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August 23, 2013

Via Email
Original via Mail

British Columbia Utilities Commission
Sixth Floor
900 Howe Street
Vancouver, B.C.
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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 Plan for 2014 through 2018

Response to the British Columbia Utilities Commission (BCUC or the Commission) Information Request (IR) No. 1

On June 10, 2013, FEI filed the Application as referenced above. In accordance with Commission Order G-99-13 setting out the Preliminary Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 1.

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

1.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 5, Jurisdictional Comparison, Table B5-1, Jurisdictional Comparison, pp. 40-41

1.1 Provide the references used for each of the five PBR plans included in Table B5-1. If these sources are available online, please provide the web address for each reference.

Response:

Please refer to the table below detailing the titles and links of the references used for each of the five PBR plans included in Table B5-1 of the Application:

Utility/Jurisdiction	Title	Link
Alberta Electricity and Natural Gas	**Decision 2012-237** - Rate Regulation Initiative, Distribution Performance-Based Regulation	http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-237.pdf
Union Gas Limited	**Decision EB-2007-0606** - Application for an Order or Orders approving or fixing a multiyear incentive rate mechanism to determine rates for the regulated distribution, transmission and storage of natural gas, effective January 1, 2008	http://www.ontarioenergyboard.ca/documents/cases/EB-2007-0606/dec_union_enbridge_20080117.pdf
Enbridge Gas	**Decision EB-2007-0615** - Application by Enbridge Gas Distribution Inc. for an Order or Orders approving or fixing rates for the distribution, transmission and storage of natural gas, effective January 1, 2008	http://www.ontarioenergyboard.ca/documents/cases/EB-2007-0615/dec_union_enbridge_20080211.pdf
Enbridge Gas and Union Gas	PEG's report -Assessment of Union Gas Ltd. And Enbridge Gas Distribution Inc. Incentive Regulation Plans, September 2011	http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0052/PEG_Final%20Report_20110930.pdf
OEB's Power Distributors	**Report of the Board** - Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 2012	http://www.ontarioenergyboard.ca/OEB/_Documents/Documents/Report_Renewed_Regulatory_Framework_RRFE_20121018.pdf
OEB's Power Distributors	**Report of the Board** - on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, July 2008	http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2007-0673/Report_of_the_Board_3rd_Generation_20080715.pdf
OEB's Power distributors	**EB-2007-0673** - Supplemental Report of the Board, September 2008	http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2007-0673/Supp_Report_3rdGen_20080917.pdf
OEB's Power distributors	**EB-2007-0673** - Addendum to the Supplemental Report of the Board, January 2009	http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2007-0673/Addendum_Suppl_Report_20090128.pdf
Gaz Metro (Official version)	**Decision D-2007-47**, "Motifs de la décision D-2007-47 portant sur le renouvellement du mécanisme incitatif à l'amélioration de la performance", May 2007	http://www.regie-energie.qc.ca/audiences/decisions/D-2007-47Motifs.pdf
Gaz Metro (English version)	Performance incentive mechanism, Agreed in NSP R-3599-2006 (Translation – Not approved by Participants)	http://www.corporatif.gazmetro.com/data/media/gazmetro%20performance%20incentive%20mechanism.pdf?culture=en-ca

1.2 For each of the five plans in the table, provide the specific X-Factor values that were approved for the plan.

Response:

The approved X-factor values for each of the five PBR plans are presented in Table 1 below:

Table 1: X-factor values and determination methodologies for each of the five PBR plans

Utility/Jurisdiction	PBR Period	Methodology	X-factor
Alberta	2013-2017	TFP (0.96%) + Stretch factor (0.2%)	0.96% + 0.2% = **1.16 %**
Union Gas	2008-2012	Negotiated Settlement (Not based on any specific study)	**1.82%**
Enbridge Gas	2008-2012	Varied based on different percentage of inflation index (GDP IPI FDD)	Varied **between 0.36% and 1.22%** (see Table 2 below)
Ontario's power distributors (3rd Generation IR)	2009-2013	TFP (0.72%) + 3 cohorts of Stretch factor (0.2%, 0.4% or 0.6%)	0.72% + (0.2%; 0.4%; 0.6%) = **(0.92%; 1.12%; 1.32%)**
Ontario's power distributors (4th Generation IR)*	2014-2018	TFP (0.1%) + 5 cohorts of Stretch factor (0 %, 0.15%, 0.30%, 0.45%, 0.6%)	0.1% + (0 %, 0.15%, 0.30%, 0.45%, 0.6%) = **(0.1%; 0.25%; 0.4%, 0.55%, 0.7%)**
Gaz Metro	2007-2012	Negotiated. (Reflective of the historical rate increases and inflation).	**0.3%**

* The TFP value calculated and proposed by the OEB's consultant (OEB has used the services of the same consultant in 3rd and 4th Generation IRs) however the X-factor value is not yet approved by the OEB.

Enbridge Gas' X- calculation of its implicit X-factor is further detailed in Table 2:

Table 2: Enbridge Gas' implicit X-factor calculation based on actual inflation rates

	2008	2009	2010	2011	2012
Coefficient (C)	0.6	0.55	0.55	0.5	0.45
Inflation (I)	2.04%	1.54%	2.73%	0.72%	1.72%
Implicit X = I * (1-C)	**0.81%**	**0.69%**	**1.22%**	**0.36%**	**0.94%**

2.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 6.1, PBR Principles, p. 43

2.1 This section refers to "principles and objectives articulated below" (line 3) but only lists five principles. What are the objectives?

<u>Response:</u>

FEI did not intend to distinguish between principles and objectives. They are essentially one and the same. FEI's objective was to achieve the principles to the extent reasonably possible.

This section states, "There are many ways to articulate principles and objectives, and B&V is aware that various jurisdictions do articulate them differently." (lines 4-6)

2.2 Provide the other principles and objectives that Black & Veatch (B&V) and FEI considered, and the references to them, when it developed the five principles in this section.

<u>Response:</u>

Black & Veatch (B&V) states that this is a reference to the fact that both economic literature and studies filed before regulatory bodies express principles and objectives (both terms are used to describe what we have labeled as principles) in slightly different terms. Please refer to, for example, the following industry publications in addition to the AUC Order filed in the case presented as Appendix D-9:3 of the Application:

- "WHAT THE LITTLECHILD REPORT ACTUALLY SAID", Jon Stern, London Business School & NERA, Regulation Initiative Working Paper No. 55, p.6 referencing the Littlechild criteria.
- System Operator incentive schemes from 2013: principles and policy, OFGEM, 31 January 2012, p.6.
- "Performance Based Regulation of Utilities: Theoretical Developments in the Last Two Decades", March 2010, C. R. (Sid) Carlson, The Van Horne Institute, pp. iv-vii.

- "Performance-Based Regulation of Utilities", Mark Newton Lowry and Lawrence Kaufman, The Energy Law Journal, 2002, pp.400- 401.

The set of principles filed by FEI in this proceeding reflects input from these sources as well as the general knowledge and experience of FEI and B&V related to incentive regulation and PBR specifically.

3.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 6.2.1, Term, pp. 45-46

In this section, FEI proposes a five-year term for its PBR plan.

3.1 Discuss the merits of having an option to extend this plan, with the agreement of FEI and the Commission, for an additional period. If such an optional extension were incorporated into the plan, what would be the length of such an extension, two years, five years, or some other term?

Response:

FEI is willing to consider an optional extension to the plan. The main benefit of a PBR plan extension would be to enable the utility to continue to pursue efficiency gains in the targeted areas (i.e. O&M and capital expenditures) over a longer period. A plan extension option should be viewed simply as another item in the overall balance of opportunities and benefits presented by a PBR plan. Just as plan elements such as the initial term, the X-factor, exogenous factors, off-ramps, earnings sharing mechanisms and others need to be considered as an entire package, a plan extension option would be another item to consider in evaluating the overall balance of a PBR plan.

The length of the extension period cannot be specified without giving consideration to any other terms and conditions associated with the extension, or to related provisions of the PBR plan.

FEI believes that it is possible to develop an extension provision that would fit into the proposed PBR plan and would permit continued benefits to be achieved for customers and the utility. However it may be appropriate to consider an extension provision as part of the Mid-Term Review after actual experience with the PBR has occurred.

4.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 6.2.2.1, Inflation Factor (I–Factor) Proposal, pp.46-48

On page 48, FEI states that it "will update both the BC-AWE and BC-CPI rates (using the same sources referenced above) to determine the value of the I-Factor for the 2015 through 2018 years." (lines 9-11)

4.1 What exactly does it mean to update the inflation rates? Is this a true-up of the forecast to the actual inflation rates? Provide an explanation of how this updating would work and a numerical example if that is helpful.

Response:

Each of the sources listed in Table B6-2 of the Application (Toronto Dominion Bank, Royal Bank, Bank of Montreal, Canadian Imperial Bank of Commerce, Conference Board of Canada and the BC Ministry of Finance) provide updates of forecast BC CPI rates. Additionally, the Conference Board of Canada provides updated forecasts of BC Average Weekly Earnings.

Each year at the Annual Review, FEI will present updated forecasts to determine the composite inflation rate that will be utilized in the I-X mechanism for the upcoming year. FEI will not adjust previous inflation rates to the actual inflation rates. Except for the use of a composite inflation factor, the annual reforecasting of inflation for the purpose of determining the I-Factor is the same approach as was used in FEI's 2004 PBR Plan.

4.2 If this updating is not a true-up to the actual inflation rate, then discuss the reasons for not trueing up the inflation forecast to the actual inflation rate. What are the consequences of not including a true-up in the PBR plan? Provide a numerical example if that is helpful.

Response:

The updating is to reflect more recent known data in the forecasts, as opposed to a true-up in the sense of adjusting previous inflation rates to the actual inflation rates.

FEI's customer rates are set prospectively each year at the Annual Review. The Annual Review occurs in the fall of each year, and actual inflation rates are not known at that time. However, in order to apply an I-X mechanism that is indicative of the inflation rate for the coming year, each year at the Annual Review, FEI will provide updated BC-CPI and AWE forecasts for the coming year.

The impact of not including an adjustment for the actual I-Factor in the PBR plan will depend on whether the composite actual inflation rate is above or below the forecast level. If the forecast I-Factor is lower than the actual, then customers will pay a slightly lower unit rate. Conversely, if the forecast inflation rate is higher than the actual rate, customers will pay a slightly higher unit rate. The forecasts are sourced from independent third parties, and FEI does not believe there will be any material impact of not adjusting the forecast composite I-Factor to the actual level. The revenue requirement impact of any small differences, one way or the other, between the forecast and actual I-Factor results will be caught up in the 50/50 earnings sharing mechanism, further diminishing any effect.

As noted in response to BCUC IR 1.11.1, the I-X formulas affect approximately one third of the delivery revenues. Therefore a 0.25% variance between the forecast and actual I-Factor calculation would (after earnings sharing) have a net effect on the delivery rates of 1/3 x 0.25% x 50% = 0.0417%. As stated previously this small difference could be in either direction and there is no reason to believe it will be sustained into subsequent years.

4.3 What is the difference in terms of the effect on the company's revenues if the inflation factor is trued up or not trued up?

Response:

An updated forecast of both BC-CPI and AWE will be presented each year at the Annual Review to ensure that the I-Factor utilized in the I-X mechanism is representative of market conditions and will provide a forecast that is as current and accurate as possible. FEI has every reason to believe that the independent third party forecasts utilized in the I-Factor calculation will be reasonable. While there may be small variations from year to year in revenues, either positive or negative, arising from differences in the forecast and actual I-Factor results, there is no basis to say that not trueing up to actual will cause any net effect on FEI's revenues over the term of the PBR.

5.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 6.2.2.2, X–Factor Estimation, pp. 48-53

On page 48, FEI states that the X-Factor "represents the amount by which a company is expected to outperform the industry and economy-wide productivity gains." (lines 15-16)

5.1 Please explain FEI's understanding of the X-Factor. Typically, the X-Factor is a measure of productivity growth in the industry in question. If this is FEI's understanding of the X-Factor, please reconcile this with the statement quoted above. Under a PBR plan characterized by I-X, is it not the case that the company has a reasonable opportunity to earn its allowed rate of return if its own productivity growth equaled the productivity growth of the industry as measured by X?

Response:

A review of economic literature indicates that the definition of X-factor varies from jurisdiction to jurisdiction and typically depends on the methodology used for determination of X-factor value. For instance, Swinand (2003)[1] explains that depending on the jurisdiction, the X-factor might be defined as "the measure of total factor productivity growth in its purest sense, or it could merely be considered a measure of how prices should change; or X could be considered a relative measure of productivity; or even a relative measure of productivity relative to price changes." In other research the Federal Communication Commission defines the X-factor as "the amount by which a company is expected to outperform the economy-wide productivity gains."[2] The FCC's articulation mirrors what FEI has said on p.48 of the Application.

B&V explains that the X-factor could be defined as "a measure of productivity growth in the industry in question" if a pure- TFP approach (where the X-factor equals to the measured TFP) is used to determine the X-factor without any additional stretch factor applied to it. However the majority of approved X-factors in Canada (such as the ones in Alberta or Ontario) also include an additional percentage applied to the X-factor (implicitly or explicitly). In this context and in choosing to propose an X-Factor that includes greater productivity than the TFP, FEI is undertaking to perform better than the industry, based on the adoption of the PBR model in its proposed form.

B&V's and FEI's view is that a utility's PBR Plan using I-X does not by itself provide a reasonable opportunity to earn the allowed rate of return even if its productivity growth exceeds

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[1] Swinand, G. "An empirical examination of the theory and practice of how to set X". London Economics, 2003.

[2] http://hraunfoss.fcc.gov/edocs_public/attachmatch/FCC-12-153A1.pdf (page 3, section 3).

the productivity calculated on the historical industry trend because the cost side of the operation is only one part of the determination of earned return. The Plan does not address issues with volumetric recovery of fixed costs and the resulting revenue impacts. To provide a reasonable opportunity to earn the allowed rate of return, a PBR Plan must be comprehensive and address exogenous cost impacts (collectively known as the Z-Factor concept) as well as issues related to growth, costs, revenue recovery and so forth. This is why FEI's proposed PBR Plan includes a number of other elements beyond the simple I-X formulaic configuration. Without the inclusion of all design elements of the Plan, there is no reasonable opportunity for an individual utility to earn its allowed rate of return. In particular, this is also why a "one size fits all plan" is not reasonable. Consistent with that conclusion, we see the OEB moving away from a single PBR plan design for all electric distribution utilities under its jurisdiction and adopting different PBR plans for Enbridge and Union Gas Limited.

6.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 6.2.2.2, X–Factor Estimation, pp. 48-53

6.1 Compare the 0.5 X-Factor FEI is recommending with the most recent approved X-Factors for the Alberta gas distribution companies, Union Gas, Enbridge Gas, and Gaz Metro as identified in Table B5-1, Jurisdictional Comparison. What are the differences in the studies used to support each of the X-Factors?

Response:

This answer responds to BCUC IR 1.6.1 and 1.6.2.

Please refer to the response to BCUC IR 1.1.2 for the comparison of the approved X-factor values and the methodologies used for their determination in each of the mentioned PBR plans. FEI and B&V do not agree with the stated premise of BCUC IR 1.6.2 that “other X-Factors [in other jurisdictions] are higher than the 0.5 recommended by FEI”, as it is an over-generalization. In summary, FEI’s proposed 0.5 X-factor is:

- higher than Gaz Metro’s fixed X-factor value,
- within the range of actual implied X-factor values applied to Enbridge gas, and
- less than the X-factors applied to Union Gas and Alberta’s utilities.

With the exception of the Alberta LDCs, the X-Factors were not based on the results of a specific study, but rather represent settlement values. The Alberta study has been discussed at length in FEI’s Application. Briefly, the study was for electric utilities with no costs or outputs associated with gas utility operations. Since the other X-Factor values are based on settlements, it is not possible to comment on the results of any specific element used to determine the X-factor values for these utilities. Regardless of this issue, B&V and FEI consider that the difference between X-factor values can be assessed and reconciled from four perspectives:

The year in which the X-factor is determined: As discussed in AUC’s Decision 2012-237 (Page 63, Paragraph 300), since the year 2000 the productivity growth “has been declining at the approximate rate of -1.4 %”. In addition, AUC acknowledges that the addition of 2008 and 2009 data in their TFP study (despite the very long measurement TFP study period) decreases the X-factor by almost 0.2%[3]. This downward trend was also restated by B&V in its review of the historic trend of approved TFP values in a sample of North American jurisdictions as presented in Figure B6-1 of the Application. Therefore regardless of the methodology used to determine the X-factor, it can be concluded that the approved X-factor values would have been lower if they were determined today. Given that Enbridge Gas and Union Gas PBR plans were both started in 2008 and considering the negative TFP trends between 2008 and 2012, one can reasonably expect that the possible X-factors for upcoming PBR plans will be less than previous terms (It shall be noted that the Union's 2008-2012 X-factor of 1.82% has already declined from its applied X-factor value of 2.5% during its earlier 2001-2003 PBR plan). Gaz Metro has abandoned PBR; however, the mentioned downward trend is true for its historic experience with X-factor value (its most recent 0.3 X-factor for 2007-2012 period was less than the 0.5 X-factor adopted under itsprevious plan).

Differences among utilities' business profiles (functions): The differences among utilities functions (distribution, transmission, storage, etc.) may have a significant influence on productivity improvement opportunities and therefore the reasonableness of the X-factor value. This issue can be best illustrated by comparing the Union Gas' and Enbridge Gas' X-factor values for their 2008-2012 PBR plans where the X-Factor for Union is over two times greater than the average implied X-Factor for Enbridge even though both utilities are in the same province, started in the same year and subject to the same regulatory authority. Enbridge explained this difference in its PBR proposal by comparing Union's business profile with its own business structure. For example it was mentioned that Union's sources of revenue include transportation, storage, and distribution whereas Enbridge earned over 90% of its revenue from distribution. The OEB's staff also acknowledged that the productivity performance of each function performed by the utilities could differ significantly due to differences in technology, capital expenditures or the potential for cost reductions in each of these functions. Ultimately these differences led to different X-factors for these two Utilities. This emphasizes the point made in response to BCUC IR 1.5.1 above that one size does not fit all for PBR plans. Similar to Enbridge, FEI's business differs from that of Union Gas in a number of respects as the result of, for instance, Union's extensive on-system storage. Therefore FEI's proposed X-factor cannot directly be compared to Union Gas' X-factor without proper adjustments.

Level of productivity gains prior to the start of the current PBR plan: A utility's past history with PBR plans may also be considered for X-factor determination. Ordinarily, utilities with no previous experience with PBR plans (as is the case for Alberta's utilities) may have a better chance to improve performance at a faster rate than the industry average (the inefficient utilities have more "low-hanging fruit" or cost savings that can be implemented easily). This may justify

[3] Considering the continued decrease in use per customer and continued increase in infrastructure replacement costs, it is logical to believe that an update of NERA's TFP study with 2010 and 2011 data (Assuming everything else is unchanged) will lead to similar decrease in measured TFP value.

a higher than usual X-factor used in Alberta in comparison to a utility like FEI that has years of recent experience with PBR and fewer available productivity improvement opportunities.

Other elements of PBR plan: Finally, comparing the X-factor values of other PBR plans without considering the other elements of the plan (the total PBR package) may lead to erroneous conclusions. The cumulative effect of PBR elements such as SQIs, ESM, off-ramps, term, etc. may all impact the reasonableness of a particular X-factor approved for a specific utility or jurisdiction.

When all of these factors are considered, FEI's X factor is reasonable, and in B&V's view more challenging than what its analysis would suggest.

6.2 What are FEI's justifications for departing from the approved gas distribution company X-Factors approved in other jurisdictions, particularly when these other X-Factors are higher than the 0.5 recommended by FEI?

<u>Response:</u>

Please refer to the response to BCUC IR 1.6.1.

7.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 6.2.2.2, X–Factor Estimation, pp. 48-53

On page 48, FEI states, "The proposed .5 percent expected productivity gain exceeds the measured industry productivity levels and represents a real challenge to the Company to seek additional efficiency and continue with its productivity improvement culture." (lines 27-29)

7.1 Provide the justification, being as specific as possible and providing references, for the statement that the 0.5 X-Factor exceeds the measured industry productivity levels (productivity growth rate). Reconcile this statement with the X-Factors approved for the other gas distribution companies listed in Table B5-1, Jurisdictional Comparison, and the studies used to support these X-Factors.

<u>Response:</u>

Based on the latest available studies of gas and electric productivity, the X-factor values have declined below those noted in Table B5-1 of the Application (please refer to the response to BCUC IR 1.6.1 prepared by B&V and FEI). Since the values reported in Table B5-1 reflect older studies, and as noted often are not based on industry specific analyses, there is every reason to believe that FEI's proposed X-Factor is above the industry productivity factors. In addition the recent TFP studies in Canada substantiate this claim that the current productivity growth rates are negative. For example the latest TFP study conducted by Concentric Energy Advisors on behalf of Enbridge Gas for its latest customized IR Plan demonstrates a negative value.[4] Further FEI retained B&V to complete a TFP study based on gas utilities, using a theoretically sound TFP methodology that shows negative TFP values, as explained in detail in B&V's Productivity Report.

The Alberta study is an electric study and, thus, contains no information on the gas distribution function. As B&V indicated in other responses and its evidence, the Alberta results are not reliable as we have demonstrated in the evaluation of the results because of the inputs used and the selected measure of output.

[4] Incentive Ratemaking Report, Concentric Energy Advisors, Inc. EB-2012-0459, Exhibit A2, Tab 9, Schedule 1

8.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 6.2.2.2, X–Factor Estimation, pp. 48-53

On page 49, in the sub-section on the measurement period for Total Factor Productivity (TFP) studies, FEI makes the statement that "In general it makes sense to use the most recent data, unless the recent past exhibits anomalous events that are not expected to continue during the PBR term." (lines 29-31)

8.1 Provide references to the economics literature that support this statement. What are the reasons to use a short-term TFP calculation based on the recent past as opposed to calculating a longer-term TFP growth rate using all of the historical data available?

Response:

B&V advises that this is a direct quotation from a report prepared by the Brattle Group for the Australian Energy Markets Commission at page 4[5]. The economic literature provides that the X-Factor may be either historic or forecast[6]. There is no discussion related to using the most current data in theoretical studies as that is not an issue of the analysis because all studies use the most current data available. The main issue is how far back the data analysis must be extended. As discussed in Appendix D-1 of the Application, the use of volumetric output data would require a longer time period to average out weather impacts on TFP estimation. Further, it is assumed in most studies that volume is a measure of output (an assumption appropriate for the manufacturing process, and thus typically used in academic literature), thus, increasing the required study period. However, the longer study periods would overstate the impact of technological change on the expected TFP value during the regulatory control period when the technological change has been fully implemented as is the case for activities such as live main insertion and directional boring, for example. Given that the gas LDC industry is a mature industry with common practices and methods, it is reasonable to assume that TFP gains based on the new technologies introduced in the past have been fully implemented in the current period. To the extent a new technology becomes available during the regulatory control period, the adoption of that technology as soon as feasible is part of the incentive aspect under PBR. Both FEI and its stakeholders are protected by the balanced ESM in the overall PBR plan.

From a theoretical perspective, the estimates of TFP relate to the production function which has a short-run and a long-run dimension. Any number of basic economic texts explain the

5 "Use of TFP analysis in network regulation case studies of regulatory practice" , Toby Brown & Boaz Moselle, 2008.

6 See "Regulation: Price Cap and Revenue Cap" , Mark A. Jamison, Public Utility Research Center, University of Florida

elements of the short-run and long-run. In particular, the concept of the short-run is a period when all factors of production are fixed. In the long-run at least some factors of production can vary as would be the case for a five-year PBR Plan. These issues are discussed in the gas productivity report prepared by B&V related to the term of the included TFP study. The use of the near-term reflects the long-run considerations of some fixed factors of production. In addition, the use of the shorter time period is appropriate because it reflects the full implementation of technology changes that are reflected as productivity gains in historic periods. See for example the discussion of the AUC report in Appendix D-1 of the Application. There is no basis for using 20 or 30 years of data when output is properly specified as in the TFP study for gas LDCs presented in Appendix D-2 of the Application.

8.2 How can the Commission be assured that the shorter-term TFP growth calculation will be more indicative of the next five years of TFP growth for the industry rather than the longer-term TFP growth figure? For example, if the economy were in a recession or a slow-growth period for the recent short term period used to calculate TFP, would the TFP resulting from that study be a good indicator of the TFP in the next five years if the economy recovered to a period of more rapid, normal growth?

Response:

B&V notes that, in the same way that utility regulators use the most recent data for operations to estimate test year costs and revenues, the Commission implicitly understands that current trends are more representative than factors from 20 or 30 years ago. A simple example will illustrate this point. Twenty years ago the Financial Accounting Standards Board (FASB) adopted FASB 106 that changed the accounting for post retirement benefits from pay as you go to accrual accounting. If one looked at 30 years of data, there would be a significant change in the cost of labor as the result of this change (assuming the cost was included in the data for input costs). All else equal, this change would reduce TFP levels in current periods. However, by averaging in lower labor costs and higher TFP amounts in the early years, current TFP estimates would be higher than the post FASB 106 period. This is a simple example that by no means represents a comprehensive list of all of the reasons that current data is preferred over data from long historic periods. Other examples include the impact of changing regulations on operating costs such as the changes to the regulations governing meter sampling or measurement accuracy, the safety emphasis that has led to accelerated replacement programs for cast iron, bare steel and defective plastic pipe, and so forth.

The issue of the impact on TFP of a slow growth period historically and a more rapid growth period subsequently is more an issue with volumetric measures of output. Using capacity as a measure of output, or customers and capacity, would not change the underlying productivity trend in any significant way with the exception of a gas LDC expanding to serve a previously unserved area that requires extensive new investment to interconnect the area to the existing delivery infrastructure. Since these are events that typically require a CPCN, they would be outside FEI's PBR Plan.

9.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 6.2.2.2, X–Factor Estimation, pp. 48-53

On page 49, FEI states that "the length of the study period for calculation of TFP varies between 5 and 20 years." (lines 32-33)

9.1 Indicate the studies, with references to the studies and web locations when available, that FEI relied on to support the statement that the length of the study period for calculating TFP varies between five and twenty years. If these studies are not available online, provide copies of the studies.

Response:

The table below includes some of the evidence that confirms FEI's statement. In addition, the suggested time frames for TFP studies by the majority of experts in the AUC's Decision 2012-237 (with the exception of Dr.Makholm from NERA) lie within this range.

Prepared for	Title of study	Sample period	Link
Quebec - Régie de l'Energie	Research for Gas Metro's Performance Incentive Mechanism	10 years (2000-2009)	http://www.regie-energie.qc.ca/audiences/3693-09_2/Demande_3693-09_2/B-25_GazMetro-2Doc1_3693-2_2sept11.pdf
OEB – Natural gas LDCs	Price Cap Index Design for Ontario's Natural Gas Utilities	11 years (1994-2004)	http://www.ontarioenergyboard.ca/documents/cases/EB-2006-0209/TFP_study_20070330.pdf
OEB – Power LDCs (2008-2012)	Supplemental Report of the Board	19 years (1988-2006)	http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2007-0673/Supp_Report_3rdGen_20080917.pdf
OEB – Power LDCs (2013)	Empirical research in support of incentive rate setting in Ontario : Report to the Ontario Energy Board	10 years (2002-2011)	http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/PEG_Report_to_OEB_4Gen_%20IR_20130531.pdf
ENMAX (Later approved by AUC)	ENMAX Power Corporation for its 2007-2016 PBR Plan*	4 years (2001-2003)	Please refer to AUC website, application No. Application No. 1550487. Appendix 3.
FERC	Docket No. RM10-25-000 - Five-Year Review of Oil Pipeline Pricing Index	5 years** (2004-2009)	http://www.ferc.gov/industries/oil/gen-info/pipeline-index/RM10-25-000.pdf

Prepared for	Title of study	Sample period	Link
SDG&E	Productivity research for San Diego Gas and Electric (SDG&E)	10 years (1999-2008)	https://www.sdge.com/sites/default/files/regulatory/Exh%20SDG&E-44%20M_Lowry_Productivity.PDF

* 2001-2003 study was based on a sample of distribution utilities in New Zealand.

** The time period of analysis includes a base year, 2004, and five points of change, 2005-2009, from which to measure cost changes against the base year.

9.2 What was the time period used in the TFP study on which the Alberta Commission relied when it established its X-Factor in Decision 2012-237?

Response:

The AUC adopted the NERA's TFP study which was based on a set of data from 1972 to 2009 (38 years). However the AUC also acknowledged that "the majority of other parties recommend a substantially shorter period". The AUC stated that this long period is justified due to the use of volumetric output measures: "Because NERA used a volumetric output measure, the resulting TFP estimate is sensitive to economic recessions and upturns". The AUC also recognized that when an output measure other than volumetric output is used, "the resulting TFP may be less sensitive to the choice of start and end dates".

9.3 Why has FEI selected the shortest time period, five years, for the calculation of its X-Factor? Provide support from the economics literature for using a short time period such as five years for a TFP study.

Response:

Please refer to the responses to BCUC IRs 1.8.1 and 1.8.2.

10.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 6.2.2.2, X–Factor Estimation, pp. 48-53

10.1 Please explain precisely which capital projects are included in the PBR plan under the I-X mechanism and which capital projects would be excluded from the I-X mechanism under FEI's proposals. Give examples to help clarify this.

Response:

This answer responds to BCUC IR 1.10.1 and includes a portion of the response to BCUC IR 1.10.2.

Included in the capital expenditures subject to the I-X mechanism are all regular capital projects that are recovered through the delivery rate but do not require a Certificate of Public Convenience and Necessity (CPCN). Such expenditures and projects are divided into the following categories:

- **Sustainment Capital**, which consists of expenditures for meter recall or meter exchange programs; system reinforcements to the distribution and transmission systems to maintain capacity to meet existing and forecast load; replacements and upgrades to the distribution and transmission systems to ensure safety, integrity and reliability; and expenditures for mains and service renewals and alterations;
- **Growth Capital**, which consists of expenditures for the installation of new mains; new services and meters; and
- **Other Capital**, which consists of expenditures for Biomethane Interconnections, Equipment Facilities, and Information Technology.

Excluded from the capital expenditures subject to the I-X mechanism are biomethane upgraders and capital projects that require a CPCN. Biomethane upgraders are not recovered through the delivery rate, but rather through a separate rate setting process, and capital projects with a $5 million cost threshold that require a CPCN are subject to a separate regulatory process and approval. These separate processes are akin to the adoption of a 'capital tracker' that treats the respective capital expenses outside the I-X mechanism.

FEI's proposed approach with respect to capital expenditures in the PBR Plan is substantially similar to the approach employed in the 2004 PBR Plan. As indicated on page 27 of the Application FEI believes the success of the 2004 PBR Plan provides a strong basis for moving forward with the same or similar model this time. The treatment of capital expenditures in the

2004 Plan was one of the successful features which FEI has carried forward in the 2014 PBR Plan (subject to some refinements as discussed in the Application).

Other, jurisdictional precedents exist for PBR plans that treat regular capital expenditures under the I-X mechanism while treating certain capital projects outside the I-X mechanisms. Examples of such jurisdictions that utilize this framework include Alberta, via its Capital Tracker Application, and Ontario's 4th Generation Incentive Regulation for Electric Distributors, via its Incremental Capital Module (ICM). Like CPCNs in FEI's case, Alberta's Capital Trackers and Ontario's Incremental Capital Model for Electric Distributors permit the treatment of certain capital expenditures outside the I-X mechanism, as determined in a separate process. B&V has provided further discussion on jurisdictional precedents in the response to BCUC IR 1.10.2.

10.2 How did FEI decide on this framework for handing capital costs under its PBR plan? Are there any precedents in North America for such a framework?

Response:

This response augments the response to BCUC IR 1.10.1.

B&V states that the simple logic of TFP analysis requires that capital-related issues be addressed differently under PBR and even under cost of service regulation where regulators have recognized the importance of timely cost recovery for the capital associated with infrastructure replacement. Numerous jurisdictions provide for separate recovery of these infrastructure costs based both on legislative mandates and regulatory decisions even using cost of service regulation for other costs.

Under PBR, the OEB has adopted three separate PBR plans designed to directly address the issue of capital recovery. Enbridge has proposed a similar customized PBR Plan with separate capital updates for the later years of the plan. There is no practical way to capture CPCN capital projects under the PBR Plan, which is reflected in the previous PBR plans for FEI. The nature of capital expenditures is such that the controllable and generally planned investments are included in the plan while other capital should be outside the plan as explained in Section B of the Application. For a further discussion of this issue, see for example the section, Treatment of Capital Expenditures, in the "Incentive Regulation Design" presented to the AUC workshop by Paul Carpenter of the Brattle Group.

10.3 What percentage of its capital spending during the PBR term does FEI estimate will be included under the I-X PBR mechanism?

Response:

FEI is unable provide the percentage of its capital spending during the PBR term that will be included under the PBR formula, primarily because the capital spending on anticipated CPCN projects over this period is uncertain. While FEI is considering a number of CPCN projects to ensure the ongoing safety, integrity and reliability of its system, cost estimates for these projects are preliminary. Major pipeline projects proposed by other companies in BC and across North America will have varying degrees of impact with respect to cost and timing of projects, as competition for both resources and materials is likely. As such, anticipated projects will not be considered until such information is known with more certainty[7]. These projects will be filed as CPCN applications and subject to BCUC review and approval in separate regulatory proceedings.

FEI provides the following preliminary estimates that it has developed for determining project feasibility.

- The Coastal Transmission System and Intermediate Pressure System sustainment projects are estimated at approximately $220 million. This estimate is subject to significant uncertainty because the individual project cost estimates are preliminary. The rate impacts of these sustainment capital projects may be partly mitigated by potential industrial load growth.
- FEI also mentioned the Kingsvale-Oliver Reinforcement Project (KORP) in the Application. 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. The most recent cost estimate for KORP is $440 million.
- With respect to regular capital expenditures, in aggregate FEI estimates approximately $672 Million to $689 Million of capital expenditures related to Sustainment, Growth and Other Capital over the PBR period, depending on the wider economic context with respect to an anticipated boom in pipeline projects and potential LNG facilities that could considerably inflate construction costs related to transmission system projects. This estimate however, is provided for reference purposes only, since it is the formula-driven

[7] See Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018, p.250-253

capital expenditure amount of approximately $680 million[8] in aggregate that will be recovered in rates over the PBR term beginning 2014. FEI believes this allowed Capital under PBR provides suitable incentive to find efficiencies for capital expenditures without raising concerns of comprising safe, reliable natural gas service or service quality.

[8] Aggregate Figure of $680 Million is based on the Application's 5-year forecast of Average Number of Customers and Service Line Additions. The Formula-Driven Capital Expenditure amounts will be determined yearly at the PBR Annual Review based on updated forecasts of both Average Customers and Service Line Additions

11.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 6.2.3, Determination of FEI Rates, pp. 53-54

11.1 What percentage of FEI's total revenues will be determined under the I-X framework of its PBR plan during the five years of the PBR plan?

Response:

FEI has provided the requested analysis under the assumptions that the forecasted inputs to both the O&M and capital formulas will equal the forecasted amounts for the five year PBR period. In reality, as these formulas are updated annually for the re-forecasted number of customers, re-forecasted composite inflation rate and re-forecasted level of service line additions, the forecasts for 2015 through 2018 will vary from the amounts shown in this Application. Additionally, FEI has provided the calculations as a percentage of delivery margins, in addition to as a percentage of total revenues, as FEI believes this is a more appropriate measure considering this Application is focused on setting the delivery rates for the utility. In summary the forecast percentage of delivery margin under the I-X formula (for O&M and capital combined) begins at approximately 30% in 2014 and grows to 41% in 2018.

The percentages of FEI's total revenues that are comprised of O&M costs determined under the PBR formula are shown in Table 1 below.

Table 1: Net PBR O&M as a % of FEI Revenue Requirements ($000s)

Line		Reference	2014	2015	2016	2017	2018	Total
1	Gross O&M	Table B6-5 of Exhibit B-1	$ 205,761	$ 210,983	$ 216,224	$ 221,636	$ 227,008	$ 1,081,612
2	Less: Capitalized Overhead	14% of Line 1	$ (28,807)	$ (29,538)	$ (30,271)	$ (31,029)	$ (31,781)	$ (151,426)
3	Net O&M	Line 1 + Line 2	$ 176,954	$ 181,445	$ 185,953	$ 190,607	$ 195,227	$ 930,186
4	Revenue	Section E, Schedule 4 & Appendix G-1 Schedules 3, 8, 13 & 18 of Exhibit B-1-3	1,111,841	1,122,951	1,143,372	1,158,056	1,179,061	5,715,281
5	O&M % of Revenues	Line 3 / Line 4	15.92%	16.16%	16.26%	16.46%	16.56%	16.28%
6	Delivery Margin	Section E, Schedule 4 & Appendix G-1 Schedules 3, 8, 13 & 18 of Exhibit B-1-3	616,031	629,387	646,794	658,281	678,281	3,228,774
7	O&M % of Delivery Margin	Line 3 / Line 6	28.72%	28.83%	28.75%	28.96%	28.78%	28.81%

The percentages of FEI's total revenues that are comprised of the cost of service items, specifically, deprecation, income tax and earned return, related to capital determined under the PBR formula are shown in Table 2 with supporting calculations in Table 3.

Table 2: PBR Capital Cost of Service as a % of FEI Revenue Requirements ($000s)

Line		Reference	2014	2015	2016	2017	2018	Total
1	Growth Capital	Table B6-7 of Exhibit B-1	$ 22,451	$ 23,893	$ 24,760	$ 24,894	$ 24,820	$ 120,818
2	Sustaining and Other Capital	Table B6-8 of Exhibit B-1	104,513	107,165	109,827	112,576	115,304	549,385
3	Capitalized Overhead	From Table 1, Line 2	28,807	29,538	30,271	31,029	31,781	151,426
4	Total Capital	Line 1 + 2 + 3	155,771	160,596	164,858	168,499	171,905	821,629
5	Cost of Service Impacts of Capital	From Table 3, Line 22	6,568	26,405	45,938	64,871	84,989	228,771
6	Revenue	Section E, Schedule 4 & Appendix G-1 Schedules 3, 8, 13 & 18 of Exhibit B-1-3	1,111,841	1,122,951	1,143,372	1,158,056	1,179,061	5,715,281
7	Capital Cost of Service % of Revenues	Line 5 / Line 6	0.59%	2.35%	4.02%	5.60%	7.21%	4.00%
8	Delivery Margin	Section E, Schedule 4 & Appendix G-1 Schedules 3, 8, 13 & 18 of Exhibit B-1-3	616,031	629,387	646,794	658,281	678,281	3,228,774
9	Capital Cost of Service % of Delivery Margin	Line 5 / Line 8	1.07%	4.20%	7.10%	9.85%	12.53%	7.09%

Table 3: Supporting Calculations for PBR Capital Cost of Service ($000s)

Line		Reference	2014	2015	2016	2017	2018
1	**Rate Base**						
2	Opening Gross Plant in Service		$ -	$ 155,771	$ 316,366	$ 481,225	$ 649,724
3	Capital Additions	From Table 2, Line 4	155,771	160,596	164,858	168,499	171,905
4	Ending Gross Plant in Service	Line 2 + Line 3	$ 155,771	$ 316,366	$ 481,225	$ 649,724	$ 821,629
5							
6	Opening Accumulated Depreciation		-	-	(5,140)	(15,581)	(31,461)
7	Current Year Depreciation	3.3% assumed rate x prior year's ending GPIS balance (Line 4)	-	(5,140)	(10,440)	(15,880)	(21,441)
8	Ending Accumulated Depreciation	Line 6 + Line 7	-	(5,140)	(15,581)	(31,461)	(52,902)
9							
10	Mid-Year Rate Base	(Line 2 + 4 + 6 + 8) / 2	77,885	233,498	388,435	541,953	693,495
11							
12	**Tax Calculation**						
13	Equity Earned Return	Line 10 x 38.5% Equity Thickness x 8.75% ROE	2,624	7,866	13,085	18,257	23,362
14	Add: Depreciation	- Line 7	-	5,140	10,440	15,880	21,441
15	Taxable Income after Tax	Line 13 + Line 14	2,624	13,006	23,525	34,137	44,803
16	Tax Rate		25%	25%	25%	25%	25%
17	Tax Expense	Line 15 / (1- Line 16) x Line 16	875	4,335	7,842	11,379	14,934
18							
19	**Cost of Service**						
20	Depreciation	-Line 7	-	5,140	10,440	15,880	21,441
21	Tax Expense	Line 17	875	4,335	7,842	11,379	14,934
22	Earned Return	Line 10 x return on rate base included in financial schedules of Exhibit B-1-3	5,693	16,929	27,657	37,612	48,614
23	Total Revenue Requirement	Line 20 + 21 + 22	$ 6,568	$ 26,405	$ 45,938	$ 64,871	$ 84,989

Table 4 below combines the O&M and capital cost of service impacts presented in Tables 1 and 2 above.

Table 4: Combined O&M and Capital Cost of Service as a % of Revenue Requirements ($000s)

Line		Reference	2014	2015	2016	2017	2018	Total
1	Net O&M	Table 1, Line 3	$ 176,954	$ 181,445	$ 185,953	$ 190,607	$ 195,227	$ 930,186
2	Cost of Service Impacts of Capital	Table 2, Line 5	$ 6,568	$ 26,405	$ 45,938	$ 64,871	$ 84,989	$ 228,771
3	Total	Line 1 + Line 2	$ 183,522	$ 207,850	$ 231,891	$ 255,478	$ 280,216	$ 1,158,958
4	Revenue	Section E, Schedule 4 & Appendix G-1 Schedules 3, 8, 13 & 18 of Exhibit B-1-3	1,111,841	1,122,951	1,143,372	1,158,056	1,179,061	5,715,281
5	O&M % of Revenues	Line 3 / Line 4	16.51%	18.51%	20.28%	22.06%	23.77%	20.28%
6	Delivery Margin	Section E, Schedule 4 & Appendix G-1 Schedules 3, 8, 13 & 18 of Exhibit B-1-3	616,031	629,387	646,794	658,281	678,281	3,228,774
7	Total % of Delivery Margin	Line 3 / Line 6	29.79%	33.02%	35.85%	38.81%	41.31%	35.89%

12.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 6.2.4.1, 2013 Base O&M, pp. 54-56

FEI proposes a positive adjustment to 2013 base operating and maintenance (O&M) costs of $12.383 million for three deferral accounts as indicated in Table B6-4, 2013 Base O&M, on page 55.

12.1 Does this mean that these deferral accounts will not be used in the PBR plan after 2013 and that the deferral account revenues will now be included in base O&M rates and subject to the I-X formula? If this is not the case, how are the deferral accounts handled under the PBR framework proposed by FEI?

Response:

No. It is intended that the deferral accounts covering BCUC Fees and Insurance, as well as Pension/OPEB will continue to be utilized throughout the PBR period. As explained in Exhibit B-1, Page 55, Lines 23 and 24 of the Application, the pro-rated portion of PST costs for 2013 were recorded in the Tax Variance deferral account, which is also expected to continue to be utilized through the PBR period; however FEI is not anticipating any specific additions related to PST in this deferral account during the PBR period.

In the case of Insurance and Pension/OPEB, FEI will reforecast the amounts at each annual review to be included in the O&M for rate setting purposes (added on to the formula O&M). In the case of BCUC fees, the amounts included in the O&M for rate setting purposes will escalate within the PBR formula. In both cases, the variances between the amounts included in O&M for rate setting and the actual amounts incurred will be captured in deferral accounts for amortization in future rates.

In this fashion, Insurance, Pension/OPEB, and BCUC fees effectively become “Flow-Through items” as discussed on Page 67 of the Application, a mechanism used on non-controllable costs to ensure that customers pay actual costs in circumstances where the Utility does not control the level of expenditures.

With this PBR, FEI is not proposing to change the items that are currently captured in deferral accounts. As stated on Page 1 of the Application, FEI’s primary objectives are around enforcing a productivity improvement culture and creating an efficient regulatory process. There is no basis on which to recommend a change in the long-standing deferral mechanisms that have been put in place to provide benefits to both customers and the utility.

12.1.1 Relate this response to Table B6-5, Forecast O&M Formula Results, on page 58 which shows three categories of O&M expenses being tracked outside of the formula.

Response:

FEI has included the amounts that were captured in deferral accounts for pension/OPEB and insurance in the 2013 Base (to have an appropriate "base" for the 2014 through 2018 forecasts). This results in the full amount of pension/OPEB and insurance costs being included in the 2013 Base as a starting point.

In Table B6-5: Forecast O&M Formula Results on Page 58 of the Application the 2013 total Pension/OPEB and Insurance (second and third lines of the table) are then removed from the 2013 Base O&M to arrive at the 2013 Base amount that will be subject to the PBR formula. Since there are no Rate Schedule 16 incremental O&M costs included in the 2013 Base, there are no amounts to remove.

Starting in 2014, the O&M that is subject to the formula is then escalated, and the full amount of Pension/OPEBs, Insurance and Rate Schedule 16 O&M is then added back to the formulaic determination of O&M in order to arrive at total O&M under PBR to be used to set the delivery rates. This demonstrates the intended treatment that non-controllable items not be subject to the I-X formula, but rather included on a forecast basis in Total O&M for rate setting purposes. Note that the amounts shown in Table B6-5 for Pension/OPEB, Insurance and Rate Schedule 16 O&M are forecasts at this point in time and will be updated each year as part of the Annual Review process.

This treatment is consistent with the 2004 PBR Plan. In that plan, although Pension and Insurance were included in the formulaic O&M, the formulaic amounts were then replaced with forecast amounts to achieve the identical effect as proposed in the 2014-2018 PBR.

A similar approach is taken with the capital formula amounts.

12.2 If these three deferral accounts were eliminated at the beginning of FEI's PBR plan, what changes, if any, would FEI recommend to its proposed PBR plan?

<u>Response:</u>

These deferral accounts have played a valuable role in ensuring that neither customers nor the Company receive any windfall gains or losses, and should be retained. The same rationale that favoured the Commission approving the use of these accounts previously also applies in the context of PBR.

The PBR recognizes Pension/OPEBs and Insurance as material examples of "non-controllable' expense. B&V, addressing "non-controllable" costs on page 68 of the Application, states *"…it is important to allow full recovery of these costs under a PBR plan, as the costs – being outside the control of management – are by definition prudently incurred costs of providing utility services that should be recovered from customers in the normal course."*

These types of prudently incurred costs, which are outside the control of the Company, should be borne by customers. The nature of the rate setting mechanism (PBR or Cost of Service) should not affect whether or not these are customer costs. A PBR is intended to incent productivity, not to transfer uncontrollable costs to the Company or ratepayers.

13.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 6.2.4.2, 2014-2018 O&M, pp. 56-59

13.1 Explain why FEI chose a revenue cap, that involves forecasting the number of customers in its annual review (page 56) rather than a revenue-per-customer cap, which would avoid the need for this forecast? Provide a detailed explanation, including references to any literature or to other PBR plans for gas distribution companies.

Response:

The premise of this question is incorrect. Revenue cap and revenue per customer cap approaches both involve forecasting the number of customers for rate-setting purposes. FEI's approach is based on its successful 2004 PBR Plan and is a building block version of the revenue cap model. Please refer to the response to BCUC IR 1.15.1 for other PBR examples of the building block approach.

14.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 6.2.4.2, 2014-2018 O&M, pp. 56-59, and Section 6.2.5.2, 2014-2018 Capital, pp. 62-66

14.1 Explain why FEI chose a revenue cap rather than a price cap for its PBR plan for both O&M and for the two types of capital.

Response:

FEI has based the 2014 PBR Plan on its successful 2004 PBR Plan which was the same revenue cap approach. As stated on page 27 of the Application "The success of FEI's 2004 PBR Plan provides a strong basis for going forward with a similar model for the proposed PBR. The model approved for use by FEI between 2004 and 2009 provided a flexible framework of incentives that allowed FEI to capture efficiencies for the long-term benefit of customers."

As indicated in section B-5 of the Application, the majority of natural gas utilities use a version of the revenue cap approach for their PBR plans. Section B-3 (Pages 32 and 33) of the Application explains the problems that natural gas distributors may face under a price cap approach:

> *"Demand variations can be problematic and unfair under a price cap model for utilities where, due to exogenous factors, there is a continuing decline in sales per customer (such as the case with current and forecast trend in natural gas use rates in BC)."*

Therefore in order for FEI to have an opportunity to earn its allowed return on and of its investments it is essential that the Company's PBR plan is designed in a way that the risk of use rate decreases is mitigated. The revenue cap will provide a framework for incenting the utilities to seek additional productivity gains while protecting them from exogenous demand variation risks.

15.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 6.2.4.2, 2014-2018 O&M, pp. 56-59

At the top of page 57, FEI presents the formula that it proposes to use for O&M expenses in its PBR plan.

15.1 Explain why FEI chose to treat O&M and capital expenses separately rather than combined into total revenue that could be indexed with the I-X formula? Is there justification in the literature or with other North American precedents for this approach?

Response:

The literature refers to this approach as the building block approach. This approach has precedent in the prior approved FEI PBR plans as well as other plans and proposals in other jurisdictions. The building block approach provides a better framework for forecasting the costs using PBR formulas since more relevant cost drivers can be used for forecasting the capital and operating expenditures rather than using one cost driver for total expenditures. In addition, the building block approach will continue to give the regulator some ability to monitor the capital and operating expenditure, while under a Totex approach the regulator has little control over how the utility allocates costs between Opex and Capex and can only approve the total expenditure.

Please refer to FEI's response to BCPSO IR 1.10.1 for additional examples of building block plans. Also please see PBR Section B page 33 where the concept is discussed in detail.

15.2 Given the revenue cap for O&M expenses, how does FEI insure that the X-Factor and I-Factor are relevant for O&M expenses and not for the overall expenses of the company? Similarly, how does FEI insure that the X-Factor and I-Factor are relevant for capital expenses considered apart from O&M expenses? Relate this response to Table B6-5, Forecast O&M Formula Results, on page 58 that shows the forecasted I and calculated X being used for O&M expenses. Similarly, also relate this response to Table B6-7, PBR Growth Capital Formula Results, on page 63 and to Table B6-8, Sustainment and Other Capital Formula Results, on page 65.

