and other thermal energy projects have been assigned to or undertaken by FAES, including the PCI Marine and TELUS Gardens projects.
- Additionally, in December 2012, FEI received the AES Inquiry Report, which recommended greater structural separation between utility services and initiation of a process to update the Code of Conduct and Transfer Pricing Policy in respect of the interaction between the regulated utility and related non-regulated businesses and between affiliated regulated businesses. In accordance with the recommendation, FEI is in the process of updating the Code of Conduct and Transfer Pricing Policy. A target to file an updated Code of Conduct and Transfer Pricing Policy by the second quarter of 2014 was developed in consultation with Commission staff.
- Also, to achieve more structural separation as recommended, FEI will transfer those employees who work on mainly thermal energy projects into a separate company effective January 1, 2014.

355.0 Reference: THERMAL ENERGY

Exhibit B-11, BCUC 1.206.2

Thermal Energy Services –O&M

In response to BCUC 1.206.2FEI states that "As a result of its competitive (i.e. market based) approach to compensation, FEI's believes that what it charges to FAES for labour services is consistent with the requirement for market price or a fully allocated cost."

355.1 Please confirm that FAES is indicating that it believes its compensation costs alone approximate the market price for the services employees provide?

Response:

FEI clarifies that a more appropriate comparison for consultant prices available in marketplace would include both FEI's fully loaded labour rates, including benefits and concessions, and related overhead costs to support the employees providing the labour services. With the use of its fully loaded labour rates that are reflective of FEI's market-based approach to compensation and the proposed $500,000 overhead allocation, FEI is essentially charging its regulated affiliate FAES market based pricing for services provided.

Please refer to the response to BCUC IR 2.355.3.

355.2 Would FAES provide services to arm's length third parties at the amounts it allocates to FAES?

Response:

FEI interprets the question as "Would FEI provide services to arm's length third parties at the amounts allocated to FAES?".

Under the existing Transfer Pricing Policy, for direct labour services, there is no requirement for FEI to provide the same services to arm's length third parties. Regarding the overhead allocation to the TESDA, FEI is currently charging a Commission-determined amount of $854 thousand. FEI cannot determine if this set amount would be the equivalent to a third party charge.

355.3 Has FAES verified, through any arm's length party, that similar services are available for the amounts allocated to FAES such as through comparing hourly rates for employees with hourly rates for contractors?

Response:

Yes, FAES has compared hourly rates and believes that the rates it is paying to FEI are appropriate and comparable. Following is a comparison of estimated hourly rates charged by FEI (including estimated amounts related to the overhead allocation – i.e. $854 thousand) to FAES for services provided compared to consultant rates available for similar services.

FAES / FEI Equivalent	$/hr.	Integral	$/hr.	Fenix	$/hr.	DEC	$/hr.
President / VP ES&ER	$ 322	Managing Principal	$ 220	Project Director	$ 250	Project Sponsor	$ 200
VP & GM / Director	$ 198	Principal	$ 205				
		Technical Director/Associate Principal	$ 200			Senior Project Engineer	$ 185
Managers (BD/Ops/Engineering)	$ 148	Associate	$ 170	Senior Energy Analyst	$ 150	Project Engineer	$ 160
Project Development Manager	$ 148	Project Manager	$ 143	Project Manager	$ 195	Project Manager	$ 120
		Commissioning Specialist	$ 122				
		Sustainability Consultant	$ 122				
		Senior Designer	$ 115	Professional Mechanical Engineer	$ 135		
		Building Analyst	$ 115				
		Designer	$ 95	Designer	$ 125	Design Engineer	$ 110
						Senior Design Technician	$ 140
		Field Administrator	$ 115				
				LEED Coordinator	$ 100		
		Draftsperson	$ 72			CAD	$ 90
Clerical/Administration	$ 74	Clerical/Project Administration	$ 66			Administration	$ 60

* Includes assignment of overhead allocation estimated at 48%

355.3.1 If so, how do these costs compare?

Response:

Please refer to the response to BCUC IR 2.355.3.

355.3.2 How do hourly rates for FEI employees who perform FAES services compare to contractors used by FEI for comparable services? Provide a table with these hourly rates by employee class.

Response:

Please refer to the response to BCUC IR 2.355.3.

355.4 How does FAES' market based approach to compensation build in a factor to account for support services to administer FAES' activities that would otherwise be necessary if FEI did not provide this administration (i.e. payroll services)?

Response:

The costs of the support services such as payroll services are currently accounted for in the overhead allocation. Following is an excerpt from page 88 of the Commission's AES Inquiry Report dated December 27, 2012 indicating that administrative costs of supporting FAES is included in the overhead component.

> The following costs are currently allocated to the TESDA:
>
> - Overhead - using an annual allocation to represent the administrative costs of supporting TES services;
> - Sales and marketing - based on the 12 employees in the TES Group as well as any direct time from other employees in other areas of the Companies and certain contributions to industry associations; and
> - Direct costs - which relate to a particular project or projects and may be capitalized as part of project costs, such as feasibility studies, design and construction of various actual thermal energy projects.

356.0 Reference: THERMAL ENERGY

Exhibit B-11, 1.172.6, 1.203-1.206

Thermal Energy Services – TESDA Overhead Allocation Variance deferral account

In response to BCUC 1.172.6, FEI states that “The amount that has been included in the 2013 Base O&M as a recovery from the TESDA is identical to the amount approved for 2013 and has been included as a placeholder only… FEI has proposed this deferral account to eliminate the need to canvass the appropriate amount of the allocation in this proceeding. This new TESDA Overhead Allocation Variance deferral account is required to keep customers whole for the PBR Period, given potential changes to the overhead allocation as a result of the TPP/COC review.”

In response to BCUC 1.205.4.1 FEI explains that “The placeholder amount is based on the amount charged that was approved in BCUC Order G- 44-12…. the estimate of approximately $500 thousand that was provided was based on an estimate of time for executive and support services provided to the alternative energy business but this may not be the allocation methodology determined appropriate in the TPP/COC review.”

In response to BCUC 1.203.2 FEI states that “The deferral account is the mechanism that will ensure that, if the Commission determines that more costs should be allocated to FAES or that too many costs have been allocated to FAES, FEI has the ability to ensure natural gas ratepayers and TES ratepayers are both held whole.”

In response to BCUC 1.206.3, FEI states that “The deferral account was requested in order to allow for a smooth transition and to hold natural gas ratepayers whole and all parties neutral while the review of the Code of Conduct and Transfer Pricing is completed.”

356.1 If it is determined that more O&M should be allocated to FAES than has been included in the 2013 base year, please explain how the ratepayers will be “kept whole” during the PBR if this adjustment is made. Include a sample calculation to demonstrate how ratepayers will ultimately receive any benefit.

Response:

The amount of O&M to be allocated to FAES in the base year (2013) has already been decided by the Commission in Order G-44-12 at $854 thousand. FEI has provided a discussion of how the O&M allocation during the PBR period would be adjusted through its TES Overhead Allocation deferral account in response to BCUC IR 1.205.3. FEI also provides the following example for illustration purposes only.

Amounts in $ thousands

	2013	2014	2015	2016	2017	2018
(I - X)		1.018085	1.019165	1.018435	1.018615	1.017975
Base and Formula	$ 854	$ 869	$ 886	$ 902	$ 919	$ 936
Amount determined by TPP/CoC		$ 850	$ 800	$ 750	$ 700	$ 650
Difference to deferral		$ 19	$ 86	$ 152	$ 219	$ 286

In the scenario presented in the table above, the amount that is included as a credit to the O&M will be escalated by the formula. So $854 thousand is the base, and it will increase each year (i.e., a larger amount of credit going to natural gas customers each year). There may be a different amount that is determined as a result of the TPP/CoC review, which in this scenario FEI has shown in the line called “Amount determined by TPP/CoC”. This is the amount that FEI will actually charge to the TESDA and will be recovered from FAES customers. In order to hold FEI natural gas customers whole, the difference between the two amounts (in 2014 the amount of $19 thousand) will be charged to the deferral account and recovered from FEI customers, so that FEI customers will received the same $850 thousand credit ($869 thousand credit to O&M in the formula less $19 thousand debit recovered through amortization of the deferral) that is charged to the TESDA. If the amount determined by the TPP/CoC is higher than the amount included in the formula, the amount recorded in the deferral account would instead be a credit which would be returned to FEI customers through amortization.

356.2 Please discuss the advantages and disadvantages of using only one deferral account (the existing TESDA) to allocate O&M, including overhead, to FAES.

Response:

Although FEI could create additional deferral accounts (for example one for overhead, one for direct O&M, one for direct capital, etc), these details are already captured by the use of internal orders in the existing TESDA deferral account. In response to BCUC IR 1.172.4 filed confidentially, FEI has provided the various categories that were segregated. Thus, FEI sees no advantage to creating more deferral accounts when no more information would be provided through these additional accounts.

356.3 If the Commission decides not to approve the proposed TESDA Overhead Allocation Variance deferral accounts, would this change either rates or the amount of overhead that FEI would allocate to FAES?

Response:

No. For 2013, the amount of recovery and delivery rates has already been approved by the Commission. For 2014 through 2018, in the absence of the TESDA Overhead Allocation Variance deferral account, the 2013 base amount will continue to be escalated by the formula and delivery rate forecasts will not be affected. Therefore, the amount allocated to the TESDA and eventually to FAES will also reflect only the formula amount.

In this scenario, it will not be possible for the amount recovered from FAES to reflect the results of the TPP/CoC that FEI and other stakeholders are currently undertaking to review. In other words, FEI customers will take the risk that the amount that should be charged under the approved TPP/CoC differs from the formula-driven amounts, positive or negative. If this is the result, FEI questions the value of undertaking the TPP/CoC review at all.

FEI submits that it would be inappropriate for the Commission to accept the current level of overhead allocation and at the same time not approve the TESDA Overhead Allocation deferral account. FEI has included the $854 thousand credit in the Base O&M as a placeholder with the understanding that the deferral account would true up to the correct amount. If the deferral account were not approved, FEI would need to re-visit an appropriate amount to include as an overhead recovery in this proceeding. The purpose of the deferral account is to allow for the TPP/CoC review to be completed before determining the appropriate allocation to FAES.

356.3.1 If not, why not?

Response:

Please refer to the response to BCUC IR 2.356.3.

356.3.2 If so, what amount of overhead is appropriate to allocate to the TESDA to be recovered from TES customers for the PBR period? Please provide a breakdown of calculations and any assumptions.

Response:

FEI has not proposed what the appropriate amount is to be recovered from the TESDA over the PBR Period. The TPP/CoC process will review the resource sharing between the regulated affiliates FEI and FAES (if any) and the appropriate cost structure. Under FEI's proposed deferral account method, the amount ultimately determined will be credited to FEI customers and recovered from the TESDA. FEI cannot prejudge what the outcome of that review will be and therefore cannot provide an estimate.

356.4 If any amount of the deferral account is unrecoverable (ie. due to a project that doesn't ultimately occur), will FEI ratepayers be asked to pay for these unrecovered amounts previously deferred in relation to the failed project?

Response:

In reference to the TESDA, no. As previously stated in various proceedings, the shareholder or the customers of thermal energy will be responsible for the recovery of all amounts that have been deferred in the TESDA.

357.0 Reference: THERMAL ENERGY

Exhibit B-11, BCUC 1.203.4, 1.203.4.1,

Thermal Energy Services – Transfer and Separation of Staff

In response to BCUC 1.203.4, FEI states that "FAES did not have any direct employees in 2012 and 2013 so it has zero FTEs and headcount for each of these years."

In BCUC 1.203.4.1, FEI states that "FEI can confirm that there are approximately 12 to 14 employees working in the TES area. FEI intends to have these employees transferred to an affiliated company effective January 1, 2014. FEI prefers to move employees effective January 1 of a fiscal year due to the negative tax consequences to the employee and employer of a move part way through a calendar year. If the employees are moved on a date other than January 1 then it may result in double contributions/deductions for employment insurance and the Canada Pension Plan."

357.1 Please quantify the total negative tax consequences that would occur if the employees were moved before January 1, 2014.

Response:

The negative tax consequences are approximately $20 thousand, which is roughly split $10 thousand to employees and $10 thousand to FEI. The negative consequences are the double payment in a fiscal year of Employment Insurance premiums and Canada Pension Plan contributions by both the employee and employer.

358.0 Reference: THERMAL ENERGY

Exhibit B-13, COC 1.6.7; Exhibit B-11, BCUC 1.204.1; Retail Markets Downstream of the Utility Meter (RMDM) Guidelines, p. 27

Thermal Energy Services – Transfer and Separation of Staff

In response to COC 1.6.7, FEI states, "If the best solution for the customer is to use a TES provider, Energy Solutions Managers are instructed to inform the customer of their options, including contacting FAES. FEI staff are trained to help customers find the best energy solution for their needs with the ideal objective incorporating natural gas use. FEI staff will therefore advise customers accordingly.

Are they specifically told to mention FAES as an alternative? No
Are they specifically told not to mention FAES as an alternative? No"

In response to BCUC 1.204.1, FEI also states that "The FEI Energy Solutions Department is dedicated to identifying the needs of customers so that the best solution may be found for them. In this context, natural gas service is discussed along with other viable alternatives. In some cases, natural gas is not the solution that the customer desires, but TES is. In those cases, the customer may be informed of the FAES-dedicated contact to reach to explore a TES solution."

358.1 Has FEI made any changes or updates to its formal Communications & Public Affairs Plan 2010/2011 filed the 2012-2013 RRA (2012-2013 RRA, Exhibit B-17, Attachment 29.1)? If so, please summarize these changes and provide the revised Communication Plan.

Response:

The Company has replaced the Communications & Public Affairs Plan filed in the 2012-2013 RRA with the 2013 Strategic Communications Overview. Please refer to Attachment 285.2 provided in response to BCUC IR 2.285.2.

358.1.1 If not, please explain why FEI believes employees are specifically not told to mention FAES activities given the role FAES plays in the Communications & Public Affairs Plan 2010/2011?

Response:

Employee behavior and approach is managed through the employee / manager relationship and guided by the Code of Conduct.

Employee communications provide employees with information about the Company so they are aware of the different projects and initiatives that the Company is involved in.

Refer to the 2013 Strategic Communications Overview for 2013 provided in BCUC IR 2.285.2.

358.2 Does FEI agree that there is value to FAES to have FEI provide information of its TES products to its customers which is not available to other competitors of FAES?

Response:

This response addresses BCUC IRs 2.358.2, 2.358.3, 2.358.4, 2.358.5, 2.358.6 and 2.358.7.

These issues were canvassed and resolved through the AES Inquiry that ***determined*** that Thermal Energy Services are regulated under the *UCA* and ***recommended*** that TES projects are most appropriately undertaken through an Affiliated Regulated Business. Accordingly, FAES is not a NRB, as implied by the extract from RMDM guidelines included with this IR.

Further, FEI is following the Commission's ***recommendation of greater separation*** by the creation of FAES and transfer of the business to an Affiliated Regulated Business. This is being performed in an orderly and responsible manner. This is consistent with the pace of the development of a Scaled Regulatory Framework that the AES Report ***directed*** Commission Staff to bring to the Commission for approval which is still underway.

Finally, FEI stands behind the practice of focusing on the best solution for the customer and will certainly inform customers of their options "***including*** contacting FAES***"***. FEI staff does not direct any customers to contact FAES, they simply make the customers aware of their energy solution alternatives, which include mentioning TES and FAES. The value in this practice accrues to FEI's customers because FEI staff are informing customers about their options, which in FEI's view is a reasonable and appropriate thing to do for its customers. It is also key from FEI's perspective that, if a customer intends to pursue TES that it is aware of the options that involve natural gas as a component. These types of solutions that allow FEI to retain some load are offered by FAES. There is no unfair competitive advantage or "value" that can or should be ascribed to this information and customer service approach. FEI staff are not selling the services of FAES, but rather informing their own customers of their options in the hope of retaining as much natural gas load as possible.

FEI submits that it is in compliance with the approved code of conduct and that its activities are consistent with the directives in the AES Report, the recommendations in the AES Report and the pace of change that both FEI and the Commission are able to implement these directives and recommendations.

358.3 What value, if any has been assigned to FAES for this benefit and how has it been determined?

Response:

Please refer to the response to BCUC IR 2.358.2.

358.4 In the absence of a formal change to the code of conduct or transfer pricing policy, does FEI believe it is reasonable that the Commission would expect FEI to take more formal interim measures to accomplish a greater degree of separating FEI and FAES activities?

Response:

No. Please refer to the response to BCUC IR 1.358.2.

358.5 Explain how the current activities are consistent with the AES Inquiry decision?

Response:

Please refer to the response to BCUC IR 2.358.2.

"iii) No regulated company personnel will **preferentially direct customers seeking competitively offered services to an NRB.** If a customer, or potential customer, requests from the regulated company information about products or services offered by an NRB or its competitors in downstream markets, the regulated company may provide such information, including a directory of retailers of the product or service, but shall not promote any specific retailer in preference to any other retailer. [Underlined for emphasis) (RMDM Guidelines, p. 27)

358.6 Does the FEI Energy Solutions Department practice of informing customers of the FAES-dedicated contact to reach to explore a TES solution constitute regulated company personnel **preferentially directing "customers seeking competitively offered services to an NRB**"? Please explain why, or why not. [Highlighted for emphasis]

Response:

No. Please refer to the response to BCUC IR 2.358.2.

358.7 Should the FEI Energy Solutions Department and all other FEI employees be prohibited from directing "customers seeking competitively offered services" to FAES or other FortisBC NRBs until the review of FEU's Code of Conduct and Transfer Pricing Policy is completed? Please explain why, or why not.

Response:

No. Please refer to the response to BCUC IR 2.358.2.

359.0 Reference: THERMAL ENERGY

Exhibit B-13, COC 1.4.3; Exhibit B-11, BCUC 1.204.1

Thermal Energy Services – Transfer and Separation of Staff

In response to BCUC 1.204.1, FEI states that "since early 2013 and going forward, the FEI Energy Solutions Department's role in promoting TES no longer exists. Currently there are two staff that are dedicated to promoting TES for FAES. These two staff members have physical separation from the natural gas sales staff although they and other staff dedicated to FAES remain as FEI employees at this time."

In response to COC 1.4.3, FEI states that "FEI is proposing to move those FEI employees who spend a significant amount of time working on TES activities to an affiliated entity starting January 1, 2014. It is expected that this would be 12 to 14 employees. Other FEI employees, who only spend a small amount of time on TES related activities, will continue to charge via completing timesheets."

359.1 Please confirm that of the of the 12 to 14 FEI employees who focus on FAES activities, only two have physical separation from the natural gas sales staff.

Response:

In fact, all the dedicated employees who focus on the FAES activities are physically separated from the natural gas sales staff that is located in Surrey. This includes the two FEI sales managers who work on FAES matters that work out of the Burnaby location at 3700 – 2nd Ave which is owned by FEI.

The AES Report ***recommended*** that TES activities are most appropriately undertaken through an Affiliated Regulated Business. Further, the AES Report recommended that FEI should ***undertake a collaborative process*** to establish a Code of Conduct and Transfer Pricing Policy governing the interactions between affiliated regulated businesses. The Commission also recommended that sharing of services among affiliates should be done on the basis of the higher of market pricing or the fully allocated costs once the Code of Conduct and the Transfer Pricing Policy are approved. This infers that there will be an ongoing relationship between regulated affiliates that may include sharing of services and does not require or even infer that there needs to be a physical separation of personnel.

FEI has decided to follow the Commission recommendation to provide TES through a regulated affiliate and is in the process of transferring staff that work solely on FAES out of FEI. Currently, there are approximately 13 personnel at FEI that are dedicated to TES activities and charge their time entirely to TES projects or TES general business development expense. As such, these costs are not included in the revenue requirements for natural gas rates and have no impact on this Application.

For this Application, given the need to include a recovery of an amount for the revenue requirement of the natural gas service, FEI is proposing to establish a deferral account for any variances in the overhead allocation as the appropriate step at this time. Subsequently, should the upcoming TPP/CoC review result in an adjustment to the overhead allocation, FEI will adjust the allocation going forward and collect or return any difference between the new amount and the $854 thousand from natural gas customers. This $854 thousand amount represents less than 0.4 percent of the total O&M for FEI in 2014 and less than 0.1 percent of the total revenue requirement for FEI in 2014.

359.1.1 Why aren't all 12 to 14 employees who focus on FAES activities physically separated from the natural gas sales staff?

Response:

In fact, the employees who focus on FAES activities are physically separated from the natural gas sales staff. Please review the responses to BCUC IRs 2.359.2 and 2.359.2.1.

359.1.2 Please explain how this is consistent with the AES Inquiry Decision?

Response:

In fact, the employees who focus on FAES activities are physically separated from the natural gas sales staff. FEI believes this is entirely consistent with the AES Inquiry Decision. Please refer to the response to BCUC IR 2.359.1.

359.2 Please provide further description of the physical separation between FEI's Energy Solutions managers, and the two TES-dedicated energy solutions managers who promote TES for FAES. Do these employees work at a different physical address? Why or why not?

Response:

Yes, these employees work at a different physical address. As explained in the response to BCUC IR 2.359.1., they and the majority of other staff who focus on TES projects are based in a Burnaby office, whereas FEI Energy Solutions managers are based in Surrey. (Besides the FAES-focused staff in Burnaby, two staff members who focus on FAES are currently based out of the FEVI Langford office).

359.2.1 Please provide the address of the offices where FAES employees will work. Please also indicate who owns the facility where these offices are located, and if it is a leased facility, which company is signatory on the lease.

Response:

As noted in the response to BCUC IR 2.359.1, the address where FAES-focused employees are based and the address where FAES employees will work is 3700 – 2nd Ave, Burnaby. This is also the corporate address of FAES. It is a building owned by FEI and FAES pays for the use of the space via the FEI overhead allocation to the TESDA.

359.3 How many FTE equivalents are allocated to FAES activities (based on tracked time and fully dedicates staff members)?

Response:

As noted in the response to BCUC IR 2.359.1, the current staff count is approximately 13, and over 2013 approximately 12 FTE have been allocated to FAES activities.

359.3.1 What is this amount as a percentage of total FEI employees?

Response:

Assuming approximately 13 FTE for FAES-focused employees and the FTE count as of September 30, 2013 for FEI of 1,579, the percentage would be approximately 0.8% in 2013.

359.4 Please elaborate on the specific "corporate and administrative services" that FEU will continue to provide FAES after the 12-14 employees are transferred to FAES.

Response:

To be clear, these FEI employees will be transferred out of FEI to an affiliate of FEI, which may be FAES.

The specific corporate and administrative services are detailed in the Attachment 353.1 provided in response to BCUC IR 2.353.1.

359.4.1 Please identify what company those employees who will provide "corporate and administrative services" to FAES reside in. Describe how these costs are allocated between the entities and provide an estimate of these costs for 2013 and 2014.

Response:

The employees reside in FEI.

For 2012 and 2013, FEI has an approved reduction of the revenue requirement for natural gas services of $750 thousand for the services that it provides to FAES that are not charged directly via timesheets, plus a further reduction of $92 thousand in 2012 and $104 thousand in 2013 for IT services (referred to in BCUC IR 2.359.4 as "corporate and administrative services"). For 2012 and 2013, the FEU submitted a breakdown of the services and costs that FEI provides to TES amounting to $497,377 and $511,686 respectively (Attachment 353.1 provided in response to BCUC IR 2.353.1). These amounts relate to the period that FEI was intending and applying to provide TES as a class of service. For 2014, FEI has proposed to maintain the allocation at $854 thousand and capture any variances from the $854 thousand and the ultimate amount approved for the overhead allocation that is expected to be an outcome of the upcoming TPP/CoC review.

359.4.2 Based on the Commission's decision in the AES Inquiry, shouldn't all support and administrative services related to these employees also be separated?

Response:

No. Please refer to the response to BCUC IR 2.359.1.

359.5 Please explain why, after the transfer of employees, there will still be FEI employees that spend small amounts of their time on TES activities. In your explanation please describe the nature of the work anticipated for those employees. Will this work be specific to TES projects, or more general business development?

Response:

The employees that will be transferred are those who are dedicated to developing and managing the FAES business. Moving these employees out of FEI is consistent with the recommendations of the AES Inquiry Report. The work of other FEI employees may support TES projects but is unlikely to support FAES/TES business development. Please note that the FAES business is not just a development exercise but has ongoing operations. As such it requires administrative and front line O&M services. It is more efficient and therefore beneficial to customers of FEI and FAES for FAES to continue to make use of these services. Such use, however, does not impair the structural separation.

359.5.1 How many individual FEI employees does FEI anticipate will continue to work on TES activities while being an employee of FEI? How many FTE hours does FEI anticipate that these individuals will work on TES activities?

Response:

Given the work is related to administrative services and front line O&M, the work will generally be a few hours per month or year for an individual employee but the work may be distributed over a relatively large number of employees. The allocation for administrative services is explained in the response to BCUC IR 2.359.4.1. FAES expects that the allocation may decline, on a forward-looking basis, as FAES may build internal capabilities for certain support functions depending on the timing and growth of FAES. FEI understands that FAES is reviewing options with respect to O&M in light of increasing O&M activities but is unable to anticipate how this may translate to the level of involvement of FEI individuals other than the expectation that it will not be significant.

359.5.2 How will costs associated with this work be accounted for and how has it be treated in the test period?

Response:

FEI assumes the costs referred to are those of the FEI staff focused on FAES that will be transferred out of FEI. The costs for these employees are allocated to FAES, either to general expense (including the TESDA) or to specific TES projects of FAES. During the test period, these employees will continue to be costs of FAES.

For the FEI RRA, the costs are currently not included nor will they be during the test period.

Please refer to the response to BCUC IR 2.359.1.

359.5.3 Does FEU consider this arrangement to be consistent with Directives of the AES Inquiry? Please explain.

Response:

Yes. Please refer to the response to BCUC IR 2.359.1.

360.0 Reference: THERMAL ENERGY

Exhibit B-13, COC 1.3.2, 1.4.2

Thermal Energy Services – Separation of Information and Resources

In response to COC 1.3.2, FEI states, "FEI confirms that FEI personnel with access to customer information do not communicate with FEI personnel working on FAES' TES projects regarding customer information including names, contact information, EEC applications, historical natural gas consumption or any relevant information known to FEI in the course of its business that is not in the public domain."

360.1 Is a formal policy documented and distributed to staff that indicates this policy?

Response:

Besides the approved Code of Conduct for FEI, there is no additional formal policy documented and distributed to staff that indicates this policy.

360.1.1 If not, how does FEI insure that all staff are aware of this policy?

Response:

The employees are made aware of the Code of Conduct (refer to the response to BCUC IR 2.354.3) and impacted staff have been made aware of the outcome of the AES Inquiry Report and specifically the Code of Conduct principles and guidelines that have been adapted to include information sharing among Affiliated Regulated Businesses.

360.2 If FEI was to become aware of an instance where this policy was not followed, what would occur and has this ever happened?

Response:

Since the publishing of the AES Inquiry Report, FEI is not aware of this happening. If this were to happen, FEI may take a range of actions, depending upon the specific nature of the issue.

In response to COC 1.4.2, FEI states "Employees from several FEI departments communicate or interact when a Thermal Energy Service (TES) project of FAES is being developed or after it is in service…. The Director, EEC, interacts occasionally with staff within FAES, primarily on regulatory matters, and with the Director, Business Development, responsible for FAES, but this is in the context of regular management meetings….As for FEI employees outside the Energy Solutions and the EEC groups, some of these employees may have had direct or indirect communications regarding TES projects of FAES during project development or after the TES projects are in service."

360.3 Please explain how time for the Director's interactions with FAES is transferred into the FAES account?

Response:

The Director, EEC, provides no oversight or direction or supervision or anything else to FAES and as such no time is allocated to FAES. The occasional interaction is no different from what it would be with any third party interaction.

361.0 Reference: THERMAL ENERGY

Exhibit B-13, COC 1.6.2, 1.6.5

Thermal Energy Services – Marketing and Website

In response to COC 1.6.2, FEI states, "The FortisBC website at the URL: www.fortisbc.com provides for a single website address that encompasses all the FortisBC regulated services and therefore includes gas, electric and TES. It is designed with the customer in mind and the type of energy service they are seeking, as opposed to being designed around specific corporate entities. As such the FortisBC website provides a single point of access for all FortisBC's regulated services, thus facilitating a positive interaction for its customers. This approach is consistent with the Commission's Determination in regards to use of the FortisBC brand name as outlined on pages 40-41 of the AES Inquiry Report… Currently, FortisBC is in the process of updating its website in order to recognize that FAES is the entity marketing and providing TES to customers…. the website provides for segregation between gas, electric and TES offerings so while the initial landing page is a common site, it allows for the customer to select the type of service(s) they are interested in."

In response to COC 1.6.5, FEI states that "While the methodology for appropriate cost allocations to FAES from FEI according to the COC/TPP is already in place, such items as the marketing of a new corporate name and thereby the creation of a distinct web page for FAES are currently still under development."

361.1 Given the Directives of the AES Inquiry, does FEI agree that the Commission expects marketing under a new corporate name and using a distinct website for FAES activities?

Response:

This is not FEI's interpretation of the AES Inquiry Report. On pages 41 of the AES Inquiry Report, the Commission determined that "the use of the FortisBC brand name in the AES and New Initiatives market space is an acceptable practice. Care should be taken to distinguish between the services offered by the traditional natural gas utility and services offered by Affiliated Regulated or Non-Regulated Business."

An example of such care taken is to show that FAES is the entity offering TES on the FortisBC website.

361.2 Does FEI agree that a website, corporate name have value?

Response:

The FortisBC name and brand is an intangible asset owned by Fortis Inc. and not by FEI. As such, there is no assigned value to FEI which would support any basis for seeking recovery from FAES for the use of the corporate name FortisBC. Additionally, FEI considers the website as another communication channel, just like media news releases, for which there no discernible market value can be assigned.

361.3 In the absence of separation, what value should FAES allocate for continued use of these FEI assets?

Response:

FEI has provided the response below based on the interpretation that the "asset" refers to the FortisBC website. FEI does not own the FortisBC name or brand.

As indicated in the response to COC IR 1.6.2, the FortisBC website provides for a single website address that encompasses all the FortisBC regulated services and therefore includes gas, electric and TES. It is designed with the customer in mind and the type of energy service they are seeking, as opposed to being designed around specific corporate entities. As such, the FortisBC website provides a single point of access for all of FortisBC's regulated services, thus facilitating a positive interaction for its customers. This approach is consistent with the Commission's Determination in regards to use of the FortisBC brand name as outlined on pages 40-41 of the AES Inquiry Report. Please refer to the response to BCUC IR 2.361.2 in regards to value of a website which is an extension of the corporate FortisBC brand.

361.4 Can FEI track the number of website visits to the TES and FAES activities? If so, how many website visits to FAES activities occurred in 2012 and 2013(to date) and how do these compare to total visits to the Gas or Electric webpages?

Response:

The site visits are provided below:

Site Visits

	2012		2013	
Natural Gas	161,581	74%	190,291	72%
Electricity	44,959	20%	61,574	23%
FAES	10,769	5%	9,046	3%
Total	219,321	100%	262,924	100%

362.0 Reference: THERMAL ENERGY

Exhibit B-11, BCUC 1.206.4

Thermal Energy Services – Corporate Services

In response to BCUC 1.206.4, FEI states that "The FEU will continue to provide corporate and administrative services to FAES as it is currently doing."

362.1 In the 2012-2013 RRA, Exhibit B-1, Appendix G, p.2, FEU indicated that the total potential of 10 TES projects amounted to $250 million. Does FEI continue to share this view?

Response:

FAES also used this figure more recently in its GCOC Stage 2 evidence as a rough and conservative estimate of its total size relative to the benchmark utility. In actual fact, given the wide range of possible projects and investments in each, while it may be possible that the capital costs for 10 projects would potentially amount to $250 million, it is unlikely. As can be seen from the projects filed with the BCUC and approved, most projects are in the range of $5 to $10 million with a few, like the Kelowna DES, in the range of $25 million. Therefore it is unlikely that 10 projects would total to $250 million. FAES does not have $250 million of such projects in development at this time.

362.2 Is it fair to assume that a significant amount of Fortis senior management and executive resources are devoted to developing and assessing new and changing activities? If not, please describe how risk management and strategic direction are influenced by senior management and executives if they do not devote their resources to these new and changing activities.

Response:

FEI's executive and senior management are devoted to managing the business on a day to day basis as well as looking for ways to retain and attract customers. The senior management and executive includes people who are devoted to operations, systems support, HR, First Nations issues, municipal government issues, labour relations, regulatory issues, operating matters and resource planning, and so on. There is an Energy Solutions department and one member of the executive, VP Energy Solutions, who spends a material amount of time related to business development, i.e. finding ways to attract gas customers and add throughput to the system. In recent years, that business development has involved new and changing activities including such things as natural gas for vehicles, new industrial customer acquisitions, etc.

If the question is getting at TES, then the answer would be that "No, it is not fair to assume that a significant amount of Fortis senior management and executive resources are devoted to FAES activities". The very limited number of employees who dedicate significant time to FAES activities provide most of the risk management activities and provide updates to executive around those changing activities. It is estimated that only one executive (VP Energy Solutions) would spend between 5 and 10 per cent of his time on FAES activities, with three other executives between one and two percent. Certain employees and senior management (at the Director level) spend a significant amount of time on FAES activities and FEI has undertaken to move those employees into a separate company effective January 1, 2014. The costs of these employees (except for executive whose time is included as part of the overhead allocation) are charged to the TESDA directly today via timesheets.

362.3 Would it be fair to describe the FAES activities as new and changing activities of Fortis? If not, please explain the extent of Fortis' activities in these areas over the past 10 years.

Response:

It would be fair to describe the activities of FAES as new to Fortis. Fortis started its investment in the thermal energy business approximately eight years ago.

362.4 Would it be fair to say that new and changing activities of Fortis occupy at least 25% of the resources of the senior management and executives? If not, please provide an alternative estimate and describe how this estimate was made.

Response:

25 percent is not representative of the time that senior management and executive spend on FAES activities. Please refer to BCUC IR 2.362.2 for time estimates for executives.

362.5 Are FAES activities reviewed or discussed at board meetings of FEI or any company that transfers/allocates costs to FEI? If yes, please describe the extent of the board's oversight of FAES activities.

Response:

The activities of FAES are included in the FortisBC Holdings Inc. Board material as FAES is a subsidiary of FHI. The Boards of FHI and FEI are the same board and provide oversight to both companies. While the FHI board does provide oversight of FAES activities, the amount of time spent on FAES activities is limited given the relatively small size of the projects in FAES in comparison to the size and complexity of the activities in other businesses. Additionally, FAES has its own Board which provides oversight of the thermal energy business. Please refer to COC IR 2.10.1.

362.5.1 If 25 percent of all senior managers and executives of time was allocated to FAES activities, what would be the resulting impact on the reduction of cost of service and rates for the test year?

Response:

Under FEI's proposal, any change in the executive time charged to FAES would be captured in the TESDA Overhead Allocation Variance deferral as requested in Section D4.1.2 of the Application, created to capture potential variances as a result of changes in time or cost following the TPP/CoC review. As a result, there would be no impact to the cost of service or rates as currently applied for in the test year (2014) since this deferral account balance could not be amortized until after 2014.

Additionally, the 25 percent proposed in this question and the 10 percent proposed in BCUC IR 2.362.5.2 are both an unrealistic and unjustified amount. FAES is a very small component of the FHI portfolio, with most senior managers and executives spending either minimal or no time on FAES activities.

Due to the two items notes above, FEI has not undertaken the analysis to respond to the magnitude of this as it would add no value to the proceeding record.

362.5.2 If 10 percent of all senior managers and executives of time was allocated to FAES activities, what would be the resulting impact on the reduction of cost of service and rates for the test year?

Response:

Please refer to the response to BCUC IR 2.362.5.1.

362.6 Please complete the table below:

Description of projects for which FEU has/expects to request approval from the Commission (CPCN, expense schedule)		2010 (actual project amount applied for)		2011 (actual project amount applied for)		2012 (actual project amount applied for)		2013 (projected amount applied for)		2014 (forecast project amount applied for)	
		$	% of Total	$	% of Total	$	% of Total	$	% of Total	F$	% of Total
Traditional operations:											
1											
2											
3											
	Subtotal										
CNG											
1											
2											
	Subtotal										
LNG											
1											
2											
	Subtotal										

NGV											
1											
2											
	Subtotal										
FAES											
1											
2											
	Subtotal										
Total value of all applied for projects:											

Response:

In preparing the requested table:

1. FEI has not included a separate row for NGV since the requested table already has rows for both CNG and LNG.

2. The information as requested in the table would be misleading because traditional natural gas operations have a CPCN threshold of $5 million and most of the capital spent in this area falls below this threshold. This is in contrast to a CPCN requirement for TES projects that has been set a zero by the BCUC. To allow for a valid comparison, FEI has included all capital (CPCN and non-CPCN) in the table.

Description of projects for which FEU has/expects to request approval from the Commission (CPCN, expense schedule)	2010 (actual project amount applied for)		2011 (actual project amount applied for)		2012 (actual project amount applied for)		2013 (projected amount applied for)		2014 (forecast project amount applied for)		2010 - 2014 Total	
($000's)	$	% of total	$	% of total	$	% of total	$	% of total	$	% of total	$	% of total
Base Capital												
FEI Base Capital	82,365	75%	95,662	80%	102,591	73%	123,781	58%	132,762	12%	537,160	31%
FEVI Base Capital	17,375	16%	17,939	15%	20,117	14%	29,006	14%	28,021	2%	112,458	6%
Subtotal	99,740	91%	$113,601	96%	$122,708	87%	152,787	72%	$160,783	14%	$649,618	37%
Traditional Operations												
1. FEI Huntingdon Station Bypass CPCN		0%		0%		0%	7,977	4%		0%	7,977	0%
2. FEI Kootenay River Crossing Upgrade CPCN	8,304	8%		0%		0%		0%		0%	8,304	0%
3. FEI CTS Transmission & IP System Reinforcements CPCN		0%		0%		0%		0%	220,000	19%	220,000	13%
4. FEI Tilbury Expansion		0%		0%		0%		0%	400,000	35%	400,000	23%
5. FEVI Woodfibre LNG Project		0%		0%		0%		0%	350,000	30%	350,000	20%
Subtotal	$8,304	8%	$0	0%	$0	0%	$7,977	4%	$970,000	84%	$986,281	57%
RNG Upgrader												0%
1. Salmon Arm Project	$1,105	1%		0%		0%		0%		0%	1,105	0%
2. Kelowna Project		0%		0%	$3,094	2%		0%		0%	3,094	0%
3. City of Vancouver Landfill		0%		0%		0%		0%	$6,900	1%	6,900	0%
Subtotal	$1,105	1%	$0	0%	$3,094	2%	$0	0%	$6,900	1%	$11,099	1%
CNG		0%		0%		0%		0%		0%	-	0%
1. Waste Management	751	1%		0%		0%	98	0%		0%	849	0%
2. BFI		0%		0%	1,885	1%		0%		0%	1,885	0%
3. Kelowna School District		0%		0%		0%	371	0%		0%	371	0%
4. Surrey Operations Pump		0%	107	0%		0%		0%		0%	107	0%
5. Smithrite		0%		0%		0%	1,398	1%		0%	1,398	0%
6. Cold Star		0%		0%		0%	1,185	1%		0%	1,185	0%
Subtotal	$751	1%	$107	0%	$1,885	1%	$3,052	1%	$0	0%	$5,795	0%
LNG		0%		0%		0%		0%		0%	-	0%
1. Vedder Transport		0%		0%	2,397	2%		0%		0%	2,397	0%
2. Denwill Stations		0%		0%		0%	800	0%		0%	800	0%
Subtotal	$0	0%	$0	0%	$2,397	2%	$800	0%	$0	0%	$3,197	0%
NGV		0%		0%		0%		0%		0%	-	0%
Subtotal	$0	0%	$0	0%	$0	0%	$0	0%	$0	0%	$0	0%
FAES		0%		0%		0%		0%		0%	-	0%
Delta School District		0%	5,218	4%		0%		0%		0%	5,218	0%
Tsawwassen Springs		0%		0%	1,184	1%		0%		0%	1,184	0%
PCI Marine Gateway		0%		0%	9,315	7%		0%		0%	9,315	1%
TELUS Gardens		0%		0%		0%	8,250	4%		0%	8,250	0%
Kelowna District Energy System		0%		0%		0%	26,900	13%		0%	26,900	2%
Glen Valley		0%		0%		0%	710	0%		0%	710	0%
Brant		0%		0%		0%	179	0%		0%	179	0%
Camden Green		0%		0%		0%	307	0%		0%	307	0%
GT&C 12A Legacy Projects		0%		0%		0%	225	0%		0%	225	0%
SOLO District		0%		0%		0%	4,400	2%		0%	4,400	0%
Marleigh		0%		0%		0%	775	0%		0%	775	0%
Sovereign		0%		0%		0%	4,380	2%		0%	4,380	0%
Seylynn		0%		0%		0%	2,880	1%		0%	2,880	0%
Children and Women's Hospital		0%		0%		0%	-	0%	15,000	1%	15,000	1%
Subtotal	$0	0%	$5,218	4%	$10,499	7%	$49,006	23%	$15,000	1%	$79,722	5%
Total Value of all applied for projects:	$109,900	100%	$118,926	100%	$140,583	100%	$213,621	100%	$1,152,683	100%	1,735,712	100%

Note:

(1) Base capital expenditures for 2010 to 2012 are based on actual expenditures for that year. 2013 and 2014 years are based on forecasts in the 2014-2018 RRA proceeding.

(2) RNG Interconnection expenditures are included in Base Capital.

(3) Tilbury Expansion Project based on preliminary estimates FEI has developed for determining project feasibility; the estimate provided is high end of estimate range of $300-$400 million.

(4) Woodfibre LNG Project based on preliminary estimates FEVI has developed for determining project feasibility; the estimate provided is high end of estimate range of $200-$350 million.

(5) City of Vancouver Landfill Project based on preliminary estimates FEI has developed for determining project feasibility; the estimate provided is mid-point of estimate range and is contingent on full approval of the RNG program.

(6) In 2014, all employees managing FAES projects will be removed from FEI and transferred to a separate company.

(7) Children and Women's Hospital expected to proceed under Stream A review process.

ENERGY EFFICIENCY AND CONSERVATION

363.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1-1, Appendix A, p. 3; Exhibit B-11, BCUC 1.212.5, 1.225.2; NZ Electricity Authority Consultation Charter, December 2012, pp. 12-13[2]

Demand Side Management (DSM) Objective

On page 3, Appendix A of the Application, FEI states, "the primary objectives of DSM are to increase the overall economic efficiency of the energy service it provides to customers and maintain the competitive position of natural gas relative to other energy sources."

FEU state, "DSM project ideas are often brought forward by individuals or companies to 'further their own agenda in some way, rather than pursuing that is best for the market as a whole" (BCUC 1.225.2) and "Declining throughput is one of the most significant challenges facing the utility." (BCUC 1.212.5)

363.1 Please explain why FEU includes 'maintain the competitive position of natural gas' as a Demand-Side Management (DSM) objective. Please include in your explanation if, in theory, this could result in a bias towards energy efficiency and conservation (EEC) programs that provide incentives on gas consuming equipment.

Response:

DSM programs in the broad sense encompass both EEC activities as well as other activities that manage the use of natural gas on the system. These other non-EEC activities include sales efforts to increase load on the system (thereby reducing cost through a more efficient use of the gas system) as well as the development of services that use load more efficiently (NGT for example). These activities help to "maintain the competitive position of natural gas".

Under the existing legislation, the utility is obligated to provide EEC activities that reduce consumption as well. By their very nature, these EEC activities include "energy efficiency and conservation (EEC) programs that provide incentives on gas consuming equipment". A primary way the FEU's EEC programs lead to more efficient use of energy or conserve energy is by providing customers with incentives to help them to upgrade the efficiency of their natural gas consuming equipment, not their equipment that consumes some other form of energy. There is no logic in the utility providing an incentive to a customer to use another form of energy as it is the gas customers that pay for EEC programs.

---

2 http://www.ea.govt.nz/dmsdocument/14242

The objective of maintaining the competitive position of natural gas does not introduce any bias into the FEU's EEC programs. This is because EEC measures help manage customers' natural gas bills through measures that lead to more efficient equipment or reduce consumption. Take the example of a residential customer replacing a natural gas water heater. In the majority of instances, the customer can incur a significantly lower capital cost if they replace the natural gas water heater with an electric water heater. In the Companies' proposed Energy Star ® water heater program, described in detail on pages 24 – 25 of Appendix I-1 to Exhibit B-1-1, the customer would receive an incentive to encourage them to replace an inefficient gas water heater with an efficient gas water heater.

Therefore, if there is a risk of customers leaving the system to another source of energy due to a higher cost of efficient gas equipment, an incentive will both encourage more efficient consumption of natural gas but also increase the likelihood that the customer will remain a gas customer. Both of these results are good for customers and the company.

363.1.1 Please provide the DSM/EEC objectives for BC Hydro and FBC and comment on whether 'maintaining the competitive position' of the utility is common in other jurisdictions.

Response:

BC Hydro's objective for DSM is to meet 66% of the increase in demand for electricity by the year 2020 through demand side measures and energy conservation as stated in the Clean Energy Act. FBC, in their 2008 Strategic Demand Side Management Report, list the following objectives:

- Objective 1 - The 2011 DSM Plan should provide a forecast for achieving the 50 percent target on an annual basis, broken down by customer class.
- Objective 2 - The 2011 DSM Plan should provide TRC calculations for all programs on an individual, sector and portfolio basis.
- Objective 3 - The 2011 DSM Plan must include a listing of collaborative demand-side measures, including:
    - New initiatives;
    - Existing initiatives; and
    - A description of how FortisBC will participate in the planned provincial government 2010/11 all-fuels CPR update, including budget cost to participate.
- Objective 4 - The 2011 DSM Plan should describe how FortisBC will:

  - Lead by example in energy reductions and promote conservation procurement policies in its operations;
  - Implement a cost-effective community-based social marketing campaign targeting the residential sector;
  - Implement a cost-effective community-based social marketing campaign targeting the small business and commercial/industrial sectors;
  - Assess adequacy of existing education programs and opportunities for schools throughout the service area; and
  - Introduce cost-effective education programs and opportunities for post-secondary schools and institutions throughout the service area.
- Objective 5 - The 2011 DSM Plan will include details of a low-income program which will:
  - develop and seek partnerships with municipal, provincial and federal agencies and non-profit organizations to leverage investment and align service and program delivery;
  - distribute benefits throughout the geographic service areas, including remote and aboriginal communities;
  - minimize cost to low-income participants; and
  - ensure programs are straightforward from the perspective of the low-income participant.
- Objective 6 - The 2011 DSM Plan should specify how PowerSense will assist the private rental market by:
  - identifying its energy use and conservation potential;
  - considering survey/focus group studies to engage landlords and further define needs;
  - supporting targeted technical evaluation, testing and demonstration;
  - supporting training of property managers and contractors;
  - developing DSM incentives and information for building owners;
  - working with landlords to develop effective means of engaging tenants in conservation action and behaviour;
  - considering targeted, short-term financial incentives for small landlords and low-income households; and
  - considering targeted, short-term financial incentives for tenants to support conservation action and behaviour.
- Objective 7 - Ensure meaningful and appropriate consultation with the DSMPAC in regards to PowerSense program changes, and engage broader stakeholder groups as appropriate.
- Objective 8 - The 2011 DSM Plan will utilize a blended long-term marginal cost of energy and capacity when calculating DSM benefits using:

  - the BC Hydro long-term marginal cost of energy and capacity when valuing avoided supply from BC Hydro, and;
  - a FortisBC long-term marginal cost of energy for valuing avoided supply from sources other than BC Hydro.
- Objective 9 - The 2011 DSM Plan should include:
  - a conservation and energy efficiency potential study for each customer class;
  - preliminary investigation and analysis of demand reduction options and technologies to 3 establish estimates, define initiatives, and assess long-term potential; and
  - detailed business planning, with savings and demand reduction targets derived from the 5 conservation potential work and demand reduction investigation, in order to prepare business case analyses that set spending and investment levels sufficient to meet corporate and regulatory requirements.
  - The 2011 DSM Plan should identify the type of studies that should be undertaken that will allow development of effective demand response programs.
- Objective 10 - The 2011 DSM Plan should identify the type of studies that should be undertaken that will allow development of effective demand response programs
- Objective 11- The 2011 DSM Plan should include an updated monitoring and evaluation plan, if required, that will apply to all new and existing programs, and will be compliant with any provincial standards.
- Objective 12- The 2011 DSM Plan should include new programs that promote technologies that are proven to be effective, but do not yet provide an economic payback for customers within 10 years.

The Companies' objective is not to "maintain the competitive position of the utility" (in the words of the IR), but is to maintain the competitive position of natural gas.

The FEU have no comment on whether maintaining the competitive position of the utility is common in other jurisdictions, and are of the view that each jurisdiction is unique, with its own statutory and operating conditions, so this information would not be relevant to conditions in British Columbia.

363.1.2 Is FEU also promoting natural gas consumption by including 'maintain the competitive position of gas' as a primary EEC objective? Please explain.

Response:

No. The Companies are pursuing EEC in accordance with the definition of Demand Side Measure in the CEA. The EEC Plan that is the subject of this proceeding is largely a continuation of the 2012-2013 EEC Plan with many of the same measures and programs previously approved by the Commission Panel.

363.1.3 Did FEU consult with Energy Efficiency and Conservation Advisory Group (EECAG) on the DSM objective? If yes, please explain the result. If no, please explain why not. In your response, please use the general consultation principles in The New Zealand Electricity Authority Consultation Charter (pp. 12 to 13) for guidance as to what constitutes adequate consultation.

Response:

As discussed in Section 4 of the 2012 EEC Annual Report, the FEU have consulted with the EECAG on various aspects of the EEC initiative generally and have received valuable feedback. The particular DSM objective referenced in the IR and found in the Glossary of the Application was not raised with the EEAG. The FEU have no reason to believe that the EECAG has any interest in discussing these matters.

The New Zealand Electricity Consultation Charter is not relevant to the EEC activities of an investor-owned natural gas utility operating in the Province of British Columbia. That Consultation Charter, deals with processes around making legal amendments to the Electricity Industry Participation Code for New Zealand, a statute administered by the New Zealand Electricity Authority, responsible for the effective day-to-day operation of a national deregulated, un-integrated electricity system. This statute governs the operation of New Zealand's deregulated electricity system. The requirements for consultation on amendments to a legal document governing the operation of national deregulated electricity system are far more rigorous than those of a voluntary group providing input to a utility DSM program. In collaboration with the membership of the EECAG, the Companies have established Terms of Reference for the activities of the group, and it is that document that is relevant in the FEU context.

363.1.4 Please reconcile the FEU DSM primary objective above with the definition of DSM found in the CEA and UCA, specifically with regard to the 'competitive position of natural gas'.

Response:

The FEU's 2014-2018 EEC Plan in Appendix 1 of the Application, which the Companies have provided in support of their request for approval of the EEC expenditures over the test period, only contains measures and programs that comply with the definition of Demand Side Measure found within the Clean Energy Act and Utilities Commission Act. Please refer to the also the response to BCUC IR 2.363.1.

363.2 Do FEU advertise EEC incentives for gas home heating in advertisements which also show cost savings that can be achieved from switching from electricity to gas? If yes, please provide examples and state if any of the costs of these advertisements are included as EEC expenditures.

Response:

The FEU have not historically advertised EEC incentives for gas home heating in any advertisements which also show cost savings that can be achieved from switching from electricity to gas. Since Order G-44-12 regarding the FEU's 2012-2013 RRA, no EEC expenditures have gone towards supporting FEU advertisements with a "switch to natural gas" message. The FEU's High Carbon Fuel Switching program (also known as "Switch N Shrink") has been cited in some advertisements that encourage switching from oil or propane heating to natural gas, but as of the 2012-2013 RRA Decision, this program is no longer considered to be an EEC expenditure.

The FEU have cited the energy calculator tool in some of the advertising and direct customer communications that EEC expenditures have contributed to, but these communications have not specifically cited electricity. The energy calculator in an online instrument which includes the energy comparison and appliance cost tools to assist users in comparing home energy costs and identifying estimated annual energy costs for a number of appliances including those appliances promoted through EEC programs.

364.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-11, BCUC 1.207.2.1, 1.224.1.1, 1.226.1, 1.233.8; Exhibit B-1-1, Appendix I, p. 21; BC Energy Plan, p. 5; American Council for an Energy Efficient Economy (ACEEE),

A National Survey of State Policies and Practices, 2012, pp. 36, 37[3]; Exhibit B-9, COPE 1.8.1; DSM Regulations, 4 (6); TGI 2010 LTRP, p.129[4]; BCH IRP, 2013, Appendix 4D; Decision G-14-11, p. 18

Framework used to set the EEC funding envelope

In response to BCUC 1.207.2.1, FEU state, “The FEU are also mindful of rate impacts to its customers from EEC expenditures and in that regard have sought to undertake an appropriate level of cost-effective DSM.” In response to BCUC 1.226.1, FEU state, “An increase in available funding may allow the inclusion of more measures ... However ... while at the same time being mindful of customer rate impact.”

FEU include as EEC guiding principles (Appendix I, p. 21), “Wherever possible, programs will be uniform ...” In response to COPE 1.8.1 FEU state that it incorrectly included in the Application a statement that EEC programs are designed to implement all cost effective DSM. BC Energy Plan (p. 5) supports BC utilities pursing all cost effective and competitive DSM.

On pages 36 and 37 of A 2012 ACEEE report titled “A National Survey of State Policies and Practices of the Evaluation of Ratepayer-Funded Energy Efficiency Programs” state, “We 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..”

364.1 Please explain (i) why FEU do not plan to pursue all cost effective EEC, (ii) from whose perspective cost effectiveness should be determined (societal, utility, both?), (iii) how FEU determine which cost-effective measures it will not include in the EEC plan, and (iv) whether FEU consulted with EECAG on this issue (if yes, what was the response, if not, why not)?

<u>Response:</u>

As noted in the response to the BCUC IR 1.224.1 and BCUC IR 1.224.1.1, the Companies used the previously approved 2012-2013 EEC Plan as a starting point for the development of the 2014-2018 Plan. This provided the Companies with a level of expenditure with which the Commission Panel

3 http://www.aceee.org/sites/default/files/publications/researchreports/u122.pdf
4 http://www.bcuc.com/Documents/Proceedings/2010/DOC_25953_B-1_Terasen-Utilities-2010-Long-Term-Resource-Plan.pdf

appeared to be comfortable as the level of expenditure was approved. In addition, the Company was comfortable with the level of EEC spend as it provided a reasonable balance between the availability of EEC programs and the overall impact on the cost of service and therefore customer rates. The development of the portfolio of activity over the test period that appears in the 2014-2018 EEC Plan was then undertaken by the EEC Program Managers and ICF Marbek. The Companies' general approach to program development can be found in the response to BCUC IR 1.222.5. Further, as stated in the response to BCUC IR 1.226.1 in the reference above, the Companies are mindful of customer rate impact resulting from EEC Expenditures.

As noted in Section 6 of Appendix I to the current Application, and again in their response to BCUC IR 1.217.5.2, the FEU consider that the appropriate way to determine the cost-effectiveness of EEC programs is to apply the TRC/mTRC at the portfolio level. The TRC/mTRC evaluates cost-effectiveness from the societal perspective, including all customers.

It must be re-iterated that a CPR is not the same as an EEC Plan. A CPR only provides an indication that a measure may be suitably included in an EEC Program. There were a handful of measures in the Residential program area that appeared to be cost-effective in the CPR that were not included in the 2014-2018 Plan. These measures were Programmable Thermostats, Solar Pool Heaters and Energy Star® Clothes Washers. The Companies' position on whether or not Programmable Thermostats provide energy savings can be found in the response to BCUC IR 2.373.3. A program for Solar Pool Heaters was felt to have too high a free rider rate to justify the provision of an incentive as the majority of residential swimming pool owners were felt to be highly "able-to-pay". As noted on page 11 of Appendix I-1 (Exhibit B-1-1), "FEU will limit investment in Energy Star® washers to short term promotions since the washer market has matured such that there is reduced opportunity to capture natural gas savings". Thus should it appear that such a promotion would be cost-effective, funding for such activity would come from the envelope of funding proposed for water heating measures. No such promotion, however, is contemplated at this time. All measures in the Commercial and Industrial sectors that do not have prescriptive programs associated with them would be covered off by the "custom" incentive option.

The FEU have consulted with EECAG on the 2014-2018 EEC Plan, and thus indirectly on the level of expenditure during a May 1 2013 conference call. The EECAG was given an opportunity to indicate if they felt there were major course corrections needed, and the EECAG indicated to the EEC team that none were required. The FEU have not consulted specifically with EECAG on whose perspective should be applied to benefit-cost analysis, nor specifically on excluded measures. The consultation was conducted on the EEC Plan overall.

364.2 Have FEU reduced the level of cost-effective EEC spending out of concern for customer rate impacts? If yes, please describe and quantify the effect on the proposed EEC budget over the PBR period.

Response:

The Companies have used previously-approved levels of expenditure as the basis for the 2014-2018 EEC Plan. The level of expenditure has not been reduced from the previously-approved level over concern for customer rate impacts. Rather the level of expenditure previously approved by the Commission panel has been maintained.

364.3 Please confirm that, while reducing the level of utility cost-effective DSM can reduce rates, it will result in an overall increase in FEU's revenue requirement over the long-term.

Response:

Not confirmed. While there is the potential for FEU's revenue requirement to increase over the long-term, the increase is not a certainty. The revenue requirement will change by the increased commodity costs resulting from reduced DSM; however, this change will be offset by savings in reduced DSM amortization and related costs. Therefore, revenue requirements have the potential to either increase or decrease over the long-term with a reduction in the level of utility cost-effective DSM. It must be noted that the Companies are not proposing to reduce levels of expenditure from those previously approved, but rather to maintain previously-approved levels.

364.3.1 Please explain what FEU consider to be a 'customer rate impact which the FEU are comfortable' (BCUC 224.1.1), how FEU arrived at this value, and whether it consulted with EECAG on this issue (if yes, what was the response, if not, why not)?

Response:

The customer rate impact from the Companies' proposed portfolio of EEC activity and expenditure arises from the continuation of the previously approved level of EEC activity and expenditure. Given that this level of expenditure was approved by the Commission Panel in the 2012-2013

Revenue Requirements proceeding, the Companies' are comfortable continuing with the same level over the 2014-2018 time period. The rate impact can be seen in Scenario 3 in Appendix I-3 (Exhibit B-1-1). Delivery rate impact peaks at 6.24 per cent over approved 2013 rates in 2023. The Companies have consulted with EECAG regarding its EEC portfolio and concerns about the level of rate impact were not raised.

364.3.2 Please confirm that use of the RIM test at the program level is not standard utility practice and not allowed by Section 4 (6) of the DSM Regulations. Given this, please explain why it would be appropriate to use the RIM test at a portfolio level.

<u>Response:</u>

The FEU are not proposing using the RIM test at the portfolio level.

It is confirmed that Section 4.6 of the DSM Regulation states that, "The commission may not determine that a proposed demand side measure is not cost effective on the basis of the result obtained by using a ratepayer impact measure test to assess the demand-side measure."

The excerpt in the Information Request states that the RIM test has been largely abandoned by <u>leading energy efficiency states</u> [emphasis added]. The Companies also note that only 2 percent of states use the RIM test as the primary test, and that the ACEEE finds that the flaws with the RIM test have been well-documented, and that ACEEE recommends that the RIM test not be used. However, page 12 of the same report shows that 51 percent of the states surveyed consider the RIM test. Given that more than half of the states surveyed consider the RIM, the Companies cannot confirm that the use of the RIM is not "standard industry practice."

While the Companies consider impacts on rates from any utility expenditure, including DSM, to be a matter worthy of consideration, as noted in the response to BCUC IR 2.364.1, it is the view of the Companies that the appropriate test is the TRC/MTRC applied at the portfolio level.

While the Companies consider impacts on rates from <u>any</u> utility expenditure, including DSM, to be a matter worthy of consideration, as noted in the response to BCUC IR 2.364.1, it is the view of the Companies that the appropriate test is the TRC/mTRC applied at the portfolio level.

364.3.3 Please confirm that a focus on rates rather than bills could also result in sub-optimal BC economic development and emission reduction outcomes.

Response:

Not confirmed. The question of what constitutes "sub-optimal economic outcomes" is subject to debate. Both rates and bills are important. Customer rate increases generally are a focus for British Columbia utilities and their customers. Balancing rate increases with levels of EEC expenditure is important, as is ensuring that the Companies customers have access to EEC programming. By continuing with a previously-approved portfolio of activity and levels of expenditure a balance between rates and bills found to be acceptable by a previous Commission Panel will continue.

364.3.4 "The easiest way to reduce rates is to shoot holes in people's windows." Do FEU consider that this statement is useful in illustrating the need to focus on bills, not rates? If no, please explain why not.

Response:

Without any context for what appears to be a quote, the Companies are unable to respond to this statement.

364.4 Do FEU consider that customer rate impact concern could be better addressed by ensuring (i) an equitable level of EEC spending between customer classes and (ii) that each key customer segment has reasonable access to EEC programs? Please explain why/why not.

Response:

Ensuring an equitable level of EEC spending between customer classes and that each key customer segment has reasonable access to EEC programs are important considerations and are reflected in the Companies' EEC Guiding Principle # 1, found on page 21 of Appendix I (Exhibit B-1-1), which states that "Programs will have a goal of being universal, offering access to energy efficiency and conservation for all residential, commercial and industrial customers…". However, the FEU also believe that the overall level of expenditures is also a relevant consideration and have taken the Commission's prior approval of the 2012-2013 level of expenditure as being an indication that that level of rate impact was reasonable.

364.4.1 Does every FEU customer class (and, where appropriate, key customer segments within each customer class) have access to at least two EEC programs? If no, please describe changes that could be made to the EEC budget to provide this.

Response:

Residential, commercial and industrial do have access to at least two EEC programs as can be seen in the 2014-2018 EEC Plan.

Every FEU customer class (residential, commercial and industrial) has access to at least two programs as can be seen in Exhibits 6, 9, 11 and 13 (the latter for low income programs, considered to be residential) of Appendix I to Exhibit B-1.

364.4.2 Do FEU consider to provide an equitable level of EEC spending among the residential, commercial, and industrial customer classes over the PBR period? Please explain why/why not and provide quantitative supporting evidence.

Response:

Yes. Please refer to the responses to BCUC IRs 1.234.7, 2.369.6, and 2.369.7. There are many ways of reviewing the split of EEC expenditures by customer class – by customer count, by volume and by revenue. Customer count has been recognized by the Companies in that it is the basis on which the non-incentive, non-utility-expenditures are allocated between the utilities, as explained in the response to BCUC IR 2.69.7. Volume is also recognized by the Companies in the levels of EEC funding projected for the different customer classes. For example, it can be seen in the response to BCUC IR 1.234.7 that in 2014, residential customers of FEI are projected to account for 39 percent of total volumes, and 31 percent of EEC expenditure, while commercial customers are projected to account for 28 percent of volume, and 32 percent of EEC expenditure. Industrial customers account for 32.6 percent of volume, and 6 percent of EEC expenditure. The lower proportional spending on industrial EEC is primarily due to the fact that the Companies are in the process of ramping up and learning about industrial EEC after receiving approval for industrial EEC activity in the 2010/2011 Revenue Requirement. In terms of revenue, it can be seen in the response to BCUC IR 2.369.6 that in 2014 the Companies are proposing a fairly even distribution of EEC spend as a percentage of customer class revenues.

It must be noted that while the Companies make programs available to customers, actual uptake and thus actual expenditures will determine the final split between customer classes.

364.5 Have FEU reduced the level of cost-effective EEC as a result of its principles to provide uniform (rather than targeted) EEC programs? If yes, please provide a revised EEC spending request assuming these restrictions are removed.

Response:

No. The level of EEC expenditure being requested is based on the approved level for 2012-2013.

364.5.1 Please explain if FEU consider these principles remain appropriate.

Response:

Yes, as noted on page 22 of Appendix I (Exhibit B-1-1), “The FEU continue to be guided by these principles in designing and carrying out their EEC program”.

364.5.2 In 2012, FEU only had one industrial participant (out of 380) implement an energy saving project (BCUC 1.233.8). Do FEU consider that a focus on uniform rather than targeted EEC programs is reducing the ability of FEU to offer EEC to industrial customers? Please explain.

Response:

No. As explained in BCUC 1.233.8, the EEC industrial program uptake by one single participant in 2012 is reasonable given the complex nature of industrial energy efficiency projects, and the fact that in 2013 the FEU expect to validate the commissioning of three new energy efficiency projects with lead times from initial contact to commissioning of one to two and half years. Moreover, in 2014, the Companies expect to fund various energy audits and commission four new upgrade projects in industrial facilities in a variety of sectors including fabricated metal, food and beverage, agriculture, asphalt, oil and gas, and manufacturing.

The Companies initial program offerings were "uniform" only in the sense that they apply similar terms and conditions, and incentive structure to industrial customers throughout their service territories. In actual application these programs offered analysis, recommendations and incentives targeted at the individual needs of each EEC industrial program participant. Participants are eligible to receive funds towards detailed energy audits targeting inefficiencies specific to their facilities, as well as incentives calculated based on costs and savings specific to each of their energy saving upgrade projects.

The FEU also note that the number of industrial customers in the province is relatively small, and that to have success, targeted (as opposed to custom) programs must assume that most potential participants in the targeted sector, or for the targeted measure, are in fact ready to proceed with natural gas saving upgrades. With funds of $1.756 million to draw upon in 2013, the number of targeted programs that could be offered is slim. In contrast, the Companies current offerings provide flexibility to adapt to the needs of any potential customer.

364.6 Please provide, and explain any differences between, FEU's requested EEC funding as a percentage of revenues, and the FEI's recommendation on page 129 of the TGI 2010 Long Term Resource Plan (LTRP) that EEC funding should be set at 5 percent of revenues.

Response:

Since revenues have not been projected beyond 2014 for FEVI and FEW, this response is based on FEI projected revenues and EEC spending, which are approximately 90 percent of the total EEC funding request.

Figure 3 in the FEU's response to BCUC IR 1.234.3 shows that requested funding over the 2014 – 2018 period for FEI is approximately 3 percent of FEI revenue, rather than the 5 percent scenario cited in the 2010 LTRP. A higher amount closer to 5 percent was requested in the 2012 – 2013

FEU RRA, following the submission of the 2010 LTRP. After a lengthy regulatory process, the Commission approved an amount closer to 3 percent of revenues for 2012 and 2013, which the FEU have maintained in the current funding request. Please also refer to the response to BCUC IR 2.364.3.1 for an explanation of why the FEU have maintained consistent funding levels for 2014-2018.

364.6.1 Please reproduce Tables 1 and 3 of the benchmarking data included in Appendix 4D to BCH's August 2013 IRP, and update them to show the equivalent results for FBC (i) 2012 (actual), (ii) 2013 (forecast), and (iii) forecast over the PBR period.

Response:

The Companies are not able to reproduce Table 1 as it shows "mandated cumulative energy savings as a percent of retail sales." The Companies do not have mandated energy savings. Table 3 in the reference above is reproduced below.

Year	2012 (actual)	2013 (forecast)	2014	2015	2016	2017	2018
Annual EEC Savings (TJ)	452.563	502.537	703.948	898.76	802.37	681.29	626.051
Annual Retail Sales Volumes (TJ)	168,793	169,949	170,567	172,102	173,473	174,797	175,656
Annual Energy Savings as % of retail sales	0.27%	0.30%	0.41%	0.52%	0.46%	0.39%	0.36%

364.7 How do FEU consider Section 44.2 (5) (b) should be interpreted given that FEU only asked for the 2010 LTRP to be 'accepted' (Decision G-14-11, p. 18)?

Response:

Section 44.1 (6) of the Act states that the Commission must either accept or reject a utility's long term resource plan and Section 44.1 (7) sets out that the Commission may accept or reject part of a utilities long term resource plan. No other alternatives were available for the FEU to seek, or the Commission to grant, with respect to the 2010 LTRP.

The FEU interpret Section 44.2 (5)(b) of the Act to mean that the Commission must consider the utility's DSM expenditure schedule in relation to the utility's most recently approved LTRP. The FEU's proposed DSM expenditure schedule is consistent with the 2010 LTRP.

364.8 Do FEU consider that adjustments should be made to the EEC portfolio when the short-run cost of gas is lower than the estimated long-run cost of gas? If yes, please explain how.

Response:

The Companies are unable to respond to the question as written as the word “adjustments” in the question has a very wide variety of potential interpretations. However, the short-run cost of gas used in the cost-benefit analysis for the Plan that is the subject of this proceeding is indeed lower than the long-run cost of gas and the EEC portfolio of activity over the period 2014-2018 reflects this.

365.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit A2-1, pp. 4-5 - 4-9; FEU 2012-13 Revenue Requirement and Natural Gas Rates Application (RRA), Exhibit B-9, 1.193.4; Decision G-44-12, p. 186

Utility Incentives

Exhibit A2-1 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." (p. 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." (p. 4-9)

Issues regarding EEC organizational structure and shareholder incentive mechanisms have been raised in the 2008 RRA and the 2012-13 RRA (Exhibit B-9. 1.193.4 of the FEU 2012-13 RRA). On page 186 of Decision G-44-12, the Commission states, "The Commission Panel believes that it is appropriate that these questions be explored in a separate review process."

365.1 Do FEU agree with the Commission's G-44-12 finding that, should a review of EEC organizational structure and shareholder incentive mechanisms occur, it should be explored in a separate review process? Please explain why/why not.

Response:

Please refer to the responses to BCUC IR 1.211.1.2 and BCUC IR 1.213.1.

Should the Commission wish to re-open the matter of the financial treatment of DSM, the FEU suggest that it would be preferable to develop a common approach for all utilities engaged in DSM in the Province, including the FortisBC Energy Utilities, FortisBC, and BC Hydro.

365.1.1 Have FEU consulted with EECAG on the need for a review of the EEC organizational structure and shareholder incentive mechanisms? Please explain why/why not.