Response:

There is no difference between FEI's proposed building-block approach and the combined (or Totex) approach in this regard since FEI's I-X mechanism is applied to both Opex and Capex, similar to the Totex approach. The proposed X-Factor is based on total factor productivity (which includes both capital and operating expenditures) and a stretch factor, with the assumption that the I-X mechanism is applied to both Opex and Capex. The same reasoning is applicable to the I-Factor in that the inflationary influences apply to the total expenditures so it is appropriate to apply the same I-Factor to both Opex and Capex because they represent the total expenditures In addition, one of FEI's stated objectives is that "The PBR plan should be easy to understand, implement and administer…" and using the same I-X mechanism for capital and operating expense, consistent with the 2004 PBR, helps to achieve this.

16.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 6.2.4.2, 2014-2018 O&M, pp. 56-59

The formula at the top of page 57 includes the average number of customers, which is forecasted.

16.1 Is there a true-up for this forecast? Explain in detail why or why not, the justification for this, and the resulting incentive consequences. Relate this response to the statement at the bottom of page 57 that "(t)he O&M allowed under PBR will be revised yearly in the PBR Annual Review, recalculated based on both the re-forecasted number of customers and the re-forecasted composite inflation rate for the upcoming year." (lines 21-24) This statement suggests that the number of customers is re-forecasted but not trued up. Is this correct? Please explain in detail the justification for this approach.

Response:

FEI used the term "true up" in describing its PBR proposal since this terminology was used in its 2004 PBR to describe what is being contemplated here. The true-up features for the PBR I-X formulas pertain to the cost drivers only (i.e. average number of customers and service line additions). However, on reflection, a better way to describe the process would be a re-forecast using the latest available information on the cost drivers in the PBR formulas (i.e., actual average customers and service line additions when these quantities are known).

The term "true up" for the O&M formula was used in relation to adjusting for actual customer growth in Table B6-1 and again in Table B6-10. In fact, the re-forecast number of customers to be used each year in the Annual Review will update prior year customer counts for actual customer growth[9] and a new forecast of customer growth for the coming year. As indicated above, this process is the same treatment that was applied for customer counts in the 2004 PBR.

[9] Since the Annual Review will occur in the fall of the year actual customer growth for the full year will not be known but a projection to year-end will be made. Any small variances in customer count (positive or negative) between the projected and actual numbers will be trued up in the following year.

17.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 6.2.5, Capital Expenditures under PBR, pp. 59-60

On page 60, FEI identifies "three categories of regular capital expenditures which FEI has included in its PBR formula – growth, sustainment, and other capital." (lines 15-16)

17.1 Does this mean that these three categories of capital are subject to the I-X mechanism? If not, please explain the treatment of each of these three categories of capital and explain why they are treated in that manner.

<u>Response:</u>

Yes. The three categories of regular capital expenditures – Growth, Sustainment and Other capital – that FEI has included in its PBR Formula are all subject to the I-X mechanism.

18.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 6.2.5.1, 2013 Base Capital, pp. 60-61

FEI indicates that there are adjustments to 2013 capital for items held in deferral accounts (point 1 at the bottom of page 60).

18.1 Explain in detail how this will work. Are the deferral accounts eliminated for the five years of the PBR plan? If not, what happens to the revenues in the deferral accounts and how are they handled on a year-to-year basis? Explain in detail. Relate this response to Table B6-7, PBR Growth Capital Formula Results, on page 63.

Response:

No the deferral accounts are maintained for the five years of the PBR Plan, as the same rationale that justified deferral treatment in the past continues to apply during PBR. Please refer to the response to BCUC IR 1.12.2 in this regard.

Regarding treatment and methodology, please refer to the responses to BCUC IR 1.12.1 and 1.12.1.1 as the methodology for capital adjustments is the same as the methodology for O&M adjustments, although capital adjustments are limited to the PST adjustment and the pension/OPEB adjustments.

18.2 If these three deferral accounts were eliminated at the beginning of FEI's PBR plan, what changes, if any, would FEI recommend to its proposed PBR plan?

Response:

The deferral accounts referenced in point 1 at the bottom of page 60 of the Application are the PST and pension deferral accounts. The PST adjustment is one-time and therefore will be eliminated after the 2013 Base is reset (although the Tax Variance deferral account will continue). The pension deferral accounts are long standing deferrals that provide benefits to customers and the shareholder and FEI submits there is no basis on which to eliminate these accounts.

The pension deferrals are unrelated to the PBR plan introduction. The effect of eliminating these deferrals is the same regardless of whether FEI uses a formula-based PBR plan or a conventional cost of service approach. The purpose of these deferrals is the same - to avoid windfall gains or losses to either the shareholder or the customer and to smooth the rate impacts of large variances in pension expenses into customers' rates.

19.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 6.2.5.2, 2014-2018 Capital, pp. 62-66

19.1 FEI proposes two capital formulas. What is the purpose of separating capital into two categories?

Response:

The reason for using two capital formulas is simply to recognize that there are different cost drivers for the types of capital that fall into the two categories. The growth capital component pertains to activities that are involved with adding customers to the system. As explained in Section B6.2.5.2, pages 62 and 63 of the Application, FEI has adopted service line additions (calculated as a percentage of gross customer additions) as the appropriate cost driver for growth capital. Service line additions (and customer growth) are currently forecast to be fairly constant in the range of 8,000 to 8,500 per year during the PBR period but there have been wide variations in growth activity in the past which may occur again in the future.

The categories of capital that fall under the second formula – sustainment and other – are more a function of the total system size and number of customers served. In other words as the overall system grows (i.e. system capacity grows) or the aggregate number of customers served increases, the level of capital activity for sustainment and other capital will increase proportionately. As explained in section C6.2.5.2, pages 63 to 65 of the Application, the average customer count has been adopted as the appropriate cost driver for capital spending in this category.

The service line additions driver for growth capital may move up or down each year depending on how the growth expectations change from year to year while the average customers driver for sustainment and other capital allows for a stable level of capital activity that grows slowly with the increasing customer base.

19.1.1 How does FEI insure that the X-Factor and I-Factor are relevant for each of these two categories of capital? What would be the consequences of treating all capital subject to the PBR I-X formula in one category? Explain in detail.

Response:

The I-Factor is relevant for capital spending as a whole because the inflationary cost pressures affecting capital spending is reasonably represented by the composite I-Factor that has been proposed. While the inflationary pressures facing different capital projects may not be identical, it is reasonable to apply a single inflation factor to capital spending in both categories. The PBR Plan finds a balance between practicality and diversity by developing formulas with representative cost drivers, inflation factors and productivity offsets that apply at the broader level. While it might be possible to develop different I-factors or X-factors for different components of capital costs, FEI believes going in that direction would tend to make the Plan unnecessarily complicated with no clear benefit from the added complication.

Regarding treating growth, sustainment and other capital all under one formula, FEI believes this would fail to recognize key cost driver differences between growth capital and the other categories. Growth capital is ultimately driven by requests from developers or potential customers to attach to the gas system and the level of growth varies for numerous reasons. In contrast, with sustainment and other capital FEI has some flexibility to manage the timing of projects. A single formula encompassing all capital would give positive or negative variances for inappropriate reasons. For instance, if the combined formula was calibrated based on customer additions in the order of 8,000 per year then capital spending would be higher or lower than formula simply because of customer growth variations even if there were no other variations from formula capital spending. This would incorrectly characterize certain aspects of capital spending over or under the formula as inefficiencies or efficiencies.

20.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 6.2.5.2, 2014-2018 Capital, pp. 62-66

20.1 Service line additions are forecasted. Are they trued up? If not, what are the resulting incentives and consequences of not trueing up the forecasts? How does this relate to the statement that the Average Growth Capital Cost per Service Line Addition will be recalculated in the PBR Annual Review? Will this cost be estimated, or it is an actual cost? If it is an estimate, will it be trued up? If not, what are the incentives and consequences? Explain in detail.

Response:

FEI used the term “true up” in describing its PBR proposal since this terminology was used in its 2004 PBR to describe what is being contemplated here. The true-up features for the PBR I-X formulas pertain to the cost drivers only (i.e. average number of customers and service line additions). However, on reflection, a better way to describe the process would be a re-forecast using the latest available information on the cost drivers in the PBR formulas (i.e. actual average customers and service line additions when these quantities are known).

Service line additions will be re-forecast along with the other cost drivers, in the Annual Review, with any adjustments resulting from actual or projected service line additions from the prior year flowing through in rates in the subsequent year. For instance, assuming the PBR Annual Review is held in October, a projection of service line additions will be made to year-end for the current year and a new forecast of service line additions for the coming year will be made. Any residual adjustments to adjust to actual service line additions relative to the Annual Review projection will occur at the next annual review when the full year’s results are known, and will be reflected in rate calculations for the following year.

As a result, there is very little incentive in variances from forecast in service line additions. First, the service line addition variances from forecast may be positive or negative. Second, customer growth capital is related to adding new customers which bring in revenues as well as adding costs. Since the revenues and costs tend to be similar in magnitude, the net amount (positive or negative) that may give rise to earnings variances is not significant.

21.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANIS

Exhibit B-1, Application, Part B, Section 6.3.2, Flow-Through Expenses, pp. 68-70

21.1 FEI proposes to flow through a forecast of interest expenses. Will these forecasts of interest expenses be trued up? If not, explain the incentives and consequences in detail.

Response:

Interest expense is “trued up” in the sense that customers pay for actual interest rates incurred. This is achieved through amortization of the Interest Variance deferral account in subsequent years’ rates. This deferral account covers both long term debt interest variances and short term interest rate variances. Long term debt interest, which comprises more than 97% of the interest expense, is adjusted to actual amounts based on debt issue timing variances, principal amount variances and interest rate variances. Short term debt, which accounts for less than 3% of the interest expense, is adjusted based on variances between the actual short term debt rate and the forecast short term debt rate. This treatment is unchanged from the current approved practice and should not be considered a “proposal”.

21.2 Explain why changes in interest expenses are not captured in the I-Factor.

Response:

Consistent with the 2004 PBR Plan, the PBR formula applies only to the controllable O&M and capital components of costs. Interest expense is largely outside of FEI’s control and interest rates have historically been subject to flow through or deferral account treatment. Capturing items in a deferral account results in actual costs being recovered from customers; applying a PBR formula results in formula-driven amounts being recovered from customers.

Since the bulk of interest expense is driven by interest expense on embedded debt, only a small amount is subject to forecasting in any given year. It is unlikely that the interest expense escalation that is forecast would be expected to follow a trend of general inflation, with or without an X factor offset.

Changes in interest expense are not captured in the I-Factor because the impact of interest expense on the rate of inflation is only the current rate effect. Actual interest expense for a utility reflects higher leverage than for the economy as a whole and a larger portion of sunk costs than for the economy. In addition, interest expense is a function of the level of capital spending from period to period that is not likely to match the implied capital spending in an index of general inflation.

21.3 Explain why changes in Commission-approved Return on Equity (ROE) are not captured in the I-Factor.

Response:

Please refer to the response to BCUC IR 1.21.2. ROE changes with the market and the capital structure of the utility. Since there is to be a regular re-determination of ROE for the utility within the proposed PBR period, these changes out of necessity must be passed through separately. Finally, the TFP calculation does not reflect the utility's allowed ROE, but rather the actual earned ROE that may or may not equal the actual allowed ROE. The reflection of actual earned ROE would also create a lag in the adjustment for the cost of equity.

21.4 Will forecasted revenues (page 69, lines 10-19) be trued up? If not, explain the incentives and consequences in detail.

Response:

The proposed treatment of gas sales and transportation revenues in the PBR is the same as revenues were treated in the 2004 PBR Plan. The total revenue stream is divided into commodity, midstream and delivery-related components. The PBR Plan pertains to the delivery component of the revenue stream.

The gas commodity and midstream portion of revenues are fully adjusted to actual through existing deferral account mechanisms. These are the Commodity Cost Reconciliation Account (CCRA) and the Midstream Cost Reconciliation Account (MCRA). The commodity and midstream costs are managed separately from the delivery rates through Commission-established commodity and midstream flow-through processes. If the commodity and midstream rates charged to customers recover more than the actual costs for these functions, the over-recovery amount is refunded to customers in a subsequent period. Conversely, if commodity and midstream rates charged to customers recover less than the actual costs for these functions, the under-recovery amount is charged to customers in a subsequent period.

The PBR Plan pertains to the delivery portion of revenues. Residential and Commercial delivery revenues, which comprise more than 85 percent of the total delivery revenues, are adjusted through a revenue decoupling deferral account called the Revenue Stabilization Adjustment Mechanism (or RSAM). The remaining delivery revenues from the industrial rate classes are not subject to a deferral account. Industrial delivery revenue variances may be positive or negative relative to the forecast used in setting rates. These positive or negative industrial revenue variances will cause a one-time increase or decrease in FEI's ROE, all else equal. Any ROE variance caused by industrial revenue variances will be subject to 50/50 sharing with customers under the PBR ESM. Since revenues are reforecast annually in the PBR Annual Review Process and the industrial revenue forecast is based on customers' forecasts of their own gas usage, industrial revenue variances from one year cannot be expected to re-occur in the next. Under conventional cost of service based revenue requirements applications, 100 percent of the industrial revenue variances (either positive or negative) affect FEI's ROE during the test period, while under the PBR, half will be refunded to or charged to customers through the 50/50 ESM.

21.5 Will the smaller components of rates, as described on page 70, lines 4-10, be trued up? How does this related to the Annual Review process? If these costs are not trued up, explain the incentives and consequences in detail.

Response:

The smaller components of rate base described on page 70, lines 4 -10 of the Application will be reforecast each year based on up-to-date information known at the time of the Annual Review. Actual results for these items may vary from forecast and give rise to positive or negative earnings variances in the year. These variances will be subject to the 50/50 ESM. The variances in any particular line item will not be expected to recur in the following year because the reforecasting of that line item at that time will use the most up-to-date information. Under conventional cost-of-service-based RRAs, 100 percent of the earnings variances attributable to these other rate base components would affect FEI's rate of return during the test period while, under the PBR, 50 percent will be attributed to customers through the ESM. Earnings variances from these other rate base items will not be included in the Efficiency Carryover Mechanism.

22.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 6.3.3, Exogenous Factors, p. 70

22.1 Is there a materiality threshold for exogenous factors? If not, why not? If yes, what is the materiality threshold and how was it determined? Provide the justification for the threshold.

<u>Response:</u>

FEI has not proposed and does not recommend any materiality threshold for exogenous factors. Please refer to the response to BCPSO IR 1.23.2 for the related reasoning on this issue provided by B&V.

23.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 6.4, Earning Sharing Mechanism, p. 70

23.1 Explain the effect on incentives from including an Earning Sharing Mechanism (ESM) in FEI's PBR plan.

<u>Response:</u>

Including the proposed 50/50 ESM in the PBR Plan shares the benefits from efficiencies achieved equally between customers and the Company. Customers therefore receive 50% of the benefits during the PBR (and efficiency carry-over period) and then receive 100% of the benefits after that.

Based on the success of FEI's prior PBR Plans which included the same ESM (along with similar other PBR Plan elements), FEI believes that inclusion of the same 50/50 ESM in the 2014 PBR Plan is appropriate and will provide FEI with suitable motivation to pursue efficiencies as it did in the previous PBR Plans. As well, while the proposed PBR Plan is structured such that the initial 0.5% of productivity achieved accrue to the customers, to the extent the Company is able to exceed that level, customers will further benefit.

23.2 If there were no ESM in the PBR plan, would FEI suggest an increase in the X-Factor? If so, why, and how much?

Response:

If there was no ROE sharing through an ESM, it would be necessary to consider changes to more than the level of the X-Factor, including off-ramps and reopeners. The absence of an ESM changes the risk profile for FEI because there is no longer a sharing of the shortfalls or gains. With the positive X-factor that is well above the negative TFP value, over the term of the PBR, it is uncertain as to the likelihood of achieving or surpassing the productivity target. The ESM, while ensuring customers benefit from positive performance, somewhat mitigates the Company's downside risk associated with the aggressive positive X-factor.

As noted in the evidence at page 51, with earnings sharing the X-Factor is less significant than with no earnings sharing. In all likelihood this could mean, absent an ESM, using an X-Factor that directionally is closer to the actual TFP value, which would likely result in a negative value for the X-Factor. FEI has not analyzed its risk profile under this option since it is inconsistent with the overall context of its proposed PBR Plan. As a result, it is not possible to quantify precisely the magnitude of a change to the X-Factor.

23.3 What is the relationship between ESM and provisions to re-open the PBR plan during its five-year term? Explain in detail. If there were no ESM, would FEI propose any changes to the re-opener provisions? If so, explain why and what these changes would be.

Response:

ESM, off-ramps and re-opener provisions are safeguard mechanisms that protect the utility and customers from potential unexpected negative consequences of the PBR plans. Similar to the 2004 PBR Plan, FEI's proposed ESM is linked to the off-ramp provision through the off-ramp financial trigger mechanism and the proposed 200 basis point trigger over or under the allowed ROE is calculated after earnings sharing.

It is clear that without an ESM, the role of other safeguard mechanisms becomes more important and that the proposed off-ramp financial trigger should be changed to accommodate for the PBR Plan's changed risk/reward balance. It is not possible to comment on the magnitude of this change without knowing the changes in all of the other PBR elements that may affect the overall risk/reward balance of the plan, since any PBR plan is composed of complementary elements.

24.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 6.4.2, Proposal for ESM, pp. 71-72

24.1 Why did FEI select the structure of the ESM that it did? Did FEI consider a deadband, so if the ROE fell within this band around the approved ROE, there would be no earnings sharing? If there were a deadband in the ESM, what would FEI consider to be a reasonable deadband, and why?

Response:

FEI reviewed the merits of various ESM structures and also considered its own experience with ESM to decide on the best option. FEI decided not to use a dead-band for following reasons:

1. **Success of 2004-2009 PBR ESM**: The 2004 ESM structure did not have any dead-band. Ratepayers benefited from this framework since all of the PBR related gains were shared with them. In the 2004 PBR the inclusion of a dead-band would have decreased the ratepayers' share of PBR benefits.

2. **Regulatory burden associated with using a dead-band:** A review of ESM structures with dead-band in other Canadian jurisdictions indicates that the inclusion of a dead-band has the potential of increasing the regulatory burden. For instance the OEB's consultant reviewed the ESM structure of Enbridge and Union during their 2008-2012 PBR Plans and concluded that "computing the returns to be shared in an ESM is an inherently controversial issue, and this process sometimes leads to mini rate cases that involve significant regulatory costs and delays." FEI believes that the controversy surrounding the OEB's approved ESM is influenced by the use of dead-bands.

3. **The no dead-band ESM better conforms with FEI's PBR principles:** With regard to PBR principles a no dead-band ESM scores better than other ESM design options as it aligns the interests of customers and the Utility to the greatest extent possible and it is easier to understand, implement and administer and may reduce the regulatory burden over time.

Consequently FEI is not proposing any dead-band. FEI believes that in the context of its overall PBR proposal the proposed ESM, in combination with the efficiency carry-over mechanism will provide suitable motivation to pursue efficiencies for the longer term benefit of ratepayers.

24.2 Is FEI's ESM symmetrical? In other words, will customer prices be increased if the ROE is below the approved ROE?

Response:

Yes, Similar to FEI's 2004-2009 PBR plan, the FEI's proposed ESM is symmetrical. The ESM will be handled through a rate rider, as it was during the 2004 PBR Plan. If the achieved ROE in any year is below the allowed ROE the resulting rate rider will increase customer rates for the subsequent year to recover FEI's 50% share of the ROE shortfall.

24.3 Did FEI consider any other structure for its ESM other than the 50-50 sharing it proposed? For example, did FEI consider either an increasing or decreasing share of earnings to customers above or below the approved ROE? Why or why not? As an example, did FEI consider an ESM in which earnings above the approved ROE be shared with 70 percent with customers, then 50-50, and then, perhaps, 30 percent to customers and 70 percent to the company as earning rose above the approved ROE? Discuss the incentive properties of alternative ESM structures.

Response:

Please refer to the responses to BCUC IR 1.24.1 and CEC IR 1.48.3.

25.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 6.5.2, Enhancing the Effectiveness of the 2004 PBR Plan ECM, pp. 73-75

25.1 Provide a numerical example to illustrate how the proposed Efficiency Carry-Over-Mechanism (ECM) would work with O&M and capital savings made at various years during the term of the PBR plan. This should clearly show how the savings were calculated and the effect on customer prices during subsequent years. The example should also show the role of forecasts in determining savings (see, for example, page 74, lines 26-27), the incentives created by the use of forecasts, if any, and whether or not such forecasts are trued up.

Response:

A numerical example of how the ECM would work is provided in Appendix D6, page 3, Exhibit B-1-1. A written description of the components of the numerical example is provided in Appendix D6, pages 1 and 2. The example in the Appendix shows that the calculation is based on the difference between the formula-based amounts as calculated in that year, and the actual amounts. Since the calculation of the ECM is a backward looking calculation, the formula-based amounts to be included in the calculation will be based on the actual cost drivers (i.e. actual average customers and actual service line additions experienced in each of the years).

26.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 6.7, Mid-Term Review and Off Ramps

26.1 Discuss the relationship between the mid-term review and off ramps and the value of the X-Factor and the ESM. Specifically, would the absence of a mid-term review affect FEI's recommendation for the X-Factor or the terms of its proposed ESM? Would changes in the off ramps affect FEI's recommendations for the X-Factor or the terms of its proposed ESM?

__**Response:**__

B&V concludes that any change in FEI's PBR Plan would impact other elements of its Plan. Since the X-Factor is a major element of the Plan, changes in any of the other design elements of the Plan would require a reassessment of the X-Factor.

With respect to the two items mentioned in the question, changes in the off ramps, other plan provisions the same, would likely be a more significant concern of the two. With off ramps, stakeholders are protected from outcomes that would otherwise not meet the standard that a utility be allowed a reasonable opportunity to recover its prudently incurred costs and earn the allowed return. Eliminating the off ramp or making it asymmetric by setting only an upper limit on the earned ROE without a floor would effectively make it necessary to have the X-Factor move in the direction of the industry average of minus four percent in order to meet the test of providing a reasonable opportunity to earn the allowed return.

Regarding the Mid-Term Review, this concept was a component of the 2004 PBR Plan that was introduced to address the concerns of some parties about having a longer term PBR and where undesirable and unanticipated outcomes not covered by other plan provisions could be given consideration without having to abandon the overall plan. Although the Mid-Term Review in the 2004 PBR Plan was mainly a confirmation that the plan was working well and did not lead to any changes in the Plan FEI believes it is appropriate to keep the Mid-Term Review in the 2014 PBR Plan as a risk mitigation element for both FEI and customers.

26.1.1 Conversely, would changes in the X-Factor or the ESM change FEI's recommendations regarding the mid-term review or off ramps?

Response:

Yes for similar reasons as those articulated in the response to BCUC IR 1.26.1.

27.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 6.8, Annual Review, pp. 78-79

27.1 Regarding point 6 at the top of page 79, are there any forecasts that are used to determine projected earnings and trued up actual earnings? If so, are these forecasts trued up and are the actual earnings adjusted to take into account any difference between the forecasts and the actuals? If not, what are the incentives created by not trueing up these forecasts and the consequences? Why has FEI chosen not to true up these forecasts?

Response:

Customers will receive (or be charged) the full correct amount, based on actual results, of the 50/50 earnings sharing through the ESM rate rider. It will be necessary to make a projection of earnings sharing at the Annual Review because the year for which the sharing is being calculated will not be complete until after the Annual Review has occurred. However, FEI will recalculate the earnings, and earnings sharing, based on actual results after the year is complete when its Annual Report is provided to the Commission. Any variances, positive or negative, between projected and actual earnings sharing will be adjusted through the ESM rate rider during the next Annual Review. This is the same approach that was agreed to during the 2004 to 2009 PBR period.

28.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Part B, Section 7, Delivery Revenue Forecasts Under PBR, pp. 82-83

28.1 The three delivery revenue scenarios described in this section, at the top of page 82 and in Figure B-5, Non-Bypass Delivery Margin Comparison, on page 82, each contain forecasts. Please explain how over or under forecasting would affect each of these scenarios. In other words, if FEI under or over forecasted, would the relative performance of the three scenarios change?

<u>Response:</u>

FEI assumes that the references to over and under-forecasting in the question refer to the O&M and capital forecasts included in the forecast cost of service line. It is evident that, if the O&M and capital forecasts are over-forecast, reducing these forecasts, absent any similar changes in the PBR formula parameters, would move the forecast cost of service line down towards the PBR line and the Revenue Cap line. If O&M and capital in the forecast cost of service are under-forecast, then increasing them would expand the gap between the forecast cost of service line and the other two lines.

Depending on the source of the over or under-forecasting there may be some corresponding adjustments that would be made to the PBR formulas. For instance, if the forecast capital spending was thought to have too much activity or too many projects in a particular area, removing some of these from the forecast might also suggest that a comparable adjustment should be made to the base year costs in the PBR formula. Since comparable adjustments would then be made to both scenarios, the relative position of the lines would be similar.

Comparisons to the Revenue Cap (AUC model) are more difficult to make. FEI has made reasonable assumptions about how its revenue requirements would fit into the AUC model; however, the utility has not closely examined the provision in Alberta to file Capital Tracker applications outside of the Revenue Cap formula and is therefore not sure of how this provision would affect the comparison.

29.0 Reference: OVERVIEW AND INTRODUCTION

Exhibit B-1, Application, Part A, Section 1, Application Overview, pp. 1-5

On page 3, FEI states that "FEI's model produces lower rate increases over the five year period than a revenue cap model of the type approved by the Alberta Utilities Commission." (lines 7-8)

29.1 Explain if this statement is dependent on any assumptions and forecasts and, if so, identify these assumptions and forecasts. Provide a clear numerical example to illustrate how the rate increases are lower under FEI's PBR proposal than under the PBR plan the Alberta Utilities Commission (AUC) has put into effect for the two gas distribution companies in Alberta.

Response:

The requested numerical example of the AUC-style Revenue (Margin) Cap analysis is provided in Attachment 29.1. Since the PBR Plan deals with delivery costs only and does not include commodity or midstream costs, this analysis has been done on the basis of delivery margin per customer and is therefore referred to as a Margin Cap analysis in the spreadsheet. The analysis has used the same customer growth forecasts as included in FEI's proposed PBR model. The Margin Cap analysis assumes that certain flow-throughs (deferral account amortization, interest costs, pensions/OPEB and insurance cost changes, and Rate Schedule 16 revenues and operating costs) will also occur under the Margin Cap model (see lines 35-36 and 44-51 on Margin Cap 2014-2018 tab in Attachment 29.1). Overall, the flow-throughs included on lines 44-51 reduce the delivery revenue collected from customers over the five-year period under the Margin Cap model by about $5 million.

During the preparation of this response an error was discovered in the analysis that was used to produce Figure B-5 on page 82 in the original Application and the Evidentiary Update. The error pertained to incorrectly capturing customer growth in the five-year PBR term resulting in an understatement of the forecast amount of revenue collected under Margin Cap analysis. With the correction made in Attachment 29.1, FEI's proposed PBR model would collect approximately $46 million less from customers than the Margin Cap model over the five year period (compared with a difference of $9 million less over five years as provided on page 83 of the Evidentiary Update). FEI will provide a corrected version of Figure B-5 when it files the next Evidentiary Update.

At a high level, the differences between the proposed PBR model and the Margin Cap analysis can be understood by looking at the forecast five-year increases. Table 1 in the covering letter of the Evidentiary Update (Exhibit B-1-3) identified the total five-year increase under the PBR as being 7.28%. In simple terms, the revenue cap per customer model is inflating the per customer delivery revenues by I-X each year. The yearly I-X results vary between 1.8% and 1.9% over the five years and sum to 9.2%.

30.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1-1, Application, Black & Veatch Report, Appendix D1, p. 32

"This assumption [that throughput explains the cost structure of the utility] has been demonstrated to be false time and again by cost of service analysis."

30.1 Provide support for the statement that this assumption, that throughput explains the cost structure of the utility, has been demonstrated to be false time and again.

Response:

B&V states that testimony has been filed in any number of rate cases in the US and Canada that demonstrates throughput is not a cost causative factor for the distribution costs of gas LDCs. This position has been supported both theoretically and empirically. For a simple explanation of this issue see the Gas Distribution Rate Design Manual published by the National Association of Regulatory Utility Commissioners, June 1989, in which the capacity cost function is described as follows: "Demand or capacity costs vary with the quantity or size of plant and equipment. They are related to maximum system requirements which the system is designed to serve during short intervals and do not directly vary with the number of customers or their annual usage."[10] (Emphasis added.)

The simplest illustration of this point is that regulators do not normalize the distribution costs of a gas utility for weather within the context of rate proceedings. Normalization applies only to volumetric revenues and gas commodity costs if included in a rate proceeding. If we assumed delivery service costs changed with volume, which they do not, it would be necessary to weather normalize operating expenses and plant costs. This does not occur (other than for purchased gas commodity costs). Further, please refer to the detailed explanation in Exhibit B-1-1, Appendix D-1, pages 31-35 and page 40. Also see Appendix D-2 starting at page 2.

FEI adds that the difference between volumetric and customer and capacity driven costs is reflected in the functionalization and classification steps of Fully Allocated Cost of Service (FACOS) studies used by utilities in this jurisdiction. For instance, the Commission described in the 1987 Inland Natural Gas (FEI) Rate Design Decision the methodology employed for the FACOS, noting that the point of functionalization and classification is to recognize that different costs have different drivers (p.36):

The FACOS study methodology consists of three steps. First, items in the BCUC uniform system of accounts are aggregated into functional components such as

[10] See pages 23 - 24

production, storage, transmission, distribution and administration. Second these functional components are classified as being either demand commodity or customer categories.

Commodity costs are those which vary with the volume of gas service provided and are referred to as variable costs. The largest component of variable costs is the cost of gas. Cost related to capacity or the maximum rate of use are assigned to demand and are referred to as fixed costs since they do not vary directly with sales. The last component, customer costs, are associated with serving individual customers. This is generally straight forward with the exception of the classification of distribution costs wherein those costs must be segregated between demand and customer-related costs.

The Commission did not identify any issues in the decision with the way in which costs were classified by Inland based on volume, demand and customer.

The Commission's Order G-42-03 and Decision on the 2003 Centra Gas Rate Design Application (FEVI) included the following passage, which is to similar effect (p.7):

The next step, classification, attempts to classify costs into cost causation categories (demand, commodity or customer). For instance, transmission costs tend to be demand-related because they are associated with the size of the facilities needed to meet the maximum demand. Classification of demand-related costs may be further refined as, for example, coincident peak ("CP") or non-coincident peak ("NCP"). CP may be further refined to reflect whether the utility experiences one demand peak per year ("1 CP"), two peaks per year such as a summer peak and a winter peak in demand ("2 CP") or demand peaks each month ("12 CP"). Procuring and delivering gas supply to the utility's system tend to be classified as commodity related. Meter reading and billing costs tend to be classified as customer related.

The same concepts apply to an electric distribution system, and the Commission described the FACOS process as follows in its Order G-36-07 and Decision in the 2007 BC Hydro Rate Design Application (p.83-84):

In cost of service studies the distribution system is commonly split between the portion of the system which was constructed solely as a result of the customer requiring service, of which customer metering is the most common example, and the portion of the system constructed because of the demand placed on electrical equipment. Distribution substations are generally classified 100 percent demand, and all equipment between this point and the meter may be determined to be demand or customer-related.

The methods used to determine the demand/customer split are more fully described by EES:

> *"There are three basic methodologies to classify distribution costs: basic customer charge (sometimes called 100% demand), minimum system and zero intercept. Variations around these three basic methods are also common. The basic customer charge methodology assumes that the distribution system is built to meet the customers' non-coincident peak demand. Therefore, the basic customer charge methodology classifies customer accounting, and O&M and capital costs for meters and services as customer-related, while the remaining distribution costs are classified as 100% non-coincident demand-related. Distribution costs are also sometimes split between demand and customer according to a zero intercept or minimum system methodology. These methodologies reflect the philosophy that the distribution system is in place in part because there are customers to serve throughout the service territory expanse, and that a zero or minimally-sized distribution system is needed to serve these customers even if they only have a 100 watt light bulb in their residences. The concept follows that any costs associated with a system larger than this minimal size are due to the fact that customers "demand" a delivery quantity of electricity greater than the minimum. These costs required to meet demands greater than those met by the minimum system are treated as demand-related (Exhibit C7-4, Testimony of EES Consulting, pp.16, 17)."*

B&V concludes that if throughput does not cause costs to be incurred by a gas utility, it cannot be a valid measure of TFP because productivity is measured in terms of what is actually produced. Gas throughput is not the product of a gas delivery system. Output consists of customer connections and design day delivery capacity.

30.1.1 If the assumption is false for a cost of service analysis, explain, with references to the economics literature on TFP growth studies, why this assumption is false for TFP growth studies.

Response:

B&V concludes that if throughput does not cause costs to be incurred by a gas utility, it cannot be a valid measure of TFP because productivity is measured in terms of what is actually produced. Gas throughput is not the product of a gas delivery system. Output consists of

customer connections and design day delivery capacity. This is discussed in B&V's Productivity Report included in Exhibit B-1-1, Appendix D-2 starting at page 2 and in the response to BCUC IR 1.30.1.

The economics literature has only sparse references to measures of output because both in theory and practice for most studies output is measured in conventional quantity measures such as "widgets." Further, most academic economists simply define the outputs of a delivery service that is not a part of the overall production process where volume is a cost driver. The academic literature recognizes the impact of spatial variables as they impact costs. See for example "Cost Analysis of Gas Distribution with Spatial Variables". Since the delivery of gas does not coincide with the production of gas and since the only quantity of delivery that matters is the design day delivery, this is a different basic model of service than for any other delivery business. Consider UPS that delivers thousands of parcels per day. They have no fixed facilities dedicated to a customer, there are no constraints on the timing of the deliveries, delivery trucks can be rented for peak periods, and so forth. If package sorting equipment is overloaded, packages may be delayed but there is no permanent loss of service to all customers in a specific area as would be the case if the gas system lost pressure. Further, the only economic consequence is for those customers whose packages are not delivered not for all customers in the area. This has minimal social costs for customers as compared to a gas system outage where social costs for even a relatively confined area would potentially be in the millions of dollars of lost wages, property damage, temporary housing costs and so forth. All things considered, most economists have not studied the depth and complexity of these issues for utility delivery service and, as a result, they use commonly available data that fits the academic paradigm.

30.2 Comment on the AUC's statement in paragraphs 394 and 395 of Decision 2012-237, supported by the experts testifying in that proceeding, that the selection of an output measure for a TFP growth study depends on the nature of the PBR plan, whether it is a revenue cap or a price cap.

Response:

B&V provides the following response.

Please refer to paragraph 396 of that decision that notes that there is no consensus on the best measure of output for TFP studies as filed before the AUC. As discussed in both B&V's Productivity Report in Appendix D-2 and the report on recent regulatory decisions in Appendix D-1, there is a superior measure of output for a gas utility, namely, customers and capacity.

There is ample discussion of the deficiencies of using throughput to measure output supported by both theory and practice, as well as by real world examples (refer to the response to BCUC IR 1.30.1). If a properly measured output is used, there is no need to distinguish between a revenue or price cap structure. The experts in the AUC proceeding all followed the academic paradigm with its fatal internal inconsistency that throughput is caused by, and directly related to, the various inputs. Some of the experts correctly recognized that customers play a role in the measure of output, but did not make the necessary analytical modifications to utilize the output measure of capacity (subsequently PEG, the OEB's consultant, has modified its estimation of TFP for electric distributors in Ontario to include customers, capacity and throughput. Under this modification, PEG weights each component with throughput having the smallest weight. Eliminating throughput from the output measure would have minimal impact because of its low weight and would allow the output specification to match cost causation.) To that extent, there is a movement toward a more correct and theoretically correct output specification.

The fundamental issue with the academic studies is that they use the academic paradigm as applied to conventional industrial output such as manufacturing widgets. For both gas and electric distribution, the output is not the volume of widgets but the capacity to deliver widgets on highly varying demand to customers dispersed over an integrated network. Thus, the inputs produce not volumes of gas or electricity but design day delivery capacity for providing system reliability and customer attachments to the network. It is not reasonable to measure output that is not produced, although from an academic point of view, it is much easier to obtain the data for throughput as opposed to making the necessary estimate of capacity.

30.3 What would Black & Veatch propose as an output measure in a TFP study if the PBR plan involved a price cap? Explain and justify the output measure.

<u>Response:</u>

Please refer to the response to BCUC IR 1.30.2. Using a correct specification for output does not require any different treatment for productivity purposes for a price cap.

31.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1-1, Application, Appendix D2, Black & Veatch Report, p. 2; Appendix D1, p. 31

Beginning on page 2 of Appendix D2, the Black & Veatch Report describes the theoretical basis for measuring productivity in a TFP study.

On page 31 of Appendix D1, Black & Veatch state that "(t)he AUC approach to X-Factor relied too heavily on an academic approach that did not reflect either the cost drivers or the proper measure of outputs for electric and gas utilities." (Exhibit B-1-1, Appendix D1, p. 31)

31.1 Explain in detail how the theoretical basis in the Black & Veatch Report differs from the theoretical basis of the NERA Economic Consulting (NERA) report on which the AUC relied for its PBR decision.

Response:

The NERA study exhibits a number of what B&V would consider to be computational flaws in its assumptions about both inputs and outputs. Exhibit B-1-1, Appendices D-1 and D-2 provide detailed explanations of these issues, and a high level summary is provided in the response to BCUC IR 1.31.1.1. There are problems beyond those enumerated in the Reports, but the most important point is that B&V TFP analysis uses different measures of output and avoids the numerous assumptions required in the NERA report to measure inputs. In B&V's view its own approach results in a more robust and transparent estimate of TFP and one that is applicable to gas LDCs which eliminates the need to rely on an electric TFP study that does not properly capture the cost drivers of gas LDCs. Please refer to the response to BCUC IR 1.31.1.1, where B&V expands on this point.

31.1.1 For each difference identified by Black & Veatch, explain how this issue was handled by Black & Veatch and how it was handled by NERA. For each of these differences, also indicate the estimated effect on the resulting TFP study. If this effect cannot be quantified, at least indicate the direction of the effect, increasing or decreasing the X-Factor.

Response:

B&V notes that it is not possible to make this comparison because the two studies are for different time periods, based on different assumptions, and in the case of FEI, to different industries.

In general, NERA did not include all costs of distribution (in its defense, the data base it used makes this difficult because of the vertical integration of the utilities studied and other data limitations).

Second, NERA used throughput as an output measure and that creates an entire set of other issues relative to: (1) the time required to factor out weather variations for residential and commercial sales; (2) the use of volumes in the industrial class served at transmission voltage as an output measure for distribution; (3) the impact of customer mix within the residential and commercial classes on distribution costs (electric heating customers require more capital investment in distribution but lower per unit costs); and (4) the system density (identified as one of the most critical variables for benchmarking utility costs).

Third, in developing the measures of input, critical costs were omitted from the analysis such as non-wage costs for labor, the cost of vehicles and equipment for distribution service, the costs of stores, the cost of outside services, and so forth.

The end result is that there is no reasonable basis to compare the two studies. Conceptually, these points imply that the TFP estimate derived by NERA would be unreliable and would overstate TFP if services were outsourced, there were greater changes in the cost increases for post retirement benefits than for wages and salaries, and so forth. Any attempt to comment on and quantify the totality of the differences in the studies would be speculative at best.

31.2 What are the differences in the Black & Veatch approach to calculating TFP that make it less academic and, presumably, more practical than the NERA approach relied on by the AUC?

Response:

The B&V TFP Studies use the most correct measures of output for gas and electric distribution utilities. By using ex-post measures of inputs, all of the assumptions related to cost shares and weighting are eliminated (this is a benefit of the Kahn Method in general). The method is fully transparent without having to understand and reflect all of the economic issues such as indexing and developing regression equations. It applies the essential principle of Occam's razor that the simplest assumptions make for the best outcome. It is also the methodology used by other regulatory bodies such as the U.S. Federal Communications Commission.

Please refer to the response to BCUC IR 1.31.1 and 1.31.1.1, where B&V expands on this point.

32.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1-1, Application, Appendix D2, Black & Veatch Report, p. 2

Page 2 of the Black & Veatch Report argues for a capacity output measure, customers and capacity, rather than a throughput measure, one thousand cubic feet (MCFs) or gigajoules (GJs) for the calculation of TFP growth.

32.1 How is the calculation of TFP growth using a capacity output measure affected when the size of the customers and their usage varies? For example, what is the consequence on the study if there are twice as many customers each using half as much gas or electricity compared to a study in which half as many customers use twice as much gas or electricity?

Response:

Under the B&V methodology, usage has no impact on cost and therefore has no impact on TFP. For smaller customers served by the utility's minimum gas distribution system, size has no impact on TFP. Adding larger customers that require additional capacity would increase the system capacity and the capital cost for the utility. The result is that both inputs and outputs grow. If the growth in inputs is faster than the growth in outputs TFP is negative. Given the scale economies related to adding capacity (per unit cost of larger mains is typically lower per unit of capacity added); it is more likely that TFP would be positive for adding the larger customer. It would also be positive for adding customers to existing mains where more customers would be served from the same capacity. For customers added to the minimum system (residential for example) costs increase at a faster rate as density declines and TFP would, other things being equal, tend to be negative. As density increases in suburban areas TFP would be positive. If density increases in urban areas where it is more costly to install and maintain distribution networks, TFP would likely be negative. To understand these issues, it is not only necessary to understand economics but also the engineering and operations of a gas delivery system. Typically, the experts performing TFP studies do not study the engineering and operating realities of utility systems as would be common for those who perform traditional cost of service analysis. This is just part of the shortcomings associated with purely academic studies being broadly applied in the real world of regulation.

32.1.1 How would the results of such studies compare to a TFP growth study using a throughput measure? In this context, which of these output measures, in the opinion of Black & Veatch, represents the most accurate measure of TFP, and why? Explain in detail.

Response:

B&V provides the following response.

Using throughput as a measure of output, adding customers using more volume than average to the system would increase TFP assuming that conservation by existing customers is not large enough to offset the growth in overall sales. That is, output would grow faster than inputs all else equal. However, the system is no more productive than the system would have been from adding a customer with lower volumes because the costs are the same in either case for small customers. In the case of larger customers, higher load factors make the system look more productive than lower load factors even though the actual output of the system is identical.

The important point is that throughput measures of output create biased and unreliable results when measuring productivity. A simple example will illustrate this point. Two systems are identical in every respect - the same number of customers, the same density, the same miles of pipe by size, operating pressures and age distribution. Their annual costs are identical in total each year for the last five years. The two systems have the same design day temperature. The only difference is that the annual Heating Degree Days for one system are fifty percent greater than for the other and there is a higher saturation of water heating and cooking in the colder system. In this case TFP measured by customers and capacity would be the same. TFP measured by volume would be greater for the system with lower volumes because the throughput for that system would grow at a faster rate because of its smaller base. The result produced is biased by the measure of output because volume does not cause costs. Similarly, if two systems had identical throughput every year but different customer counts and densities and thus different costs the one with larger cost increases each year would have a lower TFP even if they served more customers and had more capacity. Again, this is a nonsensical result from the bias of throughput as a measure of output. Using customers and capacity would eliminate this bias.

33.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1-1, Application, Appendix D2, Black & Veatch Report, p. 2; Appendix D1, pp. 32-33

33.1 Beginning at the bottom of page 32 and continuing on page 33, Black & Veatch take issue with NERA's use of class revenue to weight the output measure of kilowatt hours (kWh) volumes. Did any of the experts referenced in the AUC's Decision 2012-237 take issue with NERA's use of class revenue to weight the output measure of kWh volumes? If so, please summarize what they said.

Response:

B&V has not analyzed the evidence of all parties related to every issue. It should be noted that the assumption employed by NERA is a common assumption for academic studies. Nevertheless, using class revenue to weight the output measure is wrong, both in terms of volumetric measures and in terms of weighting. Class revenue is an inadequate measure of output for distribution because industrial customers may not even use the distribution system as some will be served from the transmission system.

Further, it is likely that the revenues bear little relationship to costs except for the largest industrial customers because the residential revenue to cost ratio will be less than one while the commercial ratio will be greater than one. This is an example of assuming away another messy problem associated with the use of a volumetric basis for measuring output.

Finally, class revenues for electric customers include revenues associated with production and transmission resulting in an over statement of the impact of volumes on the distribution system since these costs represent a different percentage of the revenues for each class of customer. Distribution related costs would be a larger percentage of the bill for residential customers than for larger commercial customers for example. Urban and rural utilities will also have different percentages of distribution revenue for each class of customers given the higher costs of urban underground systems.

All in all, the use of revenues to weight output shares creates additional noise in the estimates of TFP.

33.2 How would Black & Veatch weight the output measure of kWh volumes? Would such a weighting require cost allocations? If yes, how would these cost allocations be done?

Response:

Since there is no reasonable basis for using kWh or GJ volumes for measuring output, there is no need to weight volumes. As a result, B&V has not addressed the issue.

34.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1-1, Application, Appendix D2, Black & Veatch Report, p. 2; Appendix D1, p. 35

34.1 Black & Veatch reference the "most recent study by the Pacific Economics Group filed in Ontario" in Appendix D1, p. 35. What are the results of that TFP growth study?

Response:

The PEG Study filed as part of the electric distribution 4th Generation IR proceeding filed two studies of TFP based on nine years of data. The studies initially found TFPs of negative -0.05% and - negative 0.03%. A revised version of this study was later published. The TFP values in the new version are slightly higher and equal to 0.07% and 0.1%.

In B&V's view, the original and revised results represent an attempt to move to a more appropriate measure of output. Still, however, the capacity measure used was the actual coincident peak that has a number of shortcomings such as the fact that it varies from year to year based on weather or that it is not the peak that determines distribution costs or capacity requirements. Electric distribution costs are a function of customers and the non-coincident peaks of the customer classes and as diversity decreases for facilities closer to the customer, the customers' non-coincident peak.

34.2 Does the Pacific Economics Group also make a recommendation regarding the X-Factor? If so, what was that recommendation?

Response:

PEG's recommended X-Factor is the proposed TFP value (please refer to the response to BCUC IR 1.34.1) plus a stretch factor of 0% to 0.6% (based on different efficiency cohorts).

35.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1-1, Application, Appendix D2, Black & Veatch Report, pp. 8-10

"We have included all net plant for natural gas LDCs as well as all costs including customer accounting costs and Administrative and General (A&G) overheads. It is important to include these costs because their exclusion would result in a substantial over-estimation of the productivity associated with gas delivery since the exclusion of many of the costs associated with plant maintenance and overhead costs associated with labor are included in the A&G cost category. Failure to include these costs under-estimates changes in the cost of inputs and, thus, over-estimates productivity of the labor resource. Further, there are significant costs associated with customer service and billing as well as general plant costs to support these activities" (pp. 8-9). (Also Appendix D1, Black & Veatch Report, p. 34.)

35.1 Regarding the costs mentioned above – net plant, customer accounting costs, A&G overheads, plant maintenance and overhead associated with labor, customer service and billing, and general plant – explain if any cost allocations were necessary to include these costs in a TFP growth study.

Response:

No allocations were required.

35.2 Identify any other cost allocations that were done as part of the Black & Veatch Report.

Response:

The method used by B&V required no cost allocations.

35.3 For any cost allocations, how were these allocations done? What methodology was employed?

Response:

Not applicable. Please refer to the response to BCUC IR 1.35.2.

35.4 If any cost allocations were part of Black & Veatch's TFP growth studies, provide support in the economics literature regarding TFP growth studies to justify these cost allocations.

Response:

Not applicable. Please refer to the response to BCUC IR 1.35.2.

35.5 Provide a numerical example to demonstrate the effect on TFP growth of excluding cost categories that require cost allocations.

Response:

Not applicable. Please refer to the response to BCUC IR 1.35.2.

36.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1-1, Application, Appendix D2, Black & Veatch Report, p. 3

Page 3 of the Black & Veatch Report states "Declining use per customer [as a result of using a throughput measure in a TFP study] would suggest a decline in TFP even though the LDC provides more capacity and serves more customers."

36.1 Please explain this statement in detail, using a numerical example if helpful.

Response:

TFP is the change in output (which in this case is demand/capacity not throughput) minus the change in input (which in this case is a composite of plant, labor, materials and supplies and rents). If the change in output is negative TFP must be negative because both terms of the equation are negative.

Using a correct measure of output for a natural gas distribution utility customers and capacity TFP is unaffected by declining use rates per customer as it should be. As indicated in the response to BCUC IR 1.39.1, in the presence of declining use per customer and increasing number of new customers and capacity, a TFP study based on volumetric output measures would result in a lower productivity growth than the actual TFP using customers and capacity as the output measure (other things unchanged). This is because customer and capacity growth rate will be greater than the rate of growth of energy transported and therefore the TFP growth rate, which is determined by subtracting the rate of growth of inputs from the rate of growth of outputs, will decline when the incorrect volumetric output measure is used. This issue has also been discussed by the experts in the AUC proceeding as noted in Decision 2012-237 on page 80 (Paragraph 384 provided below).

*"**384**. Furthermore, Dr. Lowry observed that in the presence of declining use per customer, a gas TFP study based on a volumetric output index would produce a lower productivity growth estimate compared to using the number of customers as an output measure.433 Consequently, using a volumetric output measure in this instance would result in a TFP estimate and an X factor that are too low, lower than if the correct customer output measure had been used. This is because when usage per customer is falling, the rate of growth of customers will be greater than the rate of growth of energy transported. Therefore, the TFP growth rate, which is determined by subtracting the rate of growth of inputs from the rate of growth of outputs, will be greater when the correct customer output measure is used rather than the incorrect volumetric output measure."*

36.2 Is Black & Veatch arguing that declining use per customer does not result in a decline in TFP? Explain.

Response:

B&V does not use throughput as a measure of output. Declining use per customer would only affect TFP if one were to calculate TFP based on throughput. Usage is an improper and biased estimator of TFP, so usage should not be used at all. Using a correct measure of output customers and capacity TFP is unaffected by declining use per customer as it should be.

36.3 For the five year time period that Black & Veatch used for its TFP growth study, did FEI experience declining use per customer?

Response:

Yes, for Rate Schedules 1 and 2, but no for Rate Schedules 3 and 23. Over the period of the TFP study from 2007 to 2011, Rate Schedule 1 and Rate Schedule 2 Use Per Customer declined by 5.8% and 0.9% respectively, while Rate Schedule 3 and 23 increased 1.7% and 7.5% respectively. The tables below present the UPCs and, the year to year percent changes. Please also refer to the response to BCUC IR 1.36.3.1 for a discussion of why changes in FEI's use per customer are not relevant to the TFP study.

Mainland UPC – All Regions

	2006	2007	2008	2009	2010	2011
Rate 1	96.8	96.0	92.5	93.3	92.6	90.4
Rate 2	314.3	316.5	312.2	320.6	311.3	313.7
Rate 3	3,314	3,426	3,420	3,372	3,370	3,484
Rate 23	4,686	4,778	4,698	4,886	4,850	5,138

Mainland Consolidated UPC- All Regions: Perecent Change Year over Year

	2007	2008	2009	2010	2011	Average	Percent change 2007-2011
Rate 1	-0.8%	-3.6%	0.9%	-0.8%	-2.4%	-1.3%	-5.8%
Rate 2	0.7%	-1.4%	2.7%	-2.9%	0.8%	0.0%	-0.9%
Rate 3	3.4%	-0.2%	-1.4%	-0.1%	3.4%	1.0%	1.7%
Rate 23	2.0%	-1.7%	4.0%	-0.7%	5.9%	1.9%	7.5%

36.3.1 If so, how did declining use per customer affect the results of the TFP growth study that Black & Veatch performed? In other words, if there had been no declining use per customer, how would the results of the TFP growth study be different? How would these results vary with the output measure used? Explain in detail.

Response:

FEI has not been included in the TFP study. Further, as explained in a number of other responses declining use has no impact on the study in any event since throughput was not used by B&V.

Declining use per customer would only affect TFP if one were to calculate TFP based on throughput. Usage is an improper and biased estimator of TFP, so usage should not be used at all. Using a correct measure of output customers and capacity TFP is unaffected by declining use per customer as it should be.

36.4 If FEI experienced increasing use per customer, how would that affect the results of the TFP growth study, and how would the results of the study vary with the output measured used? Explain in detail.

Response:

FEI's results have no impact on the study and neither does use per customer. Please also refer to the responses to BCUC IRs 1.36.1 to 1.36.3.1.

37.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1-1, Application, Appendix D2, Black & Veatch Report, p. 3

Page 3 of the Black & Veatch Report argues that "(t)he negative productivity for capital is explained by the need to replace aging infrastructure."

37.1 Is it not the case that aging infrastructure is always being replaced? Why is the replacement of aging infrastructure not incorporated into historical TFP growth measures? Why is it only in recent years that TFP growth has become negative? Explain.

Response:

B&V agrees that there is always some replacement of infrastructure in any gas LDC system. Normal replacement is related to factors such as externally created damage, environmental effects and capacity expansions. This reactive replacement scenario would require an extended period of time to replace the entire system and enable a planned maintenance of system reliability. Beginning in the mid-1990s, gas LDCs recognized that there were benefits for system safety, reliability and costs associated with the acceleration of main replacement under a comprehensive program. By the time of the TFP study, most gas LDCs were engaged in such programs having identified the scope of required replacements based on factors such as cast iron main, bare steel main and first generation plastic pipe. The acceleration of main replacement under a comprehensive program assured a more rapid and comprehensive assessment of the replacement process. Many of the dollars associated with these programs represented a significant increase in annual capital expenditures above and beyond the normal capital budget prior to these programs. It is that change in the gross level of capital expenditures without the addition to the system of any capacity or new customers that drives TFP to be negative. The logic for this is simply that input costs increase and output remains the same. Zero change in output minus the increasing costs results in a negative TFP.

37.2 What is FEI's current need for replacing infrastructure compared to its historical pattern of infrastructure replacement? Is the anticipated capital replacement in the next five years different from its past capital replacement?

Response:

FEI has implemented a long term capital planning approach (the Long Term Sustainment Plan) that assesses asset condition and risks and creates prioritized plans for infrastructure replacement. FEI seeks to proactively address assets which are susceptible to identified risk factors or have known integrity issues, and replace them before they become a hazard to the public. Thus, FEI anticipates that it will increase expenditures related to infrastructure replacement, primarily illustrated by the increase seen in distribution mains and services renewals, which are anticipated to increase from $22.6 million in 2013 to $34.3 million in 2018, an average of $2.3 million per year. In comparison, FEI's historical expenditures increased from $7.5 million in 2007 to $16.6 million in 2012, an average of $1.8 million per year.

37.2.1 Is it different from the capital replacement in the five years used for the TFP growth study? What are the consequences of your responses on the TFP relevant for FEI during its PBR plan?

Response:

The impact of capital replacement was not isolated in the TFP study data, so FEI cannot compare its replacement capital levels with those of the companies included in the TFP study.

As discussed in the Application, FEI is not recommending an X-Factor that equals the TFP levels that came from the study. The Company relied on the study to provide an industry comparison for utilities that include all capital in the PBR model. Given FEI's exclusion of CPCNs from the PBR, and the significant difference between the study and its recommendation of a 0.5% X-Factor, the Company believes the X factor it has recommended is appropriate.

38.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1-1, Application, Appendix D2, Black & Veatch Report, p. 4

Page 4 of the Black & Veatch Report discusses infill investment and investment to replace existing facilities.

38.1 What percentage of FEI's planned investment over the PBR term is for infill investment and what percentage is for capital replacement?

<u>Response:</u>

Infill investments, primarily service conversions, are forecast at approximately $1.5 million per year or 1% of forecast gross capital expenditures. These amounts are included in the Growth Capital category.

Replacement capital investments, referred to as the "Sustainment Capital" category, are forecast at approximately $78 to $82 million per year or 57% of forecast gross capital expenditures.

38.1.1 How do these percentages compare to the percentages for the utilities that Black & Veatch used in its study to make a TFP growth recommendation for FEI? If these percentages are not the same, what is the implication for TFP growth and hence the X-Factor that Black & Veatch would recommend for FEI for the term of its PBR plan?

<u>Response:</u>

The percentages are not known and not knowable for the utilities in the TFP study. Given the trend in replacements is broad based, year to year differences in a specific utility's plan only impact the TFP for that observation in the data set.

As discussed in the Application, FEI is not recommending an X-Factor that equals the TFP levels that came from the study. The Company relied on the study to provide an industry comparison for utilities that include all capital in the PBR model. Given FEI's exclusion of CPCNs and some other flow through items from the PBR, and the significant difference between the study and its recommendation of a 0.5% X-Factor, the Company believes the X factor it has recommended is appropriate.

39.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1-1, Application, Appendix D2, Black & Veatch Report, p. 4

Page 4 of the Black & Veatch Report states, "The AUC rejected the negative measure [of TFP] because the output measure was throughput based."

39.1 Provide the specific reference in AUC Decision 2012-237 to support this statement.

Response:

This statement is not a quote from the AUC Decision 2012-237. Rather, it is distilled from the adoption of a term that excludes economic considerations associated with downturns that result in negative TFP values. See for example the discussion at paragraphs 316, 381, 384 and 391 of the AUC Decision which are reproduced below.

> **316**. In that regard, the Commission considers that Dr. Lowry's approach to determining the relevant time period to capture the entire business cycle in the sample period represents an improvement over the companies' approach of focusing on the most recent 10 to 15 years of data. However, PEG's method is also not entirely devoid of subjectivity, as judgement has to be applied as to what start and end points to use. For example, PEG offered that cooling degree days and the unemployment rate be used to select similar levels of a business cycle. Building on this logic, PEG recommended that recession years 2008 and 2009 be excluded from the analysis, because in this period the volumetric output indexes were extraordinarily depressed.[338] The gas companies did not agree with PEG's choice of start and end dates and submitted that this method resulted in biased and subjective estimates of TFP trends.[339] In AltaGas' view, it was vital that years 2008 and 2009 be included in the study to arrive at a balanced assessment of TFP.[340]

> **381**. At the same time, NERA accepted that this measure is not perfect and indicated that for the energy delivery business where much of the cost is tied up in long-lived capital, there are trade-offs in using one measure of output or another. For example, NERA pointed out that in a recession or in response to a price shock, kWh sales may decline with a distribution system that is otherwise unchanged, thereby seeming to show a decline in productivity growth. In that regard, NERA explained that its preference has always been to use kWh with the longest time series available so as to dampen the effects of the short-term or cyclical patterns that would most influence kWh sales as a measure of output.[428]

> **384**. Furthermore, Dr. Lowry observed that in the presence of declining use per customer, a gas TFP study based on a volumetric output index would produce a lower

productivity growth estimate compared to using the number of customers as an output measure.[433] Consequently, using a volumetric output measure in this instance would result in a TFP estimate and an X factor that are too low, lower than if the correct customer output measure had been used. This is because when usage per customer is falling, the rate of growth of customers will be greater than the rate of growth of energy transported. Therefore, the TFP growth rate, which is determined by subtracting the rate of growth of inputs from the rate of growth of outputs, will be greater when the correct customer output measure is used rather than the incorrect volumetric output measure.

391. Ms. Frayer noted that the use of a single output measure will make the resulting TFP estimate more volatile, as demonstrated by the year-to-year results in NERA's report. In Ms. Frayer's view, using more than one output measure would smooth out this volatility and produce a more stable output index that is more consistent with the multi-dimensional service that the distribution companies provide.[447]

39.2 What output measure would Black & Veatch have used instead of the throughput measure that the AUC rejected? What would have been the effect on the calculation of TFP growth?

<u>Response:</u>

B&V used a more theoretically and practically correct measure of output for distribution utilities – customers and capacity. The longer time period of analysis is not required and the results of the TFP study would reflect the changes in outputs and inputs properly. Based on B&V's TFP analysis, the TFP would be negative instead of positive and would be logically consistent with the underlying industry factors discussed in the TFP Report. Please refer to the discussion in the responses regarding the NERA study, upon which the AUC relied, specifically the responses to BCUC IRs 1.30.1 to 1.31.2.

39.3 Is it the case that while throughput measures would have declined ("The economic downturn that had reduced the kWh measure of output . . ." (page 4)), Black & Veatch's preferred output measure, customers and capacity, would not have declined or would have declined by much less than the throughput measure?

Response:

Yes.

39.3.1 Would the average TFP growth for the last nine-year period still have been negative using Black & Veatch's preferred output measure? If still negative, would it have been larger than the TFP growth calculated using a throughput measure of output?

Response:

B&V has not studied the nine-year period and cannot answer the inquiry with any degree of certainty. However, we would hypothesize that TFP would still have been negative just based on our understanding of when infrastructure replacement programs began on a broad scale.

We have no empirical basis for discussing a throughput based result. However, it is likely that a throughput measure would have grown more slowly than the customer capacity measure of output. When utility systems were adding many more new customers and capacity coupled with slower volumetric growth as a result of conservation, the TFP would likely be lower than the actual TFP using customers and capacity as the output measure.

40.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM
Exhibit B-1-1, Application, Appendix D2, Black & Veatch Report, p. 5

Page 5 of the Black & Veatch Report states, "From a theoretical view, TFP is much more likely to be negative on a going forward basis than it is to be positive. This result occurs because the replacement of aging infrastructure adds cost unrelated to customer growth or additional design day capacity implying a negative TFP."

40.1 Is FEI replacing aging infrastructure? If so, how does the extent of this replacement compare to FEI's replacing aging infrastructure in the past period used to calculate TFP growth? How does FEI's replacement compare to that of the utilities used to calculate TFP growth?

<u>Response:</u>

Yes, FEI is replacing aging infrastructure. In fact, the development of the Long Term Sustainment Plan has enabled FEI to establish a more proactive and longer-term view of infrastructure replacement than previously. As a result, there is a forecast increase in Sustainment Capital Expenditures as noted in Exhibit B-1, Section C4.4, page 210. And although FEI can state that capital expenditures for the replacement of aging infrastructure is increasing going forward, there are challenges in comparing those costs to both historical values internally and also to those utilities used to calculate TFP growth.

The period used to calculate TFP growth was 2007-2011. Prior to 2010, FEI's sustainment capital expenditures allocated towards the replacement of existing infrastructure were blended together with other third-party driven replacement work, making precise comparisons over time challenging. However, as a proxy for relative comparison, expenditures for Distribution Mains and Service Renewals over the period 2007-2011 increased from approximately $7.5 million to $17.7 million, whereas over the period 2014-2018 FEI forecasts expenditures will increase from $25.8 million to $34.3 million. None of these figures include CPCN sustainment projects.

FEI is challenged in comparing the extent of its aging infrastructure replacement to those plans of other utilities used to calculate TFP growth. There is little detailed information available for those utilities included in the TFP calculation.

40.2 Why has TFP growth become negative in recent years yet it has been positive on average for a longer historical period?

Response:

B&V indicates that there is no evidence as to what TFP values would be based on a longer historical period using the correct measure of output. There have been several major changes in technology related to gas delivery that have occurred over the last 40 years that have become fully integrated into gas LDC operations prior to the most recent periods. These include the replacement of low pressure mains with smaller higher pressure mains that expand capacity. Other technological changes such as live main insertions and directional boring have also reduced costs. The negative TFP results from infrastructure replacement are explained in the TFP Report.

41.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1-1, Application, Appendix D2, Black & Veatch Report, pp. 5, 11

Page 8 of the Black & Veatch Report states that they used data for their TFP study for the latest available five-year period, 2007-2011.

41.1 What is the theoretical basis for using the latest available five year period for a TFP study? Please provide references to the literature.

Response:

This issue has been discussed fully in the responses to BCUC IRs 1.8.1 and 1.8.2.

41.2 In Black & Veatch's opinion, what is the reason for using the latest available five year period for the TFP study?

Response:

Please refer to the responses to BCUC IRs 1.8.1 and 1.8.2.

41.3 What would have been the consequences on the TFP study results, presented in Table 1, Summary of TFP Results, page 11, if a longer period, for example, ten or twenty years, had been used? If a precise estimate cannot be given, indicate the direction of the change on TFP growth given what Black & Veatch knows about the historical trends in TFP growth.

Response:

Please refer to the response to BCUC IR 1.39.3.1 where this issue is discussed. B&V states that for the twenty year period the first ten years would likely have a positive TFP based on improved technology.

42.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1-1, Application, Appendix D2, Black & Veatch Report, Table 1, Summary of TFP Results, p. 11

42.1 Provide a similar table for each of the five years in the Black & Veatch TFP growth study.

Response:

The requested table with five years of results cannot be provided because one year of the data is a base year, leaving only four years of results. That table is provided below for the three TFP measures.

Summary of TFP Results by Year					
TFP Measures	**2008**	**2009**	**2010**	**2011**	**2008-2011 Average**
Composite Measure	-0.055315496	-0.040438963	-0.068090051	-0.033490667	-0.049333794
Customer Measure	-0.05699781	-0.04384457	-0.06590971	-0.02963764	-0.049097433
Capacity Measure	-0.06093168	-0.04731628	-0.06415995	-0.03896099	-0.042362968

43.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1-1, Application, Appendix D2, Black & Veatch Report, pp. 8-9

Pages 8 and 9 of the Black & Veatch Report state that they include all net plant and all administrative & general (A&G) costs in their TFP study. Black & Veatch argue that excluding these costs would result in "a substantial over-estimation of productivity. " (p. 8)

43.1 Since the TFP study is designed to calculate TFP growth and not the level of TFP, explain in detail how excluding these costs would affect the calculation of TFP growth as opposed to productivity as stated at the bottom of page 8. Use a numerical example if that is helpful.

Response:

B&V states that to the extent that these costs change at a different rate than other costs the effective rate of change in input costs will be different. Since TFP is change in output minus change in input the TFP will change. The over estimation of productivity occurs because the input related to items such as vehicles and tools as well as a portion of the labour costs specifically related to distribution are excluded and some of those costs have changed dramatically over time. More simply, it is impossible to produce capacity and customers without the inputs that were excluded by NERA in the case of the AUC proceeding. If you exclude inputs and assume the same output TFP logically increases.

44.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1-1, Application, Appendix D2, Black & Veatch Report, Table 1, Summary of TFP Results, p. 11

44.1 What, precisely, is Black & Veatch's recommendation for TFP growth for FEI in this proceeding?

<u>Response:</u>

B&V would recommend a TFP value of minus 4.0%. Refer to Exhibit B-1-1, Appendix D-2, Table 1 for the range of values from the study. The average of the values was minus 4%.

44.2 What, precisely, is Black & Veatch's recommendation for an X-Factor for FEI in this proceeding?

<u>Response:</u>

B&V recommends that the X-Factor should be zero based on the overall terms of the proposed PBR Plan. The 0% X-Factor is inclusive of a stretch factor.

44.3 Explain what adjustments Black & Veatch recommends to the TFP growth results to determine an X-Factor, and explain in detail why it is appropriate to make these adjustments.

<u>Response:</u>

B&V makes no specific adjustments to the TFP factor. B&V's recommended X-Factor is based on several features of the overall plan that we believe reduce the negative TFP closer to zero. The 0% X-Factor would include a stretch factor as well. The TFP results from the study include all new capital during the study period. Based on our review of the factors outside the PBR such as CPCN capital and other provisions we felt that even zero is a stretch.

44.4 In Exhibit 1, Productivity Improvement Factor Proposals in Alberta, in Appendix D1, PBR Jurisdictional Benchmarking Report, the proposed X-Factors from the four utilities range between -1.0 and -2.0. In Black & Veatch's opinion, what explains the difference between these recommendations and Black & Veatch's calculations in Table 1, Summary of TFP Results, on page 11 of Appendix D2, which are all very close to zero. Be as specific as possible.

Response:

The values are expressed in different units. The benchmark values are percentages while the TFP reports the values as decimals. The 1-2% range is closer to the TFP values for gas LDCs of between 3.1-5% in the TFP Study. The major differences include the sources of data and the output measures. The gas LDCs in Alberta did not perform their own studies but relied on other studies using broader industry definitions or electric industry data that was flawed.

45.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1-1, Application, Appendix D4, Deferral of Expenditures during 2004 PBR, p. 3

45.1 Regarding page 3, lines 19-34, provide a numerical example to show how this capital expenditure deadband would work.

Response:

The total capital spending under PBR for 2014 of $129.031 million, as set out in Exhibit B-1, Figure B6-3 on page 66 is used for illustrative purposes. It is also assumed for ease of illustration that no cost driver adjustments for actual customer count and service line installations are required.

If actual capital spending is below 90 percent of $129.031 million (i.e. $116.128 million) the adjustment described on page 3 of Appendix D4 in this Application would be applied.

Assume for this example that actual capital spending is at 85 percent of the capital spending level under PBR, or $109.676 million.

The difference between 90 percent and 85 percent ($116.128 million - $109.676 million = $6.452 million) is deducted from the formula-based capital expenditures spending level to establish an adjusted formula spending allowance for 2014 that will be incorporated in the rate base to establish revenue requirement calculations for future years; that is, the opening rate base for the following year will reflect the lower amount. The calculation of the formula-allowed capital spending amount for rate calculations in future years is unaffected by this adjustment.

The adjustment of $6.452 million would be deducted from the capital accounts (for ratemaking) in the same proportions as included in the $129.031 million before the adjustment.

45.2 Regarding page 3, lines 20-24, discuss in detail the incentives for the company that would result from the capital expenditure deadband and the provision that "if total regular capital expenditures vary by more than 10 percent above or below the total formula-based capital expenditures in any year, the opening plant in service for ratemaking purposes in the following year will be adjusted up or down by the amount that actual capital expenditures vary outside of the 10 percent deadband from the formula-based amount."

Response:

The proposed 10% dead-band adjustment to capital expenditures variances reduces the potential incentive power of the PBR by limiting the amount of capital savings that may be pursued in each year to 10% of the formula determined capital. As indicated in Exhibit B-1-1, Appendix D4, FEI has proposed this provision in order to respond to concerns expressed by stakeholders towards the end of the 2004 PBR Plan.

45.2.1 In this context, explain what "regular capital expenditures" are and how they are calculated. (p. 3, lines 20-24).

Response:

"Regular capital expenditures" refer to actual capital spending in the same categories that are encompassed by the PBR capital formulas (i.e. Growth, Sustainment and Other). Regular capital does not include capital expenditures for CPCNs. In addition, please refer to the response to BCUC IR 1.10.1.

45.2.2 In this context, explain what "formula-based capital expenditures" are and how they are calculated (p. 3, lines 20-24).

Response:

Formula-based capital expenditures are the capital expenditures in the Growth, Sustainment and Other categories calculated according to the I-X formulas described in Section B6.2.5.2 of this Application. For clarity, the formula-based capital expenditures that the 10% dead-band will apply to will be the amounts calculated based on the adjusted cost drivers that incorporate the latest forecasts, specifically, average customers and service line additions.

46.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1-1, Application, Appendix D6, Efficiency Carry-Over Mechanism, p. 3

The company provides an illustration of what it calls the end-of-term efficiency sharing mechanism.

46.1 Explain how the allowed O&M per PBR formula (line 4) is calculated.

Response:

As noted in the question the ECM example presented in Appendix D6 was intended to be illustrative.

The allowed O&M per PBR formula is calculated as described in Section B6.2.4.2 (the same calculation is used for the ECM as is used to set rates) with currently forecast amounts provided in Table B6-5 of the Application on the “Total O&M Under PBR” line. The amounts from Table B6-5 are the gross O&M amounts before capitalized overhead. The amounts shown on Page 3 of Appendix D6 are based on the same gross O&M amounts net of 14 percent capitalized overhead. The amounts to be used in the ECM calculations will be inclusive of any adjustments for actual cost driver results.

46.2 What does it mean “net of OH Capitalized” (line 4)? What is the consequence of this netting out of OH Capitalized on the earnings sharing amount calculated on line 14. What is the justification for this? Explain.

Response:

The mechanics and justification of capitalized overhead are described extensively in Exhibit B-1, Section D3.7 of this Application. For the table in Exhibit B-1-1, Appendix D6, page 3, “net of OH Capitalized” means Total Gross O&M as calculated in Table B6-5 less 14 percent of this amount which relates to overheads capitalized. The 14 percent amount is simply reallocated from O&M to capital to represent the overhead operating expenses attributable to capital work. Consistent with historical and current practice, the actual amount for the 14% overheads capitalized will be recorded at the forecast amount, so there will be no variances in either the capital additions or O&M specifically resulting from capitalized overhead in the ECM calculation. This treatment of Overheads Capitalized is the same treatment that FEI has applied to Overheads Capitalized in the 2004-2009 PBR and in the 2010-2011 and 2012-2013 RRAs. Since no earnings variances will be attributable to Overheads Capitalized differences, the ECM illustrative example in Appendix D6 has used the O&M amount net-of-Overheads Capitalized as the starting point.

46.3 Explain how capital expenditures allowed per PBR formula (line 10) are calculated.

Response:

As noted in the question the ECM example presented in Exhibit B-1-1, Appendix D6 was intended to be illustrative.

The allowed capital expenditures per PBR formula will be the total amounts of formula-based capital expenditures in the Growth, Sustainment and Other categories. The illustrative example provided in Appendix D6 does not tie exactly to Table B6-8. However, the calculations of the allowed amounts are described in Section B6.2.5.2 with the current forecast amounts provided in Tables B6-7 and B6-8 of the Application on the “Total Growth Capital Under PBR” and “Total Remaining Capital Under PBR” respective lines (the same calculation is used for the ECM as is used to set rates). The amounts to be used in the ECM calculations will be inclusive of any adjustments for actual cost driver results.

46.4 If the Commission were to allow an X-Factor different from the one proposed by FEI, how would the example on page 3 change? Explain in detail for both an X-Factor higher and lower than the one proposed by FEI.

Response:

The X Factor that is approved will be reflected in the calculation of the ECM.

A higher X-Factor than the one proposed by FEI would result in a reduction to the “Total O&M Under PBR” amounts in Table B6-5 discussed in the response to BCUC IR 1.46.1 and the “Total Growth Capital Under PBR” and “Total Remaining Capital Under PBR” lines, in Tables B6-7 and B6-8 respectively, discussed in the response to BCUC IR 1.46.3. These reductions would flow into the net of capitalized overhead O&M value in Exhibit B-1-1, Appendix D6, Line 4 of the table on Page 3, and the reductions in formula-based capital would flow into Line 10 of the table on Page 3 of Appendix D6. Assuming the actual O&M and capital spending is the same, flowing these X-Factor related reductions through the Efficiency Carry-Over Mechanism table would result in a reduction to the incremental benefits sharing amounts in the table and, further, a reduction in the amount of revenues FEI will collect from or return to customers as part of the ECM benefits Phase-Out.

The opposite holds true in the case where the X-Factor is lower than the one proposed by FEI in this Application.

47.0 Reference: OVERVIEW AND INTRODUCTION

Exhibit B-1, Application, Tab A, Section 3.2, p. 12

SHARING OF GAS AND ELECTRIC SERVICES

"Sharing of services across the gas and electric businesses capitalizes on some of the efficiency opportunities available. By leveraging the available employee knowledge base and skillsets of both the gas and the electric businesses, consistency of service and flexibility in staffing is improved."

47.1 Please provide a detailed description, timeline and costs by year of the planning and implementation of the "sharing of services across the gas and electric businesses."

<u>Response:</u>

FEI does not have a specific timeline and detailed description regarding the implementation of future sharing of services across the gas and electric businesses.

In the future, as indicated in Section 3.3 Productivity Focus – 2013 and Onward on page 13 of Exhibit B-1, further opportunities may emerge and will be evaluated depending on the circumstances and potential benefits to customers. Future integration opportunities are expected to be more complex and dependent on the Company's ability to overcome some challenges. These challenges include concerns raised by unions representing gas and electric employees around shifting of unionized work from one entity to another, and the need to transition to common IT platforms before more harmonization of business processes can occur. Differences in the nature of the gas and electric operations also pose challenges and limit the breadth of opportunities available. While the Company will continue its efforts to investigate productivity opportunities, future progress is expected to be considerably slower given the highlighted challenges, and may require an upfront investment in IT systems or other initiatives to achieve significant and sustainable savings.

48.0 Reference: MULTI-YEAR PERFORMANCE-BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Tab B, Section 6.2.4.1, Table B6-4, p. 55; Order G-44-12 Compliance Filing (May 1, 2012)

2013 BASE O&M

48.1 Please reconcile 2013 Decision O&M of $236.003 million in Table B6-4 to the 2013 O&M of $202.963 million in Order G-44-12 Compliance Filing (May 1, 2012), Section 7, Tab 7.1, Schedule 6, line 24 by account.

Response:

The 2013 Decision O&M of $236.003 million in Table B6-4 represents Total Gross O&M Expenses while the $202.963 million in Order G-44-12 Compliance Filing (May 1, 2012), Section 7, Tab 7.1, Schedule 6, line 24 by account represents Total O&M Expenses after Capitalized Overhead. The $33.04 million difference represents Capitalized Overhead which can be cross referenced in Section E, FORMULA, Schedule 15, line 22.

Provided below is the reconciliation.

	2013 Approved (in $ millions)
Total Gross O&M Expenses	$ 236.003
Less: Capitalized Overhead	(33.040)
Total O&M Expenses	$ 202.963

49.0 Reference: MULTI-YEAR PERFORMANCE-BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Tab B, Section 6.2.4.2, Table B6-6, p. 55; Order G-44-12 Compliance Filing (May 1, 2012)

2013 BASE CAPITAL

49.1 Please reconcile 2013 Approved Total Gross Capital of $122.698 million in Table B6-6 to the 2013 Capital Additions of $129.870 million in Order G-44-12 Compliance Filing (May 1, 2012), Section 7, Tab 7.1, Schedule 51, line 42 by account.

<u>Response:</u>

Note that the $122.698 million in Table B6-6 represents the gross capital expenditure categories that are proposed to be subject to the PBR formula starting in 2014. Please refer to the reconciliation schedule below:

($000s)	
2013 APPROVED CAPITAL ADDITIONS	129,870
LESS Reconciling Items	
418-10 Bio Gas Purification Overhaul	513
418-20 Bio Gas Purification Upgrader	2,050
484-00 Vehicles - Leased	2,860
465-00 Mains (Gateway)	250
475-00 Mains (Gateway)	1,499
TOTAL RECONCILING ITEMS	7,172
2013 GROSS CAPITAL EXPENDITURES	**122,698**

Reconciling differences between 2013 Approved Capital Additions and Table B6-6 Gross Capital Expenditures are as follows:

418 – Biomethane Overhaul/Upgrader expenditures are not included in Table B6-6 Gas Customer Gross Capital Expenditures as associated deficits/surpluses are recovered from/refunded to customers through the Biomethane Energy Recovery Charge (BERC) and not through natural gas delivery rates.

484 – Vehicles-Leased were not included in Table B6-6 Gross Capital Expenditures in 2013 as these vehicles are currently acquired through a capital lease. FEI is proposing to purchase

vehicles instead of leasing beginning in 2014 (see where this amount is added into the formula in Table B6-6).

465 & 475 – The Gateway project is not included in Table B6-6 Gross Capital Expenditures as this third party project is considered to be 100% recoverable and therefore, would net to zero through CIAC recoveries.

50.0 Reference: MULTI-YEAR PERFORMANCE-BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Tab B, Section 6.2.5.2, p. 62; 2010-2011 Terasen Gas Inc. (TGI) Revenue Requirements Application (RRA), BCUC 2.3.2

GROWTH CAPITAL – SERVICE LINES

"In determining the Growth Capital allowed under PBR, a Average Growth Capital Cost per Service Line Addition is calculated by dividing the current year's total Growth Capital by the current years' service line additions." (ExhibitB-1, p. 62)

"In 2007, in response to increasing retirements and demographic challenges within our core/emergency internal workforce footprint, Terasen Gas increased its typical Lower Mainland install crew configuration from 3 to 4 by adding an apprentice." (2010-2011 TGI RRA, BCUC 2.3.2)

50.1 Please complete the table below showing the installation crew size and include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Operations is organized to maximize synergies between installation activities, emergency response and operations and maintenance. Employees with "installation" skill sets listed in the table below are not exclusively assigned to crews. They are also utilized for operations and maintenance activities. The crew complement noted below draws its resources from the pool of employees with "installation" skill sets (i.e. the rows labeled "total number of crew members").

The number of crews identified for the Interior and Lower Mainland is the maximum. In the Interior during the low construction period winter months (December to March), the number of crews is reduced to match the work activity. Crew members are redeployed on other work activities, training, vacation and temporary assignments.

The 2007 and 2008 Interior crew numbers have been restated to reflect the maximum number of crews and crew members that are part of the installation resource pool.

	2007 Actual	**2008 Actual**	**2009 Actual**	**2010 Actual**	**2011 Actual**	**2012 Actual**	**2013 Forecast**	**2014 Forecast**
Average *Lower Mainland* Installation Crew Size	4	4	3-4	3-4	3-4	3-4	3-4	3-4
Average *Interior* Installation Crew Size	3	4	3-4	3-4	3-4	3-4	3-4	3-4
Number of *Lower Mainland* Installation Crews	22	23	22	23	22	22	22	22
Number of *Interior* Installation Crews	16	16	15	15	15	15	15	15
*Total Number of *Lower Mainland* Installation Crew Members	98	107	92	105	93	79	80	90
**Total Number of *Interior* Installation Crew Members	45	47	45	41	46	42	47	47
Total *Lower Mainland* Installation Crew Loaded Cost + Vehicle & Backhoe *(Based on 4 man crew)*	$249/hr	$263/hr	$255/hr	$271/hr	$267/hr	$261/hr	$243/hr	$250/hr
Total *Interior* Installation Crew Loaded Cost + Vehicle & Backhoe *(Based on 4 man crew except 2007)*	$202/hr	$265/hr	$289/hr	$298/hr	$297/hr	$296/hr	$295/hr	$304/hr

Crew size is typically 3 or 4 depending on whether the crew has been assigned a Distribution Apprentice. Apprentices are hired in batches and over time replace regular crew resources who leave for retirement or other reasons. Apprentices also bid into the more technical roles depending on their experience and qualifications. Please refer to Attachment 50.1.

50.1.1 Also, confirm that 2014 Forecast crew size is representative of 2015-2018. If not, please explain.

INSTALLATION CREW SIZE

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Projected	2014 Forecast
Avg Lower Mainland Installation Crew Size	4	4						
Avg Interior Installation Crew Size	3	4						
Number of Lower Mainland Installation Crews	22	23						
Number of Interior Installation Crews	6	7						
*Total Number of Lower Mainland Installation								
Crew Members	98	107						
**Total Number of Interior Installation Crew								

Members	36	39							
Total Lower Mainland Installation Crew Loaded									
Cost + Vehicle & Backhoe	$249/hr	$263/hr							
Total Interior Installation Crew Loaded Cost +									
Vehicle & Backhoe	$202/hr	$265hr							

Response:

2014 crew size is representative of 2015-2018 forecasts. Crew size for Interior and Lower Mainland units will continue to be either 3 or 4 depending on whether the crew also includes a Distribution Apprentice. Operations continues to hire Distribution Apprentices on a periodic basis to replace employees leaving for retirement and other reasons. The Apprentices are absorbed into regular crew positions and other technical positions as they gain experience and appropriate qualifications. The Apprentices are hired in batches (usually 10-12) to maximize program training efficiencies so the average crew size is generally closer to 4 after a new batch hire and closer to 3 prior to a new batch hire.

51.0 Reference: MULTI-YEAR PERFORMANCE-BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Tab B, Section 6.2.5.2, p. 62; 2010-2011 Terasen Gas Inc. (TGI) Revenue Requirements Application (RRA), BCUC 2.3.1

GROWTH CAPITAL – MAINS

51.1 Please complete the table below showing the Mains Activity Levels and Cost and include the requested information in the form of a fully functioning electronic spreadsheet.

Mains Activity Levels and Cost

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Projected	2014 Forecast
Activities (metres)	157,004	200,167						
Workforce:								
Terasen (%)	14%	13%						
Contractors (%)	86%	87%						
Terasen ($/m)	66	66						
Contractor ($/m)	48	52						
Unit Costs ($/metre)	51	54						
CIACs ($/m)	-1	-1						
Net Combined ($/m)	50	53						
Expenditures ($millions) (excluding CIAC's)	$8.10	$11.00						

1 **Response:**

FEI Mains Data	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2014 Forecast
Activities (metres)	157,004	200,167	85,665	81,259	79,355	65,411	75,000	75,000
Workforce - FortisBC (%)	14%	13%	30%	19%	17%	27%	20%	20%
Workforce - Contractors (%)	86%	87%	70%	81%	83%	73%	80%	80%
Fortis ($/metre)	66	66	82	93	107	107	106	110
Contractor ($/metre)	48	52	66	47	52	71	57	61
Unit Costs ($/metre)	51	54	72	56	59	82	67	72
CIACs ($/metre)	-1	-1	-2	-5	-6	-4	-3	-3
Net Combined ($/metre)	50	53	70	51	53	78	64	69
Expenditures ($millions)(excl.CIACs)	$8.1	$11.0	$6.1	$4.5	$4.5	$5.4	$5.0	$5.4

2

3 Please refer to Attachment 51.1 for the live spreadsheet.

4

52.0 Reference: MULTI-YEAR PERFORMANCE-BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Tab B, Section 6.2.5.2, p. 63; Exhibit A2-5

SUSTAINMENT CAPITAL

On page 63 of the Application, FEI states "The PBR formula that FEI proposes to apply to Sustainment Capital and Other Capital is tied to the average number of customers. B&V notes that in actual fact, sustainment and other capital costs are driven by both customers and capacity. However, as in the case of O&M, there is no convenient measure of capacity. By using the change in average customers as part of the formula, the impact of both customers and capacity is reflected in the determination of the expected change in capital costs. Customers become a proxy for capacity since the addition of mains to serve customers adds new capacity to the system." (Exhibit B-1, p. 63)

In Exhibit A2-5 the forecast design peak day demand and annual normal load data for each of the annual contacting plans (ACPs) for each of the contract years 2009/2010 through 2013/2014 has been extracted from the respective Executive Summaries attached to the Commission L letter under which the particular ACP was accepted for each contract year. The following was compiled from the forecast design peak day demand and annual normal demand used by FEI in determining the ACP for the each of the noted contract years.

ACP Filing	2009-10	2010-11	2011-12	2012-13	2013-14
Forecast Design Peak Day (TJ/d)	1281	1268	1240	1224	1218
Forecast Annual Normal Load (PJ/yr)	110	114.5	114.4	113.8	117.3

52.1 Please confirm that the forecast design peak day demand for sales gas customers that is used to determine the load requirements for the FEI Annual Contracting Plan for corresponding upcoming contract year has consistently declined over the past five contract years.

<u>Response:</u>

FEI Confirms that the forecast design peak day demand for sales gas customers that is used to determine the load requirements for the FEI Annual Contracting Plan for corresponding upcoming contract years has consistently declined over the past five contract years.

The decline experienced over this period of time was caused by a forecast decrease in consumption by existing customers. This decline was partially offset by forecast new customers added to the system. An increase in the forecast design peak day demand would occur in the future if the number of forecast new customers added to the system more than fully offsets any continued forecast decline in consumption by existing customers.

While FEI agrees that the forecast design peak day for gas supply contracting has been declining, this is not the same concept as system capacity that is being discussed in the quote from page 63 of the Application in the question preamble. The capacity discussed in the quotation is the capacity of the distribution system as measured by the kilometers of pipe and the operating pressure of those pipes. The physical capacity of the system to serve existing customers is already built and does not decrease because customers are forecast to use less gas on a peak day.

The physical capability of the distribution system to deliver gas to customers increases whenever new customers require main extensions or new development cannot be served from the existing main capacity and the system requires looping. The addition of customers at the periphery of the system expands design day delivery capacity. Essentially, conservation by existing customers frees up capacity within the system that for the most part cannot be used by new customers because of the differences in location of the loads on the system.

52.2 Given the relatively flat forecast annual normal load for sales gas customers that is used to determine the load requirements for the FEI Annual Contracting Plan for the corresponding upcoming contract year shown in the table above, please confirm this suggests the overall load factor for sales customers is increasing and the load is becoming less "peaky." If not confirmed, please explain.

Response:

A load factor is a ratio of normal average daily consumption to peak day (maximum) consumption, usually calculated at a region/rate class level of detail. It is used as a measure of the stress that certain groups of customers place on distribution systems. FEI uses the following formula to calculate load factors indicating how "peaky" each customer group is:

$$Load\ Factor = \frac{Daily\ Average\ Normal\ Load}{Peak\ Day\ Load}$$

Applying the formula above to the forecast peak day and annual normal load used for the FEI ACP, the load factor can be estimated as shown in the table below.

	2009/10 ACP	2010/11 ACP	2011/12 ACP	2012/13 ACP	2013/14 ACP
Forecast Design Peak Day (TJ/d)	1281	1268	1240	1224	1218
Forecast Annual Normal Load (PJ/Yr)	110	114.5	114.4	113.8	117.3
Load Factor	23.5%	24.7%	25.3%	25.5%	26.4%
Annual change		1.2%	0.5%	0.2%	0.9%

Based on the above table, FEI confirms that the estimated load factor increased slightly over the past five years, which indicates that the forecast load for core customers has become less "peaky". During this period FEI adjusted its resource mix included in the ACP by reducing some peaking resources, such as Kingsgate and Huntingdon peaking supply, and increasing annual baseload supply. However, as noted in the response to BCUC IR 1.53.1, the peak day for gas supply contracting purposes is not the same concept as system capacity being referred to in the quote from page 63 of the Application.

Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Tab A, Section 1, p. 3

Development of Base 2013 O&M – Trend from Prior Periods

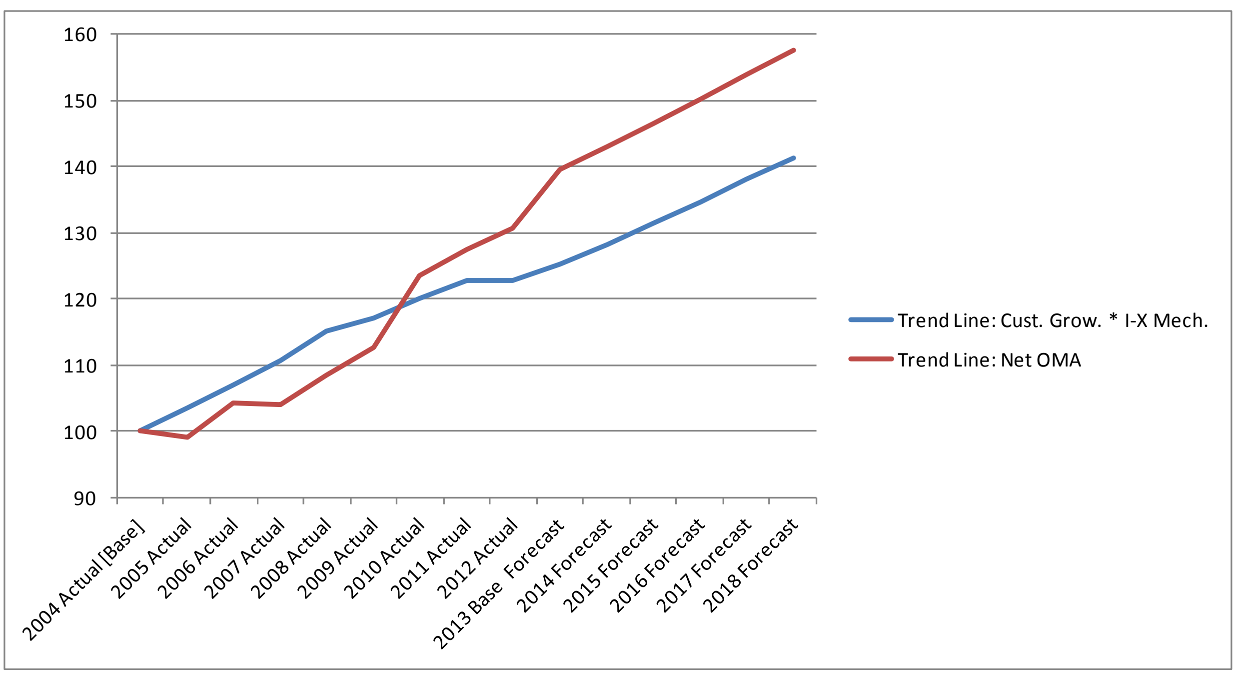
"FEI has provided forecasts of demand, revenue, O&M, and capital for the full 2014-2018 term (the PBR Period) in Section C of the Application. The 2014 through 2018 forecasts are included for reference purposes and represent a high level forecast of future trends and upcoming challenges for FEI. As FEI's proposed rates are based on the PBR Plan, FEI's cost of service forecasts should not be the focus of this proceeding. FEI has also provided an historical review of O&M expenditures since 2010. This historical review demonstrates that FEI has implemented a renewed focus on productivity which has resulted in efficiencies and sustainable savings. These sustainable savings have been incorporated into the 2013 Base O&M to which the O&M formula in the PBR Plan will be applied." [Section A, p. 3, lines 23-31]

52.3 Please comment on the appropriateness of the proposed PBR formula and, in particular, the use of customers as a proxy for capacity, given the peak day load requirement appears to be decreasing.

Response:

The decrease in gas supply peak day load requirement does not represent a corresponding decrease in system capacity. This downward trend in gas supply peak day requirements does not detract from the appropriateness of using customers as a proxy for capacity. Please also refer to the response to BCUC IR 1.52.1.

52.4 Please provide a table showing the Forecast, Actual and Variance (Actual – Forecast) Design Peak Day demand for sales gas customers for 2008/2009 to 2012/2013. Include the requested information in the form of a fully functioning electronic spreadsheet.



[Example graph by staff using FEI RRA Statistics and Statistics Canada BC-CPI and BC-AWE data]

Response:

FEI forecasts design peak day demand for sales gas customers each year based on forecast customer growth and design day temperature. Since FEI does not experience the design day weather, the actual design peak day loads are not directly observable.

The following table shows the forecast design peak day and estimated actual design peak day based on existing customers for sales gas customers for 2008/2009 to 2012/2013. The forecast reported in the annual contracting plan was prepared one year before the estimated actual design peak day. The table below shows each previous forecast was slightly higher than the estimated actual. Please refer to Attachment 52.4 for the fully functioning live spreadsheet.

Gas Year	ACP Fillling	Forecast	Estimated Actual	Variance
2008/2009	2008/2009	1,286	1,272	-1.0%
2009/2010	2009/0210	1,281	1,256	-1.9%
2010/2011	2010/2011	1,268	1,232	-2.9%
2011/2012	2011/2012	1,240	1,215	-2.0%
2012/2013	2012/2013	1,224	1,210	-1.2%

52.5 Please provide the data from 2007 through 2018 for the BC-AWE, BC-CPI, Average Customers, and Net OMA, all on the same basis as proposed for 2014-2018. Note this definition of Net OMA is without the Pension/OPEB, Insurance, and RS-16 OMA tracked outside the PBR formula shown as “Gross OMA Under PBR” in Table B6-6 on page 58 of the Application.

Response:

The following table includes data from 2007 to 2018 for the BC-AWE, BC-CPI, Average Customers, and Net OM&A, all on the same basis as proposed for 2014-2018. The definition of Net OM&A is without the Pension/OPEB, Insurance, and RS16 OMA tracked outside the PBR formula and shown as “Gross O&M Under PBR” in Table B6-5 on page 58 of the Application. The table uses 2007 as the base year and then inflates the 2007 Net OM&A by the proposed PBR formula for O&M each year. The table also assumes the labour/non-labour split remains at 55/45 and the productivity factor is 0.5 percent in all years.

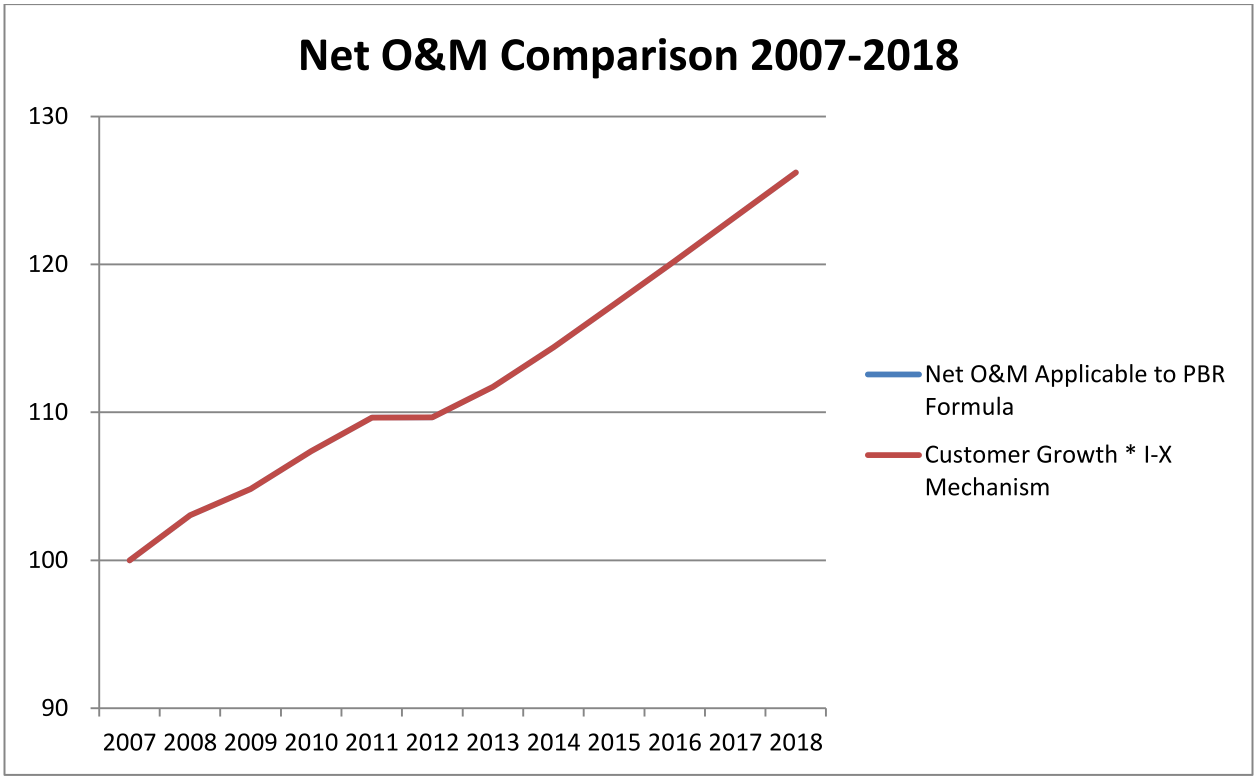
FEI Net O&M (Formula Based)	2007	2008	2009	2010	2011	2012
BC-AWE	3.4%	2.6%	0.8%	2.8%	1.5%	2.3%
BC-CPI	2.0%	2.2%	2.0%	1.4%	2.3%	1.1%
Customers (Average)	816,427	825,696	832,751	839,017	845,282	834,888
Gross O&M Expense	178,973					
Less Cost of Service Based:						
Pension/OPEB	10,188					
Insurance	5,067					
O&M Applicable to PBR Formula	**163,718**	**168,716**	**171,591**	**175,770**	**179,490**	**179,517**
FEI Net O&M (Formula Based) cont.	2013	2014	2015	2016	2017	2018
BC-AWE	2.3%	2.7%	2.7%	2.6%	2.6%	2.5%
BC-CPI	0.9%	1.8%	2.1%	2.0%	2.1%	2.1%
Customers (Average)	840,721	845,495	850,620	856,001	861,402	866,681
Gross O&M Expense						
Less Cost of Service Based:						
Pension/OPEB						
Insurance						
O&M Applicable to PBR Formula	**182,913**	**187,282**	**192,025**	**196,805**	**201,730**	**206,615**

52.6 Please provide a graph of the trend lines for the "Customer Growth times I-X Mechanism" and for the "Net OMA" from 2007 to 2018, starting at "100" in 2007.

Response:

The following graph plots two trend lines. The first trend line represents the net OM&A that would be allowed from 2007-2018, using the methodology described in BCUC IR 1.52.5. The second trend line represents the "Customer Growth times I-X Mechanism". The two separate trend lines are not visible as they overlap each other entirely for the analysis period, given that the first trend line is the 2007 calculated OM&A applicable to the PBR formula inflated by the

Customer Growth times I-X Mechanism and the second line is the cumulative Customer Growth times I-X Mechanism.



52.7 Please comment on what the graph to be provided by FEI indicates about the three time periods: 2007-2009, 2010-2013, and 2014-2018. For example, in the example graph provided above the Net OMA during the previous BPR period was consistently under the CPI-AWE trend line, the Net OMA has increased considerably since the end of the prior PBR period, and the "2012 Analysis" savings do not appear to have reset the Net OMA lower for 2014-2018.

Response:

The graph provided in response to BCUC IR 1.52.6 shows a steady increase in all years, with the exception of 2012, due to a fairly stable increase in the BC-AWE, BC-CPI and Average Customer Growth used in determining the Customer Growth times I-X Mechanism. In 2012, the line flattened out due to the decrease in FEI average customers in that year due the customer count adjustment.