Response:

The FEU have regularly conducted meetings with the EECAG. The broad EEC mechanisms, such as EEC structure and shareholder incentives mechanisms, have already been approved in prior regulatory proceedings, and are working as intended. The FEU have not heard any concerns from either the EECAG or any other stakeholder regarding EEC organizational structure and shareholder incentive mechanisms. The FEU have therefore not specifically posed the question of whether a review is needed.

365.2 Do FEU agree that that (i) capitalization is not currently a widely used EEC cost recovery method and (ii) the ideal solution is to tie incentives to program performance and to share program net benefits with ratepayers? If no, please explain why not.

Response:

Capitalization is widely used in British Columbia, as it is the method currently used by all 3 British Columbia utilities currently engaged in DSM. This complies with the legislative requirements of this Province found in section 60(1)(b)(ii) of the UCA.

Refer to the responses to BCUC IR 1.211.1.2 and 1.213.1.

365.3 Please quantify (in table and graph form) the FEU EEC related shareholder incentive earned each year over the last five years and forecast for each year over the PBR period.

Response:

The FEU EEC equity earned returns (not shareholder incentive) for 2009 through 2018 are shown in the tables and graph below. Note that the approved amounts were used for 2009 through 2013 as FEU equity returns are based on the approved amounts. Considering the opening balances in the EEC deferral accounts are trued-up to the actual balances in each subsequent revenue requirement, any equity returns from the forecasted additions exceeding the actual additions are temporary in nature and limited to the term of the revenue requirement. This is evident in the FEI and FEVI amounts in the graph below for 2012 where the opening balances in the accounts were trued-up with the filing of the 2012-2013 revenue requirement.

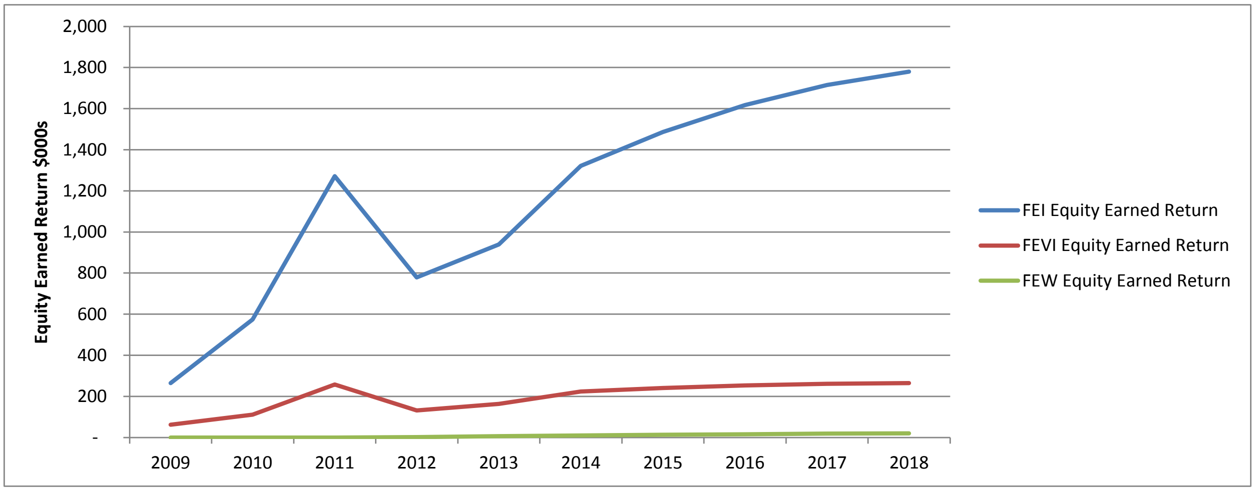
Additionally, the 2014 through 2018 mid-year rate base balances below are based on $15 million in forecasted gross additions for FEU annually to the rate base account, to reflect the amount embedded in forecasted customer rates for those years in the respective 2014 PBR and Revenue Requirement applications. As requested in Section 4.2.6 of the FEI 2014-2018 PBR Application, to the extent amounts are actually spent above the $15 million in 2014 through 2018, up to the approved funding envelope, FEI is requesting to transfer the additions, which will be captured in the EEC Incentive non-rate base deferral account, to the rate base EEC deferral account in the following year.

Lastly, the FEI mid-year rate base amounts for 2014 through 2018 have been updated to reflect the revision to the FEI EEC amortization forecast as discussed in the response to BCUC IR 2.377.2.

FEI	2009 Approved	2010 Approved	2011 Approved	2012 Approved	2013 Approved	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Mid-Year Rate Base Deferral ($000s)	8,418	15,104	33,460	20,486	27,874	39,238	44,120	48,009	50,912	52,826
Allowed ROE	8.99%	9.50%	9.50%	9.50%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%
Allowed Equity Thickness	35.01%	40.00%	40.00%	40.00%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%
Equity Earned Return ($000s)	265	574	1,271	778	939	1,322	1,486	1,617	1,715	1,780

FEVI	2009 Approved	2010 Approved	2011 Approved	2012 Approved	2013 Approved	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Mid-Year Rate Base Deferral ($000s)	1,622	2,778	6,444	3,274	4,096	5,580	6,007	6,322	6,526	6,620
Allowed ROE	9.59%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Allowed Equity Thickness	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
Equity Earned Return ($000s)	62	111	258	131	164	223	240	253	261	265

FEW	2009 Approved	2010 Approved	2011 Approved	2012 Approved	2013 Approved	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Mid-Year Rate Base Deferral ($000s)	-	-	-	56	163	236	321	395	459	511
Allowed ROE	9.49%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Allowed Equity Thickness	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
Equity Earned Return ($000s)	-	-	-	2	7	9	13	16	18	20



365.3.1 Please estimate the change in the EEC related return to the shareholder over the PBR period ($ and as % of total return) under the following scenarios: (i) EEC $ expenditure doubled but achieved energy savings remained as forecast; and (ii) EEC $ expenditure remained the same, but achieved energy savings doubled.

Response:

The scenarios posed in the question are entirely hypothetical. The Companies are not proposing a doubling of the EEC expenditure in this proceeding, nor a doubling of energy savings. More importantly, it is highly unlikely that EEC expenditures could double and that energy savings would remain the same, or that EEC expenditures could remain the same and energy savings double.

The question appears to seek to demonstrate that the FEU's equity return on investments in EEC is not linked to energy savings achieved. The reality is that the Companies must maintain a cost-effective EEC portfolio, as defined by the DSM Regulation, and by recent Commission decisions. The Companies use performance criteria such as the TRC test, the mTRC test and the EEC principle that the administration costs of EEC activity not exceed the incentive costs to guide EEC activity and as such, expenditure and energy savings are inextricably linked in the cost-benefit analysis that the Companies undertake. If the Companies were to double the amount being spent on EEC, the Commission would have to approve such an increase. Presumably the Commission would not do so without a concurrent increase in energy savings.

While the scenarios proposed in the question are very highly unlikely within the context of the manner in which the Companies operate the EEC initiative, it is possible that variances from forecast (on which the Companies earn their return on EEC expenditures) will be experienced. With respect to shareholder earnings and variances in EEC spending and energy savings, EEC spending over the amount forecast in rate base (up to the funding envelope limit approved by the Commission) will be captured in the non-rate base deferral account which attracts AFUDC. Each year the opening balance of the rate base account will be trued up to reflect actual spending, including any amounts captured in the non-rate base account, and recovered from customers through updated delivery rates.[5] As such, the equity return associated with the EEC deferral account will also be recalculated each year and recovered through the updated delivery rates. The demand forecast will also be reforecast each year of the PBR, incorporating expected energy savings, and used to determine the updated delivery rates. Any variance in energy savings from forecast will not impact shareholder earnings to the extent that the variance is captured in the RSAM deferral account for Rate Schedules 1, 2, 3 and 23.

365.4 Please provide for the last 5 years FEI volume variances for all non-RSAM customers, and for each year estimate the impact of these volume variances on the FEI margin.

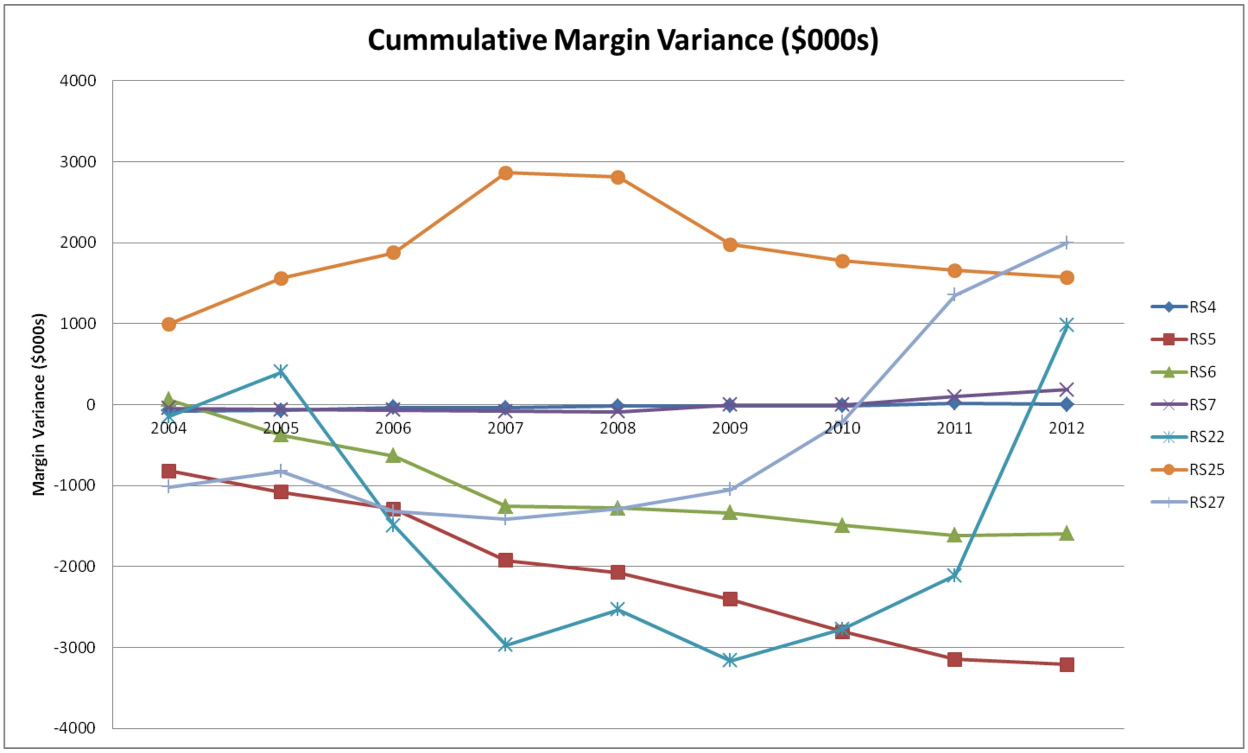
Response:

The last five years of volume variances are shown below:

[5] The current amortization period for the EEC deferral account is ten years. Thus, the actual annual additions are recovered over a ten year period.

Rate Schedule	Energy Demand (TJ) Actual	Forecast	Variance	Margin Variance ($000's)
2008				
4	191.0	161.3	29.7	$ 21.3
5	3,199.4	3,461.7	(262.3)	(146.1)
6	93.4	99.9	(6.5)	(20.8)
7	18.0	19.3	(1.3)	(1.2)
22	31,978.1	29,618.3	2,359.8	441.6
25	14,360.0	14,893.1	(533.1)	(51.9)
27	5,451.6	5,323.5	128.1	119.3
2009				
4	166.4	161.3	5.1	3.9
5	2,899.4	3,461.7	(562.3)	(333.4)
6	82.8	99.9	(17.1)	(58.1)
7	102.5	16.9	85.6	84.7
22	26,324.0	29,458.5	(3,134.5)	(629.2)
25	13,073.2	15,252.8	(2,179.6)	(830.3)
27	5,775.6	5,529.8	245.8	243.3
2010				
4	185.1	184.5	0.6	0.5
5	2,463.6	3,098.4	(634.8)	(399.3)
6	60.5	103.9	(43.4)	(155.0)
7	11.3	14.3	(3.0)	(3.1)
22	30,050.2	25,065.9	4,984.3	388.3
25	12,785.5	13,160.1	(374.6)	(206.6)
27	5,981.8	5,183.6	798.2	836.5
2011				
4	223.3	184.5	38.8	33.1
5	2,534.5	3,061.3	(526.8)	(339.8)
6	69.5	103.9	(34.4)	(125.5)
7	112.4	14.3	98.1	105.3
22	34,943.4	25,046.7	9,896.7	659.6
25	13,236.3	13,102.3	134.0	(115.1)
27	6,628.6	5,171.9	1,456.7	1,563.0
2012				
4	168.8	185.1	(16.3)	(15.0)
5	2,315.5	2,407.5	(92.0)	(62.6)
6	62.3	56.5	5.8	22.2
7	86.7	10.9	75.8	85.6
22	38,038.0	29,674.6	8,363.4	3,094.5
25	12,828.6	13,414.4	(585.8)	(87.1)
27	6,371.7	5,797.8	573.9	647.9

The five years of data requested above captures an era of lower gas prices. Under these conditions industrial customers could be expected to consume more than their survey might have indicated. Considering a longer time frame (back to 2004) shows a more balanced view. This indicated that over a longer period our industrial customers are doing a better job of forecasting their demand than the most recent five years would indicate. The cumulative margin variances extending back 8 years, representing hundreds of million GJ's of consumption, is only -$71K.



FEI relies on customers' ability to forecast their energy requirements but subsequent operational requirements may vary. In addition fuel switching due to pricing differentials may create unplanned for cost savings for industrial customers which may be temporal, and volume variances may be due to a number of customer variances.

365.5 Please provide the incentive payment scheme for the FEI Director, EEC.

Response:

Please refer to response to BCUC IR 1.79.3 and 1.79.4.1 for a description of the FEI Short Term Incentive Pay Program and Targets. The Short Term Incentive Pay Target for the FEI Director, EEC is 20 percent.

366.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

DSM Regulations

Evaluation Framework – Use of TRC/UCT

366.1 Do FEU agree that that generally: (i) the TRC/mTRC identifies whether, from a BC perspective, customers are using too much gas to provided the desired level of service (such as warmth) as a result of sub-optimal behaviour or investment decisions; and (ii) the UCT determines if it would be cost effective for the utility to put in place an EEC program to 'nudge' (or in the case of codes/standards – require) the customer into making better choices (compared to having no EEC program and instead supplying the additional gas to the customer). If FEU do not agree with either (i) or ii) please explain why.

Response:

With no references nor context provided for these assertions around what the TRC/MTRC measures and what the UCT determines, the Companies are unable to comment directly on the statements made in this Information Request.

However, it is the view of the Companies and of the DSM community generally that the Total Resource Test indicates whether the benefits to British Columbians generally from undertaking an EEC activity outweigh the costs of doing so, and that the Utility Cost Test looks at whether the benefits to the utility of undertaking an EEC activity outweigh the costs to the utility. More reading on the purposes and interpretations of the different cost tests can be found in Attachment 217.2 provided in the response to BCUC IR 1.217.2, a paper published by the American Council for an Energy Efficient Economy, entitled "Understanding Cost-Effectiveness of Energy Efficiency Programs".

366.2 Do FEU consider that, as a general rule, it is preferable that EEC programs both result in a societal benefit to BC (i.e. pass the TRC/mTRC) and reduce the utility revenue requirement over the long-term (i.e., pass the Utility Cost Test (UCT))? Please explain why/why not.

Response:

The FEU consider that it is preferable that the portfolio of EEC activity, rather than individual programs, results in a societal benefit to BC and has a benefit to the utility customers higher than the cost. This is the case for the portfolio of EEC Activity outlined in the 2014-2018 EEC Plan.

366.3 Please confirm that the DSM Regulations (Section 4(1.8)) specifically allow the Commission to reject an EEC program (other than certain specified programs) that is not cost effective under the UCT. If not confirmed, please explain.

Response:

Confirmed. Please refer to the responses to BCUC IR 1.219.7 and 2.366.2. However, doing so would mean that many of the programs enabled by the MTRC would not run, as many of them fail the UCT.

366.4 Please confirm that the UCT (unlike the TRC/mTRC) takes the size of the incentive into consideration in determine cost-effectiveness, and that FEU does consider the incentive size when determining if it should start/change an EEC programs. If not confirmed, please explain.

Response:

Confirmed.

366.5 Have FEU consulted with EECAG as 'to what extent' EEC programs should be required to pass the UCT? If yes, please provide the results of that discussion. If no, please explain why not.

Response:

The decision on how to measure the cost effectiveness of the FEU's portfolio of EEC activities has been reviewed at length by the Commission, interveners and customer groups in prior applications and the FEU's view has always been that the UCT should not be used to determine that EEC programs are not cost effective. The EECAG are provided with the cost effectiveness results of the FEU's programs within each of the FEU's EEC annual reports, which include UCT results, and the

EECAG has not expressed any concerns with those results. Thus, the FEU have not specifically posed the question of the extent to which EEC programs should be required to pass the UCT.

366.6 Please demonstrate that FEU has complied with section 4 (1.5) of the DSM Regulations.

Response:

The Companies interpret this question to mean, "Please demonstrate the FEU's slate of proposed EEC activity that is the subject of this proceeding, namely the 2014-2018 EEC Plan, qualify as cost-effective under the MTRC does not exceed 33% of the proposed portfolio of activity." This can be seen in Exhibit 3 of Appendix I-1 to Exhibit B-1, where the percentage of activity that the Companies are bringing forward in the 2014-2018 EEC Plan that qualifies as cost-effective using the MTRC is 24% over the plan period.

367.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-11, BCUC 1.208.1.1; Decision G-14-11, p. 24

Evaluation Framework - Emissions

FEU provided annual variations in actual/forecast CO2 emissions from 2010 to 2018 in response to BCUC 1.208.1.1.

The Commission, in its decision on the FEU Long Term Resource Plan (LTRP) (G-14-11, p. 24) requested that FEU provide in the next LTRP "An analysis of GHG targets as set out in British Columbia's energy objectives and an estimate of what portion of the required reduction that the Company believes it can reasonably obtain over time."

367.1 Please explain the annual variations in actual/forecast CO2 emissions from 2010 to 2018F. Please also describe (and estimate where possible) how much of the annual FEU emissions change could be due to customer switching from higher emission fuel to gas.

Response:

The variations in CO2 emissions as shown in the FEU's response to BCUC IR 1.208.1.1 are a direct reflection of the short term forecast of annual demand for natural gas among the customer groups presented. Figure 2 of that IR reflects that:

- residential demand is forecast to be flat over the PBR period,
- commercial demand is expected to continue growing at the same rate as has been experienced in recent years, and
- an uptick in industrial demand has been experienced in 2011 and 2012. The industrial demand forecast is based on a survey of industrial customers, and these customers are forecasting a flattening of their demand through the period.

The only high carbon to low carbon fuel switching demand that would be captured in this data is the growth in consumption resulting from the FEU's High Carbon Fuel Switching (HCFS) program that incents residential customers to switch from oil or propane to natural gas. The HCFS is not an EEC program but rather is administered through the FEU's O&M funding. Participation rates for this program through the PBR period are expected to be approximately 950 customers, annually. Applying the average residential annual use rate of 49.5 GJ for Vancouver Island customers where most of the participants are located, the FEU can provide a rough estimate that approximately 2,450 tonnes (950 customers/yr x 49.5 GJ/yr x 0.052 tonnes CO2e/GJ) CO2e are added each year as a result of the HCFS program (less than 0.1% of CO2e emitted by FEU customers as a result of natural gas commodity sales in 2012). It should be noted that while these customer additions slightly increase the emissions of customers served by the FEU, they result in a reduction in total CO2e emissions in BC since they have moved from a higher carbon emitting fuel to natural gas.

367.2 Is it FEU's position that, despite a forecast increase in annual CO2 emissions related to natural gas commodity sales to FEI customers over the PBR period, the FEU is supporting the BC energy objective to reduce BC greenhouse emissions? If yes, please explain how.

Response:

Yes, while annual CO2 emissions forecast increases, resulting from expected growth in customers over the PBR period, the FEU support the Provincial energy objective to reduce BC CO2e emissions through a number of activities and programs that reduce emissions from what they otherwise would have been in the absence of these activities and programs:

- The FEU's renewable natural gas program supplies carbon neutral biomethane onto the FEI distribution system, displacing natural gas from conventional sources.
- The FEU's High Carbon Fuels Switching program, which is discussed in the response to BCUC IR 2.367.1.
- The FEU's natural gas for transportation initiatives are resulting in the conversion of large return to base commercial and industrial transport fleets from higher carbon diesel and gasoline to lower carbon natural gas. These initiatives have also been exhaustively reviewed through other regulatory proceedings.
- The FEU's EEC programs result in natural gas savings that reduce CO2e emissions from those that would otherwise have occurred without such programs.

The FEU continue to explore potential new initiatives that will help to optimize the use of FEU infrastructure while supporting Provincial energy objectives.

367.3 Please estimate (i) the revised EEC budget over the PBR period, and (ii) overall reduction in FEU forecast CO2 emissions if FEU undertook all cost effective EEC (i.e., passes the Total Resource Cost/Modified Total Resource Cost Test (TRC/mTRC) and Utility Cost Test (UCT)). Please provide the details of the estimation and describe all assumptions used.

Response:

The FEU do not agree with the premise in the question that "cost effective EEC" means passing both the TRC/mTRC and the UCT.

This question can be interpreted in two ways. The first interpretation would require the FEU to further analyze the results of the most recent Conservation Potential Review in order to determine whether any additional cost-effective opportunities have been missed. This has been done at a high level for the response to BCUC IR 2.364.1. The 2014-2018 EEC Plan contains the most applicable and cost-effective measures from the CPR, therefore this question has not been answered based on this interpretation.

Another interpretation for this question relates to the assessment of the FEU's proposed 2014 to 2018 program portfolio and the impact of removing programs that have TRC/mTRC values and/or UCT values below 1.0. Other than the Energy Conservation Assistance Program (which also has a UCT value of under 1.0), the FEU did not put forth any programs in the 2014-2018 EEC Plan which have a TRC/mTRC value of below 1.0. Therefore, the FEU's response to this question summarizes the impact to the EEC budget and overall reduction in FEU forecast CO2 emissions if the FEU removed all programs which have a UCT value of less than 1.0.

Table 1 below summarizes the impact on the EEC budget over the PBR period and the overall reduction in FEU forecast CO2 emissions if all programs that have a UCT value under 1.0 were to be removed from the FEU's portfolio. Since the removal of these programs would have budget impacts that are difficult to assess, no reductions in budgets for Enabling Activities or Non-Program Specific Expenses were assumed to result.

Table 1 displays that there are currently seven programs with a UCT lower than 1.0; five Residential programs, one Commercial program, and one Low Income program. The budgets for these programs represent about 26 percent of the total EEC budget and approximately 18 percent of the CO2 emissions savings over the PBR period. If these programs were to be removed, the EEC budget over the PBR period would be cut from approximately \$178 million to \$132 million and CO2 savings would be reduced from 494 kt to 408 kt.

Table 1: Impact of Removing Programs with UCT <1.0

Program and Service Territory	Utility Expenditures ($1000s)		CO_2 Emissions Savings, Net (tonnes)	
	2014-2018	% of Total	2014-2018	% of Total
ENTIRE PORTFOLIO	**177,991**	**100.00%**	**494,327**	**100.00%**
* Furnace Replacement Program	16,705	9.40%	23,895	4.80%
Enerchoice Fireplace Program	5,823	3.30%	11,015	2.20%
* New Home Program	4,677	2.60%	6,228	1.30%
* New Technologies Program	1,556	0.90%	1,235	0.20%
* Customer Engagement Tool for Conservation Behaviours	4,428	2.50%	26,163	5.30%
Commercial Energy Assessment Program	2,339	1.30%	11,795	2.40%
Energy Conservation Assistance Program	10,240	5.80%	6,021	1.20%
ALL MEASURES WITH UCT <1.0	**45,769**	**25.70%**	**86,352**	**17.50%**
ENTIRE PORTFOLIO (COST EFFECTIVE PROGRAMS)	**132,222**	**74.30%**	**407,975**	**82.50%**
* Program requires the MTRC in order to pass the economic screen				

367.3.1 Please undertake the same analysis above, but this time increase the UCT emissions adder from $30/tonne ($1.50/GJ) to $150/tonne ($5/GJ). Please provide the details of the estimation and describe all assumptions used.

Response:

Increasing the UCT emissions adder from $30/tonne ($1.50/GJ) to $150/tonne ($5/GJ) has a positive impact on several of the programs that currently have a UCT under 1.0. As shown in Table 1 below, five of the programs that have a UCT under 1.0 with the baseline adder, have a UCT result greater than 1.0 with the $5/GJ adder. As such, only two programs still have a UCT under 1.0 with the revised UCT emissions adder.

Table 1: Revised Benefit Cost Test Results for Programs with Original UCT <1.0

Program and Service Territory	Benefit Cost Tests		
	TRC	MTRC	Utility
Furnace Replacement Program	0.7	1.41	1.26
Enerchoice Fireplace Program	2.05	4.37	1.27
New Home Program	0.55	1.12	1.35
New Technologies Program	0.52	1.04	0.5
Customer Engagement Tool for Conservation Behaviours	1.26	2.56	1.26
Commercial Energy Assessment Program	1.48	3.02	1.06
Energy Conservation Assistance Program	0.6	n/a	0.45

Table 2 below summarizes the updated impact on the EEC budget over the PBR period and the overall reduction in FEU forecast CO2 emissions if both programs that have a UCT under 1.0 (with the revised UCT emissions adder) were to be removed from FEU's portfolio. The budgets for these programs represent about 6.5% of the total EEC budget and approximately 1.5% of the CO2 emissions savings over the PBR period. If these programs were to be removed, the EEC budget over the PBR period would be cut from approximately $178 million to $166 million and CO2 savings would be reduced from 494 kt to 487 kt.

Table 2: Impact of Removing Programs with UCT <1.0 (Revised UCT Emissions Adder)

Program and Service Territory	Utility Expenditures ($1000s)		CO_2 Emission Savings, Net (tonnes)	
	2014-2018	% of Total	2014-2018	% of Total
ENTIRE PORTFOLIO	**177,991**	**100.00%**	**494,327**	**100.00%**
New Technologies Program	1,556	0.90%	1,235	0.20%
Energy Conservation Assistance Program	10,240	5.80%	6,021	1.20%
ALL MEASURES WITH UCT <1.0	**11,797**	**6.60%**	**7,256**	**1.50%**
ENTIRE PORTFOLIO (COST EFFECTIVE PROGRAMS)	**166,194**	**93.40%**	**487,071**	**98.50%**

367.3.2 What is the effective environmental premium for biomethane in $/GJ (i.e., Long Run Marginal Cost (LRMC) of biomethane less the LRMC of gas)? Please provide the details of the estimation and describe all assumptions used.

Response:

The environmental premium for biomethane in $/GJ over the PBR period is listed in the following table.

Biomethane Environmental Premium Calculation	Year				
	2014	**2015**	**2016**	**2017**	**2018**
Maximum Biomethane Energy Recovery Charge ($/GJ)	$15.28	$15.28	$15.28	$15.28	$15.28
less LRMC of Gas ($/GJ)	$5.60	$6.13	$6.46	$6.78	$6.96
less Carbon Tax Credit ($/GJ)	$1.49	$1.49	$1.49	$1.49	$1.49
equals **Environmental Premium for Biomethane ($/GJ)**	**$8.19**	**$7.66**	**$7.33**	**$7.01**	**$6.83**

This table makes the following assumptions:

- The maximum Biomethane Energy Recovery Charge will not change from its current $15.28 price over the PBR period.
- The Carbon Tax Credit will not change from its current $1.49 value over the PBR period.
- Purchases of Biomethane will continue to receive a carbon tax credit.

Please note that an error was made in responding to BCUC IR 1.218.3.2. The ceiling value for biomethane is the value indicated in the table above, not the $16.87 indicated in the response to BCUC IR 1.218.3.2.

367.4 Please provide and explain FEU's position on including a long-run marginal cost of carbon estimate in the UCT, rather than only BC's carbon tax.

Response:

The FEU's position is that establishing a value for a long-run marginal cost of carbon would be challenging, and that the value for B.C.'s carbon tax is known, and is therefore the appropriate "carbon value" to use in the benefit-cost tests applied to the Companies' EEC activity.

368.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1-1, Appendix I, p.1

5-Year PBR Period

FEU request DSM funding approval for a 5-year period (Appendix I, p.1).

368.1 Please confirm (or provide evidence otherwise) that DSM spending approval periods in other jurisdictions are: (i) One year: Rhode Island, Texas; (ii) Two years: Hawaii, New Hampshire, New Mexico; (iii) Three years: California, Colorado, Connecticut, Indiana, Massachusetts, Maryland, New York, Ohio, Pennsylvania, Vermont, Ontario; (iv) Five years: Iowa.

Response:

There is no reference provided for the spending approval periods stated in the question.

The FEU have conducted a preliminary scan of the referenced jurisdictions and has found that some of states and provinces match the DSM spending approval periods listed above and others do not.

Please refer to Attachment 368.1 which lists the DSM spending approval periods for Rhode Island, Texas, Hawaii, New Hampshire, New Mexico, California, Colorado, Connecticut, Indiana, Massachusetts, Maryland, New York, Ohio, Pennsylvania, Vermont, Ontario and Iowa. Each jurisdiction is broken down by utility, planning cycle which includes the current cycle years, the next cycle years as well as a reference source. It is important to note that FEU could not verify the DSM spending approval periods for all jurisdictions listed in the question and have marked them with a question mark in the attachment. Also, it is important to note that some states and provinces have multiple entries where different utilities may have different cycle lengths or start and end periods. Also in some cases the FEU were only able to find information specific to certain utilities in a state and could not determine if that information applied to other utilities in the state as well. For further examples of DSM spending approval periods beyond the jurisdictions listed above, please refer to Exhibit B-7, Attachment 12.2, provided in the response to BCSEA IR 1.12.2.

368.1.1 Please confirm (or calculate otherwise) that the average number of years EEC spending is approved for based on the sample above is 2.7 years.

Response:

Please refer to response to BCUC IR 2.368.1. FEU has been unable to source the data that is stated in BCUC IR 2.368.1 and therefore is unable to confirm the DSM spending approval period claims for those jurisdictions.

To assess the average number of years EEC spending is approved in other jurisdictions, the FEU conducted a preliminary scan of those jurisdictions listed in Attachment 368.1, provided in the response to BCUC IR 2.368.1 and the additional jurisdictions listed in Exhibit B-7, Attachment 12.2, provided in the response to BCSEA IR 1.12.2.

Please refer to Attachment 368.1.1 which lists the average DSM funding approval across all those jurisdictions being 3.37 years. The average was determined across 41 jurisdictions with DSM funding approval periods ranging from 1 to 10 years in length. FEU submits that this range is indicative that each jurisdiction determines the length of the DSM funding approval period that it deems to be appropriate.

Please note that duplicate jurisdictions were taken out as well as jurisdictions whereby FEU was unable to verify the DSM spending approval periods.

In reviewing the attachment, FEU submits that it is not uncommon for utilities to strive towards longer DSM funding approval periods due the benefits associated with maintaining positive program momentum and stakeholder engagement driving market transformation coupled with a reduction of regulatory work and an improvement of staff productivity that can better focus on program development and operation activities. The FEU therefore believe the request for DSM funding for a 5-year period is appropriate.

368.1.2 Have FEU consulted with EECAG on the proposal to request an EEC funding envelope for a 5-year period (rather than, say, 2 or 3 years)? If yes, please describe the feedback received. If no, please explain why not.

Response:

The EECAG has had the opportunity to review the EEC 5 year plan and did not suggest that a shorter period was necessary. There was general agreement that longer term periods of consistent funding certainty will result in a more effective portfolio as it will provide certainty to customers, contractors and suppliers of energy equipment.

368.2 Please provide the date that the following changes are expected, and comment on the extent to which they could affect the optimum level of FEU EEC funding and/or programs undertaken:

- Update of the Conservation Potential Review (CPR);
- Update to long-term resource plan (LTRP);
- Update to BC Hydro long-run marginal cost estimate;
- Finalization of the Evaluation, Measurement and Verification (EM&V) framework;
- Development of business plan for new programs.

Response:

Update of the Conservation Potential Review

Please refer to the the response to BCUC IR 2.368.6 with regard to timing of the next Conservation Potential Review. The next CPR will not impact the proposed level of funding sought by the FEU through the 2014-2018 and instead will inform the EEC funding request for the period beyond 2018.

Long Term Resource Plan

The LTRP is in the final stages of preparation and will be submitted within the next few months. Since the long term EEC analysis contained in the LTRP builds off of the results of the 2014-2018 EEC Plan, it will not impact the level of funding proposed for the 2014-2018 period.

BC Hydro long-run marginal cost estimate.

The FEU are uncertain of the process that BC Hydro will take in finalizing its revised long run marginal cost of electricity / clean electricity, nor of the timing of such. Please refer to the response to BCUC IR 1.218.3.1.1 for an explanation of how varying the value of BC Hydro's LRMC could impact the mTRC results for those programs that do not pass the TRC. In that analysis, the FEU determined that 2 residential programs would fail the mTRC at the lowest BCHydro LRMC examined ($70/MWh). If such a change to the LRMC occurred and no other value were identified for the Zero Emission Energy Alternative, the FEU expects that the funds proposed for those two programs would be reallocated to other areas of the EEC portfolio. Thus a change to the BC Hydro LRMC up or down will not impact the proposed level of EEC funding for the 2014-2018 period.

Evaluation, Measurement and Verification Framework.

The FEU consider the EM&V Framework to be a living document that will periodically be updated as new standards or best practice that evolve within the industry are adopted by the FEU and become part of the framework. The FEU consider the current version of the Framework to be up to date. Since the Framework is not a planning document and simply puts into writing the principles and practices for program evaluation already used by the FEU, it will have no impact on the level of EEC funding.

Development of Business Plans for New Programs

Program plans for all new programs, save one, have been filed with the Commission, including the assumptions and source information used to test their projected cost-effectiveness. The FEU believes that this information is sufficient for the Commission to determine that these new programs are in the public interest. As these plans have already been submitted, their development will not impact the proposed EEC funding levels. If, for the one program for which a program plan has not been submitted (the Residential New Technology Program), a cost-effective, new technology measure cannot be identified, that program would not go ahead and the funding for that program would not be spent. Please also refer to the the response to BCUC IR 2.375.1 and 2.375.3 regarding the program plans for new programs, and BCUC IR 2.375.4 regarding the Residential New Technology Program.

368.3 Please discuss the likelihood of significant changes in each of the following areas during the 5-year PBR period, and comment on whether they could affect the optimum level of FEU EEC funding and/or programs undertaken:

- Changes to the forecast long-run marginal cost of gas;
- Changes to BC Hydro/LiveSmart funding levels;
- Changes to codes and standards affecting baseline efficiency level assumptions;
- Development of new technologies, and/or positive results from FEU New Technologies Program/ Pilots (such as EnerTracker Program pilot).

Response:

Please refer to Table 1 below. The Companies will continue to file the EEC Annual Report over the test period, which will allow for consideration by the Companies and EECAG of any significant changes to the portfolio of EEC activity and funding should the EEC operating environment change significantly.

1 **Table 1: Review of the Impact of Potential Changes to the EEC Planning Environment**

Element of Operating Environment	Likelihood of Change	Comments/Impact on EEC Funding or Programs
Significant change to long-run marginal cost of gas	Low	An increase in the long-run marginal cost of gas might make more measures in the Conservation Potential Review appear cost-effective and suitable for consideration for inclusion in an EEC program, resulting in an increase to the proposed EEC budget; a decrease would have the converse 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 FEU'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	Low	Typically governments signal code changes well in advance. All currently-known code changes are incorporated into the baselines for planning purposes. Thus the Companies' view is that it is unlikely that codes and standards changes could affect EEC funding or programs.
Development of new technologies	Unknown	Disruptive technologies can arise at any time, and are very difficult to predict. However, the Companies have established a framework for transitioning technologies that emerge from successful pilots into full-blown programs and this should help to reduce risks to EEC funding and programs from new technologies.

2

3

4

5

368.4 Please explain why a 5-year EEC budget should be approved for (i) new initiatives and (ii) New Technologies Program without an FEU business case to support the budget request.

Response:

The Companies interpret this question to mean a "program plan" or "program profile" that is a document that is filed as part of an overall EEC Plan for Commission and Intervenor review. Please refer to the response to BCUC IR 2.375 series.

368.5 Please explain why a 5-year EEC budget should be approved when (i) the FEU shareholder is incentivized on the basis of the EEC $ spend, rather than results achieved, (ii) there is no EM&V approved framework or independent audit of the results, and (iii) FEU is incentivized to use EEC funding to maintain/improve the competitive position of gas relative to other fuel sources.

Response:

The assertions implicit in this question are without merit.

The nature of the financial treatment of EEC, including the return on FEU expenditures on EEC 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 Commision Act, the financial treatment of DSM for British Columbia's utilities is that 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 EEC budget should be approved because it is supported by the 2014-2018 EEC Plan being put forward, which is cost-effective under the conditions that have been established for utilities in British Columbia in the DSM Regulation. The results from the EEC activity undertaken are bound by the TRC and MTRC test, and have been extensively and transparently reported in the Companies EEC Annual Reports; the FEU have met the conditions established in British Columbia for evaluating cost-effectiveness over the last number of years. Therefore, the Companies are allowed a fair and reasonable return for operating a cost-effective portfolio of EEC activity, and are proposing to continue doing so over the 5 year test period.

The FEU have complied with all Commission directions with respect to an EM&V framework. As discussed in Appendix I of the Application, the FEU has developed an EM&V framework and consulted with the EECAG on the framework as directed by the Commission in the 2012-2013 RRA Decision. As discussed in detail in response to information requests (e.g. BCUC IR 1.214 and

2.371 series), the segregation of the FEU'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 the FEU's EM&V results from previous activities are before the Commission in this proceeding. The FEU also note that the UCA does not include a requirement for an approved EM&V framework or an independent audit of BC utility energy savings reported.

The FEU are not "incentivized to use EEC funding to improve/maintain the competitive position of natural gas". Rather if the Companies' customers choose to participate in EEC activity, and by doing so are better able to manage their energy costs and thus remain gas customers, this is good for all gas customers.

368.6 If it is determined that the CPR update should trigger the end of this EEC approval period, how many years should this EEC Application be approved for? Please explain.

Response:

The timing of an updated, gas and electric Conservation Potential Review, proposed to be undertaken by FEU in conjunction with FortisBC and BC Hydro is as follows:

- Commission decision on funding: Summer 2014
- CPR Working Committee struck: Fall 2014
- Terms of reference developed for Working Committee: December 2014
- Scope of work developed: Summer 2015
- RFP released and consultant selected: December 2015
- CPR conducted: 2016
- Results received and reviewed: Spring/Summer 2017
- EEC Plan established for 2019 and beyond: Fall 2017
- EEC funding request for2018 and beyond: 2018

The timing for the next Conservation Potential Review is well-aligned with the development of an EEC Plan and Funding Request for the post-2018 time period.

369.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Berkeley National Laboratory, the Future of Utility Customer-Funded Energy Efficiency Programs in the United States, pp.23 -24[6]; Exhibit B-11, BCUC 1.224.1, 1.234.5, 1.235.1; ACEEE, Saving Energy Cost-Effectively, 2009[7]

Decision G-44-12, p. 151

EEC Funding Envelope

On pages 23 and 24 of a Berkeley National Laboratory January 2013 report titled "The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025" states, "... in the low case, spending on gas efficiency programs recedes from its elevated level in 2015 to below $1 billion in 2025 (0.5% of revenues) ... In the medium case, spending remains roughly flat at projected 2015 levels … equivalent to 0.8% of revenues... In the high case ... spending on gas programs roughly triples from 2010 levels, reaching $3.3 billion in 2025 (1.8% of revenues)."

FEU provide a comparison of EEC spending as a percentage of distribution revenue against other utilities in response to BCUC 1.235.1. FEU state that the approach used to set the EEC budget was closer to an approach which uses the previous year's EEC budget as the starting point (BCUC 1.224.1).

A 2009 ACEEE study titled "Saving Energy Cost-Effectively: A National Review of the Cost of Energy Saved through Utility-Sector Energy Efficiency Programs" found the cost of saved energy for natural gas EEC programs was $0.39/$0.33 per therm (mean/median) with a range of $0.27-$0.55, and average customer incentives to be 76% of program costs.

369.1 Do 'distribution revenues' in response to BCUC 1.235.1 include commodity gas revenues, and if not please explain why not. Also, please update this table to include the FEU (or FEI only if FEU data is not available) forecast 'fraction of distribution revenues' data for each year to 2018.

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

"Distribution revenues" in response to BCUC IR 1.235.1 include revenues from commodity gas sales. As noted in the response to BCUC IR 1.235.1, the table in the response was taken from a first draft of the Canadian Gas Association (CGA) Report. As the draft CGA report was reviewed, it emerged that for this table, all the utilities except FEU had provided distribution only revenues, and that the FEU had provided distribution plus commodity. It also emerged that the CGA member utilities all have customers that purchase their own gas commodity, and that trying to tease out

[6] http://emp.lbl.gov/sites/all/files/lbnl-5803e.pdf
[7] http://aceee.org/files/pdf/conferences/eer/2009/4C_Friedrich_Eldridge.pdf

distribution plus commodity for a combination of customers that use utility gas and customers that buy their own gas in any common way would be far more challenging than just trying to compare distribution revenues. The CGA member utilities then attempted to compare DSM expenditure with utility distribution revenue. That comparison is presented in the table which follows. Please refer to the response to BCUC IR 2.369.1.1 for a discussion of this table.

FEU revenue forecasts for the period to 2014-2018 are not available. For FEI’s EEC forecast expenditure as a percentage of FEI’s revenues, please refer to response to BCUC IR 1.212.6.

	DSM Expenditures as a percentage of distribution revenues															
Utility	ATCO		Enbridge		FortisBC Energy		Gaz Metro		Manitoba Hydro		Sask Energy		Union Gas		Total	Average
Year	$millions	% of Dist Revenue	$millions	% of Dist Revenue	$millions	% of Dist Revenue	$millions	% of Dist Revenue	$millions	% of Dist Revenue	$millions	% of Dist Revenue	$millions	% of Dist Revenue	$millions	% of Dist Revenue
2012			30.9	3.10%	23.4	3.00%	17.753244	3.45%	6.1019111	9.53%	1.195213	1.12%	27.667177	4.02%	100.13555	2.71%
2011			26.7	2.65%	16.2	2.20%	15.461939	2.96%	9.1001384	9.33%	1.405109	1.31%	18.879716	2.77%	91.331902	2.47%
2010	1.7	0.30%	25.5	2.56%	11.4	1.60%	15.258844	2.88%	9.7942663	8.53%	1.190891	1.11%	14.779312	2.19%	88.863313	2.41%
2009	1.9	0.42%	24.3	2.46%	6.3	0.90%	14.075703	2.63%	9.8171257	7.26%	2.263815	1.97%	15.84319	2.35%	77.335834	2.18%
2008	1.3	0.29%	23.1	2.40%	2.6	0.40%	13.413238	2.62%	9.5578275	5.82%	2.265011	1.99%	13.786995	2.04%	63.423072	1.80%
2007	0.95246	0.22%	22	2.30%	3.1	0.50%	14.404102	3.08%	7.7873794	5.08%	1.89069	1.76%	9.886594	1.56%	56.921225	1.69%
2006	1.7	0.44%	18.9	2.04%	3.1	0.50%	13.499017	3.03%	5.1787637	3.50%	1.604727	1.58%	9.753351	1.47%	50.635859	1.54%
2005	2.5	0.68%	19	2.16%	3.1	0.50%	8.539645	1.93%	1.5500224	1.05%	0.521182	0.49%	5.437	0.81%	37.547849	1.16%
2004	2.8	0.82%	13.6	1.61%	2.0	0.30%	6.42616	1.43%					4.274	0.66%	27.10016	0.86%
2003	1.6	0.45%	11.5	1.42%	2.25	0.50%	3.795531	0.87%					2.347048	0.36%	19.242579	0.64%
2002	0.94925	0.29%	10.9	1.38%	2.7	0.60%	3.211767	0.76%					1.546018	0.25%	16.607035	0.61%
2001			10.5	1.33%	2.2		1.453735	0.35%					2.441878	0.42%	14.395613	0.65%
2000			6	0.78%	2.5		1	0.25%					2.209659	0.50%	9.823869	0.47%
1999			4.7	0.65%	2								2.243027		7.515201	0.49%
1998			4.8	0.67%	1.4								2.025956		8.81855	0.58%
1997													1.473446		2.89126	0.64%

369.1.1 Taking into consideration the Canadian benchmarking data and the Berkeley forecasts, do FEU consider that its proposed EEC budget for the PBR period as a percentage of revenue is in line with industry standards? Please explain why/why not.

Response:

It is extremely challenging to compare the Companies' proposed EEC expenditures over the PBR period with both the data found in the updated table from the CGA report provided in the response to BCUC IR 2.369.1, which is EEC expenditure as a percentage of utility distribution revenue, and the Lawrence Berkeley National Laboratory ("LBNL") report cited above. As such, the Companies are highly reluctant to draw any conclusions from the material presented in the Information Request and in the response to BCUC IR 2.369.1 as to whether the proposed EEC budget for the PBR period as a percentage of revenue is in line with what other utilities are doing.

The task force working on the CGA report has not been able to arrive at a common methodology as to what is included in distribution revenue for each utility, despite having worked on the matter for a number of months, and it can be seen in the notes to the table that even arriving at a common method for reporting DSM expenditures was not possible. As noted in the response to BCUC IR 1.369.1, arriving at a common methodology for determining distribution plus gas commodity revenue had proven to be even more challenging for the CGA members, and attempts to do so were abandoned. Further the Information Request above asks about the PBR period, which is forward-looking, and the Canadian Gas Association data is backward-looking, so the view of the Companies is that this data should be considered as high level and directional only,

LBNL used a complex methodology to arrive at both the expenditure projections for natural gas utilities in the United States, as well as the revenue projections. A description of this methodology can be found on pages 43-47 of the reference in the Information Request. Because of the complexity of the methodology used by LBNL, these results should also be considered loosely and directionally only.

369.2 Please calculate (i) FEU's actual/forecast cost of saved energy and (ii) incentives as a percentage of program costs, for each year from 2012 to 2018, and compare the results to those of the 2009 ACEEE findings above.

Response:

For the FEU's actual/forecast cost of saved energy (i), please see Table 1 below. The FEU's cost of saved energy fell within the range of the values reported in the 2009 ACEEE study. These values were calculated using the methodology described in the 2009 ACEEE study, which included assuming a lifetime of 19 years for natural gas measures and a real discount rate of 5%.

For the FEU's incentive expenditures as a percentage of program costs (ii), please see Table 2 below. Incentive expenditures range from 53%-61% of program costs over the years 2012-2018, with an average of 58%. The ACEEE 2009 study cites an average of 76% for the five states surveyed in this study. Note though that the FEU's achieved and projected incentive expenditures as a percentage of program costs well exceeds the minimum threshold stated in its list of EEC Guiding Principles (page 20 of Appendix I):

> *… EEC expenditures will have a goal of non-incentive costs not exceeding 50 percent of the expenditure in a given year …*

Table 1: FEU's Cost of Saved Energy from EEC Activities 2012-2018

Year	Cost of Saved Energy ($/therm)	Cost of Saved Energy ($/GJ)
2012	0.46	4.34
2013	0.45	4.24
2014	0.43	4.04
2015	0.35	3.36
2016	0.39	3.70
2017	0.45	4.30
2018	0.50	4.74
Average	0.43	4.10

**Assumes a conversion rate of 1 therm (US)= 0.1054804 GJ*

Table 2: FEU's Incentive Expenditures as a Percentage of Program Costs, EEC Activities 2012-2018

Year	Utility expenditures ($millions)	Incentives expenditures ($millions)	% of Program costs
2012	23.762	14.425	61%
2013	25.741	13.523	53%
2014	34.353	19.543	57%
2015	36.537	21.086	58%
2016	35.839	21.020	59%
2017	35.388	20.455	58%
2018	35.874	20.556	57%
Average			58%

**Forecast values are expressed in $2014. Actual values expressed in nominal terms.*

369.3 Do FEU agree that once the CPR is updated this should be the new starting point for the EEC budget rather than historical approved amounts? Please explain why/why not.

Response:

Yes, the Companies agree with this statement. An updated Conservation Potential Review will provide a comprehensive assessment of the technologies available and the magnitude of the potential for cost-effective gas and electric DSM activity in British Columbia in the time period 2018 forward. Please also refer to the response to BCUC IR 2.368.6.

369.4 Please explain why FEU's EEC budget over the PBR period does not increase with inflation.

Response:

The FEU's EEC budget over the PBR period does increase with inflation. Please refer to pages 4 and 5 of Attachment I-1 (Exhibit B-1-1). Exhibit 1 in Attachment I-1 provides a summary of expenditures, including inflation. Inflation was assumed to be 3% for FortisBC labour and 2% for all other expenses. Inflation has only been accounted for in Exhibit 1. All other expenditures over the PBR period are presented in 2014 dollars.

369.5 Please provide a table and graph showing the trend of FEU EEC actual/forecast costs per GJ conserved from 2009 to the end of the PBR period. Please explain any significant year variances and describe any assumptions made.

Response:

Please see Table 1 and Graph 1 below. FEU does not believe there are any significant year variances other than for 2009-2010. This is due to a number of factors. First, 2009 was a “transition year” for EEC activities, as the Companies set out to establish a foundation that year for broader EEC programs. The results reflect a partial year of activity for 2009 as most of the programs were rolled out in the second half of 2009 once the EEC Decision was issued and the staffing resources were set in place. While 2009 EEC programs did not get underway until the second half of the year, and respective annual energy savings were relatively low compared to the following years (130,963 GJ), the Present Value (PV) of these savings is still relatively large as those programs that got underway will continue to realize savings over the span of those program measures’ lives. Thus a lower EEC expenditure level in 2009 relative to other years still results in a high PV of energy savings, and a relatively lower ratio of spending to energy savings. Secondly, spending on activities to which the companies do not attribute energy savings, but that are important enablers of energy efficiency activity, was increased in 2010. These include Enabling Activities and Conservation Education and Outreach. Thus, the EEC spending to savings ratio increased in 2010. These activities allow the Companies to realize greater energy savings in the future, as indicated by the downward trend of EEC spending to energy savings from 2011 to 2012.

The following assumptions were used to create Table 1 and Graph 1 below:

- 2009-2012 values reported from EEC Annual reports.
- 2010 values based on Conventional EEC Portfolio (excludes Innovative Technologies) as reported in the 2010 EEC Annual report.
- 2013 values based on estimated year-end EEC expenditures and annual gas savings values.

- 2014-18 projected annual present value (PV) energy savings (GJ) were estimated by taking a ratio of the estimated annual incremental gas savings to total savings over the PBR period, and applying that ratio for each year to the total NPV of energy savings over the period. The annual incremental gas savings are not presented in the 2014-18 EEC plan, but are used here in order to provide a year-over-year comparison, as requested. These annual incremental gas savings were estimated and provided in response to BCSEA IR 2.2.1.
- Forecasted 2014-18 EEC expenditures are presented in $2014.

Table 1: FEU Annual EEC Expenditures by PV Energy Savings 2009-2018

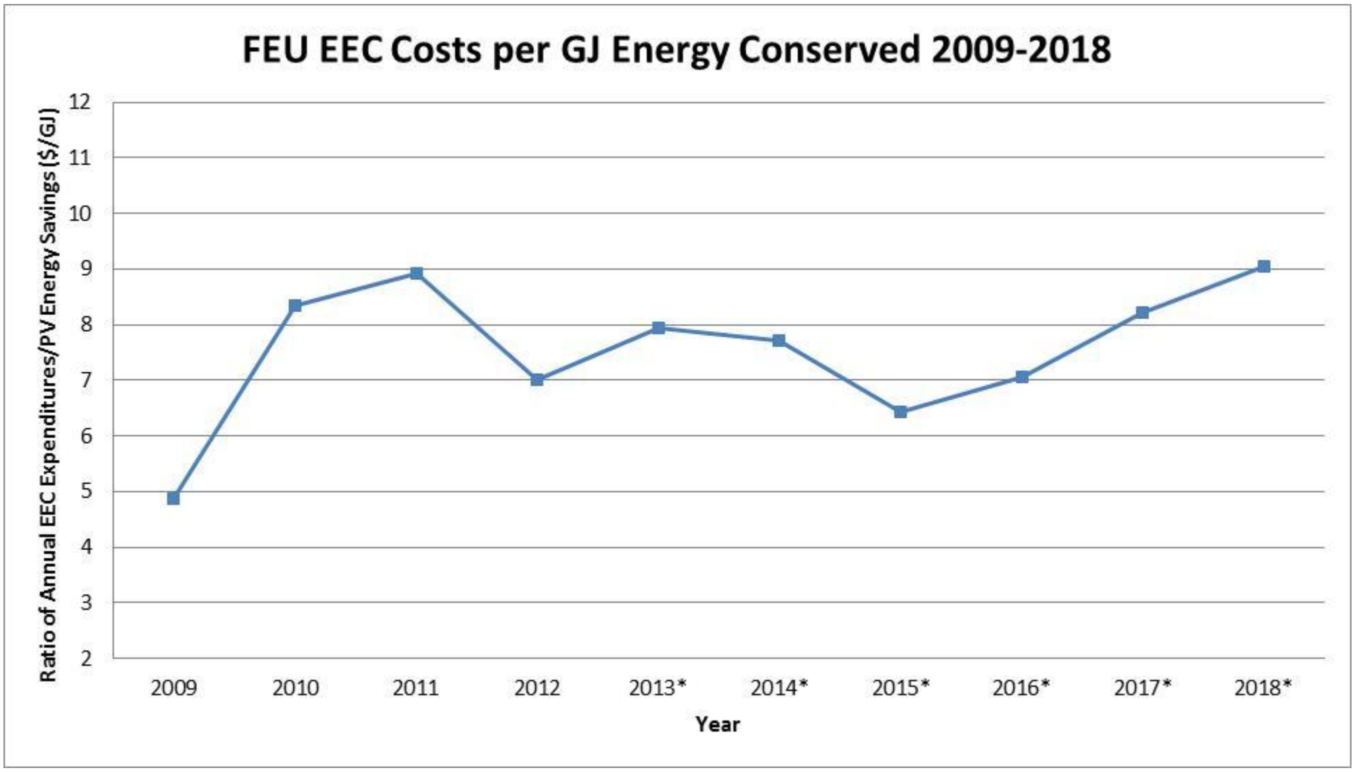
Overall EEC Portfolio Results										
	2009	**2010**	**2011**	**2012**	**2013[1]**	**2014[2]**	**2015**	**2016**	**2017**	**2018**
EEC Annual Expenditures ($)	6,261,000	11,737,000	16,182,000	23,759,000	25,741,000	34,353,000	36,537,000	35,839,000	35,388,000	35,874,000
PV Energy Savings (GJ)	1,284,100	1,408,510	1,814,357	3,385,073	3,243,459	4,456,723	5,690,085	5,079,836	4,313,274	3,963,554
Ratio of Annual EEC Expenditures/PV Energy Savings ($/GJ)	4.88	8.33	8.92	7.02	7.94	7.71	6.42	7.06	8.20	9.05

Notes:

[1] 2013 values forecasted to year-end.

[2] Forecasted 2014-18 EEC expenditures are presented in $2014.)

Graph 1: FEU's EEC Costs per GJ Energy Conserved 2009-2018



369.6 FEU include an analysis of EEC expenditures and revenues in response to BCUC 1.234.5. Using FEU's best judgment, please update this table for the following adjustments (i) allocate out other EEC expenditure categories (low income, innovative technologies, CEO, enabling activities) between the residential, commercial and industrial customer class; and (ii) estimate FEVI and FEW forecast 2014 and 2018 revenues by customer class so that the table does not include any 'n/a'. For FEU only, please also provide this updated table for each year of the PBR period. Please provide supporting details and describe any assumptions made.

Response:

Please see Table 1 below.

The table has been updated to include allocated EEC expenditure categories (low income, innovative technologies, CEO, enabling activities) between the residential, commercial and industrial customer classes. As this is an application for FEI, forecast revenues for FEVI and FEW 2015-2018 have not been estimated. 2014 forecast revenues for FEVI and FEW are provided as these were estimated and made available in the 2012-13 RRA application filed for FEVI and the 2013 Rate Continuity Application filed for FEW. As forecast revenues for FEVI and FEW 2015-2018 have not been estimated, the table has not been updated to include information for FEU for each year of the PBR period.

In populating the table, the following assumptions were made:

- All FEW EEC expenditures were included in FEI expenditures in past reporting. For the table below, FEW EEC expenditures have been calculated as 1% of FEI EEC expenditures, consistent with the FEU's previous EEC Plans.
- All Low Income program costs were allocated to Residential.
- For 2012, Enabling Activities are included in Residential and are not double counted at the portfolio level.
- For 2012, Portfolio level activities were allocated across customer classes based on a ratio of EEC Customer class spending to total EEC spending (73% to Residential, 25.5% to Commercial, and 1.5% to Industrial).
- For 2012, CEO expenditures classed "School Outreach", were allocated to the Residential customer class. All non-program specific CEO expenditures were allocated across customer classes based on a ratio of CEO Customer class spending to total CEO spending for the given year (77.3% to Residential and 22.7% to Commercial).
- For 2014 and 2018, non-program specific Enabling Activities expenditures were allocated across customer classes based on a ratio of EEC Customer class spending to total EEC spending for the given year.
- For 2014 and 2018, CEO expenditures classed "School Education Program", were allocated to the Residential customer class. All non-program specific CEO expenditures were allocated across customer classes based on a ratio of CEO Customer class spending to total CEO spending for the given year (73.7% to Residential and 26.3% to Commercial).
- For simplicity, Innovative Technologies calculations for 2014 and 2018 were generated from the amounts provided in BCUC IR 2.375.4.1 scaling 92% to FEI and 8% to FEVI in 2014, and 98% to FEI and 2% to FEVI in 2018 as per a ratio of FEI and FEVI service region spending to total spending.
- Any minor inconsistencies in numbers are due to rounding.

1 **Table 1: Analysis of EEC expenditures and revenues, 2012, 2014, 2018**

		2012			2014			2018		
		Residential	Commercial	Industrial	Residential	Commercial	Industrial	Residential	Commercial	Industrial
FEI	Total EEC spend - FEI ($000s)	$14,984	$5,163	$390	$15,772	$12,497	$1,927	$17,396	$10,357	$3,799
	% of total FEI EEC spend	73%	25%	2%	52%	41%	6%	55%	33%	12%
	Total EEC spend as a % of customer class revenues	2.1%	1.4%	0.5%	2.3%	3.4%	2.5%	2.6%	2.7%	5.0%
FEVI	Total EEC spend - FEVI ($000s)	$1,886	$1,113	$16	$1,840	$1,813	$195	$1,858	$1,820	$329
	% of total FEVI EEC spend	63%	36%	1%	48%	47%	5%	46%	45%	8%
	Total EEC spend as a % of customer class revenues	3.0%	1.1%	0.1%	2.5%	2.0%	2.4%	n/a	n/a	n/a

2

Table 1: Analysis of EEC expenditures and revenues, 2012, 2014, 2018 (continued)

		2012			2014			2018		
		Residential	Commercial	Industrial	Residential	Commercial	Industrial	Residential	Commercial	Industrial
FEW	Total EEC spend - FEW ($000s)	$151	$52	$4	$161	$128	$20	$178	$106	$39
	% of total FEW EEC spend	73%	25%	2%	52%	41%	6%	55%	33%	12%
	Total EEC spend as a % of customer class revenues	4.1%	0.7%	n/a*	4.6%	1.9%	n/a*	n/a	n/a	n/a
FEU	Total EEC spend - FEU ($000s)	$17,022	$6,328	$410	$17,773	$14,438	$2,141	$19,431	$12,277	$4,166
	% of total FEU EEC spend	72%	27%	2%	52%	42%	6%	54%	34%	12%
	Total EEC spend as a % of customer class revenues	2.2%	1.3%	0.4%	2.4%	3.2%	2.5%	n/a	n/a	n/a

**n/a applies to FEW industrial class customers in 2012 and 2014 as there are no industrial customer class revenues for FEW in these years.*

369.6.1 Please explain any significant variations in EEC spending as a percentage of revenue (i) between the three customer classes within each utility, and (ii) between the same customer classes across each utility.

Response:

As displayed in the FEU's response to BCUC IR 2.369.6, EEC spending as a percentage of revenue is weighted higher towards Residential customers in 2012 with the percentages for the Commercial and Industrial areas increasing in the 2014 and 2018 periods. This is the case across all the utilities. The main explanation for this variation is that EEC Residential programs for the most part are currently more mature than those in the Commercial and Industrial areas. As the FEU enter into the PBR period, it is projected that Commercial and Industrial EEC expenditures will experience increases over this period compared to 2012.

In the FEU's view, there are no significant variations in EEC spending as a percentage of revenue between the same customer classes across each utility.

369.6.2 Do FEU consider that (i) EEC spending as a percentage of revenue for each FEU utility, and (ii) EEC spending as a percentage of revenue for each customer class within each FEU utility, is within a generally accepted range for other utilities offering EEC? Please explain why/why not.

Response:

The FEU's EEC spending as a percentage of revenue for each FEU utility and as percentage of revenue for each customer class appears to match the range for other utilities offering EEC. Research gathered for this response reveals that demand side management (DSM) expenditures as a percentage of customer class revenue for the most part lands in the 2 percent to 3 percent range for other utilities for which this information could be gathered. The FEU's response to BCUC IR 2.369.6 reveals a similar range.

A scan of the utility industry reveals that the FEU have a fairly unique organizational structure by having three separate natural gas utilities in British Columbia all operated by one parent utility that offers essentially the same services to all three territories. There are many examples of parent companies that have subsidiaries that operate in different territories or states, but in all cases these are generally run as separate utilities that usually have different services from other utilities also under the parent company.

In addition, EEC/DSM expenditures by sector as a percentage of sector revenues, is not a metric other utilities generally report, and calculating this metric for utilities is very time intensive. As such, the FEU are only able to provide DSM expenditures by sector as a percentage of sector revenues for a small number of utilities.

Below is information on DSM expenditures by sector as a percentage of sector revenues for the FirstEnergy utilities in Pennsylvania, as well as sector specific information from Xcel Energy Minnesota and Idaho Power. Data presented is from 2011.

FirstEnergy (Pennsylvania)

FirstEnergy operates several separate electric utilities within Pennsylvania, but the general structure and services, including DSM/EE program offerings, are the same for each separate utility. The three FirstEnergy electric utilities that operate in the state of Pennsylvania with these same offerings are Met-Ed, Penelec, and Penn Power. The annual reports for these FirstEnergy utilities do not separate programs by residential, commercial, and industrial sectors but do include data that can be separated out into residential and non-residential. DSM expenditures as a percentage of revenue for each of these utilities are listed in the tables below:

Met-Ed

Sector	DSM Expenditures ($)	Revenues ($)	DSM Expenditures as % of Revenue
Residential	17,418,000	736,886,200	2.36%
Non-Residential	4,745,000	318,578,100	1.49%
Total	24,012,000	1,055,464,300	2.28%

Penelec

Sector	DSM Expenditures ($)	Revenues ($)	DSM Expenditures as % of Revenue
Residential	18,326,000	597,332,700	3.07%
Non-Residential	6,879,000	314,791,300	2.19%
Total	25,205,000	912,124,000	2.76%

Penn Power

Sector	DSM Expenditures ($)	Revenues ($)	DSM Expenditures as % of Revenue
Residential	4,097,000	171,830,500	2.38%
Non-Residential	1,343,000	61,457,000	2.19%
Total	5,440,000	233,287,500	2.33%

Xcel Energy (Minnesota)

Xcel Energy provides both electric and natural gas services in Minnesota. Revenues for natural gas were not available so the table below is only for electric DSM expenditures and revenues.

Xcel Energy Electric DSM Expenditures

Sector	DSM Expenditures ($)	Revenues ($)	DSM Expenditures as % of Revenue
Residential	21,871,324	1,003,380,000	2.18%
Non-Residential	41,592,623	1,763,133,000	2.36%
Other	5,437,165	n/a	n/a
Total	68,901,112	2,766,513,000	2.49%

Rocky Mountain Power (Idaho)

Rocky Mountain Power in Idaho provides only electric services. DSM expenditures as a percentage of revenue for each of its customer sectors are provided in the table below.

Rocky Mountain Power

Sector	DSM Expenditures ($)	Revenues ($)	DSM Expenditures as % of Revenue
Residential	1,039,675	67,904,500	1.53%
Commercial	553,986	35,495,300	1.56%
Industrial & Agricultural	1,018,912	127,791,000	0.80%
Total	2,612,573	231,190,800	1.13%

369.7 Please confirm that the Commission approved the allocation of FEU's proposed EEC costs between companies for the 2012/2013 test period only (Decision G-44-12, p. 151). If not confirmed please explain.

Response:

This response addresses BCUC IR 2.369.7 through 2.369.12.

For the period 2014-2018, the Companies are not proposing any changes to the financial treatment of EEC expenditures that were previously approved for 2012 and 2013 in the FEU's 2012-2013 RRA proceeding.

The aspects of the Decision on the FEU's 2012-2013 RRA referenced above affecting the allocation of expenditures amongst the Companies on a forecast and actual basis are as follows (at p. 151):

"2. The allocation of the 2012 and 2013 EEC rate base deferral account non-incentive additions amongst Mainland, Vancouver Island and Whistler on an average customer basis which is approximately 89 percent to Mainland, 10 percent to Vancouver Island and 1 percent to Whistler.

3. The allocation of 2012 and 2013 EEC incentive costs on an as incurred basis."

The Decision describes the FEU's proposed allocation of costs amongst FEI, FEVI and FEW on page 149 as follows:

"The FEU have also proposed that $15 million (adjusted downward from the original proposal of $20 million) of the total requested amount of $64.5 million be added to the EEC rate base deferral account in 2012 and 2013 on a net-of-tax basis. Flowing from this is the Company's proposal to create an EEC Non-Rate Base Deferral Account, attracting AFUDC, to capture any additional EEC costs as incurred on an actual spend basis in 2012 and 2013. This would be held to a maximum of $49.5 million per year (representing the total spend request less the $15 million addition to the Rate Base Deferral Account), to be recovered over a ten year period with the method of recovery determined in the next revenue requirement in 2014. The FEU further propose that the 2012 and 2013 non-incentive costs accumulating in the EEC Rate Base Deferral Accounts be allocated among the Companies on an average number of customer basis which will result in an approximate split of 89 percent to Mainland, 10 percent to Vancouver Island, and 1 percent to Whistler. Incentive costs are proposed to be allocated on an as spent basis. (Exhibit B-1-3, pp. 392-393, FEU Final Submission, p. 199)"

The allocation amongst the utilities presented in the EEC Plan (for FEI and FEVI) and in the response to BCUC IR 2.369.6 are on a forecast basis and are on the basis of the previously-approved allocation using average customer count, which is approximately 89 percent to Mainland, 10 percent to Vancouver Island and 1 percent to Whistler. While revenues are not relevant to this allocation, in order to be responsive to BCUC IR 2.369.8, FEW revenues including distribution and commodity are projected to be approximately 0.9 per cent of FEI revenues, and 0.8 per cent of FEU revenues.

The FEU's proposed approach to allocating *actual* expenditures is as follows:

- non-incentive expenditures that cannot be attributed to a particular utility over the test period will be allocated as per the previously-approved split based on an average customer basis, count, which is approximately 89 percent to Mainland, 10 percent to Vancouver Island and 1 percent to Whistler; and
- the actual incentive expenditures and any expenditures that can be allocated specifically to a particular utility will be allocated on an as-incurred basis.

Since all programs are available to all customers across all service territories, all customers have the opportunity to access and to benefit from all programs for which they are eligible. As explained above, any EEC expenditures that can be allocated to a particular utility will be allocated on an as-incurred basis to that utility, thus reflecting the costs of the EEC benefits received by that utility.

By approving the continuation of the currently approved financial treatment, there is no "locking in of funding levels between the FEU utilities" over the PBR period.

No attempt has been made to prepare projected expenditures for FEVI and FEW from the bottom up and the allocations in the 2014-2018 EEC Plan reflect the approach explained above, rather than "budgets" for each of the utilities. This is because one of the Companies' key Guiding Principles for EEC activity is that of universality and making all programs available to all customers across all service territories. The types of buildings (for example, single family dwellings, or hotels, or restaurants, or mom and pop stores) that exist in FEI exist in FEVI and FEW as well, and it is the Companies' view that customers in and owners of these similar types of buildings should have the same opportunity to participate in the Companies' EEC programs. The Companies have always had the principle of universality and this has never been challenged by intervenors, nor raised by EECAG as a concern.

The FEU see no benefit in quantifying the EEC opportunities in each utility and building a bottom-up budget for each. First, as explained above, this is inconsistent with the principle of universality as all customers should have access to all programs. Second, given the cost allocation methodology previously approved, actual expenditures will be allocated on an as-incurred basis to the extent possible. Third, the portfolio of program activity put forward in the 2014-2018 EEC Plan offers ample opportunity for residential, commercial and industrial customers in FEVI and FEW to participate in EEC initiatives.

With respect to FEW in particular, Whistler now enjoys a very strong summer tourism season, so it is inaccurate to characterize Whistler as simply a "ski resort town" as indicated in BCUC IR 2.369.11. Further, since there are also ski resorts in FEI's service territory, including Rossland, Kimberley and Silver Star, any EEC opportunities for a ski resort would not be unique to FEW. There are hotels in Whistler which are good candidates for the Commercial Space and Water Heating programs. There are restaurants in Whistler, which are good candidates for participation in the Commercial Food Service program. There are also residential fireplaces in Whistler, which are good candidates for the Enerchoice Fireplace program. Similar opportunities and others are available for FEVI's service territory.