53.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Tab A, Section 1, p. 4

Increased 0.7 percent rate impact from PBR

"The second is a delivery rate increase of approximately 0.7 percent that results from the PBR Plan and demonstrates the continuing benefits of the Company's productivity and customer focus." (p. 4, lines 10-11)

53.1 Please explain the amount of delivery rate increase, comparable to the 0.7 percent, that would result in 2014 if PBR is not implemented, and explain if there would be no continuing benefit from the Company's productivity and customer focus from the previous PBR period of 2004-2009.

Response:

In the Evidentiary Update, the 0.7 percent increase in delivery rates that is attributable to the PBR Plan has now been re-stated to 1.0 percent to reflect various updates.

There are many aspects contained within the PBR plan, as evidenced by the complexity of the PBR model in Section E of the Evidentiary Update (Exhibit B-1-3), so it is not possible to speculate what the rate impact would be if the PBR plan was not implemented.

However, if formulaic O&M was replaced with forecast O&M, this would drive an incremental 0.6 percent increase in delivery rates to yield a total increase of 1.6 percent. This continues to demonstrate the continuing benefits of the Company's productivity and customer focus, given that a delivery rate increase of 1.6 percent for 2014 is less than the Composite I-Factor forecast for 2014 of 2.31% as shown in Exhibit B-1, Table B6-5, page 58.

The continuing benefit from the Company's productivity and customer focus from the previous PBR period of 2004-2009 is reflected in the 2013 Base O&M. This benefit remains in place regardless of whether formulaic or forecast O&M is chosen.

53.2 Please provide the 2014 decrease in O&M expenses to produce a 1 percent decrease in 2014 delivery rates.

Response:

To produce a 1 percent decrease in the proposed 2014 delivery rates as requested by FEI in the July 16*th* Evidentiary Update, FEI would have to reduce the 2013 base O&M by $7.0 million. This would result in a 0.03 percent decrease compared to 2013 delivery rates (1 percent less than the 0.97 percent delivery rate increase requested by FEI.)

53.3 Please provide the 2014 decrease in capital expenditures to produce a 1 percent decrease in 2014 delivery rates.

Response:

Producing a 0.03 percent decrease in delivery rates, which equates to a 1 percent decrease from the 0.97 percent 2014 delivery rate increase requested in the July 16th Evidentiary Update under the formula method, cannot be achieved. If Growth Capital additions were set to zero for 2014, through setting the 2013 Base Forecast Service Line Additions to zero, this would result in a 0.10% delivery rate decrease compared to the requested delivery rate increase. If Sustainment Capital additions were set to zero for 2014, through setting the 2013 Base Sustainment Capital additions to zero, this would result in a 0.33% delivery rate decrease compared to the requested delivery rate increase. If Other Capital additions were set to zero for 2014, through setting the 2013 Base Other Capital additions to zero, this would result in a 0.15% delivery rate decrease compared to the requested delivery rate increase. Therefore, cumulatively, including zero capital additions to gas plant in service, excluding capitalized overhead, in the 2014 forecast would only result in a decrease to the currently requested delivery rates of 0.58 percent.

54.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Tab A, Section 3.1, p. 11; Tab D, Sections 4.3.3 & 4.3.4,

2010-2011 Terasen Gas Inc. (TGI) Revenue Requirements Application (2010-2011 TGI RRA, BCUC 1.128.2), 2012-2013 FEU RRA, BCUC 1.53.2

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

Table D4-3: FEU Gas Assets Records Project Costs ($ thousands)

	2012 Actual	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	Total
Project 'A' - Consolidate & scan critical Gas System Asset Records into Filenet	280	800	800	800	800	300	3,780
Project 'B' – Implement improved drawing management & control systems		70	150	150			370
Project 'C' - Review & analyze historical drawings	30	220	300	650	1050	1,400	3,650
Total	310	1,090	1,250	1,600	1,850	1,700	7,800

(Exhibit B-1, Section 4.3.3, p. 301)

Table D4-4: FEU BCOneCall Ticket Process Improvement Project Costs ($ thousands)

Stream	2012 Actual	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	Total
Data Consistency Stream	20	380	450	150	150	120	1,270
Conflation Stream	130	700	200				1,030
Total	**150**	**1080**	**650**	**150**	**150**	**120**	**2,300**

(Exhibit B-1, Section 4.3.4, p. 302)

"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. 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." (Exhibit B-1, Section A, p. 11, lines 26-28, 30-32)

"With the completion of the Technology Stream, this project has delivered a significant financial benefit that has reduced the long term O&M costs required for processing BC One Call tickets by approximately $600 thousand per year. The increased benefit is attributable to a higher than expected reduction in ticket processing time. Further benefits are expected as the Data Consistency and Conflation Streams are completed." (Exhibit B-1, Section D4.3.4, p. 302, lines 4-8)

54.1 Please quantify the O&M benefits received to date from the Gas Assets Records project and the BC OneCall project, identify the departments where the benefit has been received, and reference where the amounts can be seen in the Application as adjustments to Base 2013.

Response:

The O&M benefits received from the BC OneCall project are realized in the Public Underground Locations department (formerly known as Location Records). The $600 thousand O&M reduction is reflected in the 2013 Base. The reduction in O&M is 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, as discussed on page 174, line 32 to page 175, line 4 of the Application.

The Gas Asset Records Project drivers, as stated in the 2012-2013 RRA Section 6.3.5.11, are:

- CSA Z662-07 requirements with respect to records
- OGC Integrity Management Programs Self Assessment Protocols
- Association of Professional Engineers of British Columbia Bylaws
- The San Bruno gas pipeline explosion in September 2010

The Gas Asset Records Project is in the early stages of execution and O&M benefits have not yet been realized.

54.2 Please explain how the benefits received, from these two multi-year projects, in future years will be reflected in future year's O&M under the proposed BPR.

Response:

The O&M benefits received from the BC OneCall project are reflected in this Application in that the $600 thousand in financial benefits served to reduce the 2013 Base O&M amount used to calculate the 2014 through 2018 allowed O&M amounts (and hence reduced the total Revenue Requirement for those years). This allows customers to realize the achieved savings throughout the PBR period. To clarify, the $600 thousand reduction in O&M costs represents ongoing savings achieved that are expected to persist into the future. However, they are not an incremental or cumulative amount saved every year. For example, compared to Year 0, FEI does not expect to achieve an additional $600 thousand in savings in Year 1, $1.2 million in savings in Year 2, and so forth, compared to what it has already included as a reduction in the 2013 Base O&M.

O&M benefits for the Gas Asset Records project have not yet been realized and cannot be quantified at this point in time.

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.

54.3 Please update the table in 2010-20111 TGI RRA, BCUC 1.128.2, to show the actual 2009-2012, projected 2013 and forecast 2014-2018 Staffing Levels to Process BC OneCall Tickets. Also, provide the total cost of the FTEs by year for 2007-2018. Include the requested information in the form of fully functioning electronic spreadsheet.

Response:

Please refer to Attachment 54.3 and the following table for an update to the table in BCUC IR 1.128.2 submitted as part of the 2010-2011 TGI RRA, showing FTE staffing levels to process BC One Call tickets as well as the total cost of the FTE's by year for 2007 - 2018.

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

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Projected	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Total Number of Requests	57,008	61,566	72,691	78,734	82,396	86,828	92,000	97,500	103,500	109,700	116,300	123,300
Number of Requests Processed on Overtime	3,200	6,300	2,500	5,000	2,250	2,500	2,000	N/A	N/A	N/A	N/A	N/A
Number of FTE Staff	20	23	24	25	20	18	17	17	16	16	17	17
Total Cost of FTE[1]	958	1,034	1,221	1,181	840	860	840	900	910	980	1,100	1,150

Notes:

[1] Thousand Dollars ($,000s).

54.4 Please update the tables in 2012-2013 FEU RRA, BCUC 1.53.2 to show total number of Planners and Operational Support Representatives and the average cost per FTE from Actual 2007-2012, Projected 2013 and Forecast 2014-2018. Include the requested information in the form of fully functioning electronic spreadsheet.

Response:

The pre-amble to this question is related to BC One Call and Drafting/Gas Asset Records groups; however, the question itself is related to two other work groups (Closing & Planning). The latter, for the most part, are unaffected by the described technology project.

In addition, FEI is not requesting approval for these forecast amounts in this Application. FEI's proposed delivery rates will be set based on the formula-driven amount of O&M costs and not on the forecasts that are included in the table below and which were included in the Application for reference purposes only.

Department	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Projected	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
	FTE											
Closing & System Survey												
OSR's	21	19	18	18	19	19	21	21	21	21	21	21
Planning												
OSR's												
Planners	26	30	32	30	34	32	37	37	37	37	40	40
Workleaders	2	2	2	2	2	3	3	3	3	3	3	3
Total Planners/Workleaders	*28*	*32*	*34*	*32*	*36*	*35*	*40*	*40*	*40*	*40*	*43*	*43*
	49	51	52	50	55	54	61	61	61	61	64	64
	Average cost per FTE (O&M + Capital)											
Closing & System Survey												
OSR's	$52,875	$53,556	$56,308	$61,010	$63,876	$70,988	$72,852	$75,256	$77,800	$80,429	$83,148	$85,958
Planning												
Planners	$56,462	$58,649	$62,817	$71,136	$76,144	$83,362	$88,837	$91,768	$94,870	$98,077	$101,932	$104,819
Planning Workleaders	$81,264	$80,850	$84,091	$94,994	$101,328	$107,164	$114,459	$118,236	$122,233	$126,364	$130,635	$135,051

Please refer to Attachment 54.4 for the fully functioning electronic spreadsheet.

Average salaries, all things being equal, increase by annual contract salary inflation rates. COPE positions, such as Planners and OSRs, may also benefit from annual step increases depending on an employee's length of service within a position. Employee incentive earnings are also included within the average salary and these vary by employee from year to year depending on achievement of personal and corporate objectives. Average salaries also move downwards when top step employees retire or leave the department and replacement employees come into the position at the bottom or middle salary step in salary depending upon previous position. Lastly, pension and benefit overhead loadings are adjusted annually and also reflected in average annual salary changes. Excluded from the average salary calculation are overtime and any temporary premiums.

The Closing & System Survey group was significantly restructured over the 2012-2013 time period with approximately one third of the group re-assigned to various other work groups and cost centres. Offsetting the re-assignment of existing positions and work activities was the incoming transfer of existing employees and work activities from the Records group. While the groups' employee numbers are relatively consistent, the mix of the departmental positions and work activities have changed substantially.

55.0 Reference: MULTI-YEAR PERFORMANCE-BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Tab B, Section 6.2.4.2, p. 57

2014-2018 O&M Re-forecasted Adjustments

"The O&M allowed under the PBR Plan is shown in Table B6-5. As indicated above, the O&M allowed under PBR will be revised yearly in the PBR Annual Review, recalculated based on both the re-forecasted number of customers and the re-forecasted composite inflation rate for the upcoming year." (Exhibit B-1, Sec. B6, p. 57, lines 21-24)

55.1 Please explain what true-up is done to the Forecast O&M for a subsequent year if the actual growth in customers or composite inflation is different than forecast at the start of the current year. For example, is the Allowed O&M for the current year adjusted by the actual growth in customers and by the actual composite inflation from the previous year before calculating the Forecast/Allowed O&M for the subsequent year?

Response:

FEI used the term "true up" in describing its PBR proposal for the process related to both customer additions and service line additions since this terminology was used in its 2004 PBR to describe what is being contemplated here. The true-up features for the PBR I-X formulas pertain to the cost drivers only (i.e. average number of customers and service line additions) However, on reflection, a better way to describe the process would be a re-forecast using the latest available information on the cost drivers in the PBR formulas (i.e. actual average customers and service line additions when these quantities are known).

In this sense, the re-forecasting features of the 2014 PBR are the same as those included in the 2004 PBR Plan. This involves adjusting the base for the O&M formula for actual customer growth when known, but there will be no adjustment for actual composite inflation. (Please see the responses to BCUC IRs 1.4.1 and 1.4.2 regarding the treatment of the I-Factor with respect to reforecasting). The re-forecasted average number of customers will be incorporated into the O&M base for formula O&M calculation of the next year (including the actuals when known). The adjustment for the actual customer count may go in either direction.

The adjustment to actual will involve making a projection initially because the Annual Review for rate setting purposes will occur in the fall of the year when the year to which the customer addition is applicable is not fully complete. Final adjustment will occur after the year is complete. Any residual adjustment to actual of the customer count, which again may be positive or negative, will be incorporated at the next Annual Review.

FORECASTS FOR THE PBR PERIOD – DEMAND FORECAST

56.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 1

PBR Annual Reviews – Energy Demand Forecast

The PBR process involves Annual Reviews in 2014, 2015, 2016 and 2017. One of the purposes of Annual Reviews is to provide the opportunity for FEI to adjust prior forecasts to reflect more current information. The following scenario is intended to provide a clearer understanding of how Annual Reviews will impact the forecasts in the remaining years of the test period.

56.1 Please assume that the Annual Review in 2014 revealed that there had been a 5 percent under-forecast in the energy demand for Industrial rate class 22 in 2014. How would this over-forecast impact the energy demand and revenue requirement for the remaining four years of the PBR test period? Please provide a spreadsheet that includes a calculation of the impact.

Response:

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.

For Industrial demand, the variance from forecast for 2014 will not impact the remaining four years of the PBR test period, since the industrial forecast will be updated for each of the following years.

Based on the model run, revenue at existing rates will be re-forecast for all rate classes and delivery rates will be reset as required. The forecasts will be revised as part of the Annual Review rate setting process.

56.1.1 Please repeat the above question for Commercial rate classes 2 and Residential rate class 1 with the assumption that F2014 was a normal temperature year.

Response:

In the scenario described in the request, the use rate forecast for both Rate Schedule 2 and Rate Schedule 1 would be recalculated for 2015 using the latest available data. The inputs to the recalculation of the use rate are the actual use rates (by rate class) for the prior three years. For the 2015 re-forecast, data up to and including 2014 would be used.

Regardless of the size of the variance in 2014 the actual weather normalized 2014 data would be used in the calculations.

A new use rate forecast would then be created for the remaining years of the PBR.

The process would be repeated for the 2016 re-forecast.

The reforecasting process would completely replace all the remaining forecast values in the test period with new results.

56.2 Please confirm whether annual adjustments to FEI's forecasted energy demand will be applied consistently throughout the test period, irrespective of the magnitude of the forecast variance. Alternatively, please discuss the exceptions or over-ride mechanisms used.

Response:

During subsequent re-forecasts (for years 2015, 2016, 2017 and 2018) FEI will maintain the same forecast methodologies as used for this and previous filings generated from the FIS model. FEI will incorporate all adjustments from all data inputs regardless of the magnitude of those adjustments.

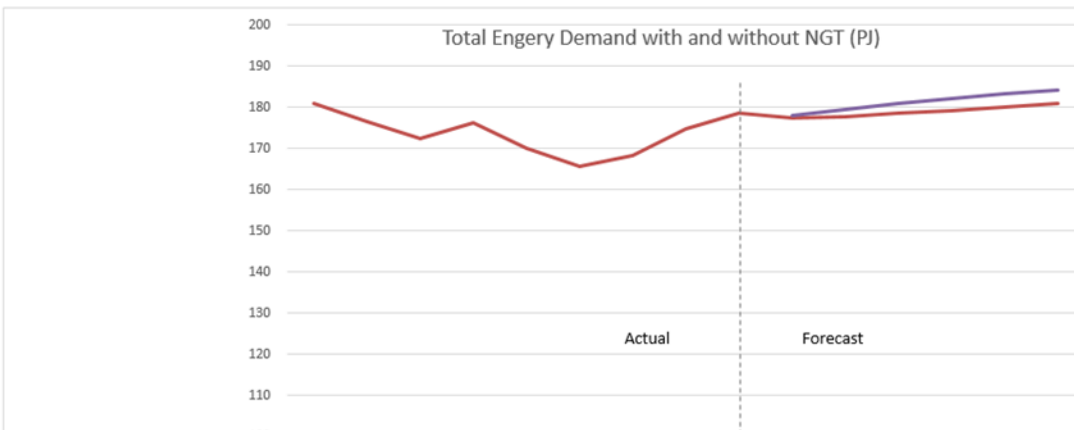
57.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 1.2, pp. 86-88

Total Energy Demand

"It should be noted that the forecast demand in this table [Table C1-1] does not include new customer additions or new energy demand related to CNG and LNG service that is presented in Section C1.4.6 and Appendix H. However, existing natural gas for transportation customers under Rate Schedule 6 have been included as part of the Industrial customer demand." (p. 86)

57.1 Figure C1-2 provides a graphical and tabular summary of the total energy demand excluding NGT rate classes. The graph presented below was prepared to assist in visualizing the impact that NGT rate classes may have in the current test period. Please confirm whether the graph is accurate. If required, please provide an updated version.

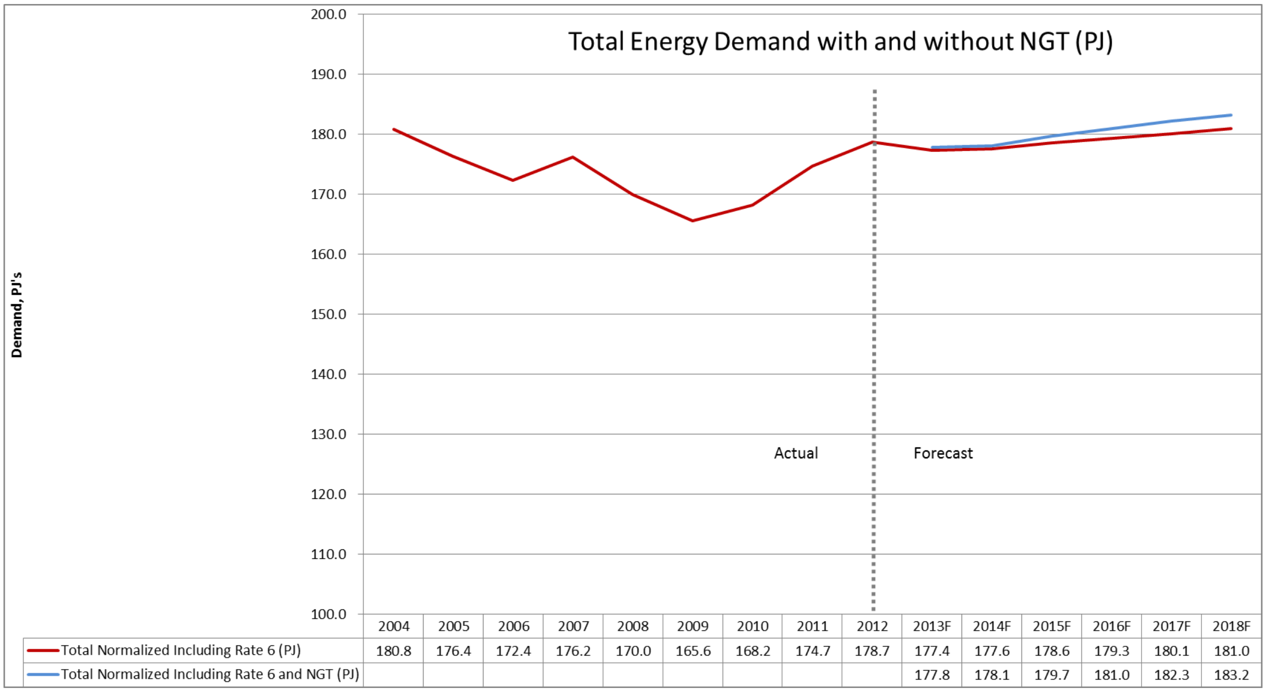


	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Total Normalized Excluding NGT (PJ)	181	176	172	176	170	166	168	175	179	177	178	179	179	180	181
Total Normalized Including NGT (PJ)										178	179	181	182	183	184

Source: Data from Exhibit B-1, Figure C1-22 and Exhibit B-4

Response:

Not confirmed. FEI's evidentiary update filed July 16, 2013 (Exhibit B1-3) updated NGT volume based on the impact that BCUC Order G-88-13 is forecast to have on the NGT market. Also, the red line should be labeled "Total Normalized Including Rate 6" consistent with the demand shown on pages 86 and 106. The following graph is an update to the graph provided in the IR.



57.2 Please calculate the financial benefit to FEI shareholders for every 1 percent that FEI under-forecasts total energy demand during the current test period. Please provide a copy of the calculation in the form of a spreadsheet.

Response:

A consistent 1% volume under-forecast for all customer classes not affected by RSAM would result in a benefit to FEI of approximately $250 thousand before sharing ($125 thousand after sharing) based on 2014 forecast volumes filed in the July 16, 2013 Evidentiary Update, Section E Formula, Schedule 6. Similarly, in the opposite direction a 1% over-forecast would result in a reduction of the same amount. While the incremental volume from the customer classes not related to the RSAM mechanism is 0.3% (504.8/170,212.3 TJ's), the incremental revenue of $253.5 thousand is only 0.02% of the total non-bypass sales and transportation revenue for 2014.

The following table shows the financial benefit to FEI for a 1 percent under-forecast of the energy demand prior to the ESM 50/50 sharing. Bypass customers volumes have been excluded because their revenues are predominantly fixed and do not change with changes in volumes transported. Consistent with the preamble to this question the table below also excluded Rate Schedule 16 LNG Sales Service as well. In responding to this question for Rate Schedules 1, 2, 3 and 23 it is assumed that the 1% under forecast is related to the use per customer forecast and would not result in any benefit to FEI as the margin revenue variance would be captured and credited to the RSAM deferral account and would be returned to these customers by way of a credit in the RSAM rate rider in the subsequent years.

FEI notes that it is highly unlikely that every rate schedule would have a consistent under or over forecast. It is more likely that some rate schedules would have higher volumes than forecast and some would have lower volumes and these would offset each other. Therefore, this $125 thousand estimate is unlikely to arise.

Rate Schedules	Forecast Volume (TJ's) [1]	1% Increment	Variable Delivery Charge $ / GJ [2]	Gross Incremental Revenue $000's	Income Tax 25%	Net of Tax Incremental Revenue ($000's)
Rate 1 - Residential	69,511.7	695.1	$ 3.663	N/A - RSAM		N/A - RSAM
Rate 2 - Small Commercial	24,246.8	242.5	$ 3.006	N/A - RSAM		N/A - RSAM
Rate 3 - Large Commercial	17,253.0	172.5	$ 2.543	N/A - RSAM		N/A - RSAM
Rate 4 - Seasonal Service	169.1	1.7	$ 0.973	$ 1.6	$ (0.4)	$ 1.2
Rate 5 - General Firm Sales Service	2,315.3	23.2	$ 0.722	16.7	(4.2)	12.5
Rate 6 - NGV Fuel - Stations	61.4	0.6	$ 3.967	2.4	(0.6)	1.8
Rate 7 - General Interruptible Service	86.7	0.9	$ 1.175	1.0	(0.3)	0.8
Rate 22 - Large Transportation Service	14,993.4	149.9	$ 0.863	129.4	(32.3)	97.0
Rate 22A - Large Transportation Service						
Firm Service	8,089.0	80.9	$ 0.096	7.8	(1.9)	5.8
Interruptible Service	749.0	7.5	$ 1.088	8.1	(2.0)	6.1
Rate 22B - Large Transportation Service						
Firm Service	5,100.0	51.0	$ 0.094	4.8	(1.2)	3.6
Interruptible Service	80.0	0.8	$ 1.013	0.8	(0.2)	0.6
Rate 23 - Large Commercial T-Service	8,721.3	87.2	$ 2.543	N/A - RSAM		N/A - RSAM
Rate 25 - General Firm T-Service	12,359.3	123.6	$ 0.722	89.2	(22.3)	66.9
Rate 27 - General Interruptible T-Service	6,476.3	64.8	$ 1.175	76.1	(19.0)	57.1
Total	170,212.3	1,702.1		$ 338.1	$ (84.5)	$ 253.5

1. Forecast Volumes per July 16th, 2013 Update, Section E, Formula, Schedule 6, excludes Rate Schedule 16 LNG Sales Service.

2. Delivery Charge ($ / GJ) approved by BCUC Order G-75-13, effective January 1, 2013; Rate Schedule 22B Interruptible rate is an average rate for Elkview and all other customers over the course of the 12 month period.

57.3 For the current test period 2014 to 2018, please confirm that the slight increase in total energy demand (excluding NGT) is solely derived from increasing demand in Commercial rate classes.

Response:

Confirmed.

57.4 Please confirm whether the following table is accurate, or in the alternative provide an updated version.

	Year	Residential	Commercial	Industrial	Total
	2013	69,644	49,611	58,157	177,412
	2014	69,512	50,221	57,886	177,619
	2015	69,406	51,073	58,081	178,559
Test Period	2016	69,320	52,009	57,940	179,269
	2017	69,235	52,940	57,928	180,103
	2018	69,135	53,896	57,928	180,960
Growth in Energy Demand		-509	4,286	-229	3,548

Source: Derived from Exhibit B-4, Forecast Data Model

Response:

Confirmed. The table above is correct.

57.5 To the extent possible, please describe FEI's understanding for the reason(s) that could account for Commercial demand increasing at a time when Residential and Industrial demand are not.

Response:

The forecast demand is derived from averages of historical data calculated for both customer additions and use per customer. This statistical method of forecasting Commercial demand, which has been in place in FIS for the past decade, does not provide a rationale for movement up or down of Commercial demand as it relates to the forecast. In the event that there is a variance between actual and forecast UPC of commercial rate classes 2, 3 and 23, the RSAM deferral mechanism is used to true up to the forecasted UPC.

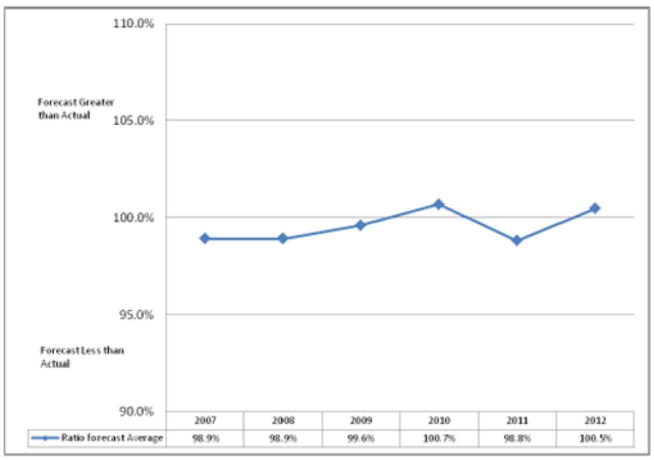
58.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 1.3, pp.95-96

Customer Additions Forecast

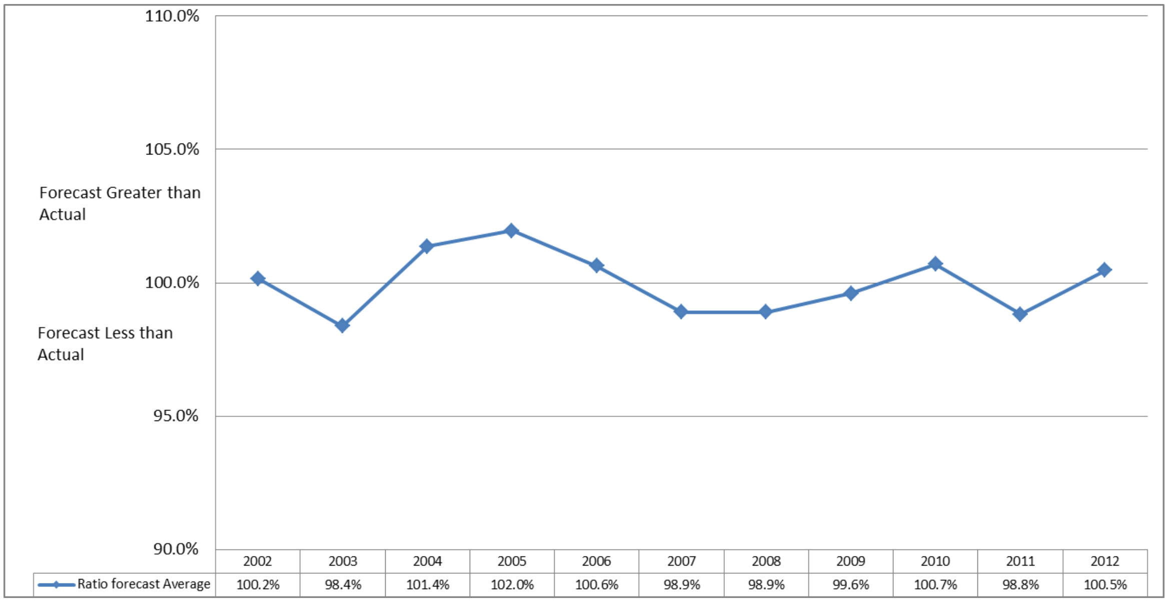
58.1 A comparison of forecasted to actual customer addition on an aggregated basis for Commercial classes 2, 3, and 23 has been provided in Figure C1-8 (copy provided below). Please provide an updated version of the same graph for the period 2002 to F2013.

Figure C1-8: Comparison of Forecast to Actual Commercial Customers



<u>Response:</u>

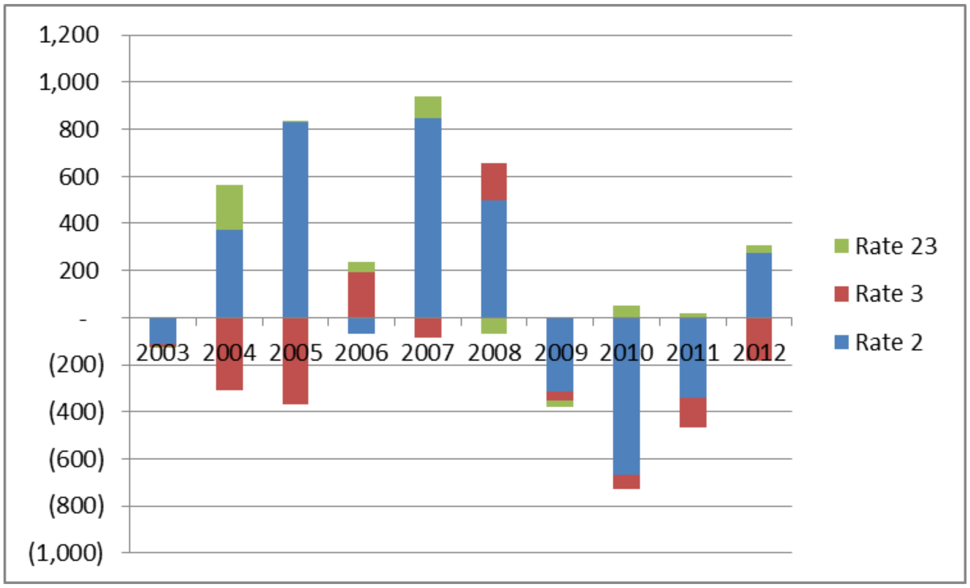
Please see below for an updated version of the same graph for the period 2002 to 2012. F2013 cannot be provided at this time because we do not have 2013 actual additions to compare to.



58.2 On aggregate for the Commercial rate classes, there appears to be a high degree of forecast accuracy. Is the aggregate a fair representation of the forecast accuracy of each individual rate class (RS2, RS3, and RS23) that comprises Commercial? In other words, if RS2 consistently over-forecasted and RS3 consistently under-forecasted, the aggregate forecast accuracy would be misleadingly high, despite there being large forecast variances. This could occur as result of variances canceling each other out. Please provide evidence that this is not the case.

Response:

As the chart below demonstrates there is no consistency in terms of over or under forecasting within a particular rate class. Over and under forecasting is random and thus there is no evidence of inherent bias in the commercial customer additions forecast for any particular rate class.



1,200
1,000
800
600
400
200
-
(200)
(400)
(600)
(800)
(1,000)
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Rate 23
Rate 3
Rate 2

59.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 1.3.1, p. 91

SAP Account Adjustment

"FEI's new CIS, which became operational as of January 1, 2012, has enabled a more accurate method of counting customers." (p. 91)

59.1 The CIS implementation resulted in differences in customer counts as a result of FEI adopting a mid-month cut-off in the algorithm used in determining the number of customers. Please confirm whether there were any other adjustments to customer counts other than the adoption of a mid-month cut-off.

<u>Response:</u>

The details of the change in customer count methodology are included in Appendix E4 of the Application and are reproduced below.

"These two definitions lead to different customer counts, and this is mainly due to what actually constitutes a customer in each system.

A customer in the new SAP-based CIS is defined as a valid contract to provide natural gas service. This definition results in a different customer count from that of the previous CIS in those situations where a premise becomes vacant or meters are connected during the reporting period. Under the new system these vacant premises or meter disconnects no longer have a valid contract as of the day the premise becomes vacant or the meter is disconnected. This is in contrast to the previous CIS where there was still an installed meter that received service during the reporting period. For example, if a customer was disconnected on January 10, under the previous CIS they would be reported as a customer for the month of January (as a meter would have been attached to that premise for at least one day during the month of January). Under the new CIS, however, they would be excluded.

Also contributing to the difference is the reporting period itself. The former CIS counted customers based on installed meters that were not disconnected over a particular reporting period (a particular calendar month). The new CIS, however, is more detailed and flexible, and enables the reporting of customer counts on a daily basis. This, in turn, provides a greater degree of precision when reporting the number of customers. Upon analyzing customer counts on various days of the month, the FEU have decided that mid-month (the 15th day of each month) is the appropriate reporting date for reporting customer counts.

Using a mid-month date helps to smooth out differences seen in customer counts that are a result of customers moving, which typically occur around the end of the month and often include small timing differences between the date a customer calls for a move-in and the date a customer calls for a move-out."

59.1.1 If there were other adjustments, please provide details.

Response:

Please refer to the response to BCUC IR 1.59.1.

59.2 Please describe what functionality has been added to the new CIS system that makes it more accurate than the previous CIS.

Response:

The primary attribute of the new CIS system that results in more accurate customer count information than the previous CIS system is a more robust data structure which separates the customer entity from the service contract. The service contract entity is the attribute that reflects the existence of an active customer. In SAP, customer count is determined through a simple count of active contracts at a point in time.

The legacy CIS system did not have a specific entity to represent the contract between the customer and the gas service. This count was derived based on customer activity at the premise over the reporting period. The complexity of the customer count methodology resulted in minor inaccuracies due to the number of factors that needed to be considered.

59.2.1 Please provide a list and description of the new or improved functionality found in the CIS system that became operational as of January 12, 2012. Please also describe the operational benefits to FEI and ratepayers associated with each improvement.

Response:

New and improved functionality benefits are listed in the table below. For a more complete discussion of the scope and benefits of the CIS System, please refer to the CPCN Application proceeding related to "Customer Care Enhancement Project – The Insourcing of Customer Care Services and Implementation of a New Customer Information System". The project delivered the functionality and benefits described as discussed in the CCE CPCN proceeding.

Description	Operational Benefit
Capture and tracking of alternate customer relationships for an account. i.e. care giver, government agencies etc. to support secondary contacts for "at risk" customers.	SAP supports adding business partner relationships to capture secondary contact information .i.e. care giver, government agencies etc. to support secondary contacts for "at risk" customers. This improves the quality of service to customers.
Ability to support multiple names on an account i.e. roommates, spouses to reflect shared liability.	SAP supports adding business partner relationships to capture secondary contact information. Eg. Spouse, contact person, etc. This improves the quality of service to customers.
Capture end use details including load information, appliance details and program participation	Supports improved handling of high bill and consumption inquiries as well as customer education related to load analysis and conservation options. This also provides opportunities for more detailed analytics related to end use in the future.
Track additional Company equipment at a premise	Supports complex inquiries related to metering as well as opportunity in the future to implement and track equipment related to automated meter reading.
Expanded electronic bill presentment options through tracking of special purpose e-mail addresses.	The company now supports 2 types of electronic bills, email PDF or email notification without PDF. This has reduced costs related to printing and mailing hardcopy bills.
Support for mass rate refund processing in the case of interim rates.	Base functionality is supported. However, multiple period reversal / adjustments will require further analysis for bill presentment and implementation. Will provide greater transparency into the impact of interim rates for customers.
Greater flexibility related to tax configuration.	Jurisdictional taxes allows greater flexibility in handling tax rate changes related to individual accounts as well as reconfiguration in response to legislated requests for mass changes. Supports billing timeliness operational efficiency.
Enhanced "business to business" transaction support for billing and payments.	Improvements in bill presentment related to complex accounts. This reduced customer inquiries as well as providing a platform for more flexible bill formats and delivery methods in the future. SAP also supports the opportunity for EDI integration in the future.
Ability to provide billing data to third party bill aggregators.	SAP supports multiple bill copies with the alternate recipient functionality as well as bill reprints to customers as well as third parties.
Auto-logging of e-mail correspondence within the CIS application.	Through the customer portal data updates and requests from customers are automatically captured in SAP and queued for response as required. Efficiencies are gained through auto-logging of requests and work queue management for handling timely responses.

Description	Operational Benefit
Increased customer access to online transactions through the customer portal.	Allows customers 7X24 access to a more robust suite of transactions including for example account update, balance inquiry, billing history, meter reading entry, Equal Payment Plan and Preauthorized Payment Plan enrolment, initiate move, product offerings and contact us.
Enhanced ability to download account and consumption information from CIS.	Web portal enables the download of 24 months of financial and consumption history into MS Excel or Text file formats for each premise.
Integration of customer choice contracts into the core SAP CIS system.	The change to an integrated Customer Choice platform within the CIS allows both contact center staff and customers to view contract details within the CIS system and through the web portal.
Support for integrated communication channels including voice, email and online chat.	All interactions can be handled via inbound call queues and the results captured in CIS. This provides efficiencies in the contact centre as well as more timely response to customer inquiries via a variety of communication channels.
Enhanced IVR capabilities.	IVR automated system supports account balance inquiry, payment inquiry, enter meter reads, moving, set up EPP, locate a gas line, request for natural gas installation. Customers have the option of using the automated system instead of waiting to speak to a representative. IVR functions are also available outside of normal contact centre hours.
Support for Integrated inbound / outbound calling.	Auto Dialer support for outbound calling to alert customers to important account and service conditions. This also includes requested call backs for customers who select this option rather than waiting in the queue for the next available representative. This is an improvement in service quality.
Integrated refund processing for customers requiring cheques related to final credit balances.	Refund cheque requests are now integrated with SAP's accounts payable module. This results in efficiencies related to manual processing as well as providing more timely cheque processing for customer refunds.
SAP / Fieldwork integration.	Service order status is now available to contact center staff providing more timely and accurate information in response to customer inquiries

59.2.1.1 Please confirm the cost of implementing the new CIS system including incremental licensing and maintenance costs.

<u>Response:</u>

The total cost of implementing the new SAP CIS system was $67.891 million including hardware, software, and implementation costs of the CIS system as well as ancillary supporting systems and interfaces. The SAP CIS system was a significant portion of the overall project budget of $115.496 million. The project was delivered on time and under budget at a cost of approximately $109 million.

The incremental licensing and maintenance costs are approximately $726 thousand based on 2013 projections.

60.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 1.3, p. 92

Use Per Customer (UPC)

"The mathematical result of a decrease in the number of customers with no change in delivery volumes is an increase in the use per customer (volumes divided by number of customers equals use per customer) in residential and commercial rate classes. These one-time increases are not indicative of recent trends and were not included in the calculation of the forecasted use rates." (pp. 91-92)

60.1 The new CIS that went live at the beginning of 2012 resulted in a one-time adjustment in the number of customers, with a corresponding adjustment in the UPC to derive a constant demand in energy demand. Is it reasonable to expect that, despite the adjustment in customer count, the underlying trends should remain unaffected by this one-time change?

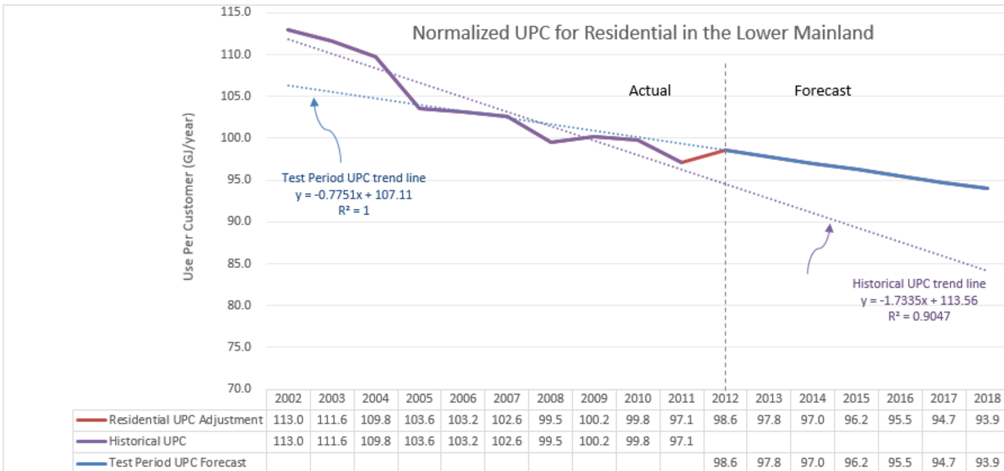
Response:

Yes, the underlying trends are not affected by this one time change.

The underlying trends responsible for the decline in UPC include but are not limited to things like improved building envelopes, smaller house sizes, a shift to more multi-family dwellings and more efficient appliances. These trends are not affected by or related to our adoption of a new billing system.

60.2 The following graph illustrates that for the current test period, FEI is forecasting a 55 percent[11] decline in the rate at which UPC is decreasing compared to historical (2002-2011) time-series data. Please confirm that the forecasted decline in UPC trend is not related to the implementation of the new CIS system.

[11] The slope of the UPC time series data indicates the rate of UPC change. Percentage change in UPC is calculated as follows: (1.7335-0.7751)*100/1.7335= 55%



Source: Data from Exhibit B-1, Figure C1-6 and Exhibit B-4

Response:

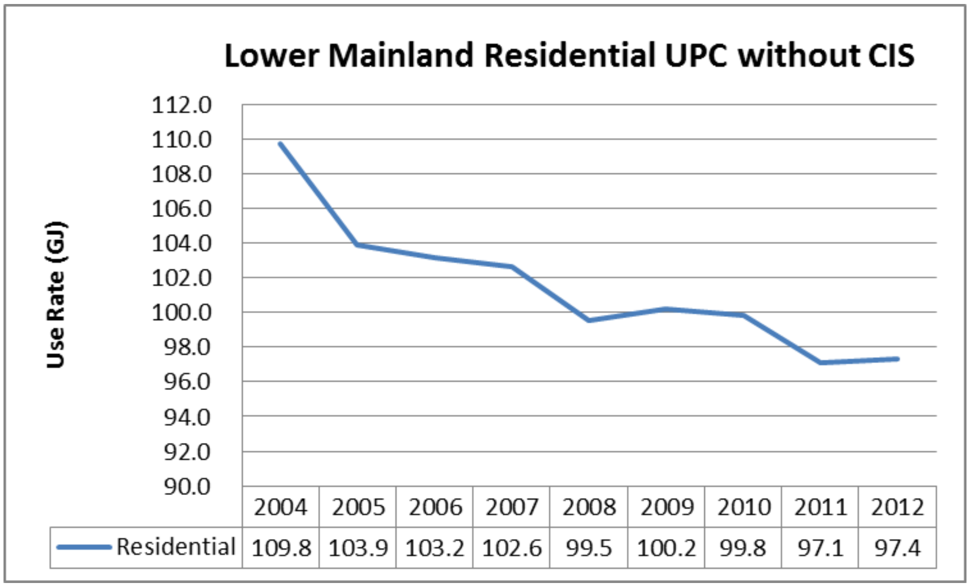
Confirmed. The forecasted decline in UPC trend is not related to the implementation of the new CIS system. The CIS implementation resulted in a one-time adjustment of the actual average use per customer in 2012.

60.2.1 Please describe the factors responsible for the change in UPC trend when compared to the trend in the 10 preceding year period.

60.3 Please provide an updated version of the graph and tabular data found in Exhibit B-1, Figure C1-6, p.93 to illustrate what the UPC would have been in 2012 had the new CIS system not been implemented.

Response:

The following chart is updated to show the UPC in 2012 without the customer count adjustment, which would have been 97.4 GJ for residential customers.



Lower Mainland Residential UPC without CIS
Use Rate (GJ)
112.0
110.0
108.0
106.0
104.0
102.0
100.0
98.0
96.0
94.0
92.0
90.0
2004 2005 2006 2007 2008 2009 2010 2011 2012
Residential 109.8 103.9 103.2 102.6 99.5 100.2 99.8 97.1 97.4

61.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 1.4.2, pp. 98-99

Revenue Stabilization Adjustment Mechanism (RSAM)

"As shown in the following Figure C1-10, demand under 1 Rate Schedules covered by the RSAM in the Mainland region can vary by +/- 12 PJs in a particular year. Negative volumes indicate below normal temperatures." (p. 99)

61.1 The last sentence in the above paragraph suggests that negative RSAM volumes are solely the result of colder than expected temperatures. This may not be entirely correct since it is possible to obtain negative RSAM volumes in years with perfect weather forecasts. This can occur when UPC has been over-forecasted, despite a normal weather year. In other words, weather is not the sole factor responsible for forecast variances, and resulting RSAM volumes. Other factors such a fuel switching, the price of natural gas, and the state of economy can have considerable effect on the demand for natural gas in the short term. Please comment on whether this understanding is correct.

Response:

FEI agrees that weather is not the sole factor causing actual UPC being greater or less than forecasted UPC affecting RSAM. However, for residential and commercial customers, in Rate Schedules 1, 2, 3 and 23, weather is the predominant factor affecting RSAM. Other factors listed in the IR above would have minimal effect in the short term on the demand for natural gas from residential and commercial customers.

61.2 Since the implementation of RSAM in 1994, RSAM has captured variances in UPC but not variances in customer additions. Originally, the justification for not including customer additions in RSAM was based on the understanding that forecast variances in customer additions have a relatively minor impact on revenue. Please confirm whether this is correct.

Response:

While the comment on customer additions variances and the impact on revenues is correct, this is not the only justification for not including customer additions in RSAM. As referenced in BCUC IR 1.210.1, the predominant reason for the RSAM design was to act as a decoupling mechanism to sever the link between sales volume and variable margin. The decoupling mechanism is not about customer count variance, but about decoupling the impact of energy consumption variance.

61.3 Based on historical data between 2004 to 2013, please confirm whether forecast variances in the number of customer additions are greater than the forecast variances in UPC. Please express the forecast variance in UPC as a percentage of normalized demand.

Response:

Please see the variance summary provided below. When variances are expressed as instructed and compared across different metrics (i.e. UPC versus Customers), forecast variances in the number of customer additions are a greater percentage than the forecast variances in UPC. However, due to the small number of customer additions, and small amount of associated volume relative to overall volumes as part of the UPC, the variance in customer additions in a given year is not material. Refer also to the responses to BCUC IR 1.64.1, 1.64.3 and 1.64.4 on customer addition and UPC variances effect on delivered volume.

Exhibit B-1-1, Appendix E5 Customer Addition Variance Tables E5-7 and E5-8 show that, for residential and commercial customers over the period from 2003 through 2012, there has been no consistency in the variance; some years are positive and other years are negative. Over the 10 year period, the total actual number of customer additions has been less than forecast by 473 customers. What is shown in Section 4 of Appendix E5 is that there is no impact on revenue or gross margin for any variances in the volume due to the RSAM mechanism.

Mainland

RESIDENTIAL (RATE 1)

Use per customer

YEAR	Actual	Forecast	Normalized Demand	Variance as a % of Normalized Demand
2004	102.6	104.7	72,033,062	0.0000029%
2005	97.2	103.3	69,299,864	0.0000088%
2006	96.8	100.6	69,997,080	0.0000054%
2007	96.0	99.8	70,638,201	0.0000054%
2008	92.5	96.1	68,840,616	0.0000052%
2009	93.3	91.1	69,999,093	-0.0000031%
2010	92.6	89.7	70,041,036	-0.0000041%
2011	90.4	88.3	68,932,358	-0.0000031%
2012	92.2	90.8	69,753,024	-0.0000019%

RESIDENTIAL (RATE 1)

Customer Additions

YEAR	Actual	Forecast	Actual Customers	Variance as a % of Actual Customers
2004	10,716	8,000	707,929	-0.384%
2005	11,427	9,652	719,356	-0.247%
2006	9,595	12,204	728,951	0.358%
2007*	12,003	12,764	740,954	0.103%
2008	7,959	11,098	748,913	0.419%
2009	4,822	8,012	753,735	0.423%
2010	6,824	4,777	760,559	-0.269%
2011	4,994	4,983	765,553	-0.001%
2012	4,475	6,507	759,712	0.267%

*Note: 2007 Customer Additions includes amalgamation with Squamish

61.3.1 Based on historical results of the forecast accuracy of customer additions, is there a rational for altering RSAM to include forecast variances in customer additions? Please discuss.

<u>Response:</u>

At this point in time there is minimal value in extending the RSAM mechanism to include variance in customer additions.

It is not the error in customer additions that is of significance for deciding to include or exclude customer addition variances from the RSAM, but rather the significance of the dollar value of the error. What is demonstrated in the evidence provided in the response to BCUC IR 1.61.3 and in Table E5-7 on page 10 of Appendix E-5 of Exhibit B-1-1, is that customer addition variances are inconsistent from year to year, both positively and negatively from forecast, and in most years the variances for each Rate Schedule are directionally inconsistent amongst the different rate schedules.

Currently the primary driver in UPC variance is weather related which will tend to affect each of the RSAM related customer classes directionally the same way.

62.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 1.4.3, Figure C1-12, p. 10; FEU 2012-2013 RRA, Exhibit B-6, BCOAPO IR 1.20.1, p. 43

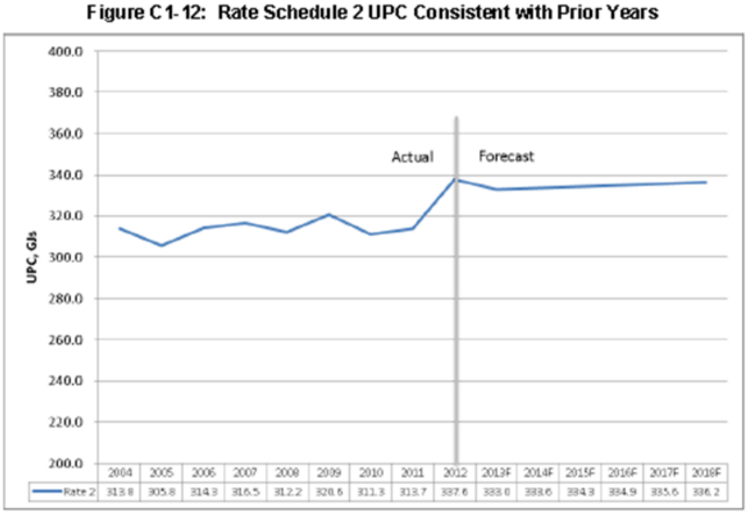
Use Rate (UPC) – Commercial RS2

"The analysis starts with the normalization of historic UPC data to remove the impact of weather variations. The Companies uses the previous 10 years of weather data for normalization.

The next step involves trending four years of normalized UPC values for each region and rate class. If a clear trend is identified, the trend line is used to predict future UPC for the region and rate class. In the absence of a clear trend, the annual percentage UPC change is calculated for the past three years, and this average is used to forecast the UPC over the forecast period." (FEU 2012-2013 RRA, Exhibit B-6, BCOAPO IR 1.20.1, p. 43)

62.1 The following question relates to Figure C1-12. Based on FEI's prescribed forecast methodology for UPC, please indicate whether the past 3 or 4 years have a "clear trend." Please also define and quantify the parameter(s) used to identify a clear trend.

Figure C1-12: Rate Schedule 2 UPC Consistent with Prior Years



Response:

Regression analysis was carried out for each class and region to determine the existence of a statistically significant trend. When the goodness of fit was favorable as well as other diagnostics such as R square, the trend calculated from the regression model was used.

Whenever the goodness of fit was not favorable, the average percentage change in the latest three years was used.

No significant trend was identified for Rate Schedule 2.

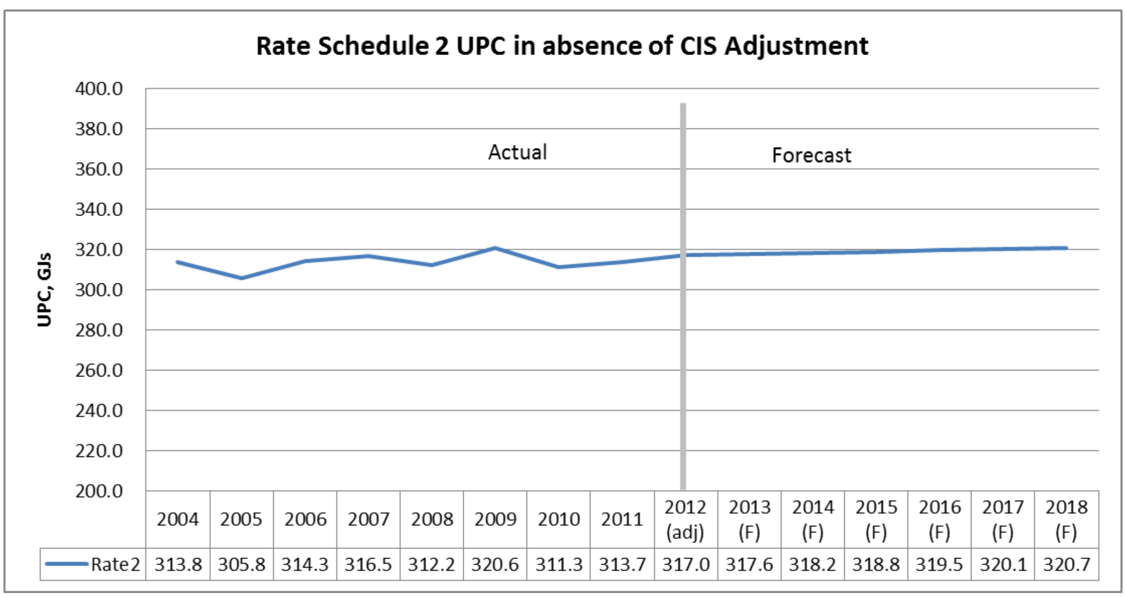
The summary of output from the regression models is shown below.

Region	Rate Class	Rsquare	Estimate.Index
COL	RATE2	0.44	(0.28)
INL	RATE2	0.00	(0.02)
LML	RATE2	0.04	0.07
RSK	RATE2	0.09	(0.19)

62.2 The large increase in UPC in F2012 is a result of the CIS adjustment. Please provide a restated version of Figure C1-12 that illustrates forecasted UPC in the absence of the CIS adjustment.

<u>Response:</u>

The following chart and table provide the Rate Schedule 2 UPC as forecasted in the absence of the CIS adjustment.



63.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 1.4.3, pp. 99-102

Residential and Commercial Use Rates (UPC)

63.1 Please confirm that the data presented in Figures C1-11 to C1-14 are the weighted averages for UPC aggregated for the four regions serviced by FEU.

<u>Response:</u>

The data presented in Figures C1-11 to C1-14 are “blended”, whereby monthly normalized UPCs are calculated (sum of monthly normalized volumes for the four regions served by FEI (i.e. Lower Mainland, Columbia, Inland and the City of Revelstoke) divided by the sum of monthly accounts for all four regions). The sum of the monthly UPCs, then provides the annual UPC for the respective year and rate schedule for all regions.

As an example, the FEI residential UPC calculation for 2012 is shown below.

Rate: Residential
Region: FEI (LML,INL,COL,RSK)
Year 2012
Consolidated UPC for 2012

	January	February	March	April	May	June	July	August	September	October	November	December
Energy GJ	10,705,619	8,997,607	7,716,232	5,672,750	3,542,498	2,306,655	1,805,759	2,038,158	2,252,275	5,087,665	8,577,451	11,050,355
Accounts	756,800	756,967	756,463	755,722	755,427	754,057	753,173	753,140	754,385	756,682	758,534	759,712
UPC	14.1	11.9	10.2	7.5	4.7	3.1	2.4	2.7	3.0	6.7	11.3	14.5
Annual UPC	**92.2**											

63.2 Please update Figures C1-11 to C1-14 to include RRA forecasted UPC for each year between F2004 to F2013. Please also include tabular data the expresses the forecast variance in terms of GJ/year and percentage.

<u>Response:</u>

Please refer to Exhibit B-1-1, Appendix E3 Forecasting Models Live Spreadsheets for the Figures showing the RRA forecasted UPC values.

The updated tables showing forecast variance in terms of GJ/year and as a percentage are provided below.

RESIDENTIAL (RATE 1)

Use per customer			AGGREGATED	
YEAR	Forecast	Normalized	Variance (GJs)	Variance (%)
2004	104.7	102.6	-2.1	98%
2005	103.3	97.2	-6.1	94%
2006	100.6	96.8	-3.8	96%
2007	99.8	96.0	-3.8	96%
2008	96.1	92.5	-3.6	96%
2009	91.1	93.3	2.2	102%
2010	89.7	92.6	2.9	103%
2011	88.3	90.4	2.1	102%
2012	90.8	92.2	1.4	101%
2013 (F)	91.4	N/A		

COMMERCIAL (RATE 2)

Use per customer			AGGREGATED	
YEAR	Forecast	Normalized	Variance (GJs)	Variance (%)
2004	300	314	13.7	105%
2005	317	306	-11.3	96%
2006	308	314	6.7	102%
2007	314	317	2.3	101%
2008	320	312	-7.7	98%
2009	303	321	17.6	106%
2010	318	311	-6.7	98%
2011	318	314	-4.3	99%
2012	308	338	29.6	110%
2013 (F)	333	N/A		

COMMERCIAL (RATE 3)

Use per customer			AGGREGATED	
YEAR	Forecast	Normalized	Variance (GJs)	Variance (%)
2004	3,342	3,501	158.6	105%
2005	3,426	3,388	-38.0	99%
2006	3,402	3,314	-87.7	97%
2007	3,394	3,426	32.3	101%
2008	3,445	3,420	-25.4	99%
2009	2,976	3,372	396.0	113%
2010	3,346	3,370	24.0	101%
2011	3,346	3,484	138.5	104%
2012	3,334	3,566	231.5	107%
2013 (F)	3,746	N/A		

COMMERCIAL (RATE 23)

Use per customer			AGGREGATED	
YEAR	Forecast	Normalized	Variance (GJs)	Variance (%)
2004	5,301	5,113	-188.2	96%
2005	4,975	4,714	-261.3	95%
2006	4,977	4,686	-290.7	94%
2007	4,796	4,778	-18.4	100%
2008	4,916	4,698	-218.3	96%
2009	4,391	4,886	495.0	111%
2010	4,680	4,850	170.0	104%
2011	4,680	5,138	458.1	110%
2012	4,901	5,238	336.6	107%
2013 (F)	5,392	N/A		

63.3 For each rate class 1, 2, 3, and 23, please provide an assessment of the impact that a 1 percent variation UPC would have on the revenue requirement for each year of the test period, and on aggregate.

Response:

The FIS model was rerun four times with a positive 1 percent variation to the UPCs of each of the four specified rate classes.

The following table shows the revenue delta compared to the base forecast presented in the filing.

The aggregate revenue delta is shown as the "Annual Totals".

		2014	2015	2016	2017	2018
Revenue ($000's)	RATE1	$5,705.40	$5,675.10	$5,667.60	$5,660.40	$5,651.80
	RATE2	$1,830.30	$1,817.00	$1,828.20	$1,839.60	$1,850.30
	RATE3	$1,159.20	$1,164.20	$1,171.70	$1,180.70	$1,188.30
	RATE23	$228.20	$243.40	$260.90	$278.10	$296.20
Annual Totals		$8,923.20	$8,899.70	$8,928.30	$8,958.70	$8,986.60

The RSAM deferral account mechanism stabilizes the margins recovered from residential and commercial customers regardless of the magnitude of the UPC variance. The RSAM stabilizes delivery margin received from residential and commercial customer classes on a UPC basis. Assuming no customer addition variance, the entire margin difference from the 1% change in

UPC would be added to the RSAM deferral, adding to the RSAM deferral changes rate base, and could have a (surplus) or deficiency influence on the next years revenue requirement.

The table below assumes 100% of the margin difference is added to RSAM and that starting RSAM is zero, then calculates the approximate annual impact to the revenue requirement. The last line of the table shows the revenue requirement impact of the 1% variation in UPC as requested in the question (between $129 thousand and $174 thousand per year or $648 thousand in total).

($000)

Line	Particulars	Reference	2014	2015	2016	2017	2018
1	RSAM Opening Balance	Prev Yr Line 11	$ -	$ (3,054)	$ (4,596)	$ (4,619)	$ (4,644)
2	RSAM Additions						
3	Gross	Delivery Margin within 'Annual Totals' from above table	(4,072)	(4,091)	(4,113)	(4,135)	(4,157)
4	Less Taxes	-Line 3 x Line 29	1,018	1,023	1,028	1,034	1,039
5	Net	Line 3 + Line 4	(3,054)	(3,068)	(3,085)	(3,101)	(3,118)
6	RSAM Recoveries						
7	Rider	(2 Prev Yrs Line 5 / 2) / (1 - Line 29)	-	2,036	4,082	4,102	4,124
8	Tax on Rider	-Line 7 x Line 29	-	(509)	(1,020)	(1,026)	(1,031)
9	Net	Line 7 + Line 8	-	1,527	3,061	3,077	3,093
10							
11	RSAM Ending Balance	Line 1 + Line 5 + Line 9	(3,054)	(4,596)	(4,619)	(4,644)	(4,668)
12							
13	RSAM Deferral Balance for Rate making Purposes[1]						
14	Opening Balance	Line 1	-	(3,054)	(4,596)	(4,619)	(4,644)
15	Net RSAM Recoveries	Line 9	-	1,527	3,061	3,077	3,093
16	Closing Balance	Line 14 + Line 15	-	(1,527)	(1,534)	(1,542)	(1,551)
17							
18	Mid Year Deferral Balance						
19	for Rate Setting purposes	(Line 14 + Line 16) / 2	-	(2,291)	(3,065)	(3,081)	(3,097)
20	Capital Structure						
21	LTD Portion	Section E, Sched 60; Appendix G, Scheds 6, 11, 16, 21	56.26%	54.97%	53.87%	56.53%	59.31%
22	STD Portion	Section E, Sched 60; Appendix G, Scheds 6, 11, 16, 22	5.24%	6.53%	7.63%	4.97%	2.19%
23	Equity Portion	Section E, Sched 60; Appendix G, Scheds 6, 11, 16, 23	38.50%	38.50%	38.50%	38.50%	38.50%
24							
25	LTD Rate	Section E, Sched 60; Appendix G, Scheds 6, 11, 16, 25	6.84%	6.77%	6.50%	5.98%	5.96%
26	STD Rate	Section E, Sched 60; Appendix G, Scheds 6, 11, 16, 26	1.75%	2.50%	3.25%	3.75%	4.75%
27	ROE	Section E, Sched 60; Appendix G, Scheds 6, 11, 16, 27	8.75%	8.75%	8.75%	8.75%	8.75%
28							
29	Tax Rate	Section E, Sched 23	25.0%	25.0%	25.0%	25.0%	25.0%
30							
31	Equity Return	Line 12 x Line 23 x Line 27	-	(77)	(103)	(104)	(104)
32	Taxable Income	Line 31 / (1 - Line 29)	-	(103)	(138)	(138)	(139)
33	Tax Expense	Line 32 x Line 29	-	(26)	(34)	(35)	(35)
34	Revenue Requirement	Line 32 + Line 33	$ -	$ (129)	$ (172)	$ (173)	$ (174)
35							
36	Note 1: FEI does not forecast RSAM Additions, so the previous years closing balance plus the expected annual RSAM recoveries are used to forecast the						
37	RSAM closing balance, the average of the opening and closing balance is included in Rate base for the revenue requirement calculation.						

For actual UPC greater than forecast, the resultant change to the revenue requirement would be a surplus (as shown above). For actual UPC less than forecast, the resultant change to the revenue requirement would be a deficiency.

64.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 1.3, p. 92

Use Per Customer Forecast Variances

64.1 Please confirm whether forecast variances in UPC have a significantly larger impact on energy demand than variances in the number of customer additions. For example, is it correct that, all other factors remaining constant, a 3 percent variance forecasted UPC would result in a much great impact on Residential energy demand than a 3 percent variance in number of customer additions?

Response:

Confirmed. Forecast variances in UPC have a significantly greater impact on the forecast of overall demand than do variances in the customer additions forecast.

Consider the following illustrated in the table below:

There are 764,028 residential customers at the end of 2013 and the forecast for residential additions for 2014 is 4,594. UPC forecast for 2014 is 90.7 GJs. The 2014 demand is 69.71 PJs.

If the account additions increased 3% to 4,732 and the UPC is held at 90.7 GJs then the demand forecast goes up slightly to 69.73 PJs.

On the other hand, if the account additions forecast is fixed at 4,594 but the UPC forecast is increased by 3% to 93.4 GJs then the demand for this scenario is 71.81 PJs. This scenario is exactly 3% higher than the base scenario because the UPC is applied to both existing and new customers.

	2014	Increase 2014 Customers additions by 3%	Increase 2014 UPC by 3%
2014 Customer Adds	4,594	4,732	4,594
2013 Customers	764,028	764,028	764,028
2014 Customers	768,622	768,760	768,622
UPC	90.7	90.7	93.4
Demand (Pjs)	69.71	69.73	71.81
Change		0.02%	3.0%

64.1.1 Please quantify the impact that a 3 percent forecast variance would have on 2014 Residential energy demand in contrast to a 3 percent forecast variance in the number of customer additions.

Response:

Please refer to the response to BCUC IR 1.64.1.

64.2 Please confirm whether customer additions are significantly harder to forecast accurately than UPC.

Response:

Please see the data tables in Exhibit B-1-1, Appendix E-3 Forecasting Models.

The data tables present the forecast and actual customer additions and the use per customer (UPC) forecasts. In general, customer additions are found to be less predictable than UPC.

The customer additions variance is attributed to factors including the recession, the time lag between housing starts and new customers, existing customer turnover, and also the smaller number of new customers in commercial rate classes.

Use per customer forecasting variance for commercial rate classes is greater than that of residential due to the volatility introduced from the smaller customer count and large range of usage patterns.

The following table compares the residential Rate Schedule 1 variance for UPC and customer additions from 2004 to 2012. While the average UPC variance is only 1.1% the customer additions variance is over 12%.

RESIDENTIAL (RATE 1)		
YEAR	UPC Variance	Account Addiitons
2004	-8.9%	25.3%
2005	-1.1%	15.5%
2006	-1.9%	-27.2%
2007	5.0%	-6.3%
2008	9.6%	-39.4%
2009	6.9%	-66.2%
2010	-6.6%	30.0%
2011	6.0%	0.2%
2012	0.9%	-45.4%
Average	1.1%	-12.6%

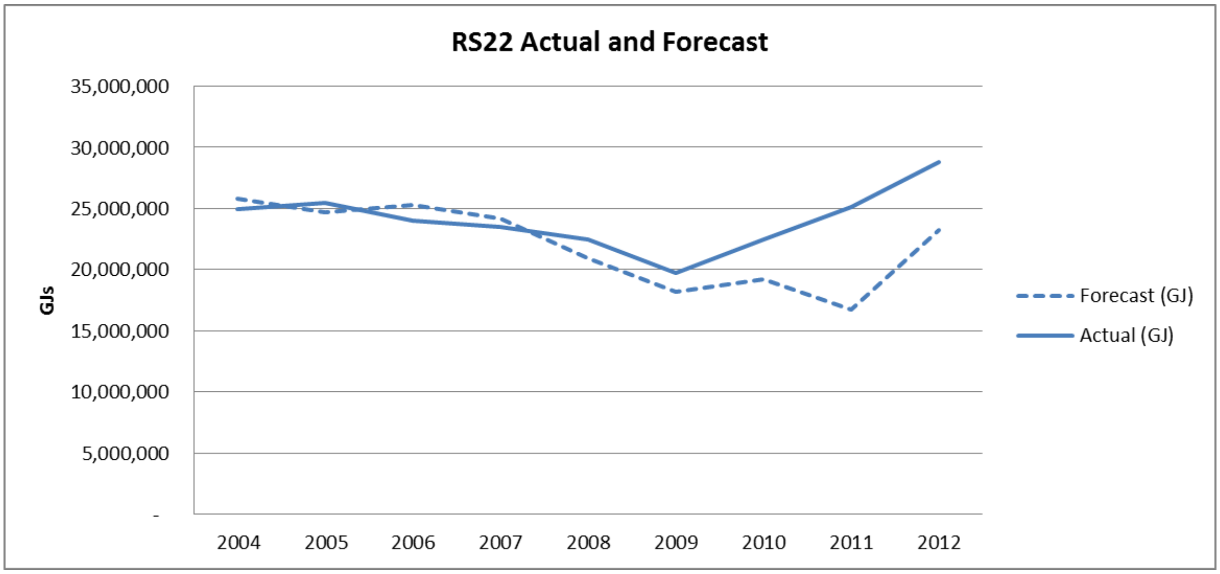
Please also refer to the responses to BCUC IR 1.61.3 and 1.64.1 regarding actual to forecast variances for UPC and customer additions.

64.3 Segmented by year for the period 2004 to 2013, please provide tabular and graphical data that summarizes the magnitude and range of forecast variance for UPC and customer additions for Residential, Commercial RS2, and Industrial RS22.

Response:

Please see Appendix E3 Forecasting Models Live Spreadsheets for tabular and graphic forecast variance data for both UPC and customer additions for residential Rate Schedule 1 and commercial Rate Schedule 2.

The forecast variance for industrial Rate Schedule 22 demand, which was not provided in Appendix E3, is provided below as a % of the actual demand. As Rate Schedule 22 is an industrial rate class, its forecast is based on surveys. For more detail on the industrial forecast process, refer to Section C1.3.5 of the Application Industrial Demand Forecast Methodology.



R22	Forecast (GJ)	Actual (GJ)	Variance as a % of Actual
2004	25,823,891	24,938,882	4%
2005	24,736,568	25,501,393	-3%
2006	25,254,831	24,029,093	5%
2007	24,206,537	23,508,062	3%
2008	20,967,980	22,487,971	-7%
2009	18,166,574	19,745,960	-8%
2010	19,183,662	22,494,945	-15%
2011	16,757,447	25,133,369	-33%
2012	23,233,216	28,807,092	-19%

64.4 On aggregate for the period 2004 to 2013, did the forecast variances in UPC or customer additions have a greater impact of forecast variances in energy demand? Please quantify.

<u>Response:</u>

FEI has provided the requested information for 2004 to 2012 as there are no actuals for 2013 to compare against.

As illustrated below, forecast variances in customer additions have far less impact compared to UPC variances for a given year as additions account for a very small portion of the overall demand.

Forecast variances and their corresponding impacts in residential demand are shown below.

Residential

Year	% of Total Demand due to Forecast Variance in Additions	% of Total Demand due to Forecast Variance in UPC
2004	0.4%	10.3%
2005	0.2%	7.5%
2006	0.4%	5.8%
2007	0.1%	1.4%
2008	0.5%	6.7%
2009	0.5%	9.8%
2010	0.3%	3.1%
2011	0.0%	8.8%
2012	0.3%	2.4%

Note: The impact of variances in each metric was considered separately assuming no variance in the other metric. For example, when calculating the impact of UPC variances, no variances in additions were assumed in order to isolate the impact due to the variances in UPC only.

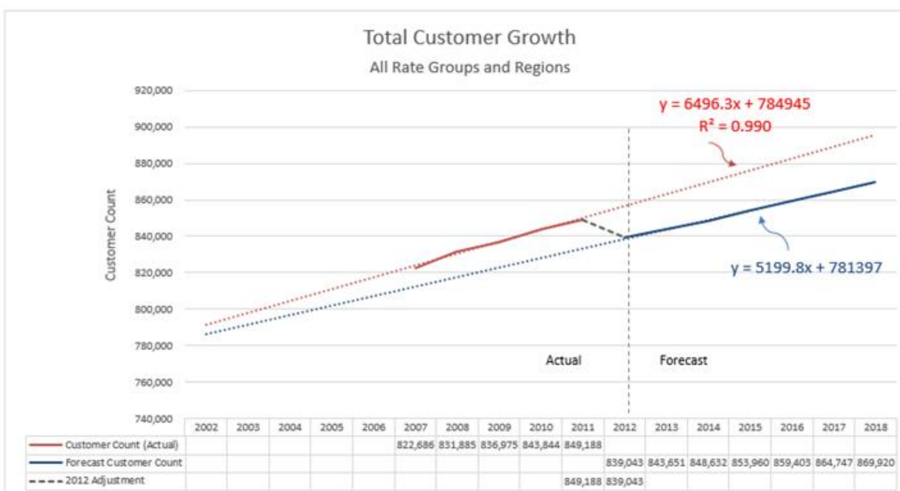
65.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 1.4.4, pp. 102-105

Customer Additions

"The above figure [Figure C1-7] demonstrates the continued strong correlation between housing starts and net residential customer additions. The correlation statistic is over 90 percent. For this reason the CBOC housing starts forecast is an appropriate proxy of the Company's customer additions forecast." (p. 95)

65.1 The following graph compares the trend in the total number of customers for all regions between 2007 to 2011 to the forecasted trend in the number of customers for the current test period. What stands out is that prior to the 2012 CIS adjustment, the trend was essentially perfectly linear (R^2=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. Please confirm whether the trends indicated in the following graph are accurate.



Data source: Exhibit B-4, FEI Data Model

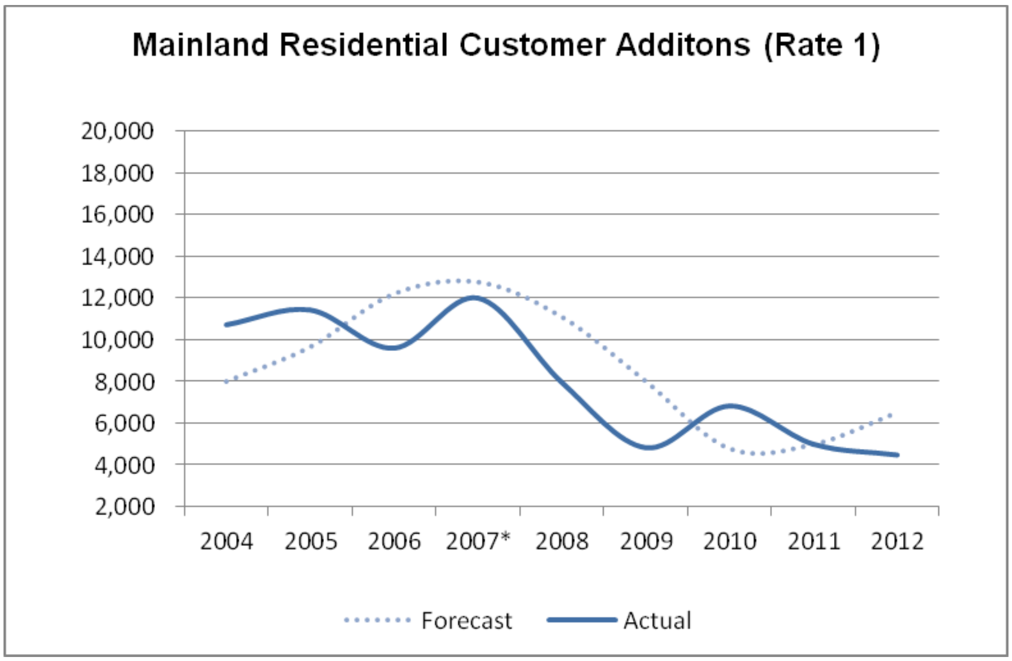
Response:

While the trends depicted in the included figure appear accurate they do not reflect the account additions methodology in use by FEI for the past decade. Our customer forecast methodology continues to be based on forecasting customer additions by rate class, as opposed to trending the total accounts aggregated across all rate classes as suggested by the included figure.

For the residential additions forecast we continue to apply growth rates (by housing type) derived from CBOC forecasts to the actual additions from the previous year. This allows us to use the forward looking CBOC forecast and the actual customer additions we experienced. In a volatile housing market FEI believes this is a more defensible methodology than assuming historical growth rates will continue.

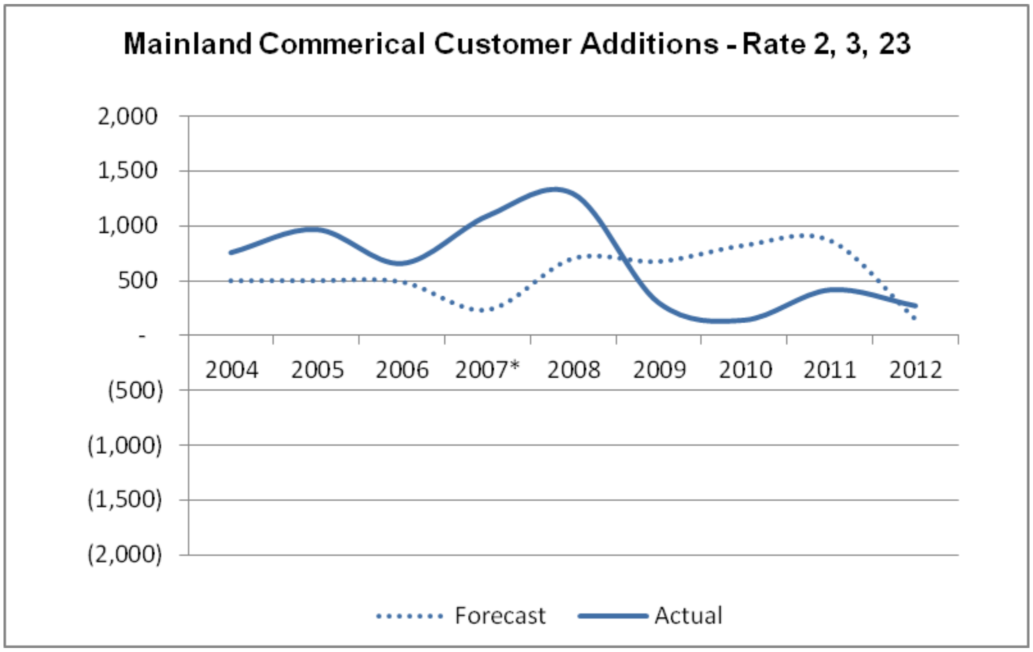
The CBOC prepares a long term forecast annually and FEI will make use of those updates to re-forecast our expected customer additions each year through the term of the PBR.

As seen from the figure below (reproduced from Exhibit B-1-1, Appendix E3 – Live Spreadsheet) the residential customer additions are generally declining.



Assuming a constant number of additions each year as suggested in this IR does not reflect the actual experience of FEI. A constant number of net additions would appear as a horizontal line in the above figure.

Commercial additions are developed using the prior three year average of actual additions. As seen from the following figure (reproduced from Appendix E3 – Live Spreadsheet) commercial additions tend to be more volatile but are generally decreasing.



Again, a constant number of commercial additions would appear as a horizontal line in the preceding figure, and that has not been the experience of FEI.

FEI believes this granular methodology that has been used for the last decade produces a reasonable forecast of customer additions, and does not warrant a change in methodology as suggested in the question.

65.1.1 Over the course of the test period, the difference in trend will result in approximately 19,038 fewer customers than would have otherwise been anticipated. Please discuss and quantify the causal factors responsible for the changes in trend.

Total Customer Growth Forecast: Actual vs. Forecasted

Test Period	FEU Customer Count Forecast	Trend Forecast (F2007-F2011)[1]	Difference
F2014	848,632	850,147	1,515
F2015	853,960	856,644	2,684
F2016	859,403	863,140	3,737
F2017	864,747	869,636	4,889
F2018	869,920	876,133	6,213
Test Period Difference:			19,038

Note 1: previous year plus 6,496 customers.

Response:

The question implies that we forecast our total aggregate (residential + commercial) customers based on a historical trend. The FEU do not develop its account forecast using a trend.

Please refer to the response to BCUC IR 1.65.1. Further, forecast volumes and customer additions will be updated as part of the annual review where the forecasts provided for any years beyond 2014 will be updated and are unlikely to be the same as those provided in this Application. Therefore the assumption made in the question is erroneous.

65.1.1.1 Please provide a financial assessment of the impact that ± 1,000 Residential and ± 1,000 Commercial customers would represent to the F2014 Revenue Requirement.

Response:

FEI assumes that the question is asking the impact of FEI increasing or decreasing its forecast of customer additions on the 2014 revenue requirement and has responded in this manner.

FEI reran the FIS forecast model for the following two scenarios:

1. In the first scenario 1,000 residential customers were added to residential Rate Class 1 for FEI. The model run shows a predicted revenue increase of $1,740,079 which, after deducting the commodity and midstream components, would result in a delivery margin increase of $950,321.
2. In the second scenario 1,000 customer were added to the commercial Rate Class 2. The residential additions were returned to the base scenario (as filed). The model run shows

a predicted revenue increase of $2,947,267 which, after deducting the commodity and midstream components, would result in a delivery margin increase of $1,380,186.

In both cases the use rates as filed were used for the scenarios.

The results are presented in the following table:

Revenue Impact of + 1000 Residential and + 1000 Commercial Customers	
	2014
Rate 1	$1,740,079
Rate 2	$2,947,267
Grand Total	**$4,687,346**

Deducting 1,000 customers from each rate class would have an equal and opposite effect on revenues.

An additional 1,000 customers added to the residential additions forecast would represent a variance of 22% compared to the customer additions forecast submitted in the filing. The average residential customer additions variance since 2004 has been 9%.

A 1,000 customer increase to the commercial additions forecast would represent a variance of 357% compared to the customer additions forecast submitted in the filing. The average commercial customer additions variance since 2004 has been 49%.

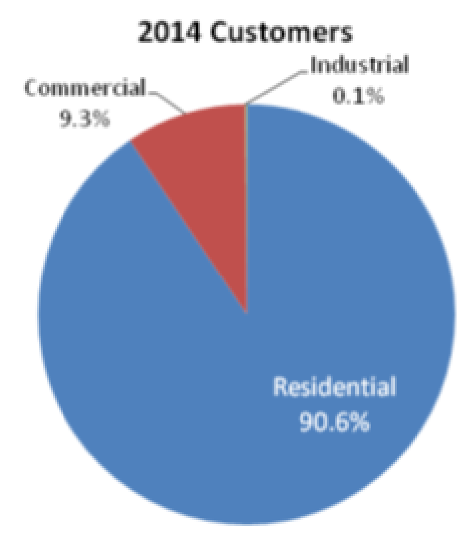
In addition to creating additional revenue, the additional customers would drive incremental costs. Under FEI's PBR proposal, the costs would include incremental O&M of $848 thousand and incremental revenue requirement related to capital estimated at $817 thousand (using an assumed rate base benefit factor of 15% applied to incremental capital under the formula of $430 thousand in sustainment capital and $5.018 million in growth capital).

Based on this, FEI concludes there would be a revenue requirement reduction in the order of $665 thousand related to increasing the customer count forecast as requested. As noted above, it would be unreasonable to increase the forecast by the amounts requested when they are not realistic increases as compared to the forecast that has been submitted.

65.1.1.2 Would it be a reasonable to assume that if the total variance in customer count was 19,038 accounts, 90 percent (17,134) would be residential and approximately 10 percent (1,900) would be Commercial customers?

Response:

As shown in figure C1-3 of the Application, the split between the three rate groups is as follows:



In a random sampling of customers it is reasonable to assume that approximately 91% would be residential and 9% would be commercial.

Please refer to the response to BCUC IR 1 65.1.

65.2 Please confirm whether customer count actuals and forecasts will be evaluated as part of FEI's proposed PBR Annual Reviews.

Response:

As a key cost driver in the PBR formulas, customer count forecasts, projections and actuals will be reviewed as part of the PBR Annual Reviews. Please also refer to the response to BCUC IR 1.56.2.

65.3 Exhibit B-1, Figure C1-16, p. 104 indicates that the number of customer addition for F2012 was 4,475. Does this number include the CIS adjustment described in section 1.3.1, SAP Account Adjustment, p. 91?

Response:

The net additions shown in Figure C1-16 are the true additions to the billing system, irrespective of the new CIS. These are the additions that would have been observed if the billing system had not been changed. These can be referred to as the "true" additions.

The details and three definitions for Rate Schedule 1 are as follows:

- The 2012 **CIS adjustment** for Rate Schedule 1 was -14,916 customers
- FEI added 4,475 **true additions**.
- The year-end **net additions** was then -10,441

The decline in net additions is what causes the UPC to appear to increase in 2012. To be clear, the account adjustment was based on the way FEI counts its customers, not in the way FEI forecasts its additions.

Note that the addition of 4475 customers is specifically an addition of customers that have contracts within the CIS for service with FEI. However, there are a number of factors, additions and subtractions of meters and customers that gives rise to the final number of 4475 true additions. These are explained, below:

- In any given month there are numerous customers who move in or out of a premise and therefore cease being a customer with a contract and then again become a customer with a contract. Variations in this on a month by month basis, and seasonally, can affect true additions.
- In 2012 FEI added 9000+ new meters to the system (note a new meter does not become a new customer and therefore a true addition until they have a contract for service within the CIS). This number is also referred to as gross additions or gross meter additions. Part of the effort of the ES&ER group is to increase the gross customer additions. New meters include new services, multi-meter services, company renewals,

conversion, service alterations, and meter upgrades. The number of gross additions affects the true additions.

- In 2012 6000+ meters were "abandoned" and removed from the system. Meters that are removed were once meters that had customers with contracts. Once removed, a new building and meter (or many meters) may be added at the same site and become part of the gross additions.

65.3.1 Taking into consideration the CIS adjustment, should the number of customer additions actually be -5,841 for 2012? It appears that some forecast data has been normalized to remove the one-time impact of the CIS adjustment, while other data has retained the CIS adjustment. If this is correct, please suggest a nomenclature for distinguishing between the two potentially confusing scenarios.

Response:

Please refer to the response to BCUC IR 1.65.3.

65.4 FEI relies on the number of housing starts as a proxy for the number of Residential customer additions. All proxies have limitations, including the reliance on housing starts to forecast the number of Residential customer additions. For example, when an existing home is demolished and subsequently replaced with a newer home, the activity is logged as a new construction, but a new natural gas account has not been created. Please comment if this interpretation is correct.

Response:

In some cases, the demolition of an existing premise will result in the formation of a new account and in some cases it will not. For example, when there is a new owner or when the re-construction period is lengthy a new account will be created. On the other hand, if the owner remains the same and the reconstruction period is short then a new account will not be created. In other cases, one house may be demolished, resulting in the loss of an account, and a multi-family condo constructed resulting in 10 new accounts. This scenario, if it occurred in the same year, would result in nine (9) true additions to the billing system.

FEI tracks all of these scenarios and reports the true additions made to the billing system.

The forecasting group uses the true additions to the billing system to forecast net additions in the future. The single and multi-family growth rates are developed from the CBOC housing starts forecast. These growth rates are then applied to the true additions to determine the net additions forecast.

For example in 2012, and irrespective of any changes to the billing system, we added 4,475 true additions. These true additions were then used with the CBOC growth rates to develop the net additions forecast.

65.4.1 Population is a main driver to housing starts. As such, does FEI believe that a more direct and accurate proxy for the number of Residential accounts may be population rather than housing starts?

Response:

No.

The FEU's established methodology for forecasting residential customer additions based on housing starts shows a high (90%) statistical correlation with customer additions.

The housing starts data from CBOC allows us to forecast the additions by different housing type. The ability to forecast based on housing type is critical as our capture rates vary significantly depending on whether the customer's house is a single family dwelling or multi family dwelling. Population data will not provide the same level of granularity.

The current methodology has been in use for a decade, supports the BCUC directive to forecast by housing type and is captured in the FIS computer model. A change in methodology without evidence of a material improvement in the forecast results, coupled with the loss of granularity provided by the housing type forecast, is not contemplated or warranted at this time.

65.4.1.1 For reference purposes only, the following table was used to assess the correlation between population and the number of FEI accounts. It suggests that there is a very strong correlation (0.93). Please discuss.

Population vs. Number of FEI Residential Accounts

Year	Population Lower Mainland[1]	Residential - Number of Accounts[2]
2006	2,530,438	508,748
2007	2,574,096	516,801
2008	2,616,378	521,437
2009	2,669,804	524,620
2010	2,728,891	529,194
2011	2,765,386	532,550
2012	2,805,577	528,192

1: BC Stats website, BC Development Region, Regional District and Muncipal Population Estimates 2006-2012

2: Data source from Exhibit B-4

Response:

Please refer to the response to BCUC IR 1 65.4.1.

66.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 1.4.4, p. 105

Commercial Rate Class Customer Count

66.1 Figure C1-17 indicates that the number of customer addition for F2012 was 272. Does this number include the CIS adjustment described in section 1.3.1, SAP Account Adjustment, p. 91?

Response:

The net additions shown in Figure C1-17 are the true additions to the billing system, irrespective of the new CIS. These are the additions we would have observed whether or not the billing system had been changed.

66.1.1 Taking into consideration the CIS adjustment, should the number of Commercial customer additions for 2012 actually be -4,303?

Response:

The net additions shown in Figure C1-17 are the true additions to the billing system, irrespective of the new CIS. These are the additions we would have observed if the billing system had not been changed.

FEI confirms the net change to the commercial accounts as a result of both the CIS change and the addition of new customer was -4,303. This value is not useful for developing future forecasts because it was a one-time adjustment and therefore only the true additions are shown in Figure C1-17.

66.2 FEI states that, "Consistent with prior forecasts, the forecast of Commercial customer additions is based upon an analysis of recent trends in the Commercial rate class."[12] Please clarify what time period constitutes "recent" and what forecasting method is used to determine the trend. For example,

[12] Exhibit B-1, Section C, p. 95, lines 11-13.

does "recent" mean the past 4 years, and is the trend determined by an ordinary least squares?

Response:

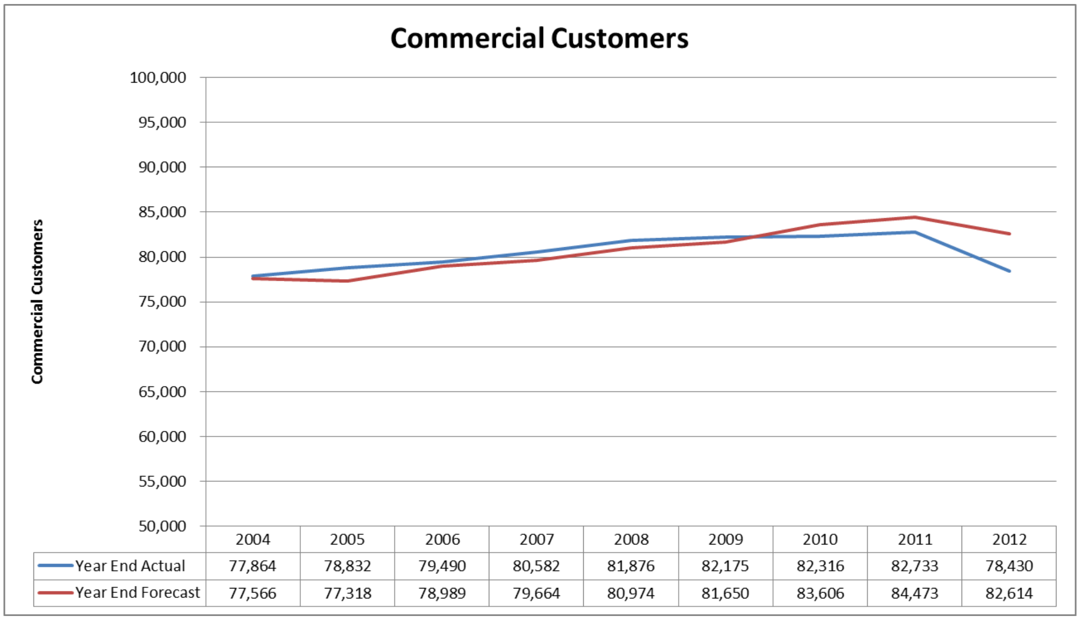
The methodology to forecast commercial additions uses a simple averaging of the actual additions recorded in the last three years, taking advantage of any recent trends that might have happened. We are not able to test the statistical significance because this is a simple average. In absence of a statistical model the trend is not determined by an ordinary least squares.

66.3 Please provide a graphical and tabular summary of the variance between the actual number of Commercial customers and RRA forecasted number of customers from 2004 to 2013. Please include the percentage variance.

Response:

Please refer to the table and graph below for the variance between the actual and forecast number of Commercial customers. Variance is expressed as a percentage of the actual year end customers aggregated over the commercial rate schedule customers.

COMMERCIAL (RATE 2, 3 and 23)			
Customers			
Year	Actual	Forecast	Variance as % of YE Actual
2004	77,864	77,566	-0.4%
2005	78,832	77,318	-1.9%
2006	79,490	78,989	-0.6%
2007	80,582	79,664	-1.1%
2008	81,876	80,974	-1.1%
2009	82,175	81,650	-0.6%
2010	82,316	83,606	1.6%
2011	82,733	84,473	2.1%
2012	78,430	82,614	5.3%



66.3.1 Is the forecast variance for the number of customers more volatile than the forecast variance of UPC? Please quantify.

Response:

Please refer to the response to BCUC 1.61.3.

Historically customer additions are known to be more volatile as actual additions are a function of many factors such as market capture rate, housing starts and the state of the economy. Although UPC for a given year may be affected by changes in customer behavior such as retrofit activities, it is a number averaged over a large group of customers and thus, is more stable year over year when compared to additions.

67.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 1.4.5, p. 109

Industrial Rate Class – Energy Demand Forecast

67.1 FEI conducts annual Industrial customer surveys to determine Industrial energy demand for the subsequent year.[13] Given that the current test period is 5 years in duration, it is assumed that FEI relied upon another forecast technique other than customer surveys to develop the forecast for years 2015 to 2018. Please confirm whether this assumption is correct.

Response:

This assumption is not correct. While the survey asks customers to forecast volumes out for five years, the Company in the short term is only concerned with the 2014 year for the purpose of the revenue requirement for that year. The industrial survey will be sent out to customers each year during the PBR period to determine industrial volumes for the following year. A further explanation is below:

FEI conducts an annual survey of our industrial customers each year.

The survey was moved to a web based interface this year but the survey form itself has not changed for a decade.

Each year the industrial customers are asked for:

1. Monthly consumption for the following year. In the case of the survey used for the Application, customers were asked for monthly consumption for 2013.
2. Annual consumption for the next 4 years. In the case of the survey used for the current Application, customers were asked for annual forecast values for 2014-2017.
3. For the 2018 forecasts included in this Application, the 2018 volume was assumed to be the same as the 2017 volume.
4. The survey is completed each year and updated survey data will be included in each of the forecast updates provided throughout the PBR test period.
5. Altogether the industrial survey requests a five year forecast from each customer.

A screen shot from the live survey web site is shown below:

[13] Exhibit B-1, Section C, p. 85, lines 28-29.

Historic Consumption Data

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2008	171,459	106,447	156,592	125,604	125,600	121,679	101,959	102,422	117,568	177,256	156,699	140,742	1,604,027
2009	191,218	180,375	166,564	154,336	148,937	119,865	58,791	133,536	151,760	161,205	141,861	195,482	1,803,930
2010	168,561	143,252	138,520	178,180	148,644	147,337	147,538	140,984	143,676	155,687	167,760	193,319	1,873,458
2011	231,424	218,824	207,490	157,756	152,493	137,034	154,542	148,052	132,217	159,111	177,235	216,559	2,092,737
2012	327,510	282,234	265,690	222,413	266,883	184,372	160,481	220,658	182,812	0	0	0	2,113,053

Projected Monthly Consumption Data (Please enter estimated monthly GJ's below)

Same as Last Year

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2013													0

Projected Annual Consumption Data (Please enter estimated annual GJ's below)

2014	2015	2016	2017

Submit Survey

Note that in this case the survey was fielded in October so consumption data for Oct-Dec 2012 is shown as "0".

67.1.1 Subject to FEI's reply to the above question, please provide details of the assumptions and technique used to forecast Industrial energy demand for years 2015 to 2018. Please also provide an electronic spreadsheet containing the forecast calculation.

Response:

Please refer to the response to BCUC IR 1.67.1.

67.2 Variances in Industrial demand are not captured by RSAM, and therefore represent a potential financial risk to rate payers. Over time the sum of over and under forecast variances should cancel each other out to produce a net variance of zero. In other words, despite some short-term volatility, in the long-run rate payers, as well as FEI, should not be financially disadvantaged by Industrial forecast variances. Please confirm or deny.

Response:

Confirmed that this is the expectation. As illustrated in Exhibit B-1-1, Appendix E3 Forecasting Models Live Spreadsheets, forecast variances are randomly distributed over the years showing positive variances in some years and negative variances in other years. This demonstrates that there is no obvious bias in the forecast.

Generally, once rates have been approved any variance in the actual versus approved forecast for industrial volumes will have no impact on other ratepayers. However, in the PBR period to the extent industrial revenue margin varies from the forecast the ESM mechanism will capture 50% of the variance to be returned to or recovered from customers. Over the long term the over/under variances should cancel each other out.

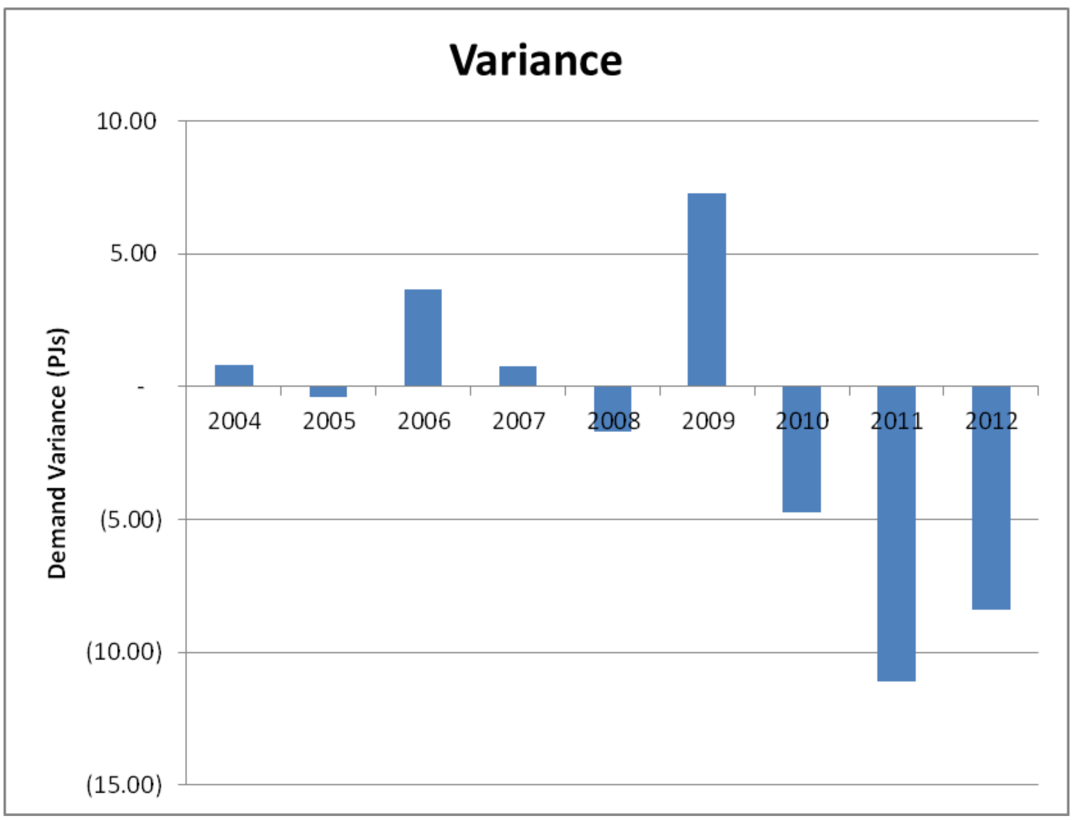
Industrial demand is not captured by the RSAM. Applying RSAM to interruptible service industrial customers would be problematic for two reasons. First, there is no methodology to adjust the RSAM for when interruptible customers are curtailed. Secondly, the RSAM methodology firms the revenue, i.e. it decouples utility revenue from the volume of gas delivered. Interruptible industrial customers, Rate Schedules 7, 27, and 22 (for those customers with zero DTQ) receive non-firm service and only pay for the volumes delivered, i.e. non-firm or non-fixed revenue for non-firm service. By having a RSAM, a fixed revenue stream is imposed on these customers for the interruptible service they receive.

For the other firm industrial customers the majority of the revenues are fixed via the monthly Demand Charge and Basic Charge so that variances in volume delivered will have no impact on the fixed or firm revenues. Please also refer to the responses to BCUC IR 1.57.2, 1.212.1 and 1.212.1.1.