In accordance with the principle of universality, industrial customers of FEVI and FEW should have equal opportunity to participate in industrial EEC programs. Under the FEU's 2014-2018 EEC Plan, should a customer of FEVI or FEW wish to participate in any of the programs in the industrial program area, they would have the ability to do so, and any incentive provided would be collected from customers of FEVI or FEW on an as-incurred basis. For example, the Companies have an application currently before them for an FEVI industrial customer seeking approval to receive Technology Retrofit program incentives towards the implementation of an energy efficiency upgrade that was identified through an audit partially funded by the Industrial Energy Audit program in 2012. This demonstrates that customers of non-FEI utilities are interested in participating in the FEU's industrial programs.

Thus, the Companies propose to continue their approach of universality over the PBR period, making all programs available to all customers, and recovering non-allocatable, non-incentive costs based on customer counts as previously approved, and actual incentive and allocatable non-incentive costs on an as-incurred basis.

369.8 Please explain why FEW EEC expenditures have been calculated as 1 percent of EEC FEI expenditures. Please include in your explanation (i) if FEI EEC programs are available to FEW, and (iii) if FEW revenues are 1 percent of FEI revenues.

Response:

This is explained on page 1 of Appendix I (Exhibit B-1-1). All EEC programs are available to all customers of FEVI and FEW as well as customers of FEI. Please refer to the response to BCUC IR 2.369.7.

369.9 Please explain how the FEVI EEC budget has been determined, specifically whether the FEVI budget was developed ‘bottom up’ based on regional specific EEC opportunities, or ‘top down’ based on an allocation of FEI program costs.

Response:

Please refer to the response to BCUC IR 2.369.7.

369.10 From a practical perspective, are (i) FEVI and (ii) FEW customers expected to benefit from EEC programs at a similar level as FEI customers? Please explain why/why not.

Response:

Please refer to the response to BCUC IR 2.369.7.

369.10.1 Please justify the EEC budget for FEVI and FEW industrial customers. Specifically, which programs are they expected to participate in?

Response:

Please refer to the response to BCUC IR 2.369.7.

369.11 Please describe the differences between FEI, FEVI and FEW in terms of EEC opportunities (for example, are there unique EEC opportunities in a ski resort town).

Response:

Please refer to the response to BCUC IR 2.369.7.

369.11.1 Do FEU consider that there would be a net benefit from developing a 'bottom up' EEC budget for FEW and FEVI, leveraging off FEI programs where appropriate but also designing EEC programs which address EEC opportunities specific to these regions? Please explain why/why not.

Response:

Please refer to the response to BCUC IR 2.369.7.

369.12 To the extent that FEU has not developed 'bottom up' EEC budgets for FEW and FEVI which target regional EEC opportunities, please explain if commitment to a 5 year PBR period could result in sub-optimal outcomes over time by locking in funding levels between the FEU utilities.

Response:

As explained in the response to BCUC IR 2.369.7, funding is not "locked in" at levels between the FEU utilities.

370.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-11, BCUC 1.218.3

Evaluation Framework – Key Inputs

370.1 Do FEU consider the EEC PBR budget request should be updated for BC Hydro's changes to its estimated long-run marginal cost of clean or renewable power (refer BCUC 1.218.3)? Please explain why/why not.

Response:

The Companies are not aware that BC Hydro has arrived at a final determination of its long-run marginal cost of clean or renewable power at the time of writing; thus the FEU are not proposing any changes to the EEC budget proposed at this time. Should BC Hydro finalize a revision to their long-run marginal cost for clean power over the PBR period, the ZEEA used by the Companies would be adjusted accordingly, and the benefit-cost analysis for those programs requiring the use of the MTRC would be re-run. Programs not found to be cost-effective under a changed ZEEA would not run.

370.1.1 Please identify any changes to the EEC budget for each year of the PBR period that would result from is FEU was required to use (i) $100/MWh and (ii) $85/MWh as an input into the zero-emission energy supply alternative (ZEEA).

Response:

In order to assess whether there would be any changes to the EEC budget if FEU was required to use either $100/MWh or $85/MWh as an input into the ZEEA, it was only necessary to focus on the six programs that currently require the MTRC in order to pass the economic screen. As shown in Table 1 below, modifying the input into the ZEEA to $100/MWh causes both the New Home Program and the New Technologies Program to fail the MTRC. Modifying the input into the ZEEA to $85/MWh causes the Furnace Replacement program to fail the MTRC, in addition to the same two programs.

Table 1: Benefit Cost Test Results and Expenditures for Programs that Require MTRC

Program and Service Territory	Benefit Cost Tests				Utility Expenditures ($1000s)	
	TRC	MTRC, Original	MTRC, ZEEA100	MTRC, ZEEA85	2014-2018	% of Total
Furnace Replacement Program	0.50	1.41	1.07	0.90	16,705	9.4%
ENERGY STAR® Water Heater Program	0.63	1.77	1.34	1.12	6,275	3.5%
New Home Program	0.40	1.12	0.85	0.71	4,677	2.6%
New Technologies Program	0.37	1.04	0.79	0.66	1,556	0.9%
Customer Engagement Tool for Conservation Behaviours	0.86	2.56	1.94	1.62	4,428	2.5%
Continuous Optimization Program	0.81	2.34	1.77	1.50	9,214	5.2%

Table 2 below summarizes the annual spending, total spending, and portion of the total spending for each of the six programs that require the MTRC in order to pass the economic screen.

Table 2: Annual Spending for Programs that Require MTRC

Program and Service Territory	Utility Expenditures ($1000s)						
	2014	2015	2016	2017	2018	Total	% of Total
Furnace Replacement Program	3,355	3,340	3,340	3,340	3,330	16,705	9.40%
ENERGY STAR® Water Heater Program	1,096	1,472	1,215	1,120	1,372	6,275	3.50%
New Home Program	1,036	1,036	1,036	784	784	4,677	2.60%
New Technologies Program	262	287	310	335	361	1,556	0.90%
Customer Engagement Tool for Conservation Behaviours	578	706	848	1,006	1,290	4,428	2.50%
Continuous Optimization Program	2,779	2,185	1,724	1,389	1,137	9,214	5.20%

Table 3 below summarizes the impact on EEC expenditures if the programs noted above were to be removed from the portfolio of programs. The $100/MWh scenario would result in a 3.5 percent reduction in overall spending, while the $85/MWh scenario would see the overall spending cut by about 13 percent. It should be noted that this analysis assumes that the removal of these programs would cause no changes to any spending for non-program specific or enabling activities.

Table 3: Impact on Expenditures for ZEEA Scenarios

ZEEA Scenario	Impact on Expenditures ($1000s)						
	2014	2015	2016	2017	2018	Total	% of Total
(i) $100/MWh	1,298	1,324	1,346	1,120	1,145	6,233	3.5%
(ii) $85/MWh	4,654	4,664	4,687	4,460	4,475	22,939	12.9%

370.2 Please identify and explain the rationale for the discount rates used for the TRC, mTRC and UCT. Please also estimate, and provide evidence to support, a BC societal discount rate.

Response:

Use of the utilities' pre-tax weighted average cost of capital as the discount rate for evaluating EEC activities has been well documented and reviewed in prior regulatory proceedings. The FEU are uncertain what additional identification and rationale the Commission are seeking. The use of the utilities' WACC represents the same carrying costs as if the companies were investing in capital assets. A pre-tax WACC adjusted for inflation is used because the FEU also use program input costs and benefits determined on a pre-tax basis. For the mTRC, since the DSM Regulation provides for a 15 percent adder to the benefits side of the equation to represent societal benefits, the WACC is not replaced by a societal discount rate. A good survey of the practices of other jurisdictions in determining discount rates can be found in the ACEEE study entitled "National Survey of State Policies and Practices of the Evaluation of Ratepayer-Funded Energy Efficiency Programs", referenced by the Commission in their Information Request series BCUC IR 2.371. This Commission-referenced study found that 49 percent of utilities surveyed used the utilities' WACC (page 20), and that 62 percent of utilities surveyed developed and filed key inputs to cost-effectiveness tests (such as discount rates) (page 22).

Prior to the 2011 amendments to the BC DSM regulation, the FEU were proposing a societal discount rate of 3 percent. No decision was made on that proposal because the DSM regulation was amended, giving utilities the option of using its own societal benefits or the 15 percent adder. Since the FEU choose to utilize the adder set out for the mTRC as per the BC DSM Regulations, they have not conducted any further work on estimating a societal discount rate and are unable to provide an updated estimate and supporting evidence at this time.

370.3 If the purpose of the TRC/mTRC is to determine if gas consumers are making inefficient investment/consumption decisions from a BC perspective, do FEU consider that the appropriate discount rate to use is the societal discount rate rather than the utility discount rate? Please explain why/why not.

Response:

The convention is to use the utility discount rate for TRC/MTRC calculations as outlined on page 4-8 of Attachment 217.2 provided in the response to BCUC IR 1.217. The same document states that a social discount rate is appropriate for use in a Societal Cost Test. The FEU put forward the use of a 3% social discount rate in the 2012-2013 Revenue Requirements proceeding, but this proposal was withdrawn as a result of the changes made to the Demand Side Measures Regulation in December 2011, which has allowed a 15 percent increase the measure of benefits for mTRC programs.

370.3.1 Do the DSM Regulations require that FEU use any particular discount rate (e.g., societal, utility) for the TRC and mTRC? If yes, please explain.

Response:

No, the DSM Regulation does not require that the FEU use any particular discount rate.

371.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-11, BCUC 1.214.5.2, 1.235.2, 1.214.3; ACEEE, National Survey of State Policies and Practices of the Evaluation of Ratepayer-Funded Energy Efficiency Programs, 2012, pp. 36-37;

EM&V - General

FEU state that the EM&V budget was 'developed to align with the Companies' EM&V budget spending guidelines' (BCUC 1.214.5.2) and that 'FEU's spending on EM&V appears at the low end of the range' (BCUC 1.235.2).

On pages29 and 30 of a 2012 ACEEE report titled "A National Survey of State Policies and Practices of the Evaluation of Ratepayer-Funded Energy Efficiency Programs" states, "... 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. ... Most states (34, 79%) utilize consultants/contractors for [evaluation] work."

On pages 112-114 of CPUC Decision 05-01-055 (2005) states, "...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."

In the response to BCUC 1.214.3, FEU state, "It is also not industry standard practice to conduct additional third party review of completed EM&V studies."

371.1 Please confirm that, based on the ACEEE report cited above, it is not standard practice for the utility to undertake the EEC evaluation role without formal approval by the Commission.

Response:

Not confirmed.

While the ACEEE report does indicate it is common 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. In any case, the legislative framework in BC does not require any approval to take on the EEC evaluation role.

371.1.1 Do FEU agree with the CPUC that allowing FEU to manage or contract directly for EM&V could undermine the independence of EM&V? If no, please explain why not.

Response:

No, the FEU do not agree. The FEU do not believe that their organizational structure and EM&V practices are the same as those of the IOU's referred to in the CPUC decision. 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.

The FEU interpret 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. There are two excerpts from the decision that clarify that the CPUC have observed that program implementers for the IOU's are the same staff that are contracting for evaluation services, and are thus subject to potential conflicts of interest:

On page 3, the CPUC stated that:

> *"Our use of the term "administration" or "administrative structure" in this decision does not, however, include the various tasks associated with program delivery, e.g., recruiting of customers and installation of measures. We refer to the entities that perform these functions as "program implementers," who operate under contracts/agreements with the entity or entities managing the entire portfolio of ratepayer-funded programs. Program implementers may deliver programs directly to customers, or hire contractors to perform these services, or a combination of both. "*

On page 113 of the CPUC Decision 05-01-055 (2005),

> *"Under the IOUs Coalition proposal, all program implementers contract directly with EM&V consultants for review of their programs…"*

The FEU agree that having the program implementer (i.e. Program Manager) directly contract the EM&V consultant could undermine the independence of EM&V. Hence, the FEU program implementers do not directly contract the EM&V consultants. The FEU's EM&V staff are organizationally separate from the program implementers, are in no way incented to show bias in any results, and have the full responsibility in retaining EM&V consultants for program evaluation. The role of the FEU EM&V staff are well defined and as a result ensures independence of EM&V

activities. It is the FEU's view that the FEU's current practice and organizational structure address the concern cited by the CPUC in the cited excerpts. The FEU note 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.

Please refer to the response to BCUC IR 1.214.2 where the FEU have presented their explanation of the independence of EM&V practice through the organizational separation by function between EEC program staff and EEC EM&V staff, and the transparency of the evaluation activities.

371.1.2 Do FEU consider that stakeholder comfort over the FEU estimate of the cost-effectiveness of its EEC 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 EECAG? Please explain why/why not.

Response:

No. To date, the EECAG members, have not expressed any concern about the FEU's analysis of the cost-effectiveness of the EEC programs or portfolio. The Companies have provided all assumptions that affect program cost-effectiveness in the EEC 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. As noted, in the response to BCUC IR1.214.5.3, the EEC Advisory Group participated and provided input in the development of the draft EM&V Framework.

Two key objectives in the 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.

This additional review is not necessary as the FEU act in accordance with the evaluation principle of providing transparency with respect to EM&V activities.

371.1.3 Using your best judgment, please provide an estimate (or estimate range) of the cost of an independent expert review of (i) FEU draft EM&V framework, and (ii) FEU annual results. If unable to provide, please explain what steps would be required to provide this estimate and why FEU is unable to undertake this analysis.

Response:

The FEU do not believe that there is any evidence demonstrating that such a review is warranted or a good use of ratepayer funds. The FEU's EM&V practices are reasonable, in line with other BC utilities and consistent with industry practice, guidelines and protocols. (As an update to the response to COC IR 2.9.2, the FEU now understand that BC Hydro does not use a third party to review the distribution of DSM funds.) The FEU developed their EM&V framework with input from the internal and external stakeholders, and utility partners. The EECAG has not requested a third party review and no intervenors in this proceeding have posed Information Requests suggesting that a third party review of the Companies EM&V framework or practices is required.

The FEU are concerned about the additional costs for an independent expert review and believe that such a review would add no value to customers.

However, to be responsive to the question, the following answers are provided.

(i) The FEU do not have sufficient understanding of the scope of work intended by the Commission with regard to a review of the FEU's EM&V Framework to provide any more than a very rough estimate of the costs for such review.

The FEU estimate 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 the FEU's internal costs for managing such an activity.

(ii) The FEU are unsure if part ii) of this IR is referring to the all of the results contained in the FEU's EEC Annual Reports or just the EM&V annual results. For the same reasons cited in Part i) of this IR response, the FEU do not have sufficient information to provide a reasonable cost estimate for this work.

Please refer to the also the response to BCUC IR1.214.3.

371.2 Please confirm that independent review of EEC evaluation results occur in the following states: Massachusetts, New York, California, Wisconsin, Rhode Island, Connecticut and Illinois.

Response:

Of the above cited 7 states, the FEU can only confirm that independent review of EEC Evaluation results occurs in two - New York and Wisconsin. As far as the FEU have been able to determine, while these particular states do have greater involvement in the evaluation process, it cannot be stated from these examples that such involvement represents standard industry practice. Further, it appears that these states focus to a greater extent on working to identify and mitigate potential issues prior to evaluation, than on implementing formal third party review of completed evaluations.

371.3 Given the level of judgment inherent with EM&V calculations, why do FEU provide a single number of estimated energy savings rather than a range or sensitivity analysis?

Response:

Contrary to the suggestion in the questions, the FEU do provide both a range of savings estimates and a single number when conducting EM&V calculations to verify program energy savings. The FEU has established the following methodology for providing energy savings results:

- a single number which represents the anticipated savings, or average savings per participant; and
- a range of savings at a given confidence level which represents the statistically valid spread of savings.

This approach is an industry standard data analysis practice and is appropriate when significant amounts of data sets have to be aggregated into representative and statistically meaningful parameters.

For example, when conducting a billing analysis to verify energy savings for an EEC program, the evaluator determines the appropriate random sample size using statistical parameters. An analysis is conducted for each individual program participant where the results can range from the lowest to highest savings estimates. These savings feed into the statistical analysis where an average savings per participant is calculated for the overall program. Thus both a range and a single average number are provided.

The use of a single number for energy savings is to allow reference to a per participant savings in program marketing, communications, and input into the cost-effectiveness analysis. For an example, please refer to Table 4, page 6 "Overall Project Summary" in the Efficient Boiler Program (Retrofit) evaluation report submission titled "Update of Energy Savings Analysis from FortisBC Efficient Boiler Program (EBP)" in response to BCUC IR1.215.1 where the energy savings results are presented as 19.4% (average per participant) with a 95% confidence interval of 17.8% to 20.9% or in other words,"one can be 95% confident that the overall average savings of the sites falls between 17.8% and 20.9%"

.

371.4 Is there a risk that concern over the ability of FEU to 'prove' energy savings can result in a bias of EEC programs towards those that are the easiest to prove (such as $ incentive based programs), rather than on addressing the key market barriers which may be harder to prove (such as information/behaviour programs)? Please explain why/why not, and how FEU ensure that it maintain the balance between identifying and mitigating key market barriers, while ensuring it can demonstrate energy savings to stakeholders.

Response:

Conceptually, the FEU agree that there could be a risk of bias toward incentive based programs with direct energy savings versus programs that do not report direct energy savings since programs with direct energy savings will improve the cost effectiveness of the overall portfolio, provided the individual programs are cost effective. However, the FEU have addressed this risk by ensuring a balance of program spending within the portfolio. The Companies' EEC program portfolio ensures all customers have access to some form of energy efficiency program or activity and include educational programming aimed at changing customer behavior as part of their EEC Plan, which must receive Commission approval. Further, the B.C. Demand-side measures regulation requires the Companies to include educational programming

Please also refer to the response to 2012-2013 RRA BCUC IR1.213.5 (attached below) where the FEU describe the policies and procedures in place to ensure that EEC funding is distributed in a fair and equitable manner.

213.5 Please describe the policies, procedures in place to ensure that EEC funding is distributed in a fair and equitable manner. Include a description of any committee that oversees the distribution of funds and any internal controls used to perform this oversight role.

Response:

In the Companies' original EEC Application submitted in May 2008, the FEU put forward a number of EEC Program Principles in Section 5 of the Application. Principle 1 is excerpted in its entirety below:

> *"Programs will have a goal of being universal, offering access to energy efficiency and conservation for all residential and commercial customers, including low income customers through the DSM for Affordable Housing initiative."*

The Companies' goal is to ensure that all its customers have access to some form of EEC program within the overall EEC portfolio of activity; the portfolio of programs is presented to the EEC Stakeholder group for their input and feedback, and is also presented in the EEC Annual Report. These two Commission-approved accountability mechanisms offer a method by which stakeholders can ensure that EEC funds are distributed appropriately between program activities and customer groups.

Internally, all EEC programs have business cases and budget projections associated with them, and these are approved in accordance with the Companies' financial approval levels. The Companies' EEC activity is reviewed annually by the FEU's Internal Audit ("IA") group, and the IA report for 2010 is attached as Appendix J to Appendix K-4 to Exhibit B-1. IA specifically reviews program activity to ensure that applications are approved consistent with the terms and conditions for any particular program. Customers need to be aware that a program is available, then they must implement the energy efficiency measure that the program is designed to support, then they must apply to the program. All customers that comply with the terms and conditions of any program are eligible for the program, and incentives are paid out in accordance with the terms and conditions of the various programs in the marketplace. Incentives are typically paid out to the participating customer, though incentives can also be paid out to members of the supply chain for energy efficiency upgrades, such as the $50 paid to gas contractors/dealers in the Energy Efficiency Residential Hot Water Storage Tank Program described in Section 3.4.2.1 of Appendix K-4 of the Application (Exhibit B-1). Terms and conditions for all programs are posted on the Companies' web page.

It should be emphasized that all customers that comply with the terms and conditions for any particular program are eligible for, and will receive, an incentive under that program, regardless of their choice of supplier. For example, BC

Housing, who use Amaresco as their energy services company, has received many thousands of dollars in Efficient Boiler Program incentives over recent years.

371.5 Do FEU consider that Air Miles provided to a customer as part of an EEC program should be treated as an incentive (i.e. a wealth transfer between the utility and the customer) rather than as an administrative cost of the program? Please explain why/why not, and quantify the effect reclassifying this benefit as an incentive on the TRC of affected programs.

Response:

No, currently the FEU do not consider that Air Miles provided to a customer as part of an EEC program should be treated as an incentive rather than an administrative cost. To date, EEC has only partnered with Air Miles on one pilot program initiative which was described in the FEU's response to BCUC IR 1.226.8. This pilot program focused on pledges and therefore was considered to be an educational program. It has been treated similarly to a community outreach event where customers may receive a prize for participating in a conservation game at the FEU booth.

Currently, the FEU do not have any plans to partner with Air Miles on any of the programs in the 2014-2018 EEC Plan which will be reporting energy savings. However, should the FEU decide in the future to provide Air Miles as part of a program which reports energy savings, the FEU would apply the costs incurred to purchase those Air Miles as incentive costs assuming that the Air Miles are awarded as part of the DSM measure purchase transaction.

371.6 Please provide the actual/forecast annual FEU EM&V budget for 2012 to 2018, in $ terms and as a % of total approved/requested EEC funding. Please explain any significant variances and describe any assumptions made.

Response:

Please refer to the table below for the FEU EM&V budget for 2012 to 2018, in $ terms and as % of total approved/requested EEC funding.

	EMV Budget (000's)	Percentage of Approved/Requested funding	BCUC Approved/Requested funding (000's)
2012	469	2.38%	19,715
2013P	603	1.70%	35,574
2014F	1,359	3.96%	34,353
2015F	1,445	3.96%	36,537
2016F	1,554	4.34%	35,839
2017F	1,467	4.15%	35,388
2018F	1,574	4.39%	35,874

Please note, 2013 figures are an estimate and an updated figure will be provided in the 2013 EEC Annual Report in Q1 of 2014.

The above EM&V budgets align with the Companies EM&V Framework and general industry practice for budget spending on EM&V activities. As more of the Companies' EEC programs reach maturity the FEU will increase in the evaluation activities.

371.6.1 Please identify the approximate proportion of the EM&V budget which relates to providing guidance over program design rather than quantification of energy savings.

Response:

The FEU cannot provide a separate breakdown of the EM&V budget between guidance over program design and quantification of energy savings activities, as all EM&V activities can provide input into program design. There is no distinct budget separation between the program guidance and verification of energy savings as the activities overlap and program guidance is an ongoing activity. The FEU rely on the guidelines contained in the EM&V Framework to ensure that program savings are adequately evaluated rather than setting a distinct budget for quantifying energy savings.

371.7 Please confirm that the FEU EEC function and the FEU EM&V functions report to different Vice Presidents. If not confirmed, please explain if this could result in a conflict of interest.

Response:

FEU EEC Program staff report to a separate Director than do EEC EM&V staff. These Directors report to the same Vice President. This separation of the two functional groups is intended to avoid potential conflicts of interest. Please refer to the response to BCUC IR 1.214.2 for clarification on the independence of EM&V activities in relation to EEC Program staff. Further, the FEU's Internal Audit group, who does report to a separate Vice President from both the EEC Program staff and the EEC Evaluations staff, reviews the EEC function annually to ensure that all controls and reporting requirements are being adhered to. The Internal Audit group's reports are included in the EEC Annual Reports for review by the Commission and EECAG and no concerns have been raised with respect to their findings.

372.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-11-1, Attachments to BCUC 1.215.1

EM&V – Draft Framework and Impact Evaluations

The Analysis of Energy Savings from FortisBC Efficient Boiler Program (EBP) published on 5 August 2011 (included as an Attachment to BCUC 1.215.1) states on page 28: "M&V of the savings from boiler retrofits is difficult to carry out using utility bill analysis" and makes recommendations as to improving the M&V, including the use of a building questionnaire. The Update of Energy Savings from the Efficient Boiler Program published on 14 August 2013 (included as an Attachment to BCUC 1.215.1) notes the same concerns on page and states on page 18 "a more accurate M&V protocol that would improve the accuracy of the results would be to submeter the boiler plant being retrofitted post installation."

Energy Specialist Program evaluation published on 31 March 2013 (included as an Attachment to BCUC 1.215.1) notes on page 1 that of 68 completed projects for which project review and saving verification were required, only 29 projects were ultimately evaluated.

372.1 Do FEU agree that submetering would be a more accurate M&V protocol for efficient boiler retrofits? If so, are there plans to use this method in future evaluations of boiler retrofits?

Response:

No. According to the IPMVP guidelines submetering, utility billing analysis, and simulation modeling are all acceptable methods to verify energy savings.

Utility billing analysis is appropriate for the Efficient Boiler Program as:

1. Over 61% of the Efficient Boiler Program participants are Multi Unit Residential Buildings (MURB); and
2. Gas consumption in MURBs is predominantly attributable the boiler for space and domestic hot water heating.

Submetering for the purpose of M&V may provide a higher level of accuracy if, for each of the building type sub categories, a considerable number of participant sites were submetered, including during a baseline data collection period of a least one full heating season prior to any boilers being replaced. However submetering is costly and intrusive for any participants subjected to such a requirement. For example, the FEU estimate that the cost to submeter a boiler installation could vary between $5,000 and $11,000[8], which is a considerable sum when compared to the program's average incentive of approximately $12,500. The installation, maintenance, and subsequent removal of submetering equipment on the other hand requires that participants consent to making their facilities available for the duration of the submetering period; something many may prefer not to do. Moreover, while submetering can identify changes in the gas consumption of a boiler plant after a retrofit, as with billing analysis, it cannot determine by itself if any changes are attributable solely to the new boiler(s). Other factors such as the installation of new controls, insulation, windows, or changes in occupancy may also be at play. Therefore, as was done in the methodology employed in the impact analysis, a survey of the affected participants would still be required to identify any such factors, even with submetering.

Despite not having used submetering in the impact analysis the FEU remain confident in the results given the IPMVP compliant methodology, the large sample size, and the results of the statistical analysis presented in section 5.2, page 6:

> *"one can be 95% confident that the overall average savings of the sites falls between 17.8% and 20.9%".*

The consultant also confirms in the Executive Summary, page 1:

> *"[The FEU's estimate of savings] …continues to be a reasonable savings projection."*

Given the conclusions above, and the cost of submetering the FEU do not currently have any plans to use submetering in future evaluations of retrofit boilers.

372.1.1 Will future boiler retrofit programs include the suggested questionnaire as a mandatory document to be filled out by the applicant? If not, why not?

---

8 Range is based on the following costs; meter, installation, permit, BCSA declaration for boilers 500mbh or higher, data logger with monitoring equipment, equipment commissioning, manipulation of raw data, and data analysis and reporting. Currently there are almost 900 Efficient Boiler Program applicants, since 2005. A minimum sample size of 270 may be required to achieve reasonable results. Total of submetering project may range from 1.3M to 2.9M.

Response:

Since the relaunch of the Efficient Boiler Program in May of 2012[9], a number of questions similar to those found in the survey have been incorporated into the program application form. Participants are asked to provide, for example, information on the building type, the use of the new boiler(s), the size and use of the old boiler(s), and whether or not other natural gas saving measures have been or will be implemented. A copy of this application form is included in Attachment 372.1.1.

Responses to all of these questions have not been made mandatory, however, as some participants (many apartment building owners for example) lack sufficient insight into their building's mechanical systems to provide an accurate, or in some cases, any, response. Requiring all participants to respond to all the questions, even when they are unwilling or unable to do so would in effect act as a barrier to participation, and may lead to a higher error rate in the data so obtained.

372.2 Do FEU consider the Energy Specialist Program evaluation final? If so, will the postponed evaluations be included in another study? If not, do FEU consider this evaluation sufficient for informing savings estimates for future program activity? If so, please explain why.

Response:

The FEU consider the Energy Specialist Program evaluation conducted for 2011/2012 (refer to Attachment 215.1 provided in response to BCUC IR 1.215.1) to be final. As new projects come to completion for the 2013 year and subsequent years, the FEU intend to continue to audit the reported natural gas energy savings of Energy Specialist projects that do not directly receive incentive funding from another EEC program. The eight project evaluations postponed in the 2011/2012 study, for reasons noted on page 1 of the Energy Specialist Program evaluation, will be reassessed in the next Energy Specialist Program energy savings audit which is slated to be completed in 2014.

[9] Note that the updated impact analysis only included customers who installed their boilers prior to Winter 2011/2012. This was done to ensure that at one full heating season's worth of data would be available for the analysis. All such customers participated in the program prior to its revision and relaunch in May of 2012

372.2.1 Please confirm, or explain otherwise, that of the 39 projects not evaluated, at least 12 projects with total estimated savings over 20,000 GJ/year were postponed, as compared with less than 10,000 GJ/year savings from projects that were evaluated.

Response:

As stated in the Energy Specialist Program evaluation (refer to Attachment 215.1 provided in the response to BCUC IR 1.215.1), all 68 completed projects put forward by the Energy Specialists through their quarterly reports were reviewed by the external evaluators (Prism Engineering and ClearLead Consulting). Of these 68 projects, it was deemed that 39 of them could not be audited to the extent that they would produce claimable energy savings. However, it was identified that eight of these 39 projects may be able to claim energy savings in the future once sufficient project documentation or post-retrofit data became available. Estimates available as of the time of the Energy Specialist Program evaluation indicated that these eight projects totaled estimated savings of 11,878 GJ/year[10].

372.2.2 The evaluation savings from projects completed in 2012 was 54 percent of claimed savings, while for projects completed in 2011 this value was 111 percent. Have FEU identified any factors that explain the decrease in evaluated savings from 2011 to 2012? Please explain.

Response:

The difference in claimed versus evaluated savings from 2011 to 2012 can be explained by the reported overestimation of savings in 2012, and the underestimation of reported savings in 2011 as outlined on page 5 and 6 of the Energy Specialist evaluation (refer to Attachment 215.1 provided in the response to BCUC IR 1.215.1).

The FEU have not identified any specific factors to explain why the total energy savings of the projects evaluated in the Energy Specialist Program evaluation were more in 2011 than in 2012. Energy Specialist projects often involve timeframes of over one year. In the case of this evaluation study more verifiable projects with larger energy savings happened to come to completion in 2011 than in 2012. Also note that the Energy Specialist Program evaluation only reviewed projects which did not directly receive incentive funding from another EEC program.

[10] Table 6: Project Verification Postponed, page 8.

373.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

BC Hydro IRP, 2013, p. 8-10; Exhibit B-7, 1.3.8; Exhibit B-11, BCUC 1.226.5, 1.232.3, 1.232.3.1; Exhibit B-1-1, Appendix I-1, p. 16-80

EEC Programs – High Performing/Missing Programs

On page 8-10 of its August 2013 Integrated Resource Plan (IRP), BC Hydro states, "... expenditures in support of codes and standards are justified on the grounds that they are cost-effective even if only 1 per cent of savings are attributable to BC Hydro's efforts."

Rebates for programmable thermostats are provided in Quebec (Gaz Metro Programmable Thermostat Rebate), Newfoundland and Labrador (takeCHARGE Thermostat Rebates) and Ontario (Union Gas).[11] In response to BCSEA 1.3.8, FEU state, 'the FEU technical team was not convinced that energy savings [from programmable thermostats] could be validated.'

373.1 Do FEU consider that EEC related codes and standards are likely to be one of the most cost effective means of promoting efficient customer investment decisions? Please explain.

Response:

If one considers the general, non-DSM definitions of cost-effective, yes, Codes and Standards are likely to be one of the most effective methods for customers to reduce consumption as the decision to do so is mandated rather than encouraged. Utilities do not need to make DSM program expenditures on a piece of equipment, a system or a building if a certain level of efficiency for that piece of equipment, system or building is mandated by a code or standard. Due to a code or standard, the decision as to the minimum efficiency level of any particular piece of equipment, system or building is made by the state and the customer therefore no longer has a choice or option to make a decision.

Utility programs are an essential part of transforming a market for any piece of equipment, system or building to the point where the level of market penetration of higher efficiency equipment, systems or buildings is such that the higher efficiency equipment has become the norm rather than the exception, and government can then introduce a code or standard mandating the higher efficiency level. Utility-provided incentives and information in the lead-up to market transformation actually gives the customer a choice and therefore increases the education level of the customer in understanding the impact of energy efficiency. The Companies are requesting approval of the attribution of the benefit of energy savings from the introduction of specific codes and standards, on a program-by-program basis, where utility activity has contributed to market transformation for a

[11] http://www.gazmetro.com/residentielactuel/efficaciteenergetique/en/html/169_en.aspx?culture=en-ca; http://takechargenl.ca/residential/thermostat-rebates/; http://www.uniongas.com/residential/energy-conservation/energy-savings/thermostat

specific code or standard. It appears from the excerpt above that BC Hydro has attributed 1 per cent of energy savings from the introduction of codes and standards to their expenditure on same and finds that such attribution justifies the expenditure, but the Companies cannot be sure of this.

373.1.1 Please compare the FEU code and standards related budget to that of BC Hydro 2013 IRP, and explain any significant differences.

Response:

The FEU are proposing a codes and standards budget of approximately $35,000 per year over the test period. BC Hydro are proposing an expenditure of $1.5 million in 2015 and 2016, with no expenditures for 2014. The information provided by BC Hydro to describe the activity that they propose will be supported by this expenditure can be found below:

> ***"8.2.3.1 Justification***
> Opportunities to leverage additional levels of DSM-related codes and standards support provides the potential to deliver a substantial amount of additional cost-effective electricity savings. However, there is considerable uncertainty regarding the implementation and achievement of these additional electricity savings. This action will investigate and further develop the range of codes and standards tactics to reduce uncertainty about their feasibility and/or savings estimates and ultimately inform subsequent IRPs. By doing so, it is expected that this recommended action will support further government work. An example is the Pacific Coast Collaborative's "2012 West Coast Action Plan on Jobs" that among other things seeks to jointly develop energy efficiency standards for appliances such as television set-top boxes, lighting, television, battery chargers, computer/servers and standby losses for a broad range of electronics.
>
> ***8.2.3.2 Execution***
> BC Hydro will undertake a range of activities focused on additional codes and standards, including: 1) strategy development; 2) market research, studies and opportunity assessments; 3) measure design, including modeling and cost-benefit analysis; 4) customer, trade ally and/or stakeholder engagement; and 5) pilot programs. BC Hydro will design and manage these activities to achieve the bjectives of enhanced certainty at a reasonable cost."[12]

The Companies are unable to comment further on the slate of activity contemplated by BC Hydro as they are not privy to BC Hydro's precise plans and so cannot explain any significant differences.

[12] Source: http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/irp-chap-8-20130802.pdf

The Companies are comfortable with the proposed level of expenditure for the test period at this time – it is in line with historical levels of expenditure and activity. Should activity related to codes and standards increase significantly, the Companies can transfer funds in to support codes and standards work from the appropriate program area.

373.1.2 As FEU codes and standards budget was derived independent of any consultation with government (BCUC 1.232.3), how can FEU assure stakeholders that the budget proposed is set at an optimal level? In your response, please provide a range of budget estimates that FEU considers could have reasonably been proposed.

Response:

Please refer to the response to BCUC IR 2.373.1.1. The Companies' proposed expenditure on codes and standards is based on historical levels of expenditure and activity. One range that could be considered is the range between the Companies' proposed level of expenditure at $30,000 and BC Hydro's proposed level of expenditure at $1.5 million, however this range is so large as to be meaningless. Should the Companies find over the test period that codes and standards warrant more activity and therefore more funding than is currently budgeted, the Companies will allocate funds to codes and standards from the appropriate program areas.

373.2 In response to BCUC 232.3.1 FEU state that it has helped the Ministry fund a Compliance Enhancement Coordinator role. Does the proposed EEC budget include continued funding for this role? Please explain why/why not and provide (i) budgeted amounts over the PBR period, or (ii) past budgeted amounts if the program is not being continued.

Response:

The Companies had contributed about $10 thousand annually to this Ministry-administered role. It is uncertain at this time whether or not the Ministry intends to continue with this activity, thus the Companies have not explicitly made a provision for this funding over the test period; however the amount is small enough such that the Companies are confident that funds could be found in the overall budget, should the need to do so arise.

373.3 Do FEU consider that a programmable thermostat program is likely to be cost effective in BC? Please explain why/why not. If FEU are unable to respond to this question as a result of difficulty in estimating energy savings, please estimate the range of probable savings and to what extent it is more likely that a program will be cost effective than not.

Response:

The following response addresses both BCUC IR 2.373.3 and BCUC IR 2.373.3.1

Although the programmable thermostat ("P-Stat") program could be cost effective in BC based on the cost effective assumptions in the table below, the FEU technical team was concerned about whether or not the energy savings claims could be validated. An E Source report[13] estimates that utilities can garner about 2.5 percent energy savings with programmable thermostats; however savings claims are controversial. Studies have shown that within the home, customers fail to program them properly, if at all. [14] In fact, in 2009, ENERGY STAR removed its label from programmable thermostats due to industry concerns about energy savings validation. In addition to controversial savings claims, the market is largely transformed. The 2012 REUS study suggests that 61 percent of FEU customers have already installed this measure versus 55 percent in 2008. Furthermore, a larger proportion (eight-in-ten) reported setting back the temperature at night or when no one was home. In researching retailers' online websites, there are very few manual thermostats for sale, and the incremental cost between a manual thermostat and programmable thermostats are not substantial.

The measure is, however, cost-effective if using assumptions stated in the table below, and assuming that the 4.1 GJ energy savings cited in the 2010 CPR can be validated. These assumptions were derived from the 2010 CPR, the 2009 Navigant Study for the Ontario Energy Board and personal communications with Union Gas about their program's cost effectiveness inputs.

[13] Savings from Programmable Thermostats , E Source, updated 2011

[14] *How People Actually Use Thermostats*, Alan Meier, Lawrence Berkeley National Laboratory (LBNL), presentation at American Council for an Energy Efficiency Economy (ACEEE) 2010 Summer Study on Energy Efficiency in Buildings.

Description of Cost Benefit Input	
Efficient Technology	Programmable Thermostat
Base Technology	Standard Thermostat
Savings per installation	4.1 GJs - 2010 CPR 5.6 GJs - *Navigant Consulting in 2009 report to Ontario Energy Board, 2009*
Equipment Life	15 Years – Navigant Consulting or 11 Years 2010 CPR
Incremental Cost -- Note: survey of retailer website revealed that few products listed were manual thermostats and essentially the market appears to be transformed.	$50 - *Navigant Consulting in 2009 report to Ontario Energy Board, 2009 and Union Gas*
Free Ridership	61% based on 2012 REUS information and the fact that market is close to being transformed
Number of participants - used for program budget purposes	3,000
Customer incentive	$25 (Union Gas and ESource)
Non-incentive costs (Admin, marketing, evaluation)	$80,000
Total Budget - Based on 3,000 participants	$155,000

Results of Preliminary Cost /Benefit Analysis

	Programmable Thermostat Cost Effectiveness
TRC	2.7
UCT	2.4
RIM	0.3
PCT	9.6

FEU's technical team will continue to conduct research on the validation of energy savings claims, and once satisfied that the claims are credible, FEU will assess the opportunity to include programmable thermostat technologies as a measure within approved program funding envelopes. For this reason, FEU do not foresee the need for a budgetary request for a stand-alone BC programmable thermostat program over the PBR period.

373.3.1 If yes, please estimate the potential EEC budgetary requirements (as a fixed $ amount or a range of reasonable $ amounts) for a BC programmable thermostat program for each year of the PBR period.

Response:

Please refer to the response to BCUC IR 2.373.3.

373.4 Please explain why FEU are not proposing an increase in the EEC budget (or a greater increase than that proposed) for the following programs with high UCT results (page numbers refer to Appendix I-1 of the Application):

- Energy efficient homes (p. 16)
- Low flow fixtures (p. 26)
- Commercial space heat and water heat (p. 42, p. 44)
- Industrial optimization and Specialized industrial process (p. 64, p. 67)
- Low income energy savings kit (p. 73)
- Low income space heat and water top-up (p. 78, 80).

Please include in the explanation the specific barrier(s) that is preventing FEU expansion of these programs, and the extent, if any, that FEU have attempted to address these barriers.

Response:

Generally, FEU believes that the budget proposed for these programs, and for the overall EEC portfolio, is appropriate. Please refer to the FEU's response to BCUC IR 1.224.1.1 which states:

> *"… The funding envelope within which the FEU are currently operating, and which is being requested for the test period supports a level of activity and customer rate impact with which the FEU are comfortable. Should it appear over the test period that existing cost effective programs warrant expansion or that more cost-effective natural gas EEC activity could be deployed in British Columbia, and if customer rate impacts were considered to be acceptable by the Companies and by the EECAG, the Companies could re-apply to the Commission for additional EEC funding."*

In addition, EEC program budgets are not derived based on their projected UCT performance. Each of the programs listed in BCUC IR 2.373.4 arrived at their respective projected budgets through a reasonable estimation of the number of participants that could be achieved. More specifically,

- **Energy Efficient Home Performance Program** – The future of the government-utility partnership such as LiveSmart BC is uncertain. If this program, through consultation with the Energy Efficiency and Conservation Advisory Group (EECAG) and acceptability by FEU, requires substantial funding expansion, FEU would apply to the Commission for expanded funding if required.
- **Low-Flow Fixtures** – FEU has proposed partnerships with multi-unit residential buildings (MURBS) and municipalities to promote low-flow fixtures. Sufficient budget should be available for this initiative. A comprehensive, province-wide direct install program would require additional investigation as to costs and benefits. If such a program is to be undertaken, it would likely be a joint initiative between utility partners as outlined in FEU's response to BCSEA IR 1.3.11.
- **Commercial Space Heat Program and Water Heating Program** – FEU has based the budget for these two programs on a reasonable estimation of the number of participants that can be achieved year to year.
- **Industrial Optimization Program and Specialized Industrial Process Technology Program** - FEU are proposing an increase to the EEC Industrial program area's budget of 70% by 2018 compared to 2013. Specifically, the Industrial Optimization Program budget and the Specialized Industrial Process Technology Program budget increases by 52% and 130% respectively over the PBR period. FEU believes the proposed gradual increase in EEC Industrial program area expenditures to be suitable to manage the program area's expected participation growth.
- **Low Income Energy Savings Kit** - This is a maturing program. FEU and BC Hydro both promote this program and have reached tens of thousands of participants over the years. While FEU continues to seek out new avenues and partnerships to promote this program, FEU has seen a continual decrease in participation in recent years. This is expected to continue in to the future and is why the budget for the Energy Savings Kit program is decreasing over the PBR period.
- **Low Income Space Heat Top-Ups and Low Income Water Heating Top-Ups** – These are both new programs to be introduced in 2014. Participation has been estimated based on experience working with non-profits and reflects FEU's best estimate of what FEU expects demand for the program to be.

373.5 Please explain why FEU have not included in the latest bill redesign project a requirement to allow for the inclusion of neighbor comparisons (BCUC 1.226.5). Please also comment on whether neighbor bill comparisons have been successfully used in other jurisdictions to change consumption/investment behaviours.

Response:

The bill redesign project is not scheduled until late 2014 or early 2015, and therefore requirements are not fully determined. Within the bill redesign project, FEU is pursuing opportunities to deliver more personalized information to customers, which may include neighbour comparisons.

Neighbour comparisons are, however, a key component in the requirements for the Customer Engagement Tool project for which an RFP is scheduled to be in market in early 2014. Project launch is intended to coincide with the Customer Portal Project deliverable estimate of Q2 of 2014.

Neighbour bill comparisons have been used by a number of jurisdictions in the United States and are starting to be used in Canada. Neighbour comparisons are mostly provided through Home Energy Reports or online Energy Visualization tools. Electric utilities predict savings of 1-3 percent while natural gas utilities predict savings of 1-1.5 percent[15]. One of the earliest programs in market, with therefore the opportunity for more extensive evaluation is Sacramento Municipal Utility District (SMUD) an electric utility who has determined about 2.2 percent annual energy savings for program years 2008-2011. A third party impact evaluation[16] noted that savings were sustained for the full three and half years customers received reports and in a group where reports were stopped two-thirds of the savings persisted for a full year.

Key learnings that support the business case for the FEU Customer Engagement Tool program include the following:

> *"Bill comparison or indirect feedback after a customer uses the energy, such as in monthly energy reports or access to monthly energy use online is consistently successful at generating a low level of savings. We see approximately 2 percent savings for home energy reports and even more for indirect feedback combined with tailored tips in an online audit (approximately 3 percent) or when combined with a pledge mechanism (5 percent or more)"[17].*

---

15 Evaluation of Pacific Gas and Electric Company's Home Energy Report Initiative for the 2010 - 2012 Program. Freeman, Sullivan and Company. 2012. Page 8

16 Impact and Persistence Evaluation Report. Sacremento Municipal Utility District Home Energy Report Program for Years 2008-2011. Integral Analytics. November 2012.

17 Efficiency Beyond Widgets: Residential Behavioural Program Options. December 2012, E Source

Furthermore, SMUD determined that 40 percent of the captured savings are attributed to home structural improvements. This recognizes that the reporting tool in itself helps drive home performance upgrades with longer persistence than one year and supports the objective of using the Customer Engagement tool platform to drive rebate program participation.

374.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-11, BCUC 1.217.4.2, 1.219.6, 1.219.7, 1.226.3, 1.226.3.1, 1.233.3.2; Exhibit B-7, 1.5.1; Exhibit B-1-1, Attachment I-1; Decision G-44-12, p. 168

EEC Programs – Questionable Programs

374.1 For Residential Appliance Service Program (BCUC 1.217.4.2, 1.226.3), please confirm (or provide evidence otherwise) that appliance servicing does not result in meaningful energy savings.

Response:

The FEU do not agree that the programs in this section of the IRs are “Questionable”. All programs in this section have been previously approved by Decision G-44-12 and further requests for funding are a result of positive program evaluations which have demonstrated high customer satisfaction, significant contractor engagement and considerable potential for energy savings (directly or, in the case of the Appliance Service program, indirectly).

The FEU interpret “meaningful energy savings” to be identifiable or measurable annual gas savings which impact the TRC or the MTRC as referenced in response to BCUC IR 1.217.4.2. For the Appliance Service program the FEU do not claim direct energy savings for the program as referenced in response to BCUC IR 1.217.4.2 and BCUC IR 1.226.3. As stated further in response to BCUC IR 1.217.4.2, it is difficult to measure annual gas savings from the Appliance Service program:

> *“[…]because the annual gas savings is too small to make the cost of determining the energy savings worthwhile; in other cases, the FEU have not yet identified a methodology for determining the energy savings in which the FEU have confidence.”*

As explained in the responses to BCUC IRs 1.217.4.2, 1.226.3, 1.226.3.1, 1.226.3.1.1, 1.226.3.2 and 1.226.3.2.1, however, the Appliance Service program results in indirect energy savings. Well-maintained heating systems will operate more efficiently. Furthermore, the program creates an opportunity for customer and contractor dialogue, to educate customers on energy saving behavior and promote future gas savings at a relatively low-cost.

374.1.1 In response to BCUC 1.226.3.1 FEU state that customers identify key benefits as: safety, improved efficiency and lower bills. If there are no meaningful energy savings, are customers being misled by this program? Please explain why or why not.

Response:

Please refer to response to BCUC IR 2.374.1 for the FEU interpretation of "meaningful energy savings". The FEU do not promote the Appliance Service program in a way which suggests that participants will experience identifiable annual gas savings.

Even without the inclusion of "meaningful energy savings" the FEU note that participant satisfaction with the Appliance Service program, as stated in the "TLC Furnace/Fireplace 2012" participant survey described on page 87 of the 2012 Annual Report, Exhibit B-1-1, Appendix I, Attachment I2, "continues to be very high" with 84 percent of respondents indicating high to very high satisfaction with the Appliance Service program. Respondents also identified multiple benefits of servicing their appliances annually.

374.1.2 Please describe the steps taken by FEU, if any, to ensure (i) contractors use this program as an opportunity to encourage customers to make efficient investment decisions and (ii) customers receive accurate and unbiased information on the costs/benefits of early replacement from contractors. Please provide any evidence FEU have that participants in this program are more likely to upgrade inefficient furnaces than non-participants.

Response:

As stated in response to BCUC IR 1.217.4.2:

> *"While there is no direct energy savings attributed to the appliance service, this program creates opportunities for contractors to start dialogues with customers about upgrading appliances to more efficient models."*

Furthermore, the Companies cannot control what actually happens in an interaction between a contractor and a customer and are therefore unable to ensure that a contractor is discussing opportunities to encourage efficient investment decisions, or to ensure that contractors are providing accurate and unbiased information on the costs and benefits of furnace early replacement. However, the response to BCUC IR 1.226.3.2.1 outlines the extensive contractor outreach activities that the Companies undertook as part of a spring marketing campaign to raise awareness of FEU's energy efficiency programs to contractors including a newsletter, direct mail to all BCSA contractors, regular email updates to contractor program members, and outreach events to the contractor community. Also, the application forms for the 2012 and 2013 Furnace Early Replacement Pilot identified repair costs, estimated remaining life, and appliance efficiency ratings to assist customers in identifying the costs and benefits of upgrading to a new heating system.

Further referenced in response to BCUC IR 1.226.3.2.1, the Companies can make their best efforts to educate customers and contractors but ultimately the interaction happens between the contractor and the customer and the FEU are not in the room while that is happening:

> *"No, the FEU do not directly train the contractors performing the appliance service to provide information on energy savings from upgrading inefficient furnaces/fireplaces; however the Contractor Program's mandate is to educate all contractors on the benefits of energy efficient appliance upgrades."*

As stated in response to BCUC IR 1.226.3.2, in the 2012 Appliance Service program, 13-16% of responders were advised to upgrade their furnace. In 2013, the Appliance Service program and Furnace Early Replacement Pilot were conducted in parallel. Program evaluation will determine if this co-promotion resulted in driving higher appliance replacement than in previous years. The FEU will consider evaluating a non-participant group for the 2013 program evaluation to help determine the impact on the Furnace Early Replacement Pilot in comparison to the overall population of FEU customer's replacement activity.

As noted in the 2012 REUS, 52 percent of respondents indicated they were somewhat or very interested in a furnace tune-up program and 39 percent were somewhat or very interested in a high-efficiency furnace program. Although the survey does not discuss program specifics, nor is the respondent required to participate in a program; this generally shows continued support for such programs in the market.

374.2 For the EnerChoice fireplace program (BCUC 1.233.3.2 and BCSEA 1.5.1), please describe the energy sources that could be displaced through this program (for example, gas furnace, electric furnace, electric base-board etc.) and the EM&V assumption made by FEU. Please confirm that it is not reasonable to assume a customer would use an ornamental fireplace to heat their home.

Response:

The FEU interpret "energy sources" to mean natural gas, propane or electric appliances. The EnerChoice Fireplace program could displace an appliance used for whole house space heating such as a gas or electric furnace or an electric heat pump, or it could displace an appliance used to heat an individual area or 'zone' within the home, such as an electric space heater, electric baseboard, gas boiler or gas wall furnace.

As noted in response to BCUC IR 1.233.3.1, the FEU assumption is that the participant has already decided to convert their existing heating appliance to a natural gas fireplace, and therefore the EnerChoice Fireplace rebate is:

> *"[…] then used to incent the customer to choose an energy efficient EnerChoice model rather than the base efficiency model."*

The EM&V assumption was based on available data from a 2004 report as described in response to BCUC IR 1.233.3. The FEU is initiating an impact evaluation to assess program savings through billing analysis in early 2014.

Decorative gas fireplaces have little to no heating ability. The 2012 REUS indicates that 69 % of FEI homes have some type of gas fireplace or gas heater stove (19% decorative fireplaces, 43% heater type fireplaces, and 7% free-standing models) as noted in Table 1 below. Further indicated in the table is that only 9% of decorative fireplaces are used for heat or a combined 38% for heat and ambiance. In all regions, the 2012 REUS indicates high penetration of gas fireplaces for condominiums and apartments (61% heater type fireplaces, 19% decorative fireplaces and 6% free standing models). The high number of customers with a gas fireplace represents a significant opportunity to continue to promote the use of energy efficient fireplaces in homes.

Table 1: Gas Fireplace Use based on 2012 REUS Results

	Gas – Decorative	Gas - Heater Type	Gas – Free Standing
FEI Penetration – % of homes	19%	43%	7%
Fireplace Use			
Ambiance	62%	15%	20%
Heating and Ambiance	29%	48%	36%
Heating	9%	37%	44%

374.2.1 Do FEU also target existing homes when delivering this program, and could this program be tailored to assist renters (for example by targeting owners of basement suites, with potentially a higher incentive level where the tenant is low-income)? Please explain.

Response:

Yes, the FEU offer the EnerChoice Fireplace incentive to both existing homes and new residential construction. Since the New Home program is new to market, in 2012 there were 42 units and in 2013 200 units forecasted. With regards to an EnerChoice Fireplace program specifically targeted at renters, the FEU believe that renters have fair access to the EnerChoice Fireplace program and all other residential programs as noted in the response to BCUC IR 2.379.3.

To date the FEU have yet to offer an EnerChoice Fireplace incentive specifically targeted to low-income renters. Several logistical challenges including obtaining verification of low income status and how to effectively target low income rental properties need to be addressed. However, the FEU are open to exploring the possibility of including an EnerChoice offering within the Low Income Program area if an incentive would provide the opportunity for additional energy savings to this customer segment.

374.3 How often do FEU update their EEC approach to engage with customers at community events, and could FEU do more to ensure the message does not become stale? Please explain.

Response:

The FEU update their EEC approach to engage with customers at community events on a frequent and regular basis throughout the year, and with biweekly meetings with the Events department and the full Street Team during the peak event season, which is June through to August. The overall strategic approach for community events is determined bi-annually to coincide seasonally (ie. fall/winter and spring/summer) and is based on demographics, location of event (indoor/outdoor) and activation to maximize cost effectiveness for any production materials or other costs required.

On a tactical level, messages are updated as EEC programs, contests and educational campaigns are launched and/or implemented into the marketplace. In the biweekly meetings with the full Events team, discussions among the team include lessons learned from past events sharing both successes and challenges, and methods to improving customer interactions with both children through educational games and educating parents on energy literacy and incentive programs.

374.4 FEU refer to Energy Conservation Assistance (ECAP) as its flagship low income program (BCUC 1.219.7), and it accounts for 67 percent of the low income EEC spending over the PBR period (BCUC 1.219.6). However, it has a TRC/UCT of 0.43/0.32, compared to 5.33/2.38 for the Energy Savings Kit, 2.92/3.09 for the low-income space top-up, and 2.72/2.02 for the non-profit customer programs. Please explain why FEU considers ECAP to be a 'flagship' low income program, when it appears to perform poorly compared to other FEU low income programs.

Response:

FEU disagrees with the statement that the ECAP program performs "poorly compared to other FEU low income programs." The program performs less favorably than the other Low Income programs only from the singular perspective of cost-effectiveness analysis. However, it's relevant to consider a broader perspective when determining the importance of a Low Income program. Today, ECAP is the low income program that affords the greatest opportunity for deep gas savings and significant bill reductions for individual low income customers.

Further, the FEU first identified the low TRC in ECAP in the 2012-2013 RRA. The Commissions' decision stated, "The only individual existing program that fails the MTRC is the Energy Conservation Assistance Program (ECAP) in the Low Income Program Area. BCSEA and BCOAPO both support the ECAP program which the FEU submit should be accepted because the overall portfolio is cost effective. (Exhibit B-92, para. 10, BCOAPO Final Submission, p. 34, BCSEA Final Submission p. 8)." The Commission approved the full funding request for the Low Income Portfolio for the 2012-2013 periods. With the confidence of this decision, FEU has continued to invest in developing and offering ECAP to low income customers.

The reason ECAP is considered a "flagship" low income program is because it shares many common traits with "exemplary" utility-funded low-income energy efficiency programs in other jurisdictions[18]. Some of these traits include:

1. **ECAP is a comprehensive whole-house program** (as opposed to a single measure program): Low income customers are a "difficult to engage" audience so when utilities are

[18] Kushler, Martin, PhD, York, Dan, Ph.D., Witte, Pattie, "Meeting the Essential Needs: The Results of a National Search for Exemplary Utility-Funded Low-Income Energy Efficiency Programs." September 2005.

successful in engaging this customer it's important to maximize the opportunity. A wide array of measures is included in this program, from low flow showerheads, to attic insulation, to conservation behavior education. ECAP is also comprehensive in that our partnership with BC Hydro allows us to address opportunities for electricity and gas energy savings within a single program.

2. **ECAP utilizes fully facilitated services:** One of the reasons the low-income customer group is difficult to engage is because they have other priorities dominating their capacity and resources such as securing food and shelter. FEU believes participation in the ECAP program would drop substantially if we required the low income participant to source their own contractors and manage their own retrofits. Further, in low income focus groups, it was revealed that there is very low levels of trust of contractors, because of past experiences. By having the utilities manage the contractors, low income customers are more likely to agree to have the work performed on their homes. ECAP utilizes skilled contractors and ensures adequate quality control and quality assurance systems are in place to ensure compliance with codes and standards.

3. **ECAP does not require the low income participant to pay any costs:** FEU believes that if customers were required to pay the costs of the retrofits that participation in the program would drop dramatically. As mentioned, when the competing priorities are items such as securing food and shelter, convincing a low income customer to front the costs of an energy efficiency retrofit is a difficult proposition to undertake.

4. **ECAP is a collaborative program:** By partnering with BC Hydro both utilities achieve cost efficiencies in the implementation and management of the program.

Many of the reasons that ECAP is a flagship program are the same reasons that the cost-effectiveness of the program is challenged. Fully facilitated services, a whole-home approach, and ensuring the installations are compliant with codes and standards are all activities that challenge conventional cost-effectiveness measures. Cost-effectiveness is an important objective that FEU strives to achieve; however, it should not be considered in isolation when evaluating the importance and impact of Low Income programs.

374.4.1 Please estimate the mTRC for ECAP for each year of the PBR period. If the mTRC is remains significantly below 1.00 (once the program is over its start-up phase), please explain how this program provides a net societal benefit to BC.

Response:

The EEC plan did not take a year by year approach. The plan pools all of the benefits for an overall cost-benefit equation for the entire PBR period. The FEU do expect the cost effectiveness to improve over the five year period; however the ECAP program is not expected to reach a TRC of 1.0.

The Low Income cost-effectiveness test that is applied in the EEC Plan is the TRC with a 30% benefits adder as set out in the DSM regulation. Low Income programs are excluded from mTRC. So, relative to other gas DSM programs, the benefits of Low Income programs are enhanced by the 30% adder; however, the benefits are calculated using the market price of the gas commodity.

The ECAP TRC for the PBR period is 0.43. If the Low Income programs were evaluated using the MTRC (ZEEA plus 15% adder), the mTRC would be 0.92. If Low Income programs were able to use the ZEEA in the MTRC and maintain the 30% benefits adder, the result would be a cost-effectiveness ratio of 1.04.

The FEU are not alone in reporting a TRC less than 1 for comprehensive direct-install low income programs. In a Research Brief published by E-Source in March 2012[19], only 5 of 11 utilities were required to use a cost-effectiveness test for their low income programs. In an additional E-Source research brief published in 2010[20], of all the low income programs in the study, only one electric utility (of 8 utilities) had a TRC greater than 1, and only one gas program was deemed "cost-effective"; however, the TRC was not published. TRC ranged from 0.37 for Pacific Gas and Electric's Energy Partners Program to 1.7 for United Illuminating's "UI Helps" program (the later being an electric-only program).

The societal benefits of offering energy efficiency programs to low income customers are substantial. The ECAP program, which is the program that affords low income customers the biggest opportunities for saving energy also affords the greatest benefits to society (relative to other low income programs). The societal benefits of weatherization programs in low income homes can be broken in to three categories:[21] environmental, social and economic:

- Environmental - reduction in air pollutants, reduced water usage (and subsequently, less sewage).
- Social – social equity, improvement in community pride through improvement in the local (low income) housing stock, and in some cases avoided unemployment benefits where low

[19] Source: E Source Research Brief, "Making Low-Income Programs Cost-Effective." March 2012.
[20] Spalding, Stephanie. E Source Research Brief, "Utility Low-Income Weatherization Programs." 2010.
[21] Martin Schweitzer, Bruce Tonn, "Non-Energy Benefits From The Weatherization Assistance Program: A Summary of Findings From the Recent Literature." April 2002. Prepared for the U.S. Department of Energy by Oak Ridge National Laboratory.

income individuals are employed in the course of the weatherization program (which does occur in the ECAP program from time to time).

- Economic – expenditures resulting in new jobs and increases in personal income which translates to increased income tax collections.

These are just a few examples of the societal benefits to BC of low income programs. There are a host of other non-energy benefits that also result from low income programs. Some of these include:

- Enhanced health and safety – energy efficiency enabling activities in such as ventilation, moisture assessment, and the installation of CO detectors enhance the health and safety of low income homes which lowers provincial health costs;
- Enhanced comfort – increasing the efficiency of the home reduces the likelihood that homes are kept at an unsafe temperature;
- Decreased bills from enhanced energy efficiency leads to less evictions, less foreclosures on mortgages, fewer people moving in to shelters or becoming homeless, less family separation, less likely to not buy food, less usage of pay day loans, less allergies and sickness, lower mental illness;
- Utilities and ratepayers benefit from reduced costs associated with arrears and disconnections.

374.4.2 Please explain why FEU are increasing the funding for ECAP by 46 percent over the PBR period (Attachment I-1 p. 75, 79, 81), while funding for low-income top-up programs declines.

Response:

The FEU have proposed increasing ECAP funding from $1.675 million in 2014 to $2.456 million in 2018 because the FEU believe that the ECAP program will take longer to reach the peak demand for this program due to this program having longer engagement cycles with participants. The engagement cycle in this program is quite long. The time between participant approval and the final quality assurance check of the installations can take several months and even longer for engagements with non-profit societies and First Nations communities.

Similarly, the low-income top-up programs' funding request was based on projected participation in the program. However, because these are single measure programs, it's expected that participant engagement cycles will be shorter and it's estimated that this will lead to a peak program participation in 2016. The participation and funding for the top-up programs are increasing from $93 thousand in 2014 to $111 thousand in 2018 before dropping back to $73 thousand in 2018.

374.4.2.1 Please comment on the following option: transfer the proposed increase in ECAP spending over the PBR period to the low-income space and water heating top-up programs, and expand these top-up programs to cover rental dwellings occupied by low-income tenants.

Response:

FEU does not believe the option described above is a good option. The Low Income program funding requests in the PBR period are based on anticipated demand for the program.

With furnaces being integrated in to the ECAP program in 2014, FEU believes the program will become more popular and the funding that has been requested is anticipated to be needed to enable all projected participants to participate in the program.

The primary target for the top-up programs is in fact Multi-Unit Residential Buildings (usually apartment buildings or group homes) that have tenants that are significantly all low-income tenants/renters. This target is expected to be primarily non-profit housing societies and provincially or municipally owned low income buildings. This is a very specific target market and FEU has requested budgets that align with the anticipated demand for the programs.

374.5 Furnace Replacement program (pp. 18- 19 of the Attachment I-1): Please provide the business plan for the Furnace Replacement Program. Please demonstrate that this plan complies with each of the Commission's expectations articulated on page 168 of Decision G-44-12.

Response:

Please refer to Exhibit B-1-1, Appendix I, Attachment I5 for a report which demonstrates that the 2012 and 2013 Furnace Replacement Pilot Programs and research complied with each of the Commission's expectations articulated on page 168 of Decision G-44-12. The report also provides insight into 2014 – 2018 program design considerations based on pilot learnings to date. The FEU have provided the program plan for the Furnace Replacement Program in Section 3.4.2 of Appendix I-1 (Exhibit B-1-1).

374.5.1 Given that this program does not pass the UCT, and requires the mTRC, please explain why FEU consider that the Commission should allow FEU to increase the funding for this program such that it now comprises 30 percent of the total residential EEC budget (Attachment I-1 pp. 13-14). Please include in your response if FEU consider that this program is the best use of residential EEC dollars compared to other options, and the steps FEU has taken to ensure this is assumption is valid.

Response:

The FEU believe that the Furnace Replacement Program is a cornerstone program in the EEC Residential Program Area and therefore requested that the $2 Million approved funding for the 2012 and 2013 "pilot" phase be increased to $3.3 Million per year to fulfill customer demand. In 2012, over 3000 participants benefitted from the pilot that ran September and October. In 2013, the FEU estimates that 2400 participants benefited from the pilot that ran April through August outside the heating season, a timeframe selected to emphasize the requirement for **early** rather than **emergency** replacements. The 2014-2018 funding request was for approximately 4000 participants. The FEU was anticipating this funding would cover 2500 – 3000 participants for the April through August program, plus funding for an additional 1000 participants for special offers for community partnerships such as Energy Diets. The funding could also be used to fund a Deep Retrofit Champion Bonus in the Home Performance Program.

The FEU have spent the past two years evaluating the Furnace Replacement Program to develop a design that is cost-effective and meets the needs of customers and the trades as described in 2014-2018 Revenue Requirements and Rate Application, Exhibit B-1-1, Appendix I, Attachment I5. The FEU believe the Furnace Replacement Program is the best use of funding in the Residential Program Area, as experienced by the success of the pilot and response from contractors and manufacturers. Customer surveys from the 2012 program indicated that ninety-one percent of participants and 72 percent of contractors rate their overall satisfaction with the program 8, 9, or 10 out of 10. The point of greatest dissatisfaction for contractors was the short length of time in market.

The 2012 REUS demonstrates the momentum for furnace replacement in the past 5 years. Without FEU funding, there will be no government rebates in market for heating system replacements and replacement rates may return back to 4.0 percent as experienced prior to government incentive programs.

Appliance Replacement Rates	2002 REUS* Annual Replacement (1998-2002)	2008 REUS Annual Replacement (2003 – 2008)	2012 REUS Annual Replacement (2009 – 2012)
Furnace	4.0%	4.4%	6.2%
Fireplace	N/A	N/A	0.3%

*Note *-REUS estimates were based on participants providing replacement in past five years. These rates were provided as annual rates for comparative purposes.*

The FEU also suggest that the UCT of 0.90 is marginal and could be improved to 1.0 for the 2014 – 2018 test period through a number of mechanisms such as reduced program administration costs, a review of contractor incentives, or allowing only standard efficiency furnaces to be replaced since there are greater savings achieved.

In the 2010 CPR, Furnace Replacement provided 51% of most likely achievable energy savings potential in the Residential Sector.

As outlined in BCUC IR 1.219.7:

The Furnace Replacement Program provides the following net benefits to British Columbians:

- *Reduces GHG emission by educating customers about an early rather than emergency replacement decision.*
- *Enables the FEU to further strengthen relationships with contractors, distributors, retailers and trade associations.*
- *Enables the FEU to monitor the quality of installations and the opportunity to support government and industry in training and certification of HVAC contractors.*
- *As heating systems tend to be the "gateway" to other savings opportunities as evidenced in the LiveSmart program, this provides an opportunity for further energy savings in deeper retrofits*
- *Participation in any rebate program may lead to awareness of energy bills and therefore behavioural changes as a by-product of participation.*

374.5.2 If the Commission rejects the funding request for this program, please explain how FEU would be ensure an equitable level of EEC funding by customer class is maintained.

Response:

Residential programs across North America face challenges in offering cost-effective DSM programs. In developing the EEC Plan, the FEU believe they have prioritized programs and measures that offer British Columbians the most comprehensive opportunities to reduce natural gas consumption.

There are no other programs that the FEU believe can replace this cornerstone furnace program.

Further, without government funding for heating systems and windows to drive program participation in the Home Performance Program, it may be under-subscribed in future years, also reducing the Residential Program area contributions to EEC portfolio savings.

Please refer to the FEU's report on the Furnace Replacement Program included in Exhibit B-1-1, Appendix I5 and the other responses to the BCUC IR 2.374 series.

374.6 For the Furnace Replacement program and the ENERGY STAR Water Heater Program, do FEU consider that these programs should be restricted to customers with existing gas or propane appliances in order to ensure the EEC funding is not used to increase gas consumption (unless BC emissions are decreased)? Please explain why/why not.

Response:

The FEU have followed the directive outlined in the BCUC Decision and Order No. G-36-09 on the 2008 EEC Programs Application in which the Commission Panel states:

> *"The Commission Panel accepts EEC expenditures directed at fuel switching from fossil fuels with a higher carbon content than that of natural gas. Expenditure programs specifically directed at encouraging fuel switching away from electricity are rejected, as are Incentive payments for appliances for which an Energy Star rating is not available.* ***However, expenditures are accepted for incentives to install Energy Star and EnerChoice equipment and appliances for customers, who, at their own initiative, wish to switch to natural gas as the fuel of choice"***

Thus the ability for customers, at their own initiative, to switch to natural gas varies depending on program terms and eligibility.

In the case of the Furnace Early Replacement program, the FEU agrees that the program should be restricted to customers with existing gas or propane heating systems. The program has the greatest savings opportunity during the period of early replacement from the existing gas or propane heating system to the upgraded high-efficiency system as noted in response to BCSEA IR 1.4.5.

In the case of the Energy Star Water Heater program, the program should not be restricted to gas or propane appliances since the FEU, as directed, believes that customers whom at their own initiative want to replace their electric water heater should be encouraged through this incentive program to install an efficient natural gas water heater rather than an inefficient one. The incentive available under this program is intended to address the cost increment between high-efficiency Energy Star tanks and new technologies rather than the minimum efficiency 0.62 EF base models. This program supports upcoming federal and provincial Efficiency Act standards as part of a long-term market transformation strategy for gas and propane-fired water heaters. All customers will benefit from increased availability and increased education of the trades regarding the installation of these new high-efficiency water heating technologies.

In fact, in November 2013, Natural Resources Canada awarded FEU an ENERGY STAR® Market Transformation Award as the Regional Utility of the Year for the Company's market transformation efforts in the Water Heater pilot and program. The official news release from Natural Resources Canada can be found here: http://www.nrcan.gc.ca/media-room/news-release/2013/7511. As stated in the release, the Award recognizes "leadership in offering Canadian consumers the most energy-efficient products and technology available on the market".

374.6.1 Please identify what percentage of participants in the Furnace Replacement pilot switched heating fuel from electricity to gas. Please estimate the net gas savings overall from this pilot by deducting the increase in gas load growth from fuel switching (electricity to gas) customers from the gas savings from previous gas heating customers.