The following table extends the Industrial Total Deliveries table found in the Appendix E3 Forecasting Models Live Spreadsheets to show the variance (PJs).

Industrial (Rate 4, 5, 6, 7, 22, 25, 27)
Total Deliveries (PJs)

Year	Actual	Forecast	Variance
2004	63.6	64.4	0.80
2005	63.3	62.9	(0.40)
2006	58.3	62.0	3.68
2007	60.0	60.8	0.79
2008	55.3	53.6	(1.69)
2009	48.4	55.7	7.28
2010	51.5	46.8	(4.74)
2011	57.7	46.6	(11.10)
2012	59.9	51.5	(8.40)
		504.3	**(13.78)**
		Variance	**-2.7%**



The aggregate variance since 2004 is -13.8 PJs. The total delivery since 2004 is 504.3 PJs. The variance as a percent is -2.7% over 9 years.

The Company understands from customers that the variance has increased recently due to in part to industrials customers' response to falling gas prices as compared to other sources of energy. In this situation it is not unreasonable for customers to consume more than forecast. There are many other factors involved that affect each industry and customer differently. It is mainly for these reasons that FEI has chosen to survey each customer individually.

67.2.1 Please provide graphical and tabular data with historical data of not less than 10 years to illustrate whether Industrial forecasts have a bias. Please assess whether there is a forecast bias.

Response:

Please refer to the response to BCUC IR 1.67.2

67.3 Please provide a graphical and tabular summary that compares Industrial energy demand forecasted from FEI's Annual Customer Surveys compared to actual energy demand. Please include not few than 10 years of historical data.

Response:

Please refer to Exhibit B-1-1, Appendix E3 – Live Forecasting Models.

67.4 Do historical data for Industrial energy demand over the past five years support the assumption that there will be no increase in Industrial energy demand for the test period? Please explain why, or why not.

Response:

FEI gathers the surveys and amalgamates them to develop the forecast for industrial demand. There is far too much diversity in the industrial classes for FEI to forecast any more accurately than our customers are able to. The methodology in this area remains unchanged for over a decade. FEI continues to assume that our customers are better able to forecast their future demand than FEI is.

In its Decision on the FEU's 2012-2013 RRA, the Commission has accepted the FEU's methodology of determining industrial consumption as reasonable and approved it for use in determining the 2012 and 2013 RRA forecasts. There has been no change that would warrant a different approach at this time.

In 2012 FEI used an enhanced forecasting tool in the form of a modern and secure web site. The web site provided each industrial customer with 10 years of historical consumption data (if available). The web site also displayed a graph of their most recent survey (if completed) compared to the actuals for 2012. The forecast to actuals graph was a new feature and designed to help each customer develop a more accurate forecast.

The actual aggregate consumption for the industrial classes declined sharply in 2009 but then rebounded to 59.9 PJs in 2012. FEI's industrial customers believe that the aggregate volume will decline slightly before flattening.

The Industrial Survey will be sent out each year of the test period. The survey system is expected to remain the same and will continue to ask each customer for their 5 year forecast of gas consumption. The questions and information required by the survey are unchanged for the past 10 years.

In 2012 customers representing over 88% of the industrial volume replied to the survey.

68.0 Reference: MULTI-YEAR PERFORMANCE BASED RATE-MAKING MECHANISM

Exhibit B-1, Application, Tab A, Section 1, p. 3

Development of Base 2013 O&M – Trend from Prior Periods

"FEI has provided forecasts of demand, revenue, O&M, and capital for the full 2014-2018 term (the PBR Period) in Section C of the Application. The 2014 through 2018 forecasts are included for reference purposes and represent a high level forecast of future trends and upcoming challenges for FEI. As FEI's proposed rates are based on the PBR Plan, FEI's cost of service forecasts should not be the focus of this proceeding. FEI has also provided an historical review of O&M expenditures since 2010. This historical review demonstrates that FEI has implemented a renewed focus on productivity which has resulted in efficiencies and sustainable savings. These sustainable savings have been incorporated into the 2013 Base O&M to which the O&M formula in the PBR Plan will be applied." [Section A, p. 3, lines 23-31]

Response:

Since no question was posed, Commission Staff later advised that the above was intended to be the preamble to IR 1.52.3, and has been replicated there to assist readers.

69.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Tab C, Application, Section 1.4.7.1, p. 111; Greenhouse Gas Reduction (Clean Energy) Regulation, B.C. Reg. 102/2012 (GGRR); Order G-88-13

RATE 16 REVENUES

"[40]Implications to Rate Schedule 16 Revenues pursuant to Order G-88-13 received on June 4, 2013 will be addressed through an evidentiary update to this application once the decision has been fully evaluated."

69.1 Have any customers that were awarded incentives for LNG vehicles under GGRR the returned their incentives as a result of Order G-88-13? If yes, please provide the name(s) of the customer(s).

__Response:__

Under the incentive process, customers can only receive an incentive after they have signed the contribution agreement and provided evidence of a contractual commitment to purchase vehicles. FEI also notes that the only customer to have received an incentive related to service under Rate Schedule 16 prior to BCUC Order G-88-13 was Vedder Transport Inc. As such, customers would not be expected to have returned their incentives due to BCUC Order G-88-13.

However, as expected, FEI has experienced a delayed response to the purchase of vehicles as well as a cancellation of participation as a result of Order G-88-13.

FEI, by way of letter, awarded "preliminary" vehicle incentives to six LNG fleet operators and one marine vessel from the 2012 incentive call. Of the total number of LNG customers that applied for incentives, only 3 have progressed to signing Contribution Agreements and, of those three, only two customers have completed the incentive process by submitting the purchase order. FEI has paid out the incentive amount to these two customers. The other successful LNG applicants are still in discussions with FEI and have not provided any confirmations to move forward with their purchases at this time.

FEI provided an Evidentiary Update to the Commission on July 16, 2013 that provided an updated forecast in Exhibit-B-1-3, Tables H-3 and H-4. The tables illustrate the revised vehicle additions and load forecast pursuant to BCUC Order G-88-13 and other NGT related updates. In summary, FEI expects the market uptake for the LNG class 8 tractors to decrease by 48% from 460 to 241 vehicles and the load growth to decrease by 44% from the initial 2,235,744 GJ to 1,247,000 GJ during the forecast period.

As stated on page 10, line 14 of FEI's Evidentiary Update, it is likely that market confidence has been negatively impacted and as a result fewer potential LNG Class 8 truck customers will pursue LNG as a viable fuel for transportation.

69.2 Have any customers that were awarded incentives for LNG vehicles under GGRR indicated that they will reduce number of vehicles and LNG purchases as a result of Order G-88-13? If yes, please provide the reduction in number of vehicles and the volume of LNG.

Response:

Refer to the response to BCUC IR 1.69.1 regarding the incentive process. As stated in response to BCUC IR 1.69.1, FEI has experienced customers reducing their intended number of vehicles that they will purchase as a result of Order G-88-13.

Specifically, the following companies have reduced their commitment to purchase natural gas vehicles at this point in time.

- Ledcor – reduced from 60 vehicles to 15 vehicles
- Sutco - reduced from 8 vehicles to 6 vehicles
- Denwill - reduced from 12 vehicles to 10 vehicles

Applicants who had been conditionally awarded incentives but have not expressed their interest to proceed with the actual vehicle purchase and consequently have received no incentive at this time are Arrow Transportation (30 vehicles), Bison Transport (20 vehicles) and Westcan Bulk (12 vehicles).

The reduction in LNG vehicles from these companies translates into a reduction in consumption of approximately 547,000 GJ per year.

FORECASTS FOR THE PBR PERIOD – OTHER REVENUE

70.0 Reference: OTHER REVENUE

Exhibit B-1, Application, Tab C, Section 2, Table C2-1, p. 117; Tab E, Schedule 12, Line 3

Late Payment Charge

70.1 Please explain how the projected 2013 Late Payment Charge of $2,134 thousand was calculated. Please include a discussion of any assumptions that FEI made in determining this projection.

<u>Response:</u>

Please note that in the PBR Evidentiary Update filed on July 16, 2013 the 2013 Late Payment Charge projection was updated to $2,109 thousand.

The projected Late Payment Charge revenue is calculated as a percentage of total projected delivery margin revenue for Rate Schedule 1, 2 and 3 customers. Each month, a late payment charge factor is applied to the monthly delivery revenue for these three rate classes. In 2014, total delivery margin revenue for Rate Schedule 1, 2 and 3 customers is forecast to be lower than in 2013, therefore forecast Late Payment Charge revenue in 2014 will also decrease.

The following tables summarize the calculation of Late Payment Charges:

(Revenue * LPC Factor = LPC Revenue)

2013 Late Payment Charge Revenue Calculation ($ thousands)

	Rate 1, 2 & 3 Revenue			LPC Factor			LPC Revenue			
	Mainland	Inland	Columbia	Mainland	Inland	Columbia	Mainland	Inland	Columbia	Total
January	103,295	36,865	3,519	0.001567	0.001860	0.002009	162	69	7	238
February	89,943	29,732	3,012	0.001963	0.002535	0.002792	177	75	8	260
March	88,501	25,918	2,696	0.002161	0.003109	0.002926	191	81	8	280
April	62,694	16,683	1,890	0.002143	0.003556	0.002340	134	59	4	198
May	44,695	11,670	1,322	0.003322	0.004608	0.005969	148	54	8	210
June	34,413	9,090	1,050	0.003941	0.006210	0.006025	136	56	6	198
July	29,538	8,609	809	0.003539	0.004836	0.005847	105	42	5	151
August	26,527	7,563	766	0.003282	0.004848	0.005764	87	37	4	128
September	33,191	10,149	1,030	0.002371	0.003025	0.003653	79	31	4	113
October	55,173	17,863	1,860	0.001104	0.001473	0.001332	61	26	2	90
November	78,437	25,411	2,599	0.000905	0.001106	0.001119	71	28	3	102
December	98,216	32,844	3,293	0.001064	0.001196	0.001326	105	39	4	148
Total	744,620	232,396	23,845				1,455	597	65	2,116
									Rounding	-7
									Total Forecast Late Payment Charge Revenue	$ 2,109

2014 Late Payment Charge Revenue Calculation ($ thousands)

	Rate 1, 2 & 3 Revenue			LPC Factor			LPC Revenue			
	Mainland	Inland	Columbia	Mainland	Inland	Columbia	Mainland	Inland	Columbia	Total
January	102,115	36,620	3,436	0.001567	0.001860	0.002009	160	68	7	235
February	88,873	29,526	2,940	0.001963	0.002535	0.002792	174	75	8	258
March	87,440	25,743	2,632	0.002161	0.003109	0.002926	189	80	8	277
April	61,993	16,570	1,847	0.002143	0.003556	0.002340	133	59	4	196
May	44,232	11,623	1,294	0.003322	0.004608	0.005969	147	54	8	208
June	34,045	9,060	1,031	0.003941	0.006210	0.006025	134	56	6	197
July	29,292	8,581	795	0.003539	0.004836	0.005847	104	41	5	150
August	26,283	7,547	755	0.003282	0.004848	0.005764	86	37	4	127
September	32,870	10,107	1,012	0.002371	0.003025	0.003653	78	31	4	112
October	54,625	17,766	1,822	0.001104	0.001473	0.001332	60	26	2	89
November	77,634	25,270	2,543	0.000905	0.001106	0.001119	70	28	3	101
December	97,220	32,731	3,222	0.001064	0.001196	0.001326	103	39	4	147
Total	736,620	231,143	23,328				1,439	594	63	2,096
									Rounding	-7
							Total Forecast Late Payment Charge Revenue			$ 2,089

Under the 2012-2013 FortisBC Energy Utilities RRA Decision (2012-2013 FEU Decision), FEU was approved for 2012 and 2013 Late Payment Charge amounts of $2,333 thousand each year.

70.2 Please explain why, given that Actual 2012 Late Payment Charges were $69 thousand higher than the 2012 approved amount, FEI is forecasting that revenue from these charges will decrease by $199 thousand for 2013 and $219 thousand for 2014?

Response:

Please refer to the response to BCUC IR 1.70.1.

71.0 Reference: OTHER REVENUE

Exhibit B-1, Application, Tab C, Section 2, Table C2-1, p. 117; Tab E, Schedule 12, Line 5

Connection Charges

The 2012 Approved amount for Connections Charges was $2,662 thousand; whereas, the 2012 Actual amount of revenue from Connections Charges was only $2,390 thousand, which is a difference of $272 thousand.

71.1 Given the 2012 actual results, please explain why FEI's 2014 Forecast revenue from Connection Charges of $2,636 thousand is reasonable and not over-forecast?

Response:

The Connection Charge revenue is calculated based on three factors; a $25 connection fee, the historical move ratio and the projected or forecast number of average customers.

The $25 connection fee and the historical move ratio remain unchanged between the 2012 Approved and 2012 Actual figures. However, in 2012 there was a large decrease from the forecast number of average customers, resulting in the decrease of Connection Charge revenue from $2,662 thousand to $2,390 thousand.

In 2013 and 2014, the forecast number of average customers is forecast to increase, therefore the forecast for Connection Charge revenue is also anticipated to increase. This methodology of calculating Connection Charge revenue has been consistently applied in previous years, and is therefore considered to be reasonable.

The following table summarizes how FEI has calculated the 2013/2014 Projected/Forecast amounts in Connection Charge revenue (revenue shown is in $ thousands):

(Connection Charge * (Average Customers/1000) * Move Ratio = Connection Charge Revenue)

	2013	2014
Connection Charge	$ 25	$ 25
Average Customers		
Lower Mainland	585,099	587,634
Inland	233,127	235,218
Columbia	22,544	22,660
Move Ratio		
Lower Mainland	12.5%	12.5%
Inland	12.5%	12.5%
Columbia	11.5%	11.5%
CC Revenue		
Lower Mainland	1,828	1,836
Inland	729	735
Columbia	65	65
Total	$ 2,622	$ 2,636

71.2 Please explain how FEI has calculated the 2013 projected amount of $2,622 thousand. Please also describe the assumptions that FEI made in determining this projection.

Response:

Please refer to the response to BCUC IR 1.71.1.

72.0 Reference: OTHER REVENUE

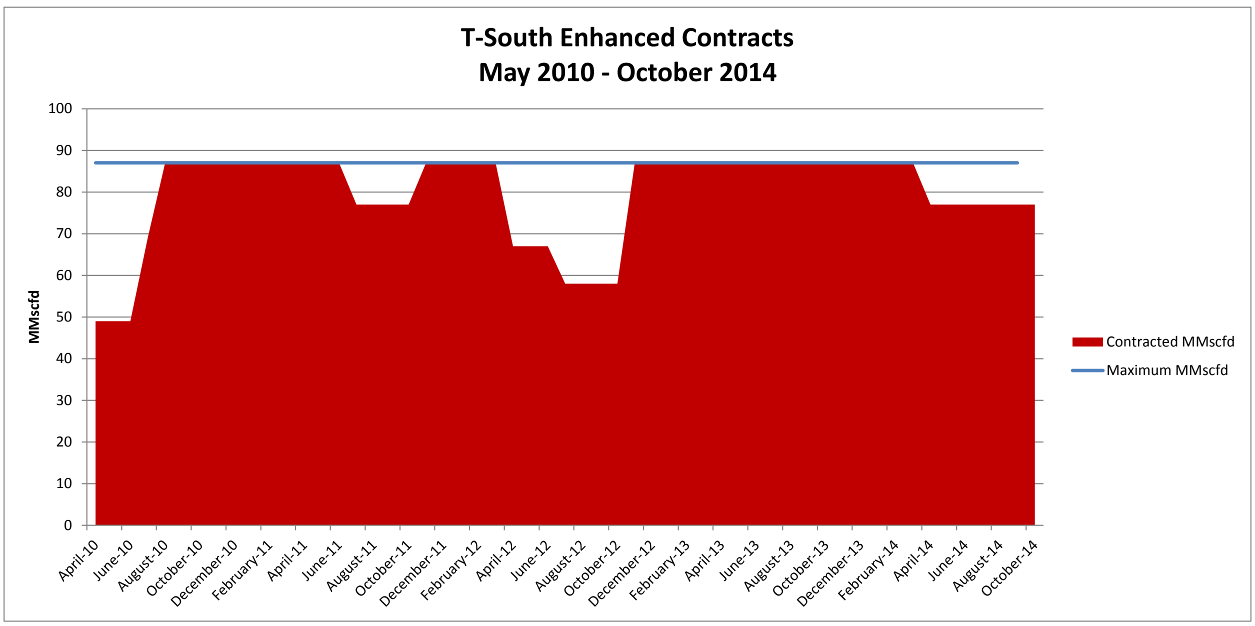
Exhibit B-1, Application, Tab C, Section 2.3, pp. 119-120

Net Mitigation Revenue (T-South Enhanced Service)

72.1 Please indicate whether or not the T-South Enhanced Service offering is fully contracted.

<u>Response:</u>

The T-South Enhanced Service has been fully contracted at 87 MMscfd since November 2012, and it remains fully contracted until March 31, 2014, at which time one 10 MMscfd contract expires. The remaining 77 MMscfd of T-South Enhanced contracts expire October 31, 2014. The figure below illustrates the historical and current contracting levels of the T-South Enhanced Service from initial offering in May 2010, through to the end date of October 2014.



FEI has received Commission approval to further extend the Transportation Service Agreement between FEI and Spectra to continue to support T-South Enhanced Service for a two year period from November 1, 2014 to October 31, 2016 and to increase the maximum volume available to 91 MMscfd, an increase from the original 87 MMscfd. The actual contracted volume and the revenues FEI will receive during this extension term will depend on the level of T-South Enhanced Service that is contracted by Spectra shippers.

72.1.1 If the Service is fully contracted, please indicate when these contracts are due to expire.

Response:

Please refer to the response to BCUC IR 1.72.1.

72.1.2 If the Service is not fully contracted, please indicate to what extent it is contracted.

Response:

Please refer to the response to BCUC IR 1.72.1.

73.0 Reference: OTHER REVENUE

Exhibit B-1, Application, Tab C, Section 2.3, p. 120; Commission Order G-104-13 dated July 4, 2013

NET MITIGATION REVENUE (T-SOUTH ENHANCED SERVICE)

On page 120 of the Application, FEI states: "The initial term of the T-South Enhanced Service was May 1, 2010 to April 30, 2012. As a result of the success of this service, Spectra Energy and the Company executed an extension of the Service to October 31, 2014 which was approved by the Commission in Order G-69-11 dated April 14, 2011. FEI anticipates the service will be extended beyond the current expiry date."

In Commission Order G-104-13 dated July 4, 2013, the Commission approved an extension of the term of the Firm Transportation Service Agreement between FEI and Westcoast Energy Inc. to October 31, 2016 and an increase in the maximum volume from 2464.5 10^3m^3 (87 MMscfd) to 2577.8 10^3m^3 (91 MMscfd).

73.1 To what extent does the amendment to the maximum volume in the Firm Transportation Service Agreement impact FEI's forecast of $5.7 million per year of revenue from T-South Enhanced Service?

Response:

If the agreement is extended, the incremental 4 MMscfd (91 MMscfd - 87MMscfd) has the potential to increase revenue by $0.26 million per year assuming the full 91 MMscfd is fully contracted. As the incremental volume is offered effective November 1, 2014, the impact to the overall potential revenue for 2014 is approximately $0.044 million (2 months of this incremental revenue). The revenues are a forecast and all variances are captured in the SCP Mitigation Revenues deferral account and amortized as part of future rates.

73.1.1 Please provide an updated estimate of the T-South revenue reflecting the amendment approved in Commission Order G-104-13.

Response:

Please refer to the response to BCUC IR 1.73.1.

73.2 If the terms of the Firm Transportation Service Agreement between FEI and Westcoast Energy Inc. are amended for the period from October 31, 2016 to December 31, 2018 such that the revenue is impacted, please describe how any resulting changes to the forecast revenue would be accounted for under the proposed PBR.

Response:

FEI has forecast the SCP revenue, along with the other components of Other Revenue in Section 2 of the Application, for 2014. The forecasts for each component of Other Revenue, including SCP revenue, for the years 2015-2018 will be updated as part of the Annual Review process and any changes to the Firm Transportation Service Agreement between FEI and Westcoast Energy Inc., after expiration of the extension which ends October 31, 2016, will be dealt with at that time.

FORECASTS FOR THE PBR PERIOD - LABOUR

74.0 Reference: LABOUR

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

FTEs

74.1 Please provide a breakdown of the FTEs by year and affiliation (Executive, COPE, IBEW, M&E) for 2007-2012. Include the requested information in the form of a fully functioning electronic spreadsheet.

<u>Response:</u>

Please refer to Attachment 74.1 for the fully functioning electronic spreadsheet. The FTE numbers provided reflect only those employees who are employed directly by FEI and does not include any employees who cross-charge from FBC or FHI.

75.0 Reference: LABOUR

Exhibit B-1-1, Appendix F6, p. 1; 2012-2013 FEU RRA, BCUC 1.63.1

LABOUR COST

[Communications and public affairs plan] "Funding was made possible by savings associated with headcount vacancies across the organization and lower than forecast bad debt amounts." (2012-2013 FEU RRA, BCUC 1.63.1)

75.1 In electronic format, please provide an organizational chart as of June 30, 2013 showing all FEI employees and their job titles.

Response:

Please refer to Attachment 75.1 for FEI's organizational chart as of June 30, 2013 showing all FEI employees by job titles.

The attachment includes some non-FEI employees as a reference only, as many of the business areas of the gas and electric utilities are now integrated. Non-FEI employees are highlighted for clarity.

FEI's organizational chart is a picture in time of all of its employees and positions held. It is not possible to compare this to any information that references FTEs, since FTEs are calculated by converting all hours worked to a full-time equivalent.

75.2 For 2007 to 2014 by year, please provide the following:

- Total salaries, wages and benefits for the Executive group before bonuses or other incentive provisions. Also provide the Executive salaries, wages and benefits group before bonuses or other incentive provisions recovered from ratepayers;
- Bonuses and other extraordinary incentive provisions for the Executive group and the amount of bonuses and other extraordinary incentive provisions recovered from ratepayers;
- The number of executives for each year;

- Total salaries, wages and benefits for all non-Executive employees by affiliation (COPE, IBEW, M&E) and the amount of salaries, wages and benefits recovered from ratepayers;
- Bonuses and other extraordinary incentive provisions for all non-Executive employees by affiliation (M&E, COPE, IBEW) and the amount of bonuses and other extraordinary incentive provisions recovered from ratepayers;
- The number of FTEs by affiliation (Executive, M&E, COPE, IBEW) with annual salaries greater than or equal to $100,000;
- Please provide the average headcount vacancies and associated cost saving.
- Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

The following information for the FEI Executive group for the years 2007 to 2014 is included in the fully functioning electronic spreadsheet in Attachment 75.2a:

- Total salaries, wages and benefits before bonuses or other incentive provisions.
- Bonuses and other extraordinary incentive provisions.
- The number of executives for each year.

Of the items listed, the employee share purchase plan and stock based compensation are not recoverable from ratepayers. However, the question asked about the amounts that were recovered. The amount of Executive compensation that was recovered would not equal the amounts incurred that have been included in the Attachment 75.2a. During the years 2007 through 2009, formula-driven O&M amounts were included in the rates, using 2003 O&M as the base. Therefore, a conclusion cannot be reached about the amounts that were recovered. Finally, even for 2010 through 2012 actual, the amounts shown may not equal the specific amounts recovered in rates as rates would reflect forecast O&M expense.

The following information for the non-executive FEI employees for the years 2007 to 2014 is included in in the fully functioning electronic spreadsheet in Attachment 75.2b:

- Total salaries, wages and benefits for all non-Executive employees by affiliation (COPE, IBEW, M&E) (for 2007 to 2012, per explanation below).

- Bonuses and other extraordinary incentive provisions for all non-Executive employees by affiliation (M&E, COPE, IBEW) (for 2007 to 2012 (2013 payments reflect 2012 performance), per explanation below).
- Number of FTEs by affiliation (Executive, M&E, COPE, IBEW) with annual salaries greater than or equal to $100,000.

It can be assumed that salaries, wages and benefits for 2013 and 2014 are anticipated to be the same as for 2012, adjusted for inflation according to labour inflation tables provided in the Application (Section C3.3.3.4.1 Labour Inflation).

Of the items listed, the amount of the employee share purchase plan is not recoverable from ratepayers. The same discussion regarding the amounts actually recovered that has been included for executives applies equally here.

Information regarding average headcount vacancies and associated cost savings has not been included, because FEI does not track vacancies at the level of detail to be able to provide a cost savings. In addition, the timing of the savings and the regulatory mechanism in place at the time would affect how these costs would be recovered from customers. Therefore, the information is not relevant to this Application.

76.0 Reference: LABOUR

Exhibit B-1-1, Application, Tab C, Section 3.3.3, p. 125

BENEFITS – CONTRIBUTORY/NON CONTRIBUTORY

76.1 For employees by affiliation (Executive, M&E, COPE and IBEW) please identify which of the following items are contributory or non-contributory:

- Pensions
- Benefits
- Other Post-Employment OPEB

Response:

FEI defines contributory to mean that employees contribute to the cost of the benefit; non-contributory means that FEI pays the cost of the benefit

Note that COPE Customer Service is included as a separate affiliation, as it is covered by its own Collective Agreement with a different benefits structure than COPE.

Pensions for all affiliations are contributory.

Benefits for full-time regular employees of COPE Customer Service are non-contributory. Benefits for all other affiliations are contributory. (Executives, M&E, COPE and IBEW participate in a flexible benefits program where a non-contributory level of core benefits is funded for full-time regular employees. Benefits are contributory for part-time regular employees, and for employees who select a level of benefit higher than the core level of benefit provided.)

COPE Customer Service employees are not eligible for OPEB. OPEB for all other employee groups is contributory and subject to an annual deductible.

The information for pension and OPEB represents the plans for current employees; historically this has been different with some benefits being paid solely by FEI.

76.2 For 2007-2014 please provide breakdown of the total Pension, Benefit and OPEB cost by affiliation (Executive, M&E, COPE and IBEW), and by company and employee contributions.

Response:

The total benefit costs by affiliation and by company and employee contributions are set out in Table 1 below. For benefits, only actual costs are available at this level of detail. The table below reflects those employees who are employed by FEI.

All tables below are in $ thousands.

Table 1: Total Benefit Costs for FEI by Affiliation Including Company and Employee Contributions

	2007	2008	2009	2010	2011	2012	2013 (YTD)
Executive - Employer Contributions	$ 135	$ 157	$ 156	$ 154	$ 130	$ 46	$ 29
Executive - Employee Contributions	$ 23	$ 26	$ 23	$ 28	$ 17	$ 15	$ 2
Executive - Total Cost	$ 158	$ 183	$ 179	$ 182	$ 147	$ 61	$ 31
M&E- Employer Contributions	$ 2,246	$ 2,512	$ 2,883	$ 3,455	$ 4,160	$ 3,615	$ 1,524
M&E - Employee Contributions	$ 178	$ 211	$ 215	$ 225	$ 257	$ 219	$ 12
M&E - Total Cost	$ 2,424	$ 2,723	$ 3,098	$ 3,680	$ 4,417	$ 3,834	$ 1,644
COPE- Employer Contributions	$ 1,871	$ 1,933	$ 2,038	$ 2,186	$ 3,328	$ 3,350	$ 1,580
COPE - Employee Contributions	$ -	$ -	$ -	$ -	$ 174	$ 175	$ 91
COPE - Total Cost	$ 1,871	$ 1,933	$ 2,038	$ 2,186	$ 3,503	$ 3,525	$ 1,671
Customer Service - COPE - Employer Contributions	$ -	$ -	$ -	$ -	$ 26	$ 549	$ 318
Customer Service - COPE - Employee Contributions	$ -	$ -	$ -	$ -	$ -	$ 25	$ 12
Customer Service - COPE Total Cost	$ -	$ -	$ -	$ -	$ 27	$ 573	$ 330
IBEW - Employer Contributions	$ 2,154	$ 2,415	$ 2,368	$ 2,467	$ 3,544	$ 3,292	$ 1,689
IBEW- Employee Contributions	$ -	$ -	$ -	$ -	$ 144	$ 160	$ 74
IBEW - Total Cost	$ 2,154	$ 2,415	$ 2,368	$ 2,467	$ 3,572	$ 3,865	$ 1,763

There have been no projections for 2014 as it is assumed these will be similar to 2013 after adjusting for inflation.

The total OPEB costs by affiliation are set out in Table 2 below. Note that all OPEB costs are paid by the company.

Table 2: Total OPEB Costs for FEI by Affiliation Including Company and Employee Contributions

	2007	2008	2009	2010	2011	2012	2013	2014
M&E [1]	$ 1,456	$ 1,346	$ 1,106	$ 1,429	$ 1,724	$ 2,639	$ 3,327	$ 3,592
Union	$ 7,127	$ 6,722	$ 4,024	$ 2,091	$ 2,781	$ 4,628	$ 4,871	$ 5,070
	$ 8,583	$ 8,068	$ 5,130	$ 3,520	$ 4,505	$ 7,267	$ 8,198	$ 8,662
Notes								
[1] - Executive OPEB costs are included in M&E								
OPEBs are employer funded other than the employee deductible amount								

The total pension costs by plan are set out in Table 3 below. Note that this information is not available by affiliation, as some of the pension plans have more than one affiliation participating.

Table 3: Total Pension Costs for FEI by Plan Including Company and Employee Contributions

	2007	2008	2009	2010	2011	2012	2013	2014
Executive Supplemental DC Net Benefit Expense [1]	$ -	$ 250	$ 250	$ 330	$ 410	$ 250	$ 250	$ 400
M&E Legacy Net Benefit Expense	$ (498)	$ (337)	$ (233)	$ 1,689	$ 2,750	$ 4,484	$ 4,299	$ 3,075
M&E Legacy Funding Employer Contributions [2]	$ 1,595	$ 1,413	$ 1,664	$ 1,488	$ 2,920	$ 2,892	$ 2,897	$ 4,078
IBEW/COPE Net Benefit Expense	$ 64	$ (502)	$ 286	$ 3,964	$ 3,543	$ 10,549	$ 11,338	$ 10,106
IBEW/COPE Funding Employer Contributions	$ 3,080	$ 3,413	$ 4,087	$ 4,997	$ 5,606	$ 5,871	$ 6,021	$ 8,193
IBEW/COPE Funding Employee Contributions	$ 3,078	$ 3,411	$ 4,033	$ 4,963	$ 5,576	$ 5,860	$ 6,021	$ 8,193
IBEW/COPE Total Contributions:	$ 6,158	$ 6,824	$ 8,120	$ 9,960	$ 11,182	$ 11,731	$ 12,042	$ 16,386
FEI - FHI Plan -(Jan 2007) Net Benefit Expense	$ 2,238	$ 2,203	$ 1,488	$ 1,966	$ 7,922	$ 5,182	$ 6,007	$ 6,423
FEI - FHI Plan - Funding Employer Contributions	$ 1,082	$ 1,365	$ 1,626	$ 1,943	$ 3,052	$ 3,379	$ 3,748	$ 3,843
FEI - FHI Plan - Employee Contributions Cost	$ 1,071	$ 1,332	$ 1,592	$ 1,898	$ 2,986	$ 3,317	$ 3,748	$ 3,843
FEI - FHI Plan Total Contributions:	$ 2,153	$ 2,697	$ 3,218	$ 3,841	$ 6,038	$ 6,696	$ 7,496	$ 7,686

Notes

[1] No employee or employer contriutions were made to the supplemental DC plan

[2] Legacy pension plan is 100% funded by the employer so no employee contributions were made

77.0 Reference: LABOUR

Exhibit B-1-1, Appendix F6, p. 1

O&M - Employee Expenses per FTE

77.1 Using the format below please provide a schedule showing the Employee Expenses per FTE by affiliation (Executive, COPE, IBEW and M&E) for 2007-2014. Include the requested information in the form of a fully functioning electronic spreadsheet.

Employee Expenses per FTE

	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Approved 2013	Projected 2013	Forecast 2014
Total Employee Expenses ($)									
FTEs									
Employee Expense per FTE									

Response:

Provided below is a schedule showing the employee expenses per FTE for 2007-2014. Please refer to Attachment 77.1 for the fully functioning electronic spreadsheet.

Employee Expense per FTE

	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Projection 2013	Base 2013	Forecast 2014
Total Employee Expenses ($ thousands)	3,498	4,422	4,254	5,805	5,859	5,898	5,671	5,719	5,828
FTEs	1,084	1,124	1,165	1,241	1,427	1,571	1,571	1,571	1,571
Employee Expense per FTE ($ thousands)	3.23	3.93	3.65	4.68	4.11	3.75	3.61	3.64	3.71

A further breakdown to the affiliation level is not available since FEI does not track employee expenses by affiliation.

As discussed in Section 3.1, 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 FTE levels for this time period. Projected 2013 FTEs are expected to be similar to

2012. Therefore, for this response, the FTE levels of 2013 Projection and 2014 Forecast have been maintained at the level of 2012 Actuals.

In addition, 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, BCUC 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 BCUC Order G-44-12, FEI did not submit revised FTE forecasts. Therefore, FEI does not have an Approved 2013 FTE figure to provide.

78.0 Reference: LABOUR

Exhibit B-1, Application, Tab C, Section 3.3.3.1, p. 125; Exhibit A2-8, p. 4

Executive Employees

On page 125 of the Application (Exhibit B-1) FEI states: “the Company compensates executives at a level generally equivalent to the median of practice among a broad reference group of Canadian commercial industrial companies.”

On page 4 of Exhibit A2-8, Form 51-102F6 – Statement of Executive Compensation, For the Year Ended December 31, 2012 FortisBC Holdings Inc., Fortis states: “As part of the annual review process, Fortis engages Hay Group Limited (“Hay Group”), its primary compensation consultant, to provide comparative analyses of market compensation data reflecting the pay levels and practices of Canadian Commercial Industrial companies.” On page 5 of Form 51-102F6 Fortis states: “The Corporation also engages Towers Watson and Mercer (Canada) Limited to consult on certain pension and benefit components and to perform certain administrative and actuarial functions related to the Corporation’s pension programs.”

Section 3.3.3.1, page 125 of Exhibit B-1, FEI states: “The Company’s executive compensation program involves four main elements: base pay; short term incentive pay; long term incentive pay; and benefits.”

78.1 Please produce any Hay Group Limited reports related to Fortis’ executive compensation program produced within the last 5 years.

Response:

FEI is disciplined in the regular review of the market competitiveness of its executive compensation program through the Hay Group.

The Hay Group has produced a number of reports related to Fortis’ executive compensation program within the last five years. Please refer to Confidential Attachment 78.1 for a copy of a 2008 one market pricing for the VP & GM Terasen Energy Services.

The remainder of the reports are provided confidentially under separate cover, as they contain commercially sensitive compensation information for planning purposes.

The CONFIDENTIAL Attachment 78.1, includes:

a. 2012 (FortisBC) Triennial Review summary findings

b. 2012 (FortisBC) Triennial total remuneration summary review

c. 2013 (FortisBC) Response to BCUC directive based on 2012 review

d. Annual market verifications for 2008 – 2012

78.2 On what basis are the comparable commercial industrial companies chosen for the reference group that is used to benchmark executive compensation?

Response:

As stated in the preamble, the executive compensation policy of FEI is to compensate executives at a level generally equivalent to the median level of the Canadian Commercial Industrial Comparator Group. The Canadian Commercial Industrial Comparator Group consists of all Canadian publicly traded and privately owned companies within Hay's database, excluding financial organizations. This comparator group represents a broad spectrum of Canadian industrial organizations with which FEI competes for executive talent. For a complete list of these companies please refer to Attachment 78.2.1.

78.2.1 Please list the companies that are part of the Comparable Canadian Commercial Industrial reference group used produced by Hay Group Limited.

Response:

Please refer to Attachment 78.2.1 for a list of the Companies that are part of that reference group.

78.2.2 Please elaborate in detail on how these reference group companies are appropriate comparators for Fortis?

Response:

The Hay Group recommends the peer reference group to enable the FEU to attract and retain executive talent. The FEU have attracted its executive talent from a broad spectrum of backgrounds in the private sector including, but not limited to, properties, real estate, business development, oil, gas and the energy and utilities sectors.

Please refer to Attachment 78.2.2 which was provided by the Hay Group in response to BCOAPO IR 1.9.2 in respect of the FEU 2012-2013 RRA proceeding. The methodology and underlying reference group relied upon in 2012-2013 has not changed in this Application.

78.2.3 Where does actual compensation for FEI executives rank against the comparator group?

Response:

The FEU and FortisBC Inc. engaged the Hay Group to conduct a review of executive compensation in May of 2013.

According to those findings, the FEU and FortisBC Inc.'s target total direct compensation (base salary plus target short- and long-term incentives) is below market median for all roles. While base salary and target total cash are generally positioned around market median, long term incentive compensation is competitively weak. However, in actual total direct compensation this shortfall in long-term incentive is somewhat offset by the strong actual short-term incentive which position most executives close to market median, in keeping with FEI's compensation philosophy for executives.

Please refer to Confidential Attachment 78.1 provided in response to BCUC IR 1.78.1, for a copy of the Hay Group's full report.

78.3 Please produce any reports from Tower Watson or Mercer (Canada) Limited related to Fortis' executive compensation program within the last 5 years.

Response:

FEI monitors, reviews, and evaluates its executive compensation program annually to ensure that it provides a reasonable compensation program at appropriate levels and remains competitive and effective. To do this, FEI engages compensation consultants from time to time to provide comparative analyses of market data.

Hay Group serves as FEI's primary external independent advisor on matters relating to executive compensation. In addition, the following reports have been produced by Towers Watson related to Fortis' executive compensation program within the last 5 years and are provided in Confidential Attachment 78.3. Attachment 78.3, is being filed under separate cover confidentially as it contains commercially sensitive compensation information for planning purposes.

a. 2013 Letter responding to the 2013 BCUC directive and corresponding e-mail

b. 2011 Executive pension and benefits review focusing on a review of the competitiveness of the pension and benefit programs offered to FortisBC executives.

c. 2009 Total Rate Base Review

Mercer (Canada) has not produced any reports related to Fortis' executive compensation program within the last 5 years.

78.4 Please explain and quantify individual components of each of the 4 elements of FEI's executive compensation program e.g., base pay; short term incentive pay; long term incentive pay; and benefits?

Response:

The four elements of FEI's executive compensation program noted above are described below. Note that these elements cannot be quantified for the executive group as a whole, because their value is dependent on the specific executive's compensation and performance.

1. Annual Base Salary: Salary is a market-competitive, fixed level of compensation. Base salaries are established annually by reference to the range of salaries paid generally by comparable Canadian commercial industrial companies and are targeted at the median of the comparator group.
2. Short-term Incentive Pay: An annual short term incentive plan provides for annual cash bonuses which are determined by way of an annual assessment of corporate and individual performance in relation to targets. FEI's annual earnings must reach a minimum threshold level before any payments are made. The objectives of the annual incentive plan are to reward achievement of short-term financial and operating performance and focus on key activities and achievements critical to the ongoing success of the company.
3. Corporate performance is determined with reference to the performance of FEI relative to weighted targets in respect to financial, safety, customer satisfaction and regulatory performance.
4. Individual performance is determined with reference to individual contribution to corporate objectives.
5. Long-term Incentive Pay includes:
    a. Stock Options: Annual equity grants are made in the form of stock options. The amount of annual grant will be dependent on the level of the executive and their current share ownership levels. Planned grant value is converted to the number of shares granted by dividing the planned value by the pre-determined, formulaic planning price derived using the Black-Scholes Option Pricing Model.
    b. Performance Share Units (PSU): Annual PSU grants are made to executive members. The number of units to be granted is dependent on the executive's base salary, level of the executive and the market price of the common shares on the grant date. Payment of PSU's is performance based consisting of four elements; compound average growth rate in earnings per share, compound average growth rate in Property, Plant & Equipment and total Shareholder return.
6. Benefits:
    a. Health Benefits include: medical, extended health, dental, various insurances, employee and family assistance plan, Short Term Disability (STD), and Long Term Disability.

b. Contribution to a registered retirement savings plan (RRSP) equal to 6.5% of an executive's base salary which is matched by the executive up to the maximum annual contribution limit allowed by the Canada Revenue Agency.

c. Supplemental Employee Retirement Plan (SERP) is an accrual of 13% of base salary and annual incentive in excess of the Canada Revenue Agency annual limit. At time of retirement, paid in one lump sum or in equal payments up to 15 years.

78.4.1 Are there any other items of total executive compensation that are not covered under base pay; short-term incentive pay; long-term incentive pay; or benefits? If so, please list and explain them.

Response:

There is one additional item of total executive compensation included in FEI's executive compensation program: Each member of the executive team is provided with the use of a company-leased vehicle, the value of which has a pre-determined maximum based on the position. All normal lease, maintenance and operating costs are paid by FEI. The cost of this is included in the O&M base upon which delivery rates are calculated.

78.5 What human resource metrics does FEI use to make decisions regarding executive performance and compensation? Please list and explain each metric.

Response:

Human resource metrics are not used by FEI to make decisions regarding executive performance and compensation. Decisions regarding executive performance are made by determining the degree to which annual individual and corporate objectives are met under FEI's short-term incentive program. Each year, individual objectives are set consistent with corporate objectives and that executive team member's deliverables. This variable pay component is dependent upon both corporate and individual performance and is based on a percentage of salary. For executives, 50% of short-term incentive is based on attainment of individual objectives, and 50% is based on attainment of corporate objectives.

HR objectives are included as individual executive performance objectives.

78.6 How are vacation time, other time-off, and work hours reflected in total annual executive compensation when compared to the reference group?

Response:

Compensation comparisons to the reference group for executive employees generally include base salary and incentive pay only. However, in 2011, FEI engaged Towers Watson to conduct a review of the competitiveness of the company's pension and benefit programs, including vacation, holidays and other paid time off. Results for the three executive profiles used indicated that vacation, holidays and paid time off for the FEU and FBC executives studied were above the market median. Subsequent to this study, FEI reduced leave options within the flex benefits program by 2% of base pay and reduced the number of earned days off from 17 to 12. The result of these changes aligned executive leave provisions within the executive team of the utilities and brought the value of the pension and benefits program to approximately market median.

A copy of this review is included in Attachment 78.3 in response to BCUC IR 1.78.3.

FEI reviews all elements of its compensation program regularly to ensure that its offerings are market-competitive in order to allow it to retain (and attract, where appropriate) competent executive talent.

78.7 How is job security and employee position turnover reflected in total annual executive compensation when compared to the reference group?

Response:

FEI's executive compensation philosophy is designed to provide market-competitive compensation which allows FEI to retain (and attract, where required) qualified, competent executive talent.

While job security and employee position turnover are not directly reflected in total annual executive compensation at FEI, FEI believes that its executive compensation offerings are appropriately positioned to mitigate the risk of turnover on its executive team.

Please refer to the response to BCUC IR 1.78.4 for a description of the elements of FEI's executive compensation program, and to BCUC IR 1.78.2.3 for a comparison of how compensation for FEI executives ranks against the comparator group.

78.8 How are pensions and pensionable earnings reflected in total annual executive compensation when compared to the reference group?

Response:

The pension provisions provided to FEI executives are market competitive and include an RRSP and supplemental retirement (SERP) provision. The SERP provides for the accrual of 13% of earnings in excess of the Income Tax Act RRSP limit.

In June of 2011, an Executive Pension and Benefits Review was conducted by Towers Watson (a copy of which is included in Attachment 78.3 provided in response to BCUC IR 1.78.3). At that time, the pension provisions also included a 3% savings plan component. The company-provided value of the pension (RRSP and SERP) and savings programs provided to FEI Executives was tested against a peer group. The 3% savings plan component was eliminated in 2012 to produce a pension value for the executive group of approximately the median of the peer group used in that study.

In response to a BCUC directive, in May of 2013, FEI engaged the Hay Group to perform a review which included FEI's SERP pension arrangement. The Hay Group found the annual total employer contribution rate of FEI's retirement benefits (RRSP and SERP) to be within the norm of other executive retirement programs in the commercial industrial reference group. The Hay Group's review is included in Attachment 78.1 provided in response to BCUC IR 1.78.1.

78.9 Please confirm that any stock options and its related costs have not been recovered from FEI ratepayers in the last 5 fiscal years and are not proposed to be recovered from ratepayers in the proposed test years.

Response:

The executive stock option plan and its related costs have not been recovered from FEI ratepayers in the last 5 fiscal years and are not proposed to be recovered from ratepayers in the 2014 through 2018 period.

79.0 Reference: LABOUR

Exhibit B-1, Application, Tab C, Section 3.3.3.2, p. 126

M&E Employees

On page 126 of the Application (Exhibit B-1), Section 3.3.3.2 (M&E Employees), FEI states: "As a general policy, FEI establishes base salary and incentive compensation targets at the median level of a peer group of companies. The peer group is representative of a commercial/industrial group with an emphasis on natural resources and utilities."

79.1 For M&E employees, does FEI engage a compensation consultant or review compensation studies when establishing compensation targets? If so, please produce all sources relied upon over the last 5 years to set M&E employee compensation.

Response:

FEI engages its primary compensation consultant, the Hay Group as required for M&E compensation matters. In addition, on an annual basis FEI subscribes to the Hay Group Compensation Planning Update Bulletins, which provide forecasts for base salary policy and base salary actuals for the year ahead, including anticipated increases and base salary policy movement. This data permits FEI to obtain information relative to Canadian economic and national and regional salary forecasts.

FEI also annually participates in and subscribes to the Hay Group Total Compensation Survey and the CBOC Compensation Outlook survey. FEI also remains abreast of Stats Canada information and BC economic reporting information. Survey results and Stats Canada information are accessed on-line and are not available to include as attachments.

The primary sources FEI has relied upon over the last 5 years to set M&E employee compensation are provided in CONFIDENTIAL Attachment 79.1, being filed under separate cover confidentially as it contains commercially sensitive compensation information for planning purposes.

79.2 On what basis is the representative commercial/industrial peer group for M&E employees chosen?

Response:

The basis for the selection of the representative commercial/industrial peer group for M&E compensation is described in Attachment 79.2 which is a letter from the Hay Group.

Selection of a common representative commercial/industrial peer group for the FortisBC gas and electric utilities supports HR's efforts toward the alignment of the utilities. The establishment of a common M&E compensation platform creates efficiencies in the area of compensation administration and supports equity among the utilities and movement of staff throughout the FortisBC Group of Companies facilitating operational flexibility and employee growth and development.

79.2.1 Please list the companies that are part of the commercial/industrial peer group for M&E employees.

Response:

The companies that are part of the commercial/industrial peer group for M&E employees are:

Ainsworth Engineered Canada L. P.	Air Products Canada Ltd.
ALS Canada Ltd.	AltaSteel Ltd.
Aluminerie Alouette Inc.	ArcelorMittal Dofasco Inc.
Babcock & Wilcox Canada Ltd.	Barrick Gold Corporation
Bekaert Canada	BHP Billiton - Ekati Diamond Mines
Bluewater Power Distribution Corporation	British Columbia Hydro and Power Authority
British Columbia Safety Authority	Bruce Power L.P.
Campbell Company of Canada	Canadelle Inc.
Canadian National Railway Company	Canadian Pacific Railway
Canexus Corporation	Canfor Pulp Limited Partnership
Canpotex Limited	Cargill Limited
Caterpillar of Canada Corporation	Centerra Gold Inc.
Daishowa-Marubeni International Ltd.	De Beers Canada Inc., Corporate Division
De Beers Canada Inc., Exploration Division	De Beers Canada Inc., Mining Division
Dow Chemical Canada Inc.	Dundee Precious Metals
E.I. du Pont Canada Company	Elkem Métal Canada Inc.

Enbridge Gas Distribution Inc.	Enersource Hydro Mississauga Inc
ERCO Worldwide	Essar Steel Algoma Inc.
Finning (Canada)	Finning International Inc.
Fortis Inc.	Fortis Properties Corporation
FortisAlberta Inc.	FortisOntario Inc.
General Kinetics Engineering Corporation	Guelph Hydro Electric Systems Inc.
Halifax Regional Water Commission	Hecla Mining Company
Hydro One Brampton	Hydro One Inc.
IAMGOLD Corporation	Industry Training Authority
Ingersoll-Rand Canada Inc.	INVISTA (Canada) Company
Kinross Gold Corporation	Kuehne + Nagel Ltd.
Lantic Inc. - Rogers Sugar Division	Maritime Electric Company
McElhanney Consulting Services Ltd.	McElhanney Land Surveys Ltd.
Minas Basin Pulp & Power Co. Ltd.	Mitsubishi Canada Limited
Newfoundland Power Inc.	Newmont Mining Corporation of Canada Limited
NOVA Chemicals Corporation	Nova Scotia Power Inc.
Ontario Power Authority	Ontario Power Generation Inc.
Oshawa PUC Networks Inc.	Pan American Silver Corporation
Potash Corporation of Saskatchewan Inc.	Praxair Canada Inc.
Rio Tinto - Diavik Diamond Mines	Rio Tinto Iron Ore
Russel Metals Inc.	Saint-Gobain Abrasives Canada Inc.
SaskEnergy Incorporated	SaskPower
SaskTel	Schneider Electric
Sherritt Coal	Sherritt International Corporation
Shore Gold Inc.	Sofina Foods Inc.
Suncor Energy Inc.	Teck Resources Limited
Teck Resources Limited - Trail Operation	Teck Resources Limited - Highland Valley Copper
Teekay Corporation	Tembec Inc.
The Churchill Corporation	The McElhanney Group Ltd.
The Mosaic Company	Tolko Industries Ltd.
Toronto Hydro-Electric System Limited	Twin Rivers Paper Company
Ultramar Ltée	VPL Enterprises Ltd.
West Fraser Timber Co. Ltd.	Xstrata Copper Canada
Xstrata Nickel Canada	Xstrata Zinc Canada
Yukon Energy Corporation	Zellstoff Celgar Partnership Limited

As mentioned in the preamble, this peer group is representative of a commercial/industrial group with an emphasis on natural resources and utilities.

79.2.2 Please elaborate in detail on how these reference group companies are appropriate comparators for Fortis?

Response:

Please refer to the response to BCUC IR 1.79.2, and Attachment 79.2.

79.2.3 Where does actual compensation for FEI M&E employees, rank against the comparator group?

Response:

Average actual compensation for FEI M&E employees for 2013 is at 93% of the market median for the various ranges. FEI has and will continue to carefully manage compensation costs through consistent market and performance based administration of the M&E Compensation Program.