Response:

The energy savings captured in the Furnace Replacement Program are dependent on advancing the replacement purchase decision of a natural gas standard or mid-efficiency gas furnace. The 2012 and the 2013 Furnace Early Replacement Pilot had zero (0) participants who switched heating fuel from electricity to gas as each pilot was restricted to participants with an existing gas or propane heating system as outlined in the terms and conditions. Please refer to response to BCSEA IR 1.4.1 and BCSEA IR 1.4.7 for further description on the program eligibility criteria. As no participants switched their heating fuel from electricity to gas within each pilot, the net gas savings overall from fuel switching customers in this pilot would be zero (0).

374.6.2 Please identify any other EEC programs that could result in an increase in gas consumption (for example, the EnerChoice fireplace program).

Response:

All EEC programs assume that the baseline condition is natural gas use and that participants subsequently install a higher efficient measure or measures which result in a reduction of natural gas consumption compared to the baseline condition.

While not actively promoted, the FEU do permit switching from another fuel source to natural gas for the ENERGY STAR® Water Heater Program and the EnerChoice Fireplace Program. However, with both of these programs the FEU assume that participants switching from another fuel source would have switched to natural gas anyway under the baseline condition but choose to upgrade to a higher efficient model of natural gas appliance then what they would have selected under the baseline condition.

375.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1-1, Attachment I-1; Decision G-44-12, p. 167; Exhibit B-11, BCUC 1.227.4, 1.238.1

Navigant, Review of the Efficiency Main Trust Plan, 2010, pp. 27-34[22]

EEC Programs – New Programs

In response to BCUC 1.238.1, FEU state that they have not finalized a business case for any of the new programs other than the Mechanical Insulation Pilot, and that they are awaiting Commission approval to pursue these programs before investing the time and resources required to do so.

In the last FEU Revenue Requirement Application, the Commission rejected a funding request for New Initiative Program Areas stating: "the Commission Panel finds that it would need to have a more detailed plan for such programs, including information on how a particular program will be developed, tested (perhaps through pilot programs), implemented and evaluated, before it can be assured that the program is in the public interest." (Decision G-44-12, p. 167)

375.1 Given that the Commission has a fundamental obligation to ensure EEC costs passed along to ratepayers are just and reasonable and were prudently incurred, please explain how the Commission can support a 5-year funding request for new programs when FEU have not yet developed a business case and program plan.

Response:

It is important to add context to the excerpt from the Commission's Decision G-44-12 in the preamble to the IR. This part of the Decision was related to the Companies' request for approval for funding for three New Initiatives put forward in the 2012-2013 Revenue Requirements Proceeding: the Furnace Early Retirement program (original funding request of $10 million annually), the Solar Thermal program (original funding request of $4 million annually), and the Thermal Energy for Schools program (original funding request of $11 million annually). The Decision related to the rejection of these expenditures for New Initiatives states on page 167:

"The $25 million of proposed expenditures exceeds by a significant margin the total spending on EEC that occurred in 2010 and 2011. Because of the magnitude of the expenditures being proposed, the Commission Panel finds that it would need to have a more detailed plan for such programs, including information on how a particular program will

---

22 http://www.navigant.com/~/media/WWW/site/downloads/energy/navigant_maine_triennial_plan_review_final_6_8_10.ashx, pp. 27-29

be developed, tested (perhaps through pilot programs), implemented and evaluated, before it can be assured that the program is in the public interest."

The approvals being requested in the current proceeding for new programs are materially different than the New Initiatives approvals requested in the 2012-2013 Revenue Requirements proceeding, and referred to in the Information Request, both in the magnitude of the proposed expenditure (less than 5 per cent of the overall EEC budget) and in the type of program (most of the proposed new programs in this proceeding are extensions of previously-approved programs).

An analysis of all proposed new program expenditures as a percentage of overall EEC expenditure year over year provided in the table below shows that new program expenditures range from 2.76 to 4.27% of total proposed EEC expenditures.

Total Proposed budget for new programs as a percentage of total expenditure, by year						
	2014	2015	2016	2017	2018	
	2.76%	3.11%	3.57%	4.27%	4.27%	

The table below provides some perspective on the magnitude of the budget for individual new programs, both as a percentage of program area budgets, and as a percentage of overall budgets. It can be seen that in all cases, proposed new programs form less than 25% of program area budgets.

		New Program Name				
		New Technologies program	Specialized Industrial Process Technology program	Low Income Space Heat Top Up	Low Income Water Heating Top Up	Non-Profit Custom Program
Proposed Budget (000's)	**2014**	262	277	78	15	316
	2015	287	399	86	16	348
	2016	310	461	94	17	383
	2017	335	665	76	15	421
	2018	361	636	60	13	463
Proposed Budget as percentage of program area budget	**2014**	2.48%	14.49%	2.97%	0.57%	12.02%
	2015	2.57%	16.93%	3.05%	0.57%	12.33%
	2016	2.79%	17.32%	3.09%	0.56%	12.59%
	2017	3.13%	22.29%	2.34%	0.46%	12.97%
	2018	3.17%	21.32%	1.72%	0.37%	13.29%
Proposed budget as percentage of overall EEC budget	**2014**	0.76%	0.81%	0.23%	0.04%	0.92%
	2015	0.79%	1.09%	0.24%	0.04%	0.95%
	2016	0.88%	1.30%	0.27%	0.05%	1.08%
	2017	0.95%	1.88%	0.21%	0.04%	1.19%
	2018	1.01%	1.77%	0.17%	0.04%	1.29%

Program profiles for the proposed new programs have been developed and presented in the 2014-2018 EEC Plan filed in Appendix I-1 of the Application, in the format discussed for the presentation of program information by the FEU's EEC staff with previous Commission staff.

Four out of five of the program profiles provide the assumptions and sources used to arrive at the cost-effectiveness projections included for the proposed new programs in the EEC Plan. The one proposed new program that does not have these assumptions provided is the New Technologies program in the Residential program area. The Specialized Industrial Process Technology Program is aimed at process heat in the manufacturing sector, and as such, is a key element of the Industrial program area of activity. (Refer to the BCUC IR 2.228 series.) The Low-Income Space Heat Top-Up, Water Heating Top-Up and Non-Profit Custom Design programs are all extensions of previously approved programs: the Commercial Space Heat and Water Heating Programs and the Customized Equipment Upgrade Program, respectively. This is indicated in the program profile. The FEU submit that there is enough evidence on the record to justify these programs as being in the public interest.

Less information has been provided for the New Technologies program because, as explained in Section 8 of the 2014-2018 EEC Plan, this program is designed to bring forward a DSM measure for a new technology from the Innovative Technology Program Area. The four steps of the Innovative Technology Selection and Implementation Process are described in Section 8.2 of the EEC Plan. The new technologies are screened in a feasibility study process, and, if they pass, a pilot project is usually developed to gather operational experience. As noted in the EEC Plan, a pilot can take approximately two to three years. The pilot project is then monitored and actual performance verified. Pilot technologies that demonstrate acceptable levels of technical performance and cost-effective energy savings are included in the applicable sector programs. As the assumptions for the actual DSM measure are taken from the pilot, FEI cannot at this time provide the detailed cost effectiveness assumptions and sources that it has for the four other programs discussed in the paragraph above. It is also noted that if no new technology emerges from the innovative Technology Program area, there would be no expenditures in the New Technologies program.

375.2 Please comment on why FEU considers it should be able to obtain EEC funding approval for new programs without a business plan, and start new EEC programs without Commission approval, when the previous Commission decision rejected this approach.

Response:

Please refer to the response to BCUC IR 2.375.1.

375.2.1 Please provide, in table form with total column/rows included, the annual budget request for each of FEU's new programs.

Response:

Please refer to the response to BCUC IR 2.375.1.

375.3 Do FEU agree that a business plan should address (i) each of the items described in BCUC 1.238.1 and (ii) 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 Companies are assuming that the Information Request intends to refer to the report prepared by Navigant Consulting entitled "Review of the Efficiency Maine Trust Triennial Plan (2011-2013)". The Companies are satisfied that the program profiles for EEC programs are suited to those purposes. Detailed program profiles for all but one of the programs proposed for the 2014-2018 period can be found in the 2014-2018 plan. These program profiles contain all the assumptions used to determine program cost-effectiveness.

Further, in the Companies' view, that 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 Fortis Energy Utilities' proposed 2014-2018 EEC Plan and associated expenditure schedule.

375.3.1 Do FEU commit to inclusion of the above items in its business plan for new EEC programs, and to provide this information to EECAG for review/input? If no, please explain why not.

Response:

No. The Companies have reviewed the 2014-2018 EEC Plan that is the subject of this proceeding with the EECAG. The EEC Plan contains detailed program-by-program profiles for all programs with the exception of the New Technologies program in the Residential Program Area. The EECAG have not indicated any desire to review and provide further input to the Companies program plans.

375.3.2 For each of the new programs, please state when FEU commit to having a business plan prepared for EECAG review/input, and what actions FEU will take it if appears that the EEC PBR funding request has been over/understated for a new program.

Response:

Please refer to the responses to BCUC IRs 2.375.1 and 2.375.3.1.

If it appears that funding for a new program has been over- or under-stated, the Companies process would be the same as for any other program. Program funding levels are monitored monthly in the Companies' Monthly EEC Management Report, and reported on annually in the EEC Annual Report. Should actual funding levels vary significantly from budgeted levels, the Companies will advise the EECAG and seek their input as deemed necessary by the Companies and the EECAG.

375.4 New Technologies Program (pp. 30- 31 of the Attachment I-1): FEU have $6 million budgeted over the PBR period for the Innovative Technologies Program (p. 98 of Attachment I-1), and $1.5 million to bring cost-effective new technologies to market (200-300 customers per year). Do FEU agree that, depending on the results of the Innovative Technologies Program, the budget requested could be significantly higher or lower than an optimal amount? Please explain why/why not.

Response:

The FEU confirm that the actual budget expenditures for the New Technologies Program as listed in pages 30-31 of Attachment I-1 will depend on whether cost-effective and feasible programs filter into the Residential program area through the Innovative Technologies program area. Just as important as identifying new technologies that should be incorporated into the New Technologies Program are findings that indicate which technologies should not. During the PBR period, the FEU plan to report on any changes to the New Technology Programs budget in future compliance filings. Should it appear that more cost-effective new technologies could be deployed within the New Technology Program than originally budgeted over the test period, and if customer rate impacts were considered to be acceptable by the Companies and by the EECAG, the Companies could re-apply to the Commission for additional EEC funding.

Refer to the also the response to BCUC IR 2.375.1.

375.4.1 For Innovative Technologies programs please provide a table showing the annual EEC budget request for the PBR period for each program, grouped by the customer class the program primarily supports. Please provide sub-totals by customer class. If funding appears to be weighted more towards programs that support one customer class over another, please comment on whether this approach is equitable.

Response:

Please refer to Attachment 375.4.1 which illustrates the annual EEC budget request for the PBR period for each Innovative Technologies program, grouped by customer class. Sub-totals for each customer class are also included. (Attachment 375.4.1 is based on information available at the time of submitting the Application, which is subject to change as the programs listed in the Attachment are filtered through the Innovative Technologies screening process as described in Exhibit B-1-1, Appendix I, Attachment I2, Figure 8.1, p. 59.

The results show that an average of 49.21 per cent of funds requested for the PBR period primarily support the commercial customer class. This compares to 16.17 per cent and 9.09 per cent for the industrial and residential customer classes, respectively. 25.53 per cent of funds are not allocated to any specific customer class. These pertain to Prefeasibility Studies and Non-Program Specific activities whose relative impact across customer classes is not easily determined.

The approach for allocating funds within the Innovative Technologies program area is customer-agnostic because it focuses on technologies. Three factors that are shaped by technology characteristics may explain relative differences in allocation across customer classes: (1) efficiency upgrades in the industrial customer class may be customer-specific and may thus not lend themselves to testing for wider market application via the Innovative Technologies filter; (2) per-technology costs for screening applications for the residential customer class may be lower than such costs for the other customer classes because screening setups for residential applications may, on average, be less complex than such setups for their non-residential counterparts; and (3) for the commercial customer class, a greater number of technologies may be available for testing than for the other customer classes. The distribution of technologies in the FEU 2010 Conservation Potential Review (CPR) illustrate the third factor: the Most Likely Achievable Scenario lists 22 commercial technologies at an average cost effectiveness of 3.2, 13 residential technologies at an average cost effectiveness of 1.7, and twelve industrial technologies.[23]

[23] http://www.bcuc.com/Documents/Proceedings/2011/DOC_28081_B-1_FEU-2012-2013-RRA-REDACTED-Public-Version-R.pdf, pdf pages 1474, 1482, 1490.

375.5 Mechanical Insulation Pilot (BCUC 1.227.4): Please provide the business plan for the Mechanical Insulation Pilot. If the pilot indicates that this program would be cost effective, please explain why FEU assumes it will not be able to enter into a satisfactory agreement with a 3rd party contractor to deliver the project over the PBR period.

Response:

The FEU do not assume that they will not be able to enter into a satisfactory agreement with a third party. Rather, the FEU have tried to enter into such an agreement with a third party (HB Lanark Consultants Ltd. in association first with the BC Insulators and Besant and Associates Engineers Ltd., then RDH Group), but ultimately the parties could not come to a satisfactory agreement. The Companies remain open to the possibility of running this pilot during the plan period, though a suitable contractor first needs to be found. Any required funding could be sourced within the requested funding envelope. Conversely, as:

1. the FEU are not currently aware of an alternative contractor;
2. pilots by their very nature can only assist a limited number customers at a time; and
3. this project did not represented a significant investment of EEC funds.

The FEU are not currently actively pursuing this project and are instead focusing resources and efforts on the administration and improvement of programs that have been recently launched or are already in market.

The requested business case that was developed for this pilot is provided confidentially in Confidential Attachment 375.5, as it includes both a letter and a proposal developed by the third party, and FortisBC has not obtained permission from the third party to disclose this information publically. The business case underwent two revisions as the scope and particulars of the pilot project evolved following discussions with the third party. Both versions are included in the attached document. Since the business case developed out of discussions with the third party and no suitable agreement could be negotiated with the third party, the business case is not current and the conditions or details in the business case would not necessary apply on a go forward basis.

375.5.1 If FEU were directed to deliver this program (once a satisfactory contractor is obtained) please provide an estimate of the budget required for each year of the PBR period, and estimated TRC/UCT results.

Response:

Please note that Exhibit 10 on page 41 of Exhibit B-1-1, Attachment I-1, erroneously included GJ savings estimates and benefit/cost test results for the Mechanical Insulation Pilot. As indicated in Table 4.5.9, page 58 of the same document, these data were not known with certainty at the time of preparing the plan, and should not have been included in Exhibit 10. The objective of the pilot was in fact to investigate this information. The FEU have updated the commercial area benefit cost test results, with the removal of any GJ savings previously attributed to the Mechanical Insulation Pilot, as provided in the table below:

Program and Service Territory	Revised Benefit/Cost Ratios				
	TRC	MTRC	Utility	Participant	RIM
ALL PROGRAMS					
FEI	1.02	N/A	1.67	1.92	0.58
FEVI	1.21	N/A	1.75	3.63	0.38
Total	1.05	N/A	1.68	2.16	0.54

No change has occurred in FEVI's performance, as the savings were only applied to FEI. Conversely, all FEI test scores have been reduced by 1/100th of a point. The overall total TRC remains unchanged at 1.05, though the Utility, Participant and RIM tests have been revised downwards from 1.69, 2.18 and 0.56 respectively. These changes do not materially affect the overall portfolio combined TRC/MTRC.

Under the original pilot proposal the FEU planned to spend up to $60,000 per building, on three mid-sized multi-unit residential buildings, to install mechanical insulation, collect and analyze data according to the International Performance Measurement and Verification Protocol (IPMVP), and produce a final report of the findings. Total spending then would have been approximately $180 thousand.

While this is a reasonable starting point the FEU note some caution is required, as this number may not accurately reflect the cost of a subsequent attempt to run a pilot program. A greater or lesser number of buildings or different building types may be included, and/or more sophisticated measurement and verification protocols may be required than those suitable for use with multifamily buildings. Moreover, a contractor or the participants may require more, or perhaps less, funding than was previously estimated in order to proceed with the project. All of these would impact the ultimate budget required to run the pilot program.

375.6 Low-income space heat/water heat top-ups (pp. 78-81 of Attachment I-1): Please provide the information used by FEU to arrive at the budget request for these programs. Please note whether these budget requests could be subject to material measurement error.

Response:

The Companies assume that “material measurement error” means, “material errors in program assumptions as presented in the program profile.”

The top-op programs are still in their early stages of development. The budget requests for these programs were based on our best estimate from experience working within the non-profit sector and also the participation of the Commercial Space Heat and Water Heat programs. Roughly speaking, the low income population in BC is estimated to be 10 to 20 percent of the total population. The participation in the Low Income Top-Up programs has been estimated at roughly 10-20 percent of the participation that is expected in the Commercial Space Heat and Water Heat programs. As mentioned in the FEU EEC Plan, the Low Income top-up program budgets don’t include the full incentive paid to the participant. The top-op programs propose that a 30 percent additional incentive will be paid to Low Income participants and only this 30 percent additional incentive will come from the Low Income budget. The remaining incentive will come from the Commercial programs.

Also as stated in the FEU EEC Plan, the Low Income Space Heat and Water Heat programs will piggy-back on the Commercial programs which are already in market. Therefore the estimates of measure life, incremental costs, and energy savings are all founded based on the experiences of the Commercial programs.

Once the top-op programs have been in market for a year, FEU will be better able to determine participant demand for these programs. FEU has the ability to shift funds from one low income program to another low income program and the ability to move a limited amount of budget from one program area to another. With this flexibility, there is a reasonably small likelihood that any low income customers will be denied access to any low income program due to program budget constraints. It should not be assumed that program participation will be limited solely to non-profit housing societies providing rental housing to low-income tenants; rather, should a building be able to prove that it provides rental housing to low-income tenants, thus making it eligible for a program that requires the 30 percent low-income adder pursuant to the DSM Regulation, it would be able to participate in this program.

375.6.1 Please explain why the low-income space heat and water top-up programs are restricted to non-profit housing societies, and are not expanded to include rental dwellings occupied by low-income tenants.

Response:

The Low Income Top-Up programs are not restricted to non-profit housing societies. Any building that has tenants whom are significantly all Low Income would be eligible for the Top-Up programs. However, the Low Income Space Heat and Water Heat top-op programs both involve measures that are shared amongst the whole building and, as such, FEU is not able to provide Low Income benefits to buildings that have a significant number of able-to-pay tenants. The estimates of participation in these programs are based on buildings that provide homes to tenants that are significantly all low income tenants. Mixed income buildings would still be eligible to apply to the Commercial Water and Space Heat programs.

375.6.2 FEU are proposing to spend 54 percent of its low income budget on incentives, compared to 71 percent for its other residential programs (pp. 13, 70 of Attachment I-1). Please explain why, and comment on whether this is consistent with general industry practice.

Response:

Low Income programs in BC and elsewhere have a lower proportion of spending on incentives primarily due to the fact that low income programs, such as ECAP, provide fully facilitated services for the low income sector. Residential programs for the able-to-pay, or non-low-income customer segment, require the participant to hire their own contractors, schedule the work, pay the contractor, and apply for a rebate. Once the program is developed and marketed, the utility needs to review the applications and process rebates. In contrast, Low Income programs tend to have a greater proportion of administration costs because the utility hires and manages the contractors, schedules the work, ensures adequate quality control and quality assurance processes are in place, manages a robust set of health and safety policies and installation policies, and pays the contractors. This fully facilitated approach is consistent with low income programs in other jurisdictions and aligned with industry best practices.

375.7 Please explain why the following Enabling Activities (Attachment I-1, pp. 104-105) have not been identified as new programs: Efficiency Partners Program, Codes and Standards, Home Energy Efficiency Web Portal, and Energy Management Education Funding. For each program, please provide the 2012/2013 approved funding levels (if any), and actual/forecast amounts.

Response:

The FEU do not consider any of these Enabling Activities to be "new programs". In previous EEC filings these activity items were listed under other EEC areas except for Codes and Standards which has been listed as an Enabling Activity in each of the FEU's EEC Annual Reports since 2009. The Efficiency Partners Program and Home Energy Efficiency Web Portal have been previously listed under the Residential program area and Energy Management Education Funding was originally supported under the Energy Specialist Program. As the EEC portfolio has developed, the FEU have determined that for ease of reporting and transparency it is more logical to group these items at the EEC portfolio level under the area of Enabling Activities. Further evidence for why these activity items should not be considered as "new" is outlined below.

The **Efficiency Partners Program** was approved in the 2012-13 RRA Decision and Order G-44-12, dated April 12, 2012. Page 177 of the 2012-13 RRA Decision states:

> *"… the Commission Panel sees merit in the Efficiency Partners program in this Application and approves it …"*

As indicated, **Codes and Standards** has been listed as an Enabling Activity in each of FEU's EEC Annual Reports since 2009. In addition, the FEU's response to BCUC IR 1.217.7 in the 2012-13 RRA (Exhibit B-9) stated:

> *"… it is expected that enabling activity in 2012 and 2013 would continue in the areas established in 2011; namely, Research and Evaluation, working with Efficiency Partners, Codes and Standards and Energy Management."*

The **Home Energy Efficiency Web Portal** was listed on pages 6, 8 and 13 of the 2012-2013 FortisBC EEC Plan and page 33 of the 2012 EEC Annual Report (Exhibit B-1-1, Appendix I2 of the Application).

Energy Management Education Funding fits under the Admin expenditures under the Energy Specialist Program as listed in the 2012-2013 FEU RRA, Appendix I (Exhibit B-25), on page 44 of the 2012-2013 EEC Plan. It was important for the FEU to support energy management education in order to have a capable workforce to draw from to fill Energy Specialist positions. However, by the time of the 2012 EEC Annual Report filing it was determined by FEU that the expenditure for Energy Management Education better fit under Portfolio Level Activities.

The following table lists the 2012/2013 approved funding levels and actual/forecast amounts for each of these activity items.

Activity Area	Expenditures ($1000s)			
	2012 Approved	2012 Actual	2013 Approved	2013 Projected
Efficiency Partners Program	500	334	500	500
Codes & Standards	n/a	15	n/a	100
Home Energy Efficiency Web Portal	40	0	80	0
Energy Management Education Funding	n/a	100	n/a	150

Note that “not applicable” is listed under 2012 Approved and 2013 Approved for Codes and Standards and Energy Management Education Funding. Codes and Standards were spread out among all program areas and Energy Management Education Funding fell under Energy Specialists Program in the 2012-13 EEC Plan. Therefore, the budget amounts for these activity items were amalgamated within those higher level cost categories.

As stated in the table above, the FEU have not yet incurred any expenditures in the 2012/2013 period for the Home Energy Efficiency Web Portal. Please refer to the FEU’s response to BCUC IR 1.223.1.1 for further information on the status of the Home Energy Efficiency Web Portal.

375.7.1 For each program above, please provide the business case. If no business case has been prepared, please provide the information used by FEU to arrive at the budget request for these programs.

Response:

As noted in the response to BCUC IR 2.375.7, these are not new programs; rather they have all been approved previously.

Please refer to the FEU’s response to BCUC IR 1.232.2 for how the FEU arrived at the budget request for these programs.

376.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1-1, Appendix I, p. 17, Attachment I-1, pp. 13-105; Decision G-44-12, p 164

EEC Programs - General

376.1 Please provide an updated Exhibits 6, 9, 11, 13, 16, and 19 of Attachment I-1 to the Application, by showing only the 'All Spending' columns for each program, and including columns showing EEC 'all spending' for 2012 (approved and actual) and 2013 (approved and projected). Please reclassify 2012 and 2103 programs to follow the same categorization used for the PBR period to provide an 'apples to apples' comparison. Please provide an explanation for any significant changes from 2012/2013 approved levels.

Response:

Please refer to Attachment 376.1. Note that explanations for any significant changes from 2012/2013 approved levels have been included at the bottom of each program area spreadsheet in Attachment 376.1.

376.1.1 For the updated Exhibits 6 and 9, please separate the funding of each program between the new construction and retrofit categories, and provide annual subtotals of total spending in each category. Please explain on any significant annual changes in these subtotals.

Response:

Please refer to Attachment 376.1 provided in response to BCUC IR 2.376.1 which includes subtotals for new construction and retrofit for the Residential and Commercial program areas.

376.1.2 For Enabling Activities, please provide annual budget requests in a format consistent with Exhibit 19, but also including EEC spending from 2012 (approved and actual) and 2013 (approved and projected). Please reclassify 2012/2013 approved amounts as necessary to provide an 'apples to apples' comparison and to enable identification of new vs.

existing activities. Please explain any significant changes from 2012/2013 approved levels.

Response:

Please refer to the "Enabling" tab in Attachment 376.1 provided in response to BCUC IR 2.376.1. The Market Saturation Study is the only item under Enabling Activities that FEU has not either undertaken previously or filed information on in a previous Regulatory proceeding. Other than some of the research studies listed under Enabling Activities (which have been undertaken by FEU previously but not in the 2012/2013 period), there are no significant changes from 2012/2013 approved levels.

376.1.3 Please provide a reconciliation of the updated Exhibits provided above with Table 1-4 in Appendix I to the Application.

Response:

For the purposes of this response, the FEU assume that by "Table 1-4" the Commission intends to mean "Table I-4".

The FEU do not understand what is meant by the term "reconciliation" in relation to the exhibits provided in Attachment 376.1 provided in response to BCUC IR 2.376.1 with Table I-4 in Appendix I to the Application. However, the FEU believe that Attachment 376.1 provided in response to BCUC IR 2.376.1, should provide the Commission with every program expenditure and sub-total comparison reasonably possible to produce for the 2012 to 2018 period.

376.1.4 For any programs where the 2012/2013 approved expenditure was zero or much lower than the PBR requested amounts, and where FEU have not identified it as a new program, please explain why this has not been identified as a new program and provide a business case for this program. Where a business case is not available, please provide the information used by FEU to justify this budget request.

Response:

The FEU believe that none of the programs previously approved in the 2012/13 RRA should be considered as new programs due to the fact that they have been previously approved in that proceeding, and program plans were provided the 2012-2013 EEC Plan.

376.1.4.1 Please update Table 8.4 in the Commission's FEU 2012-2013 RR and Rates Decision (G-44-12, p. 164), to show approved amounts for 2012 and 2013, and FEU's actual/forecast expenditures for those years. Please explain any significant differences.

Response:

Please refer to Attachment 376.1 provided in response to BCUC IR 2.376.1, the tab entitled "Updated Table 8.4". Any significant differences are explained in the respective program area tabs in Attachment 376.1.

376.2 Please split table I-4 of the Appendix I to the Application, into two sub-tables: (i) existing program areas, and (ii) new program areas. Please provide sub-totals for these tables and also include data showing approved 2012 and 2013, actual 2012 and forecast 2013.

Response:

The FEU have not proposed any new program areas for EEC. For the purposes of this response, the FEU presume that the Commission is referring to existing programs and new programs. Please refer to the individual program area tabs in Attachment 376.1 provided in response to BCUC IR 2.376.1 which includes subtotals for programs approved for 2012-2013 and new programs.

376.3 Please provide an updated Table 1-4 of the Appendix I to the Application, with Approved 2012, Actual 2012, Approved 2013, Forecast 2013, and the requested expenditure for each year from 2014 to 2018. Please reclassify 2012 and 2013 programs to follow the same categorization used for the PBR period to provide an 'apples to apples' comparison. For each program area, please provide a high level explanation of requested changes over the PBR period from 2012/2013 previously approved levels.

Response:

The FEU believe that this question is redundant with BCUC IR 2.376.1. Please refer to Attachment 376.1 provided in response to BCUC IR 2.376.1. The FEU believe that Attachment 376.1 should provide the Commission with every program expenditure and sub-total comparison reasonably possible to produce for the 2012 to 2018 period.

376.3.1 Using the updated Table I-4 above as the starting point, please allocate Enabling Activities to the most appropriate program area (residential, commercial, industrial etc). Please provide an explanation of the allocation methodology used. For each program area, please provide a high level explanation of requested changes over the PBR period from 2012/2013 previously approved levels.

Response:

The FEU do not consider that it would be appropriate to allocate Enabling Activities in this manner. Please refer to the responses to BCUC IRs 1.232.1 and 1.232.2.3.

The FEU's response to BCUC IR 1.232.1 states:

> *"Enabling Activities are initiatives that support and supplement the FEU's EEC program development and delivery. These programs, activities and projects provide resources common to the support and delivery of all program area activities …"*

The FEU's response to BCUC IR 1.232.2.3 states:

> *"All of the items listed as enabling activities in Exhibit B-1-1, Appendix I, Attachment I-1, p. 103 are considered to be enabling activities because they support multiple EEC program areas. The estimated cost listed for each enabling activity has been applied as an administrative cost at the EEC portfolio level. EEC portfolio level benefit/cost ratio calculations and utility expenditures include costs listed under enabling activities. Therefore, these costs have been allocated as "overhead" but only at the EEC portfolio level. They*

have not been allocated to a specific program area because they support all EEC program areas."

376.4 Several companies now manufacture high-efficiency combination boilers and water heaters (so-called "combi" boilers). Under current FEU programs, are efficient combi boilers eligible for rebates? If so, do they receive the rebate amount for both space and water heating systems?

Response:

The FEU interpret "high-efficiency combination boilers and water heaters" or "combi boilers" to mean boilers that supply space heating and domestic hot water capabilities utilizing two heat exchangers within a single package.

The FEU have distinct space heating and water heating programs with unique program terms and conditions. Under the FEU's current programs, combi-boilers are only eligible for rebates under the Company's space heating programs provided that the combi-boiler meets the space heating efficiency requirements of the program. In such a case, the incentive is calculated as if it were a space heating boiler.

While a select few combi-boilers meet the FEU's space heating program requirements, at time of writing, the FEU are not aware of a test standard capable of determining the domestic (potable) water heating efficiency of a combi-boiler. As a result, combi-boilers are currently not eligible for an incentive under the Company's water heating programs. Further analysis is required to determine the feasibility of providing incentives for combined space and water heating appliances within programs and as such is conducting a prefeasibility study. Results from this feasibility study are expected Q1 of 2014 and will be used to determine whether the technology can be included within a program area or whether further field research is required.

376.5 Please provide a summary of total FEU EEC related labour costs (separating out those directly charged to programs from those included as enabling activities), for each year of the PBR period, Approved 2012, Actual 2012, Approved 2013, and Forecast 2013. Please also provide a breakdown of labour costs by activity (EM&V, residential program administration etc). Please explain any significant changes from previously approved levels and describe any assumptions.

Response:

The table below provides a summary of the FEU EEC related labour costs for Approved 2012, Actual 2012, Approved 2013, 2013 Year-To-Date, Forecast 2013, and for each year of the PBR period. The only significant change in approved FEU EEC related labour costs is from 2012 to 2013. This is primarily due to the 2012-2013 RRA Decision which allocated a lesser amount of approved EEC expenditures to FEU in 2012 than in 2013.

Please note the following:

- EEC budgets are prepared and costs are managed at the program level and not split into labour and non-labour components. Therefore, labour costs for 2012 Approved, 2013 Approved, 2013 Projected, and each year of the PBR period cannot be separated out by program area or activity.
- 2012 Approved and 2013 Approved figures listed here were determined through internal labour budgeting and were not specifically cited in the FEU 2012-2013 RRA Decision.
- “Portfolio” labour costs listed under 2012 Actuals and 2013 YTD Sept Actuals represents EEC labour costs that cannot be assigned to an individual program area.

EEC Area	2012 Approved	2012 Actuals	2013 Approved	2013 YTD Sept Actuals	2013 Projected	2014	2015	2016	2017	2018
Low Income		191,152		157,044						
Commercial		819,175		729,260						
Conservation Education & Outreach		546,434		508,856						
Industrial		157,486		99,215						
Innovative Technologies		228,139		162,086						
Portfolio		818,279		773,811						
Residential		685,967		279,185						
TOTAL	**2,445,920**	**3,446,632**	**3,288,630**	**2,941,529**	**3,461,445**	**3,500,000**	**3,500,000**	**3,500,000**	**3,500,000**	**3,500,000**

376.6 Please confirm that FEU are requesting a total of $915k in funding for 5 studies over the PBR period (Attachment I-1, pp. 104, 105, Activity 5 to 9). If not confirmed please explain.

Response:

Correct. The FEU are requesting a total of $915 thousand in funding for 5 studies over the PBR period. Note though that this amount is in 2014 dollars and does not include inflation.

376.6.1 For each study, please explain (i) when the budgeted amounts are expected to be spent, (ii) how FEU arrived at the requested budget amounts (please include amounts spent previously on similar studies), (iii) whether these estimates could be subject to material measurement error, and (iv) how FEU propose to deal with significant differences in actual vs. budgeted amounts for these studies.

Response:

i. The estimated timing for the budgeted amounts of each study is outlined under the column "Timing" in Exhibit B-1-1, Appendix I-1, p. 105.

ii. Further detail on how the FEU arrived at the budgeted amounts for each of these studies is listed below:

a. **Conservation Potential Review (CPR)** – The 2010 CPR cost approximately $590 thousand. However, the 2010 CPR included a Commercial End Use study, an Economic Impact paper and an Options to the TRC Benefit-Cost Test paper. The proposed 2015 CPR would not include these extra studies/papers.

b. **Residential End-Use Study (REUS)** – The 2012 REUS study cost approximately $270 thousand in total with EEC contributing $50 thousand. To cover inflation and any possible small changes to study scope, $55 thousand was estimated for the 2016 version of this study.

c. **Commercial End-Use Study (CEUS)** – The 2010 CEUS was incorporated into the 2010 CPR and, separated out, cost approximately $30 thousand. The CEUS proposed for 2017 would likely be independent of the CPR and would include a more comprehensive surveying of Commercial buildings based on learnings from the 2010 CEUS. Therefore, it is projected that the 2017 CEUS would cost approximately $100 thousand overall with EEC contributing $30 thousand.

d. **Market Saturation Study** – The $300 thousand cost is a broad estimate of FEU's share for this study which was derived from BC Hydro's estimate of an overall study cost of $600 thousand. FEU has not undertaken a study like this before and therefore has no previous study to compare the budget amount to.

e. **New Homes Study** – The 2010 New Homes Study cost approximately $100 thousand. The 2017 New Homes Study is expected to incur a similar cost. It is estimated that EEC's contribution to this study would be $30 thousand.

iii. "Material measurement error" is a term commonly used in scientific statistical analysis. No scientific statistical analysis was utilized to produce the budget estimates for the studies.

iv. FEU put forward its best budget estimate at the time of the Attachment I-1 filing. Significant differences in actual vs. budgeted amounts for these studies will be dealt with similar to actual vs. budgeted differences that occur in other EEC program areas in that they will be proportioned within Enabling Activities ensuring not to exceed the overall Enabling Activities area budget.

376.7 Please provide a table comparing FEU measure life assumptions with the California Database for Energy Efficient Resources (DEER) for the following programs: residential air sealing; commercial water heater – on demand, and Commercial spray value/aerator. Please explain any significant differences.

Response:

Please refer to the table below for a comparison of FEU's measure life assumptions with the California Database for Energy Resources.

Please note the following:

1. The DEER database does not contain the measure life assumptions for the measures in question. FEU has compared the FEU measure life assumptions based on an equivalent measure assumption in DEER to that of Residential Air Sealing, and Commercial water heating – on demand.

2. The DEER database does not contain a measure that is equivalent to the Commercial spray valve/aerator therefore; the FEU cannot provide a comparison figure.

		Residential Air Sealing	**Commercial Water Heater - On demand**	**Commercial Spray valve/aerator**
FEU	Measure life	12	12	5
	Source	LiveSmart BC	FEU 2010 CPR	Ontario Energy Board approved DSM assumption
DEER 2008 for 2009 to 2011[1]	Measure life	11	20	N/A
	Equivalent Measure	Low-Income Weatherization (which includes air sealing)	Instantaneous Hot Water Heater or Tankless Water Heaters	N/A

[1] http://www.deeresources.com/

The FEU's value for Commercial Water Heater – on demand is based on a more recent study, the Conservation Potential Review, conducted by the FEU compared to the DEER database which references back to 2008.

376.7.1 Please explain why FEU use a 10 year life for industrial wood drying processes. Specifically, is this the expected life of the equipment?

Response:

No. A 10 year measure life was assumed to be the average persistence of the energy savings across all eligible upgrades included in the wood drying process measure. Feedback from wood drying facilities' managers indicates that most wood drying equipment should be expected to operate for more than 20 years.

The FEU could not find utility incentive programs that specifically target wood drying processes, hence information on persistence is limited. However, two reports confirm that 10 years is an accurate average measure life for wood drying process measures.[24]

[24] DNV KEMA Energy & Sustainability for Austin Energy (2012). Austin Energy DSM Market Potential Assessment. Willis Energy Services Ltd. for FortisBC Energy Inc. (2013). Lumber Kiln Market Evaluation.

377.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Decision G-44-12, pp. 184-185; Exhibit A2-1, p. 4-6, 4-7

EEC Amortization Period

The Commission stated in its Decision G-44-12: "Of concern to the Commission Panel is the potential for FEU's deferral accounts to grow significantly over the next period ... However ... we believe a final resolution of this matter can wait." (pp. 184-185).

Exhibit A2-1 states: "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)

377.1 Do FEU agree that carrying large regulatory assets on the balance sheet can weaken a utility's financial rating? If no, please explain why not.

Response:

FEU 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, and the perceived risk of disallowance by the regulator of the recovery of the regulatory asset balance in customer rates.

In the instance of FEU's EEC expenditures, which are referenced to in the preamble to this question, such risks are mitigated as FEU's EEC 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.

377.2 Please provide the actual/forecast amount in the utility's EEC deferral account for 2012 to 2018, showing the change each year (additions, amortization).

Response:

The actual and forecasted amounts for FEI's EEC rate base deferral account, as embedded in the September 6th, 2013 Evidentiary Update, are shown in Table 1 below.

It has come to FEI's attention that the amortization of the 2012 actual after-tax additions to the non-rate base EEC Incentive deferral account, while transferred to the rate base EEC deferral account January 1, 2014, were excluded inadvertently for the 2014 through 2018 amortization calculation in both the original Application and the subsequent evidentiary updates. The revenue requirement impact of this change is an approximately increase of $927 thousand in 2014 with an approximately delivery rate increase of 0.15 percent. The cumulative impact when comparing 2018 amounts to 2013 approved amounts is an increased revenue requirement of $695 thousand and an approximate delivery rate increase of 0.11 percent.

Table 1 – FEI EEC Rate Base deferral as filed Sept. 6th, 2013

FEI EEC Rate Base Deferral Account ($000s)

	2012 Actual	2013 Projected	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Opening Balance	$ 16,528	$ 22,698	$ 29,459	$ 42,636	$ 47,728	$ 51,832	$ 54,949
Opening Adjustments	-		7,089				
Gross Additions	11,940	13,350	13,350	13,350	13,350	13,350	13,350
Net of tax	(3,674)	(3,438)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)
Net Additions	8,267	9,912	9,879	9,879	9,879	9,879	9,879
Amortization	(2,097)	(3,152)	(3,791)	(4,787)	(5,775)	(6,763)	(7,751)
Closing Balance	$ 22,698	$ 29,459	$ 42,636	$ 47,728	$ 51,832	$ 54,949	$ 57,077
Mid-Year Balance	$ 19,613	$ 26,078	$ 39,592	$ 45,182	$ 49,780	$ 53,391	$ 56,013

Table 2 – Updated EEC FEI Rate Base deferral

	2012 Actual	2013 Projected	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Opening Balance	$ 16,528	$ 22,698	$ 29,459	$ 41,928	$ 46,311	$ 49,707	$ 52,116
Opening Adjustments	-		7,089				
Gross Additions	11,940	13,350	13,350	13,350	13,350	13,350	13,350
Net of tax	(3,674)	(3,438)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)
Net Additions	8,267	9,912	9,879	9,879	9,879	9,879	9,879
Amortization	(2,097)	(3,152)	(4,499)	(5,495)	(6,483)	(7,471)	(8,459)
Closing Balance	$ 22,698	$ 29,459	$ 41,928	$ 46,311	$ 49,707	$ 52,116	$ 53,536
Mid-Year Balance	$ 19,613	$ 26,078	$ 39,238	$ 44,120	$ 48,009	$ 50,912	$ 52,826

377.2.1 Please provide the estimated utility's EEC deferral account balances from 2012 to 2033, assuming EEC annual spending in future years is line with that forecast over the PBR period, using the following EEC amortization periods: 5-year, 10-year and 20-year.

Response:

FEI has provided this response using the updated EEC deferral account forecasts as provided in the response to BCUC IR 2.377.2. Separate tables have been provided using the currently approved 10-year amortization period, and the scenarios with 5-year and 20-year amortization periods. FEI has assumed the same $13.35 million embedded in 2014 to 2018 forecasted rates will continue until the end of the analysis period.

FEI EEC Rate Base Deferral Account ($000s) - 10 year amortization

	2012 Actual	2013 Projected	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
Opening Balance	$ 16,528	$ 22,698	$29,459	$41,928	$46,311	$49,707	$52,116	$53,536	$54,077	$54,180	$55,083
Opening Adjustments	-		7,089								
Gross Additions	11,940	13,350	13,350	13,350	13,350	13,350	13,350	13,350	13,350	13,350	13,350
Net of tax	(3,674)	(3,438)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)
Net Additions	8,267	9,912	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879
Amortization	(2,097)	(3,152)	(4,499)	(5,495)	(6,483)	(7,471)	(8,459)	(9,338)	(9,776)	(8,977)	(10,260)
Closing Balance	$ 22,698	$ 29,459	$41,928	$46,311	$49,707	$52,116	$53,536	$54,077	$54,180	$55,083	$54,702
Mid-Year Balance	$ 19,613	$ 26,078	$39,238	$44,120	$48,009	$50,912	$52,826	$53,807	$54,129	$54,631	$54,892

FEI EEC Rate Base Deferral Account ($000s) - 10 year amortization

	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast
Opening Balance	$54,702	$54,334	$54,334	$54,334	$54,334	$54,334	$54,334	$54,334	$54,334	$54,334
Opening Adjustments										
Gross Additions	13,350	13,350	13,350	13,350	13,350	13,350	13,350	13,350	13,350	13,350
Net of tax	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)
Net Additions	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879
Amortization	(10,247)	(9,879)	(9,879)	(9,879)	(9,879)	(9,879)	(9,879)	(9,879)	(9,879)	(9,879)
Closing Balance	$54,334	$54,334	$54,334	$54,334	$54,334	$54,334	$54,334	$54,334	$54,334	$54,334
Mid-Year Balance	$54,518	$54,334	$54,334	$54,334	$54,334	$54,334	$54,334	$54,334	$54,334	$54,334

FEI EEC Rate Base Deferral Account ($000s) - 5 year amortization

		2012 Actual	2013 Projected	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
	Opening Balance	$16,528	$ 22,698	$29,459	$39,117	$39,711	$38,328	$34,970	$29,636	$29,636	$29,636	$29,636
	Opening Adjustments	-		7,089								
	Gross Additions	11,940	13,350	13,350	13,350	13,350	13,350	13,350	13,350	13,350	13,350	13,350
	Net of tax	(3,674)	(3,438)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)
	Net Additions	8,267	9,912	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879
	Amortization	(2,097)	(3,152)	(7,310)	(9,286)	(11,261)	(13,237)	(15,213)	(9,879)	(9,879)	(9,879)	(9,879)
	Closing Balance	$22,698	$ 29,459	$39,117	$39,711	$38,328	$34,970	$29,636	$29,636	$29,636	$29,636	$29,636
1	Mid-Year Balance	$19,613	$ 26,078	$37,833	$39,414	$39,019	$36,649	$32,303	$29,636	$29,636	$29,636	$29,636

FEI EEC Rate Base Deferral Account ($000s) - 5 year amortization

		2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast
	Opening Balance	$29,636	$29,636	$29,636	$29,636	$ 29,636	$29,636	$29,636	$29,636	$29,636	$29,636
	Opening Adjustments										
	Gross Additions	13,350	13,350	13,350	13,350	13,350	13,350	13,350	13,350	13,350	13,350
	Net of tax	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)
	Net Additions	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879
	Amortization	(9,879)	(9,879)	(9,879)	(9,879)	(9,879)	(9,879)	(9,879)	(9,879)	(9,879)	(9,879)
	Closing Balance	$29,636	$29,636	$29,636	$29,636	$ 29,636	$29,636	$29,636	$29,636	$29,636	$29,636
2	Mid-Year Balance	$29,636	$29,636	$29,636	$29,636	$ 29,636	$29,636	$29,636	$29,636	$29,636	$29,636

FEI EEC Rate Base Deferral Account ($000s) - 20 year amortization

		2012 Actual	2013 Projected	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
	Opening Balance	$16,528	$ 22,698	$29,459	$44,599	$52,157	$59,221	$65,790	$71,866	$77,448	$82,536	$87,130
	Opening Adjustments	-		7,089								
	Gross Additions	11,940	13,350	13,350	13,350	13,350	13,350	13,350	13,350	13,350	13,350	13,350
	Net of tax	(3,674)	(3,438)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)
	Net Additions	8,267	9,912	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879
	Amortization	(2,097)	(3,152)	(1,827)	(2,321)	(2,815)	(3,309)	(3,803)	(4,297)	(4,791)	(5,285)	(5,779)
	Closing Balance	$22,698	$ 29,459	$44,599	$52,157	$59,221	$65,790	$71,866	$77,448	$82,536	$87,130	$91,230
3	Mid-Year Balance	$19,613	$ 26,078	$40,574	$48,378	$55,689	$62,506	$68,828	$74,657	$79,992	$84,833	$89,180

FEI EEC Rate Base Deferral Account ($000s) - 20 year amortization

	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast
Opening Balance	$91,230	$94,836	$ 97,948	$100,566	$102,690	$104,320	$105,457	$106,099	$106,247	$105,902
Opening Adjustments										
Gross Additions	13,350	13,350	13,350	13,350	13,350	13,350	13,350	13,350	13,350	13,350
Net of tax	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)	(3,471)
Net Additions	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879	9,879
Amortization	(6,273)	(6,767)	(7,261)	(7,755)	(8,249)	(8,743)	(9,237)	(9,731)	(10,225)	(10,719)
Closing Balance	$94,836	$97,948	$100,566	$102,690	$104,320	$105,457	$106,099	$106,247	$105,902	$105,062
Mid-Year Balance	$93,033	$96,392	$ 99,257	$101,628	$103,505	$104,889	$105,778	$106,173	$106,075	$105,482

377.3 Please provide a comparison of the 10-year EEC amortization period requested with the average EEC measure life assumption. Please provide supporting details/assumptions.

Response:

An analysis was carried out on the proposed portfolio of FEU programs to calculate average EEC measure life values. Two different approaches were taken: One version of the average measure life was weighted by spending while the other version was weighted by savings. The following bullets summarize the approach that was used in each case:

- **Weighted by Spending**: The total cost of each program throughout the entire PBR period was used. However, enabling programs and activities with no savings were not included in the weighting. This approach is consistent with the method that is employed by FBC in its calculation of average measure life.
- **Weighted by Savings**: The total savings that would occur as a result of the programs being implemented during the PBR period were used to weight the measure lifetime by savings. As such, the savings occurring over an extended period of 2014-2043 (i.e. 20 years) were employed. This allowed for a fairer weighting, since many of the measures that are being implemented will result in long-term savings that will persist long after the end of the 5-year PBR period. In addition, gross savings were used, so they do not include the impacts of free ridership.

It should also be noted that weighted lifetimes have been assumed for the Innovative Technologies program area since the savings and costs for this program area are less certain.

Please refer to Attachment 377.3 for an electronic spreadsheet which summarizes all of the inputs into this calculation and the resulting average measure life for each program area and for the portfolio as a whole. The average measure life weighted by cost was found to be 13.0 years, while the average measure life weighted by savings was found to be 13.2 years.

377.4 Please estimate the increase/decrease in FEU shareholder EEC related incentive from 2012 to 2033 if the 10 year EEC amortization period was: 5 year, 15 year and 20 year. Please provide supporting calculations and assumptions.

Response:

The Companies would not characterize the return that FEU makes on EEC investments as "FEU shareholder EEC related incentive". Rather it is the equity return related to the rate base, and provides the FEU with "a fair and reasonable return on any expenditure made by it to reduce energy demands" as outlined in Section 60 (1) (b) (ii) of the Utilities Commission Act.

The Companies are not proposing any change in the current amortization period of 10 years.

Based on the assumptions below and the resulting calculations shown in Table 1, the FEU shareholder equity return related to the rate base EEC deferral account ranges from a total of $22.9 million over the entire 22 year period from 2012 to 2033 for the 5 year amortization method compared to a total of $60.1 million over the same period using the 20 year amortization method. The currently approved amortization period of 10 years results in an equity return of $37.1 million.

It should be noted that reducing the amortization period to 5 years would result in an increase to customer rates for the 2014 – 2018 PBR period, as is evident through the increased revenue requirements in Table 1. On a larger scale, an increase in revenue requirements would result from the reduction to any of FEU's existing approved depreciation or amortization periods for plant-in-service or rate base deferrals, so the results below should be expected.

The analysis uses the approved mid-year rate base amounts for 2012 and 2013 as FEI equity returns are based on the approved amounts. The remaining years are the same mid-year rate base balances as provided in BCUC IR 2.377.2.1 for calculating the equity earned return for the 5 year, 10 year and 20 year scenarios, which have been updated to reflect the correction to the EEC deferral account identified in BCUC IR 2.377.2. The 15 year scenario uses the same forecasted additions as provided in the other scenarios, and is shown in Table 2 below.

For reference, Appendix I-3 in the Application also includes a detailed analysis of the impacts of various disposition periods for the EEC deferral account. This includes amortizing the account over a 5 year, 10 year and 20 year period. However, that analysis assumes adding 89 percent of the FEU EEC requested funding envelope for 2014 through 2018 and inflating that ask by 2 percent every year thereafter.

Table 1 – Shareholder equity returns for 5, 10, 15 and 20 year amortization periods

	MID-YEAR RATE BASE ($000s)				ROE	EQUITY THICKNESS	EQUITY EARNED RETURN ($000s)				REVENUE REQUIREMENT ($000s)			
	5 YEAR	10 YEAR	15 YEAR	20 YEAR			5 YEAR	10 YEAR	15 YEAR	20 YEAR	5 YEAR	10 YEAR	15 YEAR	20 YEAR
2012	20,486	20,486	20,486	20,486	9.50%	40.00%	778	778	778	778	4,709	4,709	4,709	4,709
2013	27,874	27,874	27,874	27,874	8.75%	38.50%	939	939	939	939	6,768	6,768	6,768	6,768
2014	37,833	39,238	40,269	40,574	8.75%	38.50%	1,274	1,322	1,357	1,367	13,091	9,413	6,713	5,916
2015	39,414	44,120	47,382	48,378	8.75%	38.50%	1,328	1,486	1,596	1,630	15,872	11,147	8,179	7,217
2016	39,019	48,009	53,837	55,689	8.75%	38.50%	1,314	1,617	1,814	1,876	18,458	12,747	9,543	8,429
2017	36,649	50,912	59,633	62,506	8.75%	38.50%	1,235	1,715	2,009	2,106	20,865	14,232	10,807	9,550
2018	32,303	52,826	64,770	68,828	8.75%	38.50%	1,088	1,780	2,182	2,319	23,205	15,759	12,160	10,779
2019	29,636	53,807	69,249	74,657	8.75%	38.50%	998	1,813	2,333	2,515	15,778	17,027	13,417	11,924
2020	29,636	54,129	73,069	79,992	8.75%	38.50%	998	1,823	2,462	2,695	15,778	17,646	14,620	13,029
2021	29,636	54,631	76,230	84,833	8.75%	38.50%	998	1,840	2,568	2,858	15,778	16,607	15,769	14,093
2022	29,636	54,892	78,733	89,180	8.75%	38.50%	998	1,849	2,652	3,004	15,778	18,363	16,864	15,117
2023	29,636	54,518	80,578	93,033	8.75%	38.50%	998	1,837	2,714	3,134	15,778	18,314	17,905	16,100
2024	29,636	54,334	81,763	96,392	8.75%	38.50%	998	1,830	2,754	3,247	15,778	17,802	18,892	17,042
2025	29,636	54,334	82,290	99,257	8.75%	38.50%	998	1,830	2,772	3,344	15,778	17,802	19,825	17,945
2026	29,636	54,334	82,159	101,628	8.75%	38.50%	998	1,830	2,768	3,424	15,778	17,802	20,704	18,807
2027	29,636	54,334	81,369	103,505	8.75%	38.50%	998	1,830	2,741	3,487	15,778	17,802	21,530	19,628
2028	29,636	54,334	79,920	104,889	8.75%	38.50%	998	1,830	2,692	3,533	15,778	17,802	22,301	20,409
2029	29,636	54,334	79,031	105,778	8.75%	38.50%	998	1,830	2,662	3,563	15,778	17,802	19,826	21,149
2030	29,636	54,334	79,031	106,173	8.75%	38.50%	998	1,830	2,662	3,577	15,778	17,802	19,826	21,849
2031	29,636	54,334	79,031	106,075	8.75%	38.50%	998	1,830	2,662	3,573	15,778	17,802	19,826	22,508
2032	29,636	54,334	79,031	105,482	8.75%	38.50%	998	1,830	2,662	3,553	15,778	17,802	19,826	23,127
2033	29,636	54,334	79,031	105,482	8.75%	38.50%	998	1,830	2,662	3,553	15,778	17,802	19,826	23,127
Total							**22,933**	**37,103**	**50,443**	**60,075**				

Table 2 – EEC Deferral account continuity with 15 year amortization period

	Deferral Beginning Balance	Opening Adjustment	Net Additions	Amortization	Deferral Ending Balance	Mid-Year Rate Base ($000s)
2012	16,528		10,013	(2,097)	24,444	20,486
2013	24,444		10,013	(3,152)	31,306	27,874
2014	29,459	7,089	9,879	(2,437)	43,990	40,269
2015	43,990		9,879	(3,095)	50,774	47,382
2016	50,774		9,879	(3,754)	56,899	53,837
2017	56,899		9,879	(4,412)	62,366	59,633
2018	62,366		9,879	(5,071)	67,174	64,770
2019	67,174		9,879	(5,730)	71,323	69,249
2020	71,323		9,879	(6,388)	74,814	73,069
2021	74,814		9,879	(7,047)	77,646	76,230
2022	77,646		9,879	(7,705)	79,820	78,733
2023	79,820		9,879	(8,364)	81,335	80,578
2024	81,335		9,879	(9,023)	82,192	81,763
2025	82,192		9,879	(9,681)	82,389	82,290
2026	82,389		9,879	(10,340)	81,929	82,159
2027	81,929		9,879	(10,998)	80,809	81,369
2028	80,809		9,879	(11,657)	79,031	79,920
2029	79,031		9,879	(9,879)	79,031	79,031
2030	79,031		9,879	(9,879)	79,031	79,031
2031	79,031		9,879	(9,879)	79,031	79,031
2032	79,031		9,879	(9,879)	79,031	79,031

378.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

SERA, Lessons Learned and Next Steps in Energy Efficiency, 2009, p. 5, Appendix A[25]; ACEEE, A National Survey of State Policies and Practices of the Evaluation of Ratepayer-Funded Energy Efficiency Programs, 2012, p. 38; SERA/CIEE, National Review of Best Practices and Issues in Attribution and Net-to-Gross, 2010, pp. 353-354[26]; Exhibit B-11, BCUC 1.220.5.1

CPUC, Energy Efficiency EM&V Plan, 2013, p. 120[27]

Spillover/Codes and Standards

A SERA report on Energy Efficiency Measurement and Attribution dated November 2009 includes California Codes and Standards Compliance Enhancement Evaluation Protocol in Appendix A, and states on page 5: "Spillover is more complicated than free ridership to measure and as a consequence, a number of utilities that include free ridership never estimate spillover. Free ridership emanates from the pool of identified program participants; the effects from spillover are not realized from the participating projects and, in many cases, not even the entities that participated. Identifying who to contact to explore the issue of spillover and associated indirect effects can be daunting."

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 found that 25 states (64%) reported that they made an adjustment for free riders, but only 17 states (44%) made an adjustment for free-drivers/spillover. ... we recommend that if a state wants to estimate and report "net savings," their methodology should incorporate both free riders and free drivers/spillover."

A 2010 SERA/CIEE paper titled "National Review of Best Practices and Issues in Attribution and Net-to-Gross" stated on pages 353-354: "Estimating spillover and applying ranges or confidence intervals to the values in assessing the program may be preferable to ignoring spillover. [Footnote] Or looking for that threshold value of spillover that 'turns the decision' may be another way to address the accuracy issue. If the threshold is outside the estimated range for spillover or outside any credible or feasible range based on the rough estimate, the program decision-making is improved."

A 2013 CPUC Report on the Energy Efficiency EM&V Plan states on page 120, "The Codes and Standards program accounts for 23% of the statewide projected energy savings but only 1.44% of the IOU approved budget for 2013-14 cycle."

---

[25] http://uc-ciee.org/downloads/EEM_A.pdf
[26] http://aceee.org/files/proceedings/2010/data/papers/2078.pdf
[27] http://www.cpuc.ca.gov/NR/rdonlyres/64110971-52C4-4DAD-8F84-559D09E727E4/0/20132014_EE_EMV_PlanVer2.pdf

378.1 Do FEU agree with the 2010 SERA/CIEE extract above? Specifically, have FEU considered taking the approach of calculating a range of values that may represent the spillover rate, or only estimating spill-over for programs which would not otherwise pass the TRC/UCT?

Response:

In answer to the first question: Theoretically yes, the FEU agrees with the 2010 SERA/CIEE extract stated on pages 353-354 of the "National Review of Best Practices and Issues in Attribution and Net-to-Gross". Applying a range of values for spillover is one approach but requires a high level of knowledge in determining the appropriate values. As noted in the 2010 SERA/CIEE paper, "The degree of accuracy needed in the NTG computation for these various applications are more stringent if higher dollars are involved." On the other hand, another approach mentioned in the SERA/CIEE paper is spillover may be ignored for low value programs or for a programs for which spillover is not an integral part. For this reason, there should be flexibility in the application of NTG, free ridership and spillover results depending on the type of program. Hence, FEU's approach to evaluate program effects is on a program-by-program basis.

In answer to the second question: No, the FEU have not at this time considered taking the approach of calculating a range of values that may represent the spillover rate nor considered the approach to estimate spill-over for programs which would not pass the TRC/UCT calculations. As discussed in the FEU's response to BCUC IR 1.210.1, below, the Companies plan to evaluate program effects on a program-by-program basis to determine the appropriate approach to determining spillover effects, and may at that point consider using these approaches described by the Commission (reproduced below).

210.1 Does the FEU have a specific proposal to quantify additional energy savings from spillover effects? If so, please provide the proposal in detail.

Response:

No, the FEU do not have a specific proposal to quantify additional energy savings from spillover effects. The FEU would evaluate program effects on a program-by-program basis, using consultants to conduct surveys of program participants and non-participants, to determine both free rider rates and spillover effects. As noted during the original EEC proceeding in 2008, in which the Companies proposed to use gross energy savings to calculate benefit-cost results, free rider rates are notoriously subjective. Spillover rates are the same in that they are primarily determined by surveying individuals as to the effect that a utility DSM program has had on the respondent's actions, generally a significant amount of time after the action has been undertaken. It is the view of the Companies, however, that by not accounting for program spillover effects and only adjusting program results downward *for free rider effects, evaluation of the Companies' programs is creating a lopsided view of the Companies' EEC activity.*

378.1.1 Please confirm that inclusion of spillover estimate primarily affect the UCT, rather than TRC or mTRC. If not confirmed please explain.

Response:

The inclusion of spillover estimates affects both the TRC/mTRC and UCT calculations. However, the effect on the UCT is more prominent than in the TRC/mTRC calculation as explained in the response to BCUC IR 1.217.5.4

378.1.2 Please confirm that a program can have low free ridership and high spillover, and vice versa. If not confirmed, please provide evidence otherwise.

Response:

Confirmed. FEU believes on a portfolio level, the free ridership and spillover will offset one another.

378.2 Please describe the methodology used for the LiveSmart program to identify the population to contact for surveys designed to measure free ridership. Do FEU see this as an appropriate method for identifying the spillover population for other programs? Please explain.

Response:

The LiveSmart BC evaluation collected information on participant experience and satisfaction, in comparison to non-participant decision-making on home retrofits to inform free rider and spillover estimates. Additional demographic and housing parameters were collected for both customer satisfaction attributes and for billing consumption analysis. A print and online survey methodology was selected to afford respondents the time to formulate and express well-considered responses to the number of complex questions being asked of them.

The LiveSmart participant population was all households in British Columbia that completed home retrofits and received program rebates via LiveSmart within the evaluation period. A near-census approach was primarily used to ensure a very large survey sample to facilitate a billing analysis down to the measure level and in consideration of lower response rates typically associated with self-administered surveys. This large sample size also facilitated a detailed analysis of free-ridership and spillover. A small portion of households were excluded due to the following: participants on the 'do not consent' list, households from smaller local distribution company territories[28], and reasons relating to inconsistent or incomplete program information. A total of 28,254 program participants were mailed a survey with 8,631 surveys completed and returned.

For non-participants, a sample of program eligible households was randomly drawn from the BC Hydro and FortisBC customer billing systems. A total of 29,469 non-participating households were mailed a survey and 4,457 surveys were completed and returned.

The samples of survey respondents were then compared to the population of participants and non-participants to ensure they were representative.

FEU sees a very limited potential to adopt the LiveSmart methodology for identifying the spillover population for other EEC programs. The methodology used in the LiveSmart evaluation was a near-census approach which is effective when there is a very large sample population of participants and non-participants within which to conduct the analysis. LiveSmart is a multi-measure home retrofit program where a large non-participant sample can easily be established compared to the non-participant sample for a program with a single measure. At this time FEU do not have other programs similar in magnitude to the LiveSmart program, thus utilizing the same approach is not appropriate. FEU's approach to evaluate program effects is on a program-by-program basis, and where appropriate, FEU may apply a similar methodology.

378.3 Have FEU identified further opportunities to measure spillover associate with other programs? If not, why not. If yes, what are these opportunities and do FEU intend to pursue them?

28 Local distribution companies include: New Westminster, Grand Forks, Summerland, Penticton, Nelson & (parts of) Kelowna.

Response:

No, FEU have not identified further opportunities at this time to measure spillover with other programs. The Companies plan to evaluate NTG ratios on a program-by-program basis. As evaluation plans are drawn up for individual programs, the opportunity to evaluate NTG ratios will be examined, and decisions made as to whether to have a balanced look at NTG that incorporates both free riders and spillover, or whether the approach should be to look only at free riders. Please refer also to the response to BCUC IR2.378.1

378.4 Do FEU have any plans to explore methods for calculating net to gross ratios other that self-report surveys? Please include in your response a description of other alternative methods, including Econometric methods (use of statistical tools and techniques) and Market share methods (use of sales and saturation data). If no, please discuss the reason FEU believe self-report surveys to be the best strategy.

Response:

Yes, the FEU do plan to further explore the applicability of alternate methods for calculating the net to gross ratio.

The description of the methodologies references in this IR are listed below:

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.

Econometric 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.

378.5 Please explain why FEU in response to BCUC 1.220.5.1 indicates that it may modify or discontinue a program with a high estimated spillover rate. Isn't a high spillover rate a good thing?

Response:

The operative word in the response to BCUC IR 1.220.5.2 is "may". The FEU states in that response that high spillover may indicate a need to make adjustments to a program. That response also states that high spillover would need to be examined in conjunction with other program and market environment factors to determine if program adjustments or cancellation is necessary, and if so, what the course of action should be. Alternatively, a high spillover rate can be a good thing and may result from a program addressing other market failures. If so, an examination of the program in conjunction with the market environment may reveal that it should continue as is. Independent of other factors, a high spillover rate is not enough information to determine a course of action.

378.6 Please describe the approach used by BC Hydro to attribute savings from codes and standards. Will FEU adopt a consistent approach, and if not, please explain why.

Response:

To the best of the FEU's knowledge, BC Hydro has not published or released a formal approach to attributing savings from codes and standards, and therefore the FEU cannot comment on their approach nor whether the FEU would use a similar approach.

378.6.1 Will FEU codes and standards EM&V approach comply with California Codes and Standards and Compliance Enhancement Evaluation Protocol? If no, please explain why.

Response:

The FEU currently cannot comply with the California Codes and Standards and Compliance Enhancement Evaluation Protocol since FEU currently do not attribute savings from codes and standards.

However, as stated in our 2012 EEC Annual Report[29], the Companies will continue to explore and review acceptable methodology for measuring and attributing energy efficiency savings from Codes and Standards work and will claim savings on a program-by-program basis at such time when an appropriate methodology has been determined.

378.6.2 Do FEU agree that, as codes and standards could have a very high TRC/UCT result, attribution of savings from codes and standards should not be included in the EEC overall portfolio results as it could be distortionary? If no, please explain why not.

Response:

No, the FEU do not agree. The FEU do not believe that a high TRC/UCT is an acceptable criterion for omitting an EEC activity from inclusion in the EEC portfolio results. If such a criterion were to be used in such a way, it could be argued that all programs resulting in a high TRC/UCT should be excluded from the portfolio results, which defeats the purpose of using a portfolio approach for determining cost-effectiveness. Further, Section 1(e) of the BC Demand-side Measures Regulation identifies codes and standards activities as a specified demand-side measure, for which Section 4(4) of the Regulation states that the Commission must determine cost effectiveness by determining whether the portfolio is cost-effective as a whole.

[29] 2012 EEC Annual Report, Page 81

379.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

DSM Regulations, Section 1, 3; Decision G-36-09, p. 22

Adequacy

379.1 For each EEC category identified in Section 3(a) of the DSM Regulations, and each specified DSM measure defined in Section 1, please identify the supporting EEC programs.

Response:

For the purposes of answering this question, FEU assumes that the Commission meant to refer to the entire Section 3 of the DSM Regulations and not just Section 3(a), as Section 3(a) refers to only one EEC category.

The table below identifies the supporting EEC programs which meet the specified demand-side measures defined in Section 1 and the categories identified in Section 3 of the DSM Regulations. Note that 2014-2018 EEC Plan references (Exhibit B-1-1, Appendix I-1) have been indicated in parentheses next to each program.

DSM Regulations		Supporting EEC Programs
Section 1 - specified demand-side measure	(a) a demand-side measure referred to in section 3 (c) or (d)	School Education (pp. 94-95)
	(b) the funding of energy efficiency training	Efficiency Partners Program (p. 104)
	(c) a community engagement program	Residential Education (pp. 90-91)
	(d) a technology innovation program	Innovative Technologies program area (pp. 96-102)
	(e) financial or other resources provided: (i) to a standards-making body to support the development of standards respecting energy conservation or the efficient use of energy, or (ii) to a government or regulatory body to support the development of or compliance with a specified standard or a measure respecting energy conservation or the efficient use of energy in the Province	Codes and Standards (p. 104)
Section 3 - Adequacy	(a) a demand-side measure intended specifically to assist residents of low income households to reduce their energy consumption	Energy Savings Kit (pp. 72-73), Energy Conservation Assistance Program (pp. 74-75), Low Income Space Heat Top-Ups (pp. 78-79), Low Income Water Heating Top-Ups (pp. 80-81), Non-Profit Custom Program (pp. 82-83)
	(b) if the plan portfolio is submitted on or after June 1, 2009, a demand-side measure intended specifically to improve the energy efficiency of rental accommodations	All Residential program area programs (pp. 10-35), Energy Savings Kit (pp. 72-73), Energy Conservation Assistance Program (pp. 74-75), Low Income Space Heat Top-Ups (pp. 78-79), Low Income Water Heating Top-Ups (pp. 80-81), Commercial Space Heat Program (pp. 42-43), Commercial Water Heating Program (pp. 44-45), Commercial Energy Assessment Program (pp. 54-55)
	(c) an education program for students enrolled in schools in the public utility's service area	School Education (pp. 94-95)
	(d) if the plan portfolio is submitted on or after June 1, 2009, an education program for students enrolled in post-secondary institutions in the public utility's service area.	School Education (pp. 94-95)

379.1.1 Please provide a table which summarizes, for each category noted above, each supporting EEC's program's budget for the PBR period, 2012 and 2013 approved amounts, 2012 actual results and 2013 forecast. Where there are significant changes in budgeted expenditures compared to 2012/2013 approved amounts, please explain why and (where budgeted amounts are decreasing) whether the EEC portfolio could still be considered adequate.

Response:

Please refer to the FEU's response to BCUC IR 2.376.1 for each program's budget for the PBR period, 2012 and 2013 approved amounts, 2012 actual results and 2013 forecast and for an explanation of any significant variances.

The EEC portfolio should still be considered adequate as there are EEC programs in place to support each of the adequacy categories and specific DSM measures identified in the DSM Regulations. Each of these EEC programs have been allocated appropriate budgets to cover their respected anticipated customer participation.

379.2 Please describe the research FEU have undertaken to identify energy efficiency related market barriers that specifically affect renters (such as the landlord tenant split incentive) and summarize the results of this research.

Response:

The issue of split incentives is not as prevalent in gas utility DSM as it is in electric utility DSM because gas equipment is generally for the whole building, and is owned by the building owner. From the building owner's perspective, the incentives, motivations, benefits and energy savings are all well aligned and our programs suit this scenario well. Upgrading a piece of gas equipment reduces the owner's operating costs, and increases his margin provided that rents stay constant, providing a motivating factor for the building owner. The challenge that can be faced is that the tenants of a building are not incented, nor do they necessarily receive any direct benefits from reducing their natural gas consumption as typically rental buildings are on a single gas meter.

The research that the FEU has undertaken to better understand market barriers in rental housing, and the findings from that research is discussed below.

1. A partnership with BC Hydro and BC Housing in 2010 on engaging the BC non-profit housing sector on energy management. Findings:
    - There is significant potential for energy savings and GHG emission reductions in the non-profit housing sector (a 10% reduction in energy consumption in the sector would

be equivalent to an annual 111Gwh or 400TJ in energy savings, 13 kilotonnes of Carbon Dioxide emission savings, and $5M in fuel cost savings).

- The average energy intensity of most non-profit housing building types is higher than the BC average.
- Apartment buildings provide the largest energy savings opportunities among building types in the sector.
- Metering structure influences energy consumption behaviour.
- The Lower Mainland represents a focal area for energy savings opportunities.
- Buildings with hydroelectricity tend to have energy intensity values that are below average.
- Further information on non-profit housing and the people living within the housing is required to create a comprehensive and strategic energy management initiative for the sector.

2. A partnership with BC Housing in 2011 focused on behaviour-based energy education through the Tenant Engagement Pilot. Findings:

   - Significant barriers to engagement include tenants struggling just to meet basic sustenance, belonging and emotional needs. In terms of changing behaviour, the activities that had the greatest impact were those that lead to enhanced relationships and trust between neighbors and the facilitator.
   - Planning an engagement strategy is heavily tenant and staff capacity, resources available, existing knowledge/assets/interest, and the length of time that can be committed.
   - The proposed strategy for achieving energy conservation suggests engagement through an umbrella of sustainability rather than through a program solely focused on energy conservation.

3. A partnership with BC Housing in 2012 focused on a needs assessment study for the development of a training program for building operators. Findings:

   - Significant barriers to training building operators are costs and location; however, the number one barrier is time.
   - Provided accessibility (i.e., cost, language, delivery mode) is not an issue, it is recommended that some basic introductory module on building operations be mandatory for all staff engaged in building operations. This might involve a series of introductory videos that transcend language barriers and are available to individuals regardless of location.
   - Consider making certain courses mandatory for specific BC Housing positions with exemptions where staff already have equivalencies. BCNPHA to provide tools such as

draft job descriptions, policies and training material for adoption by non-profits on a voluntary basis.

- Provide an introductory module on building operations for all staff engaged in building operations to access on a voluntary basis.
- Offer hands-on training in each region wherever possible.
- Incorporate video into online training offerings

In addition, FEU is in the early stages of planning a study on a Multi-Unit Residential Building Natural Gas End Use Study which has the potential to shed further light on market barriers that affect rental suites. FEU is also working on a MURB pilot with the City of Surrey to look at behavioural change that may reduce energy consumption in MURBs. FEU's intention is to select one or several rental buildings for this pilot.

379.3 Please confirm that FEU do not have any programs aimed specifically at rental accommodations. If not confirmed, please explain.

Response:

Not confirmed. Please refer to the the response to BCSEA IR 1.15.1 which describes the activities that have been designed specifically to improve the energy efficiency of rental accommodations. The DSM Regulation does not require natural gas DSM programs to be designed *exclusively* for rental accommodations. Typically rental buildings are single-metered for gas, and as noted in the response to BCUC IR 2.379.2, the owner of the building can increase their margin by upgrading natural gas equipment for efficiency and therefore there is good motivation for building owners of rental accommodations to participate in several of FEU's incentive programs .

Further, according to a preliminary scan performed by eSource (a market research company) using their database of more than 3,000 DSM and renewable energy programs in Canada and USA, there were only 3 programs found that were exclusively available to rental accommodations. The vast majority of programs for this market segment are commercial, residential, or low income programs that are made available to rental accommodations.

To further illustrate that FEU's programs are in fact specifically intended to improve the energy efficiency of rental accommodations, an analysis of the participation in our programs from January 2012 to October 2013 shows an estimated:

- 1,000 rental units (146 buildings) benefited from our Commercial programs (based on Efficient Boiler Program and Efficient Commercial Water Heater Program only);

- 5,000 rental units (mixed apartments and other home types) benefited from our Residential programs; and
- 6,000 rental units (mixed apartments and other home types) benefited from our Low Income programs.

379.3.1 As the DSM Regulation in Section 3(b) requires a utility to offer programs aimed specifically at rental accommodations, please explain how the Commission can be satisfied that FEU's EEC portfolio can be considered adequate.

Response:

Please refer to the response to BCUC IR 2.379.3. It is important to recognize that the regulation states a utility's plan portfolio is adequate if it includes, "…a demand-side measure intended specifically to improve the energy efficiency of rental accommodations."

The regulation does not state that programs must be geared exclusively to rental accommodations.

FEU offers many demand-side measures that are intended specifically to improve energy efficiency in rental accommodations. These measures and the adequacy of FEU's portfolio as it pertains to rental accommodations have been addressed in response to BCSEA IR 1.15.1.

379.3.2 Please provide examples of EEC programs provided in other jurisdictions to address split incentives for (i) residential tenants (in single family dwellings and apartments) and (ii) commercial tenants, and explain why FEU are not offering similar programs.

Response:

As noted, split incentives are not as much of an issue for gas DSM in rental buildings as most buildings are single-metered for gas, and the gas equipment therein is generally for common uses such as central water heating boilers and make-up air units. A market scan of other jurisdictions in North America reveals several methods used to address the issue of split incentives. Note that FEU is already offering each of these programs except for "Mandatory energy efficiency upgrades" which is currently outside of FEU's capability. The following list includes the methods and examples of

EEC programs outside of British Columbia that use each particular method along with the FEU equivalent program.

On-bill repayment/financing: On-bill repayment is considered to be a method to overcome split incentive issues as the payment plan is attached to the meter/property and not to the property owner. This method can be used for both residential and commercial tenants. One example of on-bill financing/repayment is the Midwest Energy's How$mart program. Renters can participate in this program as long as the landlord also agrees to it. Another example is the California Housing Partnership Corporation's pilot on-bill repayment program at a 274-unit multifamily apartment rental building complex, City Gardens, in Santa Ana, CA.

Similar programs exist for the commercial sector. One example is Connecticut Light & Power's Small Business Energy Advantage program, which states that common energy-efficiency measures financed include lighting, HVAC upgrades, among others.

Although not applicable to commercial buildings, FEI is currently legislated to offer the Financing Pilot which is equivalent to on-bill repayment/financing.

Rebates: Offering rebates to property owners can help make the cost of an energy efficient appliance more affordable and cost effective, therefore removing the financial barrier of installing energy efficiency measures. One example of this program are the rebates Pacific Gas & Electric offers specifically to multifamily property owners and managers. This program encourages energy efficient upgrades to individual tenant units and to common areas of residential apartment buildings, mobile home parks, and condominium complexes. For the commercial sector, Efficiency Vermont has the Building Performance Program that "offers up to $5100 per building to help owners pay for energy efficiency improvements."

FEU's EEC Commercial program area offers the Space Heat Program, the Water Heating Program and the Commercial Energy Assessment Program, all of which are available to multi-family buildings that provide rental housing.

Mandatory energy efficiency upgrades: One way to address the issue of split incentives is to mandate that rental properties need to meet certain energy efficiency standards. The city of Boulder, CO adopted SmartRegs, the first energy code for rental housing in the U.S. Rental properties are required to meet the mandated standards by 2019. Meanwhile, the City of Austin, TX has an ordinance that requires all buildings to complete an energy audit/benchmark. According to the Energy Conservation Audit and Disclosure Ordinance, an owner of a multifamily facility (meaning a site with five or more dwelling units)that uses 150% the average energy use of per square foot by multifamily properties, must reduce its energy use by 20%. Condominium owners who own 5 or more dwelling units in the same building also must meet the same energy audit and disclosure requirements as multifamily facilities. Because Austin energy is the municipal utility, it is involved by offering workshops around this ordinance.

It should be noted that these programs are municipal initiatives and that as a utility, FEU are not in a position to enact similar requirements.

Building operator certification: Building operator certification programs are when the utility helps fund the training of a building operator who is well-versed and certified in energy-efficient practices. This type of program could help get around split incentives because the utility is helping to educate a commercial client (some of whom lease their space) to be more energy efficient. Southern California Gas offers a Building Operator Certification Training Program in which the utility is offering the classes for this certification. Kansas City Power & Light also has a program in which it offers the course for a reduced fee and a rebate to those who successfully complete the training.

FEU has funded building operator training for building operators / facility managers through funding of select Natural Resources Canada “Dollars to Sense” workshops.

Energy manager program: Similar to the building operator certification program, the energy manager program is designed to help businesses save energy by adopting energy-efficient practices through knowledgeable staff. Unlike the building operator certification program, energy manager programs are where the utility helps the business employ an energy manager. While most of the savings generally come from behavioral changes, the energy manager could help champion for no- or low-cost improvements. Similar to the building operator certification program, this program only address split incentives when the business leases its space. One such program is Puget Sound Energy’s Resource Conservation Manager Program. The resource conservation manager is held accountable for bill savings that stem from efficiency improvements. Puget Sound Energy typically funds 25% of the first year’s salary of the resource conservation manager and provides other support to make the resource conservation manager successful.

FEU’s Energy Specialist Program, which works in conjunction with BC Hydro’s Energy Manager Program, is FEU’s equivalent of an energy manager program.

379.4 Funding was approved in 2009 (G-36-09, p. 22) for a pilot project to label homes and buildings with an energy consumption/efficiency rating. Please provide an update on this pilot, and comment on whether a home efficiency labeling program could be developed to assist renters.

Response:

In 2007, the provincial government initiated the BC Energy Plan, part of a comprehensive GHG emission reduction strategy. Within the Energy Efficiency and Conservation objectives, the government sought to undertake pilot projects for energy performance labeling of homes and buildings in co-ordination with local and federal governments, First Nations and industry associations. These pilots were developed as the first step towards the introduction of mandatory "time of sale" building labeling. The Ministry coordinated two pilots, one in Oak Bay and the other in Prince George, the pilot project cited above. There was very limited uptake in these pilots, and reluctance from the Realty community, who feared that home labeling could introduce an additional barrier to home sales.

The current EnerGuide label provides an EnerGuide score out of a 100. A new energy efficient home is EnerGuide 80, while an older renovated home will be in the EnerGuide 60 range. However, this label does not effectively inform the residents about the operating costs of a home. However, in 2014, NRCan will introduce a new Home Energy Rating System, in which a new label represents the home's energy consumption in GJ's. This scale can therefore be directly translated into home operating costs for electricity and natural gas.

At the time of writing, full details about the introduction of this new system have yet to be announced by NRCan. FEU will assist with this introduction into BC where practical, and will consider pilot programs to test the new NRCan Home Energy Rating System with various market segments; renters may be one such segment.

380.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Decision G-44-12, p. 173; Exhibit B-1-1, Appendix J, Appendix I, p. 17

Transfer of funds

On page 173 of the 2012-2013 FEU RR and Rates Decision (G-44-12),the Commission states, "The Commission believes that to ensure proper oversight and accountability, it must balance the advantages of the FEU being able to move funds freely among approved Program Areas to meet the needs of existing or new programs against the need for the Commission to be assured that EEC expenditures continue to be in the public interest. ..., the transfer of funds to new programs, not approved in this Application, or to Innovative Technologies ... will require prior Commission approval."

380.1 If FEU EEC approval was for a 3-year period only, would FEU still request permission to transfer EEC funds to new projects without Commission approval? If yes, please explain why, given that this request was rejected in the previous Revenue Requirements Decision.

Response:

Yes. It is the view of the Companies that should a new program present itself over the plan period, the Companies should be able to proceed with such a program if the program is cost-effective under the cost-effectiveness "rules" established by the Demand Side Measures Regulation, meets EEC Principles, meets existing benefit/cost test requirements, and has not been previously been rejected by the Commission.

380.2 Please explain why FEU are requesting transfer of the non-rate base EEC Incentive deferral account accumulated balanced to the FEI rate base EEC deferral account in the following year. Please describe in your response any changes from existing practice.

Response:

Currently the FEU have received approval to record amounts in the non-rate base EEC Incentive deferral account for both 2012 and 2013; however they have not received approval on a method of recovery for the amounts accumulated in this account. The forecasted balance accumulated in this account represents the difference between the actual after-tax EEC costs additions in 2012 and the accumulated AFUDC on this amount in 2013, and the amount of $15 million approved in FEU's rate base for 2012. FEI is now requesting to transfer the balance accumulated in this account to the rate base deferral account in 2014 so that it may be recovered from customers. As discussed on Page 295 of the Application, FEI is not proposing any change to the approach of using these deferral accounts to manage EEC expenditures.

380.3 Please reconcile the Section 44.2(a) EEC expenditure request in FEU's draft Commission Order (Appendix J to the Application) with Table I-4 of Appendix I to the Application and explain any differences.

Response:

The footnote in Table I-4 of Appendix I states that the values presented in this table are in 2014 dollars and do not include inflation. The values presented on page 6 of the draft Order include inflation, and reconcile to the values presented in Exhibit 1 on page 5 of Appendix I-1 to Exhibit B-1.

380.4 Are FEU requesting that EEC 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 Companies are not requesting approval to shift funds between years, either within the PBR period or outside the PBR period. The Companies are not proposing any change from the financial treatment approved for 2012/2013.

380.4.1 Please describe the advantages/disadvantages of being able to shift EEC funds between years during the PBR period, and whether program funding transfers greater than a maximum amount (such as 15 percent) should be subject to Commission approval.

Response:

The Companies are not proposing to shift funds between years and this concept has not been contemplated by the FEU.

380.5 Please confirm, or explain otherwise, that FEU will only receive a return on actual EEC amounts spent (up to the EEC approved expenditure level) during the PBR period.

Response:

As long as the FEU spend is at least $15 million each year (the amount forecast in rate base), then the FEU will only receive a return on actual EEC amounts spent during the PBR Period. This outcome would be the same under either PBR or traditional cost of service rate-making.

To summarize the EEC requests in the Application, the FEU have only included $15 million of the total requested annual funding envelope amount in the rate base forecast each year. This limits the immediate impact to customers from underspending on the annual funding envelope amount. Any amounts spent over the $15 million and up to the funding envelope amount will be captured in the non-rate base EEC deferral account, earning AFUDC, and transferred to the rate base EEC deferral account the following year to be recovered from customers.

To summarize the impacts to customers in this Application, amounts are re-forecast every year during the Annual Review process so opening balances will reflect actual EEC amounts spent. With the request on Page 296 of the Application to transfer the non-rate base EEC Incentive balances to rate base each subsequent year, this will ensure forecasted costs only include actual costs from the previous years and the forecasted amount in rate base for the current year which FEI has capped at $13.35 million ($15 million x 89%) each year for the term of the PBR. This benefits customers in that they only pay for actual amounts incurred.

Additionally, isolation of a single component of the rate base, such as the EEC deferral account, or cost of service does not provide a comprehensive perspective of the performance of the FEU or the total quantitative and qualitative benefits provided to our customers in a given year.

380.5.1 What assurances, if any, will ratepayers have that the approved EEC budget will not be materially underspent for each year of the PBR period? Please explain.

Response:

Please refer to the response to BCUC IR 2.380.5. Expenditures are "trued up" in the Annual Review for the PBR period. The Companies cannot ultimately control whether customers choose to participate in EEC programs. That is why the Companies are not proposing any change to the currently-approved financial treatment of EEC expenditures, with $15 million going into rates, and the remainder of the actual expenditure going into a deferral account attracting AFUDC. The FEU originally proposed this financial treatment in the 2012-2013 RRA to mitigate the risk to ratepayers of EEC budgets being underspent and it was approved by the Commission.

381.0 Reference: Exhibit B-1-1, Appendix I, Attachment I4;
Exhibit B-11, BCUC 1.241.1.1, 1.241.2, 1.241.4
EEC Incentives for AES/TES – Cost of PricewaterhouseCoopers (PWC) Proposal

381.1 Please explain why the cost criterion for selecting the fairness advisor, and subsequently the TES Incentive administrator, was weighted only 10 percent, less than several other criteria.

Response:

Cost is certainly a factor in selecting the right advisor to ensure that the services delivered are within a reasonable range and competitive. However, FEI gives greater importance to qualifications, experience and the vendor's understanding of the scope of work and their ability to deliver relative to cost.

381.2 In PWC's proposal (Attachment I4 to Appendix I of the Application) are PWC's estimates of the annual number of TES project per program reasonable? Are the estimates consistent with past number of TES projects per program? Why or why not?

Response:

Note that according to this proposal, PWC would review all incentive applications where a third party TES provider is involved, not simply those where the FAES fills that role. Since information as to the involvement of third party providers of thermal energy services to customers participating in these programs was not previously tracked in any systematic manner, there is little historical evidence to which these estimates may be compared.

381.3 In BCUC 1.241.4 FEI explains that reviewing applications for custom incentive programs is more involved. Please confirm whether or not PWC would perform all aspects of reviewing the application, including the detailed energy studies, technical reviews and development of measurement and verification plans? If not confirmed, please explain.

Response:

Confirmed. In accordance with FEU's understanding of the directive, the Companies have obtained a proposal from PWC that would have PWC perform all aspects of individual project reviews, which would otherwise have been performed by FEU, as soon as a customer's intention to engage a third party thermal energy services provider has been established.

Please refer to Exhibit B-1-1, Appendix I, Attachment I4, Appendix A – Business Process Diagrams, for process diagrams indicating visually the tasks that PWC will perform.

381.4 Based on the existing PWC proposal including in the Application, what is the total amount that FEU has budgeted for this project for each year of the PBR period. Has FEU forecasted any of this amount in the deferral account, and if so, how much? Please explain how the cost of the PWC proposal impacts rates.

Response:

The FEU have not budgeted any amount for the PWC proposal for the PBR period due to the uncertainty in the costs. PWC has estimated a range from approximately $140 thousand to $260 thousand to conduct the work and there are unknown factors that will influence the actual costs, such as the number of applications that will need to be reviewed, time for review, and the complexity of applications for review, which are beyond the FEU's control. There is also uncertainty because the Commission has not yet made a decision as to whether to accept the proposal and if so, what the scope of the third party review should be. As such, the Companies cannot accurately forecast the cost of the PWC proposal.

If the Commission approves a third party review, the FEU proposes and requests approval to place any actual expenditures from the review in the non-rate base EEC deferral account that attracts AFUDC. This treatment is appropriate as the review would form part of the administrative costs for EEC programs: the review is intended to ensure that EEC expenditures are dispensed appropriately. This is the same treatment applied to costs of other non-incentive administration costs for EEC. The costs of the third party review would be incremental to the FEU's existing EEC expenditure request.

Like other amounts in the non-rate base deferral account, FEI would apply to transfer new amounts accumulated in the non-rate base deferral account relating to the FEI during the 2014-2018 period to the FEI rate base EEC deferral account in the following year, with amortization over 10 years commencing the year in which the balance was transferred.

382.0 Reference: Exhibit B-1-1, Appendix 1, attachment I4; Exhibit B-11, BCUC 1.241.6.1, 1.241.6.3

EEC Incentives for AES/TES – Proposed Process

382.1 In PWC's proposed process flow for the Efficient Boiler program and the Residential New Home Program the customer speaks first with Fortis and then, upon deciding to incorporate thermal energy, he/she is directed to PWC. Please explain how this is consistent with the direction of the AES Inquiry.

Response:

The referenced process diagrams illustrate the functioning of EEC activities only. The condition diamonds labeled "3rd Party TES Project?" do not represent a decision made by customers to engage (or not) thermal energy services, while in discussion with the FEU. Rather, these represent the FEU identifying whether or not the customer has already engaged, or in the case of an application inquiry intends to engage, with a third party thermal energy provider. Should the participant indicate that they have not engaged, or do not intend to engage a thermal energy provider the FEU will process the application as usual. Should the participant indicate that they have engaged, or intend to engage a thermal energy provider, the FEU will immediately forward all inquiries or application documents to PWC for processing.

The FEU believe that this is entirely consistent with the directive provided in Commission Order G-201-12. In the process described above the FEU ask customers at the very outset if they are or will be using a thermal energy provider. When the answer is yes, the FEU are immediately removed from the approval and administration of EEC funds, and any potential to inappropriately use such funds for the benefit of the FEU is eliminated.

382.1.1 Please discuss the advantages and disadvantages of reversing the process, in that customers would speak to PWC first in regards to the two programs, and if it is determined that they have no interest in incorporating thermal energy in their project they are directed to Fortis. Please explain why FEU/PWC have not proposed this. Please refer to the decisions and recommendations of the AES inquiry in your discussion.

Response:

Commission Order G-201-12 indicated[30] that the Commission was concerned that:

> *"Where FEU are the direct or indirect beneficiary of funds being awarded by themselves, there is a conflict of interest with the potential for preferential treatment;"*

The proposed arrangement in the IR appears to be an attempt to address this concern by eliminating the FEU as the first point of contact for the customer. While the arrangement may alleviate the Commission's concern about preferential treatment, the FEU believe that it is neither necessary nor in fact practical.

Consider first that some participants apply for a rebate without having had any prior contact with FortisBC. The Efficient Boiler Program for example sees a considerable number of applications from multifamily customers under the guidance of their mechanical contractors. In these cases the rebate eligible measures have already been installed and, if a customer were working with a third party Thermal Energy Services (TES) provider, the contract may already have been signed. As such it is not possible in these instances to influence a participant's decision by providing preferential access to EEC funding and there is no reason for these applications to go first to PWC or for ratepayers to bear this additional cost.

Only when, prior to any decisions being made, customers make initial inquiries seeking out clarity on program eligibility, incentives, terms and conditions, and/or application processes, does the potential to use preferential treatment in order to secure additional business exist. This suggests that, in order to eliminate the FEU as the first point of contact, PWC would need to screen all such inquiries, and leads before any involvement by the FEU. If program delivery were as simple as awaiting and responding to phone calls or emails from interested parties this may be practical, though clearly at additional cost. The efficient boiler program should see over 225 applications in 2014, while 500 represents a reasonable estimate of the number of applications to the Residential New Homes Program in the same year. At roughly 30 minutes per application (the time to receive an application, perform data entry/tracking tasks, call applicants to clarify any unclear details, and forward any non TES applications to the FEU), receiving and reviewing applications represents approximately 50 days of work. Based on PWC's approximate daily rate of $1790, this equates to an annual cost of around $90,000 for PWC just to receive and review applications for these programs.

In reality, however, there are many more touch points than simply receiving an application. The FEU currently have 4 EEC Energy Solutions Managers, 9 Commercial & Industrial Account managers, and 15 new construction sales managers engaged in presenting and discussing EEC incentives with customers via a number of channels including:

[30] AES Inquiry, Report, December 27, 2012, pg. 87

a. In person visits to discuss the programs, and any forthcoming rebate eligible projects;
b. Phone calls and emails;
c. Presentations and information sessions;
d. Tradeshows, conferences and seminars; and
e. Lunch and learn sessions with customers and design/construction professionals.

Delivering program messaging and working with customers through all of these channels is critical to program success and PWC would need to commit a significant number of staff to perform all of these functions, to entirely avoid the possibility that the FEU speak with any customer before it is definitely determined that there is no intention to contract with a TES provider. It becomes clear then that eliminating the FEU as the first point of contact would result in considerable additional cost if program participation levels and a satisfactory customer experience are to be maintained.

Moreover the Commission's concern can be substantially addressed simply by directing PWC to ask any EEC applicants submitted to its review whether or not any FEU staff member indicated that the availability or size of EEC incentives was dependent upon the customer's selection of FAES or any other company as a TES provider. PWC could then report on the findings.

Finally, Commission Order G-201-12 directed[31] the FEU:

> *"…to bring forward a proposal for mechanisms for approval and administration of funds by a neutral third party where… …there is a potential for FEU to benefit, either directly or indirectly, from that funding."*

Having PWC act as the front line in regards to the two programs goes beyond "approval and administration of funds", but rather represents something more akin to program administration and/or delivery.

In short the FEU believe that the proposal as put forward in the Exhibit B-1-1, Appendix 1, Attachment I4, is the most reasonable and effective way to address the Commission's directive.

[31] AES Inquiry, Report, December 27, 2012, pg. 87

383.0 Reference: Exhibit B-1-1, Appendix 1, Attachment I4; Exhibit B-11, BCUC 1.241.7; May 11, 2012 BCUC Clarification of G-44-12

EEC Incentives for AES/TES – Two Year Historical Review

FEU state "The FEU asked PWC for a proposal around an annual review going back two years in order to meet the Commission directive around approval and administration of funds by a neutral third party. EEC incentives may be provided to projects that subsequently become part of a thermal energy services provider's project." (Exhibit B-11, BCUC 1.241.7)

According to its response in BCUC 1.241.7 the two-year time frame of the proposed review is required as a result of Directive 80 of the FEU 2012-2103 RRA Decision together with the Commission's May 11, 2012 response to the FEU's Request for Clarification of Order G-44-12 and Decision on the 2012-2013 Revenue Requirements Application and Natural Gas Rates Application.

The Commission's May 11, 2012 letter states, "the Commission acknowledges that these projects are not always clearly identifiable at the time of issuing EEC Funds. Given this uncertainty, the Commission finds that a holding period of a minimum of two years is reasonable. Therefore, the Commission clarifies that the FEU should hold funds in the manner specified by the Decision for a period of at least two years, not the one year suggested within the Letter." (May 11, 2012 BCUC Clarification of G-44-12)

PWC's annual review report template states, "The primary review objective was to determine whether the EEC grant awarded met the established program guidelines and policies and that the award process was free of any bias or influence. PwC conducted a review of the application intake, review and selection processes, with a focus on decision points and determination of incentive award amounts. The report includes our review conclusions, a summary of the scope and objectives of the assignment, the methodologies applied and any relevant findings from the activities undertaken." (Appendix I, Attachment I4)

383.1 Please provide further explanation as to why FEU asked PWC for a proposal that included an annual review. In your answer please refer to Commission directives or recommendations that specifically instructed FEU to conduct such a review, which is in addition to the proposal of third-party administration of EEC funds for AES or TES technologies.

Response:

The FEU asked PWC for a proposal that included an annual review so that any funds granted to a customer who was <u>subsequently</u> found to be a third party thermal energy services customer could be reviewed for fairness. The Commission instructed the Companies to go back over a two year period and to maintain any such funds in a separate deferral account. The purpose of the PWC annual review is as stated above – to ensure that any programs potentially available to projects with a thermal energy services component were operating fairly with all customers having equal access to program funds, and to ensure that EEC program funds granted to projects with a thermal energy services component end up in the "2 year holding deferral account" outlined in the Commission's May 12 letter. It should be noted that once the issues of third party review of distribution of EEC funds to projects with thermal energy components has been canvassed in this proceeding, and a decision as to how to deal with this issue arrived at, the Companies intend to ask program applicants in programs that may involve a third party thermal energy services provider at the time they apply to the program whether or not their project either has or contemplates a third party energy services provider. Thus, such an annual review may not be necessary beyond the initial year.

383.1.1 Is the objective of the review solely to determine which EEC distributions should be held in the separate deferral account for EEC incentives provided for AES or TES technologies projects which FEU is a participant? If this is the sole objective, please reconcile this with PWC's description of the primary review objective. If not, please describe the full objectives of the review.

Response:

No. Please refer to the response to BCUC IR 2.383.1. It is the view of the Companies that all such funds, regardless of whether or not FAES is a participant, should be held in the 2 year holding deferral account.

383.2 In PWC's proposal (Attachment I4 of the Application) it anticipates approximately ten school districts and municipalities in BC meet the criteria for their initial annual review. Please provide further explanation as to the criteria for projects for the proposed annual review. What is the basis for this criteria?

Response:

This is the best estimate available as to the numbers of potential program participants with thermal energy services components over a 2 year period. It may be the case that after the initial review, no further annual reviews are needed.

383.2.1 Do FEU support this estimate of 10 school districts and municipalities? Why or why not

Response:

Please refer to the responses to BCUC IRs 2.383.2 and 2.381.2.

383.3 PWC's proposal indicates that "FortisBC has requested a third-party review of EEC grants involving TES components that have been awarded in the previous two years since inception of the program, and an annual review and reporting of EEC grants involving TES components on a go forward basis." (p.1) Please confirm whether FEU intends to engage PWC to conduct the proposed review on an annual basis for every year of the PBR period. If no, please clarify the number of proposed reviews FEU anticipates. If yes, please provide clear justification why a third-party review is necessary on an annual basis.

Response:

Please refer to the response to BCUC IR 2.383.1. It may be that there is no need to conduct an ongoing annual review after the first year, as once the issue of third party review of EEC incentives provided to customers with thermal energy services projects has been canvassed in this proceeding, it is the intent of the Companies to ask program applicants up front whether their project either has or contemplates a thermal energy services component.

383.3.1 If yes, why does PWC's design of the process to administer EEC funds to projects with a TES provider not prevent the need for an annual review of this nature?

Response:

Please refer to the response to BCUC IR 2.383.3.

383.4 Is PWC prepared to provide the first component of its proposal (third-party program administration of TES-related incentives) if the second component, the annual review, is not approved? Please explain.

Response:

Yes. PWC will provide service in accordance with the Commission's Decision.

383.5 Could FEU conduct a similar review as that proposed by PWC on its own? Why or why not? What kind of resources or capacity would be required for FEU to complete a similar review on its own?

Response:

The Companies are interpreting this question to mean, "could the FEU conduct a 2 year review and identify program participants with a third party thermal energy services provider." Yes, the Companies could conduct such a review, potentially undertaken by its Internal Audit Services group. The Companies have available the program application files, and have IAS staff in-house.

In order to respond to the second part of the question, the Companies have provided the table below. Cost estimates for options other than "do nothing" and the PWC proposal are not available. "Do nothing" would have a cost of zero, and the PWC proposed cost for the annual review is $25 thousand.

Review Methodology	Advantages	Disadvantages
Do nothing	Saves costs of doing an annual review.	Does not address misconception that the FEU are using EEC funds to unfairly disadvantage competitors to FAES in the provision of thermal energy services to British Columbians.
FEU conducts own review	Familiarity with programs, easy access to program application files	Does not address misconception that the FEU are using EEC funds to unfairly disadvantage competitors to FAES in the provision of thermal energy services to British Columbians.
PWC conducts review as proposed	Familiarity with programs, proposal received	None seen
Review goes to competitive tender	Opportunity for market to bid on work	Adds time, cost and complexity; would require winning bidder to familiarize themselves with FEU programs and processes, if winning bidder is not PWC; may not save significant dollars since PWC proposal for annual review cost is $25,000

Commission staff identify four potential alternatives to achieve the same outcome: i) Do nothing, ii) FEU conduct own review, iii) PWC conducts review as proposed, iv) review goes to competitive tender. Please identify (in table form) the cost estimate, advantages and disadvantages of these alternatives, and any other alternatives that FEU foresees.

383.6 If the annual review in PWC's proposal is approved, what would the next steps and consequences be if PWC finds that an award of EEC funds to a project involving a TES provider was not free of any bias or influence? Please explain.

Response:

The FEU do not have a proposal at this time for the consequences if PWC finds that an award of EEC funds was not free of bias or influence. However, the FEU envision that the results of PWC's review would be provided to the FEU and to the Commission. At that time, the FEU would consider and determine an appropriate action to take. The Commission could also determine whether any action is required and direct the FEU accordingly.

383.7 PWC's proposal states that its review "will evaluate the application intake, review and award processes, and will focus on decision points and determination of incentive award amounts. PwC will develop standardized review protocols that will be applied to each application." (p. 3) If possible, please provide the criteria or metrics by which PWC intends to evaluate grant applications determined to involve a third party TES provider. How did/will PWC determine the criteria or metrics? How did/will FEU contribute to the development of such evaluation criteria?

Response:

These criteria and metrics have not yet been developed; however, it is anticipated that the review will be to determine that the program applicant complied with the program terms and conditions, and that the incentive amount provided complied with the program terms and conditions.

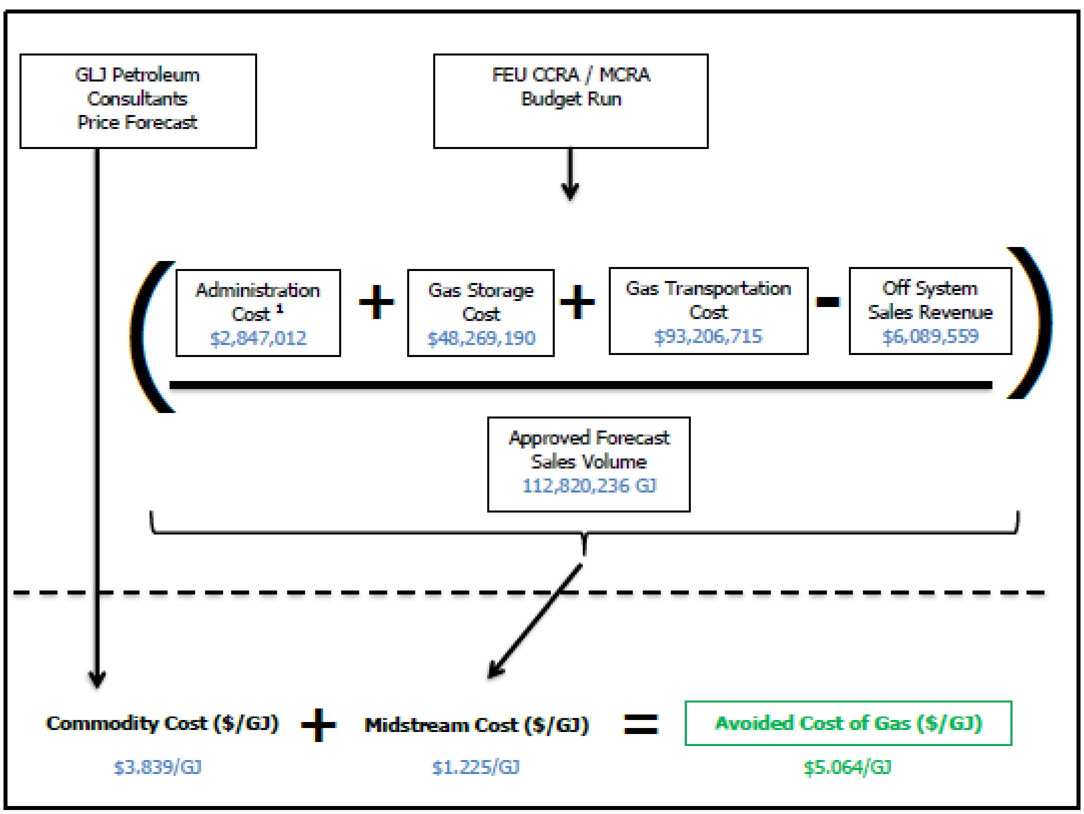
384.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-11, BCUC 1.218.2, 1.219.6; FortisBC Energy Inc. – Lower Mainland, Inland, and Columbia Service Areas Commodity Cost Reconciliation Account (CCRA), Midstream Cost Reconciliation Account (MCRA), and Biomethane Variance Account (BVA) Quarterly Gas Costs 2012 Fourth Quarter Gas Cost Report, Tab 1, p.6; Commission Letter L-43-13; FEU 2012-2013 RRA, BCUC 1.40.1

Long Run Marginal Cost of Gas Input to TRC Calculation

In response to BCUC 1.218.2, as evidence to support the long-run marginal cost of gas used in the TRC calculation, FEI provided the following figure to illustrate the avoided cost calculation.

Avoided Cost of Gas Calculation



[1] The administration cost used is the Core Market Administration Expense for managing midstream costs

FEI states that the figure "illustrates the avoided cost calculation and provides the component costs used to determine the 2013 avoided cost. The FEU input the commodity cost based on the price forecast published by an independent consulting firm called GLJ Petroleum consultants. The midstream cost is made up of four components from FEU's

MCRA budget run and escalated at 3 percent per year representing inflation and increasing transportation/storage costs. The FEU add up the total budgeted administration cost, gas storage cost, and gas transportation cost, subtract the off-system sales revenue and then divide that total by the approved forecast gas sales volume37 (in this case from the 2012-2013 RRA) in its system to derive the midstream cost. By adding up the commodity cost and midstream cost, the FEU are able to calculate the avoided cost of gas." (Exhibit B-11, BCUC 1.216.2)

384.1 Please confirm that the intended avoided cost of gas to be used in the TRC calculation is the "Companies' avoided cost of gas". (emphasis added)

Response:

Confirmed.

384.1.1 If not confirmed, please explain.

Response:

Please refer to the response to BCUC IR 2.384.1.

384.2 Please confirm that the proxy for the "Companies' avoided cost of gas" is the 2013 FEI cost of gas and that this is then used by FEU as the base from which to apply the escalation factors to arrive a future "Companies avoided cost of gas".

Response:

Not confirmed. The Companies' avoided cost of gas includes a commodity component and a midstream component. The commodity component reflects a marginal cost of commodity supply rather than the FEI cost of gas. The GLJ Petroleum Consultants commodity price forecast is used to determine this commodity cost component for future years. The midstream component reflects the cost for midstream resources required to balance the daily customer load on a normalized annual basis. The midstream cost components are based on FEI's forecast costs and then a 3 percent escalation factor is applied for future years. The sum of these commodity and midstream components equals the avoided cost of gas.

384.2.1 If not confirmed, please correct and clarify the statement as necessary.

Response:

Please refer to the response to BCUC IR 2.384.2.

Tab 1, Page 6 of the "FortisBC Energy Inc. – Lower Mainland, Inland, and Columbia Service Areas Commodity Cost Reconciliation Account (CCRA), Midstream Cost Reconciliation Account (MCRA), and Biomethane Variance Account (BVA) Quarterly Gas Costs 2012 Fourth Quarter Gas Cost Report" dated November 22, 2012 (2012 Fourth Quarter Gas Cost Report) sets out the costs, revenues and volumes projected for the period from January 1, 2013 to December 31, 2013. The table on Page 6 of Tab 1 of the 2012 Fourth Quarter Gas Cost Report shows total projected MCRA costs of $136,696,000 for 2013 with projected costs and revenues components as follows:

a) CMAE costs of $2,847,000:
b) Gas storage costs of $48,078,000;
c) Gas transportation costs of $100,866,000;
d) Midstream commodity purchase costs (including hedging costs) of $94,408,000;
e) Mitigation revenue (from both transportation mitigation and commodity resales) of $109,502,00

384.3 The amounts in the "Avoided Cost of Gas Calculation" figure for "Administration Cost" and "Gas Storage Cost" match the amounts projected in the 2012 Fourth Quarter Gas Cost Report for MCRA CMAE costs and MCRA gas storage costs, respectively. Please confirm that this was the source of these amounts.

Response:

The "Administration Cost" in the "Avoided Cost of Gas Calculation" of $2,847,012 is taken directly from the FEI 2012 Fourth Quarter Gas Cost Report. However, the "Gas Storage Cost" of

$48,269,190 in the "Avoided Cost of Gas Calculation" only accounts for the "Storage Demand Charges" portion of the "Total Net Storage Cost" in the FEI 2012 Fourth Quarter Gas Cost Report and excludes the "Storage Injection and Withdrawal Costs". In the "Avoided Cost of Gas Calculation", FEI has used only the main components of the FEI storage costs, as a high level estimate or approximation, to determine the "Total Storage Cost". Please also refer to the response to BCUC IR 2.384.5.

The following figure explains the relationship between the midstream components used in the "Avoided Cost of Gas Calculation" compared to the FEI 2012 Fourth Quarter Gas Cost Report. Note that the resulting estimated midstream cost under both methods is largely the same. This is because commodity purchases and commodity resales, and storage injections and withdrawals, generally offset each other on a forecast basis and items like company use gas are immaterial in the calculation.

Figure 1: Midstream Cost Comparison Diagram

Avoided Cost of Gas Calculation			
Gas Storage Cost	$	48,269,190	
Off System Sales Revenue	$	(6,089,559)	
Gas Transportation Cost	$	93,206,715	
Administration Cost	$	2,847,012	
Total MCRA Cost	**$**	**138,233,358**	
Approved Forecast Sales Volume		112,820,236	GJ
Midstream Cost	**$**	**1.225**	**/GJ**

2012 Q4 Gas Cost Report ('000)				
Midstream Commodity before Hedging			96,515	
Mark to Market Hedges Cost / (Gain)			67	
Company Use Gas Recovered from O&M			(2,174)	
Total Midstream Commodity		$	94,408	
Storage Demand Charges			48,269	
Injections into Storage			(113,773)	
Withdrawals from Storage			113,581	
Total Net Storage		$	48,078	
Transportation Mitigation			(7,659)	
Cost of Sales	(96,754)			
Sales Margin	(6,090)			
Commodity Resales			(102,843)	
GSMIP Incentive Sharing			1,000	
Total Mitigation		$	(109,502)	
Total Transportation Charges		$	100,866	
Core Market Administration Costs		$	2,847	
Total MCRA Costs		**$**	**136,696**	
Total Core Sales Volumes			112,820	GJ
Midstream Cost		**$**	**1.212**	**/GJ**

384.3.1 If not confirmed, please explain.

Response:

Please refer to the response to BCUC IR 2.384.3.

384.4 The amounts in the "Avoided Cost of Gas Calculation" figure for "Gas Transportation Cost" and "Off System Sales Revenue" do not appear to match the amounts projected in the 2012 Fourth Quarter Gas Cost Report for MCRA gas transportation costs and MCRA off-system sales revenue, respectively. Please explain why not.

Response:

The "Gas Transportation Cost" amount of $93,206,715 from the "Avoided Cost of Gas Calculation" figure combines the "Total Transportation Charges" of $100,866,000 and "Transportation Mitigation" of $(7,659,000) from the FEI 2012 Fourth Quarter Gas Cost Report. The "Off System Sales Revenue" from the "Avoided Cost of Gas Calculation" figure is the Sales Margin component of the Midstream Commodity Resales only and for the purposes of the "Avoided Cost of Gas Calculation" the costs of midstream-related commodity purchases and resales are excluded. Please refer to the response to BCUC IR 2.384.3.

384.4.1 Please provide the source of the "Gas Transportation Cost" and "Off System Sales Revenue" quantities.

Response:

Please refer to the response to BCUC IR 2.384.4.

384.5 Please confirm that, in addition to the four components that FEI included in the "Avoided Cost of Gas Calculation" figure, the "Midstream Cost" should also include all of the other midstream cost and revenue components including the cost of midstream commodity purchases, hedging costs, unaccounted for gas costs and revenue from the mitigation of transportation.

Response:

In the "Avoided Cost of Gas Calculation", FEI used only the main components of the FEI forecast midstream costs based on normalized annual consumption to determine the "Midstream Cost". In general, the avoided cost of commodity purchases for normalized annual consumption is captured in the commodity component of the calculation. The commodity purchases and sales in the midstream component largely offset each other on a forecast basis. It is the storage and transportation capacity costs, and to a minor extent, the administrative costs that comprise the cost of the midstream function on a normalized annual basis. Therefore, in the interests of simplicity, FEI has not used all of the components of midstream costs and revenues, such as hedging costs or gains and unaccounted for gas. The calculation does include the mitigation of transportation (as discussed in the response to BCUC IR 2.384.4).

Including all midstream cost components in the calculation would not result in a material difference to the estimate, as discussed in the response to BCUC IR 2.384.3.

384.5.1 If not confirmed, please explain.

Response:

Please refer to the response to BCUC IR 2.384.5.

384.5.2 Why did FEI choose to not include all of the midstream cost/revenue components? Please explain.

Response:

Please refer to the responses to BCUC IRs 2.384.3 and 2.384.5.

Commission Letter L-43-13 dated July 11, 2013, accepted FEI's proposed changes to the FEI supply portfolio for the contract year of November 1, 2013 to October 31, 2014, including the following:

> "**Commodity Portfolio**: change the baseload supply receipt point allocation, effective November 1, 2013, by increasing Station 2 from 70% to 75%, decreasing Huntingdon from 15% to 0%, and increasing AECO/NIT from 15% to 25% in 2013/14 compared to previous years' allocations."

384.6 Please provide the receipt point allocation and the respective aupply hub price indices that were used in determining the calculation of the 2013 Commodity Cost component of $3.839/GJ in the avoided cost of gas calculation.

Response:

FEI did not use a receipt point allocation in determining the calculation of the 2013 Commodity Cost component of $3.839/GJ in the avoided cost of gas calculation. As the avoided cost of gas calculation is meant to represent the marginal or most expensive, rather than the average, cost in the gas portfolio, FEI instead derived a Sumas price for the commodity component. This derived Sumas price is based on the GLJ Petroleum Consultants (GLJ) AECO/NIT price forecast, then adding the AECO/NIT-Station 2 differential and T-South pipeline fuel to determine a Sumas price equivalent.

384.6.1 Is the Commodity Cost component of $3.839/GJ as provided in BCUC 1.218.2 derived from GLJ Petroleum Consultants price forecasts for each of the supply hubs based the Commission accepted receipt point allocations for the FEI supply portfolio for the 2012-2013 year or is it based on the accepted allocation for the 2013-2014 year or a weighted average of the two? Please indicate which one.

Response:

Please refer to the response to BCUC IR 2.384.6.

384.6.1.1 If it is not based on the Commission accepted allocation for either of the 2013-2014 contract year or the 2012-2013 contract year or a weighted average of the two, please explain why not.

Response:

Please refer to the response to BCUC IR 2.384.6.

In Exhibit B-9 of the FEU 2012-2013 RRA, in response to BCUC 1.40.1 FEI described the allocation of the CMAE as follows: "the CMAE costs, related to the integrated gas supply function, continue to be allocated 90 percent to FEI, which now includes FEW in its gas supply portfolio, and 10 percent to FEVI. Also consistent with current practice the FEI, including FEW, share of the CMAE is allocated 30 percent to the CCRA and 70 percent to the MCRA." (FEU 2012-2013 RRA, BCUC 1.40.1)

In this proceeding, in response to BCUC 1.218.2 FEI indicates that the Midstream Cost used to determine the avoided cost of gas includes Administrative Cost which is the MCRA share of the approved 2013 CMAE.

384.7 Does the Commodity Cost in the Avoided Cost of Gas Calculation in the response to BCUC 1.218.2 include the CCRA share of the 2013 CMAE, which is projected to be $1,220,000 in the 2012 Fourth Quarter Gas Cost Report?

Response:

No, the Commodity Cost in the Avoided Cost of Gas Calculation in the response to BCUC IR 1.218.2 does not include the CCRA share of the 2013 CMAE. As discussed in the response to BCUC IR 2.384.6, the Commodity Cost is based on the GLJ AECO/NIT price forecast plus the AECO/NIT-Station 2 price differential and T-South fuel to derive a Sumas price. Therefore, the Commodity Cost used in the Avoided Cost of Gas Calculation is not based on FEI's commodity cost components shown in the 2012 Fourth Quarter Gas Cost Report. Furthermore, the CCRA share of the CMAE is not a material component of FEI's commodity costs.

384.7.1 If not, why not?

Response:

Please refer to the response to BCUC 2.384.7.

384.8 Please confirm that the approved Commodity Cost Recovery Charge was set at \$2.977 /GJ for the period from January 1, 2013 to June 31, 2013, at \$3.913/GJ for the period from July 1, 2013 through September 30, 2013 and is currently set at \$3.272 per GJ for the period from October 1, 2013 through December 31, 2013.

Response:

Confirmed.

384.8.1 If not confirmed, please explain.

Response:

Please refer to the response to BCUC IR 2.384.8.

384.8.2 Please calculate and provide the weighted average 2013 FEI Commodity Cost Recovery Charge weighted on the basis of gas sales during each of the three periods.

Response:

Based on actual gas sales for January to September 2013 and forecast gas sales for October to December 2013 the weighted average 2013 FEI Commodity Cost Recovery Charge is \$3.167/GJ.

384.8.3 Does FEI agree that this would be an accurate representation of the 2013 Commodity Cost on the FEI system? If not, please explain.

Response:

No, FEI does not agree that this would be an accurate representation of the 2013 Commodity Cost on the FEI system. A weighted average of FEI's commodity rates for 2013, as per the response to BCUC IR 2.384.8.2, would not only include the impacts of CCRA deferral account balances along with the forecast of the commodity costs, but the underlying forecast commodity costs embedded in rates reflects a rolling 12-month prospective period. Deferral account balances, whether surplus or deficit balances, can result in commodity rates that are materially different than FEI's commodity costs.

Even when excluding deferral account balances in commodity costs, as discussed in the response to BCUC IR 2.384.6, FEI's intent has been to derive a marginal cost of gas in the "Avoided Cost of Gas Calculation" rather than an average cost of gas.

384.9 It would appear from FEI's description of the methodology for calculating the avoided cost of gas that FEU calculates one long-run avoided cost of gas that is used for all customer classes regardless of load shape. Please confirm that this is the case.

Response:

Confirmed.

384.9.1 If confirmed, is this the industry accepted best practice? Please explain.

Response:

The FEU do not believe that there is a single accepted industry best practice for the calculation of the avoided cost of gas. The FEU believe that the method of calculating the avoided cost of gas for the purpose of evaluating demand side management programs varies from one utility to the next depending on the specific circumstances of each utility. The FEU believe that their method of calculating the avoided cost of gas, as explained in the response to BCUC IR 1.218.2, considers elements common to many utilities and is an appropriate methodology.

The table provided below contains a summary of methodologies used by gas utilities in the Pacific Northwest U.S., and indicates that there is no single methodology best practice. Further, in providing a response to this IR, the FEU requested E Source, a leading energy efficiency and conservation industry benchmarking organization, to conduct a review of avoided cost of gas calculation methodologies. E Source concluded that there is no industry best practice for this calculation. The E Source report is included as Attachment 384.9.1.

Summary of the Avoided Cost of Gas calculation methodology for DSM

	Avista	Cascade	Northwest	PSE
Benefits				
Natural gas resource avoided cost for application to all resources	Avoided commodity costs are derived from SENDOUT leading to a 20 year market price forecast. The costs from SENDOUT include commodity costs, and variable interstate pipeline charges. This forecast is extrapolated as necessary for longer measure lives.	Avoided commodity costs are derived from SENDOUT's Marginal Cost" report uisng our internal 20 year market price forecast. The costs from SENDOUT include commodity costs, and variable interstate pipeline charges and some element of strorage (winter only). The 20 year forecast is extrapolated to cover an additional 25 years.	Avoided costs are derrived from SENDOUT and include the long term gas price forecast, gas storage carrying costs for inventory, and upstream variable transmission costs.	PSE's avoided cost of gas gas includes: 1. A weighted average commodity cost of gas 2. An avoided Pipeline Demand Charge 3. Avoided pipeline variable transportation charge 4. Avoided pipeline fuel reimbursement 5. Avoided distribution capacity costs.
Modifications to the natural gas resource avoided cost unique to DSM resources	Avista incorporates an estimate of incremental distribution capacity cost into the avoided cost calculation for DSM purposes. This incremental cost of distribution capacity is small ($0.009 levelized cost per year per therm). Avista adds an additional 10% to the aggregation of all of these avoided cost as a DSM preference.	None	NWN increases the avoided cost by 10% to account for non-quanitifiable non-energy benefits.	As described above, we add avoided pipeline demand charges, avoided pipeline transportation charges, avoided pipeline fuel reimbursement, and avoided distribution capacity costs.

384.9.1.1 Have FEU calculated long-run marginal cost of gas specific to load shape of the customer class in the past and, if so, why has FEU varied from this practice?

Response:

No, the FEU have not calculated the long-run marginal cost of gas specific to load shape for each customer class in the past. Please also refer to the response to BCUC IR 2.384.9.1.

384.9.1.2 Please confirm that the FEI Midstream Cost Recovery Charge varies based on the load shape of the customer class. If not confirmed, please explain.

Response:

Confirmed.

384.9.2 If not confirmed, please explain how the long-run marginal cost of gas was determined on a load shape basis and provide the calculated 2013 avoided cost of gas on a customer class/load shape basis.

Response:

Please refer to the response to BCUC IR 2.384.9.

384.10 The carbon tax does not appear to be included in the avoided cost of gas calculation. Please confirm that it is not included.

Response:

The FEU confirm that the carbon tax is not included in the avoided cost of gas calculation. Please refer to the response to BCUC IR 2.384.10.1 for further explanation.

384.10.1 If confirmed, please the rationale for not including it in the calculation of the avoided cost of gas.

Response:

The FEU confirm that the carbon tax is not included in the avoided cost of gas calculation; however, it is included in the cost-effectiveness calculation as part of the benefits (i.e. costs avoided by society by consuming less gas).

The carbon tax is transferable revenue from the customer to the government. The cost of carbon represents neither a capacity nor energy avoidance. It is a cost determined by government policy rather than an operational cost. Therefore, the FEU include it amongst the benefits of the cost effectiveness calculation but not as part of the avoided cost of gas.

384.10.2 If it is included, please explain how it is included in the calculation of the avoided cost of gas.

Response:

Please refer to the response to BCUC IR 2.384.10.1.

384.10.3 Describe FEI's assumption regarding the carbon tax over the next 15 years.

Response:

The FEU assumption is based on the market price of carbon for natural gas in 2013 is $30 per tonne, which translates to about $1.50 per GJ. The FEU have kept the carbon tax rate constant over the next 15 years considering the FEU have no information suggesting that the carbon price will go up. The B.C. government has recently announced that it does not have any plans to increase the carbon tax for the next five years.

384.11 Using the same format and line items as set out on Page 6 of Tab 1 of the 2012 Fourth Quarter Report, please provide a revised version of this page for the period January 1, 2013 through December 31, 2013 by populating the data elements on the page with actual for those months for which actuals are now available and projections for the remaining months.

Response:

The table below provides the requested information.

FORTISBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
INCLUDING FORTISBC ENERGY (WHISTLER) INC.
GAS COST SUMMARY FOR THE PERIOD JAN 1, 2013 TO DEC 31, 2013
UPDATED ON NOV 12, 2013
INCLUDED ACTUAL DATA FROM JAN. 2013 TO SEPT. 2013 AND FORECAST DATA
FROM OCT. 2013 TO DEC. 2013 (BASED ON SECTION 2 OF THE 2013 THIRD QUARTER GAS COST REPORT)

Line No.	Particulars	Costs ($000)		Volumes (TJ)		Unit Cost ($/GJ)
	(1)	(2)	(3)	(4)	(5)	(6)
1	**CCRA**					
2	Commodity					
3	Station No. 2 Total		$ 234,496		78,226	$ 2.998
4	AECO Total		54,433		18,023	3.020
5	Huntingdon Total		46,083		13,272	3.472
6	Commodity Costs before Hedging		$ 335,012		109,520	$ 3.059
7	Mark to Market Hedges Cost / (Gain)		17,019		-	
8	Subtotal Commodity Purchased		$ 352,031		109,520	$ 3.214
9	Core Market Administration Costs		1,037		-	
10	Fuel Used in Transportation		-		(2,560)	
11	**Total CCRA Costs**		**$ 353,069**		**106,960**	**$ 3.301**
12						
13	**MCRA**					
14	Midstream Commodity					
15	Midstream Commodity before Hedging		$ 48,260		15,786	$ 3.057
16	Mark to Market Hedges Cost / (Gain)		581			
	Imbalance		(1,871)		(485)	3.858
17	Company Use Gas Recovered from O&M		(1,769)		(300)	5.904
18	Total Midstream Commodity		$ 45,201		15,002	$ 3.013
19						
20	Storage Gas					
21	BC - Aitken Creek					
22	LNG - Tilbury & Mt. Hayes					
23	Alberta - Niska & CrossAlta					
24	Downstream - JPS & Mist					
25	Injections into Storage		$ (76,312)		(21,682)	$ 3.520
26	BC - Aitken Creek					
27	LNG - Tilbury & Mt. Hayes					
28	Alberta - Niska & CrossAlta					
29	Downstream - JPS & Mist					
30	Withdrawals from Storage		103,958		26,365	$ 3.943
31	BC - Aitken Creek					
32	LNG - Mt. Hayes					
33	Alberta - Niska & CrossAlta					
34	Downstream - JPS & Mist					
35	Storage Demand Charges		45,939			
36	Total Net Storage (Lines 28, 33, & 38)		$ 73,585		4,683	
37						
38	Mitigation					
39	Transportation	$ (27,316)			(1,243)	
40	Commodity Resales	(79,016)			(22,437)	3.522
	Other GSMIP Mitigation	(11,242)			(171)	
	GSMIP Incentive Sharing	1,318				
41	Other Non-GSMIP Mitigation	(987)				
42	Total Mitigation		$ (117,243)		(23,851)	
43						
44	Transportation (Pipeline) Charges					
45	WEI	$ 95,731				
46	NOVA / ANG	12,164				
47	NWP	4,075				
48	Total Transportation Charges		$ 111,970			
49						
50	Core Market Administration Costs		$ 2,462			
51						
52	Fuel Used in Storage & UAF (Sales & T-Service)				(210)	
53						
54	Net MCRA Commodity (Lines 21, 39, 45, & 55)				(4,376)	
55	**Total MCRA Costs** (Lines 21, 39, 45, 51, & 53)		**$ 115,975**			**$ 1.021**
56	**Total Core Sales Volumes**				**113,609**	
57	**Total Forecast Gas Costs** (Lines 14 & 58)		$ 469,044			

Notes: Slight difference in totals due to rounding.
(1*) The total cost of UAF is included as a component of gas volumes purchased. Sales UAF costs are recovered via gas cost recovery rates, while T-Service UAF costs are recovered via delivery revenues.

1

384.11.1 Using this data, please recalculate the current avoided cost of gas for 2013 taking into account the all of the commodity and midstream costs and revenues and using the total sales volumes.

Response:

The recalculated avoided cost of gas for 2013, based on the updated gas cost summary presented in the response to BCUC IR 2.384.11, is $4.32/GJ (Commodity Cost of $3.30/GJ plus Midstream Cost of $1.02/GJ).

384.11.2 Using this recalculated 2013 avoided cost of gas, please calculate and provide the long-run marginal cost of gas assuming GLJ Petroleum Consultants price forecasts for Station 2, AECO and Huntingdon and the receipt point allocation accepted in Commission Letter L-43-13, and using the indicated escalation factor for the midstream cost for each of the following scenarios:

384.11.2.1 A 1% escalation on the Midstream Component;

Response:

This response addresses BCUC IRs 2.384.11.2.1 through 2.384.11.2.3.

The following table provides the requested long-run cost of gas based on the cited assumptions. As discussed in the response to BCUC IR 2.384.6, the FEU do not believe this represents a marginal cost, but rather an average or allocated cost, due the receipt point allocation requested by the Commission in this calculation.

Long Run Average or Allocated Cost of Gas Based on Avoided Cost Calculation Using 1%, 2% and 3% Escalation on the Midstream Component with Requested Receipt Point Allocation

	Midstream Component Cost Escalation Factor	Year					
		2013	2014	2015	2016	2017	2018
Cost of Gas ($/GJ)	1%	4.02	4.39	4.77	5.14	5.52	5.77
	2%	4.02	4.40	4.79	5.17	5.56	5.82
	3%	4.02	4.41	4.81	5.20	5.61	5.88

Note that the difference between the avoided cost of gas using a 1 percent escalation on the midstream component versus a 3 percent escalation over the five year period is not material.

384.11.2.2 A 2% escalation on the Midstream Component; and

Response:

Please refer to the response to BCUC IR 2.384.11.2.1.

384.11.2.3 A 3% escalation on the Midstream Component

Response:

Please refer to the response to BCUC IR 2.384.11.2.1.

384.11.3 Using the recalculated long-run marginal cost of gas for each of these three scenarios, please provide updated versions of the table provided by FEI in response to BCUC 1.219.6.

<u>Response:</u>

The three tables below provide the requested updates to the table provided in the FEU's response to BCUC IR 1.219.6. The FEU note that the only changes to these tables occur within the cost-effectiveness results. These changes are very minor (immaterial) such that they must be examined closely to be identified. The FEU note that the natural gas savings shown in these tables are net of free ridership and spillover effects, and only show the savings that occur within the 2014-2018 period. They do not include savings beyond 2018 that occur for measures with longer lifetimes.

Table A: Program Cost Effectiveness Results Using an Avoided Cost of Gas with a 1% Escalation of the Midstream Component

Program and Service Territory	Utility Expenditures ($1000s)		Gas Savings, Net (GJ)		Benefit Cost Tests			
	2014-2018	% of Total	2014-2018	% of Total	TRC (Ratio)	MTRC (Ratio)	Utility (Ratio)	Utility ($/GJ)
RESIDENTIAL (ALL PROGRAMS)	**54,902**	**30.8%**	**2,362,301**	**24.4%**	**0.63**	**2.01**	**1.02**	**7.66**
Energy Efficient Home Performance Program	7,901	4.4%	618,980	6.4%	0.94	3.00	2.54	3.15
* Furnace Replacement Program	16,705	9.4%	468,527	4.8%	0.44	1.41	0.80	9.85
Enerchoice Fireplace Program	5,823	3.3%	215,973	2.2%	1.38	4.37	0.85	9.03
Appliance Service Program	2,281	1.3%	0	0.0%	0.00	0.00	0.00	
* ENERGY STAR® Water Heater Program	6,275	3.5%	207,105	2.1%	0.55	1.77	0.97	8.18
Low-Flow Fixtures	1,450	0.8%	192,375	2.0%	2.69	8.49	2.52	2.99
* New Home Program	4,677	2.6%	122,125	1.3%	0.35	1.12	0.86	9.45
* New Technologies Program	1,556	0.9%	24,216	0.2%	0.33	1.04	0.32	23.79
* Customer Engagement Tool for Conservation Behaviours	4,428	2.5%	513,000	5.3%	0.80	2.56	0.80	8.60
Financing Pilot	1,105	0.6%	0	0.0%	0.00	0.00	0.00	
Non-Program Specific Expenses	2,700	1.5%	0	0.0%	0.00	0.00	0.00	
COMMERCIAL (ALL PROGRAMS)	**54,144**	**30.4%**	**4,296,483**	**44.3%**	**0.94**	**3.00**	**1.51**	**5.11**
Space Heat Program	10,066	5.7%	848,671	8.8%	2.21	7.05	2.67	2.99
Water Heating Program	1,442	0.8%	215,798	2.2%	1.02	3.21	3.46	2.21
Commercial Food Service Program	2,448	1.4%	215,842	2.2%	1.59	5.03	2.12	3.61
Customized Equipment Upgrade Program	12,272	6.9%	771,502	8.0%	0.94	3.01	2.02	3.97
EnerTracker Program	964	0.5%	218,078	2.2%	1.48	5.04	1.42	4.42
* Continuous Optimization Program	9,214	5.2%	1,780,325	18.4%	0.74	2.34	1.78	3.94
Commercial Energy Assessment Program	2,339	1.3%	231,267	2.4%	0.93	3.02	0.67	10.11
Energy Specialist Program	9,882	5.6%	0	0.0%	0.00	0.00	0.00	
Mechanical Insulation Pilot	16	0.0%	15,000	0.2%	4.94	15.78	25.98	0.31
Non-Program Specific Expenses	5,500	3.1%	0	0.0%	0.00	0.00	0.00	
INDUSTRIAL (ALL PROGRAMS)	**12,896**	**7.2%**	**2,192,299**	**22.6%**	**2.71**	**8.55**	**3.66**	**2.08**
Industrial Optimization Program	9,148	5.1%	1,552,971	16.0%	2.56	8.07	3.44	2.19
Specialized Industrial Process Technology Program	2,438	1.4%	639,328	6.6%	4.15	13.12	6.50	1.19
Non-Program Specific Expenses	1,310	0.7%	0	0.0%	0.00	0.00	0.00	
LOW INCOME (ALL PROGRAMS)	**15,223**	**8.6%**	**406,432**	**4.2%**	**0.84**		**0.64**	**12.19**
Energy Savings Kit	651	0.4%	136,063	1.4%	4.82		3.10	2.38
Energy Conservation Assistance Program	10,240	5.8%	118,065	1.2%	0.38		0.29	26.98
REnEW	405	0.2%	0	0.0%	0.00		0.00	
Low Income Space Heat Top-Ups	394	0.2%	36,766	0.4%	2.57		2.73	2.91
Low Income Water Heating Top-Ups	77	0.0%	10,742	0.1%	1.25		2.94	2.58
Non-Profit Custom Program	1,931	1.1%	104,796	1.1%	2.40		1.78	4.50
Non-Program Specific Expenses	1,525	0.9%	0	0.0%	0.00		0.00	
CONSERVATION EDUCATION AND OUTREACH (ALL PROGRAMS)	**12,000**	**6.7%**	**0**	**0.0%**	**0.00**	**0.00**	**0.00**	
Residential Education Program	4,950	2.8%	0	0.0%	0.00	0.00	0.00	
Commercial Education Program	2,250	1.3%	0	0.0%	0.00	0.00	0.00	
School Education Program	3,600	2.0%	0	0.0%	0.00	0.00	0.00	
Non-Program Specific Expenses	1,200	0.7%	0	0.0%	0.00	0.00	0.00	
INNOVATIVE TECHNOLOGIES (ALL PILOTS)	**6,086**	**3.4%**	**435,173**	**4.5%**	**1.51**	**4.81**	**1.97**	**4.01**
ENABLING ACTIVITIES (ALL ACTIVITIES)	**22,740**	**12.8%**	**0**	**0.0%**	**0.00**	**0.00**	**0.00**	
ENTIRE PORTFOLIO	**177,991**	**100.0%**	**9,692,688**	**100.0%**	**0.83**	**2.49**	**1.16**	**6.68**

Note: Whistler (FEW) is included in the FEI service territory

* Program requires the MTRC in order to pass the economic screen

1 2 **Table B: Program Cost Effectiveness Results Using an Avoided Cost of Gas with a 2% Escalation of the Midstream Component**

Program and Service Territory	Utility Expenditures ($1000s)		Gas Savings, Net (GJ)		Benefit Cost Tests			
	2014-2018	% of Total	2014-2018	% of Total	TRC (Ratio)	MTRC (Ratio)	Utility (Ratio)	Utility ($/GJ)
RESIDENTIAL (ALL PROGRAMS)	**54,902**	**30.8%**	**2,362,301**	**24.4%**	**0.64**	**2.01**	**1.04**	**7.66**
Energy Efficient Home Performance Program	7,901	4.4%	618,980	6.4%	0.95	3.00	2.58	3.15
* Furnace Replacement Program	16,705	9.4%	468,527	4.8%	0.45	1.41	0.81	9.85
Enerchoice Fireplace Program	5,823	3.3%	215,973	2.2%	1.39	4.37	0.86	9.03
Appliance Service Program	2,281	1.3%	0	0.0%	0.00	0.00	0.00	
* ENERGY STAR® Water Heater Program	6,275	3.5%	207,105	2.1%	0.56	1.76	0.98	8.18
Low-Flow Fixtures	1,450	0.8%	192,375	2.0%	2.72	8.49	2.54	2.99
* New Home Program	4,677	2.6%	122,125	1.3%	0.36	1.12	0.87	9.45
* New Technologies Program	1,556	0.9%	24,216	0.2%	0.33	1.04	0.32	23.79
* Customer Engagement Tool for Conservation Behaviours	4,428	2.5%	513,000	5.3%	0.80	2.56	0.80	8.60
Financing Pilot	1,105	0.6%	0	0.0%	0.00	0.00	0.00	
Non-Program Specific Expenses	2,700	1.5%	0	0.0%	0.00	0.00	0.00	
COMMERCIAL (ALL PROGRAMS)	**54,144**	**30.4%**	**4,296,483**	**44.3%**	**0.95**	**3.00**	**1.53**	**5.11**
Space Heat Program	10,066	5.7%	848,671	8.8%	2.24	7.05	2.71	2.99
Water Heating Program	1,442	0.8%	215,798	2.2%	1.03	3.21	3.50	2.21
Commercial Food Service Program	2,448	1.4%	215,842	2.2%	1.61	5.03	2.15	3.61
Customized Equipment Upgrade Program	12,272	6.9%	771,502	8.0%	0.95	3.01	2.06	3.97
EnerTracker Program	964	0.5%	218,078	2.2%	1.48	5.04	1.42	4.42
* Continuous Optimization Program	9,214	5.2%	1,780,325	18.4%	0.75	2.34	1.79	3.94
Commercial Energy Assessment Program	2,339	1.3%	231,267	2.4%	0.93	3.02	0.67	10.11
Energy Specialist Program	9,882	5.6%	0	0.0%	0.00	0.00	0.00	
Mechanical Insulation Pilot	16	0.0%	15,000	0.2%	5.02	15.78	26.39	0.31
Non-Program Specific Expenses	5,500	3.1%	0	0.0%	0.00	0.00	0.00	
INDUSTRIAL (ALL PROGRAMS)	**12,896**	**7.2%**	**2,192,299**	**22.6%**	**2.74**	**8.55**	**3.70**	**2.08**
Industrial Optimization Program	9,148	5.1%	1,552,971	16.0%	2.59	8.07	3.48	2.19
Specialized Industrial Process Technology Program	2,438	1.4%	639,328	6.6%	4.21	13.12	6.58	1.19
Non-Program Specific Expenses	1,310	0.7%	0	0.0%	0.00	0.00	0.00	
LOW INCOME (ALL PROGRAMS)	**15,223**	**8.6%**	**406,432**	**4.2%**	**0.85**		**0.65**	**12.19**
Energy Savings Kit	651	0.4%	136,063	1.4%	4.86		3.13	2.38
Energy Conservation Assistance Program	10,240	5.8%	118,065	1.2%	0.38		0.29	26.98
REnEW	405	0.2%	0	0.0%	0.00		0.00	
Low Income Space Heat Top-Ups	394	0.2%	36,766	0.4%	2.58		2.74	2.91
Low Income Water Heating Top-Ups	77	0.0%	10,742	0.1%	1.26		2.98	2.58
Non-Profit Custom Program	1,931	1.1%	104,796	1.1%	2.43		1.81	4.50
Non-Program Specific Expenses	1,525	0.9%	0	0.0%	0.00		0.00	
CONSERVATION EDUCATION AND OUTREACH (ALL PROGRAMS)	**12,000**	**6.7%**	**0**	**0.0%**	**0.00**	**0.00**	**0.00**	
Residential Education Program	4,950	2.8%	0	0.0%	0.00	0.00	0.00	
Commercial Education Program	2,250	1.3%	0	0.0%	0.00	0.00	0.00	
School Education Program	3,600	2.0%	0	0.0%	0.00	0.00	0.00	
Non-Program Specific Expenses	1,200	0.7%	0	0.0%	0.00	0.00	0.00	
INNOVATIVE TECHNOLOGIES (ALL PILOTS)	**6,086**	**3.4%**	**435,173**	**4.5%**	**1.54**	**4.81**	**2.00**	**4.01**
ENABLING ACTIVITIES (ALL ACTIVITIES)	**22,740**	**12.8%**	**0**	**0.0%**	**1.01**	**3.20**	**1.15**	
ENTIRE PORTFOLIO	**177,991**	**100.0%**	**9,692,688**	**100.0%**	**0.84**	**2.49**	**1.17**	**6.68**

Note: Whistler (FEW) is included in the FEI service territory
3 * Program requires the MTRC in order to pass the economic screen

4

Table C: Program Cost Effectiveness Results Using an Avoided Cost of Gas with a 3% Escalation of the Midstream Component

Program and Service Territory	Utility Expenditures ($1000s)		Gas Savings, Net (GJ)		Benefit Cost Tests			
	2014-2018	% of Total	2014-2018	% of Total	TRC (Ratio)	MTRC (Ratio)	Utility (Ratio)	Utility ($/GJ)
RESIDENTIAL (ALL PROGRAMS)	**54,902**	**30.8%**	**2,362,301**	**24.4%**	**0.65**	**2.01**	**1.05**	**7.66**
Energy Efficient Home Performance Program	7,901	4.4%	618,980	6.4%	0.97	3.00	2.63	3.15
* Furnace Replacement Program	16,705	9.4%	468,527	4.8%	0.46	1.41	0.83	9.85
Enerchoice Fireplace Program	5,823	3.3%	215,973	2.2%	1.41	4.37	0.88	9.03
Appliance Service Program	2,281	1.3%	0	0.0%	0.00	0.00	0.00	
* ENERGY STAR® Water Heater Program	6,275	3.5%	207,105	2.1%	0.57	1.77	1.00	8.18
Low-Flow Fixtures	1,450	0.8%	192,375	2.0%	2.75	8.49	2.57	2.99
* New Home Program	4,677	2.6%	122,125	1.3%	0.36	1.12	0.89	9.45
* New Technologies Program	1,556	0.9%	24,216	0.2%	0.34	1.04	0.32	23.79
* Customer Engagement Tool for Conservation Behaviours	4,428	2.5%	513,000	5.3%	0.80	2.56	0.80	8.60
Financing Pilot	1,105	0.6%	0	0.0%	0.00	0.00	0.00	
Non-Program Specific Expenses	2,700	1.5%	0	0.0%	0.00	0.00	0.00	
COMMERCIAL (ALL PROGRAMS)	**54,144**	**30.4%**	**4,296,483**	**44.3%**	**0.97**	**3.00**	**1.55**	**5.11**
Space Heat Program	10,066	5.7%	848,671	8.8%	2.28	7.05	2.76	2.99
Water Heating Program	1,442	0.8%	215,798	2.2%	1.04	3.21	3.55	2.21
Commercial Food Service Program	2,448	1.4%	215,842	2.2%	1.63	5.03	2.18	3.61
Customized Equipment Upgrade Program	12,272	6.9%	771,502	8.0%	0.97	3.01	2.10	3.97
EnerTracker Program	964	0.5%	218,078	2.2%	1.49	5.04	1.42	4.42
* Continuous Optimization Program	9,214	5.2%	1,780,325	18.4%	0.75	2.34	1.80	3.94
Commercial Energy Assessment Program	2,339	1.3%	231,267	2.4%	0.94	3.02	0.67	10.11
Energy Specialist Program	9,882	5.6%	0	0.0%	0.00	0.00	0.00	
Mechanical Insulation Pilot	16	0.0%	15,000	0.2%	5.10	15.78	26.86	0.31
Non-Program Specific Expenses	5,500	3.1%	0	0.0%	0.00	0.00	0.00	
INDUSTRIAL (ALL PROGRAMS)	**12,896**	**7.2%**	**2,192,299**	**22.6%**	**2.77**	**8.55**	**3.74**	**2.08**
Industrial Optimization Program	9,148	5.1%	1,552,971	16.0%	2.62	8.07	3.52	2.19
Specialized Industrial Process Technology Program	2,438	1.4%	639,328	6.6%	4.26	13.12	6.67	1.19
Non-Program Specific Expenses	1,310	0.7%	0	0.0%	0.00	0.00	0.00	
LOW INCOME (ALL PROGRAMS)	**15,223**	**8.6%**	**406,432**	**4.2%**	**0.86**		**0.66**	**12.19**
Energy Savings Kit	651	0.4%	136,063	1.4%	4.90		3.15	2.38
Energy Conservation Assistance Program	10,240	5.8%	118,065	1.2%	0.39		0.29	26.98
REnEW	405	0.2%	0	0.0%	0.00		0.00	
Low Income Space Heat Top-Ups	394	0.2%	36,766	0.4%	2.66		2.82	2.91
Low Income Water Heating Top-Ups	77	0.0%	10,742	0.1%	1.28		3.01	2.58
Non-Profit Custom Program	1,931	1.1%	104,796	1.1%	2.48		1.84	4.50
Non-Program Specific Expenses	1,525	0.9%	0	0.0%	0.00		0.00	
CONSERVATION EDUCATION AND OUTREACH (ALL PROGRAMS)	**12,000**	**6.7%**	**0**	**0.0%**	**0.00**	**0.00**	**0.00**	
Residential Education Program	4,950	2.8%	0	0.0%	0.00	0.00	0.00	
Commercial Education Program	2,250	1.3%	0	0.0%	0.00	0.00	0.00	
School Education Program	3,600	2.0%	0	0.0%	0.00	0.00	0.00	
Non-Program Specific Expenses	1,200	0.7%	0	0.0%	0.00	0.00	0.00	
INNOVATIVE TECHNOLOGIES (ALL PILOTS)	**6,086**	**3.4%**	**435,173**	**4.5%**	**1.53**	**4.71**	**1.99**	**4.14**
ENABLING ACTIVITIES (ALL ACTIVITIES)	**22,740**	**12.8%**	**0**	**0.0%**	**0.00**	**0.00**	**0.00**	
ENTIRE PORTFOLIO	**177,991**	**100.0%**	**9,692,688**	**100.0%**	**0.86**	**2.49**	**1.19**	**6.68**

Note: Whistler (FEW) is included in the FEI service territory

* Program requires the MTRC in order to pass the economic screen

385.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1, Tab C, Section 4.7.2 pp.252-253; Exhibit B-11, BCUC 1.10.3, 1.218.2, 1.218.3.2

Long Range Avoided Capital Costs

In response to BCUC 1,218.2 when describing the components and methodology used to determine the long-run marginal cost of gas, FEI states "The midstream cost is ….. escalated at 3 percent per year representing inflation and increasing transportation/storage costs."