79.3 Please explain and quantify the various components of M&E employee compensation.

Response:

The two main components of the M&E compensation program are:

1. base pay
2. short-term incentive pay

Base pay is designed to maintain market competitiveness at a level permitting FEI to attract and retain quality talent. FEI's base pay structure for M&E employees includes five broad bands within four job families that positions are matched to using the Hay job evaluation system. Salary ranges are set around the job rate at 80% of the job rate for the range minimum and at 110% of the job rate for the range maximum. Individual salaries are reviewed annually with annual adjustments made within an overall corporate budget. The adjustments at the individual level are performance based.

Short-term incentive pay recognizes and rewards the achievement of individual and corporate objectives by putting compensation at risk. The value of short-term incentive pay assigned to each broad band is positioned at approximately the market median for the peer group and ranges from 5-20% of regular earnings, with the maximum payout set at 150% of target. The amount of incentive pay is based 50% on the achievement of individual objectives, and 50% on the achievement of corporate objectives.

Structuring M&E compensation in this way allows FEI to offer competitive compensation at the market-median level. This in turn assists with the retention of existing employees and the attraction of new employees as required, in a labour market which is competing for competent, qualified talent. The incentive program puts focus on corporate and individual performance targets that in turn drives for and rewards the achievement of personal and corporate objectives.

79.4 What human resource metrics does FEI use to make decisions regarding M&E staffing levels at FEI? Please list and explain each metric.

Response:

FEI does not use human resource metrics to make decisions regarding M&E staffing levels. Decisions regarding M&E staffing levels are made at the departmental level, taking into account such factors as forecasted work volume and organization of the department.

79.4.1 Please provide the following HR Metrics for FEI M&E Employees for the last 5 years: 1) Hire Cycle Time, 2) Separation Rate, 3) Total Hire Rate, 4) External Hire Rate, 5) Span of Control, 6) Variable Compensation Ratio.

Response:

Please refer to Table 79.4.1 below for information regarding the HR metrics listed above.

Table 79.4.1: HR Metrics for FEI M&E Employees for the Last 5 Years

	2007	2008	2009	2010	2011	2012
Hire Cycle Time (Days)	103.2	71.7	90.6	78.1	35.3	43.7
Separation Rate	10.85%	8.03%	4.50%	5.87%	3.97%	10.43%
Total Hire Rate	10.47%	12.04%	11.25%	18.37%	14.35%	5.22%
External Hire Rate	8.14%	10.58%	9.97%	16.33%	12.80%	2.49%
Span of Control	n/a	n/a	n/a	n/a	n/a	n/a

FEI has defined these metrics to mean as follows:

1. Hire Cycle Time: the number of days from the date a job is posted to the date the offer letter is sent to the successful applicant;
2. External Hire Rate: the number of external M&E hires, divided by M&E headcount;
3. Separation Rate: is the number of M&E employees terminated involuntarily, retired, and terminated voluntarily, divided by M&E headcount;
4. Total Hire Rate: the number of new M&E hires, divided by M&E headcount (where new hires includes any external hires, plus employees moving from temporary to regular status);
5. Span of Control is not a metric that FEI tracks.

As shown in Table 79.4-1, Hire Cycle time has decreased continuously since 2010, with a significant drop in 2011. This metric is one that FEI has focused on since 2010, believing that a shorter Hire Cycle Time provides a more positive experience to a job applicant, which in turns assists FEI with its goals to attract qualified, competent employees where required. The metrics above show that FEI's efforts in this area have been successful

Total Hire Rate also dropped in 2011 and 2012, which FEI believes reinforces its philosophy of looking at each vacancy as an opportunity to explore efficiencies.

External Hire Rate has been decreasing since 2010, which is due to FEI's emphasis on hiring from within in an effort to achieve operational flexibility through moving employees across the organization, as well as to provide developmental opportunities to current employees.

Regarding Variable Compensation Ratio, FEI M&E Employees short term incentive pay targets are associated with the salary band for their position.

Variable compensation ratios differ, depending on the salary band the M&E position falls into, as well as the individual employee's performance. The incentive pay targets by salary band are shown below:

Band	Target
5	20%
4	15%
3	10%
2	10%
1	5%

STI is calculated for M&E as follows:

Base earnings * STI target * ((gas scorecard * 50%) + (employee personal rating * 50%))

79.4.2 Also, provide the anticipated values for the proposed test years for the above HR Metrics?

Response:

The HR Metrics listed in the response to BCUC IR 1.79.4.1 are not regularly measured at FEI as they are not used to make decisions regarding M&E staffing levels. Values for the proposed test years have not been forecast.

79.5 How are vacation time, other time-off, and work hours reflected in total annual M&E employee compensation when compared to the reference group?

Response:

Compensation comparisons to the reference group for M&E employees generally include base salary and incentive pay only. However, in 2011, FEU and FBC engaged Towers Watson to conduct a review of the competitiveness of M&E pension and benefit programs as it worked toward alignment of its M&E compensation platform between the gas and electric utilities. The review considered vacation, holidays, and paid time off and concluded that FEI M&E employees were slightly above the market median, by 2.5%. In response to this FEI reduced the leave options available in the flex benefits plan by 2% to move towards the market median. In addition to this, the earned day off program was changed to reduce the number of earned days off from 17 to 12.

A copy of this review is provided in Attachment 79.5.

FEI reviews all elements of its M&E compensation program regularly to ensure that its offerings are market-competitive in order to allow it to retain (and attract, where appropriate) competent executive talent.

79.6 How is job security and employee position turnover reflected in total annual M&E employee compensation when compared to the reference group?

Response:

FEI's compensation philosophy for M&E employees is to target compensation at the market-median specifically to attract and retain qualified, competent talent.

Job security and employee position turnover are not otherwise reflected in total annual M&E employee compensation at FEI when compared to the reference group.

Please refer to the response to BCUC IR 1.79.3 for a description of the various components of M&E employee compensation, and to BCUC IR 1.79.2.3 for a comparison of how compensation for FEI M&E employees ranks against the comparator group.

79.7 How is the span of control reflected in total M&E employee compensation when compared to the reference group?

Response:

Job family role profiles used to evaluate all M&E jobs were developed utilizing the HayGroup job evaluation methodology, which measures job factors commonly known as the input (knowledge, skills and abilities), throughput (problem solving) and output (accountability). Span of control is reflected within the assessment of these HayGroup factors.

79.8 How are pensions and pensionable earnings reflected in total annual M&E compensation when compared to the reference group?

Response:

Pensions and pensionable earnings have not historically been included in total annual M&E compensation when compared to the reference group. However, in 2011, FEI engaged Towers Watson to determine the company's benefits values for M&E employees relative to market. The value of pensions and savings programs for FEI M&E employees was found to be slightly above the market median. Since this study was conducted, FEI has reduced the value of the M&E pension and savings program by 3%.

Please refer to Attachment 79.5, provided in response to BCUC IR 1.79.5, for a copy of this study.

80.0 Reference: LABOUR

Exhibit B-1, Application, Tab C, Section 3.3.3.3, p. 126

Unionized Employees

On page 126 of the Application (Exhibit B-1), Section 3.3.3.3 (Unionized Employees) FEI states: "Recent agreements with the IBEW and COPE focus on competitive rates of pay, productivity, retention of management rights and cost effectiveness. Negotiated settlements that include general wage increases also include saving offsets in other compensation and benefit areas."

80.1 For unionized employees, how does FEI establish competitive rates of pay for each of COPE, COPE Customer Service, and IBEW?

Response:

Rates of pay for all of FEI's unionized employees are contained in the applicable collective agreement and are the subject of negotiated agreements reached with the respective union. Similar to M&E employees, FEI's approach with respect to compensation for unionized employees is to provide competitive compensation with a view to base pay being at or near the market median.

For COPE Customer Service employees, a joint commitment to market competitiveness is included in the Collective Agreement as a Letter of Understanding. Please refer to Attachment 80.1 for a copy of the Letter of Understanding.

80.1.1 Does FEI engage a compensation consultant or review compensation studies when establishing compensation for each of the unionized employee groups? If so, please produce all sources relied upon over the last 5 years for each of the unionized employee groups.

Response:

FEI seeks to set bargaining unit wage rates at or near the market median in order to be able to attract and retain quality talent. To enable it to do so, FEI has engaged a compensation consultant to conduct compensation studies with two of its unionized groups: COPE and IBEW.

1. COPE: In 2011, FEI engaged Mercer (Canada) Limited to facilitate a joint market comparator survey for selected positions within the COPE bargaining unit. The commitment to conduct a market comparator survey was contained in the Collective Agreement, and was based on FEI's philosophy, endorsed by COPE, that base salaries for positions at FEI are intended to be at or near market median.

Please refer to CONFIDENTIAL Attachment 80.1.1 for a copy of the market review, being filed confidentially under separate cover due to commercial sensitivity.

2. IBEW: In preparation for bargaining for its 2011-2015 Collective Agreement with IBEW, and in an effort to align to FEI's overarching compensation philosophy of providing compensation at or near market median, FEI engaged Mercer (Canada) Limited to develop and execute a compensation and policy review for selected positions within the IBEW bargaining unit.

Please refer to CONFIDENTIAL Attachment 80.1.1 for a copy of the compensation and policy review, being filed confidentially under separate cover due to commercial sensitivity.

3. FEI did not engage a compensation consultant or review compensation studies when establishing compensation for the COPE Customer Service group of employees. FEI conducted its own review of wage rates for comparable jobs with comparable employers by reviewing publicly available collective agreements and corresponding wage rates. Going forward, per a Letter of Understanding between FEI and COPE, a joint market comparator survey will be conducted in advance of the collective agreement expiring. Please refer to Attachment 80.1 provided in response to BCUC IR 1.80.1, for a copy of the Letter of Understanding, which also identifies the compensation elements to be surveyed and the comparator group of companies.

80.1.2 Please explain and quantify the individual compensation components for each of the unionized employee groups.

Response:

Compensation components for each of the unionized employee groups at FEI are as follows:

1. COPE: Compensation for COPE employees includes base pay and short-term incentive pay. Base pay is negotiated for 12 successive salary groups; each salary group contains 6 steps. Jobs are assigned to a salary group according to a joint job evaluation plan, and employees progress along the steps of a salary group based on time in a job. Incentive pay for eligible employees is based on 3% of base pay, with 2% based on corporate scorecard results, and 1% available to employees based on attendance.
2. IBEW: Compensation for IBEW employees includes base pay (and short-term incentive pay for new employees). Base pay is negotiated for each job. Incentive pay for new employees can be up to $1,900 annually: $1,000 based on corporate scorecard results, and $300 each for meeting individual targets for attendance, motor vehicle accidents, and lost-time injuries.
3. COPE Customer Service: Compensation for COPE Customer Service employees includes base pay and short-term incentive pay. Base pay is negotiated for 10 successive salary groups; each salary group contains 5 steps. Jobs are assigned to a salary group through joint agreement with the union, having regard to market competitiveness. Incentive pay for eligible employees can be up to 3.5% of regular earnings, based upon corporate, departmental and individual performance within specific metrics.

Compensation for each of the unionized employee groups follows FEI's philosophy of providing market-competitive compensation, at or near the market median, in an effort to retain and attract qualified, competent employees.

80.2 How are vacation time, other time-off, and work hours reflected in each of the unionized employee groups' annual compensation when compared to the appropriate reference group(s)?

Response:

Generally, only base pay and incentive pay are considered in any compensation comparisons or reviews for market competitiveness. However, in 2011 in preparation for collective bargaining, FEI engaged Mercer to conduct a market review of the compensation practices for selected positions within the COPE bargaining unit. The review focused primarily on pay, but did consider standard hours of work and found FEI's COPE employees to be slightly less than the market median. Vacation and other time-off were not considered in this review.

Please refer to CONFIDENTIAL Attachment 80.1.1, provided in the response to BCUC IR 1.80.1.1, for a copy of this review.

Also in 2011, FEI engaged Mercer to conduct a market review of the compensation practices for selected positions within the IBEW bargaining unit. The review considered standard hours of work and vacation and unearned time off. FEI was found to be at the 25th percentile of the market for standard hours of work, and FEI's current vacation schedule for IBEW employees is very similar to the market median arrangement. However, other time off for FEI's IBEW employees was found to be above the market median.

Please refer to CONFIDENTIAL Attachment 80.1.1, provided in the response to BCUC IR 1.80.1.1, for a copy of this review.

80.3 How is job security and employee position turnover reflected in each of the unionized employee groups' compensation when compared to the appropriate reference group(s)?

Response:

FEI's philosophy for unionized employees of providing compensation that is market-competitive to attract and retain qualified, competent talent.

Job security and employee position turnover are not otherwise reflected in any of the unionized employee groups' compensation at FEI when compared to the appropriate reference groups.

Please refer to the response to BCUC IR 1.80.1.2 for a description of the individual compensation components of the unionized employee groups, and to the response to BCUC IR 1.80.1 for information around how competitive rates of pay for each of the unionized employee groups are established.

80.4 What human resource metrics does FEI use to make decisions regarding unionized staffing levels at FEI? Please list and explain each metric.

Response:

FEI does not use human resource metrics to make decisions regarding unionized staffing levels. Staffing decisions are made at the departmental level, based on forecasted work volume.

80.5 Please provide the following HR Metrics for FEI unionized staff for the last 5 years: 1) Hire Cycle Time, 2) Separation Rate, 3) Total Hire Rate, 4) External Hire Rate, 5) HR Staff to Full-Time Equivalent Ratio.

Response:

FEI manages its unionized workforce deliberately and consistent with corporate objectives:

1. Provide service at a reasonable cost
2. Action efficiencies continuously as opportunities present

Table 80.5 below provides a historical review of the metrics requested and supports this conclusion.

Table 80.5: HR Metrics for FEI Unionized Staff for the Last 5 Years

	2007	2008	2009	2010	2011	2012
Hire Cycle Time (Days)	99.02	82.75	88.45	75.2	54.9	39.35
Separation Rate	6.49%	8.99%	4.70%	7.61%	7.79%	8.07%
Total Hire Rate	8.85%	11.54%	4.82%	15.12%	29.95%	5.47%
External Hire Rate	7.08%	8.26%	2.53%	10.75%	26.62%	1.79%
HR Staff to Full-Time Equivalent Ratio	1:22	1:22	1:22	1:18	1:22	1:24

FEI has defined these metrics to mean:

1. Hire Cycle Time: the number of days from the date a job is posted to the date the offer letter is sent to the successful applicant.

2. External Hire Rate: the number of external union hires, divided by union headcount.
3. Separation Rate: is the number of union employees terminated involuntarily, retired, or who terminated voluntarily, divided by union headcount;
4. Total Hire Rate: the number of new union hires, divided by union headcount (where new hires includes any external hires, plus employees moving from temporary to regular status).

As shown in Table 80.5, Hire Cycle time has decreased continuously since 2009, with significant drops in 2011 and 2012. This metric is one that FEI has focused on in recent years, believing that a shorter Hire Cycle Time provides a more positive experience to a job applicant, which in turns assists FEI with its goals to attract qualified, competent employees where required. The metrics above show that FEI's efforts in this area have been successful

Total Hire Rate in 2010 and 2011 increased due to the addition of COPE Customer Service staff for the Customer Service group. Note that FEI continues to look at each vacancy as an opportunity to explore efficiencies.

External Hire Rate also increased in 2010 and 2011, again due to the addition of Customer Service staff in those years.

The ratio of HR staff to FEI FTEs has remained fairly constant over the period in question, with the exception of 2010. In 2012, FEI's HR department reinforced its commitment to finding efficiencies by managing to support an increased number of corporate FTEs without adding HR staff.

80.5.1 Also, provide the anticipated values for the proposed test years for the above HR Metrics?

Response:

The HR Metrics listed in the response to BCUC IR 1.80.5 are not regularly measured at FEI as they are not used to make decisions regarding unionized staffing levels. Values for the proposed test years have not been forecast.

FORECASTS FOR THE PBR PERIOD OPERATIONS AND MAINTENANCE EXPENSE

81.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3; Exhibit B-1-1, Appendix B2

Comparative O&M 2007 through 2018

Table C3-1 on page 123 of the Application presents O&M for 2010 Actual through 2013 Approved.

Table C3-2 on page 124 of the Application presents 2013 Approved reconciled to 2013 Base.

Table C3-3 on page 127 of the Application presents O&M for 2014 Forecast through 2018 Forecast.

Appendix B2 provides Key Operating Facts including the Gross O&M Actual for 2010 through 2012.

81.1 Please explain why the Gross O&M Actual for 2010 through 2012 in Appendix B2 does not appear to be the same as in Table C3-1.

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

The gross O&M figures shown in Table C3-1 exclude deferred Customer Service O&M, Fort Nelson allocation, and Fort Nelson capitalized overhead. In comparison, the gross O&M figures shown in Appendix B2 include these amounts.

Provided below is a reconciliation that shows the differences between the two schedules.

Comparison of Actual Gross O&M ($ thousands)

	2010 Actual	2011 Actual	2012 Actual
Gross O&M (Table C3-1)	206,518	213,606	212,269
Fort Nelson Allocation	680	739	793
Fort Nelson Capitalized Overhead	114	114	122
Customer Service Deferral			7,435
Gross O&M (Appendix B2)	207,312	214,459	220,619

81.2 Please provide the data, in an unprotected Excel spreadsheet, for the following: (i) Gross O&M 2007 Actual through 2013 Projected, (ii) Gross O&M for 2013 Base, and (iii) Gross O&M for 2014 Forecast through 2018 Forecast on a comparable basis.

Response:

Please refer to Attachment 81.2, which provides a response to BCUC IR 1.81.2 and 1.81.3.

Note: With the in-sourcing of Customer Service beginning in 2012, certain expenses subsequent to this date, tied to the support of Customer Service appear in the departments providing the support. Year over year comparison of certain departments prior to 2012, as a result, is more difficult. Also note that due to changes in accounting policies that have classified items differently between O&M and capital over the time period shown, the Gross O&M in each year is not directly comparable. 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.

81.3 Please also provide the Net O&M for the same years 2007 through 2018 as above, in an unprotected Excel spreadsheet. Net O&M is without the Pension/OPEB, Insurance, and RS-16 OMA as tracked outside the PBR formula as shown in Table B6-6 on page 58 of the Application.

Response:

Please refer to the response to BCUC IR 1.81.2.

81.4 For 2007-2013 Projected, please provide a table showing the Gross O&M, capitalized overheads and Gross O&M less capitalized overheads by the departments listed in Table C3-1. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

FEI does not allocate capitalized overhead by department. Attachment 81.4 provides the Gross O&M, the Capitalized Overhead, and the Net O&M in total for the years requested.

81.5 Please provide the O&M expenses per customer for 2007-2012 and Projected 2013. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Please refer to Attachment 81.5. As noted in other responses, due to changes in accounting policies that have classified items differently between O&M and capital over the time period shown, the total O&M in each year is not directly comparable.

81.6 Please calculate an estimated 2013 O&M expenses per customer by escalating the 2007 O&M expenses per customer by BC CPI. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Please refer to Attachment 81.6. Comparing (i) the 2013 equivalent of the 2007 O&M per customer escalated by CPI as requested in this response, to (ii) the O&M per customer as calculated in response to BCUC IR 1.81.5, demonstrates that FEI's O&M has historically grown at a rate that exceeds BC CPI.

82.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3, p. 123

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

"As discussed in Section B6.2.4, the total sustainable savings reflected in the 2013 projection and 2013 O&M Base was based on an analysis of 2012 Actual experience. FEI segregated the variance between 2012 Actual and 2012 Approved into sustainable and temporary savings, and deducted the sustainable savings from the 2013 Approved amount. In total, FEI is projecting $9.4 million in sustainable labour savings and $5.3 million in sustainable non-labour savings." (Section C3, p. 123, lines 16-20)

82.1 Please provide the full analysis of the "2012 Actual experience" where FEI segregated the variance between 2012 Actual and 2012 Approved into sustainable savings and temporary savings.

Response:

This response addresses BCUC IRs 1.82.1, 1.82.1.1, and 1.82.1.2. Please refer to the table below.

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)	293	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

As shown in Exhibit B-1, Table C3-1, page 123, the savings achieved in 2012 with respect to 2012 Allowed was $14.724 million, of which $7.435 million is tied to the Customer Service deferral, $2.989 million has been identified as sustainable and $4.299 million as temporary in nature.

Sustainable savings have been interpreted as lasting through the term of the PBR.

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.

Further analysis of these savings is found in the department sections within Section C-3 of the Application.

This review of savings did not entail an analysis of savings between labour and non-labour.

82.1.1 Please provide both the sustainable and temporary savings items separated by division and at the department level.

<u>Response:</u>

Please refer to the response to BCUC IR 1.82.1.

82.1.2 Please provide the rationale for each variance classification as either “temporary” or “sustainable.”

<u>Response:</u>

Please refer to the response to BCUC IR 1.82.1.

83.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3, p. 124

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

"This section reconciles the 2013 Approved to the 2013 Base on a departmental basis, to provide a starting point for departmental discussion of future trends and pressures for the PBR Period. The reconciliation of the 2013 Base O&M to the 2013 Approved O&M by department is shown below in Table C3-2. This table highlights those departments that have achieved sustainable productivity savings for 2013 that will be realized by customers over the PBR Period as discussed above." (Section C3, p. 124, lines 8-15**)**

83.1 Please provide a reconciliation of the "Productivity (Sustainable Savings)" column of Table C3-2 which separates the net ($14,670,000) into the "2012 Actual experience" analysis savings, other identified savings, and identified increases. Please separate the data by department and division to facilitate matching to the Application.

<u>Response</u>

2013 Department O&M Review ($ thousands)

	2013 Projection	Customer Service Deferral	2012 Sustainable Savings	2013 Sustainable Savings	2013 Approved
Operations	63,509		(203)	(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

As shown on Table C3-2, page 124, the sustainable productivity savings that are being forecast in the 2013 Projection as compared to 2013 Allowed total $14.671 million.

This consists of the Customer Service deferral of $10.285 million, $2.990 million of sustainable savings that were generated in 2012, plus additional $1.396 million of sustainable savings forecast to be generated in 2013

This review of savings did not entail an analysis of savings between labour and non-labour.

84.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.3, p. 127; Exhibit B-1-1, Appendix B2

Projected Full Time Equivalents (FTE)

84.1 Please provide the forecast Average FTE for 2013 Base through 2018 Forecast on the same calculation basis as the Average FTE for 2005 through 2012 provided in Appendix B2, and which are represented by the Forecast Labour and Benefit Inflation in Table C3-3. It is recognized the Average FTE for 2010 through 2012 reflect the move of Customer Service in-house.

<u>Response:</u>

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.

85.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.3.6, p. 130; G-44-12 Compliance Filing,

FEU Five-Year Retirement Management and Workforce Plan (2012-2017)

Demographics

"A five year workforce plan was submitted to the BCUC on August 1, 2012 for the FEU. This section is consistent with this five year workforce plan, summarizes the challenges of the aging workforce and describes the actions, practices and measures that the Company is using to prudently manage the demographic transitions.

Between 2013 and 2018, 552 employees, or roughly 24 percent of the total employee population of the combined gas and electric utilities are eligible to retire with unreduced pensions. When including the 357 employees also eligible to retire with reduced pensions, the total number of employees eligible to retire (unreduced and reduced pensions) increases to 909 or 39 percent of the current workforce. It is difficult to forecast the actual number of employees who will retire when they become eligible. While many retirements are anticipated, the actual experience of the Company over time has been less. Between 2008 and 2012, only 14 percent of those eligible to retire with a reduced or unreduced pension exercised their retirement option." (Exhibit B-1, Sec. 3.3.6, p. 130, lines 5-20)

"In this section the FEU summarizes the demographic challenge the Companies are facing as outlined in the 2012-2013 RRA. Between 2012 and 2017, 399 employees, or roughly 20% of the total employee population of 1,960 of the FEU, are eligible to retire with unreduced pensions … When including the 250 employees also eligible to retire with reduced pensions, the total number of employees eligible to retire (unreduced and reduced pensions) increases to 649 or 33% of the current workforce … Between 2007 and 2011, only 15% of those eligible to retire with a reduced or unreduced pension exercised their retirement options … This historical data would suggest that we can expect a total of 50 probable retirements in 2012, a number that grows cumulatively to 97 employees by 2017, if retirement is deferred." (FEU Five-Year Retirement Management and Workforce Plan (2012-2017))

85.1 Please confirm, or otherwise explain that the demographic data presented in this Application is for the Fortis Energy Utilities.

Response:

The demographic data noted in the preamble is combined for the FortisBC Energy Utilities and FortisBC Inc. (the gas and electric utilities). The data has been combined in this way because workforce planning is approached from an integrated perspective in order to maximize productivity and employee development opportunities across the organizations.

85.2 Please explain the reference "total employee population of the combined gas and electric utilities", and in particular the number of employees directly related to this Application represented in the demographic data presented in this Application and the company which employs them.

Response:

Please refer to the response to BCUC IR 1.85.1 with respect to the reference to the "Total employee population of the combined gas and electric utilities.

Respecting the number of employees of FEI represented in the demographic data, between 2013 and 2018, 220 employees, or roughly 14% of FEI employees, are eligible to retire with an unreduced pension. An additional 374 FEI employees are eligible to retire with a reduced pension within the same time frame, meaning that approximately 38% of current FEI employees are eligible to retire between 2013 and 2018 with either reduced or unreduced pensions.

Note that retirement eligibility figures were updated for the Application since the Workforce Plan was originally filed, as per FEI's response to BCUC IR 1.85.3. The retirement eligibility numbers reflected in the Workforce Plan will therefore be different from those in the Application.

85.3 Please confirm, or otherwise explain that the number of employees related to the demographic data in this Application is 2,300 and is comparable to the 1,960 referenced in the 2012 Compliance Filing quoted above. Please confirm, or otherwise explain, that the increase from 1,960 to 2,300 is primarily due to moving the Customer Service function in-house and the cut-off dates for the two studies.

Response:

The number of employees of 2,300 related to the demographic data includes both the gas and electric utilities and uses data available as of January 1, 2013. The 2012 Compliance Filing referenced above was filed in respect of FEU only, and used data available in early 2012. The total employee population of FEU at the time of filing that report was 1,960. Therefore, the difference between 1,960 and 2,300 is not an increase; rather, it is a difference due to the different employee populations included in each figure, as well as the different points in time the data represents.

85.4 Please explain the significant increase, from 649 to 909 between the two studies, of those eligible to retire with a reduced or unreduced pension.

Response:

Similar to the response to BCUC IR 1.85.3, the difference in numbers between the two studies reflects different employee populations, rather than an increase in the number of employees eligible to retire with a reduced or unreduced pension.

There are 649 FEU employees eligible to retire with a reduced or unreduced pension, and there are 909 employees of the combined gas and electric utilities eligible to retire with a reduced or unreduced pension.

86.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.3.6.1, p. 131

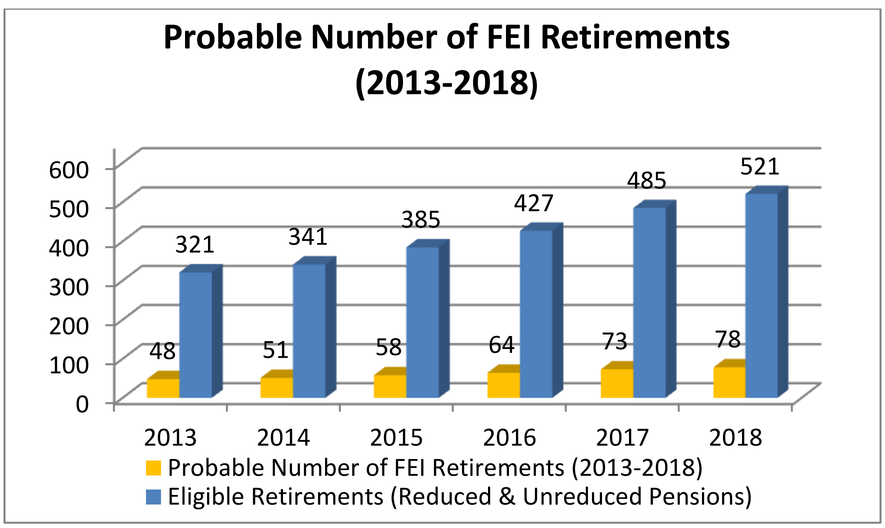
Workforce Planning

86.1 Please provide the probable number of FEI retirements in each of the years from 2013 to 2018.

Response:

It is difficult to forecast the actual number of employees who will retire when they become eligible. Choosing when to retire is an important life decision that each individual must make for themselves and their families. The decision involves weighing many personal factors such as financial situation, retirement benefits, state of health, life expectancy, health benefits, interests and activities, the economy. Between 2007 and 2011, only 15% of those eligible to retire from FEU with a reduced or unreduced pension chose to do so.

Using this historical rate of 15% would suggest we can expect a total of 48 probable retirements in 2013, growing to 78 by 2018, if retirement is deferred. Please refer to the figure below.



86.2 Please provide the number of positions included in costs within the FEI Base 2013 O&M that are currently unfilled.

Response:

FEI has not included dollars for vacancies in its 2013 Projection which forms the 2013 Base.

The current level of vacancies does not provide useful information on the O&M projection for the year, partly because vacancies do not necessarily translate into O&M dollars (they may be capital related or they may be filled through contractors, overtime or other resources) and because they are only a snapshot of a point in time (it is only an annualized figure that could have any meaning).

86.3 Please provide the number of temporary employees currently on the FEI payroll, and the number projected for January 1, 2014 and for December 31, 2014.

Response:

There were 101 temporary employees on the FEI payroll as of June 30, 2013. Temporary employees are generally used to backfill regular employees who are on leave or otherwise absent from the workplace, or to supplement the existing workforce when work volumes are higher than normal. In addition, within the contact centres, temporary employees are hired to allow for scheduling flexibility. (Note that of the 101 employees mentioned above, 19 are contact centre employees.)

FEI does not forecast the need for temporary employees in advance, because the decision to bring on a temporary employee is not made until a department has considered whether there are existing available resources which could be used more productively.

87.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.3.6.2, p. 131

Targeted Recruitment

87.1 Please provide the average fully loaded salary cost for FEI employees hired in the past year, and the average fully loaded salary cost for FEI employees that have retired in the past year.

Response:

The average fully loaded salary cost for FEI employees hired in 2012 was approximately $66 thousand. The average fully loaded salary cost for FEI employees retiring in 2012 was $138 thousand.

FEI believes the most representative group to include in the data is M&E, COPE and IBEW employees only, as minimal numbers of COPE Customer Service employees are expected to retire in the near future. Therefore, FEI has excluded the COPE Customer Service employees from the hiring data and the Executive from the retiring data.

The difference in these average salaries can be explained in part due to approximately 35% of the retirements being attributed to long-service M&E employees at the senior manager or director level. However, in keeping with its philosophy to review all vacancies in an effort to determine how to fill them most efficiently, the majority of hires were at the union employee level; only 25% of employees hired in 2012 were M&E.

87.2 Please confirm, or otherwise explain that this average differential, between hiring and retiring FEI costs, is likely to continue over the 2014-2018 period.

Response:

Whether the average differential between hiring and retiring costs set out in the response to BCUC IR 1.87.1 continues over the 2014-2018 period is dependent on how and whether retiring employees are replaced and the nature of the positions that are replaced. As FEI is unable to forecast exactly which employees will retire, it is not possible to predict whether the trend will continue.

88.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.5.1, p. 143

Customer Service Department – Mass Market Customer Communications

88.1 Please provide the Customer Service Department Mass Market Customer Communications expenditures for 2007-2018. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

The Customer Service mass market communications ensure that we address the needs of our customers in keeping them informed through ongoing awareness and education for customer directories, rate changes and the Customer Choice program. The forecasted (2014 through 2018) mass market communication expenditures have been prepared at a high level and remain consistent with the 2013 levels, adjusted for 2% inflation. Please refer to Attachment 88.1 for the fully functioning electronic spreadsheet.

89.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.5, Table C3-14, pp. 145-146

Customer Service Department - # of FTEs

FEI states: "In 2013, on a temporary basis only, 13 additional FTE were required to support the meter reading transition to the new service provider. These 13 FTE are not required in 2014 and on." (p. 146)

89.1 Please confirm, or explain otherwise, that the cost of these 13 project FTEs have not been included in the 2013 O&M Base.

Response:

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). This results in the 2013 O&M Base for the formula being overstated by $373 thousand. The impact of this is that the revenue deficiency for each year of the PBR period is overstated by this amount, inflated by the appropriate formula for the year. Correcting for this error would result in a decrease in the delivery rate for each year (2014 through 2018) of approximately 0.05%. Since this has a minimal impact, FEI has not updated its delivery rate requests at this time, but will update for this item when the final financial schedules are filed to set the rates for 2014.

89.2 Please provide the total cost for the 13 temporary FTE.

Response:

Please refer to the response to BCUC IR 1.89.1.

In the 2011-2012 FEU RRA, FEU stated: "An increase in proficiency will result in the need for fewer resources over time. Through the period of 2011 to 2013, increased proficiency is expected to result in the reduction of 58 employees." (2012-2013 FEU RRA, Exhibit B-1, p. 193) [Emphasis Added]

89.3 Please confirm, or explain otherwise, if FEI's number of employees has been reduced by approximately 58 employees for 2013.

Response:

The reduction of 58 employees, as stated in the preamble and indicated in the FEU 2012-2013 RRA, was based on 2011 projection of 367 FTEs compared to 2013 forecast of 309 FTEs. FEI has been able to achieve further employee reductions, over and above the 58 initially anticipated in the 2012-2013 RRA proceeding.

As shown in Table C3-14 on page 145, FEI is forecasting 301 FTEs for 2013 when taking into account temporary employees (13) required for meter reading. It is worthy of note that without temporary FTEs, FEI has seen a reduction of 79 FTEs from the 367 FTEs projected in 2011 to 288 FTEs in 2013. This reduced number of employees is expected to remain consistent during the PBR period.

89.3.1 If confirmed, please indicate in which departments these reductions have been recorded. Please indicate what the total cost savings are from these employee reductions and where these savings have been recorded.

Response:

The reduction of FTEs from 2011 to 2013 is mainly from Contact Centre and Billing Operations. Based on an average salary, the annual cost savings would be approximately $3.2 million.

The savings from the 58 FTEs reduction was accounted for in the FEU 2012-2013 RRA. The savings from the additional reduction of FTEs since then has been included in the Customer Service Variance Deferral Account.

90.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.5, p. 144; Exhibit B-1-1, Appendix F6

Customer Service Department – Productivity Improvements

FEI states that it "realized a sustainable reduction in O&M from the 2013 Approved to the 2013 Projection of $10.6 million (of which $8.6 million is from a new meter contract)." (p. 144)

90.1 Please describe where this $10.6 million savings between 2013 Approved and 2013 Projection is reflected in the O&M Activity View Schedule provided in Appendix F6. Please indicate which specific "activities" the savings have been reflected in.

Response:

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).

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. These savings have been reflected in in the activity view line items as follows:

- Line 47 - customer assistance ($13 thousand)
- Line 50 - credit and collections ($64 thousand)
- Line 51 - customer operations ($265 thousand)

90.2 Please explain how the $8.6 million in O&M reduction from the signing of a new meter contract is an example/evidence of FEI "leveraging the Customer Care function to maximize productivity opportunities."

Response:

The signing of a new meter reading contract was made possible by the decision to insource the customer service functions. Prior to 2012, the meter reading contract was embedded in the general customer service contract and therefore there would have been no opportunities for FEI to go to the market for a new meter reading service provider.

90.3 Please specifically describe how the $2 million in sustainable O&M reductions not related to the signing of the meter contract were achieved and what they relate to.

Response:

As outlined on page 151 of the Application, Customer Service realized $2 million in O&M savings in addition to the meter reading savings. Some of these savings are allocated to the Customer Service Variance Deferral Account. These savings are as follows:

- $1.235 million – due to lower billing operation costs [deferral]
- $0.423 million – due to transfer of Knowledge and Learning department to Human Resources [deferral]
- $0.342 million – due to research studies and bad debt expense [non-deferral]

The O&M savings from lower billing operation costs is due to a number of factors, including: lower print vendor contract costs were negotiated, fewer letters were mailed out due to an improved system with outbound calls, and lower than anticipated resource levels as Customer Service realized efficiencies and became more proficient.

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.

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.

Lastly, savings related to bad debt can be generally attributed to lower commodity costs, a warmer winter season and improved collections procedures.

91.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.5, pp. 143-145 and Table C3-14

Customer Service Department – Productivity Improvements

FEI states that it "Realized a permanent reduction in staffing levels from the 2013 Approved to the 2013 Projection." (p. 144)

FEI also states that it "successfully completed the stabilization phase of the CCE Project in the second quarter of 2012." (p. 143)

91.1 Please confirm, or explain otherwise, if this permanent reduction in staffing levels refers to the decrease of 284 FTEs to 278 FTEs, as shown in Table C3-14.

Response:

Confirmed.

91.2 Given that FEI just completed the stabilization phase of the CCE Project half-way through 2012, please explain why FEI is forecasting that it will require an equal number of FTEs for 2013 as it required in 2012 (i.e. Actual 2012). Should there not be further reductions to staff levels in 2013 as FEI gains efficiencies from the implemented CCE Project?

Response:

The FTE figures provided in Table C3-14 reflect year-end FTEs. Therefore, the 2012 figures provided reflect the ongoing FTE requirements, and not the FTEs related to the stabilization phase (which occurred in the first half of 2012).

As stated in Section C3.5, FEI expects that overall staffing levels will remain consistent with the reduced 2013 level of approximately 290 staff. However, it is also expected that the Customer Service department will become more efficient as a result of refinement in the end to end business processes and the improved ability to match resources to volumes of work.

FEI states that it has "adopted the insourced customer service model which has allowed for greater integration with other departments of the FEU." (p. 144)

91.3 Has this integration resulted in a decrease in staff levels in other departments? If yes, please indicate which department(s) and the level of staff reduction achieved. If no, please explain why not.

Response:

The integration that FEI has referred to relates to increased communication and collaboration between customer service and other departments in support of the customer experience. It was not intended to mean an organizational integration with changes in reporting relationships. As such, these improvements have not resulted in any reductions in staffing levels in other departments.

However, as noted on page 151, lines 12 to 13 of the Application and discussed in BCUC IR 1.90.3, there has been one organizational change that resulted in reduced costs which was the transfer of the Knowledge and Learning department responsibilities to the Human Resources group within HR's existing budget.

92.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.5, p. 145

Customer Service Variance Account

FEI states: "The balance of this [Customer Service Variance Account] at the end of 2013 is forecasted to be approximately $13 million on an after-tax basis…"

92.1 Please provide the forecast balances for the Customer Service in-sourcing and the meter reading costs separately for 2013.

Response:

The Customer Service Variance Deferral Account includes forecast pre-tax additions, related to O&M cost savings, of $10.285 million in 2013 (Exhibit B-1, Section E, Schedule 47, Line 26, Column 4). The breakdown of the cost savings is as follows:

- $8.627 million – due to meter reading cost savings
- $1.235 million – due to lower billing operation costs
- $0.423 million – due to transfer of Knowledge and Learning department to Human Resources

93.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.5, p. 145

Customer Service Department – Productivity Improvements

FEI states: "In future, customer service operations will improve its efficiency by bringing more work into the contact centre from other parts of the organization during times of low call volumes and will investigate changing the hours of operations."

93.1 Please explain the nature of the work that FEI would be able to transfer to the contact centre and from which parts of the organization the work would be transferred.

Response:

In addition to handling customer contacts, Customer Service Representatives routinely handle other types of work. This type of work includes account updates, processing customer transactions and outbound customer communication. FEI continues to look for this type of work being done in any other area of the organization and when found, determines if that work can be done more effectively or efficiently at the Contact Centers.

93.1.1 If FEI were able to transfer work from other departments to the contact centre, does FEI anticipate this would result in decreases to staff levels in these other departments or reductions of overtime in those other departments? If not, why not?

Response:

It is possible that there would be decreases in staffing levels or overtime costs in those other departments. However, until the nature and volume of this work is known and more certain, it is difficult to speculate as to the magnitude of those reductions. These are the kind of efficiencies that FEI will be exploring to achieve its productivity improvement factor as part of its PBR proposal.

93.2 Has FEI investigated other options for addressing times of low activity due to low call volumes? For instance, would it be a possibility to reduce staffing levels during these times of low call volumes? Please discuss.

Response:

FEI forecasts expected call volume and the expected timing of calls based on historical information. Then, resources are scheduled to match this forecast in order to provide the level of service that has been committed to. If different patterns are identified during the day, resources are further adjusted to the extent possible.

The statement in the preamble to the question above relates to intra-day fluctuations in volume, as calls do not typically arrive in an even pattern throughout the day. Even if the forecasted number of calls for an hour is accurate, those calls may come in heavier in the first half hour than the last half hour. Therefore, it is important to have other work available to ensure that an efficient operation is being maintained at all times during the day.

93.3 Please explain what the hours of operation for the contact centre are now and how FEI would potentially change these operational hours.

Response:

Currently, the hours of operation for non-emergency calls at the contact center are 7 am to 8 pm Monday to Friday and 9 am to 5 pm on Saturdays. FEI is evaluating closing one hour earlier on weekdays and looking at various options for Saturday. Potential cost savings will be evaluated against customer impact including looking at what other contact options are available to customers during the hours that the contact center is closed. The general hours of operation for emergency calls will remain 24 hours per day, 7 days per week.

94.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.5, p. 145

Customer Service Department – Cost Per Interaction

FEI states: "A measure that the Company is now able to monitor to assess productivity in our contact centres is cost per interaction… The Company expects that cost per interaction will be lower in 2013 than in 2012, and that this measure should be stable for the PBR Period." (p. 145)

94.1 Please describe what the cost per interaction was for 2012 and what FEI is forecasting the cost per interaction will be for 2013.

Response:

The cost per interaction for 2012 was $7.53. Cost per interaction is not forecasted. However, as of June 30, 2013, the year to date cost per interaction was $7.25. Cost per interaction includes inbound and outbound telephone calls, emails, faxes and other correspondence, as well as self-serve transactions.

94.2 Please explain the benchmarks that FEI is using (beyond year to year comparisons) to assess the reasonableness of the cost incurred per interaction.

Response:

The comparability of cost per interaction is strongly influenced by a company's policies and business processes and is not comparable across different industry segments or geographic regions. Although other contact centers use cost per interaction as a measurement, there are no standards to dictate what costs or types of interactions should be included, thereby rendering any comparison of limited use. Therefore, FEI believes that the best way to utilize this data is to look at cost per interaction comparisons month over month and year over year. Through this comparison, FEI can identify trends in contact center costs and put actions in place if required.

95.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.5.2, pp. 147, 149

Customer Service Department – Contact Centres

FEI states: "As a result of these calls and other improvements made to the collections process, accounts receivable has improved and the volume of traditional outbound live-agent collections calls prior to disconnection in 2012 was reduced by 35 percent from the three year average." (p. 147)

95.1 Please quantify the improvement in accounts receivable for 2012 related to the automated reminder calls.

Response:

In 2012, post stabilization, accounts receivable (AR) over 60 days averaged 4.93%. This was an improvement over 2011, when average AR over 60 days for the same period was 5.76 %. While part of the improvement in AR for 2012 can be attributed to the new automated reminder calls for overdue bills, there were other changes implemented throughout 2012 that also would have influenced AR, including additional training for staff and process changes to improve the customer experience.

95.2 Does FEI anticipate further improvement to accounts receivable for 2013? Please discuss.

Response:

FEI intends on refining policies and processes every year as opportunities are identified. However, at this time, we do not believe that there are other opportunities to achieve further savings resulting from planned changes to the collections processes in 2013.

FEI also states: "FEU believes the historical bad debt expense is a good indicator of the expected levels." (p. 149)

95.3 Have the improvements to accounts receivable seen in 2012 been reflected in FEI's forecast of bad debt expense? If not, why not?

Response:

Yes. The 2012 mass market bad debt experience rate, in conjunction with previous year experience rates, is included in the calculation of the forecasted bad debt expense for 2014 – 2018. Bad debt expense is forecast based on historical levels and is influenced by a number of factors, such as accounts receivable, process changes, rates and general economic conditions. FEI believes that using a longer term average vs. a one year experience rate is most appropriate to forecast bad debt levels going forward. In this case, the average used to forecast bad debt expense includes the 2012 actual experience rate.

96.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.2, Table C3-1, p. 123;

Exhibit B-1-1, Appendix F6

Customer Service Department – Historical O&M By Department

96.1 Please confirm, or explain otherwise, that the 2012 O&M amount for Customer Service of $48,172,000 shown in Appendix F6 (page 1) is the Actual 2012 Customer Service O&M incurred, including any amounts deferred to the Customer Service Variance Deferral Account.

Response:

Confirmed. The 2012 O&M amount of $48.172 million, as presented in Appendix F6, does include cost savings included in the Customer Service Variance Deferral Account.

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)

Table C3-1 on page 123 of the Application shows a 2012 Approved amount of $49,115,000 and a 2012 Actual amount of $40,737,000 for Customer Service. Footnote 1 of Table C3-1 further states that the Customer Service amount for 2012 Actual excludes deferred Customer Service O&M.

96.2 Given the above, please confirm, or explain otherwise, that of the $8,378,000 reduction in 2012 Actual Customer Service O&M from 2012 Approved, $7,400,000 was deferred to the Customer Service Variance Deferral Account.

Response:

Confirmed.

96.3 Please describe the nature of the $7.4 million in costs which were deferred to the Customer Service Variance Deferral Account.

Response:

Customer Service realized $7.4 million in O&M savings in 2012 which were deferred in the Customer Service Variance Deferral Account. These cost savings are as follows:

- $1.0 million – customer assistance (BCUC account 210-12)
- $2.7 million –customer billing (BCUC account 210-13)
- $3.7 million –meter reading (BCUC account 210-14)

Cost savings for contact center and customer assistance were achieved due to being able to reduce temporary staff levels more quickly as staff became more proficient in handling customer inquiries. Cost savings from customer billing were mainly from lower print and mailing costs and temporary staffing being reduced faster than anticipated. Cost savings from meter reading were possible due to the extension of shared meter reading costs between electric and gas meters resulting from delays of BC Hydro's smart meter program.

96.3.1 Please provide a breakdown of the $7.4 million deferred costs at the activity view level.

Response:

Please refer to the response to BCUC IR 1.96.3.

In the FEU 2011-2012 RRA, FEI provided the following explanation for establishing the Customer Service Variance Account: "In 2012 and 2013, the Customer Service department will be faced with business uncertainties…" (Exhibit B-1, p. 404)

96.4 Given the purpose of the deferral account, would FEI agree that the $7.4 million reduction in 2012 Actual Customer Service costs from 2012 Approved is more a result of mis-forecasting of the 2012 costs during the last RRA, not sustainable savings achieved through increased productivity? If not, why not?

Response:

No, FEI does not agree. The O&M savings achieved in the first year of operations will flow back to customers through the Customer Service Variance Deferral Account and be carried forward into 2013 and beyond as sustainable savings.

The estimates provided for customer service costs for 2012 and 2013 were reasonable given the information available at the time and given the assumption that procedural changes for efficiency would be limited in the first year of operation. The $7.4 million reduction in 2012 actual customer service costs is related to a combination of related factors including the negotiation of reduced rates from key vendors, process efficiencies gained by the new customer service staff, refinement of staffing levels based on these process efficiencies and variances in cost drivers (both positive and negative) from what was anticipated prior to go-live.

It was discussed in the 2012 -2013 RRA that the operating cost estimates provided at that time were subject to a number of uncertainties related to the first year of operating under the new service model and technology platform. The types of uncertainties included fluctuations in call volumes, the rate of customer adoption of new communication channels and self-serve options being offered, the stabilization of the new CIS and its impact on the end to end business processes, along with a potentially longer than anticipated duration required for new staff to become skilled and proficient at their responsibilities.

97.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.5.2.2, p. 150

Customer Service Department – Billing Operations

"The main drivers of cost for the Billing Operations are the number of customers, postage, printing and labour." (Exhibit B-1, p. 150)

97.1 Please provide a table showing the number of customers and the Billing Operations costs for postage, printing and labour for 2007-2018. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Data for the years 2012 to 2018 has been provided below. Data prior to 2012 is not available as this service was provided for through our service agreement with CustomerWorks LP (who outsourced to Accenture). The service provider did not provide a breakdown of the costs in this manner.

Please refer to Attachment 97.1 for the fully functioning electronic spreadsheet.

	Actual 2012	Base 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
Billing Opns Labour	4,559	4,723	4,863	4,992	5,155	5,336	5,580
Postage	5,660	6,545	6,676	6,810	6,946	7,085	7,226
Printing	832	1,058	1,079	1,100	1,122	1,145	1,168
Total Printing & Postage	6,492	7,603	7,755	7,910	8,068	8,229	8,394
Total Labour, Postage & Printing	11,051	12,326	12,617	12,902	13,223	13,566	13,974
Average customers	834,859	840,721	845,495	850,620	856,001	861,402	866,681

Note: 2007 to 2011 not available as it was provided for through contract with Accenture.

97.2 By customer type (Residential, Commercial, Industrial), please provide a table showing the number of bills prepared annually and the percentage of bills that are distributed electronically for 2007-2018. Include the requested information in the form of fully a functioning electronic spreadsheet.

Response:

FEU Customer Billing

Year	Total Number of Bills	Number of Electronic Bills	% of Bills Distributed Electronically
2007			
2008	**2007 to 2008 data not available**		
2009	10,966,596	109,740	1.0%
2010	11,105,552	493,538	4.4%
2011	11,184,510	636,065	5.7%
2012	11,380,292	1,058,367	9.3%
2013	11,471,940	1,376,633	12.0%
2014	11,569,403	1,700,702	14.7%
2015	11,673,801	2,031,241	17.4%
2016	11,780,644	2,367,909	20.1%
2017	11,885,175	2,709,820	22.8%
2018	11,987,635	3,056,847	25.5%

Please note the data prior to 2009 is not available from the previous outsource provider. Additionally, the historical information requested is not available by customer type (i.e. residential, commercial, industrial) as the company does not track the information at this level of detail.

For an indication of the split of bills by customer type, please refer to the table below which shows the customer count for FEU at the end of July 2013.