On pages 252-253 of the Application FEI describes the Kingsvale-Oliver Reinforcement Project (KORP) as follows: "The KORP consists primarily of a 161 km, 24-inch expansion project from Kingsvale to Oliver, BC. The reinforcement would further integrate and expand service using available capacity on T-South and SCP. The KORP provides an opportunity to deliver a growing supply of British Columbia gas to the Pacific Northwest and California markets. Removing pipeline capacity constraints would build on the T-South Enhanced Service offering for FEI customers, including additional demand charge revenue, T-South toll savings, and improved access to competitively prices and reliable gas supply, as well as additional security of supply and liquidity in the region." (Exhibit B-1, Section C4.7.2, pp.252-253)

385.1 Is the KORP an example of an expansion project in the region that will impact "transportation/storage costs" that would in turn impact the long range avoided cost of gas for FEI? Please explain the response.

Response:

Yes, KORP is one example of an infrastructure expansion project that could potentially impact or benefit the long range avoided cost of gas for FEI. Similarly, the "transportation/storage costs" for FEI could be impacted by other regional infrastructure projects, toll changes to existing pipeline capacity contracted by FEI, and any price changes associated with storage contract renewals.

If KORP were to be developed this would expand the alternative of potential resources available to FEI for its gas supply portfolio and this resource may replace an existing resource already included in the forecasted long range avoided cost of gas for FEI. It is difficult at this time to determine if the availability of KORP capacity by FEI as part of its Annual Contracting Plan (ACP) would increase or decrease FEI's avoided cost of gas; however, for FEI to hold KORP capacity it is expected that FEI would have to demonstrate an overall net benefit for FEI customers.

385.1.1 Is KORP expected to increase the FEI long range cost of gas or decrease the FEI long range cost of gas?

Response:

Please refer to the response to BCUC IR 2.385.1.

In response to BCUC 1.10.3 FEI states that "Due to market conditions KORP does not yet have sufficient commercial commitments to proceed. For KORP to proceed, however, it would be expected to generate revenues to offset the costs of the project. "

.

385.2 Is the lack of commercial commitments to the KORP evidence that there is currently no need for additional system capacity in the region? Please explain the response.

Response:

For KORP to be successful, a threshold level of long-term, firm commitments is required. At this time, due to market conditions and the uncertainty related to the development of new loads, the timing is simply not optimal to obtain sufficient long-term commitments from the market.

Despite abundant unconventional gas reserves and bullish long-term forecasts, drilling activity in northern BC (in particular the Horn River) has slowed due to lower natural gas prices. The lower natural gas prices have delayed decisions on pipeline projects to add capacity to transport gas from the supply basins to market. Also, there is uncertainty related to pipeline routing for LNG export projects, and whether pipelines will be directly connected to supply basins or to traditional supply hubs, such as Station 2 or AECO (the Alberta trading hub). This has created market uncertainty in regards to the distribution of gas flows between the Spectra Energy and Nova Gas Transmission Ltd. systems. The need for incremental supply to the Pacific Northwest to meet traditional market demand has also slowed. The Northwest Gas Association (NWGA) 2012 Gas Outlook showed, based on forecasted regional demand, the region would require new resources by 2017/18. The NWGA 2013 Gas Outlook shows this need deferred to 2020/21 (based on Expected Case and excluding non-firm load). Although the NWGA 2013 Outlook recognizes that the potential for new demand related to the power generation, industrial loads, and natural gas for transportation is significant, this is not included in this forecast.

While the pace of KORP activities have been reduced, FEI continues to believe that a system expansion will ultimately be required. New baseload markets are emerging in southern BC with potentially significant incremental baseload demand. FEI has observed that several project developers are assessing pipeline alternatives to the south coast, which include a focus on supply diversity from BC and/or Alberta. These markets are anticipated to drive the need for additional regional infrastructure in the region.

Despite delays, FEI believes KORP will be an integral part of serving new market demand, while also continuing to provide delivery options for northern BC production. Given the project development progress to date, FEI will be in a position to respond quickly when the market opportunity becomes more certain.

385.2.1 If so, please explain why an escalation factor of 3 percent per year is appropriate for the Midstream Cost.

<u>Response:</u>

FEI has used an escalation factor of 3 percent per year for the Midstream Costs. This is a high level estimate used to forecast Midstream cost increases and is not based on a detailed analysis of historical or expected future costs. Nor does it include analysis of the potential impacts of KORP or other regional infrastructure developments. It is an approximation based on observed historical increases as well as expectations for future storage and transportation costs.

FEI's Midstream costs, including storage and pipeline costs, have increased during the past few years. For example, Spectra T-South pipeline costs, which represent the majority of Midstream costs, have risen approximately 10 percent per year over the last few years.

Looking forward, FEI expects storage and pipeline costs to increase. Overall storage costs, which are primarily based on market prices, are expected to go up with the increases in the summer-winter market price spread as one goes further out in time. Pipeline costs are expected to go up based on increases related to revenue requirements including long term sustainment plans, O&M, depreciation expense, etc.

385.3 For a scenario where no new transportation or storage infrastructure is required over the time period in question, what is the appropriate escalation factor for the Midstream Cost component of the long-run marginal cost of gas? Please discuss.

Response:

Please refer to the response to BCUC IR 2.385.2.1.

Attachment 243.1.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 249.3

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 249.4

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 250.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 250.3

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 252.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 253.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 253.2

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 254.2

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 255.2

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 257.1

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 271.1

6.3.5.10 2010-2011 Customer Service O&M and Cost of Service

Pursuant to Commission Order No. C-1-10, Commission Order No. G-23-10 and Commission Order No. G-141-09, FEI has transferred the Customer Care Enhancement Project non-rate base deferral account to rate base effective January 1, 2012. This account captures the costs associated with the Project incurred prior to the project implementation and go live date of January 1, 2012 in addition to project costs expected to be incurred in the early months of 2012.[141] In this application FEI is seeking approval to allocate the balance in this deferral account amongst the FortisBC Energy Utilities on the basis of average customers, resulting in an allocation of 89 percent to Mainland, 10 percent to Vancouver Island and 1 percent to Whistler. The Companies are seeking approval to amortize this account in delivery rates over eight years, the same amortization period that was used in the CCE Project CPCN Application.

Deleted: ***<#>2011 Kootenay River Crossing Cost of Service¶***
As approved by Commission Order No. C-9-10, FEI has transferred the Kootenay River Crossing Cost of Service non-rate base account to rate base effective January 1, 2012. This account captures the October through December 2011 cost of service related to the plant in service, consisting of depreciation expense, income taxes and earned return and is amortized in delivery rates over a three year period commencing January 1, 2012. Any variances between the forecast account balances and the actual incurred costs will be amortized in rates starting in 2014.

6.3.5.11 Gas Asset Records Project

Governments, Regulators, codes, and best practices have always required that pipeline operators collect, retain and manage records pertaining to their gas system assets. Due to more recent events and resulting public pressure, more stringent requirements have been put in place related to the collection, retention and management of gas system asset records. Along with industry, the FEU must continue to invest to ensure we meet the gas system records collection, retention and management requirements of the codes, regulations and standards that govern our business. The paragraphs that follow provide a summary of what is driving our specific records related actions, what steps we have taken in the last few years, and what we still need to do.

At this time, there are four key external drivers that are prompting the FEU to pursue more rigorous actions with their gas system records. First, on January 17, 2011, The OGC issued a Safety Advisory informing all pipeline operators in BC of their requirements under CSA Z662-07 with respect to records. The Advisory states that;

[141] The approved project costs as per Commission Order No. C-1-10 and Commission Order No. G-23-10 include deferred O&M of approximately $5 million in 2012.

> *In light of the San Bruno incident, the Commission reminds Pipeline Permit Holders that they must develop and maintain records of materials used within their pipeline system as part of their permanent records as per clause 5.7.1 of CSA Z662. The Commission recognizes that over time records may become damaged or lost due to causes beyond the Permit Holder's control. In such instances, the Commission expects that Permit Holders will have plans and programs in place for the management of their pipeline system in the absence of these records as well as programs for reestablishment of the records.*[142]

Second, on the same day, the OGC issued a directive to pipeline operators informing them of the OGC's Integrity Management Programs Self Assessment Protocols and Regulatory Process[143]. Under Section 6 of the Self Assessment form, the following requirement is specified.

> *The permit holder must establish, implement and maintain a records management program encompassing the creation, security, updating, retention, retrieval and deletion of all information and records necessary for the execution of the IMP. Permit holders are required to maintain all records as required within Annex N and within the broader context of CSA Z662. Where records are incomplete due to asset transfers or other reasons, the permit holder should acknowledge this in their self assessment and provide information on how the IMP manages in the absence of these records as well as how these records are being recovered.*[144]

Third, the Association of Professional Engineers of British Columbia ("APEGBC") has recently amended its Bylaws to expand the scope of its quality management clause. The new clause states that:

> *Members and licensees shall establish and maintain documented quality management processes for their practices, which shall include, as a minimum:*
>
> > *(1) retention of complete project documentation which may include, but is not limited to, correspondence, investigations, surveys, reports, data, background information, assessments, designs, specifications, field reviews, testing information, quality assurance documentation, and other engineering and geoscience documents for a minimum period of 10 years*[145]*;*

As seen above, the recent San Bruno gas pipeline explosion in September 2010, has led to a focus on the importance of gas system asset records. Even though the results of the various

[142] BC Oil and Gas Commission Safety Advisory 2011-01, January 17, 2011, Records Requirements for Pipelines
[143] BC Oil and Gas Commission Safety Advisory 2011-01, January 17, 2011, Records Requirements for Pipelines
[144] OGC Self Assessment Protocol – Integrity Management Programs for Pipeline Systems; OGC website
[145] http://www.apeg.bc.ca/resource/publications/governancepolicies/documents/bylaws.pdf

investigations and inquiries into the explosion are still pending, it appears that the lack of historical records for the pipeline in question played a key role in the incident.

The FortisBC Energy Utilities have been and will continue to be diligent about the collection, retention and management of gas system records. We have records in various systems, locations and formats dating back to the original construction of our gas systems. Recognizing the challenges presented by such disparate systems, locations and formats, we have been focusing on capturing all of our critical gas system asset compliance records into a formal and rigorous management system. In 2006, we implemented a pilot records project to test a Filenet[146] implementation for gas system asset records. Issues were identified and solutions developed thorough 2007 and 2008. In 2009, we successfully implemented a customized Filenet solution which includes a governance framework, and a sustainment organization for gas system asset compliance records. Gas system asset compliance records resulting from new gas system asset projects continue to be prudently managed in accordance with policy and regulatory requirements. In short, we have been actively pursuing strategic improvements to our collection, retention and management of our gas system records and, as explained below, we intend to continue with these improvements.

In 2010 and early 2011, the FEU undertook a review of and planning for its handling of historic gas system asset compliance records. The 2010/11 review and planning led to the development of three distinct projects which will improve access to records, the integrity of compliance record information, the completeness of existing compliance records, the protection of compliance records, and the retention and disposal of compliance records no longer needed for operational, or other requirements. These projects follow a phased and consistent approach to move historic gas system asset compliance records into Filenet. The historic gas system asset compliance records funding sought for 2012, 2013 and beyond will permit the Utilities to manage historic gas system asset compliance records and provide ready access, authenticity, security and disposition. It will also ensure that compliance records are correctly assigned to the asset and, in the case of drawings, confirm that all appropriate drawings are in place.

To take the collection, retention and management of our gas system asset compliance records to the next level of performance, we are seeking approval for the creation of a deferral account to capture and recover the costs of this project, as outlined in Table 6.3-14 below. The costs to be incurred under this Project are one time in nature and have lasting value for customers, and are more appropriately reflected in a deferral account than through an increase in the base level of O&M. This will allow the Utilities to spread the costs out over a longer period better matching with the period that benefits will be realized.

The project will consist of three distinct components. Project "A" will consolidate and scan or move vital records from various locations (paper and electronic based) into one electronic

[146] FileNet is an IBM software application that we are using for the secure capture, retention and management of gas system asset compliance records.

management system (Filenet). It will be implemented approximately equally over four years (2012 - 2015) using internal resources and an external scanning service. When completed, we will have processed the following records:

1. Pipeline Design Files (60 File Drawers)
2. Offsite Files - Project Files located in Interior offices (200 File Drawers)
3. Iron Mountain Files - Previous Engineers' Files (200 Boxes = 100 File Drawers)
4. Iron Mountain Files - OGC Reconciliation Project Files (30 boxes = 15 File Drawers)
5. Shared Drive - OGC Historic Certificate Files (Vancouver Island)

Project 'B' will review and improve the management and control systems related to engineering drawings management to support ongoing sustainment of a single set of current and as built drawings for assets. The review and improvement in the management and control systems will be undertaken to support the revised OGC and APEGBC requirements.

Project 'C' will review historical drawings to determine the best available complete and current set of drawings for each asset. Under this project we estimate that it will be necessary to index and scan approximately 50,000 hard copy drawings into Filenet, and index and move approximately 100,000 drawings from the shared drive into Filenet. We have taken great care to break this project down into manageable components to achieve a successful outcome.

Table 6.3-14: Forecast Costs for Gas Assets Records Project

	2012	2013	2014	2015
Project 'A' - Consolidate & scan critical Gas System Asset Records into Filenet	1,150,000	1,150,000	1,100,000	400,000
Project 'B' – Implement improved drawing management & control systems	350,000	275,000		
Project 'C' - Review & analyze historical drawings	500,000	825,000	1,050,000	1,000,000
Total	2,000,000	2,250,000	2,150,000	1,400,000

In summary, due to more recent events and resulting public pressure, the actions of Governments, Regulators, and Associations are sending a clear and direct signal to pipeline operators with respect to their gas system asset compliance records. That directive is to ensure that gas system asset compliance records are indeed collected, retained and managed prudently. The FEU has been working diligently for quite some time on the management of our gas system asset compliance records. We introduced the FileNet technology, reviewed and assed the state of our historic records and are now seeking funding to complete the work we started in a timely and systematic manner.

To continue to meet the records management requirements of the codes, regulations and standards that govern our business, we are requesting approval for up to $7.8 million for the four year period ending December 31, 2015 and to manage these costs within the framework of a deferral account mechanism, to be amortized in delivery rates over five years, commencing January 1, 2012. FEU believe that a five year amortization period is appropriate because it mitigates the rate impacts of the costs and generally coincides with the period over which the costs are incurred. The $7.8 million is an estimate of the total project costs; only the actual project costs will be recorded in the deferral account and ultimately recovered from customers. Furthermore, FEI is seeking approval to allocate the balance in this deferral account amongst FortisBC Energy Utilities on the basis of average customers, resulting in an allocation of 89 percent to Mainland, 10 percent to Vancouver Island and 1 percent to Whistler. The 2012 and 2013 forecasts as provided in Table 6.3-14 have been included in the deferral account for the purposes of determining the revenue requirements in this Application.

6.3.5.12 BCOneCall Project

The external environment around BCOneCall has been evolving and shifting since its inception in 1994. The corresponding actions of Government, the Regulator and industry have brought new requirements to the operations of many individual organizations. In response, we have implemented many successful initiatives in the past and we must build on those successes to take the FEU BCOneCall process to the next level of performance. As such, we need to fund a multi-stream project that will automate a portion of the BCOneCall process and allow us to realize significant benefits immediately upon completion of the project. The following sections describe the current state, the future state, the drivers for the project, the scope of work, and the benefits that are forecast to be realized.

Presently, the BCOneCall process is a “manual” process despite the use of software applications and technology. All BCOneCall tickets go through the same rigorous and labour intensive process. Location Records ticket processing staff use various technologies (SAP, AMFM[147], SIA[148], DCRS[149], and TelDig[150]) to identify the location and the nature of the request and then use these technologies to assemble the package of information that is sent to excavators. Even though different applications are involved, the current operating model is manually driven.

In the future, the processing of BCOneCall tickets will be significantly automated as determined by the nature of the request. The various technologies, SAP, AMFM, SIA, DCRS, and TelDig will be integrated and aligned such that they will automatically assemble certain BCOneCall

---

[147] AMFM is short for Asset Management/Facilities Management and refers to our GIS system.
[148] SIA is short for Service Information Application and is where we store the alpha numeric service data that is used to produce service lists and provide general service information.
[149] DCRS is short for Digitized Construction Records System and is where the actual copy of the service document resides in digital format.
[150] Teldig is the name of the company that provides the software we use for processing BC One Call tickets

packages with little or no human intervention. Following a Quality Assurance (QA)/Quality Control (QC) process, these assembled packages will then be sent to customers. Automation will be maximized and human intervention will be minimized in the new operating model.

The key drivers that influence the decision to proceed with this project at this time are:

- The Utilities have been continuously managing the efficiency and effectiveness of the BCOneCall process and this project is the next major step in that journey. This project will improve our ability to process increasing numbers of BCOneCall tickets more quickly and at a reduced unit cost in a sustainable and scalable manner.
- We expect our ticket volumes to continue to increase at 8 percent - 12 percent per year. Government, the BC Safety Authority, industry and individual organizations (including the FEU) are actively promoting the BCOneCall concept. Activities are in place to increase public and contractor awareness of BCOneCall and the requirement to "Call Before You Dig". The intended impact of these activities is to increase BCOneCall ticket volumes as much as possible and as quickly as possible.
- The current BCOneCall ticket processing operating model is not sustainable or scalable into the future. It is an inefficient model that takes a long time to ramp up production capacity to meet ticket volume demand.
- While we have no control over ticket volumes or their increase, we can control unit costs for processing tickets. As such, our only option is to establish an operating model that minimizes the response time and unit costs through the use of technology and automation.
- We believe that technology, municipal landbase and software integration capacity are at a state where we can achieve some degree of automation after we address key data related issues.

The scope of this project encompasses three streams - Technology, Data Consistency, and Conflation.

The Technology Stream of this project enhances and integrates technologies in a way that enables automatic classification of tickets in order to seamlessly process select groups of tickets. Most of the technology related work is on the AMFM system. Minor enhancements are planned for the SAP, SIA, and DCRS systems to allow them to continue to provide customer information but be more integrated with the other technologies to support the automation. Finally, TelDig is enhanced to perform the automatic assembly and dissemination of processed tickets. The Technology Stream will be completed by mid 2011 and is being funded through our IT capital process. The Technology Stream provides technology enhancements, integrations and process improvements necessary to automate a portion of the BCOneCall ticket process.

The intent of the Data Consistency Stream is to correct identified data inconsistency issues in order to reduce the numbers of exceptions requiring a stop to the BCOneCall process. For example, under this stream, we will ensure that we have consistent asset and customer data in our SIA system for all areas of the Province in order to be able to deploy automation Province wide. Improvement to the consistency of data consumed within the BCOneCall ticket process is one of the foundation elements of automation.

The Conflation Stream will import the most current landbase available for the FEI service territory and shift the FEI gas mains/assets so that they correctly align with this new landbase. This stream of the project is necessary because the gas mains in the AMFM system are attached to a landbase that is about 8 years old and somewhat out of date. Having the most current Municipal landbase is essential to the successful automation of the BCOneCall process.

Technology, consistent data, and current Municipal landbase are foundational to the success of our automation of the BCOneCall process. The Technology Stream is implementing the technology that will enable the automation, while the Data Consistency Stream and Conflation Stream will ensure that we have consistent data and current landbase in our various systems to reduce exceptions to the process.

The BCOneCall Ticket Process Improvement project offers a significant financial benefit that will see a reduction in our long term O&M costs required for processing BCOneCall tickets. The source of this financial benefit is from the direct reduction of the average ticket processing time by up to 34.7 percent as a result of automation. This equates to a decrease in processing time of up to 10.9 minutes (from the current average of 31.5 minutes). This processing time reduction is estimated to result in an average $540 thousand annual sustainable O&M savings per year after 2014 - once the project is fully implemented and stabilized.

Once approved, the project is expected take two and half years to fully implement and to stabilize. We are forecasting a budget of $2.3 million dollars to fund the project as shown in the table below for each of the streams.

Table 6.3-15: BC One Call Ticket Process Improvement Project Costs

($ thousands)

Stream	2012	2013	2014	Total
Technology Stream	$ 96	$ -	$ -	$ 96
Data Consistency Stream	760	510	-	1,270
Conflation Stream	375	375	190	940
Total	**$ 1,231**	**$ 885**	**$ 190**	**$ 2,306**

We are requesting approval to manage these costs within the framework of a deferral account mechanism, to be amortized in delivery rates over five years, commencing January 1, 2012. FEU believe that a five year amortization period is appropriate because it mitigates the rate impacts of the costs and generally coincides with the period over which the costs are incurred. The $2.3 million is an estimate of the total project costs; only the actual project costs will be recorded in the deferral account and ultimately recovered from customers. The costs to be incurred under this Project are one time in nature and have lasting value for customers, and are more appropriately reflected in a deferral account than through an increase in the base level of O&M. This will allow the Utilities to spread the costs out over a longer period better matching with the period that benefits will be realized. Furthermore, FEI is seeking approval to allocate the balance in this deferral account amongst FortisBC Energy Utilities on the basis of average customers, resulting in an allocation of 89 percent to Mainland, 10 percent to Vancouver Island and 1 percent to Whistler. The 2012 and 2013 forecasts as provided in Table 6.3-15 have been included in the deferral account for the purposes of determining the revenue requirements in this Application.

6.3.6 RESIDUAL DEFERRAL ACCOUNTS

The Utilities have included the following previously approved Residual deferrals in rate base for 2012 and 2013:

Table 6.3-16: Forecast 2012 and 2013 Residual Deferral Accounts[151]

2012 Forecast, Mid Year Balance, ($ thousands)					
Residual Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
SCP Tax Reassessment	$ 684	$ -	$ -	$ -	$ 684
Other	(63)	-	(23)	-	(86)
Residual Delivery Rate Riders	89	-	-	-	89
Mid Year Balance, Residual Deferral Accounts	**$ 711**	**$ -**	**$ (23)**	**$ -**	**$ 688**

2013 Forecast, Mid Year Balance, ($ thousands)					
Residual Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
SCP Tax Reassessment	$ 684	$ -	$ -	$ -	$ 684
Other	-	-	-	-	-
Residual Delivery Rate Riders	-	-	-	-	-
Mid Year Balance, Residual Deferral Accounts	**$ 684**	**$ -**	**$ -**	**$ -**	**$ 684**

6.3.6.1 Southern Crossing Pipeline Tax Reassessment

FEI continues to hold an amount for reassessment of PST related to the SCP project in a rate base deferral account, as approved by Commission Orders No. G-160-06 and G-153-07. In 2007, the Province of B.C. reassessed the Company for provincial sales tax related to the SCP project. The Company had made a deposit of $7.043 million in respect of this matter. During 2010, the B.C. Court of Appeal decided the appeal in the Company's favour. In August 2010, the Company received a refund of $7.049 million, representing a refund of the Company's

[151] Section 7.1 to 7.4, Schedule 69 and 71

Attachment 280.3

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 285.2

FortisBC
2013 Strategic Communications Overview

February 2013

Table of Contents

FortisBC 2013 Communications Planning Overview

1. 2013 Communication Planning Overview outline

The FortisBC 2013 communications planning overview sets out a strategy for delivering a broad range of integrated key messages for customers and British Columbians while facilitating a positive corporate reputation throughout the year and beyond.

A high-level communications strategy for FortisBC's business plan objectives will be outlined in addition to the strategy for each of the main four communications channels (employees; external relations; media relations; digital and paid media), keeping in mind that the purpose of this document is to provide a high-level strategic snapshot of the execution of the company's focus on customers and meeting their energy needs while delivering key business priorities. Individual communications plans will be prepared for each of the company's many initiatives.

1.1 Objective

The objective of FortisBC's 2013 communications activities is to provide key information to customers and all FortisBC audiences and to best utilize all channels.

Specifically, that FortisBC employees are knowledgeable ambassadors; that the company has strong relationships with stakeholders; and that it actively engages with our customers through our contact centres, community events, public consultation, the media and social media. Our integrated communications activities must address business challenges and leverage opportunities to support FortisBC's 2013 business priorities, including:

- Customer service
- Electric and gas businesses
- Growth opportunities
- Integration (and productivity)

Inherent in each of these priorities is FortisBC's ongoing focus on safety and environmental commitment; energy efficiency and conservation; government and First Nations relations; community investment; and employee retention and attraction.

1.2 Audiences

FortisBC has many business touch points and the audiences are broad. This 2013 communications overview focuses on the overall strategy for customers – builders and developers, the public, customers (residential, commercial, industrial) governments, First Nations, media, and employees. Individual plans will address specific channels and messages for greater, targeted segmentation.

1.3 2013 Business / Communications Challenges and Opportunities

The following 2013 business challenges and opportunities will be addressed in FortisBC's 2013 business and communications activities.

Challenges

- Low economic growth and lower customer attachment numbers
- Declining use (electricity and gas) per customers creating rate pressure
- The rate differential between FortisBC electrical rates and BC Hydro rates
- Activism regarding natural gas from shale, including celebrity commentary resulting negative media coverage
- Segment of customers protesting AMI application
- Low consumer awareness of energy options
- Customer expectations – one call resolution and mobile web
- Ensuring FortisBC managers are accountable to share communications content with their teams

Opportunities

- B.C. energy utility offering a variety of energy solutions, including electricity, natural gas and thermal energy solutions.
- Growth through system expansion to support natural gas transportation service for LNG export facility
- Long-term lower price outlook for natural gas
- Internal focus on safety and productivity
- Strong stakeholder relations (government; partner organizations and businesses
- Move to higher-profile public engagement tools to support public consultation
    - Use on-line channels and ads to increase public participation while benefiting from increased brand awareness

1.4 Corporate Message theme

FortisBC's commitment to being customer-focussed will be reflected in the overarching message for all of the organization's communications, *"Energy Solutions for every customer".*

This main message is being launched as the title of the company's corporate report to be distributed in March and will also serve as the overarching theme for the company's External Relations activities. It will be made relevant by supporting messages reflecting the key areas of the 2013 business plan to demonstrate how FortisBC products and services meet a variety of needs. Specific individual plans will include program specific messaging and information but all communications will be unified with the main message and appropriate support point.

1.5 Metrics

- Increased recognition of FortisBC information
- Increased positive and neutral/balanced media coverage regarding our products, services, and attributes such as safety, energy efficiency and community investment
- Increased third party comment about the company and acknowledging our role as an energy provider in B.C.
- Maintaining or further increasing 2012, nine per cent jump in customer satisfaction re: recognition of FortisBC ads
- Positive call centre verbatims (re: messaging from field staff and contact centre reps due to clear messaging)
- Minimize customer complaints
- Maintaining a solid employee and public safety record
- Increasing awareness regarding infrastructure upgrades and greater awareness about the need for maintenance and upgrades to enhance system reliability
- EEC and PowerSense reports (meeting targets set for individual programs)
- Recognition of FortisBC as a preferred place to work and as B.C.'s leading energy provider
- Surveying British Columbians in our service territory regarding their awareness of key safety information such as gas odour awareness and action and the need to Call Before You Dig.

2. High-level strategic approach

Being a well-known and well-respected energy provider will be the result of a customer-focussed business strategy, effective relationships and an appropriate amount of paid, earned and social media activities.

This plan sets a high-level communications strategy for FortisBC's 2013 priorities which require communications, including

- Customer service
- Electric and gas businesses
- Growth opportunities
- Integration (and productivity)

With collaborative communications planning across the company, based on the 2013 business priorities, FortisBC's message will be consistent throughout every communication and delivered through cost-effective; high-reaching channels:

- Employees
- External relations
- Media relations and social media, and
- Paid media

3. 2013 FortisBC Business Priorities

3.1 Customer Service

Strategy

As a customer-driven organization, FortisBC will continue to focus on simple, high-quality interactions for our customers and continuous improvement of processes from both a customer experience and efficiency perspective. Through research, FortisBC has learned that first contact resolution is directly correlated to customer satisfaction and that customers are looking for more self-serve options to manage their account and receive information.

The Customer Service communications strategy will focus on putting tactics in place to aid a first contact resolution as well as contribute to customer satisfaction. This will primarily involve information for contact centre reps in addition to digital self-serve solutions and ensuring all FortisBC communications are easy to understand; attractive and timely.

In the past year, the use of mobile devices to access the FBC website has increased 20 per cent. The communications strategy for 2013, will also ensure the website is mobile friendly and that the site is accessible without having to “pinch” or “zoom” to access content.

A more mobile friendly site is also key to ensure that customers have accessible and timely information about service outages at their fingertips, this is particularly important for electric customers where an outage would prevent web access via a computer. Enhancements are being made within electric operations to provide more rapid outage information to communications, contact centres and the executive to improve communications in this area. Rapid, clear communications helps the organization increase public understanding, awareness and support of our operations and demonstrates that we effectively manage issues related to our infrastructure and facilities.

Another aspect of the strategy is to communicate that we value customer feedback and we make the necessary changes to our business that reflects their feedback. A key opportunity for 2013 will be communicating to gas customers the move away from billing estimates to monthly reads.

High-level tactics

- Messaging for contact centre reps on all announcements and issues to better help answer customers’ questions efficiently during the first call
- Mobile-friendly web project
- Print bill and digital bill portal enhancement project to provide consistent information between the print and online bill statements in addition to incorporating new design elements that reflect customers’ feedback regarding the information that’s important to them. Graphics will be incorporated on the electric bills to show the steps from generation to distribution to increase the understanding of costs recovered through electricity rates
- Continue using social media, primarily Twitter to drive information to customers that follow the company’s Twitter feed. We also respond directly to customers who may make comments to or about our customer service; safety; energy efficiency or other timely topics
- AMI (electric) – communicating benefits such as timely and accurate reads as well as cost-benefit

- Regular review of research and web analytics to revise content, as appropriate, to reflect customer feedback

3.2 Electric and Gas Businesses

Strategy

Our ability to meet our customers' expectations around safe and reliable electricity and natural gas at the lowest reasonable costs is fundamental to their impression and satisfaction with FortisBC and to achieving our responsibility as an energy provider.

Results of recent FortisBC research indicated that both electric and gas customers want clearer communications explaining rates. There are a number of rate changes being implemented for gas and electric customers in 2013 that will need to be communicated clearly to avoid confusion.

The BCUC decision to deny rate amalgamation (Common Rates) means business will remain as usual; however, at this point it is not known if a re-consideration application will filed with the Commission or what this will mean for long-term rates on Vancouver Island. As a result of a number of regulatory decisions (Residential Conservation Rate; rate rebalancing and the 2012/2013 revenue requirement decision, electricity customers will notice an increase in their electricity bills, particularly as the latter two came into effect in January, one of the highest use months in heating season. A focus for 2013 will be helping electric customers understand different rate pressures for their bills.

The competitiveness of the electric base business is impacted by the spread between its rates when compared to BC Hydro's rates. Minimizing the company's rate increases with consideration for narrowing the gap between the company's electricity rates compared to those of BC Hydro's will position it to maintain reputation. Corporate positioning will be developed to be used, on an as needed basis, by executives and employees to explain the rate differential.

Strategic consideration needs to be applied with communications to ensure that a certain audience segment is not receiving too many messages and communications at a single time. This is a particular consideration for the 72,000 customers in the Interior which receive both electric and gas service from FortisBC.

The company already has annual communications programs in place to support PowerSense as well as the Energy Efficiency and Conservation initiatives. Both programs provide FortisBC with an opportunity to engage the public around effective strategies to lower their monthly energy bills. Through rebate programs and strategic partnerships, both groups allow customers to realize immediate savings, offset the cost of efficiency upgrades and facilitate choices that provide greater benefits to the environment and reduce future demand needs for the company.

Employee communications can support an internal safety culture but it is truly managers through face-to-face discussions that can drive change. The focus for employee communications will be supporting manager communications while continuing to highlight a set number of safety initiatives through the company's employee communications channels.

High-level tactics

Safety

1. Continue building awareness with all audiences about the company's commitment to safety. In 2013, Employee communications will support and build upon the work of the Environment, Health and Safety group and the Training department in managers having meaningful conversations with employees about safety. A set number of updates each month in existing communications channels will also be used to highlight achievements and to demonstrate safety as an integral part of FortisBC's culture.
2. A priority for 2013 is to further co-ordinate the Co-op Safety Program with the natural gas service territory safety paid media. Safety messaging for the electric service territory will also be augmented to include Dam safety and farm safety to better support public safety around those topics.
3. Focus group research taking place in Q1 will contribute to the development of new creative concepts to effectively drive targeted outcomes regarding gas odour awareness and Call Before You Dig awareness.

Reliability

1. Communicate with customers about key developments and infrastructure improvement projects including 2013 capital projects communications, scheduled work communications, and profiling of key growth and operations and maintenance projects. This could contribute to a better customer understanding of how rates are used by the company to invest in the safety and reliability of the system and how they benefit from growth.
2. Communicate improved electricity service reliability as a result of completed and planned capital project investments.
3. Maintain and enhance service outage communications, and build in messages to increase awareness about and reduce electricity "cold load" pick up issues helping address some issues our electricity operations team has identified.

Energy efficiency

1. Use paid, earned and social media in addition to attendance at community events to educate customers on energy efficiency and why we offer these programs.
2. Partner with others to promote joint initiatives and maximize earned media such as the, *Turn Down the Heat* campaign with the Business Improvement Associations of B.C.
3. Encourage energy conservation habits to even out power use patterns, especially during peak load times.
4. Further implement the use of PowerSense as the common energy efficiency brand in the shared service territory. Outside of the shared service territory, partner with BC Hydro for appropriate programs such as the Continuous Optimization program to create awareness for customers and to enable both organizations to enhance productivity.

Natural gas competitiveness

A paid media campaign and stakeholder outreach for consumers and builders and developers will be launched in the Fall to promote service improvements to reduce the cost of natural gas installations and wait times.

3.3 Growth

Strategy

FortisBC's product offerings in natural gas including natural gas for transportation and renewable natural gas, electricity and thermal energy solutions needs to be communicated to capture future growth opportunities.

The various product lines and services will continue to work strategically with Communications to build individual marketing communication plans for their respective programs or campaigns with customer retention and customer additions/growth being a priority. The results will be a seamless customer experience and ensure materials are presented in a similar tone and style that reinforces FortisBC's key corporate message(s). Our goal is to make all aspects of communications such as paid media, sales promotion, digital and social media work together as a unified force, rather than permitting each to work in isolation, which in turn will also maximize efficiencies in resources and cost effectiveness.

The first quarter will focus on early consultation with the product teams making planning for the year ahead more strategic than previous years. The advantages to this include being able to see more clearly any overlaps, look for efficiencies and adjust quickly to change. The second through fourth quarter will have a strong focus on the execution of the new natural gas creative platform, which will be incorporated through all gas customer campaigns where possible to ensure touch points with key customer segments.

High-level tactics

- Paid media campaigns promoting natural gas and creating awareness of all natural gas product lines
- Attending key industry; government and community events and managing all communications requirements
- Communications support for government relations activities
- Earned media and social media activities
- Messaging for the sales team
- Interactive marketing materials for the sales team
- With YouTube ranked as the second largest search engine, this year we will begin placing YouTube pre-roll video ads. These are short 15-30 sec videos used as an ad break before or during a YouTube video. Viewers can click on the ad at any time to learn more and we can track their engagement when they do. This is extremely cost effective as we only pay for those who click the ads. Additionally the ad placement is based on geographic, demographic and psychographic filters which allows for very targeted placement.

3.4 Integration and Productivity

Strategy

These efforts are primarily content for internal communications with employees.

Significant progress was made in 2012 regarding the integration of the electric and natural gas business, including a single point of leadership for the gas and electric operations in the Interior.

The next phase in building a common culture will look at a culture of productivity that will emphasize managing costs and working more efficiently and effectively with an outlook to facilitating growth opportunities. FortisBC will continue manage the workforce size through attrition and promote the use of internal hires to create opportunity for committed employees willing to take on new challenges.

High-level tactics

- Leadership Forum where company leadership was updated on the need to change and culture of productivity by the Executive Leadership Team
- Spring (March / April) visits by the Executive Leadership Team to employees across the service territory
- Continuing to create internal awareness about the Employee Talent Portal and internal postings
- Developing a common Intranet hosted on SharePoint (launch Spring 2014)
- Employee events that bring employees together and also provide an opportunity to support local communities such as the *Moving Mountains* event organized by employees across the lines of business

Metrics

- Number of employee suggestions for alignment and integration opportunities
- Number of employees participating in training; registered in the talent portal and using the education policy to gain skills to advance and transition into new roles within the organization
- Employee feedback re the spring Executive Leadership Tours
- Annual employee survey feedback
- Solid customer satisfaction scores
- Positive call centre verbatims
- Minimal negative media coverage of customer complaints
- Recognition of FortisBC as a preferred place to work and its key role as an energy provider

4. Communications Channels

4.1 Employees

Strategy

Ensuring employees are educated FortisBC ambassadors supporting a common, integrated culture reflecting safety, customer service and productivity. Employees will receive information to ensure they are aware of FortisBC's business activities including providing customers with electricity, natural gas and thermal energy solutions. All FortisBC employees will receive information through communications delivered by channels including face-to-face with their manager and company leadership.

High level tactics

- In Q1, Executive Leadership Team members will visit with employees in the different service regions to provide them with a common understanding of the company's 2013 business priorities and review 2012 successes.
- Internal campaigns on rates, safety, energy efficiency and product knowledge will also be rolled out on a quarterly basis in advance of similar external campaigns in addition to quarterly internal Scorecard updates.
- Employee communications will continue to foster a safety culture for all aspects of work including safe work planning and proper personal protection equipment. The *Drive to Zero avoidable incidents* campaign will continue and in Q1 a *Move Safe* campaign will be launched to help reduce twists, sprains and strains. Employees will also be provided with information to about energy efficiency and conservation with an awareness to the different programs offered and the company's business reasons for offering these types of programs.
- Further supporting integration and a common culture, the company will move to a new, single intranet site hosted by SharePoint effective spring 2014. Work over the next year, will see content from the existing electric (Iris) and gas (Pipeline) sites merged together with the Employee News Portal as a basis for the new common site.
- Reflecting feedback from employees, fewer editions of the *Connections* newsletter will be produced and printed. Team members at the Burnaby and Prince George Contact Centres will move to digital access and copies will be placed in the lunchrooms. Electronic Bulletin Boards were piloted in 2012 but given employee feedback, it is unlikely that these will move forward as a channel for 2013. Prep packs and other updates/messaging will be provided to help managers speak to their teams about key initiatives. An accountability metric should be explored to ensure managers are delivering information to teams in a timely manner.
- Communications will continue using a grassroots approach to highlight employee customer service achievements. The Executive Leadership Team (ELT) will be involved in informally recognizing employees whose names have been brought forward as a result of a customer, their manager or another contact.
- Employees will continue to be educated about the value of their compensation (pay and benefits) and how it compares to the market. Information about direction from the BCUC regarding productivity and managing rate pressures for customers will also be communicated. All employees will receive labour negotiation updates from the company so it can provide neutral, balanced updates to increase the level of employee education around bargaining.

4.2 External Relations (Community, Government and Aboriginal Relations)

Strategy

FortisBC will continue to create awareness and recognition for our ability to provide customers with electricity, natural gas and thermal energy solutions. Information will also be communicated about our role in investing in communities across the province, creating jobs and contributing to the social fabric of the communities in which we operate.

In 2013, External Relations and Communications are building on initial activities established in 2012 to work together and better support FortisBC through an integrated public affairs strategy. This will result in better leveraging our investment (labour and dollars) to support all audiences.

High-level tactics

All 2013 events will have met assessment criteria to ensure they target specific customers and audiences to promote and align with 2013 key messages and the company's corporate report. Media relations and social media will be used to capitalize on these face-to-face interactions ensuring further delivery of these messages to audiences. Also, FortisBC will submit opinion-editorial pieces in newspapers to further leverage key engagements. For 2013, more live tweeting will be activated during events.

- A key deliverable in 2013 will be a FortisBC executive speaking tour with Spectra Energy promoting the benefits of natural gas to different regions of the province at local Chambers and business associations. By increasing energy literacy, British Columbians will be better able to understand the positive impact of natural gas to the economy and job creation as well as the province's stringent regulations around production from traditional and non-traditional sources. The program puts forward another perspective as opposed to the criticism of the sector projecting misconceptions regarding perceived environmental impacts. Social and traditional media coverage is activated for each engagement.

Other notable speaking engagements include an international LNG conference hosted in Vancouver by the Government of B.C.; Local Area Association meetings and the Union of British Columbia Meeting.

- A move to higher-profile public engagement tools to support public consultation. By using on-line channels and ads public participation will increase. It will involve redirecting some public consultation budget to paid media dollars. A public information site hosted on the Vancouver Sun / Province site will be piloted for an initiative in late 2013 or 2014. The results will be assessed prior to further initiatives being undertaken. The BCUC confirmed support for this approach in Q1 2013.

- A co-ordinated campaign will be launched with Municipal stakeholders and MLAs.
    - The messages, themes and images from the 2012 Corporate Report will be introduced at the local area association meetings and then the annual Union of British Columbia Municipalities convention scheduled for September. Digital copies will be provided to community leaders in March / April and all MLAs. Following the provincial election in May, digital copies will be sent to any new MLAs along with an introductory note.
    - In all interactions, Community / Aboriginal Relations Managers will deliver key messages touching on:
        - Energy Solutions for every customer
            - Safe, reliable energy at the lowest reasonable cost
        - Opportunities for NGT; high-efficiency equipment and integrated energy options
        - Energizing communities through economic impact; job creation and community investment.
- In 2013, Executive Leadership Team (ELT) members will be provided with greater opportunities to engage with communities.
    - Community engagement meetings will be scheduled to coincide with employee visits
    - Speaking engagements will be promoted
    - ELT briefing notes on priority aspects of the company's operations and energy policy will be available for ELT to use as a speaking resource.

4.3 Media relations and digital

Strategy

Proactively drive out media stories which further FortisBC's commitment to a customer service culture (rates; safety and energy efficiency); growth (electricity, natural gas and thermal energy solutions) and support for communities. Media coverage often includes third party validation from business partners or community leaders, helping to increase message opportunities.

FortisBC actively pursues and maintains relationships with key media outlets to promote volume and tone of coverage while also leveraging paid media activities. FortisBC's customer service culture is the driving philosophy with the company's relations with the media. The company media line is answered 24 /7 and all calls are to be returned within minutes. Team members are active in meeting the media outlets needs while driving out the company's message.

Continue using social media to interact with media and customers, primarily through Twitter. This provides direct two-way communication and enables the company to drive out information about emergency response; rebates; customer-focused information and community investment and events. It also can help mitigate customer service issues when dealt with promptly and ending in a positive customer experience. Customers are provided with the ability to share information through re-tweeting; bring service issues to our attention and compliment the company, often this occurs once a service issue has been resolved.

The digital strategy is designed to enhance the customer service experience and provide more self-serve options for customers, including accessing the site with mobile devices.

High-level tactics

- Proactively developing and fostering relationships with editors and reporters to present earned media opportunities
- Ensure corporate report photos and other high quality photos of key business initiatives are available in the FBC media centre on FBC.com
- Ensure digital clips of FortisBC key projects and business initiatives are readily available to be used by media as b-roll. This includes having images available at events through the use of QR codes on hard copy releases and footage on jump drives, handed out to media at events
- Ensure key messages are updated and available to quickly respond to media inquiries
- All corporate communications team advisors are challenged to drive one piece of positive earned media each week in addition to planned FortisBC announcements
- Ensure business partnerships have a joint media opportunity to increase positive coverage
- Update all employees on the media policy card to ensure every media call is directed to the corporate communications advisors, to provide information to media
- In conjunction with business units, ensure that briefing notes are prepared on key and new areas of the business for distribution and used by ELT members to prepare them for any media calls or speaking opportunities
- Using tweeting to forward all media announcements and events
- Revising the website based on usability findings and research outcomes including making it regionally focused

4.4 Paid media

Strategy

Paid media guarantees the timing and complete context of information to be communicated. The use of paid media is to increase public information and knowledge around key topics that reflect customer research and satisfaction studies in addition to public awareness requirements as set out in regulation. In 2013, FortisBC will use paid media to provide information on topics ranging from safety, energy efficiency and conservation; customer service offerings and product information.

All paid media efforts are leveraged through relationships to gain value such as additional placements or earned media. A strategic priority for 2013 is to develop and foster additional relationships to increase investments made. As well, remnant or “last minute” media space will be purchased for small campaigns to further leverage the spend. This strategy also supports FortisBC’s internal culture of productivity. The use of paid digital media will be explored in 2013. More and more customers have expressed they look for information the web first. Such items as Google ad words, YouTube pre-roll ads, leveraging social media advertising strategies, etc. could be effective in reaching those audiences. FortisBC will build on changes implemented in 2012 to the messaging and look and feel of paid media and collateral. Over the first half of 2012, these changes resulted in a nine per cent increase in a rating on the customer satisfaction measurement.

In the Interior, energy efficiency for gas and electric will be promoted under the PowerSense name (with costs coded back to the appropriate business.) This provides customers with a more concentrated and aligned energy efficiency and conservation message, increased customer service; joint webpage for program inquiries and a streamlined application process. This will create efficiencies through shared costs for items such as events, promotional materials and print ads in local newspapers. Outside of our shared service territory, we will be moving to co-branded materials for the joint work being done with BC Hydro, PowerSmart, where it makes sense to do so.

High-level tactics

- Focus group testing to develop new creative in support of the company's gas safety messaging (gas odour and Call Before You Dig)
- Focus group testing to ensure the company's natural gas consumer information messaging is effective in communicating the benefits of using natural gas
- Leverage awareness from the Canadian Gas Association's paid media campaign in support of the Canadian Natural Gas initiative. The campaign ads demonstrate the contributions of natural gas to the daily life of Canadians and its economic benefit
- Further develop a series of ads on key topics that can be used throughout the year to reduce labour and production costs
- Continue to produce ads that feature customers and quotes from third parties as customers respond well to this approach
- To feature our business partners in our advertisements to also communicate our scope of impact in local communities and the B.C. economy
- To build joint graphic standards with BC Hydro to promote our combined energy efficiency initiatives in paid media; events and online
- Continuing to promote PowerSense as the joint brand for FortisBC's electricity and natural gas energy efficiency offerings in the Interior

Attachment 286.1

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 288.1

UNION OF B.C. MUNICIPALITIES
Suite 60 - 10551 Shellbridge Way
Richmond, B.C. V6X 2W9

Tel: (604) 270-8226 Fax: (604) 270-9116
Email: ubcm@ubcm.ca

REQUEST FOR PAYMENT

REQ. #: CS-1211

DATE: 2012-06-27

YOUR P.O. #

TO: Amy Hennessy
Community & First Nations Relations Manager
Fortis BC
16705 Fraser Highway
Surrey, BC V4N 0E8

RE: Sponsorship of the Annual UBCM Convention
Victoria, BC
September 24 – 28, 2012

- **Banquet Reception**
- **Banquet Entertainment**

AMT DUE: **$15,000.00**

Notes:

Amy Hennessy
681331 63112

A. HENNESSY

Please return a copy of this statement with payment to the above address. Any questions regarding this statement can be directed to Kathleen, Manager of Finance & Corporate Operations.

Maraway Holdings Inc. - Promo Sales
12 - 1560 Prince Street
Port Moody, BC V3H 3W8

Invoice

GST Registration #: 874717 5441 RT0001
PST Registration #: R809100

Invoice #: 00001162

Bill To:

Fortes B.C.
16705 Fraser Hwy
Surrey B.C.

Ship To:

Fortes B.C.
16705 Fraser Hwy
Surrey B.C.

SALESPERSON	YOUR NO.	SHIP VIA	COL	PPD	SHIP DATE	TERMS	DATE	PG.
Wayne Yack			X			C.O.D.	10/2/2012	1

QTY.	ITEM NO.	DESCRIPTION	PRICE	UNIT	DISC %	EXTENDED	TAX
1,100	HG425	Deluxe 15oz Stemless Wine Glasses	$3.85			$4,235.00	B
1	09	Set-up Charge	$20.00			$20.00	B

681331 63403

Angel Hennessy

CODE	PST RATE	AMOUNT	GST RATE	AMOUNT	SALE AMOUNT
B	12%	$536.92	0%	$0.00	$4,474.33

SALE AMOUNT	$4,255.00	
FREIGHT	$219.33	B
GST	$0.00	
PST	$536.92	
TOTAL	$5,011.25	
PAID TODAY	$0.00	
BALANCE DUE	$5,011.25	

Memo: Thank You Very Much for Your Business

UNION OF B.C. MUNICIPALITIES
Suite 60 – 10551 Shellbridge Way
Richmond, B.C. V6X 2W9

Tel: (604) 270-8226 Fax: (604) 270-9116
Email: ubcm@ubcm.ca

REQUEST FOR PAYMENT

YOUR P.O. # ______________

REQ. #: CS-1301

DATE: 2012-12-12

TO: Amy Hennessy
Community & First Nations Relations Manager
FortisBC
16705 Fraser Highway
Surrey, BC V4N 0E8

RE: Corporate Sponsorship of the 2013 UBCM Annual Convention
Banquet Reception & Banquet Entertainment - DEPOSIT
Vancouver, BC
September 16 – 20, 2013

AMT DUE: **$15,000.00**

Notes:

Please return a copy of this statement with payment to the above address. Any questions regarding this statement may be directed to Kathleen Spalek, Manager of Finance & Corporate Operations.

Attachment 291.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 304.1

FILED CONFIDENTIALLY

Attachment 308.3

Decision 2007-017

EUB Proceeding

Implementation of the Uniform System of Accounts and Minimum Filing Requirements for Alberta's Electric Transmission and Distribution Utilities

March 6, 2007

Alberta Energy and Utilities Board

ALBERTA ENERGY AND UTILITIES BOARD
Decision 2007-017: EUB Proceeding
Implementation of the Uniform System of Accounts and Minimum Filing Requirements for Alberta's Electric Transmission and Distribution Utilities
Application No. 1468565

March 6, 2007

Published by
Alberta Energy and Utilities Board
640 – 5 Avenue SW
Calgary, Alberta
T2P 3G4

Telephone: (403) 297-8311
Fax: (403) 297-7040

Web site: www.eub.ca

Contents

List of Tables

ALBERTA ENERGY AND UTILITIES BOARD
Calgary Alberta

EUB PROCEEDING
IMPLEMENTATION OF THE UNIFORM SYSTEM OF ACCOUNTS AND MINIMUM FILING REQUIREMENTS FOR ALBERTA'S ELECTRIC TRANSMISSION AND DISTRIBUTION UTILITIES

Decision 2007-017
Application No. 1468565

In Bulletin 2006-25 issued on July 12, 2006, the Alberta Energy and Utilities Board (EUB or Board) approved in principle the form and content of consensus Uniform System of Accounts (USA) and Minimum Filing Requirements (MFR) documents (Consensus Documents). The consensus USA and MFR documents were the result of a USA-MFR collaborative process that the Board had established by letter dated December 6, 2004. Concurrent with its approval of the Consensus Documents, the Board also indicated that a public process would be conducted to determine whether it would be in the public interest to proceed with the implementation of the USA and MFR for the regulated electric utility companies in Alberta.

By letter dated August 29, 2006, the Board advised interested parties that it had initiated Proceeding No. 1468565 to address whether implementation of the USA and MFR would be in the public interest.

In this Decision, the Board discusses issues pertaining to the implementation of the USA and MFR and provides the reasons for its decision to direct the regulated electric transmission and distribution utilities in Alberta to proceed with the implementation of the USA and MFR.

1 INTRODUCTION AND BACKGROUND

1.1 EUB Process and Schedule for Proceeding 1468565

On August 29, 2006, the Board issued a letter which outlined the issues to be addressed in the proceeding along with the process schedule to be followed. The process provided for an oral hearing to commence on November 28, 2006.

On November 6, 2006, the Board issued further correspondence to parties to provide direction respecting the scope of the USA-MFR proceeding, and, in particular, to address issues raised by parties respecting the extent to which benchmarking should be made a focus of the proceeding. In this regard, the Board advised that:

> In the Board's view, the hearing concerns the USA and MFR. It is not a hearing respecting benchmarking. In the Board's view, investigation of issues should be focused on whether the development of a common 'language' (USA) and presentation (MFR) is of benefit to utilities, customers and the Board and whether USA and MFR will assist in providing a tool that will enable parties to readily understand trends in the costs and descriptions of costs. In the Board's view, benchmarking may be one of many related issues with respect to USA and MFR. Evidence, questions and argument submitted in this

> regard may be germane to determining whether the benefits to implementing a USA and MFR are justifiable in relation to the estimated costs of implementation.[1]

On November 22, 2006, six days before the scheduled commencement of the oral hearing, AltaLink Management Ltd. (AltaLink) advised that it had "…revised its proposed approach to implementing USA/MFR from a Coding Block[2] approach to a Special Ledger (SL) Allocation[3] approach".[4] AltaLink included a revised cost and timeline estimate for the proposed SL Allocation approach. AltaLink went on to advise that "…the information responses provided have also been answered in the context of the SL Allocation approach".[5]

The Board responded to AltaLink's revised filing submission on November 24, 2006. The Board determined that if AltaLink's proposed SL Allocation approach to implementing the USA and MFR had been filed on September 29, 2006, the date by which the utilities' cost submissions were due, it may have generated information requests (IRs) different from those that were put to AltaLink in respect of AltaLink's Coding Block approach. As such, AltaLink's responses to the IRs in the context of the SL Allocation approach may not have provided the Board and parties with a complete understanding of AltaLink's SL Allocation approach. Consequently, the Board rescheduled the oral portion of the hearing in order to provide parties with the opportunity to investigate and consider AltaLink's SL Allocation approach. The proceeding was rescheduled to include an interrogatory process related to the AltaLink SL Allocation approach and a new hearing date of December 4, 2006 was set.

In addition, the Board advised that in the event expert witnesses were not required to attend the hearing because no parties wanted to cross-examine them on their evidence, these witnesses could confirm their evidence by affidavit. As a result, the following expert witnesses confirmed their evidence by affidavit:

- Mark Lowry (for FortisAlberta Inc.)
- Johannes Pfeinfenberger (The Brattle Group for AltaLink)
- William Marcus (for AAMDC/AFREA/CCA/PICA)

Oral argument and reply was completed on December 7, 2006. Accordingly, the Board considers that the record of Proceeding 1468565 closed on December 7, 2006.

---

1 Exhibit 079, Page 2

2 The ERP software (SAP, PeopleSoft) accumulates costs in cost elements / general ledger accounts in order to comply with Generally Accepted Accounting Principles (GAAP) classification of costs and revenues. A second field (cost centre, project, or work order) is used to subdivide accounting detail for those charges related to expense transactions. These two fields are generally defined as the SAP accounting coding block. Coding Block Extension requires modifying the standard SAP software to add an additional field to the accounting coding block to capture the USA activity code.

3 The utility would maintain its existing chart of accounts and associated planning and data collection processes and report to the EUB in the MFR format after allocating costs into USA activities. This involves the development of an allocation methodology to divide the operating expense accounts into their USA account classifications.

4 Exhibit 095, Page 1

5 Ibid

2 DEFINITION OF THE ISSUES

The Board's final issues list and ranking are contained in the table below.

Table 1. EUB Ranked Issues List

	Issue Identifier	Board Ranking
1	Utilities' Cost for Implementation	High
2	USA-MFR Benefits	High
3	Decision Methodology	Medium
4	Affiliates Cost	Low
5	Cut-over Date	High
6	Transition Plan for Regulatory Filings	High
7	Applicability to Smaller Utilities	Low
8	Monitoring of Utilities' USA Implementation Process	Low
	Issue added as a result of Participants' Feedback	
9	Future Review Processes	Low

This information was conveyed to parties in a letter dated September 22, 2006.

3 DISCUSSION OF THE ISSUES AND CONTEXTUAL BACKGROUND

During the course of the proceeding the Board provided parties with its views with respect to the matters under consideration. Some of these views have been repeated in this Decision to assist in establishing the context of the discussion of the issues that follow.

The Board advised parties that the purpose of this proceeding was not to approve the utilities' cost estimates. The prudence of a utility's implementation costs will be assessed when that utility's USA deferral account is reviewed and reconciled either through its General Tariff Application (GTA) process or as part of a separate process. The type of cost scrutiny to be undertaken at this stage is different than that undertaken to test forecast costs under a GTA.

The Board urged parties to focus their attention on assessing the cost estimates for reasonableness with the aim of incorporating their conclusions into a recommendation as to whether moving to a USA-MFR environment makes sense from an overall public interest perspective.

The Board has addressed the issues listed in Table 1 of the previous section in their order of ranking from high to low.

3.1 Utilities' Cost for Implementation

The Board is interested in understanding the degree of confidence that can be placed on the utilities' cost estimates, the possible variance that could be expected in the implementation costs, and the framework for monitoring implementation costs.

In order to establish a degree of confidence in the estimates, it is necessary to understand whether the proposed functionalities and associated costs are necessary for the implementation of the USA and MFR. The Board considers that the framework for monitoring implementation costs, as those costs are incurred, is also an important factor in assessing the degree of confidence to be attached to the utilities' implementation cost estimates. The Board will address the cost monitoring framework later in this Decision.

To understand the degree of confidence that it should place on the utilities' cost estimates, the Board examined the cost estimates from the following perspectives: Overall Approach, Project/Work Plan, Feasibility of Solution Proposed, Compliance with the USA and MFR, Budget, and Risk Management. Some general observations resulting from the Board's high-level review are contained in the following sections. While these observations were useful in helping the Board determine the degree of confidence to be attached to the proposed cost estimate, they also will provide guidance to the utilities as they proceed with the implementation of the USA and MFR. The Board expects the implementation cost monitoring process to have regard for these observations.

3.1.1 EPCOR Cost Estimates and Implementation Plan

EPCOR Distribution Inc. (EDI) and EPCOR Transmission Inc. (ETI) use an Oracle financial accounting system that is activity cost based. This has positioned EDI/ETI to readily meet the USA-MFR requirements.

EDI/ETI presented a comprehensive, detailed cost estimate that outlined precisely what steps would be taken, the rationale for these actions and the effort required to implement them. The Board finds the EDI/ETI plan to be reasonable. It allocates adequate time for testing and confirmation and can be completed in a very short time. The budget presented by EDI/ETI is reasonable and economical. Oracle skills (IT) costs of $100/hour may be on the low side of current market rates, but given the estimated number of 500 hours related to this cost, an increase in the hourly rate will not materially affect the budget. The Board also finds that the minimal training costs and no increase in ongoing maintenance costs projected by EDI/ETI meets the Board's expectations given EDI/ETI's starting position.

3.1.2 ENMAX Cost Estimates and Implementation Plan

ENMAX Power Corporation (EPC) uses PeopleSoft financial applications. The approach proposed by EPC involves the use of a new chart field in PeopleSoft which EPC has determined to be the optimal approach. EPC has provided a risk management plan that identifies most risk factors and mitigation strategies.

EPC's submission should meet the requirements of the USA and MFR as there are no significant technical or operational challenges to prevent the achievement of this objective. Although seemingly expensive, the Board finds this option to be a reasonable way for EPC to achieve USA-MFR compliance.

The cost of implementation proposed by EPC for a modification of their financial system is significantly lower than that proposed by FortisAlberta. However, it is still an expensive proposition. Therefore, budget areas should be closely examined for cost saving opportunities. Such areas could include: Project Set Up ($250,000), Analysis, Change Management, Training (it is not a new implementation), and Transition. EPC's assumption that resources utilized 25% or greater on the implementation project will be backfilled, is still not clearly understood. It remains unclear exactly how EPC will account for the cost of their time as well as the degree to which jobs have been backfilled. As well, the job descriptions for the full time equivalents (FTEs) for Sustainment, at a projected cost of approximately $1,000,000 from 2008-2010, remain unclear. Last, the proposed project schedule appears too long. EPC has forecast close to 3 months of project set-up activities and significant transition time for a system augmentation. While such extended durations are understandable for a new implementation, they may not be necessary for customization.

The Board directs EPC to carefully review the project plan to ensure the managerial effort applied is consistent with the scope of work.

3.1.3 ATCO Electric Cost Estimates and Implementation Plan

ATCO Electric (AE) uses an Oracle financial accounting system that is activity cost based. AE's cost accounting and financial systems are similar to the Federal Energy Regulatory Commission (FERC) Code of Accounts on which the USA was based. In addition, AE's 2005-2006 GTA filing was used as the model for the MFR Consensus Document filed with the Board. Therefore, AE does not require significant process or information system modifications to meet the USA-MFR requirements.

The Board acknowledges that AE's plan will readily meet the USA-MFR requirements. However, AE should take a closer look at its forecast costs. The plan, on its face, provides insufficient detail to support a cost claim of $400,000 of which $100,000 is for training costs. The minor changes and verification required by AE can be considered very low risk yet AE's proposed implementation cost estimate is higher than that of EDI/ETI. With nominal system changes, $100,000 in training costs appears high.

3.1.4 AltaLink Cost Estimates and Implementation Plan

AltaLink operates on an SAP platform.

AltaLink determined that it was feasible to develop allocation methods for those relatively few accounts that required allocation to the USA accounts, which would reasonably approximate the costs that would have been captured by its original coding block extension (CBE) approach. AltaLink noted that 10% or less of its annual revenue requirement, which constitutes some 40% of its operating and maintenance (O&M) costs, would need to be allocated.

AltaLink rejected the suggestion that the allocation of costs to the USA categories in those few instances where AltaLink does not directly capture costs, is inherently inaccurate or negates the objectives of the USA and MFR to have all electric utilities file costs on a consistent basis. AltaLink noted the following:

- Allocation of costs is not unique to AltaLink. The Office of the Utilities Consumer Advocate (UCA) and the Alberta Urban Municipalities Association (AUMA) witness testified that many U.S. utilities that use the FERC-based USA allocate costs in identical categories and in a greater number of accounts than will AltaLink;
- Allocating costs on the basis of properly developed factors which reflect the factors actually driving the costs does not detract from the precision of capturing those costs. The UCA/AUMA, based on a review by its experts, was satisfied that the required level of accuracy will not be sacrificed by the allocation of costs in the manner proposed by AltaLink;
- Supervisory costs need to be allocated in any event; and

- There will be a transparent and collaborative process to develop allocation methods and factors.

AltaLink's SL Allocation approach did not have the broad support of the parties.

The Industrial Power Consumers Association of Alberta (IPCAA) asserted that the kinds of allocations contemplated by AltaLink were not consistent or compliant with the USA and MFR. IPCAA acknowledged that allocations cannot be avoided, but was of the view that they were used mainly for very minor accounts and expenditures. IPCAA disagreed with the UCA/AUMA that FERC filing utilities have a lot of allocations. It was IPCAA's view that one of the fundamentals around the FERC activity based accounting system and the use of work orders and other such instruments, is to eliminate allocations. IPCAA urged the Board not to approve AltaLink's SL Allocation proposal. IPCAA viewed AltaLink's SL Allocation approach as a compromise to the Consensus Documents and submitted that such compromise could eliminate the perceived benefits of comparability, transparency and consistency. This would result in the worst of all worlds, where significant implementation costs would have been incurred and none of the potential indefinable benefits are achieved. IPCAA was supportive of AltaLink's more rigorous CBE approach provided there was proactive scrutiny of the implementation costs. IPCAA appeared to be of the view that although the CBE costs were higher, the potential benefits would be greater than if the SL Allocation approach were adopted.

The AACP (Alberta Association of Municipal Districts and Counties, the Alberta Federation of Rural Electrification Associations Ltd., Consumers Coalition of Alberta, and the Public Institutional Consumers of Alberta) considered AltaLink's SL Allocation approach to be incomplete. Therefore, it was reluctant to accept AltaLink's compromise proposal because of the effect the proposal may have on the overall usefulness of the entire USA-MFR process. The AACP urged the Board to reject the proposal and direct AltaLink to reassess the original and other appropriate alternatives. The AACP had the following specific concerns with AltaLink's SL Allocation approach:

- It is not in compliance with the principles of the USA and MFR and was not an approach that was accepted by the USA-MFR Committee;
- Allocation was rejected by AltaLink (originally), FortisAlberta and EPC as not meeting their selection criteria. These utilities considered that transparency, data integrity and support for variance analysis would be difficult to achieve due to the nature of allocating costs between business units and activities;
- Flexibility for change may be difficult to achieve;
- Allocations do not adequately address the USA General Instruction 9 relating to charging actual time to classes of work;
- It requires the updating of allocation studies; and
- Organizational changes compounded by changes in the USA and MFR would become unwieldy.

EDI/ETI submitted that although minimizing the cost of implementation is a very important objective, the Board should be wary of adopting lower cost approaches that could fall short of meeting the objectives and expected benefits of the USA and MFR. EDI/ETI cautioned that adopting approaches that might rely too heavily on allocations for the sake of mechanically matching the USA-MFR format, could diminish regulatory efficiency by creating the need for duplicate accounting and by also adding further layers of allocations which have historically been sources of controversy and contention among parties. In addition, too much allocation could result in losing significant clarity and transparency, and ultimately, a significant loss of regulatory efficiency. However, because EDI/ETI did not review the SL Allocation proposal in detail, it could not determine where on the allocation continuum that proposal might lie.

AE was of the view that the common filing format of the USA and MFR should also facilitate the review of filings by both the Board and interveners. However, AE submitted that if approaches that allocate a significant portion of operating expenses are adopted, even those potential benefits would be diminished. AE noted that operating expenses are typically the focus of interest in general tariff applications and asserted that they were likely the primary focus of the USA-MFR initiative.

FortisAlberta indicated that it wanted and would welcome the Board's direction to look at its Alternative 4, which was also an allocation approach. FortisAlberta noted that contrary to IPCAA's assertion that AltaLink's SL Allocation approach was not compliant with the USA and MFR, there was evidence from the UCA on this point. FortisAlberta noted that General Instruction 9 of the USA states that cost tracking is to be done to the extent practicable, which requires the exercise of judgment. FortisAlberta further noted that the Board, as the overseer of the USA, would define what was practicable and what constituted compliance.

The UCA/AUMA indicated that based on the detailed review of its consultants, it was comfortable that the SL Allocation proposal met the requirements of the USA and MFR without loss of transparency and accuracy. They noted that the proposal has far less allocations than the companies that are regulated by the FERC. The only concern of the UCA/AUMA related to the determination of the allocation methodologies and factors. They wanted the Board to direct a collaborative process to establish the allocation methodology and factors to be used.

The Board notes that although AltaLink's SL Allocation approach will cost less than its original CBE approach, it still involves significant costs. Therefore, prudence would suggest that AltaLink should only proceed with its SL Allocation proposal if it can be reasonably demonstrated that the amount of accounts and expenditures to be allocated are such that potential benefits of the USA and MFR will not be diminished or eliminated.

Unfortunately, this determination cannot be made using the current record. Details on the amount and type of accounts to be allocated and, more importantly, an indication of possible allocation methods and factors are missing. As such, the Board considers AltaLink's SL Allocation approach to be incomplete. In the Board's view, the conceptual nature of AltaLink's SL Allocation proposal and its heavy reliance on a future process to determine appropriate allocation methods and factors casts doubt on the wisdom of proceeding with the SL Allocation approach. There is no certainty that the allocation methods and factors, when determined, would be robust enough to withstand the passage of time between GTAs. This could result in the allocation methods and factors becoming sources of contention in future GTAs. Consequently, the potential clarity and regulatory efficiency benefits of the USA and MFR could be in jeopardy, particularly if consensus cannot be reached during the collaborative process.

The Board acknowledges that some amount of allocation is unavoidable. However, the Board firmly believes that when it comes to allocations, less is better. Allocations should only be made when there is no other feasible alternative. For the sake of implementation cost savings, AltaLink's SL Allocation approach introduces allocations in areas that have traditionally been sources of controversy and contention among parties. The Board is not convinced that the SL Allocation approach will deliver the potential benefits of the USA because it allocates a significant portion of the O&M expenses, which is usually a major focus of AltaLink's GTAs. In the Board's view, the additional O&M allocations increase the probability of ending up with the worst of all worlds that IPCAA alluded to, with the result that adopting the SL Allocation approach could end up costing more in the long run.

In contrast, AltaLink's original CBE approach is more costly to implement, but contains a minimum amount of allocations. This suggests that unless implementation costs were an overriding factor in the determination to proceed with a USA and MFR, the CBE approach would be preferable to the SL Allocation approach.

The Board notes IPCAA supported the CBE approach provided there was proactive scrutiny of the implementation costs. In section 3.8 of this Decision, the Board discusses the need for an independent consultant to monitor and report on the implementation process.

3.1.5 FortisAlberta Cost Estimates and Implementation Plan

FortisAlberta, like AltaLink, operates using an SAP platform. The submission by FortisAlberta proposes the implementation of the Profit Centre Accounting (PCA) module of SAP to meet the USA-MFR requirements. This solution has been identified by FortisAlberta as the most economical of the alternatives that meets the needs and preserves the integrity of the core SAP system. Other alternatives were not explored to any meaningful extent.

The Board accepts that the solution proposed by FortisAlberta will meet the requirements of the USA and MFR.

FortisAlberta indicated that the implementation period of the PCA module will occur from May 2007 to June 2009. Of note is that all project work from May – December 2007 is for the SAP Upgrade. Since the upgrade is being done with the view to adding the PCA module in 2008, there appears to be an inordinately long period for the addition of a module when such extensive system/business analysis has recently been completed for the upgrade.

The proposed budget for the implementation of this solution is very high and the Board has several observations respecting the estimated costs. To begin, the plan contains phases for a Technical Upgrade and System Stabilization at a projected cost of $3 million. These activities are associated with a business as usual SAP upgrade and though a prerequisite to the addition of the PCA module, the costs of this SAP upgrade should be separated from the estimate for USA-MFR compliance. In addition, under the costs claimed for maintenance of the USA-MFR system, FortisAlberta indicated a need for 10 FTEs at an annual cost of $1.6 million yet failed to provide job descriptions to support the need for these resources. As well, the Business Blueprint phase of the project appears to be extensive for a system augmentation initiative. The Board notes FortisAlberta's evidence that the plan was developed by IBM and that the details were not available. Further, FortisAlberta did not provide the confidence factor or assumptions on which the plan is based. Given these limitations, the Board considers this plan to be very preliminary and not necessarily an accurate reflection of the effort required to implement the recommended solution. As such, there appears to be numerous areas for potential cost reduction/containment.

FortisAlberta has indicated that the risks associated with this initiative have not yet been properly examined so mitigation strategies could not be developed. For the risks identified in the USA-MFR cost estimates (Availability of Skilled Resources, Implementation Based on New SAP Technology, and Impact on FortisAlberta Business), very little has been presented in the way of mitigation.

Risk is defined as the possibility of suffering harm or loss. The Board views risk as it pertains to the USA-MFR implementation as the possibility of an event, or series of events, jeopardizing the utility's ability to meet the goals of the project. These goals include completing the project during the timeframe that has been established with the resources that have been allocated and with the quality that is expected. The goal of a risk management plan is to determine the method that will be used to monitor risk, the steps that will be taken to mitigate risk, and the process by which risks will be communicated to the project stakeholders. While the filing of a risk management plan is not critical at this stage, the Board would have found it helpful if FortisAlberta had included in its filing some discussion about its proposed approach to risk management. The Board notes that the other utilities did include some risk management discussion in their cost submissions.

3.1.6 Summary of Cost Estimates

The following cost estimates were provided by the utilities for the implementation of the USA and MFR:

Table 2. Utilities' Cost Estimates

Company	Capital Costs	Annual Operating Costs
EDI/ETI	$0.3 million	$0.2 million
EPC	$6.7 million	$0.5 million[6]
AE	$0.4 million	$0.0 million
AltaLink	$17.8 million	$2.8 million
FortisAlberta	$15.6 million	$1.6 million
Total	$40.8 million	$5.1 million

The cost estimates included for AltaLink are based upon their CBE approach.

The Board has indicated in its findings above that there may be potential cost saving opportunities, namely with regard to the AE, EPC and FortisAlberta proposals. This gives the Board confidence that the combined cost estimates provided by the utilities are if anything, at the higher end of the scale.

The Board has obtained the following information from the 2005 EUB Directive 014[7] filings submitted by the utilities. The application numbers for these filings are indicated after the utility's name.

[6] EPC included forecast annual operating costs of $0.1 million for year one, $0.4 million for year two and $0.5 million for subsequent years

[7] EUB Directive 014: Requirements for Annual Financial and Operating Reporting by Electric Utilities.

Table 3. Board Approved Forecast Revenue Requirement, Rate Base and O&M for 2005 ($ millions)

Utility	Revenue Requirement	Mid-Year Rate Base	O&M
ETI (#1478150)	$37.1	$158.8	$15.8
EDI (#1478149)	90.7	303.2	55.6
AE-Trans (#1474043)	164.6	786.6	48.0
AE-Dist (#1474043)	239.1	605.0	88.8
EPC (#1459029)	162.8	488.8	41.6
AltaLink (#1458975)	181.5	758.7	62.6
Fortis (#1458815)	215.4	675.5	115.4
Total	$1,091.2	$3,776.6	$427.8

Table 4. Actual Revenue Requirement, Rate Base and O&M for 2005 ($ millions)

Utility	Revenue Requirement	Mid-Year Rate Base	O&M
ETI (#1478150)	$32.8	$158.0	$16.1
EDI (#1478149)	91.2	308.7	57.2
AE-Trans (#1474043)	166.8	771.5	50.0
AE-Dist (#1474043)	245.1	608.3	93.9
EPC (#1459029)	161.7	492.1	45.2
AltaLink (#1458975)	176.3	741.1	58.1
Fortis (#1458815)	213.4	682.0	113.2
Total	$1,087.3	$3,761.7	$433.7

The total capital cost estimate in Table 2 of $40.8 million is approximately 1% of the total 2005 actual mid-year rate base for these utilities. As such, the annual revenue requirement associated with the $40.8 million would not be material when compared to the total approved 2005 revenue requirement for these utilities. In addition, the total annual operating costs estimate of $5.1 million shown in Table 2 is approximately 1% of the total 2005 actual operating and maintenance costs for these utilities. The Board believes that, even though the cost estimates provided in Table 2 are significant, the amounts are not material when viewed in the context of the total overall costs and investment involved for these utilities.

In light of the foregoing, and given the broad support for implementation of the USA and MFR, the Board believes that the utilities' implementation cost estimates filed in this proceeding represent a reasonable basis on which to proceed with the implementation of the USA and MFR.

3.2 USA-MFR Benefits

In announcing its approval in principle of the form and content of the Consensus Documents the Board stated the following:

> The EUB believes that the adoption and use of an activity-based USA similar to that used by the United States Federal Energy Regulatory Commission will improve the ability to compare financial information from year to year for a utility and, to the extent possible, across utilities when testing the reasonableness of a utility's filings and budgets. The EUB and interveners will have greater confidence that the costs being considered are comparable. This increased confidence, combined with MFRs based on information from the USA, should result in more complete and comprehensive General Tariff Applications (GTAs), a more efficient interrogatory process, and reduced cross-examination time at hearings.[8]

[8] EUB Bulletin 2006-25, dated July 12, 2006

As part of this proceeding, parties were requested to file submissions to address what benefits, if any, they considered would arise from the implementation of a USA and MFR. All parties, with the exception of AE, provided written submissions on expected benefits from the implementation of a USA and MFR. The benefits outlined in the submissions were mainly the same as those identified by the Board in the above quote from Bulletin 2006-25. There were also some additional benefits included such as:

- confidence that a USA framework would work well within the context of alternative rate making, such as formula based rate design;[9]
- general consistency of utility information which would provide for an easier understanding of applications and additional transparency into the material provided;[10]
- promotion, facilitation and more meaningful use of ratios and benchmarks;[11]
- comparisons to provide greater opportunity for settlements;[12] and
- standardization to assist the Board in its audit function by providing auditors with a uniform starting point for all utilities.[13]

The proposed benefits that received the most discussion and commentary from parties were:

- consistency of information which provides for easier understanding of applications;
- comparability of information over time both within a utility and between utilities;
- more complete and comprehensive applications; and
- regulatory efficiencies.

The Board's views and observations of these matters follow.

3.2.1 Consistency of Information / Easier Understanding of Applications

All of the utilities considered consistency of information as a benefit of the USA and MFR. FortisAlberta identified it as the main benefit.[14] AltaLink viewed consistency as a primary benefit.[15] EDI/ETI acknowledged that the standardization of accounts under the USA will likely make it simpler for the Board and interveners to understand a utility's costs.[16] AE acknowledged that the ability to consistently evaluate the performance of a specific utility over time may be a potential benefit; however, it cautioned the Board that this benefit alone may not justify the implementation of the USA and MFR.[17]

The AACP expert submitted that continual changing of cost accounting makes it difficult or impossible for regulators and interveners to analyze utility operations on a consistent basis on both a forecast and actual basis.[18] He submitted that addressing this inconsistency does not necessarily require the implementation of the USA and MFR. He was of the view that this issue

9 Exhibit 045 – ENMAX Letter to the Board re USA-MFR Benefits, dated October 13, 2006
10 Exhibit 047 – AltaLink Benefits Submission, dated October 13, 2006
11 Exhibit 052 – IPCAA Benefits Submission, dated October 16, 2006
12 Ibid
13 Exhibit 046-01 – UCA Benefits Submission, dated October 13, 2006, Page 1, Lines 20-21
14 Transcript, Volume 3, Page 494, Line 24
15 Transcript, Volume 4, Page 767, Lines 1-5
16 Exhibit 048-01 – EDI/ETI Benefits Submission, Page 1, Lines 26-27
17 Transcript, Volume 4, Page 717, Lines 22-25, Page 718, Lines 1-12
18 Exhibit 051 – AFREA/AAMDC/CCA/PICA Evidence of William B. Marcus, dated October 13, 2006, Page 2

could also be addressed if the Board simply ordered the utilities to use the accounting format that they have been previously using and to not make any changes without the approval of the Board.[19]

The Board agrees with parties that consistency of information is an important benefit of the implementation of the USA and MFR. The continual changing of cost accounting policies by utilities makes it extremely difficult to analyze a utility's operations from year to year. As well, the continual change in how utilities report their operations in regulatory applications also makes analysis and understanding quite difficult. The Board sees value in ensuring that utilities are accounting for and reporting items on a consistent basis year over year. Consistent reporting eliminates the situation where utilities have forecasted and reported items on one basis and, for internal reasons, have actually recorded and reported them on a different basis. These types of situations have, in the past, required utilities to restate either the forecasted amounts or the actual amounts so that the Board and interveners are able to understand the impact of the change and to assess the forecasting accuracy of the utility. This practice not only involves additional time for the Board and interveners, but the utility staff as well. The elimination of these restatements will obviously aid in regulatory efficiency.

The Board recognizes that a USA and MFR are not absolutely necessary to achieve consistent reporting over time for a single utility. However, the Board view must extend beyond that of a single utility to all of the utilities that it regulates. The Board considers that more benefits could be derived if all utilities were required to use the same accounting treatment and the same reporting treatment for regulatory applications. The Board believes that there are efficiencies to be gained by having each utility record and report information on the same basis. In this way, the Board and interveners would not have to spend time, as is currently done, basically refreshing themselves on the different approaches each utility takes to record and report regulatory information in their applications. The Board considers that regulatory efficiencies would be gained when an application are filed using the USA and MFR because all parties would know exactly where to look for any information it wished to examine. In addition, all parties would understand what types of costs are included in the accounts being reported upon. Parties would no longer have to wonder, for example, how a particular utility defines, records and reports information on full time equivalents and labour costs. The Board believes that this consistency across all utilities will lead to more regulatory efficiencies than simply allowing each separate utility to continue recording and reporting on a different basis, albeit with the requirement that each individual utility be required to consistently apply their unique recording and reporting. The Board considers that this consistency across all utilities will only be achieved through the implementation of the USA and MFR.

3.2.2 Comparability of Information Within and Between Utilities

This benefit is closely linked to the consistency benefit discussed above. The basis for the comparison of information within a utility as well as between utilities lies in the consistency of the information being recorded and reported upon. The Board believes that it is much easier to compare information when it has been recorded and reported on a consistent basis. This eliminates the need for any restatements as discussed in Section 3.2.1 above. For this reason alone, the benefit of consistency lends itself immediately to the benefit of comparability.

[19] Exhibit 051 – AFREA/AAMDC/CCA/PICA Evidence of William B. Marcus, dated October 13, 2006, Page 3

None of the parties in this proceeding argued that the USA and MFR would result in less comparability of information. However, a majority of the utilities stated that comparisons between utilities, or benchmarking for rate making purposes, were not a benefit of the USA and MFR. EDI/ETI stated that while high level comparisons for diagnostic purposes can be helpful, detailed benchmarking efforts for rate-making purposes will result in substantial additional costs and diminished regulatory efficiency while yielding no meaningful benefit.[20] AE strongly opposed the use of information filed in accordance with the USA and MFR for this purpose.[21] AltaLink submitted that the adoption of the USA and MFR will not provide a reasonable basis for the use of benchmarking or cross-utility comparisons for purposes of rate setting or for determining the reasonableness of rates filed by utilities under the Board's jurisdiction.[22] FortisAlberta believed that the implementation of the USA and MFR would not enable parties to make simple comparisons and draw conclusions that would be beneficial in determining revenue requirements as compared to the manner in which current filings are done.[23]

The Board considers that no party to this proceeding has made the specific recommendation that benchmarking be used to determine revenue requirements or rates. The AACP's evidence clearly indicated that benchmarking amongst Alberta utilities should not be generally used to determine rates.[24]

The Board sees no requirement to use benchmarking between utilities to determine revenue requirements or rates. The Board recognizes that any possible future efforts in this regard will involve substantial challenges. IPCAA also recognized the difficulties associated with benchmarking when it acknowledged that benchmarking is something that one has to consider carefully because there are problems and challenges with benchmarking different utilities.[25]

However, the Board does consider there are benefits in the ability to compare the operations of the different utilities in the Province. The Board notes that the majority of the utilities have voluntarily participated in organizations that collect operating statistics and issue summarized results to all participants. The Board considers that the utilities derive some benefit from this participation, even if it was only to obtain some meaningful indices on which to measure performance. The Board believes that the standardization and consistency of recording and reporting information will allow parties to develop and calculate certain metrics and performance measures that can be used for comparison purposes. This will afford all parties the opportunity to identify any major areas of concern between the utilities. The Board realizes that there probably are valid reasons that could explain the differences in performance measures between the utilities and the Board sees value in exploring and understanding these reasons. The Board believes that this would benefit not only customers and the Board, but utility management as well. For example, the requirement to record and report O&M performed by contractors separately from O&M performed by FTEs could be used to assess the cost effectiveness of these two work execution methods.

The Board believes that current attempts to meaningfully compare any cost items between utilities usually start out with the parties determining what types of costs are included and then

[20] Transcript, Volume 4, Page 695, Lines 7-15
[21] Transcript, Volume 4, Page 723, Lines 10-19
[22] Transcript, Volume 4, Page 769, Line 25, Page 770, Lines 1-6
[23] Exhibit 100, Response to BR-FAI-018 (a)
[24] Transcript, Volume 4, Page 858, Lines 14-18
[25] Transcript, Volume 4, Page 807, Lines 9-10

making adjustments to make sure that the comparison is made on an apples to apples basis. This process results in inefficiencies that could be alleviated through making comparisons between items that are recorded and reported on the same basis. The adoption of the USA and MFR would accomplish this.

3.2.3 Complete and Comprehensive Applications

The Board is aware that content differences currently exist between the GTAs filed by the various utilities. As part of the revisions to EUB Bulletin 2005-31,[26] the Board introduced a step entitled: Pre-notice Application Assessments by EUB Staff. This step was put in place to ensure that applications filed with the Board met the EUB's regulatory requirements. The UCA stated that the USA and MFR will reduce the need for these pre-application assessments.[27] The Board agrees with the UCA and considers that the implementation of the USA and MFR could virtually eliminate this procedural step and therefore lead to increased regulatory efficiency.

AE was also of the view that the implementation of the USA and MFR would raise the standard of all utility filings in the Province and be a consistent standard for all the filings in the Province.[28]

The question of how much or what type of information to include in a regulatory application has been a long standing issue for utilities. There has also been a concern expressed by the interveners over the years regarding information asymmetry. The Board considers that regardless of the type of reporting format in place, there will always be information asymmetry as there is simply no way for the utilities to report every single piece of data it has compiled over a financial year. However, the Board recognizes that through the efforts of the USA-MFR Committee, the parties have agreed that there is at least a minimum amount of data that should be included in a regulatory application. This will provide guidance to the utilities in preparation of their regulatory applications. The Board believes that this will result in reduced information requests regarding the information asymmetry topic. The adoption of the USA and MFR will mean that interveners will know what to expect when they receive a regulatory application.

While the Consensus Documents were the result of a collaborative process, it is similar in nature to negotiated settlements that are filed with the Board. As such, there is an onus on both the utilities and the interveners to live up to the agreement on the USA and MFR. AE submitted that:

> While in our view the minimum filing requirements should in most circumstances provide sufficient information to justify requests contained within a GTA, ATCO Electric acknowledges that in certain circumstances additional information would be required in order to fully justify a specific aspect of the requested revenue requirement.[29]

The Board agrees with AE that even with the establishment of the USA and MFR, the onus is still on the applicant utility to justify its forecast costs. The Board expects utilities to exercise professional judgment in deciding if additional information is required above the USA and MFR requirements. Likewise, the Board also expects interveners to respect the spirit and intent of the

[26] Bulletin 2005-31, Revisions to EUB Cost Policies and Prehearing Processes for Utility Matters, dated October 28, 2005
[27] Exhibit 046-01 – UCA Benefits Submission, dated October 13, 2006, Page 11, Lines 24-25
[28] Transcript, Volume 2, Page 228, Lines 19-23
[29] Transcript, Volume 4, Page 720, Lines 16-23

USA and MFR when preparing information requests to test a utility's application. In this regard, the Board expects that questions will be well justified.

The Board believes that one of the keys to increased regulatory efficiency is high standard, quality applications by the utilities. The Board considers that the USA and MFR will lead to this result on a consistent basis.

3.2.4 Regulatory Efficiencies

The majority of the parties in the proceeding anticipated that the implementation of a USA and MFR would lead to regulatory efficiencies.

EDI/ETI stated that, among other things, the USA and MFR should obviate the need for interveners to pose information requests and questions in cross examination for the mere purpose of understanding, for example, the types of activities that are included in a certain account.[30] One benefit that FortisAlberta foresaw arising from adoption of the USA and MFR was a material reduction in costs of regulatory proceedings, and in particular GTAs.[31] The UCA considered that the USA and MFR would allow interveners to focus information requests on the "why" questions, and not on "what is this" questions.[32]

On the other hand, AE remained skeptical of the benefits being claimed by some proponents of the USA and MFR. AE stated that, given its applications were used as the model for the Consensus Documents, some of the anticipated benefits such as shortened hearing time and reduced number of IRs should have been evident in its recent GTA proceedings. AE stated that this has not been the case.[33]

In addition to simply identifying regulatory efficiencies, some parties also emphasized the importance of achieving these regulatory efficiencies. For example, AltaLink considered that it was critically important that the efficiencies be achieved if the costs of implementing the USA and MFR were to be justified.[34]

The Board shares the desire of parties to increase regulatory efficiency through the implementation of the USA and MFR. However, the Board does not expect these efficiencies to be immediately apparent. Therefore, the Board expects that in the short term the implementation of the USA and MFR may result in increased regulatory costs as all parties adjust to the new filing requirements. The Board notes that the AACP shares this view.[35]

While there will be some adjustment period, the Board does not anticipate the learning curve will be too steep since the composition of the USA-MFR Committee exposed both utilities and interveners to the requirements of the USA and MFR. In addition, as AE's recent GTA filings have been based on the Consensus Documents, some interveners will have had some experience with this format.

[30] Exhibit 048-01 – EDI/ETI Benefits Submission, Page 1, Lines 28-30
[31] Exhibit 050 – Fortis Potential Benefits Letter, dated October 13, 2006, Page 1
[32] Exhibit 046-01 – UCA Benefits Submission, dated October 13, 2006, Page 16, Lines 4-5
[33] Exhibit 088 – Response to BR-AE-3 (a)
[34] Transcript, Volume 4, Page 768, Lines 1-4
[35] Transcript, Volume 4, Page 861, Lines 19-21

With respect to the regulatory efficiency associated with reduced hearing times, information requests or other procedures, the Board cannot and will not guarantee that this will occur in every application put before it using the USA-MFR format. The Board expects that, if the level of intervention is maintained at current levels or increases in the future, the interveners will be able to justify their reasons for examining any particular area of an application in greater detail. The Board will continue to monitor the effectiveness of interventions as it currently does and expects that this role may become even more important in the early years of the USA and MFR.

Overall, the Board finds that having a standardized, consistent format will, over time, lead to a better understanding of the applications filed with the Board. The elimination of "what is in here" types of questions posed during the information request and cross-examination stage will certainly aid in improving not only the efficiency of interventions, but also their effectiveness as well.

3.3 Cut-over Date

Parties presented various opinions respecting the establishment of a date beyond which all utilities must be in compliance with the USA and MFR.

AltaLink suggested that although in principle it made sense for the implementation or transition to start on a set date, it intended to file its next GTA in the MFR format. AltaLink expected to be in a position to implement the USA and MFR with the filing of its next GTA covering the test period commencing in 2009 provided the USA and MFR proceeded and its proposed SL Allocation approach was approved.

EDI/ETI preferred a fixed go-live date. Notwithstanding this preference, EDI/ETI intended to file its next GTA application in either complete or very nearly complete compliance with the USA and MFR in the second quarter of 2007. EDI/ETI also recommended that utilities implement the USA and MFR as soon as possible as doing so would enhance all parties' understanding of the new format during the transition process.

AE argued that in principle, all utilities should convert at the same time. However, AE also stated that for all intents and purposes, it was currently complying with the USA and MFR.

FortisAlberta recommended implementation for a utility as soon as possible. For itself, FortisAlberta proposed a USA-MFR transition date of January 1, 2009 as it required a fiscal year of data collection under an operating USA before it could prepare a forward looking MFR-based GTA filing.

EPC developed an implementation schedule whereby it would be able to prepare its 2009 budget under the USA reporting requirements, track actual results against this budget through 2009, and then be in a position to submit a GTA in the MFR format by 2010. EPC also indicated that it would be filing its next GTA in 2007 which may be for a period up to five years. Assuming that this filing will not be USA-MFR compliant, if a 5 year filing were made in 2007, EPC would not be filing a USA-MFR compliant GTA until the 2012 test year.

In summary, the Board notes that the submissions of the parties can be separated into two camps. The first camp, which includes parties such as FortisAlberta, the UCA/AUMA and IPCAA, suggest that utilities should proceed with the USA and MFR when ready as there will be a learning curve for utilities, Board and interveners. The second camp, which includes AE, EDI/ETI and AltaLink, indicated a preference for a fixed implementation date applicable to all utilities. The Board notes that notwithstanding AE, EDI/ETI and AltaLink's stated preference, they have targeted compliance with the USA and MFR coincident with their next GTA filings.

All utilities indicated that they could comply with the USA and MFR by 2010. The anticipated years are shown in Table 5 below. The actual dates and test periods for which GTAs will be filed are not known to the Board at this time.

Table 5. Earliest Dates Anticipated by Utilities for Filing GTA in USA-MFR Format

	Year that Historical USA Data is available	Earliest Date GTA could be filed in USA-MFR format with one year historical data
ATCO	Currently	Currently
EPCOR	2006	2007
AltaLink	2008[36]	2009
FORTIS	2009	2010
ENMAX	2009	2010-2012

Given these timelines, the Board considers that 2010 represents a reasonable and achievable date by which each utility can file its GTA in accordance with the USA and MFR. Accordingly, the Board directs AE, EDI/ETI, AltaLink, FortisAlberta and EPC to file their GTAs in accordance with the USA and MFR no later than 2010. Utilities that are currently in a position to comply with the USA and MFR should do so immediately. Utilities that are very close to compliance with the USA and MFR should proceed to become fully compliant as soon as possible. Other utilities who have much to do to achieve compliance, should nonetheless endeavour to meet the spirit and intent of the USA and MFR to the extent possible during the period of time it takes for them to become compliant, but in any event, no later than 2010.

3.4 Transition Plan for Regulatory Filings

In a letter to the EUB dated May 8, 2006,[37] the USA-MFR Committee outlined further process items it considered would be necessary before the Board could decide whether to implement the USA and MFR. A section entitled "Transition to a USA and MFR Regulatory Regime" of that letter read as follows:

> If the Board ultimately decides to direct the utilities to implement the proposed USA and MFR, a plan to transition smoothly to the new USA and MFR regime would need to be established. A transition plan would assist in ensuring that there is a good measure of comparability between a utility's last GTA filed under the current system and its first GTA under the new USA-MFR regime. The Committee considers that the EUB can develop this plan in consultation with the utilities and interveners once the decision is made to proceed with implementation of the USA and MFR.

The Board considers the approach proposed by the USA-MFR Committee to deal with transitioning to a USA-MFR regime to be reasonable.

[36] The Board anticipates that as part of AltaLink's 2009 filing, 2008 historical data on a comparable basis will be provided.

[37] Exhibit 001, EUB Endorsed USA & MFR, Cover Letter Dated May 8, 2006, Page 2

Now that the Board has decided to order the electric transmission and distribution utilities to proceed with the implementation of the USA and MFR, the Board provides the following comments to assist in the development of a transition plan (Transition Plan).

An important tool that interveners and the Board use in assessing a utility's application is the comparison of actual results to forecasts. In order to permit this comparison, it is imperative that the forecast and actual figures be recorded and reported on a similar basis. If utilities find themselves in the situation where the forecasts and actuals are prepared on a different basis, work will have to be done by the utilities to restate either the forecast or the actuals in order to provide for meaningful comparisons. The Board considers this activity to be part of the short term increase in regulatory costs that were discussed in Section 3.2.4 above. The Board expects the utilities to restate any such years that are affected by this change. The Board also expects that the restatement will be on an account by account basis. This will provide the interveners and the Board with the information they require to assess the forecasting accuracy of each group of costs. In other words, the proposal brought forward by EPC regarding restatements is not acceptable to the Board. This proposal was outlined by EPC as follows:

> Our position would be to the extent that the bottom line number for the application for the revenue requirement was within a reasonable change, there would be no reconciliations performed.[38]

The Board also expects that in the case of any longer term alternate rate making scenarios, the utilities would have to ensure that any information used for such things as formula calculations would have to be recorded and reported on a consistent basis, even if the actuals and forecast were prepared on a different basis.

The Board considers that one option for developing a Transition Plan would be to re-constitute the USA-MFR Committee, or a similar type of committee, and charge that committee with the task of developing a plan for all utilities to follow in transitioning from their current system of recording and reporting to the USA–MFR system. However, the Board recognizes that there may be other options for achieving the same result. Therefore, following the issuance of this Decision, the Board will issue a letter (USA Process Letter) canvassing the views of parties on the appropriate process for developing the Transition Plan.

3.5 Decision Methodology

As discussed in the preceding sections, although there were differences of opinion as to the specific details of the USA and MFR and the timing of implementation, parties were either neutral or supportive of the implementation of the USA and MFR. Given this support, the Board's review was concentrated on implementation details such as cost estimates, cutover dates, transition plans, affiliate costs and project monitoring.

Having identified the various benefits that could be achieved through the implementation of the USA and MFR, the Board must now consider whether these benefits are sufficient to support the imposition of the USA and MFR given the projected implementation costs identified by the utilities.

[38] Transcript, Volume 2, Page 251, Lines 5-9

During the IR portion of this proceeding, the Board requested the views of all parties as to whether it was possible to quantify the potential benefits of the USA and MFR and to do some type of quantitative analysis to determine if it should proceed with the USA and MFR. All parties responded to this question by stating that such a quantitative analysis was not possible.

The Board also attempted to assess the potential dollar value of reduced intervention time by asking the interveners and the utilities to quantify the time, effort and resources dedicated to responding to and understanding the content of an application. The parties were unable to provide any meaningful response as they did not track the amount of time they spent pursuing this issue.

The Board has concluded that it cannot perform the usual quantitative analysis to compare the dollar costs of the implementation of the USA and MFR with the expected dollar savings associated with the benefits of having such a system. Therefore, the assessment must be done on a more qualitative basis.

The Board is persuaded by the evidence that there are benefits to be gained through the implementation of the USA and MFR. Moreover, the Board is reassured that the interveners also consider there to be benefits to be achieved from the implementation of the USA and MFR as they would not otherwise have been willing to participate in the USA-MFR Committee or support this initiative in this proceeding. The Board also notes that although the implementation costs at this stage are uncertain, customer representatives are willing to pay the costs provided the implementation is done on a prudent basis.

The Board notes the following question and response with IPCAA:

> Q: No. I think it does. I mean, I think you're saying, do this exercise right. IPCAA appreciates there's going to be, I'll call it, hefty price tag attached. And assuming there's the proper scrutiny on those costs, you are putting your money where your mouth is. You think the benefits are there.
>
> A: That's right.[39]

The Board also has given some weight to the fact that the use of a USA and MFR by the FERC, has been in place for many years. The Board believes that since this system is continuing to be used it must still be considered to be an effective recording and reporting mechanism. This gives the Board confidence that the USA and MFR will also provide benefits to regulated electric transmission and distribution utilities in Alberta. The Board believes that on an overall qualitative basis, these benefits are sufficient to justify the costs associated with the implementation of the USA and MFR.

3.6 Affiliates Cost

Affiliates costs associated with the implementation of the USA and MFR do not appear to be a significant issue. Affiliate costs can arise in a regulated utility when its financial and reporting systems are integrated with its unregulated affiliates.

[39] Transcript, Volume 4, Page 849, Lines 6-13

All of the utilities indicated that their proposed approach to implementing the USA and MFR would not have any impact on their affiliates. Therefore, their cost estimates did not contain any affiliate costs associated with the adoption of the USA and MFR.

EDI/ETI noted that should the Board direct EDI/ETI to embed the actual FERC account numbers in their Oracle chart fields, there would be a huge associated cost for EPCOR Utilities Inc. In this event, the entire cost associated with the change would be recoverable by EDI and ETI through their regulated tariffs because the regulated business would be the sole driver of the need for the change. The Board has noted EDI/ETI's concern, but will not be providing any findings on this matter at this time as it is outside the scope of this proceeding. If an affiliate cost issue does arise in the future it will be addressed at each utility's GTA following the implementation of the USA and MFR.

Therefore, as no utility has included in its cost estimates any affiliate costs associated with the adoption of the USA and MFR, this matter has not impacted the Board's determination in this proceeding to approve the implementation of the USA and MFR.

3.7 Applicability to Smaller Utilities

The USA and MFR approved in principle by the Board in Bulletin 2006-25 provides as follows:

> *Applicability of Uniform System of Accounts:* Subject to any Board accounting requirements under the EUB Act, the EUA, the PUB Act, the HEEA, and as noted in General Instruction 1,this system of accounts is applicable in principle to all licensees engaged in the transmission (including any associated isolated generation) or distribution of electric energy, unless exempted by the AEUB,

This provision allows the smaller utilities such as the Cities of Lethbridge and Red Deer, and TransAlta to seek exemption and persuade the Board that some other type of requirement better suited to their circumstances should apply. It recognizes that an administrative burden could be imposed on the smaller utilities if they are required to conform to the USA and MFR that is developed for the larger utilities.

Parties were either neutral or supportive of the above-noted USA provision that would allow for a more practical and pragmatic USA-MFR approach for smaller utilities. However, the AACP submitted that, should an exemption be granted, the Board should approve the accounting format used by the exempted utilities and require that no changes to their approved format be made without approval of the Board. The AACP recommended that, if changes are approved, prior period data should be restated for five years for regulatory purposes.

The Board considers that the approach adopted by the USA-MFR Committee reasonably provides for the smaller utilities to be exempted from the USA if their particular circumstances warrant a more practical and pragmatic treatment. Applications for exemptions should be filed well in advance of the required USA-MFR implementation date to ensure that smaller utilities can be in a position to comply with the prescribed USA-MFR implementation date of 2010, if an exemption is not granted.

If the Board decides to grant an exemption application, it will determine at that time what conditions, if any, should be attached to its approval.

3.8 Monitoring of Utilities' USA Implementation Process

It was proposed by the USA-MFR Committee that the implementation projects for USA-MFR compliance be monitored by a neutral third party (Independent Monitoring Contractor). The USA-MFR Committee's May 8, 2006 recommendation to the Board stated:

> The Committee recognizes that if implementation proceeds, the final cost for implementing the USA will be subject to review and determination through the GTA process. However, the Committee felt that the overall public interest would be better served if a more proactive approach to scrutinizing the USA implementation costs were established. In this regard, the Committee considers that the on-going review by a neutral third party (Contractor) knowledgeable in IT and accounting process matters would assist in ensuring that only prudent systems and infrastructure are built. The Contractor would be retained by the EUB, but the associated cost would be recovered through utility rates.

A majority of the parties were supportive of the USA-MFR Committee's recommendation. While it did not directly oppose the idea of an Independent Monitoring Contractor, AltaLink questioned the value of an external review or audit of the USA-MFR project capital costs or implementation process. AltaLink stated that the Board's review of utility costs through the GTA process or the Board audit process, if deemed necessary, should cost effectively test the reasonableness of the implementation costs.

The AACP stated that the detailed role of the Independent Monitoring Contractor position, including such matters as the skill set required and the level of responsibility and authority for this position, has not been fully explored in this proceeding and needs to be defined. Nonetheless, the AACP was of the view that the active monitoring of the utilities' implementation process and costs by a qualified independent third party should facilitate a more meaningful review of the utilities' costs in a GTA or deferral account process. The acceptance of this process by the AACP was conditional on customer participation in the terms of reference and in the selection of the Independent Monitoring Contractor. The AACP submitted that the Independent Monitoring Contractor should provide to the Board and customers progress reports, perhaps quarterly, including recommendations on the prudence of the actions and costs of the utilities' implementation to date. Last, the Board should advise the utilities that costs will not be approved if the review process finds the processes or costs have not been conducted in a prudent manner.

IPCAA considered that it would be a challenge to find the right Independent Monitoring Contractor because the skills and experience needed would require a mix of IT and financial, some engineering, and significant regulatory knowledge. However, IPCAA was of the view that, if the right person could be found, significant hearing time would be saved during the GTAs where the utilities will seek to recover their USA-MFR implementation costs.[40]

The Board agrees with the concept of an Independent Monitoring Contractor and believes that such a position would bring discipline and focus to the USA-MFR implementation process. It will also serve to greatly reduce the challenges involved in the future prudence review of the USA-MFR implementation costs to determine the amount that should be paid for by customers. Therefore, the Board will retain an Independent Monitoring Contractor to perform this monitoring and reporting function during the implementation process. The USA Committee had suggested that the Independent Monitoring Contractor would be retained by the EUB, but the

[40] Transcript, Volume 4, Page 842, starting at line 18

associated cost would be recovered through utility rates. The Board considers this to be a reasonable framework for the retention and compensation of the Independent Monitoring Contractor.

The Board acknowledges that the selection of the Independent Monitoring Contractor and that person's roles, responsibilities and function will require much thought and consideration. Therefore, the Board will also seek parties' views on these matters in its USA Process Letter.

However, the Board provides below its preliminary thoughts on the role of the Independent Monitoring Contractor to assist parties in responding to the USA Process Letter.

The Board considers that the primary function of this role is to ensure the public interest is being served by the utilities' USA-MFR implementation approaches, that the projects are being executed effectively, that the projects stay within budget, and that the scope of the project is solely for the purpose of USA-MFR compliance. The Board is of the view that the roles and responsibilities of the Independent Monitoring Contractor should include:

- The Independent Monitoring Contractor is an independent consultant who reports quarterly to a Committee comprised of representatives from the utilities, interveners and the EUB.
- The Independent Monitoring Contractor is the project representative of the interveners and the EUB.
- Responsibility for updating interveners and the EUB, and for ensuring that any outstanding issues or problems are adequately raised as necessary.
- Reviewing and providing input to key project deliverables prior to distribution to the Project Committee.
- Reviewing Project Management Documents, Scope Change Requests and Customization Requests.
- Reviewing monthly project status reports.
- Reviewing risk management, issue management, problem resolution and escalates to the Project Committee, if required.
- Meeting with the respective Project Managers and Project Steering Committees as determined by agreed schedule.
- Conducting project audits or detailed review of project components if there is concern.
- Ensuring sustained understanding/buy-in of the project(s) at the intervener and Board levels.

3.9 Future Review Processes

With the exception of IPCAA, all parties were neutral or supportive of an MFR that evolved, under the direction of the Board, to respond to the needs of utilities, interveners and the Board.

The Preamble to the MFR document filed May 8, 2006, by the USA-MFR Committee states:

> The Board is the custodian of the Minimum Filing Requirements (MFR) and is responsible for ensuring the requirements are amended from time to time, as required. The Board will conduct an initial formal review of the content of this MFR within three years after implementation. On an ongoing basis, the Board will initiate a formal review

of this MFR document every 3 years to ensure that its content reflect the regulatory circumstances existing at the time of the review.

The AACP, AE and FortisAlberta spoke directly to this section of the MFR and supported it. EDI/ETI stated that the Board should monitor the process before determining whether any further generic review process becomes necessary.

The AACP and EPC indicated that the ongoing development and refinement of the accounts and sub-accounts is critical to the achievement of the final benefits. They, along with EDI/ETI, advised that as with any chart of accounts, refinements will be required as utilities start to utilize it and interpret the account definitions. These parties considered that there will be growing pains as the utilities become familiar with the new accounts and filing format, and as interveners and the Board explore how each utility has approached the USA-MFR requirements.

Parties indicated that although relatively precise, accounts may be subject to differing interpretations by the utilities. Therefore, there needs to be a party responsible for advising utilities on the interpretation and use of the USA and MFR. There will also be changes in accounting requirements created either from changes in the industry or changes in accounting standards.

The AACP and EPC indicated that refinements to the USA and MFR should be controlled by the Board to ensure that all utilities are subject to the same reporting requirements and reporting is complied with on a consistent basis. There also needs to be a controlled forum in which reviews or audits are conducted on the application of the USA and MFR to the utilities operations to check that accounts are correctly and consistently used from year to year. FortisAlberta agreed to participate in and support any such process.

The AACP submitted that the EUB should establish a person or group within its utility or audit section that is active in these processes and would be available on an ongoing basis to address questions that may arise. In the initial period of setting up the USA and MFR, there may be frequent issues to be resolved regarding interpretation and application of the USA and MFR requiring the advice of the Board. The AACP recommended that all communications and directions between the utilities and the Board to resolve these issues should be in writing.

As an alternative to an independent review, AltaLink proposed that the utilities be required to file quarterly process updates in respect of the USA-MFR project costs, scope and timelines with the Board and with interested parties. AltaLink stated it does not see the need for future review processes beyond those outlined in the USA-MFR Committee report.

EDI/ETI agreed that the USA and MFR is a good starting point and that the path forward is to allow the MFR to be refined through the utility's tariff applications. It stated that through this process it will become clear how the MFR can be refined as a tool to improve the tariff application process rather than frozen in a format that may make good sense for one utility, but which may detract from clarity for others.

IPCAA, the UCA and the AACP rejected EDI/ETI's proposal for flexibility in meeting the USA-MFR requirements.

IPCAA was concerned that a number of parties indicated that changes are still required to the USA and MFR. In IPCAA's view, the purpose of the USA-MFR Committee, which met for a year, was to obtain agreement on specific accounts to arrive at some consistency for a minimum filing requirement. The agreement reached resulted in the Consensus Documents filed with the Board. IPCAA understood that there are many possible solutions to the USA and MFR and that issues can arise when companies are forced to change their regulatory approach and business models and practices. However, notwithstanding these issues, the fact remains that the USA-MFR Committee did agree on the USA-MFR model which all parties recommended to the Board.

The Board places little weight on the position of EDI/ETI that changes should be made through a utility's tariff application. The Board agrees with the AACP that

> EPCOR's request for reporting flexibility would, with respect, and in the submission of AACP, defeat the basic purpose of the USA.[41]

In the Board's view, changes to the USA resulting from an individual utility's application would reduce the comparability of the USA and circumvent the agreement which all parties, including EDI/ETI, reached.

The Board also notes that the USA-MFR Committee report stated that:

> The Board is the custodian of the Minimum Filing Requirements (MFR) and is responsible for ensuring the requirements are amended from time to time, as required.

The Board recognizes that ongoing changes, perhaps more frequent than the original three year cycle contemplated in the USA-MFR Committee's report, may be required. The Board acknowledges the achievement of the interveners and utilities in developing the Consensus Documents and considers that it would be desirable to address any future changes through a joint forum.

The Board also considers that the future review provision in the MFR is adequate and should be similarly applied to the USA. However, this provision should not preclude on-going incorporation of changes that are considered necessary to immediately capture clarity, transparency and regulatory efficiency benefits. There is no need to wait for three years after implementation to make urgent and necessary changes.

The Board is also of the view that any committee established to develop the Transition Plan could also address changes to the Consensus Documents and report back to the Board during the USA-MFR implementation phase. The Independent Monitoring Contractor may also be able to provide assistance in this regard. Therefore, the Board will also canvass views on this matter in the USA Process Letter.

The Board also recognizes that it may be necessary to review the USA and MFR to ensure that with the passage of time they are current and that they continue to adequately reflect the regulatory regime. In this regard, the Board may initiate a formal review of the USA and MFR in three years following the issuance of this Decision.

[41] Transcript, Volume 4, Page 877, Lines 12-15

3.10 Other Matters

3.10.1 Project Control and Cost Accountability

In response to a question from the Board, FortisAlberta described the process that it would use to manage the implementation of the USA and MFR as follows:

> The approach we would use is we do set up steering committees for these projects, and they would be comprised with people from the business. And then when you get down a level, you do have a manager, say a program manager that would likely be from the business and then the individual -- you know, then you'd have -- a layer below that would probably be IT folks. Because there is a mix you have to see. We do anticipate having significant involvement from the operations and other areas. Because you are right; you'd have to make sure you meet the needs of the businesses in these exercises.[42]

The Board recognizes this approach as reasonable and encourages all utilities to invite participation from other areas of the business in the USA-MFR implementation projects. However, the Board sees increased value from Executive stakeholders representing broader business interests and providing the oversight necessary for the success of these complex projects.

The Board considers the implementation of the USA and MFR by the electric transmission and distribution utilities is not a technology initiative. Rather it is a strategic initiative that may impact the way the organization does its business. Therefore, it is important that the USA-MFR implementation project has sponsorship at the Senior Management level and has the involvement of the business unit heads. It should not be a project to be undertaken solely by the IT Team of the companies. Ensuring success of the USA-MFR implementation project should be an overall Executive responsibility.

The Board expects the Senior Management of the electric transmission and distribution utilities to sponsor, budget and regularly review the progress of the USA-MFR implementation process. Additionally, it would be helpful if the Executives examine the USA-MFR implementation from an overall business perspective, not simply as a technical project.

Senior Management involvement would facilitate the decision making in the project, thus reducing time and consultant costs of delays. It also makes it easier to free up key business resources to ensure the project team is given the best information and guidance further contributing to project success.

The proposed implementations are a significant expense and once implemented, the USA may well have implications for management control and budgeting. To that end, the project will require the input and control from a senior financial leadership team in order to ensure that the beneficial outcomes are maximized.

The Board understands that the USA-MFR implementation process is going to change the way of doing business. Therefore, the risks are business risks rather than technology risks. Implementation of the USA and MFR could disrupt the operations and cost considerable dollars in loss of time and opportunity. The executive team must be aware of the assessment of risks

[42] Transcript, Volume 3, Page 505, Lines 4-18

along with the planned risk mitigation strategies. This could cover organizational issues like re-training of staff for the new system, re-structuring the organization due to the anticipated changes in process or ensure availability and uptime of mission critical systems.

4 SUMMARY OF BOARD FINDINGS AND CONCLUSIONS

Based on all of the discussion, observations, and analysis in the foregoing sections the Board has provided a summary of its findings as follows:

Implementation Costs

- Notwithstanding the finding below with respect to the proposal by AltaLink which came well after the collaborative process was completed and which suggested allocation of costs from their existing departmental budgets rather than an activity account approach which would see budgets prepared based on activities, the implementation costs and plans submitted by the utilities represent a reasonable basis on which to proceed with the implementation of the USA and MFR, particularly when viewed from the perspective of the overall cost to provide utility service in the Province and the broad support from all parties for moving forward with implementation.

- AltaLink's late suggestion of an allocation approach is unlikely to achieve the desired clarity, transparency and regulatory efficiency goals sought by most of the parties in the long run. Although it is significantly more expensive, AltaLink's original CBE approach, based on budgeting by activity, fully meets the intent and requirements of the USA. AltaLink should proceed with its CBE approach rather than its revised allocation approach for implementing the requirements of the USA and MFR.

- Project cost control is a critical and extremely important factor in the successful implementation of the USA and MFR. Therefore, even though IT is a significant aspect of the USA implementation process, project control and cost accountability must extend beyond the IT departments of the utilities to the senior management of the companies.

Benefits

- The expected benefits of adopting the USA and MFR, although somewhat unquantifiable, have the potential to be significant and to be realized if the appropriate measures are put in place. Potential benefits include: consistency and comparability of information over time; more complete and comprehensive applications, and regulatory efficiency. The Board, interveners, and the utilities each have important roles to play to ensure the potential clarity, transparency and regulatory efficiency goals are achieved.

Cut-Over Date and Transition

- Except for smaller utilities who may apply for and receive exemption, all applications filed on or after January 1, 2010 must be filed in compliance with the USA and MFR. Utilities that are in a position to meet these requirements sooner should do so.

- Subsequent to the issuance of this Decision, the Board will canvass the views of parties on the most appropriate way to develop a plan to transition smoothly from the current regime to the USA-MFR regime.

Decision Methodology

- The usual quantitative analysis to compare the dollar costs of the implementation of the USA and MFR with the expected dollar savings associated with the benefits of having such a system could not be fully performed because the benefits are more qualitative by their nature. Therefore, the assessment to determine whether it is in the public interest to proceed with implementation was done on a qualitative basis.

Affiliate Costs

- Based on the utilities' cost filings, affiliate costs are not a cause for concern in determining whether implementation of the USA and MFR should proceed. Should an issue relating to this matter arise in the future, it can be adequately addressed in the particular utility's GTA.

Future Review

- A proactive approach to monitoring the implementation processes of those utilities that require a significant amount of expenditure, a longer period of time and a complex plan to comply with the USA and MFR should be employed. Upfront and continual monitoring would inject discipline into the implementation process. It will also reduce the challenges involved in the future prudence review of the USA-MFR cost to determine the amount that should be paid by customers. Therefore, the Board will retain an independent contractor to perform this monitoring and reporting function during the implementation process. The EUB will invoice the utilities for the independent contractor costs, which will ultimately be recovered from customers.

- The Board may initiate a formal review of the USA and MFR three years after implementation to ensure that it remains current and continues to adequately reflect the existing regulatory regime.

- The future review provision in the MFR is adequate and should be similarly applied to the USA. However, this provision should not preclude on-going incorporation of changes that are considered necessary to immediately capture clarity, transparency and regulatory efficiency benefits. There is no need to wait for three years after implementation to make urgent and necessary changes. When canvassing views on the development of the transition plan, the Board will also seek comment on the method to deal with urgent and necessary changes to the USA and MFR that are identified prior to implementation.

5 ORDER

For and subject to the reasons set out in this Decision, IT IS HEREBY ORDERED THAT:

(1) All of the electric transmission and distribution utilities that fall under the EUB jurisdiction shall adopt and use for regulatory purposes the USA and MFR whose form and content were approved in principle in EUB Bulletin 2006-25.

(2) Except for any small electric transmission or distribution utility that may apply for and receive approval for an exemption from the provisions of the USA and MFR, all EUB regulated electric transmission and distribution utility applications filed on or after January 1, 2010 shall be filed in compliance with the USA and MFR.

(3) Notwithstanding (2) above, utilities that are currently in a position to comply with the USA and MFR should do so immediately. Utilities that are very close to compliance with the USA and MFR should proceed to become fully compliant as soon as possible. Other utilities who have much to do to achieve compliance, should nonetheless endeavour to meet the spirit and intent of the USA and MFR to the extent possible during the period of time it takes for them to become compliant.

(4) While the Board is not approving in this proceeding any of the approaches or their attendant costs to implement the USA and MFR that have been filed by the utilities, the Board's discussion and views in this Decision will form the basis for any future prudence or compliance assessments of a utility's implementation plan and cost.

Dated in Calgary, Alberta on March 6, 2007.

ALBERTA ENERGY AND UTILITIES BOARD

(original signed by)

J. I. Douglas, FCA
Presiding Member

(original signed by)

R. G. Lock, P.Eng.
Member

(original signed by)

B. T. McManus, Q.C.
Member

APPENDIX 1 – HEARING PARTICIPANTS

Name of Organization (Abbreviation) Counsel or Representative	Witnesses
EPCOR Distribution Inc./EPCOR Transmission Inc. (EDI/ETI) J. Liteplo	R. Stout D. Fung J. Bryon
ATCO Electric Ltd. (AE) L. Keough K. Beattie	D. Freedman
ENMAX Power Corporation (EPC) D. Wood	K. Hubick S. Spooner (Consultant)
AltaLink Management Ltd. (AltaLink) H. Williamson, Q. C. S. Wahl-Hrdlicka	B. Crnkovic M. Higgins J. Piotto
FortisAlberta Inc. (Fortis) T. Dalgleish, Q. C.	M. Olson A. Skiffington G Smith G. Holizki (Consultant)
Industrial Power Consumers Association of Alberta (IPCAA) D. Macnamara	
Public Institutional Consumers of Alberta (PICA) N. McKenzie	
Consumers Coalition of Alberta (CCA) J. Wachowich	
Alberta Urban Municipalities Association (AUMA) N. J. Parker C. R. McCreary	
Utility Consumer Advocate (UCA) R. Henderson N. J. Parker	D. Gray J. Laskoski (Consultant) R. Bell (Consultant) H. Vander Veen (Consultant)
The AACP consisting of AFREA, AAMDC, CCA and PICA T. Marriott	

Alberta Energy and Utilities Board Board Panel J. I. Douglas, FCA, Presiding Member R. G. Lock, P.Eng., Member B. T. McManus, Q. C., Member Board Staff C. Wall (Board Counsel) M. L. Asgar-Deen, P.Eng. D. Mitchell C. Buchanan (Consultant)	

Attachment 308.7

BCUC Activity View Reporting

February 5, 2013

FORTIS BC™

History of Activity View Reporting

1961	BCUC Uniform System of Accounts (USoA) established and ordered to be adopted by gas utilities in the Province of BC
2007	FEU approved to depart from USoA in favor of Resource and Activity view reporting (Order G-153-07)
Apr-12	BCUC instructs FEU to begin investigating the cost of fully converting to the USoA prior to filing their next RRA (Order G-44-12)
Oct-12	FEU propose to retain Resource and Activity view reporting and propose an implementation plan to meet BCUC objectives
Dec-12	BCUC accepts FEU proposal for next RRA only

FORTIS BC™

Implementation Plan to meet BCUC Objectives

- Work with Commission staff to review/modify New Code of Accounts (Resource and Activity)
- Provide Commission with updated description of Activity view prior to the next RRA
- Implement revisions to Activity and Resource views into SAP
- Provide test year and 5 year historical in future RRA using the modified New Code of Accounts
- Ensure the Activity view aligns with the Department view in the next RRA
- Provide Commission with ongoing updates to Activity view
- Continue to utilize Activity and Resource view in the BCUC Annual Reports

FORTIS BC™

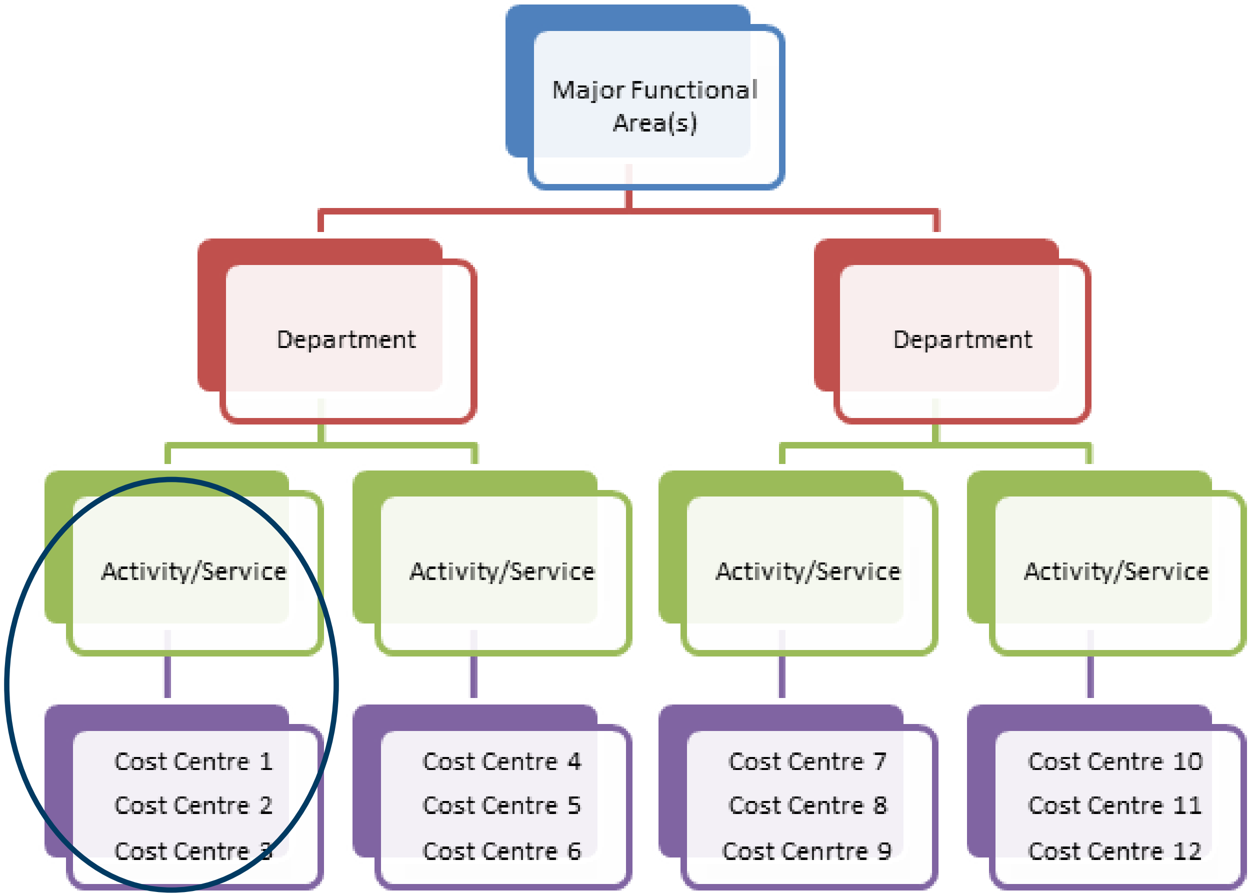
Guiding Principles of Activity View Reporting

BCUC	Provide an acceptable alternative to the Uniform system of Accounts for Gas Utilities
	Provide reporting that is: transparent, comparable, consistent, and understandable
FEU	Accurately aligns with how the business is organized and how responsibility is assigned
	Aligns with internal reporting by department
	Avoid the need for duplicate record keeping
	Adaptable to changes in org structure
	Easily modified/updated over time

Cost Center = lowest hierarchal level of Activity View Reporting

FORTIS BC™

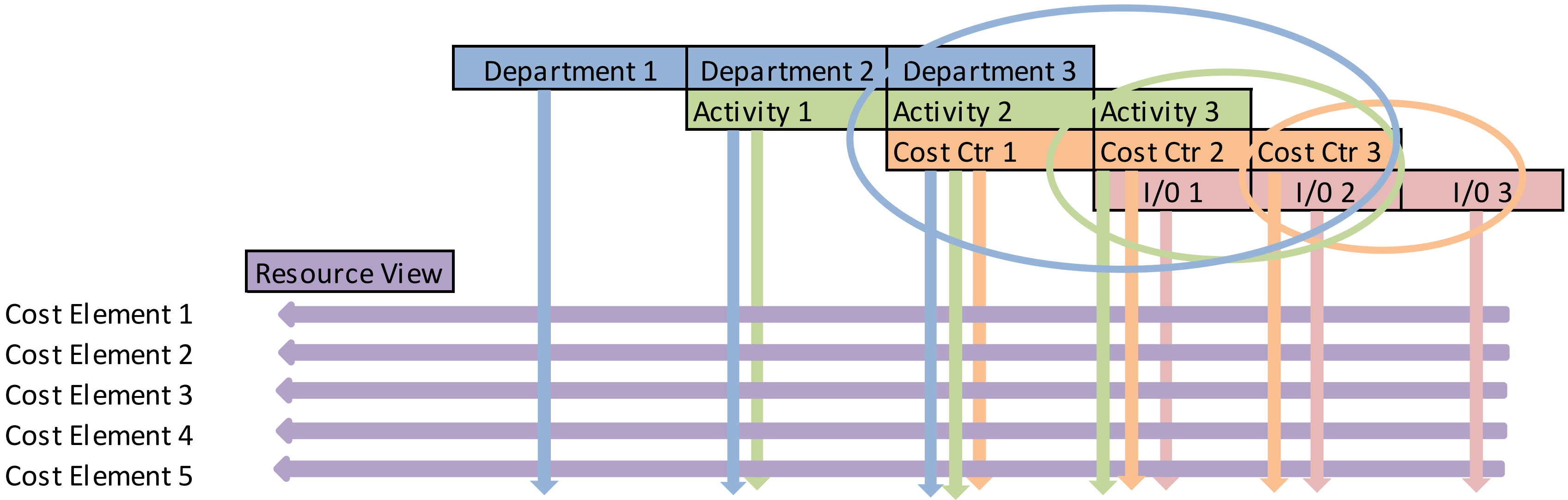
Hierarchy of Activity View Reporting



Internal Orders produce additional segregation within Cost Centers

FORTIS BC™

O&M Reporting Matrix



BCUC	Department View Resource View Activity View
O&M Alert	Department View
Managers	Cost Centre View I/0 View *

* Internal Orders (I/O's) track projects, geographic location, programs, etc.

FORTIS BC

Hierarchy Statistics

Activity View

Departments (as reflected in RRA write-up)	13
Activities (as reflected in BCUC Activity View)	51
Additional layers of hierarchy	
Cost Centers (approx.)	400
Internal Orders	Several Hundred

Resource View

Resources (reflected in BCUC Resource View)	9
Additional layers of hierarchy	
Cost Elements (approx.)	350

FORTIS BC™

FORTISBC ENERGY INC.

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2013
($000)

Line No.	Particulars	BCUC Reference	2009 ACTUAL	2010 ACTUAL	2011 ACTUAL	2012 ACTUAL	2013 FORECAST
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Distribution - Supervision	110-11	-	-	-	-	-
2							
3	Operation Centre	110-21	-	-	-	-	-
4	Distribution – Preventative Maintenance	110-22	-	-	-	-	-
5	Distribution - Operations	110-23	-	-	-	-	-
6	Distribution – Emergency Management	110-24	-	-	-	-	-
7	Distribution – Field Training	110-25	-	-	-	-	-
8	Distribution - Meter Exchange	110-26	-	-	-	-	-
9	Distribution Operations Total	110-20	-	-	-	-	-
10							
11	Distribution - Corrective	110-31	-	-	-	-	-
12	Distribution Maintenance Total	110-30	-	-	-	-	-
13							
14	Distribution – Account Services	110-41	-	-	-	-	-
15	Distribution – Bad Debt Management	110-42	-	-	-	-	-
16	Distribution Meter to Cash Total	110-40	-	-	-	-	-
17							
18	**Distribution Total**	**110**	-	-	-	-	-
19							
20	Transmission - Supervision	120-11	-	-	-	-	-
21							
22	Pipeline/Right of Way Operations	120-21	-	-	-	-	-
23	Compression Operations	120-22	-	-	-	-	-
24	Measurement Control Operations	120-23	-	-	-	-	-
25	Transmission Operations Total	120-20	-	-	-	-	-
26							
27	Pipeline/Right of Way Operations	120-31	-	-	-	-	-
28	Compression Maintenance	120-32	-	-	-	-	-
29	Measurement Control Operations	120-33	-	-	-	-	-
30	Transmission Maintenance Total	120-30	-	-	-	-	-
31							
32	**Transmission Total**	**120**	-	-	-	-	-
33							
34	LNG Plant Operations	130-11	-	-	-	-	-
35	LNG Plant Maintenance	130-21	-	-	-	-	-
36	**LNG Operations Total**	**130**	**-**	**-**	**-**	**-**	**-**
37							
38	**Operations Total**	**100**	-	-	-	-	-
39							
40	Customer Service - Supervision	200-11	-	-	-	-	-
41	Customer Assistance	200-12	-	-	-	-	-
42	Customer Billing	200-13	-	-	-	-	-
43	Meter Reading	200-14	-	-	-	-	-
44	Credit & Collections	200-15	-	-	-	-	-
45	Customer Operations	200-16	-	-	-	-	-
46	**Customer Service Total**	**200**	**-**	**-**	**-**	**-**	**-**

FORTISBC ENERGY INC.

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2013
($000)

Line No.	Particulars (1)	BCUC Reference (2)	2009 ACTUAL (3)	2010 ACTUAL (4)	2011 ACTUAL (5)	2012 ACTUAL (6)	2013 FORECAST (7)
1	Energy Solutions & External Relations – Supervision	300-11	-	-	-	-	-
2	Energy Solutions	300-12	-	-	-	-	-
3	Energy Efficiency	300-13	-	-	-	-	-
4	Corporate Communications, Marketing & Public Affairs	300-14	-	-	-	-	-
5	Resource Planning, Market and Business Development	300-15	-	-	-	-	-
6	**Energy Solutions & External Relations Total**	**300**	-	-	-	-	-
7							
8	Energy Supply & Resource Development	410-11	-	-	-	-	-
9	Gas Control	410-12	-	-	-	-	-
10	**Energy Supply & Resource Development Total**	**410**	-	-	-	-	-
11							
12	Information Technology - Supervision	420-11	-	-	-	-	-
13	Application Management	420-12	-	-	-	-	-
14	Infrastructure Management	420-13	-	-	-	-	-
15	**Information Technology Total**	**420**	-	-	-	-	-
16							
17	System Planning	430-11	-	-	-	-	-
18	Engineering	430-12	-	-	-	-	-
19	Project Management	430-13	-	-	-	-	-
20	**Engineering Services & Project Management Total**	**430**	-	-	-	-	-
21							
22	Supply Chain	440-11	-	-	-	-	-
23	Measurement	440-12	-	-	-	-	-
24	Property Services	440-13	-	-	-	-	-
25	**Operations Support Total**	**440**	-	-	-	-	-
26							
27	Facilities Management	450-11	-	-	-	-	-
28	**Facilities Management Total**	**450**	-	-	-	-	-
29							
30	Environment Health & Safety	460-11	-	-	-	-	-
31	**Environment Health & Safety Total**	**460**	-	-	-	-	-
32							
33	**Business Services Total**	**400**	-	-	-	-	-
34							
35	Financial & Regulatory Services	510-11	-	-	-	-	-
36	**Financial & Regulatory Services Total**	**510**	-	-	-	-	-
37							
38	Human Resources	520-11	-	-	-	-	-
39	**Human Resources Total**	**520**	-	-	-	-	-
40							
41	Legal	530-11	-	-	-	-	-
42	Internal Audit	530-12	-	-	-	-	-
43	Risk Management/Insurance	530-13	-	-	-	-	-
44	**Governance Total**	**530**	-	-	-	-	-
45							
46	Administration & General	540-11	-	-	-	-	-
47	Shared Services Agreement	540-12	-	-	-	-	-
48	Retiree Benefits	540-13	-	-	-	-	-
49	**Corporate Total**	**540**	-	-	-	-	-
50							
51	**Corporate Services Total**	**500**	-	-	-	-	-
52							
53	**Total Gross O&M Expenses**		-	-	-	-	-

Attachment 311.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 311.3

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 311.4

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 311.5

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 311.6

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 311.7

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 311.8

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 323.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 323.3

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 323.4

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 324.5

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 324.7

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 328.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 332.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 332.2

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 345.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 346.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 346.1.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 346.6

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 347.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 351.1

REFER TO LIVE SPREADSHEET MODEL
Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 353.1

THERMAL ENERGY SOLUTIONS

2012 ALLOCATED COSTS

		2012 Estimates	2012 Estimates
	Totals	**497,377.44**	**497,377.44**
ALLOCATION OF OVERHEADS FOR THERMAL ENERGY SOLUTIONS		**SUBTOTAL ($)**	**TOTAL ($)**
AREA	SERVICES TO AES		
Executives	President & CEO	4,220.00	
	EVP, Finance	8,440.00	
	VP Finance & CFO	8,440.00	
	VP Energy Solutions & External Relations	34,815.00	$ 55,915.00
Finance	Accounts Payable	618.72	
		1,167.84	
		537.00	
		241.86	$ 2,565.42
	Operations Financial Analyst/Co-ord	2,474.88	$ 2,474.88
FortisBC Holdings Inc.	Financial Reporting (Carrie Mah)	34,155.00	$ 34,155.00
Regulatory Affairs	Cost of Service group	33,618.75	
	Tariffs & Rate Design group	33,412.50	
	Project Management group	51,150.00	$ 118,181.25
Human Resources	Recruiting related	1,800.00	
	Compensation & Benefits	9,045.14	$ 10,845.14
Information Technology	IT management costs	51,571.85	$ 51,571.85
Facilities	Surrey Facilities costs	63,269.99	
	Garbally Facilities costs	47,910.00	
	Burnaby Facilities costs	110,488.92	$ 221,668.91

THERMAL ENERGY SOLUTIONS

2013 ALLOCATED COSTS

		2013 Estimates	2013 Estimates
	Totals	511,685.86	511,685.86
ALLOCATION OF OVERHEADS FOR THERMAL ENERGY SOLUTIONS		**SUBTOTAL ($)**	**TOTAL ($)**
AREA	SERVICES TO AES		
Executives	President & CEO	4,380.00	
	EVP, Finance	8,760.00	
	VP Finance & CFO	8,760.00	
	VP Energy Solutions & External Relations	36,135.00	$ 58,035.00
Finance	Accounts Payable	642.72	
		1,212.96	
		557.76	
		251.28	$ 2,664.72
	Operations Financial Analyst/Co-ord	2,570.88	$ 2,570.88
FortisBC Holdings Inc.	Financial Reporting (Carrie Mah)	35,145.00	$ 35,145.00
Regulatory Affairs	Cost of Service group	34,856.25	
	Tariffs & Rate Design group	34,650.00	
	Project Management group	52,937.50	$ 122,443.75
Human Resources	Recruiting related	1,880.00	
	Compensation & Benefits	9,400.02	$ 11,280.02
Information Technology	IT management costs	51,227.52	$ 51,227.52
Facilities	Surrey Facilities costs	65,168.09	
	Garbally Facilities costs	49,347.30	
	Burnaby Facilities costs	113,803.59	$ 228,318.97

Attachment 368.1

State	Utility/ Efficiency Program Administrator	Portfolio/ Planning Cycle	Current Cycle Years	Next Cycle Years	Notes	Resource	Link
California	IOUs	Triennial	2013-2014 (transition, see notes)	2015-undetermined	The 2010-2012 efficiency program portfolio cycle recently ended and the CPUC is considering the policy development for post-2012 efficiency programs. The CPUC has recognized that it will not be prepared to commence the next program cycle in 2013 and so is examining the schedule, mechanics, and policy guidance for the 2013-2014 transition period between portfolio cycles, as well as the structure for future portfolios.	California Energy Efficiency Industry Council - Policy Activity	http://www.efficiencycouncil.org/policy-activity/cpuc
Colorado	Xcel Energy	Biennial	2012-2013	2014	In Colorado, Xcel Energy's DSM plan follows a biennial schedule. Xcel is also required to report on an annual basis the results of its programs, including an analysis of cost-effectiveness (second section of Decision C08-0560. Xcel told us that 2014 will be an annual cycle, then going back to biennial after that. The current cycle is 2012-2013.	Xcel CO DSM Annual Status Report 2011	http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/CO-DSM-2011-Annual-Status-Report.pdf
Colorado	Black Hills Energy	Triennial	July 2012- June 2015	July 2015-June 2018	On November 21, 2008 Black Hills filed an Application for Approval of its Electric DSM Plan for calendar years 2009, 2010, 2011. The 2011 – 2012 Annual DSM Status Report for the third and final year of the Electric DSM Plan for period from July 1, 2011 through June 30, 2012	BHE CO DSM Annaul Status Report	https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_fil=G_141481&p_session_id=
Connecticut	IOUs	Biennial	2012-2013	2014-2015	The companies are also continuing to present a two-year budget cycle that will allow for program continuity over a multibple budget year period	2012 Electric and Natural Gas Conservation and Load Management Plan	http://www.ctsavesenergy.org/files/2012%20CLM%20Electric%20and%20Gas%20Plan%20FINAL.pdf
Hawaii	IOUs	Annual?	July 2013 - June 2014	July 2014 - June 2015	On behalf of SAIC, Energy Environment, & Infrastructure , LLC ("SAIC") as the Hawaii Public Benefits Fee Administrator (PBFA), the PBFA's proposed Annual Plan for Program Year 2013 (PY13), July 1, 2013 – June 30, 2014, is presented Uncertain if this is annual funding cycle or just annual review of multiple year portfolio cycle.	Hawaii Energy; Your Conservation and Efficiency Programs Program Year 2013 Annual Plan	http://www.hawaiienergy.com/media/W1siZiIsIjIwMTMvMDYvMjkvMDFfNTRfMDlfODQ2X0hhd2FpaV9FbmVyZ3lfMjAxM19Bbm51YWxfUGxhbl9GSU5BTC5wZGYiXV0/Hawaii%20Energy%202013%20Annual%20Plan%20FINAL.pdf?sha=06225350
Iowa	Alliant	5 year	2013-2017	2018-2022	Alliant Energy implements a 5-year energy efficiency plan to Iowa regulators (the next plan beginning 2013, is due by December 1, 2012). Alliant is required to submit annual reports before May 1 which assess, among other programmatic items, cost-effectiveness (Final order<https://efs.iowa.gov/efiling/groups/external/documents/docket/016067.pdf>, Docket # EEP-08-1, pdf page 38 numbers 1,2, and 3).	EEP-2008-0001 Energy Efficiency Plan	http://www.state.ia.us/government/com/util/energy/energy_efficiency/ee_plans_reports.html
Iowa	MidAmerican	5 year	2013-2017	2018-2022	MidAmerican Energy also follows a similar 5-year energy-efficiency plan according to this order<https://efs.iowa.gov/efiling/groups/external/documents/docket/004253.pdf>from the Iowa Utilities Board (pdf pages 7-8).	EEP-2008-0002 Energy Efficiency Plan	http://www.state.ia.us/government/com/util/energy/energy_efficiency/ee_plans_reports.html

Indiana	IOUs	Triennial	2011-2013	2014-2016	1st resource: On July 1, 2010, the utilities must submit their first DSM plans to the Commission to address progress with respect to their annual DSM savings goals. Subsequent DSM plansmust be filed with the Commission on July 1, 2013, 2016, and 2019, with annual supplemental updates in the interim periods. 2nd resource: IURC's Generic Order in Cause No. 42693, requires the jurisdictional electric utilities to submit a series of three discrete three year DSM plans. The next set of three year DSM plans for achievement of the IURC targets for the period from 2014 to 2016 will be filed in 2012.	Indiana Utility Regulatory Commission	http://www.in.gov/iurc/2571.htm
Maryland	IOUs	Triennial	2012-2014	2015-2017	Portfolio cycle is triennial. It is currently in the 2012-2014 cycle. The Companies filed their Plans for the 2012-2014 period with the Commission on or about September 1, 2011	Maryland PSC - Order No. 84569	http://webapp.psc.state.md.us/Intranet/sitesearch/Press%20Releases/Commission%20Renews%20and%20Expands%20Commitment%20to%20EmPOWER%20Maryland.pdf
Massachusetts	IOUs	Triennial	2013-2015	2016-2018	Triennial. Filed EE plan in 2012 for 2013-2015 cycle. Updates to the plan are provided annually.	Massachusetts Joint Statewide Three-Year Electric Energy Efficiency Plan	http://www.mass.gov/eea/docs/doer/energy-efficiency/statewide-electric-and-gas-three-year-plan.pdf
New Hampshire	Electric Utilities	Biennial	2013-2014	2015-2016	This filing for the 2013-2014 CORE Energy Efficiency Programs is being made jointly by Granite State Electric Company d/b/a Liberty Utilities, New Hampshire Electric Cooperative, Inc., Public Service Company ofNew Hampshire and Unitil Energy Systems, Inc. (referred to throughout the remainder of this document as the "NH Electric Utilities") Note: the aceee states "The PUC reviews and authorizes the utilities' joint program plans and budgets annually" so perhaps the option to file annual plans exists	2013-2014 CORE New Hampshire Energy Efficiency Programs	http://www.puc.nh.gov/Regulatory/Docketbk/2012/12-262/TRANSCRIPTS-OFFICIAL%20EXHIBITS-CLERKS%20REPORT/12-262%202012-12-21%20EXH%202%20PSNH%20MERGED%20ATTACHMENT%20A%20AND%20B%20TO%20SETTLEMENT%20AND%20UPDATED%20TO%20INCLUDE%20LATEST%20CORRECTIONS.PDF
New Mexico	Xcel Energy	Annual?	2013	2014	Resource 2: The New Mexico Public Regulation Commission states that " Requests for program approval shall be made in a single filing at least every two years, except for good cause shown or as otherwise ordered by the commission." Each utility providing energy efficiency or load management programs shall file an annual report with the commission, and post that report on a publicly accessible website.	2012 Energy Efficiency and Load Management Plan	http://www.xcelenergy.com/About_Us/Rates_&_Regulations/Regulatory_Filings/NM_DSM
New York	IOUs	Triennial	2012-2015	2016-?	Triennial. In October of 2011, the Commission authorized the next phase of Energy Efficiency Portfolio Standard from 2012 through 2015. Directly related to NYSERDA's programs, in October 2011, the PSC authorized the next phase of the System Benefits Charge (SBC) funded programs from 2012 through 2016. The EEPS, which runs through 2015, focuses on energy efficiency resource acquisition.	NYSERDA: Toward a Clean Energy Future: A Three-Year Strategic Outlook 2012–2015	https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&cad=rja&ved=0CCsQFjAA&url=http%3A%2F%2Fwww.nyserda.ny.gov%2FEnergy-Data-and-Prices-Planning-and-Policy%2F-%2Fmedia%2FFiles%2FAbout%2FStrategic%2520Plan%2FStrategic%2520Outlook.pdf&ei=hf93UoH1KsKSyAGf3YCIBQ&usg=AFQjCNH_F6qEtEBk_iHRMxj1X6PHB7J4Kg&bvm=bv.55819444,d.aWc

Ohio	AEP Ohio	Triennial	2012-2014	2015-2017	AEP Ohio is subject to a triennial planning cycle for its DSM programs, which are referred to as Energy Efficiency/Peak Demand Reduction (EE/PDR) programs. It is currently in the 2012-2014 program cycle. The current EE/PDR programs will be up for renewal in 2015.	Ohio Energy Efficiency and Peak Demand Order/Rules Highlights	http://www.puco.ohio.gov/puco/index.cfm/industry-information/industry-topics/energy-efficiency-and-peak-demand-orderrules-highlights/
Ohio	Ohio Edison	Triennial	2013-2015	?	Typically, Ohio Energy operates its energy efficiency and demand response programs in a three-year cycle. On March 23, 2011 the Public Utilities Commission of Ohio (PUCO) approved the utility's plan for 2010-2012. On November 15, 2012, Ohio Edison requested to extend their existing efficiency and DR programs for 2013-2015. On December 12, 2012 PUCO approved the programs through the end of 2013. It is not clear why PUCO did not grant an extension through the end of 2015.	Ohio Energy Efficiency and Peak Demand Order/Rules Highlights	http://www.puco.ohio.gov/puco/index.cfm/industry-information/industry-topics/energy-efficiency-and-peak-demand-orderrules-highlights/
Ontario	Enbridge Gas	Triennial	2012-2014	2015-2017	Most recently, the Board developed new DSM guidelines to help the natural gas distributors form new multi-year DSM plans for 2012-2014. Both distributors applied for and received approval of new DSM plans based on the new guidelines in early 2012. Enbridge Gas Distribution was approved of a one-year DSM plan for 2012, with the intention that it would file for approval of its 2013-2014 DSM plan sometime in 2012.	Ontario Energy Board - Natural Gas Demand Side Management	http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory%20Proceedings/Policy%20Initiatives%20and%20Consultations/Conservation%20and%20Demand%20Management%20(CDM)/Natural%20Gas%20DSM
Ontario	Union Gas	Triennial	2012-2014	2015-2017	Most recently, the Board developed new DSM guidelines to help the natural gas distributors form new multi-year DSM plans for 2012-2014. Union Gas Limited was approved of a three-year DSM plan, with the exception of its large industrial program which was approved on a one-year basis.	Ontario Energy Board - Natural Gas Demand Side Management	http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory%20Proceedings/Policy%20Initiatives%20and%20Consultations/Conservation%20and%20Demand%20Management%20(CDM)/Natural%20Gas%20DSM
Ontario	Electric Utilities	Quadrennial	2011-2014	?	The Conservation and Demand Management framework sets out policy priorities for conservation, prescribes targets for local utilities and establishes funding for conservation programs. It began in 2011 and applies until the end of 2014.	Guidelines for Electricity Distributor Conservation and Demand Managagment	http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2012-0003/CDM_Guidelines_Electricity_Distributor.pdf
Pennsylvania	IOUS	Triennial	June 2013-May 2016	June 2016-May 2019	Three year plans for IOUs, Duquense, PECO, PPL	Act 129 Phase II , PUC press release	http://www.puc.state.pa.us/about_puc/press_releases.aspx?ShowPR=3098
Rhode Island	National Grid	Triennial	2012-2014	2015-2017	National Grid (NGrid) Rhode Island's current three-year efficiency cycle concludes December 31, 2014. Updates to the plan are provided annually.	RI PUC	http://www.ripuc.org/eventsactions/docket/4284page.html

Texas	Distributing Utilities	Annual	2013	2014	Resource 1: According to aceee "Utilities submit plans for the forthcoming year and reports on energy and capacity savings from the previous year to the PUCT. The PUCT approves the plans. Utilities receive performance bonuses based on their energy savings." Resource 2:"The Energy Efficiency Rule requires the electric utilities to file an Energy Efficiency Plan & Report (EEPR) by April 1 of each year. The EEPR describes how the utility intends to achieve the goals set forth by the PUC and is divided into a Plan, which describes how the utility intends to implement its energy efficiency programs over the next two years and a Report, which outlines actual program results and spending for the previous program year."	ACEEE, Texas Energy Efficiency	http://aceee.org/sector/state-policy/texas
Vermont	IOUs	Triennial	2012-2014	2015-2017	The PSB determines overall budgets (including budgets for EVT, BED, the DPS, and the Fiscal Agent) for energy efficiency program delivery on a three year cycle The Evaluation Plan and budget for the 2012-2014 time period will be developed in the Board's Demand Resource Plan proceeding	Vermont Department of Public Service Biennial Report July 1, 2006 - June 30, 2010	http://publicservice.vermont.gov/sites/psd/files/Pubs_Plans_Reports/Biennial_Reports/2010%20Biennial%20-%20Publication%20Draft.pdf

Attachment 368.1.1

State	Utility/ Efficiency Program Administrator	Portfolio/ Planning Cycle	Current Cycle Years	Next Cycle Years	Notes	Resource	Link
Florida	FPL	10	2010-2019	2020-2029	A representative with Florida Power and Light explained that the Florida Public Service (FPS) reviews its DSM goals every 5 years (or more frequently if the commission decides so), at which time the commission sets goals for the subsequent 10-year period. For example, in 2004 FPS set goals for the 2005-2014 period. In 2009, FPS then re-set the goals for the 2010-2019 period. Upon development of each new plan every five years, FPL re-assesses cost effectiveness of all measures & programs included in its DSM plan to be filed to ensure the plan is cost effective. My contact at FPL noted that FPS has recently requested an annual assessment of cost effectiveness based on current planning assumptions.	DSM Plan of FPL for 2010-2019	http://www.psc.state.fl.us/library/FILINGS/11/01989-11/01989-11.pdf
Iowa	Alliant	5	2013-2017	2018-2022	Alliant Energy implements a 5-year energy efficiency plan to Iowa regulators (the next plan beginning 2013, is due by December 1, 2012). Alliant is required to submit annual reports before May 1 which assess, among other programmatic items, cost-effectiveness (Final order<https://efs.iowa.gov/efiling/groups/external/documents/docket/016067.pdf>, Docket # EEP-08-1, pdf page 38 numbers 1,2, and 3).	EEP-2008-0001 Energy Efficiency Plan	http://www.state.ia.us/government/com/util/energy/energy_efficiency/ee_plans_reports.html
Iowa	MidAmerican	5	2013-2017	2018-2022	MidAmerican Energy also follows a similar 5-year energy-efficiency plan according to this order<https://efs.iowa.gov/efiling/groups/external/documents/docket/004253.pdf>from the Iowa Utilities Board (pdf pages 7-8).	EEP-2008-0002 Energy Efficiency Plan	http://www.state.ia.us/government/com/util/energy/energy_efficiency/ee_plans_reports.html
South Dakota	MidAmerican Energy Company	5	2013-2017	2018-2022?		MidAmericanEnergy Company South Dakota Energy EfficiencyPlan2013-2017 Executive Summary	http://puc.sd.gov/commission/dockets/gas&electric/2012/GE12-005/exhibit1revised.pdf
West Virginia	Monongahela Power Company	5	2012 - 2016	2017-2021	"The Companies represented that the Plan was designed to achieve energy and demand reduction targets of approximately 67,437,000 megawatt-hours (MWh) of net energy savings and 13.8 megawatts (MW) of system peak demand savings in a five-year period between 2012 through 2016." Required to file annual progress reports starting in 2013	Petition for approval of Phase I Plan for Energy and Demand Reduction Efforts and related cost recovery mechanisms.	http://www.psc.state.wv.us/scripts/WebDocket/ViewDocument.cfm?CaseActivityID=336129
West Virginia	Potomac Edison Company	5	2012 - 2016	2017-2021	"The Companies represented that the Plan was designed to achieve energy and demand reduction targets of approximately 67,437,000 megawatt-hours (MWh) of net energy savings and 13.8 megawatts (MW) of system peak demand savings in a five-year period between 2012 through 2016." Required to file annual progress reports starting in 2013		"
Ontario	Electric Utilities	4	2011-2014	?	The Conservation and Demand Management framework sets out policy priorities for conservation, prescribes targets for local utilities and establishes funding for conservation programs. It began in 2011 and applies until the end of 2014.	Guidelines for Electricity Distributor Conservation and Demand Managagment	http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2012-0003/CDM_Guidelines_Electricity_Distributor.pdf

Pennsylvania	IOUS	4	2009-2013	2014-2018	Duties of electric distribution companies.-- (1) (i) By July 1, 2009, each electric distribution company shall develop and file an energy efficiency and conservation plan with the commission for approval to meet the requirements of subsection (a) and the requirements for reduction in consumption under subsections (c) and (d). The plan shall be implemented upon approval by the commission. (ii) A new plan shall be filed with the commission every five years or as otherwise required by the commission. The plan shall set forth the manner in which the company will meet the required reductions in consumption under subsections (c) and (d).	Act of Oct. 15, 2008, P.L. 1592, No. 129	http://www.legis.state.pa.us/WU01/LI/LI/US/HTM/2008/0/0129..HTM
Wisconsin	Focus on Energy	4	2011-2014	2015-2018	Focus on Energy is subject to a quadrennial planning docket. The current docket covers calendar years 2011 through 2014 and will be up for renewal in 2015.	Focus on Energy	
California	IOUs	3	2013-2014 (transition, see notes)	2015-undetermined	The 2010-2012 efficiency program portfolio cycle recently ended and the CPUC is considering the policy development for post-2012 efficiency programs. The CPUC has recognized that it will not be prepared to commence the next program cycle in 2013 and so is examining the schedule, mechanics, and policy guidance for the 2013-2014 transition period between portfolio cycles, as well as the structure for future portfolios.	California Energy Efficiency Industry Council - Policy Activity	http://www.efficiencycouncil.org/policy-activity/cpuc
Colorado	Black Hills Energy	3	July 2012- June 2015	July 2015-June 2018	On November 21, 2008 Black Hills filed an Application for Approval of its Electric DSM Plan for calendar years 2009, 2010, 2011. The 2011 – 2012 Annual DSM Status Report for the third and final year of the Electric DSM Plan for period from July 1, 2011 through June 30, 2012	BHE CO DSM Annaul Status Report	https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_fil=G_141481&p_session_id=
Illinois	ComEd	3	2011-2013	2014-2016	Triennial - file in 2010 and 2013. Current cycle is 2011-2013 and next cycle is 2014-2016.	Illinois Energy Efficiency Stakeholder Advisory Group - Administrative Portfolio Plans	http://ilsag.org/administrative_portfolio_plans
Illinois	Ameren	3	2011-2013	2014-2016	Triennial - file in 2010 and 2013. Current cycle is 2011-2013 and next cycle is 2014-2016.	Illinois Energy Efficiency Stakeholder Advisory Group - Administrative Portfolio Plans	http://ilsag.org/administrative_portfolio_plans
Indiana	IOUs	3	2011-2013	2014-2016	1st resource: On July 1, 2010, the utilities must submit their first DSM plans to the Commission to address progress with respect to their annual DSM savings goals. Subsequent DSM plansmust be filed with the Commission on July 1, 2013, 2016, and 2019, with annual supplemental updates in the interim periods. 2nd resource: IURC's Generic Order in Cause No. 42693, requires the jurisdictional electric utilities to submit a series of three discrete three year DSM plans. The next set of three year DSM plans for achievement of the IURC targets for the period from 2014 to 2016 will be filed in 2012.	Indiana Utility Regulatory Commission	http://www.in.gov/iurc/2571.htm

Louisiana	Entergy New Orlean	3	April, 2011 - March, 2014	April, 2014 - March, 2017?	According to aceee: Entergy is the only utility offering a portfolio of energy efficiency programs to customers in the City of New Orleans.	Energy Smart: Year 1 Annual Repo	http://www.entergy-neworleans.com/content/docs/Year_1_Energy_Smart_Annual_Report.pdf
Maine	Efficiency Maine	3	2011-2013	2014-2016	Triennial plan filed in 2012 for the fiscal years 2014-2016	Triennial Plan For Fiscal Years 2014-2016	http://www.efficiencymaine.com/docs/reports/TriPlan2-11-26-2012.pdf
Maryland	IOUs	3	2012-2014	2015-2017	Portfolio cycle is triennial. It is currently in the 2012-2014 cycle. The Companies filed their Plans for the 2012-2014 period with the Commission on or about September 1, 2011	Maryland PSC - Order No. 84569	http://webapp.psc.state.md.us/Intranet/sitesearch/Press%20Releases/Commission%20Renews%20and%20Expands%20Commitment%20to%20EmPOWER%20Maryland.pdf
Maryland	PEPCO	3	2012-2014	2015-2017	Potamac Electric Power Company (Pepco) currently operates its EmPOWER Maryland programs in a three-year cycle, currently slated to conclude December 31, 2014.		
Massachusetts	IOUs	3	2013-2015	2016-2018	Triennial. Filed EE plan in 2012 for 2013-2015 cycle. Updates to the plan are provided annually.	Massachusetts Joint Statewide Three-Year Electric Energy Efficiency Plan	http://www.mass.gov/eea/docs/doer/energy-efficiency/statewide-electric-and-gas-three-year-plan.pdf
Minnesota	Xcel	3	2013-2015	2016-2018	The portfolio cycle period is triennial. The most recent Triennial Plan for the 2013-2015 period was filed in June 2012. The DSM portfolio will next be up for renewal for the period 2016-2018 and the next Triennial Plan will likely be filed in mid-2015.	Xcel Energy - 2013-2015 Minnesota Electric and Natural Gas Conservation Improvement Program	http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/MN-DSM/MN-DSM-2013-2015-CIP-Triennial-Plan.pdf
Minnesota	CenterPoint Energy	3	2013-2015	2016-2018	Conservation Improvement Program Triennial Plans available on MN Center for Energy and Environment	MN Center for Energy and Environment	http://www.mncee.org/Innovation-Exchange/Resource-Center/Data-and-Reference/Minnesota-Energy-Dockets/
Minnesota	IPL	3	2013-2015	2016-2018	Conservation Improvement Program Triennial Plans available on MN Center for Energy and Environment	MN Center for Energy and Environment	http://www.mncee.org/Innovation-Exchange/Resource-Center/Data-and-Reference/Minnesota-Energy-Dockets/
Minnesota	MN Energy Resources Corp	3	2013-2015	2016-2018	Conservation Improvement Program Triennial Plans available on MN Center for Energy and Environment	MN Center for Energy and Environment	http://www.mncee.org/Innovation-Exchange/Resource-Center/Data-and-Reference/Minnesota-Energy-Dockets/
Minnesota	Minnesota Power	3	2011-2013	2014-2016	Conservation Improvement Program Triennial Plans available on MN Center for Energy and Environment	MN Center for Energy and Environment	http://www.mncee.org/Innovation-Exchange/Resource-Center/Data-and-Reference/Minnesota-Energy-Dockets/
Minnesota	Otter Tail	3	2011-2013	2014-2016	Conservation Improvement Program Triennial Plans available on MN Center for Energy and Environment	MN Center for Energy and Environment	http://www.mncee.org/Innovation-Exchange/Resource-Center/Data-and-Reference/Minnesota-Energy-Dockets/

Missouri	Ameren	3	2013-2015	2016-2018	According to the DSM section of the 2011 IRP, Ameren Missouri filed for a three-year portfolio cycle to begin January 1, 2012 and extend through December 31, 2014 (see page 1). However, Ameren made 2012 a bridge funding year as it discussed rate recovery mechanisms with the Commission to avoid company losses due to efficiency spending. In 2012, Ameren filed a three-year efficiency plan for 2013-2015. Therefore, the current efficiency cycle is slated to conclude December 31, 2015. Here is a link to Ameren Missouri's 2013-2015 Energy Efficiency Plan.	Ameren 2013-2015 Energy Efficiency Plan	https://www.efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=935658690
Nevada	NV Energy (two IOUs: Nevada Power Company & Sierra Nevada Power under this brand)	3	2013-2015	2016-2018	The 2013-2015 Demand Side Plan is included in the Nevada Power Company's Integrated Resouce Plan for 2013-2032. The Demand Side Plan begins on pg. 78/319	NV Energy: The 2013-2015 Demand Side Plan	https://www.nvenergy.com/company/rates/filings/IRP/NPC_IRP/images/vol_7.pdf
New York	IOUs	3	2012-2015	2016-?	Triennial. In October of 2011, the Commission authorized the next phase of Energy Efficiency Portfolio Standard from 2012 through 2015. Directly related to NYSERDA's programs, in October 2011, the PSC authorized the next phase of the System Benefits Charge (SBC) funded programs from 2012 through 2016. The EEPS, which runs through 2015, focuses on energy efficiency resource acquisition.	NYSERDA: Toward a Clean Energy Future: A Three-Year Strategic Outlook 2012–2015	https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&cad=rja&ved=0CCsQFjAA&url=http%3A%2F%2Fwww.nyserda.ny.gov%2FEnergy-Data-and-Prices-Planning-and-Policy%2F-%2Fmedia%2FFiles%2FAbout%2FStrategic%2520Plan%2FStrategic%2520Outlook.pdf&ei=hf93UoH1KsKSyAGf3YCIBQ&usg=AFQjCNH_F6qEtEBk_iHRMxj1X6PHB7J4Kg&bvm=bv.55819444,d.aWc
Ohio	AEP Ohio	3	2012-2014	2015-2017	AEP Ohio is subject to a triennial planning cycle for its DSM programs, which are referred to as Energy Efficiency/Peak Demand Reduction (EE/PDR) programs. It is currently in the 2012-2014 program cycle. The current EE/PDR programs will be up for renewal in 2015.	Ohio Energy Efficiency and Peak Demand Order/Rules Highlights	http://www.puco.ohio.gov/puco/index.cfm/industry-information/industry-topics/energy-efficiency-and-peak-demand-orderrules-highlights/
Ohio	Ohio Edison	3	2013-2015	?	Typically, Ohio Energy operates its energy efficiency and demand response programs in a three-year cycle. On March 23, 2011 the Public Utilities Commission of Ohio (PUCO) approved the utility's plan for 2010-2012. On November 15, 2012, Ohio Edison requested to extend their existing efficiency and DR programs for 2013-2015. On December 12, 2012 PUCO approved the programs through the end of 2013. It is not clear why PUCO did not grant an extension through the end of 2015.	Ohio Energy Efficiency and Peak Demand Order/Rules Highlights	http://www.puco.ohio.gov/puco/index.cfm/industry-information/industry-topics/energy-efficiency-and-peak-demand-orderrules-highlights/
Ohio	Duke	3	2011-2013	2013-2015	Program cycles are roughly triennial. On December 29, 2009 Duke Energy Ohio filed an updated portfolio plan for approval, which was approved by the commission on December 15, 2010 for implementation through April 15, 2013.	Ohio PUC	_

Ontario	Enbridge Gas	3	2012-2014	2015-2017	Most recently, the Board developed new DSM guidelines to help the natural gas distributors form new multi-year DSM plans for 2012-2014. Both distributors applied for and received approval of new DSM plans based on the new guidelines in early 2012. Enbridge Gas Distribution was approved of a one-year DSM plan for 2012, with the intention that it would file for approval of its 2013-2014 DSM plan sometime in 2012.	Ontario Energy Board - Natural Gas Demand Side Management	http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory%20Proceedings/Policy%20Initiatives%20and%20Consultations/Conservation%20and%20Demand%20Management%20(CDM)/Natural%20Gas%20DSM
Ontario	Union Gas	3	2012-2014	2015-2017	Most recently, the Board developed new DSM guidelines to help the natural gas distributors form new multi-year DSM plans for 2012-2014. Union Gas Limited was approved of a three-year DSM plan, with the exception of its large industrial program which was approved on a one-year basis.	Ontario Energy Board - Natural Gas Demand Side Management	http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory%20Proceedings/Policy%20Initiatives%20and%20Consultations/Conservation%20and%20Demand%20Management%20(CDM)/Natural%20Gas%20DSM
Pennsylvania	IOUS	3	June 2013-May 2016	June 2016-May 2019	Three year plans for IOUs, Duquense, PECO, PPL	Act 129 Phase II , PUC press release	http://www.puc.state.pa.us/about_puc/press_releases.aspx?ShowPR=3098
Rhode Island	National Grid	3	2012-2014	2015-2017	National Grid (NGrid) Rhode Island's current three-year efficiency cycle concludes December 31, 2014. Updates to the plan are provided annually.	RI PUC	http://www.ripuc.org/eventsactions/docket/4284page.html
Vermont	IOUs	3	2012-2014	2015-2017	The PSB determines overall budgets (including budgets for EVT, BED, the DPS, and the Fiscal Agent) for energy efficiency program delivery on a three year cycle The Evaluation Plan and budget for the 2012-2014 time period will be developed in the Board's Demand Resource Plan proceeding	Vermont Department of Public Service Biennial Report July 1, 2006 - June 30, 2010	http://publicservice.vermont.gov/sites/psd/files/Pubs_Plans_Reports/Biennial_Reports/2010%20Biennial%20-%20Publication%20Draft.pdf
Virginia	Dominion	3	2012-2014	2015-2017	Current cycle is 2012-2014		https://www.dom.com/about/pdf/irp/addendum-1.pdf
Colorado	Xcel Energy	2	2012-2013	2014	In Colorado, Xcel Energy's DSM plan follows a biennial schedule. Xcel is also required to report on an annual basis the results of its programs, including an analysis of cost-effectiveness (second section of Decision C08-0560. Xcel told us that 2014 will be an annual cycle, then going back to biennial after that. The current cycle is 2012-2013.	Xcel CO DSM Annual Status Report 2011	http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/CO-DSM-2011-Annual-Status-Report.pdf
Connecticut	IOUs	2	2012-2013	2014-2015	The companies are also continuing to present a two-year budget cycle that will allow for program continuity over a multibple budget year period	2012 Electric and Natural Gas Conservation and Load Management Plan	http://www.ctsavesenergy.org/files/2012%20CLM%20Electric%20and%20Gas%20Plan%20FINAL.pdf
New Hampshire	Electric Utilities	2	2013-2014	2015-2016	This filing for the 2013-2014 CORE Energy Efficiency Programs is being made jointly by Granite State Electric Company d/b/a Liberty Utilities, New Hampshire Electric Cooperative, Inc., Public Service Company ofNew Hampshire and Unitil Energy Systems, Inc. (referred to throughout the remainder of this document as the "NH Electric Utilities") Note: the aceee states "The PUC reviews and authorizes the utilities' joint program plans and budgets annually" so perhaps the option to file annual plans exists	2013-2014 CORE New Hampshire Energy Efficiency Programs	http://www.puc.nh.gov/Regulatory/Docketbk/2012/12-262/TRANSCRIPTS-OFFICIAL%20EXHIBITS-CLERKS%20REPORT/12-262%202012-12-21%20EXH%202%20PSNH%20MERGED%20ATTACHMENT%20A%20AND%20B%20TO%20SETTLEMENT%20AND%20UPDATED%20TO%20INCLUDE%20LATEST%20CORRECTIONS.PDF

Texas	Distributing Utilities	1	2013	2014	Resource 1: According to aceee "Utilities submit plans for the forthcoming year and reports on energy and capacity savings from the previous year to the PUCT. The PUCT approves the plans. Utilities receive performance bonuses based on their energy savings." Resource 2:"The Energy Efficiency Rule requires the electric utilities to file an Energy Efficiency Plan & Report (EEPR) by April 1 of each year. The EEPR describes how the utility intends to achieve the goals set forth by the PUC and is divided into a Plan, which describes how the utility intends to implement its energy efficiency programs over the next two years and a Report, which outlines actual program results and spending for the previous program year."	ACEEE, Texas Energy Efficiency	http://aceee.org/sector/state-policy/texas
Average DSM funding approval		**3.37**					

Attachment 372.1.1

Efficient Boiler Program application

FORTIS BC™

FortisBC use only:	Application number	Date received (Yr/Mth/Day)

1. Applicant information (Please print clearly. Retain copy for your records.)

Is this application for: ☐ New construction? ☐ Replacement?	Account number	Premise number/point of delivery number	Date (Yr/Mth/Day)

Company/business name/strata plan number	Contact name	Title

Street address	Town/city	Province/state	Postal code/zip code

Email address	Phone number

Please check one

☐ Property owner ☐ Builder/developer ☐ Long term lease holder ☐ Other (please specify):

2. Contractor information

Gas contractor name	BCSA gas contractor licence number	BCSA/municipal gas installation permit number

Contact name	E-mail address	Phone number

Boiler contractor name	BCSA boiler contractor licence number	BCSA gas installation permit number

Contact name	E-mail address	Phone number

3. Building information

Building address	Town/city	Province/state	Postal code/zip code

Building use

☐ Multifamily ☐ Office ☐ Hotel/Motel ☐ School/College/University ☐ Restaurant ☐ Retail ☐ Warehouse ☐ Hospital/Healthcare

If other please specify:	Heated area (square feet)

4. Heating system information

What will the boilers be used for? (please check all that apply) ☐ Space heating ☐ Pool heating (complete and attach the *Pool Data Requirements Sheet*)	Will the boiler also be used for domestic water heating? ☐ Yes ☐ No

Please specify any other uses for the boiler(s)

Type of heating system terminal units

☐ Baseboard ☐ Radiant floor ☐ Fan coil ☐ Radiator ☐ Air handling unit ☐ Other (specify):

Replacement projects: Existing boiler plant (please list the boilers that are being replaced)

	Input rating (Btu/hr)	What is the boiler used for? (please check all that apply for each boiler)
1		☐ Space heating ☐ Domestic water heating ☐ Pool heating ☐ Other (please specify):
2		☐ Space heating ☐ Domestic water heating ☐ Pool heating ☐ Other (please specify):
3		☐ Space heating ☐ Domestic water heating ☐ Pool heating ☐ Other (please specify):

New construction projects: (Note: include letter or calculations from professional engineer detailing the estimate along with application)

Estimated annual gas savings from an energy efficient boiler versus a standard atmospheric boiler (GJ per year)

5. Boiler rebate calculation

For boilers with an input rating less than or equal to 299,000 Btu/hr (299 MBH)

A	B	C	D	E	F	G	H
Make	Model	Input rating (MBH)	Number of boilers	Incentive ($ per MBH) Condensing boiler $12 Mid efficiency boiler $4	Total incentive (C x D x E)	Boiler purchase price (Appliance price only. No installation costs)	Total installation cost (before tax)

For boilers with an input rating greater than 299,000 Btu/hr (300 MBH)							
A	B	C	D	E	F	G	H
Make	Model	Input rating (MBH)	Number of boilers	Incentive($ per boiler) Please refer to eligible boiler list	Total incentive (D x E)	Boiler purchase price (Appliance price only, no installation costs)	Total installation cost (before tax)

6. Boiler right sizing (replacement participants only)

Have you completed a design space heating load calculation?

☐ Yes ☐ No If yes, you MUST include a copy of the heat load calculations and heat load invoice to be eligible for the right sizing bonus.

7. Energy efficiency measures

Did you implement any other energy efficiency measures with the boiler installation to reduce your gas consumption?

☐ Yes ☐ No If yes, please describe below.

Description of other energy efficiency measures	Date implemented (Yr/Mth/Day)	Expected gas savings (GJ per year) *optional*

Are you considering implementing any additional energy efficiency measures in the future to reduce the gas consumption at this facility?

☐ Yes ☐ No If yes, please describe below.

Description of other energy efficiency measures	Date implemented (Yr/Mth/Day)	Expected gas savings (GJ per year) *optional*

Did you consider replacing the boiler with a standard efficiency (atmospheric) model instead of a high efficiency boiler?

☐ Yes ☐ No

To what degree did the Efficient Boiler Program incentive affect your decision to purchase a high-efficiency boiler?

☐ Strongly affected ☐ Somewhat affected ☐ Did not affect ☐ Do not know

Applicant declaration

I, the Applicant, declare that:

- I have read, fully understand and agree to abide by the Efficient Boiler Program Terms and Conditions.
- I am an eligible participant as defined in the Efficient Boiler Program Terms and Conditions.
- The existing boilers listed above have been fully installed, are operational and provide thermal energy for only program admissible end uses, namely space heating, pool heating or a combination of space and or pool heating and domestic hot water heating.
- I understand that falsification of information submitted to FortisBC as a part of this application or failure to comply with any of the Efficient Boiler Program Terms and Conditions as determined by FortisBC in its sole discretion, means that I will need to repay FortisBC any incentive amount paid to me under this Program.
- If the Applicant is not a natural person (for example, a corporation), the undersigned has the authority to bind the Applicant.

Applicant name (please print)   Applicant title   Applicant signature   Date (Yr/Mth/Day)

***Note: Supporting documents must be submitted within 90 days of the date of application. Refer to checklist on page 3.**

Mail to: Energy Efficiency & Conservation
FortisBC Energy Inc. 16705 Fraser Highway
Surrey BC, V4N 0E9

Fax to: 604-592-7618
Email to: commercialrebates@fortisbc.com

Efficient Boiler Program application checklist

The following documentation must be submitted to FortisBC in order to receive a rebate under the Efficient Boiler Program:

- ☐ Completed and signed Efficient Boiler Program application form
- ☐ Completed "Gas Notification of Completion, Installation or Alteration" indicating the contractor's licence no. and gas fitter no.
- ☐ Copy of proof of purchase;
  - **Retrofit applications**: Paid invoice indicating the make, model number, and serial number of the boiler(s) purchased and installed.
  - **New construction applications:** The paid invoice indicating the make, model number, and serial number of the boiler(s) purchased and installed ***or*** shop drawings approved by the project engineer, indicating the job name and address, as well as the make and model number of the boiler(s) purchased and installed.
- ☐ **For new construction projects:** Estimate of the annual gas savings by upgrading to an energy efficient boiler over an atmospheric boiler. **Note: Failure to provide this estimate will invalidate the application.**
- ☐ **For pool heating applications:** Completed Pool Data Requirements Sheet. **Note: Failure to provide this data sheet will invalidate the application.**
- ☐ **For the right sizing bonus (Retrofit only):** Completed heat loss calculation to show the boiler has been sized correctly to meet the heating load. Invoice for this service must also be provided.
- ☐ **For boiler pre purchases:** Completed boiler pre-purchase form filled out and submitted to FortisBC prior to the date of purchase of the boiler(s) as evidenced by the boiler invoice date or the shop drawing approval date.

<u>NOTES</u>

1. Applications must be submitted to FortisBC no later than 90 days after the boiler in service date as shown on the Gas Notification of Completion, Installation or Alteration.
2. All supporting documents outlined above must be submitted to FortisBC no later than 90 days after the date of application. FortisBC strongly encourages all applicants to submit all required supporting documentation with the application.
3. Applicants who wish to purchase their boiler more than 90 days prior to the boiler in service date as shown on the Gas Notification of Completion, Installation or Alteration, must complete the boiler pre-purchase form and submit the completed form to FortisBC prior to the date of purchase of the boiler(s) as evidenced by the boiler invoice date or the shop drawing approval date. In no case may the boiler(s) be purchase more than 180 days prior to the boiler in service date as shown on the Gas Notification of Completion, Installation or Alteration.

Efficient Boiler Program -Terms and Conditions

Overview

The Efficient Boiler Program (the "Program") from FortisBC Energy Inc., FortisBC Energy (Whistler) Inc., and FortisBC Energy (Vancouver Island) Inc. (collectively "FortisBC") is designed to stimulate investment in high-efficiency natural gas fired hot water boiler plants in commercial and institutional buildings that reduce natural gas consumption, greenhouse gas ("GHG") emissions and associated operating costs.

The Program is applicable to onsite boiler installations in both new construction and replacement markets. A rebate is provided to qualifying applicants to offset a portion of the higher cost of purchasing and installing high, versus standard, efficiency boilers. If you're installing, replacing or upgrading a boiler plant in your building or facility, you may qualify for a cash rebate of up to $12 per MBH by installing an eligible high-efficiency natural gas fired hot water boiler (each, an "Eligible Boiler).

Eligibility criteria

Eligible participants

1. To be eligible to receive a rebate, participants must be:
   1.1. New construction—a Builder/Developer or Property Owner
   1.2. Retrofit—a Property Owner or Long-term Lease Holder
2. For the purposes of these terms and conditions,
   2.1. **Builder/Developer** means a commercial entity that constructs new commercial buildings for the purposes of resale to the public. **NOTE:** Upon request, a Builder/Developer that is not also the Property Owner will provide, in a form satisfactory to FortisBC in its sole discretion, Property Owner details, including confirmation that FortisBC will own any environmental attributes as contemplated by section 3 of the Additional terms and conditions below.
   2.2. **Property Owner** means a legal person who holds registered title to the building or facility that is the subject of an application to the Program. FortisBC, in its sole discretion may request the Property Owner to provide proof of such registered title. **NOTE:** Upon request, a Property Owner that is not also the Builder/Developer or Long-term Lease Holder, as applicable, will provide, in a form satisfactory to FortisBC in its sole discretion, Builder/Developer details, including confirmation that FortisBC will own any environmental attributes as contemplated by section 3 of the Additional terms and conditions below.
   2.3. **Long-term Lease Holder** means a legal person who occupies the building or facility that is the subject of an application to the Program, under a commercial lease with a term of 120 months or more, with an option to renew for at least a further 60 months, which lease will continue for at least 36 months prior to expiry at the time of the Application. **NOTE:** Upon request, the Long-term Lease Holder will provide, in a form satisfactory to FortisBC in its sole discretion, landlord details and confirmation of a long term lease with respect to the proposed building or facility, including permission granted by the landlord to the Long-term Lease Holder to install, repair and/or upgrade the boiler plant and confirmation that FortisBC will own any environmental attributes as contemplated by section 3 of the Additional terms and conditions below.
3. Participants replacing existing non natural gas boilers (i.e. conversion customers) with Eligible Boilers can apply for rebate from the Program if they conform in all other respects to the Program's eligibility criteria. The rebates are offered regardless of the previous fuel type.
4. Property / facility managers and/or third party energy service providers are NOT eligible or entitled to receive a rebate for an Eligible Boiler installation carried out under their direction regardless of whether or not they have the permission of the Property Owner, Builder/Developer or Long-term Lease Holder to install, repair and/or upgrade the boiler plant of the building(s) or facility of one of the aforementioned. Customers of such service providers may be eligible to receive a rebate for the installation of Eligible Boilers within a building or facility if they are the Building Owner, Builder/Developer or Long-term Lease Holder, and have a contract with the property / facility managers and/or third party energy service providers for the provision of services including the installation of boilers.
5. Property / facility managers and/or third party energy service providers who own and operate boiler plants within buildings or facilities they do not own are NOT eligible or entitled to receive a rebate for the installation of an Eligible Boiler. Customers of such service providers may be eligible to receive a rebate for the installation of the Eligible Boiler within a building or facility by the service provider if they are the Building Owner, Builder/Developer or Long-term Lease Holder.

Eligible buildings/facilities

The building or facility where the Eligible Boiler(s) are to be installed must:

1. Be in the FortisBC service territories of the Lower Mainland, Fraser Valley, Squamish, Whistler, Interior of BC, Vancouver Island and Sunshine Coast.
2. Receive natural gas service from FortisBC under any rate class except rates 1, RGS, and 1.B.
3. Use the Eligible Boiler for space heating, pool heating, or space heating in combination with domestic water heating and/or pool heating for the purpose of maintaining human comfort and sanitation. Process Loads (as defined below) are not applicable;
   3.1. **Process Load** means any use of the thermal output of the Eligible Boiler(s) other than for maintaining human comfort and sanitation via space, domestic hot water or pool heating. Examples include, but are not limited to, snow melting, car washing, greenhouse heating, or the production of a good or service of economic value such as food processing.
4. Use the Eligible Boiler(s) as the primary source of thermal input for space and/or pool heating, providing more than 75 per cent of the thermal energy required, by the building or facility's heating system. Secondary, peaking, stand-by or back up applications do not qualify; and
5. Not be a single family residence.

Eligible boilers

To qualify for a rebate under the Program, the Boiler must:

1. Be a natural gas fired, hot water boiler (no steam).
2. For boilers with input ratings less than or equal to 299,000 BTU/hr, **be designated by Natural Resources Canada's ENERGY STAR® program as an ENERGY STAR qualified boiler AT THE TIME OF PURCHASE as evidence by the date on the proof of purchase**. Applications for boilers which are added to the list after the date of purchase ARE NOT eligible for rebate. Please refer to NRCan's list of ENERGY STAR rated boilers.
3. For boilers with input ratings in excess of 299,000 BTU/hr, **be listed on the FortisBC Eligible Boiler List AT THE TIME OF PURCHASE as evidenced by the date on the proof of purchase.** Applications for boilers which are added to the list after the date of purchase ARE NOT eligible for a rebate. The list is available at: **fortisbc.com/eligibleboilers**. **Note:** this list may be updated during the course of the Program.

4. Be used to provide thermal energy to a single Premises, Property Owner or Long-term Lease Holder. (Boilers serving multiple Premises, Property Owners or Long-term Lease Holders are not eligible under this Program. Please refer to the Eligible Boiler Notes below.)
5. Be installed by a BC Safety Authority registered contractor in accordance with the manufacturer's specification and must comply with all applicable laws, orders, regulations, ordinances standard, codes and other rules, licences and permits of all lawful authorities
6. Be new. (Used or rebuilt boilers do not qualify for a rebate.)
7. Be purchased ***within 90 days prior to the boiler in-service date as shown on the Gas Notification of Completion, Installation or Alteration***. Customers wishing to pre-purchase boilers in advance of this 90 day period may do so by informing FortisBC in advance. Refer to the program process section below for more information. In no case shall the boiler(s) be purchased more than 180 days prior to the boiler in-service date as shown on the Gas Notification of Completion, Installation or Alteration
8. Be installed on or after March 22, 2012

Eligible boiler notes:

1. Eligible Boilers with an input rating of over 5,000,000 Btu/hr may be eligible for greater incentives through another FortisBC program. Pre-approval may be required prior to purchasing the Boilers or proceeding with the project. Contact a FortisBC representative as soon as possible to determine if you qualify.
2. Eligible Boilers or boiler plants serving more than one Property Owner or end customer may be eligible for incentives through another FortisBC program. Pre-approval may be required prior to purchasing the Eligible Boilers or proceeding with the project however. Contact a FortisBC representative as soon as possible to determine if you qualify.

Program rebates

The rebate is independent of the price of the Eligible Boiler or the total cost of the mechanical system. The Program does not provide any additional rebate or incentive for labour, vent modifications, piping changes, design calculations, or other equipment. Rebates are available for multiple Eligible Boilers in a single building or facility and will be calculated per boiler as follows:

New construction market

- Condensing: $12 per MBH input rating
  The maximum rebate payable per boiler is limited to $60,000.

  NOTE: New construction participants must retain the services of a professional engineer to estimate the annual natural gas consumption in gigajoules per year (GJ/yr) of both a baseline 80 per cent efficient boiler plant as well as that of the submitted higher efficiency boiler plant.

Replacement market

- Mid-efficiency: $4 per MBH input rating
- Condensing: $12 per MBH input rating
  The maximum rebate payable per boiler is limited to $20,000 for mid-efficiency boilers or $60,000 for condensing boilers.
- Right-sizing bonus
  - The right-sizing bonus is available to participants who are installing Eligible Boiler(s) in existing buildings. FortisBC strongly encourages all applicants to engage the services of a professional to review their thermal heating requirements and ensure that their Eligible Boilers are sized accordingly. Eligible Boilers which have been sized in accordance with the right-sizing guidelines in the FortisBC Boiler Sizing & Installation Guidelines (available on the Program webpage) are eligible for the following right-sizing bonus:
  - Boilers systems with an input rating of less than 1,500 MBH: the lesser of $500 or the amount indicated on the right-sizing proof of purchase.
  - Boiler systems with an input rating of 1,500 MBH or greater: the lesser of $1,000 or the amount indicated on the right-sizing proof of purchase.
  - One right-sizing bonus per building or facility per year.

2. A single rebate will be provided per application. Only one (1) eligible participant is entitled to receive a rebate per installation of Eligible Boilers.
3. Rebates will only be issued when all required documentation is received and deemed acceptable by FortisBC in its sole discretion.
4. Rebates will be issued to successful participants by a cheque.
5. Projects receiving rebates in excess or $25,000 will be inspected by FortisBC or one of its authorized agents prior to the rebate being issued.

Application process

Standard application process

1. To be eligible for any rebates under the Program, the participant or participant's authorized agent must return a copy of the following:
   1.1. The completed application form. **NOTE:** The participant (not the participant's agent) <u>must</u> sign the application form. Signature of a third party agent is not acceptable.
   1.2. The "Gas Notification of Completion, Installation or Alteration" (indicating the contractor's licence no. and gas fitter no.).
   1.3. The required proof of purchase of the Eligible Boiler(s):
   1.3.1. **Retrofit applications:** The paid invoice indicating the make, model number, and serial number of the Eligible Boiler(s) purchased and installed.
   1.3.2. **New construction applications:** The paid invoice indicating the make, model number, and serial number of the Eligible Boiler(s) purchased and installed or shop drawings approved by the project engineer, indicating the job name and address, as well as the make and model number of the boiler(s) purchased and installed.
2. In addition to the above, the following is required for pool heating or new construction applications:
   2.1. **New construction projects:** Professional Engineer's estimate of the annual natural gas savings by upgrading to an Eligible Boiler over an atmospheric boiler. *Note: Failure to provide this estimate will invalidate the application*.
   2.2. **Pool heating applications:** Completed Pool Data Requirements Sheet. *Note: Failure to provide this data sheet will invalidate the application.*
3. Applications must be submitted to FortisBC ***no later than 90 days after the Eligible Boiler in-service date as shown on the Gas Notification of Completion, Installation or Alteration***.
4. All and all accompanying documents or information as shown above must be submitted to FortisBC ***no later than 90 days after the date of application.*** FortisBC strongly encourages all applicants to submit all required supporting documentation with the application.

Eligible Boiler Pre-purchase application process

1. Participants wishing to pre-purchase Eligible Boiler(s) in excess of the allowed 90 days prior to the Eligible Boiler in-service date as shown on the Gas Notification of Completion, Installation or Alteration must apply to FortisBC in writing.
   1.1. Applicants must fill out a copy of Eligible Boiler pre-purchase form available on the Program webpage. Forms must be filled out and submitted to FortisBC prior to the date of purchase of the Eligible Boiler(s) as evidenced by the Eligible Boiler invoice date or the shop drawing approval date.
   1.2. In no case may the Eligible Boiler(s) be purchase more than 180 days prior to the Eligible Boiler in-service date as shown on the Gas Notification of Completion, Installation or Alteration.

2. Participants shall subsequently follow the standard application process described above.

Rebate payment

1. Rebates will only be paid to an eligible participant, as described under the program Eligibility Criteria.

Eligible Boiler Right-sizing Bonus application process (replacement market only)

1. Participants wishing to receive the Eligible Boiler right-sizing bonus must complete and submit an estimate of the building heating load in accordance with the right-sizing guidelines in the FortisBC Boiler Sizing & Quality Installation Guidelines available on the Program webpage.
2. Calculations showing the estimated building heating load as well as the invoice for the calculations must be submitted with the application.
3. The right-sizing bonus will only be issued if FortisBC finds, in its sole discretion that the submitted right sizing analysis is true and accurate and complies with one of the acceptable methodologies for boiler sizing outlined in the Boiler Sizing and Quality Installation Guidelines.

Representations and warranties

1. The participant represents, warrants, acknowledges and agrees that:
   1.1. The participant or the participant's authorized representative has read all the eligibility requirements as set forth in these terms and conditions (the "Eligibility Requirements") and the participant fully meets all such requirements to participate in the Program set out.
   1.2. All products, equipment and materials installed by the participant pursuant to this Program will fully qualify and comply with the Eligibility Requirements.
   1.3. All information submitted by the participant to FortisBC pursuant to application to the Program and otherwise communicated to FortisBC with respect to the Program are be true and correct.

Repayment of funding

1. The participant acknowledges and agrees that FortisBC may at its sole discretion, require the participant to repay all or part of the rebate provided by FortisBC under the Program within 90 days of receipt by the participant of such notice in the event of any of the following:
   1.1. FortisBC determines, in its sole discretion, that any information provided by the participant is incorrect or untrue, including but not limited to failure to install the Eligible Boiler(s) and any misrepresentation as to the specifications, energy efficiency or installation particulars of the Eligible Boiler;
   1.2. FortisBC determines, in its sole discretion that the participant has failed to comply with these terms and conditions.
2. The decision by FortisBC to provide any rebates under this Program to the participant is based on the information provided by the participant to FortisBC. In the event there is any change to such information, the participant will notify FortisBC immediately, and FortisBC may, in its sole discretion, recalculate the amount of rebate that the participant is eligible for, void the application and terminate any obligation to pay any rebate to the participant, or demand repayment of any funds already disbursed to the participant.

Additional terms and conditions

1. The participant does hereby grant a non-exclusive licence to FortisBC and its authorized employees, contractors and agents to access the building, facility or premises in which the Eligible Boiler(s) have been installed for the purposes of performing an on-site inspection of the installed Eligible Boiler(s). The Eligible Boiler(s) must be complete, operational and accessible at the time of the inspection. FortisBC agrees to provide 48 hours prior notice to the participant in order to make arrangements for access to the building, facility or premises for such inspection purposes.
2. FortisBC may amend, modify or terminate this program at any time based on funding limitations or for any other reason, without notice.
3. The participant acknowledges that by applying to or participating in the Program, the participant's Eligible Boiler(s) may use less natural gas and produce fewer emissions. The parties agree that, unless the participant is mandated, by legislation or regulation, to claim any environmental attributes associated with the reduction in emissions, FortisBC will own any environmental attributes associated with the reduction in emissions from the Eligible Boiler(s) and at FortisBC's own cost, administer any environmental attributes, including, but not limited to, GHG offsets associated with the installation of the Eligible Boiler(s), which may include quantifying, validating and registering the environmental attributes or GHG credits, and retention or disposition to third parties of the associated environmental attributes or GHG credits.
4. The participant acknowledges that FortisBC is a "public utility" as defined in the Utilities Commission Act, R.S.B.C 1996, c. 473, and further acknowledges and agrees that payment of rebates is subject to the approval of the British Columbia Utilities Commission ("BCUC") on terms satisfactory to FortisBC, acting in its sole discretion. In the event that the BCUC withdraws approval or changes the terms and conditions of such approval either with respect to this Program or energy efficiency funding generally, on terms and conditions not satisfactory to FortisBC, in its sole discretion, FortisBC may terminate the Program and the Applicant acknowledges and agrees that FortisBC shall be under no obligation to pay any rebate to the Applicant.
5. Provision of a rebate under this Program does not constitute FortisBC assuming any ownership interest, either in whole or in part, of Eligible Boiler(s) that is the subject of the rebate.
6. FORTISBC, NOT BEING THE DESIGNER OR MANUFACTURER OF THE ELIGIBLE BOILER(S), MAKES NO REPRESENTATION OR WARRANTY, EXPRESS OR IMPLIED AS TO THE FITNESS, DESIGN OR CAPABILITY OF THE MATERIAL, EQUIPMENT OR WORKMANSHIP OF THE ELIGIBLE BOILER(S), NOR ANY WARRANTY THAT THE ELIGIBLE BOILER(S) WILL SATISFY THE REQUIREMENTS OF THE PARTICIPANT OR ANY LAW, SPECIFICATION, OR CONTRACT.
7. THE PARTICIPANT DOES HEREBY INDEMNIFY AND SAVE HARMLESS FORTISBC AND ITS RESPECTIVE DIRECTORS, OFFICERS, AGENTS AND EMPLOYEES FROM ALL LIABILITY, DAMAGES, CLAIMS, DEMANDS, EXPENSES AND COSTS FOR CLAIMS, COSTS FOR INJURY OR DEATH OF ANY PERSON, DAMAGE TO OR DESTRUCTION OF PROPERTY, AND ALL ECONOMIC LOSS SUFFERED BY ANY PERSON ARISING FROM OR OCCURRING BY REASON OF THE PROGRAM, RECEIPT OF REBATE(S) OR ACTUAL OR ALLEGED PREPARATION OR INSTALLATION OR USE OF THE ELIGIBLE BOILER(S), INCLUDING ANY ACTIONS OR OMISSIONS BY THIRD PARTY CONSULTANTS OR CONTRACTORS IN THE PREPARATION OR INSTALLATION OF THE BOILER(S).
8. FortisBC does not endorse any particular consultant, manufacturer, product, system, design, contractor, supplier or installer in promoting this Program.
9. The participant acknowledges and agrees that the participant is responsible for the disposal of all hazardous materials that may result from the installation of the Eligible Boiler(s), and such disposal will be conducted in accordance with all applicable government regulations and the participant agrees that FortisBC has no responsibility with respect to same.
10. The participant is solely responsible for any tax liability imposed as a result of payment of the rebate.
11. The Program is independent of other incentives and rebates by FortisBC and/or other utilities, manufacturers, or government incentive programs or grants.
12. Rebates cannot be assigned or transferred. Rebates will be payable to the participant only.

13. In applying for this Program, the participant acknowledges and agrees that FortisBC or one of its agents may contact the participant in the future to participate in a survey about this offer and may review and analyse the gas consumption at the building or facility in which the Eligible Boiler(s) is installed for Program evaluation purposes.
14. FortisBC may in its sole discretion accept applications up to 90 days after terminating the Program, but in no event will it accept applications received more than 90 days after the termination of the Program.
15. FortisBC reserves the right to limit the number of rebates it provides under the Program; rebates will be paid on a first come first serve basis.
16. The participant does hereby agree to allow FortisBC to publish the participant's business name, a general description of the project and resulting energy performance and payback period for the purpose of promoting the Program. The participant will review and approve any promotional material prior to publication, such approval not to be unreasonably withheld or delayed. The participant further agrees not to use the FortisBC name or any of its trademarks or logos without the express written consent of same, such approval not to be unreasonably withheld.
17. The participant agrees to acknowledge the assistance provided by FortisBC in all publications, publicity material and other forms of release or communication pertaining to the installation of the boiler(s). All such communications mentioning FortisBC must first be submitted to and approved in writing by FortisBC before publication.
18. Subject to section 16 FortisBC will keep confidential any confidential business, technical or financial information or records made available to FortisBC by the participant in connection with matters arising under the Program, and will not disclose such information except as may be required by law.
19. Processing of applications may take a minimum of 90 days.
20. FortisBC is not responsible for lost, delayed, damaged, illegible or incomplete applications.
21. FortisBC reserves the right to refuse applications which it determines, in its sole discretion, are incomplete, inaccurate or otherwise do not meet Program requirements.

Contact information

Toll-free: 1-866-884-8833
Fax: 1-604-592-7618
E-mail: commercialrebates@fortisbc.com

Mail:
Efficient Boiler Program
Energy Efficiency and Conservation
FortisBC
16705 Fraser Highway
Surrey BC V4N 0E8

Attachment 375.4.1

Program Area Spending Summary	Expenditures ($1000s)						Distribution
Primary Customer Classes	**2014**	**2015**	**2016**	**2017**	**2018**	**Total**	**% of Total**
Commercial	**653**	**733**	**689**	**895**	**24**	**2995**	**49.21%**
Other	**234**	**691**	**24**	**287**	**8**	**1244**	**20.43%**
Air Curtain Pilot	0	0	0	120	4	124	2.04%
Condensing Unit Heater Pilot	117	4	4	0	0	125	2.05%
De-Aerator Vent Steam Recovery Pilot	0	251	7	7	0	265	4.35%
Ice Rink Efficiency Pilot	0	0	0	151	4	155	2.55%
Ozone Commercial Laundry Pilot	0	432	9	9	0	450	7.39%
Radiant Tube Heater Pilot	117	4	4	0	0	125	2.05%
MURBs	**420**	**42**	**665**	**609**	**16**	**1751**	**28.78%**
City of Vancouver Green MURB Pilot	9	9	0	0	0	18	0.30%
Condensing Gas-Fired Ventilation Unit Pilot	13	13	0	0	0	26	0.42%
Fireplace Inserts Pilot	2	2	0	0	0	4	0.07%
Occupancy Sensor MURBs Pilot	0	0	471	4	4	479	7.87%
Recirculating Demand Control Pilot	396	18	18	0	0	432	7.10%
Thermal Bridging Pilot	0	0	176	4	4	184	3.02%
Transpired Air Collector Pilot	0	0	0	601	8	609	10.01%
Industrial	**3**	**0**	**216**	**5**	**760**	**984**	**16.17%**
-	**3**	**0**	**216**	**5**	**760**	**984**	**16.17%**
Catalytic Radiant Burner Pilot	0	0	0	0	285	285	4.68%
Ceramic Manufacturing Microwave Assist Technology Pilot	0	0	0	0	470	470	7.72%
Kiln Control Pilot	3	0	0	0	0	3	0.05%
Water Spray Kiln Misting System Demonstration Project	0	0	216	5	5	226	3.71%
Residential	**240**	**174**	**17**	**7**	**115**	**553**	**9.09%**
-	**240**	**174**	**17**	**7**	**115**	**553**	**9.09%**
Combination Units Pilot	227	10	10	0	0	247	4.06%
ENERGY STAR © 0.67 Storage Tank Water Heater Pilot	3	0	0	0	0	3	0.05%
Heat Reflector Pilot	0	0	0	0	115	115	1.89%
Residential High Efficiency Water Heater Pilot	10	0	0	0	0	10	0.16%
Residential HVAC Zoning Pilot	0	164	7	7	0	178	2.92%
Unallocated	**311**	**311**	**311**	**311**	**311**	**1554**	**25.53%**
-	**311**	**311**	**311**	**311**	**311**	**1554**	**25.53%**
Non-Program Specific Expenditures	131	131	131	131	131	654	10.74%
Prefeasibility Studies	180	180	180	180	180	900	14.79%
Grand Total	**1208**	**1218**	**1233**	**1218**	**1210**	**6086**	**100.00%**

Attachment 375.5

FILED CONFIDENTIALLY

Attachment 376.1

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 377.3

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 384.9.1

Your E Source Member Inquiry Response

Thank you for trusting E Source with your inquiry.

Answered by Melanie Wemple

Contributors: Tim Stout, Mike Weedall

Your inquiry:

Please provide FortisBC with a review of how other gas utilities in North America calculate their long run avoided cost of natural gas for the purpose of conducting cost-benefit analysis for their DSM programs.

Sub questions:

- Is there an industry standard practice for doing so?
- Do other Gas Utilities calculate a separate avoided cost for each rate class, or a single avoided cost for all rate classes?
- What are the components of the avoided cost of gas calculation (example: Commodity, Administration Costs for Managing Gas Supply, Gas Storage Costs, Gas Transportation Costs, less Any Revenue Offsets, over sales volume)?
- Do other gas utilities include an amount for avoided or delayed system capacity requirements?
- What future cost escalation assumptions are included?
- Please try to include some gas utilities in both Canada and the US Pacific Northwest in your survey if possible.

-is the commodity component based on the marginal (or most expensive resource) cost of gas rather than average cost of the portfolio ?

Our response:

There are a variety of avoided cost studies that examine the method for calculating the avoided cost of natural gas. The three examples below demonstrate that there is no industry standard for calculating avoided cost of natural gas, as each varies.

NEW ENGLAND

Synapse has long done the avoided cost studies for New England. Most recently, it produced the report Avoided Energy Supply Costs in New England: 2013 Report (PDF) which outlines the components of the avoided costs of gas beginning on PDF page 23, and in more detail in Chapter 2. The report states, "Initiatives that enable retail customers to reduce their natural gas use also have a number of benefits. The benefits from those reductions include some or all of the following avoided costs:

- Avoided gas supply costs due to a reduction in the annual quantity of gas that has to be produced;
- Avoided pipeline costs due to a reduction in the quantity of gas that has to be delivered; and

- Avoided local distribution infrastructure costs due to delays in the timing and/or reductions in the size of new projects that have to be built resulting from the reduction in gas that has to be delivered."

Synapse calculates the overall avoided cost and the avoided cost by end-use (i.e. residential, commercial, industrial). "The avoided cost of gas at a retail customer's meter has two components: (1) the avoided cost of gas delivered to the LDC; and (2) the avoided cost of delivering gas on the LDC system (the "retail margin"). AESC 2013 presents these avoided gas costs without an avoided retail margin and with an avoided retail margin, as the ability to avoid the retail margin varies by distribution company. Exhibit 1-9 and 1-10 provide a summary of the avoided cost by sector.

The following excerpt from PDF page 38 provides an overview of New England's methodology. I recommend reviewing the report for more details on assumptions, etc.:

> **"Methodology**. We developed our forecast of annual Henry Hub natural gas prices for the short term and for the mid to long term using the same basic methodology used in AESC 2007, 2009, and 2011. Under that methodology, we base the forecast on futures prices from NYMEX for the first few years of the study period, then on an appropriate long-term forecast from the EIA for the bulk of the study period, and finally on an extrapolation for the remaining years not covered by the EIA forecast. Thus, the AESC 2013 Base Case forecast is developed as follows:
>
> - January – March 2013, Henry Hub actuals monthly prices
> - April 2013 – March 2016, NYMEX futures as of March 15, 2013
> - April 2016 – December 2035, forecasts of monthly prices derived from our Base Case forecast of annual Henry Hub prices
> - January 2036 – December 2043 extrapolation using the average compound annual growth rate (CAGR) from the prior ten years (2026 to 2035).
>
> "Our forecast is based on NYMEX futures in the near term because they provide the market's estimate of prices for the future months for which trading volumes are significant. Our forecast is based on an AEO long-term forecast for the remaining period because a long-term forecast captures the market fundamentals that will drive those prices (i.e., demand, supply, competition between fuels) and because the inputs and model algorithms underlying AEO forecasts are public.

CALIFORNIA

California uses the E3 avoided cost model which calculates time- and area-specific avoided costs to evaluate energy efficiency, distributed generation, and demand response programs using publically available data and transparent forecast methods. The costs are calculated by sector (residential and commercial) as well. You can download an Excel file that allows you to calculate the avoided cost of natural gas.

The methodology for calculating the avoided cost is explained in the report Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs (PDF). The following summary comes from PDF page 50:

"The total gas avoided costs are shown in Figure 15, as the sum of the forecasted commodity price for natural gas, the avoided transmission and distribution costs, and the emissions costs. The total avoided gas costs are calculated for each utility, service class, combustion type (emission control technology), month, and year.

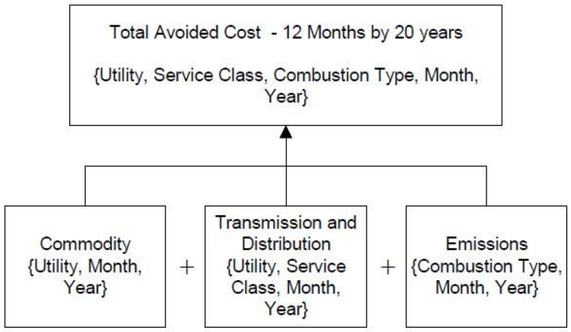


Figure 15: Formulation for Total Gas Avoided Cost

In Figure 16, we show the calculation of the avoided commodity for each utility, month, and year. The avoided commodity is calculated as the product of the forecasted market price and one plus the avoided compression gas and reduced loss and unaccounted for gas percentages. Similar to the avoided electricity calculation, the gas commodity is forecasted for three periods. Period 1 is the period when forward market prices for gas are available from NYMEX, Period 2 is a transition, and Period 3 is based on a long-run forecast of future prices. In addition to the gas avoided cost, the gas commodity costs are used in conjunction with the UDC.s gas transportation tariff for generation to estimate the long-run avoided electricity generation costs.

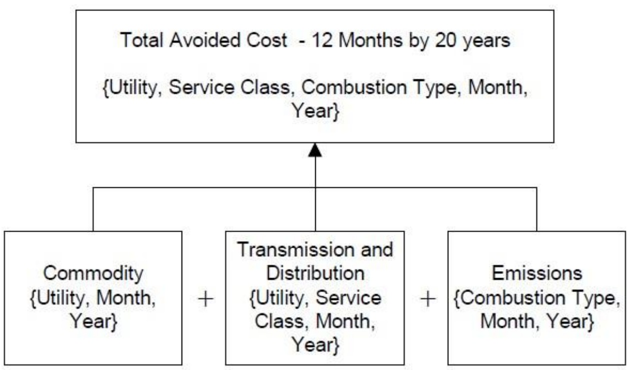


Figure 15: Formulation for Total Gas Avoided Cost

You can find a summary of the inputs on PDF page 51.

NORTHWEST NATURAL GAS

NW Natural Gas includes its avoided cost in its 2011 Modified Integrated Resource Plan (IRP) (PDF) beginning in Chapter 6, PDF page 126. NW Natural uses The SENDOUT® resource planning model to generate the avoided costs. The reports states:

> SENDOUT® contains a marginal cost report which lists the daily incremental cost to serve the next unit of demand for each demand region. The DSM functionality was turned off so energy conservation was not an option for the model; demand was served with supply side resources only. In addition to existing supply side resources, the resource options included Mist Storage Recall, Grants Pass Lateral pipeline capacity, Palomar East pipeline capacity, and satellite storage. The model determines the lowest cost method for serving the next unit of demand and computes a marginal cost. This computed marginal cost includes 1) the long term gas price forecast compiled from Intercontinental Exchange (ICE) futures and a consultant's gas price forecast; 2) Gas

storage carrying costs for inventory; 3) Upstream variable transmission costs; 4) Peak related on-system transmission costs; and 5) the cost for gas used to push gas through the system.

I hope you find this information useful. If you need any additional assistance, please e-mail Customer Service or call 1-800-ESOURCE.

Inquiry Number: 00023028