2013 Customers by Type (#)		
Residential	856,441	90.6%
Small Commercial	79,061	8.4%
Large Commercial	6,475	0.7%
Seasonal Rate 4	33	0.0%
All Other Rate Classes	3,488	0.4%
Total	945,498	100.0%

The data from 2009 – 2012 represent actuals recorded. For 2013 and onwards, the number of bills produced annually is forecast based on the number of customers and the number of bills produced for a customer annually (i.e. 12 bills per year per customer). In some cases, the number of bills produced annually for a customer may not be 12 bills per year due to multiple accounts billed on a customer's bill.

In forecasting the percentage of bills that will be distributed electronically from 2013 – 2018, an annual growth factor of 2.7% was developed based on the average from 2009 – 2012. The 2.7% growth factor is applied with the 2012 percentage of bills distributed electronically as the starting point. The ability of the company to increase customer take-up for electronic billing is dependent on campaigning and promotional efforts by the company to sign-up customers and whether these efforts are successful.

FEI provides the forecast activities for reference purpose only as the information for 2014 through 2018 represents a high level forecast of future trends. As FEI's proposed rates are based on the PBR Plan, FEI's O&M and capital forecasts and related requests such as this question should not be the focus of this proceeding. Please refer to Attachment 97.2 for the fully functioning electronic spreadsheet.

98.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.6;

FEU 2012-2013 RRA, Application, Figure 5.3-4, p. 208

Energy Solutions and External Relations

98.1 Please provide the staffing levels for the following years: Actual 2010, Actual 2011, Actual 2012, Approved 2013, and Forecast 2013.

<u>Response:</u>

This response addresses BCUC IRs 1.98.1 and 1.98.1.1.

Provided below is a summary of average FTE for the Energy Solutions and External Relations department.

Summary of Energy Solutions and External Relations Average FTE

	2010 Actual	2011 Actual	2012 Actual	2013 Projection
ES&ER Average FTE	90	108	123	136

Please find below this average FTE shown based on the current organizational structure. In order to maintain consistency with the information presented in this filing the FTE count has been shown based on the department's organizational chart, as it exists today.

Functional Group	2010 Actual	2011 Actual	2012 Actual	2013 Projection
ES&ER Supervision	2	2	2	2
Energy Solutions	25	32	35	38
EEC	15	16	21	29
Communications	17	19	23	20
External Relations	7	8	9	9
Forecasting & Market Development	11	18	20	20
Business Development	12	13	13	18
Average FTE	**90**	**108**	**123**	**136**

Note: There are some staff members that work on EEC Programs and their FTE count is captured in the functional group in which they reside. All EEC Program expenditure including labour costs are appropriately captured in the deferral account. 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. The additional staffing for GGRR are required to develop training materials, safety guidelines, and codes and standards including evaluation of shop upgrades. These costs will be captured in the GGRR deferral account.

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.

98.1.1 For each year, please group the staff in the same organizational chart structure for each year as was provided in the 2012-2013 RRA Application (Figure 5.3-4, p. 208).

Response:

Please refer to the response to BCUC IR 1.98.1.

99.0 Reference: FORECASTS FOR THE PBR PERIOD

FEU 2012-2013 RRA, Application, Tab C, Table 5.3-39, pp. 212-213

Energy Solutions and External Relations – Incremental Spending

FEU requested incremental spending in the amounts of $3.1 million for 2012 and $1 million in 2013 for various initiatives as part of its 2012-2013 RRA. (2012-2013 FEU RRA, Exhibit B-1, Table 5.3-39)

99.1 Please explain which of these initiatives have or are expected to have been completed by the end of the 2012-2013 period.

Response:

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. The 2012/13 approved incremental expenditure pertained primarily to three programs areas - Safety Education Messaging, the LTRP and the Renewable Natural Gas (RNG) service offering. These programs are not short-term or temporary initiatives, but are required throughout 2012-2013 and the 2014-2018 forecasted period as described below. With respect to the Safety Education Messaging, the Commission Panel stated in its Reasons for Decision to the FEU 2012-2013 RRA at page 55:

> *"Other than the LTRP and areas discussed elsewhere in this Decision, the Commission Panel approves the O&M budget for the ES&ER department for the test period as the Commission Panel supports the Companies initiatives to increase public safety education."*

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. As such, throughout 2014 to 2018, public safety education will continue to be an integral part of the company's integrity management system and therefore the expenditure for this activity will remain at existing 2012/13 levels through the 2014-2018 forecasted period

Similarly, FEI expects to continue compilation and filing of a LTRP, through the five year forecasted period, that requires the greater depth, research and analysis to meet Commission directives and stakeholder expectations. 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. As such FEI has ramped up its research, analytics, planning and consultation capabilities in response to meeting these expectations. FEI 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.

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, subject to the Commission decision on FEI's Biomethane Service Offering (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.

Given that all three programs are expected to continue into the forecasted five year period and FEI will maintain the same level of activities in these areas, as compared to 2012/2013 levels it is appropriate that these approved amounts be included in the base 2013 O&M. Consequently, the 2013 base is an appropriate base from which to develop a formulaic O&M for the 2014-2018 forecasted period.

99.2 Please explain why it is appropriate for all of the incremental spending requested as part of FEI's previous RRA to be included as part of the 2013 Base for the PBR Period.

Response:

Please refer to the response to BCUC IR 1.99.1

100.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.6, Table C3-17, p. 158

Energy Solutions and External Relations – Department O&M Review

Table C3-17 shows 2013 Projected O&M to be $19,215,000.

100.1 Please separate the 2013 Projected O&M into the major programs/initiatives planned/undergone for 2013.

<u>Response:</u>

It is incorrect to characterize the ES&ER department as one that only partakes in work described as major programs or initiatives. The ES&ER department is a core group of staff with ongoing tasks and responsibilities providing service either directly or indirectly to customers, not unlike many other groups within FEI. The work provided by this group impacts customer satisfaction, the acquisition of new customers, and retention of existing customers. This group provides ongoing account management of commercial and industrial customers, EEC programs, communications to customers, interaction with municipalities and government, customer additions and retention and new initiatives such as RNG and NGT. These efforts enable FEI to meet customer expectations and satisfaction levels. Additionally, they ensure that the company continues to adapt existing and offer new service offerings in the current period and into the future period which serve to increase natural gas throughput.

Department staff maximize their time and expertise by working on various tasks, programs and initiatives as they arise. As such, the Company, and staff groups, do not separate O&M into specific initiatives as this would be an administrative burden with little or no benefit.

The table below shows the 2013 Projected O&M costs for the ES&ER department segregated by functional group. Alongside each functional group, the associated roles and responsibilities together with the major programs/ initiatives that staff work on, is also provided.

Functional Group	2013 Projected O&M ($000's)	Major Program / Area of Responsibility
ES&ER Administration	671	• Management and administration
Energy Solutions	5,117	• Management of key customer accounts, including the province's largest energy users, industrial and commercial customers resolving billing issues • Working closely with existing and potential customers (including builders, developers, large and small businesses, homeowners, municipalities, school districts and other government organizations) to analyze and determine how natural gas will meet their current and future energy needs • Identification, development and implementation of service enhancements for the benefit of customers including new products and services like individual metering through vertical subdivisions, piping to suites, on-demand hot water heaters and clothes driers, new EEC programs, RNG, NGT, etc. • Educating customers regarding service options and available products and programs including EEC programs, RNG, CNG and LNG.
EEC	302	• High Carbon Fuel Switching Program - Incentives (All other EEC Program expenditures are captured in the EEC deferral account)
Communications	5,045	• Development , implementation and delivery of customer, employee and stakeholder communications • Safety Education Messaging to increase public awareness of gas safety risks and the steps to be taken to minimize harm • Natural gas awareness and outreach to increase preferences for natural gas use • Responding to customer and stakeholder group inquiries • Maintenance and management of internal and external company website and digital communications • Management of media inquiries
External Relations	1,944	Renewal I of operating agreements with municipalities • Building awareness of key projects with key stakeholders, including communities, First Nations, key government ministries, and business associations to proactively address issues and concerns and to meet public consultation requirements • Working closely with municipalities and local government staff on ongoing system maintenance within municipalities to resolve operational issues such as Right Of Way and tree clearing. • Working with provincial government staff, elected officials, and business organizations to develop and support regional and provincial energy policy

Functional Group	2013 Projected O&M ($000's)	Major Program / Area of Responsibility
Forecasting & Market Development	3,263	• Customer demand forecasting • Compilation of the Long Term Resource Plan • Natural gas tariff offerings, changes and support including MX Test development and reporting. RNG customer education and, NGT Incentive program administration • Evaluation of market conditions including emerging gas technologies and upcoming changes to codes and regulations • 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 • EM&V, M&V and EEC Reporting activities for EEC programs (these costs are captured in the EEC Deferral account)
Business Development	2,875	• Identification of potential new large scale growth initiatives • Development of business plans and strategies for developing new business opportunities. • Development of new service offerings, including but not limited to NGT services, low carbon product offerings Renewable Natural Gas, CNG and LNG for remote communities and off-grid applications and development of high horsepower transportation applications such as ferries, locomotives and mine haul trucks. • Development and regulatory filings for demonstration projects and new initiatives • Market assessment for new markets for natural gas.. For example use of natural gas as a fluid for fracking shale gas reserves. • Evaluation of new technologies and products required for the successful development of new markets. E.g. fueling station compression technology
Total ES&ER	Labour: $11,460 Non- Labour: $7,755 **Total: $19,215**	

Please also refer to the response to BCUC IR 1.98.1.1 which provides for the appropiateness of this 2013 department expenditure level given that programs examined and approved in the FEU 2012-2013 RRA will continue through the five year PBR forecasted period.

101.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1-1, Appendix F6, p. 2

Energy Solutions and External Relations

Per Appendix F6, the historical five-year average of actual costs spent for "Forecasting, Market & Business Development" is $3,659,000, but FEI shows a 2013 Projected cost in this activity of $6,138,000.

101.1 Please explain why it is reasonable that FEI is projecting an increase in 2013 Forecasting, Market & Business Development costs of $2,479,000, which is an increase of 68%, over the five year historical average.

Response:

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 of expenditure over this five year horizon is not relevant or appropriate. The use of a five year average assumes a static environment, which is not the case. The company has continued to adapt to the changing market circumstances over this period.

For these reasons, what occurred five years ago in the business environment is not a good measure for what is required today. A more suitable and reasonable comparison is to expenditures more closely representative of the current operating environment and those that have been examined in the most recent rate applications filed with the Commission. As such, a comparison of the 2013 Projection for this group of $6.2 million to the 2011 actual expenditure of approximately $4.9 million shows an increase of approximately $1.3 million. This projected increase is largely attributable to expenditures that have been examined and approved by the Commission, specifically: approximately $600 thousand for the LTRP and $416 thousand for the re-classification of RNG service offering expenditure from deferral account to O&M for the Forecasting & Market Development group. The remaining increase is largely driven by recent growth initiatives, to increase natural gas throughput and thereby revenues, such as the GGRR.

For further details of the reasonableness of 2013 expenditure levels please refer to the response to BCUC IR 1.99.1.

102.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.6.4, Table C3-18, pp. 160-162

Energy Solutions and External Relations Forecast

FEI states: "In addition, the 2014 Forecast is higher than the 2013 Base by approximately $2.6 million, as the 2014 Forecast includes programs and initiatives necessary to address the competitive and market threats identified above which will continue to remain relevant through the forecast period." (p. 160)

102.1 Please clarify whether or not FEI is proposing to increase the 2014 O&M amount for ES&ER by more than the PBR formula.

Response:

This response addresses BCUC IRs 1.102.1 and 1.102.1.1

In this Application, FEI is seeking approval for customer rates based on the PBR formula, and not for individual department expenditure levels. Rather, individual department expenditures have been provided in this Application to provide a reference to the business drivers being faced by each department in the five year forecast period, and therefore impact on cost pressures during this same period. To clarify, in this Application, FEI is proposing each year that the component of rates designed to recover O&M expenses will adjust the previous years' amount by the formula which includes a productivity factor. The resulting O&M amount determined by the PBR formula will be representative of the aggregate of all FEI departments for the respective year. How this aggregate O&M level is allocated among the individual department will be determined by FEI management.

The purpose of the O&M formula approach set forth by FEI is to provide a strong incentive for FEI to find efficiencies in its O&M spending. How and in which departments those efficiencies will be garnered in the five year forecasted period will be the responsibility of FEI's management.

102.1.1 If FEI is proposing this, please explain how this is consistent with the PBR methodology as proposed by FEI, and please indicate what the 2014 Forecast O&M would be if FEI used the PBR Formula only to calculate Forecast 2014 O&M.

Response:

Please refer to the response to BCUC IR 1.102.1.

103.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.6, Table C3-17, pp. 158-159

Energy Solutions and External Relations – Department O&M Review

FEI provides the following explanation for the 2013 projected increase over Approved 2013 O&M: "Enhancing the high carbon fuel switching program to increase customer uptake and to accommodate customer participation rates." (p. 158)

103.1 Please describe in the detail the "enhancements" FEI plans to make to the high carbon fuel switching program and how FEI anticipates these enhancements will increase customer uptake.

Response:

It should be clarified that the excerpt above in the preamble to IR refers to enhancements made in 2013, while the IR asks about planned enhancements. This response addresses enhancements made in 2013.

The enhancements FEU have made to the High-Carbon Fuel Switching Program in 2013 include a more focused marketing effort to both contractors and customers. In April of 2013, the FEU added a $50 contractor incentive, since contractors provide an effective means for customers to learn about our EEC programs and to facilitate participation. A contractor package was distributed to the BCSA database in spring of 2013 to inform contractors about the introduction of the contractor incentive and other program rules. For customers, the marketing message has also been enhanced through marketing collateral and tools that inform customers about the monetary savings and other benefits of switching from oil to natural gas. The online Home Energy Calculator, at www.fortisbc.com/calculator, educates customers about costs and energy savings that can be achieved when switching from an old oil furnace to a new high efficiency natural gas model. A spring marketing campaign was undertaken and a fall marketing campaign is planned for the latter half of 2013. FEI is also initiating projects for conversions in the Interior which will add participants in future years.

103.2 Please provide the specific cost forecast for this initiative.

Response:

The 2013 expenditure forecast for this initiative is $302 thousand.

103.2.1 Please indicate where these costs will be recorded at the "activity level".

Response:

The costs will be recorded under Account No. 310-13 Energy Efficiency.

103.3 Please explain how this additional expenditure/initiative relates to the approximately $2.6 million additional non-labour increases in the 2014 forecast shown in Table C3-18.

Response:

The 2014 additional expenditure for this program is an inflationary increase of $6 thousand, which is included in the approximately $2.6 million increase in the 2014 forecast.

104.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.6, pp. 158-162

Energy Solutions and External Relations Forecast – Incremental Spending

FEI provides the following explanation for the 2013 projected increase over Approved 2013 O&M: "Increasing preferences and demand for natural gas products by way of creating awareness of benefits of natural gas use, through comprehensive customer education and outreach programs." (p. 159)

FEI provides the following explanation for the incremental spending forecast for 2014 over the 2013 Base: "This initiative [Customer Education, Awareness, and Outreach Programs] is aimed at increasing preferences and demand for natural gas use through comprehensive customer education, awareness and outreach programs." (p. 161)

104.1 Please explain why it is necessary for FEI to forecast an increase of $1 million for 2014 for this initiative when it is already forecasting an increase in 2013 over the Approved 2013 amount related to this initiative?

Response:

This response addresses BCUC IRs 1.104.1, 1.104.2 and 1.104.3.

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.

This initiative is designed to increase preferences and demand for natural gas use and the incremental activities planned for 2014 will build further upon the 2013 successes by providing for increased channels of communication and with tailored messaging based on customer segmentation. The specific costs for this initiative will be non-labour and will include the development, design, production and delivery of this messaging along with the ongoing evaluation of results.

104.2 Please describe the additional work that FEI intends to undertake which would be considered incremental to what has already been planned for 2013.

Response:

Please refer to response to BCUC IR 1.104.1.

104.3 Please provide the specific cost forecast for this program/initiative.

Response:

Please refer to response to BCUC IR 1.104.1.

104.4 Please explain how the additional expenditures relate to the approximately $2.6 million additional non-labour increase in the 2014 Forecast, as shown in Table C3-18.

Response:

Of the $2.6 million additional non-labour increase, this initiative accounts for $1 million.

FEI provides the following explanation for the 2013 projected increase over Approved 2013 O&M: "Enhancing the high carbon fuel switching program to increase customer uptake and to accommodate customer participation rates." (p. 158)

FEI provides the following explanation for the incremental spending forecast for 2014 over the 2013 Base: "This [Incentive] program will leverage the successes of the high carbon fuel switching program. This program accounts for $500 thousand of the increased expenditure for 2014." (p. 161)

104.5 Please explain why it is reasonable to further increase the forecast for Incentive program spending in 2014 when FEI has already forecasted an increase to the Incentive program for 2013 above the Approved 2013 amount.

Response:

The increase in expenditure in 2013 pertains to the High Carbon Fuel Switching Program which is distinct from the Incentive Program. The Incentive Program is new for 2014 and is described in response to BCUC IR 1.105.2.2

104.6 Please confirm, or explain otherwise, that FEI has now requested incremental funding related to Incentive programs for each of the 2012, 2013 and 2014 years.

Response:

Not confirmed.

FEI's O&M forecasts included in Section C3 of the Application are not a funding request. As stated on page 121 of the Application, the 2014 through 2018 O&M forecasts are included for reference purposes. FEI's proposed PBR Plan does not rely on the forecast O&M costs.

The Incentive Program is a new initiative for 2014, distinct from the High Carbon Fuel Switching Program, and is described in the response to BCUC IR 1.105.2.2.

104.6.1 If confirmed, please discuss why this is appropriate.

Response:

Not confirmed.

105.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.6.4, p. 161

Energy Solutions and External Relations Forecast (ES & ER) – Incremental Spending

105.1 Please explain whether or not the "Advancing Natural Gas end-use Technologies and Applications" initiative is a new initiative planned for 2014 or a continuation of an initiative already in place from previous years.

Response:

This response addresses BCUC IRs 1.105.1, 1.105.1.1 and 1.105.1.2.

The Advancing of Natural Gas end-use Technologies and Applications initiative represents an expansion of the Company's involvement in an initiative through the Canadian Gas Association (CGA) called Energy Technology Innovation Canada (ETIC) that was launched in 2011. ETIC works collaboratively with various stakeholders including utilities, industry and the government to facilitate and drive natural gas technology innovations, and to remove the barriers to deployment of a desired technology. ETIC seeks to enable investment in technologies and innovation in end-use oriented markets. Collaboration happens amongst the participating CGA membership to leverage funding and expertise nationally.

To date, the Company's involvement in ETIC has been primarily related to the start-up and the organization and participation in a few technology projects. The additional $500 thousand for 2014, relates to an opportunity that the Company believes will begin in early 2014.

The preliminary terms of the collaboration would involve the CGA ETIC members collectively investing $5 million per year for a minimum of three years. $500 thousand is the Company's estimate of its proportional share of the $5 million to be paid by all ETIC members. This will enable FEI access to funding and to leverage co-funded opportunities that would otherwise not be possible if the utility were to go it alone.

The benefit of collaboration and leveraging investment can be seen through a hot water pilot project recently undertaken by ETIC. The project successfully resulted in the development and implementation of a regional retrofit pilot to confirm energy savings and build a knowledge base on technologies with ratings above 0.80 EF, including potential technical issues or difficulties in installation and end-use. The project also included an education component for both customers and contractors about the high efficiency hot water heater so the market is ready when the legislation comes in effect in 2016. FEI, Sask Energy, Gaz Metro, Union Gas, Enbridge Gas Distribution and NRCAN all collaborated in the project allowing for greater breadth of the pilot project than if the individual utilities had pursued pilots on their own. For example, participating utilities were only required to contribute their proportional share of the total budget yet they received access to all the project benefits

This collective investment is geared towards projects which benefit customers in the advancement and commercialization of technologies and examples include:

- Testing next generation highly efficient hot water heater technology in Canadian homes
- Demonstrating how natural gas can contribute to an efficient energy grid
- Identifying natural gas cooling solutions

ETIC offers a unique forum for projects to move forward with interested partners where technology and innovation lessons are shared and dollars are leveraged, with a focus on stimulating the application of new and the improvement of existing, natural gas end-use technologies. Utilities, such as FEI, play a unique role in furthering this initiative as they have the knowledge and expertise to operate natural gas systems and through cooperative joint efforts can bring natural gas end-use technologies into operation quickly, to the benefits of its customers. In addition, the Innovative Technologies EEC program also is able to make use of the ETIC resources to co-develop programs with other utilities across Canada.

Such advancements in natural gas end-use technologies will assist FEI in growing future demand for natural gas and thereby a means of maintaining natural gas throughput given the decline in UPC and the slowing customer addition growth it has been experiencing.

The entire $500 thousand will go to non-labour costs. Note, FEI is not specifically requesting an additional $500 thousand in incremental funding from the BCUC 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 for this program will be managed internally through savings achieved elsewhere in the organization.

105.1.1 If the initiative is not new, please explain why FEI requires an additional $500 thousand for this initiative in 2014 above what has already been incorporated into the budget from previous RRAs.

Response:

Please refer to the response to BCUC IR 1.105.1.

105.1.2 Please specifically outline how the $500 thousand will be spent. Please include an explanation of whether or not the costs are related to labour or non-labour.

Response:

Please refer to the response to BCUC IR 1.105.1.

105.2 Please explain whether or not the "Incentive Programs" initiative is a new initiative planned for 2014 or a continuation of an initiative already in place from previous years.

Response:

The Incentive Program is a new initiative planned for 2014. Please refer to the response to BCUC IR 1.105.2.2.

105.2.1 If the initiative is not new, please explain why FEI requires an additional $500 thousand for this initiative in 2014 above what has already been incorporated into the budget from previous RRAs.

Response:

The initiative is new for 2014.

105.2.2 Please specifically outline how the $500 thousand will be spent. Please include an explanation of whether or not the costs are related to labour or non-labour.

Response:

FEI is seeking approval in this Application for its 2014-2018 O&M expenditure level to be determined by the proposed PBR formula as applied to the 2013 Base O&M. FEI is not seeking approval for funding for the specific program referenced in the IR. With this understanding, FEI has provided the following information on this program as requested by the Commission.

FEI is currently exploring prospects to offer incentives to aid customers in offsetting the high upfront gas appliance and installation costs, and the incremental funding will support this initiative. This program is similar in concept to the High Carbon Fuel Switching Program in that the company is looking into offering incentives to facilitate customers to choose a natural gas appliance.

Given that the decline in natural gas space and domestic hot water heating can in part be attributed to the higher upfront capital and installations costs of gas equipment compared to electric equipment, incentives provide a means of overcoming this cost barrier. Builders and developers surveyed in the 2010 Residential New Home Survey attributed the decline of space and gas water heating to such factors as regulation, i.e. changes to appliance standards/building codes that compel customers to install more costly, high efficient units. While new and more efficient units provide for energy savings they often require new technologies and are therefore more costly than the status quo unit. An option currently been investigated by FEI, as a groundwork to launching this initiative in 2014, is a financing offering for a residential customer to purchase a domestic hot water heater. This will enable the customer to spread the appliance and installation costs over a period of time and at a favourable financing rate. These will be non-labour costs.

105.3 Please specifically outline how the $200 thousand related to the "Community Investment in Education" will be spent. Please include an explanation of whether or not the costs are related to labour or non-labour.

Response:

While FEI is currently in the planning stage of this initiative, the following are examples of the type of community investments that FEI would make in education. FEI plans to sponsor speakers' series at universities and colleges, which enable these institutions to bring in guest speakers to educate students and faculty members on energy issues and efficient energy use. In addition, education community investment funds may be used to fund co-op work terms for BC university and college students with a focus on learning about energy. FEI believes universities and colleges are a key audience with which to engage, given the importance of energy to BC's economy, and the role that these institutions have in shaping the dialogue on energy. University and college students are future employees, customers, and stakeholders of FEI.

In the K-12 education sector, funds will focus on promoting math and sciences and high school completion rates so that students can prepare themselves for post-secondary education and have opportunities for both trades and professional careers. Some funding will support specific investments in Aboriginal education, as FEI sees BC Aboriginal communities as key stakeholders. An example of one such initiative is the Dogwood 25 initiative, which focuses on supporting Aboriginal students to complete their high school education.

These costs could be a combination of labour (to fund a co-op student or intern) and non-labour expenditures, but as a placeholder are included under non-labour. In accordance with the Commission's Decision in Order G-44-12, only 50 per cent ($100 thousand) has been included in FEI's forecast and the remainder is accounted for as a non-regulated item.

106.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.6.1, pp. 153-154; 2012-2013 FEU RRA, BCUC 2.26.1); Greenhouse Gas Reduction (Clean Energy) Regulation, B.C. Reg. 102/2012 (GGRR)

ES& ER –COMMUNITY INVOLVEMENT SPENDING

106.1 By year for 2007-2018, please provide a table showing FEI's Total Community Involvement Spending, sponsorship of the Union of BC Municipalities (UBCM) Conference costs, and the UBCM sponsorship costs as a percentage of FEI's Total Community Involvement Spending. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Please refer to Attachment 106.1 for the fully functioning electronic spreadsheet.

Note that from 2012 onwards, and as per Commission Order G-44-12, only fifty percent of community involvement spending is allocated to the ratepayer.

106.1.1 Should a portion of FEI's Total Community Involvement Spending be allocated to FAES and the separate classes of NGT service? Please explain why, or why not?

Response:

As per Commission Order G-44-12, only fifty percent of community involvement costs are allocated to FEI ratepayers.

The primary focus of FEI's community involvement spending is to the benefit of natural gas utility customers by way of the development of relationships within the community the company serves. These relationships are critical in supporting FEI's ability to manage operations in the communities where existing facilities are in place and to move future projects and initiatives forward in a timely manner. It is therefore appropriate that FEI ratepayers bear these costs.

NGT customers pay a conventional delivery charge which includes a provision for general O&M costs from all departments, and thereby are paying a portion of Community Involvements costs.

Such is the case with LNG service delivery under Rate Schedule 16 or CNG service offering under Rate Schedule 25; these rate schedules already include a delivery charge component to them.

In the event that staff in this group promote or further FAES they would appropriately charge their time to FAES according to the Code of Conduct/Transfer Pricing Policy.

Therefore, a further direct allocation of FEI's community involvement costs to NGT customers or FAES would not be appropriate.

> "…actual Local Community Events and Other Program Sponsorships costs exceeded budgeted costs by $76,674 (or 46 percent) in 2009 and $96,119 (or 58 percent) in 2010. (2012-2013 FEU RRA, BCUC 2.26.1)

In 2012-2013 FEU RRA, BCUC 2.26.1, FEI stated that the causes of increased cost pressures in support of Community Events and Sponsorship included:

(i) The Province's Energy Plan of 2007 and the 2010 Clean Energy Act both created challenges for the acceptance of natural gas as a fuel source by governments and communities across BC as a result of the focus on GHG reductions.

(ii) The fact that over 30% of the FEU's operating agreements with municipalities across BC have come up for renewal in 2010 and 2011

(iii) Support of the Union of BC Municipalities ("UBCM") activities such as the UBCM annual conference in November of each year.

(iv) The economic downturn and the drawing away of other sources of community support as the 2010 Winter Olympic and Para Olympic games approached…

106.2 Please provide the number of FEI operating agreements that needed to be renewed by year for 2007-2018.

Response:

The following are the FEI Operating Agreements that needed to be renewed by year for 2007-2018:

Year	Agreements Needing to be Renewed
2007	Chase – new agreement January 1, 2007
2008	Warfield – new agreement Jan 27, 2008
2009	None
2010	Midway – new agreement May 13, 2010 Princeton – new agreement July 6, 2010
2011	Lumby – new agreement August 24, 2011 Peachland – new agreement April 12, 2011 Sparwood – new agreement Sep 9, 2011
2012	Clinton – new agreement March 5, 2012 Coldstream – new operating terms July 1, 2012 Greenwood - new agreement January 1, 2012 MacKenzie – new agreement April 2, 2012 Revelstoke - new agreement Sep 6, 2012
2013	Ashcroft expiry date August 29, 2013 Cache Creek expiry date Sep 6, 2013 Elkford expiry October 31, 2013
2014	Keremeos expiry October 15 2014 Logan Lake expiry April 8, 2014
2015	None
2016	Salmo – expiry Sep 18, 2016
2017	Fruitvale – expiry April 20, 2017 Montrose – expiry April 21, 2017
2018	Kelowna expiry October 31, 2018

In addition to revisiting expiring agreements, many of the older operating agreements in the Lower Mainland have been, and continue to be the subject of discussion. The most notable discussions have been with the City of Surrey which has taken issue with those agreements. Issues concerning the City of Surrey include the legal enforceability of the operating agreement entered into by the British Columbia Electric Company in 1957 and assigned to BC Gas, which is now FEI; whether intermediate pressure pipelines should be covered by the operating agreement and cost apportionment of pipeline relocations. Discussions between FEI and the City of Surrey to determine a new mutually agreeable operating arrangement have been underway since January 2013 and will likely involve the Union of British Columbia Municipalities and possibly various British Columbia government agencies.

Also, since 2011, FEI has provided services to FEVI through the FEI-FEVI Shared Services Agreement to negotiate new operating agreements with potentially 28 municipalities in the FEVI area and for FEW, through the FEI-FEVI Shared Services Agreement, for one in the FEW area. Considerable effort has been made to renew six operating agreements which have now expired, as follows:

- Comox: expired September 29, 2012
- Courtenay: expired September 23, 2012
- Gibsons: expired September 11, 2012
- Cumberland: expired September 10, 2012
- Colwood: expired September 11, 2012
- District of Powell River: expired February 7, 2012

Negotiations have been facilitated by the City of Nanaimo by hosting 5 workshops since November 2011, and which appear to be resulting in the development of a mutually acceptable model agreement. Efforts to negotiate and finalize operating agreements with as many municipalities as possible will continue.

Negotiations with the Sechelt Indian Band, whose operating agreement expired on September 26, 2012, have been successful and a new agreement has been entered into and a CPCN was issued by the BCUC on February 28, 2013.

106.3 Given the approval the GGRR, improvement in the economy and the completion of the 2010 Winter Olympic and Para Olympic games, should Community Involvement Spending be reduced to the Actual 208/2009 costs to reflect the decrease in cost pressures? Please explain why or why not?

Response:

FEI is not requesting approval of a Community Involvement spending budget in this Application. The O&M forecasts are provided for references purposes only. The following information is provided in that context.

FEI community involvement budgets have not changed significantly since 2008/09 and the above referenced quote is an explanation of why spending exceeded budgets in 2009 and 2010. Community involvement spending is not a cost element that can, or should, be stopped and started based upon past spending and events. The Company believes it would not be responsible to customers to reduce spending in this area because of the completion of past activities. Rather the Company believes it must continue investment in this area as a proactive measure as new and often unforeseen initiatives will arise each year.

In the Application, FEI has forecast an initiative to support educational programs related to energy. This is in addition to the current community involvement program and not related to the cost pressures identified above.

FEI continues to monitor external influences and as such makes changes to spending priorities to meet the changed circumstances.

107.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.6.1, pp. 153-154; FortisBC Inc. (FBC) 2012-2013 Revenue Requirements and 2012 Integrated System Plan (ISP) Decision (2012-2013 FBC RR and 2012 ISP Decision), pp. 67; 2012 UBCM Convention Sponsors, http://www.ubcm.ca/EN/main/convention/past-conventions/2012-convention/2012-convention-sponsors.html

ES& ER –DONATIONS

"ICG takes the position that all corporate sponsorships and donations should be borne 100 percent by the shareholder and not the ratepayer. ICG notes the testimony of Mr. Walker where he acknowledges that FortisBC determines the recipients of its corporate largesse and that its customers, whom FortisBC believes should continue to be responsible to pay 100 percent of these costs, may not share FortisBC's opinion as to the appropriate beneficiaries. (T2:181-182)" (2012-2013 FBC RR and 2012 ISP Decision, p. 67)

At the 2012 UBCM Conference, FortisBC sponsored the Reception & Entertainment for the Banquet and also provided Wine Glasses. (2012 UBCM Convention Sponsors)

107.1 Please provide the total cost of the Reception & Entertainment for the UBCM Banquet, the number of UBCM Banquet attendees, and the UBCM Banquet per attendee. Also provide a copy of the menu for the reception.

Response:

FEI is one of the companies that supports the Annual UBCM conference through sponsorship. The conference provides an opportunity to engage with all elected local municipal government representatives from across the Company's service territory in one central location. These individuals represent their constituents and so bring forward their concerns and ideas.

FEI's sponsorship helps to offset the cost of holding the conference in general and, as is the case with many conferences, the conference organizer often recognizes sponsors of their event. In the case of the UBCM conference, FEI is recognized at the annual banquet. This banquet is managed by the UBCM staff, and FEI does not coordinate the menu, the entertainment, or the attendees. 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.

107.2 Please provide the total cost of the Wine Glasses, the number of Wine Glasses and the cost per Wine Glass.

Response:

As part of FEI's sponsorship of the annual UBCM Reception & Banquet, FEI has provided wine glasses as an attendee gift. Note that per Commission Order G-44-12, only 50 percent of costs related to community involvement are allocated to the rate payer. The total cost of the wine glasses was $5,111. In 2012, 1,100 wine glasses were purchased, at a cost of $3.85 per wine glass.

108.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.6.1, pp. 153-154; 2012-2013 FBC RR and 2012 ISP Decision, p. 69

ES& ER –DONATIONS

"The Commission Panel finds that contributions to political parties should be solely for the account of the shareholder." (2012-2013 FBC RR and 2012 ISP Decision, p. 69)

108.1 Please provide the FEI contributions to political parties by year for 2007-2014.

Response:

FEI's political donations are generally for ticket purchases to attend select party hosted events. FEI believes these events are important to attend as they provide an avenue to engage with political representatives and express our customers' concerns through the political process.

The opportunity to participate at these events vary year to year, and FEI has seen an increase in the importance of participating in such events over the last several years due to the importance of engaging in energy policy development and the impacts of energy policy on our ability to serve our customers effectively. FEI also uses these opportunities to assist elected officials in understanding the utility business and the issues facing it and our customers.

FEI Political Contributions	
2014 Forecast	$50,000
2013 Projection	$50,000
2012 (Actual)	$42,450
2011 (Actual)	$23,475
2010 (Actual)	$31,276
2009 (Actual)	$39,726
2008 (Actual)	$21,676
2007 (Actual)	$7,488

108.2 Is the cost of FEI contributions to political parties recovered from ratepayers?

Response:

Yes, it is part of the FEI O&M included in the cost of service and is treated the same way as other O&M costs (the 2013 Base amount will be escalated by the O&M formula).

109.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.6.1, p. 154; Commission Order G-66-13A

COMMUNICATIONS AND EXTERNAL RELATIONS

"For example, there will be considerable interaction with all levels of government, government agencies, First Nations and the public in support of development to serve the proposed **Woodfibre LNG project**." (Exhibit B-1, p. 154)

109.1 Please provide a table showing the cost of interacting with government, government agencies, First Nations and the public in support of development to serve the proposed Woodfibre LNG project by year and resource.

<u>Response:</u>

The reference noted above pertains to the External Relations group that performs activities for both FEVI and FEI and recovers costs from FEI through shared services or through direct charges for specific projects. The costs incurred in bringing this project forward reside in FEVI, not FEI, and as such are not within the scope of this proceeding.

109.2 Please confirm that FEI is charging FEVI for these services and that the costs are being charged to the non-rate base deferral account attracting AFUDC to capture the Development Costs and Commitment Fees approved by Commission Order G-66-13A.

<u>Response:</u>

Yes, FEI confirms FEVI is being charged for services rendered in accordance with Commission Order G-66-13A.

110.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.6.1, p. 154; FEI Inquiry into the Offering of Products and Services in Alternative Energy Solutions (AES) and Other New Initiatives Report (AES Report)

BUSINESS DEVELOPMENT

"The Business Development group is responsible for identifying, developing and implementing new energy service offerings such as: renewable natural gas (RNG), or biomethane, natural gas for transportation (NGT) and Liquefied Natural Gas (LNG) or Compressed Natural Gas (CNG) for new markets." (Exhibit B-1, p. 154)

110.1 For the Business Development group, please provide a schedule showing the total fully loaded labour cost, Employee Expenses and FTEs for 2007-2014. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Given that the company's business environment has changed over the past few years, largely as the result of changes in energy policies, regulations, and provincial GHG emission reduction targets, the Company and, in particular, the ES&ER Department has similarly changed and adapted over these years to address the market impacts to the business. 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. While the information requested for 2007 to 2009 has been provided, this is not useful as a point of comparison.

Please refer to Attachment 110.1.

"All proposals for new business activities must be accompanied by a clear and concise description of the planned cost allocation methodology." (AES Report, p. 33)

"In other words, costs related to competing 'for the market' are not subject to the regulatory compact, although costs related to a regulated project "in the market" are properly treated within the regulatory compact concept. This does not preclude the recovery of costs of competing for the market, but it puts the onus on the utility to demonstrate a reasonable business case for the recovery of such costs, with any residual risk of cost recovery falling on the utility." (AES Report, p. 40)

110.2 Given that FEI has not provided a list of new business activities, or clear and concise description of the planned cost allocation methodology new business activities, please explain why the cost of the Business Development group should be included the forecast for the proposed PBR period.

Response:

FEI understands the question to relate to why the cost of the Business Development group should be included in the 2013 Base to which the PBR formula is applied, rather than why the cost of the group should be included in the forecast. The forecast is not used to set rates, and is therefore irrelevant to the discussion other than as a general point of comparison.

The Business Development group is not a new group and has been part of FEI, by the specific name of Business Development or another name, for many RRA and PBR cycles and as such the costs incurred by this group have been approved the Commission many times.

Business Development is responsible for identifying, developing and integrating new gas initiatives in order to adapt to changing market conditions. It is a strategic and proactive group that monitors the company's operating environment to explore and assess future customer needs and opportunities for natural gas and its use. Without such a forward-looking approach, FEI would be limited in its ability to provide new natural gas services and offerings for which our customers benefit. Further, FEI needs to be able to continue to innovate and adapt to changing market conditions and employ opportunities to mitigate potential negative impacts to existing and future ratepayers.

For clarity, as it pertains to cost allocation methodology, as new service offerings are being developed these are brought forward to the Commission for approval and it is through these regulatory proceedings that appropriate cost allocation methodologies are approved by the Commission. This has been the case with new service offerings, such as RNG, NGT and prior to the AES Decision, the AES offerings. With respect to new future business initiatives, it is not reasonable for FEI to provide a proposal of new business activities to be developed and offered to customers in future years since these have not yet been identified. When FEI next files a comprehensive rate design application along with supporting COSA models, a review of how the cost allocation related to these services integrates with the overall cost allocation methodologies employed, will be reviewed.

FEI submits that there is no justification to treat the activities of the Business Development group in a different manner than any other department. As the business development activities that benefit natural gas ratepayers are ongoing activities which often require development over a period of time, often exceeding at least one year, in order to move through the various phases of feasibility, implementation and management, the cost of the Business Development group should be included in the base to which the O&M formula is applied during the PBR period. It would not be appropriate and would incur unnecessary complexity, to exclude the cost of the Business Development group from the revenue requirements in the year that they are incurred and have FEI request recovery of the actual Business Development costs at the Annual Review, for recovery in following year. In addition, FEI requires stability in personnel and budget planning and the Business Development group should be treated no differently than any other part of the company that supports FEI's sustainment, growth and customer offerings.

110.2.1 Would it be appropriate to exclude the cost of the Business Development group from the revenue requirements in the year that they are incurred and have FEI request recovery of the actual Business Development costs at the Annual Review, for recovery in following year (i.e. 2014 Business Development cost would be reviewed at the 2014 Annual Review and recovered in 2015 rates)? Please explain why, or why not.

Response:

As clarification, it is important to note that the costs captured in FEI's O&M for the Business Development group is in support of natural gas load growth initiatives, and does not include any costs for AES initiatives as the preamble to this IR implies. The group develops and implements new natural gas service offerings, including development of tariffs and seeking regulatory approval. Such service offerings include, but are not limited to, NGT services, low carbon product offerings, Renewable Natural Gas, CNG and LNG for remote communities and off-grid applications and the development of high horsepower transportation applications such as ferries, locomotives and mine haul trucks.

Please refer to the response to BCUC IR 1.110.2.

111.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application: Tab B, Section 1.3.3, p. 95, Section 1.4.4, Figure C1-15, p. 103, Tab C, Section 3.6.2, pp. 153, 155; Exhibit B-1-1, Appendix B2; 2013 British Columbia Utilities Commission Generic Cost of Capital Proceeding (GCOC) Stage 1 (2013 GCOC Stage 1), BCUC 1.2.1.1

ES& ER – BUSINESS DRIVERS

"The above figure demonstrates the continued strong correlation between housing starts and net residential customer additions. The correlation statistic is over 90 percent. For this reason the CBOC housing starts forecast is an appropriate proxy of the Company's customer additions forecast." (Exhibit B-1, p. 95)

111.1 Given "strong correlation between housing starts and net residential customer additions" please explain how ES&ER determines the effectiveness of its expenditures to attract new customers.

<u>Response:</u>

There is a statistically strong correlation of housing starts to net residential customer additions. The figure on page 95 shows actual results from 2001 through to 2012 and the correlation shown is the outcome of activities undertaken by the department and the company to add and retain customers

Natural gas does not sell itself, as customers have competitive options other than natural gas available to meet their residential energy needs. Furthermore, in recent years the company has seen a shift in the composition of the builder and developer groups where small builder and developer groups now make up a large proportion of the new customer service requests where historically large builder and developers groups initiated new meter and service line requests. This shift requires FEI's sales effort to reach a much wider audience than ever before.

ES&ER determines the effectiveness of its expenditures to attract new customers through ongoing review of relevant measures and metrics, and these include:

- Trending of actual customer additions against forecast
- New housing market capture rates
- Measures of customer satisfaction of the company's products and service offerings
- Monitoring of natural gas end-use appliance penetration

- Monitoring individual development sales efforts and successes

An example of such a sales effort is the Yorkson Creek townhome development in Langley, which without the collaborative and on-going education efforts with the builder/developer, the company would have lost the natural gas load for space and water heating of 158 townhomes and potentially an additional 170 townhomes planned for the second phase of the development (Reference: Exhibit B-1, p. 157).

111.2 For 2007 -2014 by year, provide a schedule showing the total ES&ER cost, the customer additions (Figure C1-15) and the ES&ER cost per customer addition and the ES&ER cost per customer (using the average number of customers from Exhibit B-1-1, Appendix B2)

Response:

While FEI has provided the calculation requested for the years 2010 through 2014, such a calculation does not provide for a relevant or appropriate measure. This is because the ES&ER department is responsible for a variety of activities which include customer attraction, customer retention, increasing natural gas throughput, the development and implementation of new service offerings, safety education messaging, the preparation of the LTRP, internal and external communications, among others, and not all of these activities are directly related to customer additions. Furthermore, there are other areas of the Company's operations that play a role in customer retention and additions. For these reasons, the calculations provided in the schedule do not provide any meaningful or relevant information from which to base decisions.

Given that the business environment in which the company operates has changed over the past several years, largely the result of changes in energy policies, regulations, and provincial GHG emission reduction targets, the Company and, in particular, the ES&ER department, have similarly changed and adapted over these corresponding years to address these market challenges. As such, information going back to 2010 has been provided below as it provides for a trending which is more reflective of the current business environment and is reflective of customer expectations. Furthermore, the 2013 expenditures have been thoroughly examined in FEI's most recent rate application and are most reflective of current business conditions, and as such FEI submits that 2013 Approved O&M should form the basis for the evaluation of the appropriate levels of 2013 Base O&M on which the 2014 to 2018 rates will be set.

Provided below is a schedule showing the total ES&ER O&M expenditure and this cost divided by annual customer additions and total average customers, as requested.

ES & ER Cost Per Customer Addition and Cost Per Customer

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2014 Forecast
Total O&M ($ thousands)	14,636	15,456	18,075	19,215	23,275
Net Customer Additions	6,869	5,344	4,743	4,631	4,982
Total Average Customers	839,017	845,282	834,888	840,721	845,495
Cost per Customer Addition	$ 2,131	$ 2,892	$ 3,811	$ 4,149	$ 4,672
Cost per Average Customer	$ 17	$ 18	$ 22	$ 23	$ 28

Note: due to the adoption of the SAP CIS system, the customer count methodology has changed. This resulted in a one-time change in the customer count. In 2012 it appears that the total average customers have declined. This is only due to a change in counting methodology and does not represent an actual decline. This does not affect overall volume of gas through the system as noted in Exhibit B-1 Section 1.3.1. For the purpose of this response it does have the effect of *artificially* increasing the 'Cost per Average Customer' metric.

"Increased competitive and market risk factors have warranted the enhanced focus of the Company's ability to retain existing customers, attract new customers and maintain throughput levels in a challenging and evolving environment." (Exhibit B-1, p. 155)

"The following table shows that FEI's natural gas throughput would have to decrease by 76% based on 2009 natural gas and Step 2 electricity rates and by 83% based on today's natural gas and Step 2 electricity rates." (2013 GCOC Stage 1, BCUC 1.2.1.1)

111.3 The statement that FEI faces "a challenging and evolving environment" appears inconsistent with fact that natural gas rates would need to FEI's natural gas throughput would have to decrease by 83 percent in order for natural gas rates would become equal to BC Hydro's tier 2 electric rate. Please explain.

Response:

There is extensive evidence in the GCOC proceeding regarding the factors that affect FEI's business risk, including competitive risk, and the referenced information is but one aspect to it. For instance:

- First, natural gas commodity price is one factor impacting price competitiveness of natural gas relative to electricity. Other factors include natural gas price volatility and the relative purchase and installation costs of natural gas appliances compared to electric appliances.
- Second, there are also non-price competitive factors (climate change and energy policies, customer perception of energy and the shift towards smaller, higher density housing), that impact FEI's throughput levels.

It is due to these factors that FEI continues to face a challenging and evolving environment.

Please refer to the response to BCUC IR 1.97.1 of the GCOC Stage 1 Proceeding, included as Attachment 111.3, for further discussion on this topic.

112.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 2.2.1, p. 118, Section 3.6.3, p. 158; Exhibit B-1-1, Appendix H, p. 13; 2010-2011 TGI RRA, BCUC 1.21.1, AES Report p. 33

ES & ER - NATURAL GAS FOR TRANSPORTATION (NGT) PROGRAMS

"For NGV [Compression and refueling service], Terasen Gas currently has one staff member devoted to this initiative in addition to support from other regional sales staff that to date have been selling Rate Schedule 6 Natural Gas Vehicle Service." (2010-2011 TGI RRA, BCUC 1.21.1)

112.1 For the FEI employees involved in the NGT Programs, please provide a schedule showing the total fully loaded labour cost, Employee Expenses and FTEs for 2007-2014. Include the requested information in the form of a fully functioning electronic spreadsheet.

<u>Response:</u>

Please refer to Attachment 112.1. Please also refer to the response to BCUC IR 1.112.3 for further discussion of the employees involved in FEI's NGT program.

The time spent by these employees is not limited to developing fueling station offerings, but also includes other aspects associated with FEI's NGT program as well as other business development activities.

Attachment 112.1 shows the percentage of time each employee is involved in CNG and LNG fueling stations. The total fully loaded labour cost plus employee expenses are shown from 2010-2014 at an annual escalation factor of three percent. The positions involved in developing fueling stations are:

- Senior Manager, Business Development
- Business Development Manager
- Business Development Specialist
- Manager, NGT Solutions (formerly Commercial and Industrial Manager)
- NGT Account Manager
- Manager, New Product Development

Two of these positions, Manager, NGT Solutions and NGT Account Manager do not reside within the Business Development Group, but rather in the Energy Solution group.

In addition to fueling station development, there are other activities which relate to FEI's NGT programs. These include operations support and product implementation. FEI does not have an estimate of the time allocated for these activities; however, the staff associated with these activities are included in the Business Development group costs as presented in the response to BCUC IR 1.110.1.

[Regarding the overhead and marketing charge of $0.52 per GJ] "In FEI's view, the total OH&M recoveries far exceed the amount of actual O&M costs embedded in the natural gas class of service, and at the current rate represents a cross subsidization from the NGT classes of service." (Exhibit B-1-1, Appendix H, p. 13)

112.2 Please provide the 2014-2018 amortization of the NGV Incentives deferral account by year.

Response:

The 2014-2018 amortization of the NGV Incentives deferral account as embedded in the updated financial schedules filed as part of the July 16th Evidentiary Update (Exhibit B-1-3) are as follows:

2014: $2.420 million

2015: $3.061 million

2016: $3.453 million

2017: $3.453 million

2018: $3.453 million

The 2014 amount is included in the 2014 forecasted cost of service for traditional natural gas rate payers. Forecasts for 2015 through 2018 will be updated as part of the Annual Review process based on current forecasts at that time.

112.2.1 Is the recovery of the amortization of the NGV Incentives deferral account from the non-bypass ratepayers a cross subsidization of the NGT classes of service? Please explain why, or why not.

Response:

The NGV Incentives deferral account captures the grants to eligible trucks and buses, expenditures on administration, marketing, training and education, grants to implement safety practices or to improve maintenance facilities and a portion of the regulatory costs of the GGRR Application as an administrative expense of Prescribed Undertaking 1. The recovery of the balance from the NGV incentives deferral account is consistent with the GGRR, which requires that the costs associated with the GGRR be recovered from all non-bypass customers. The Commission's Decision in respect of the GGRR incentives has confirmed this treatment.

Even in the absence of this legislated requirement, FEI does not believe the amortization of the NGV Incentives deferral account in the rates of non-bypass customers represents a cross subsidization of the NGT classes of service.

In addition to promoting GHG emission reductions through the adoption of natural gas in the heavy duty and return to base sectors, the vehicle grants provided under the Greenhouse Gas Emission Reduction (Clean Energy) Regulation will create additional throughput on the natural gas delivery system. The non-bypass customers receive the delivery margin benefit of the gas volume consumed through the (proposed) NGT classes of service. The NGT volume growth driven by the GGRR incentives will provide overall net benefits to non-bypass customers. The amortization of the incentives into non-bypass customers' delivery rates is essentially matching the benefits of increased system throughput with the costs that derive those benefits.

> "The recovery of these costs, from the NGT class of service, is captured in "Other Revenue" and is also discussed in Appendix H." (Exhibit B-1, p. 158)

> "• A service provided by the parent utility, or from one class of service or affiliate to another class or affiliate, will be on the basis of an approved Transfer Pricing Policy.

- There should be transparency in cost allocation among different customer groups." (AES Report, p. 33)

112.3 Please describe in detail how employees in each of the O&M departments track their time related to NGT Programs.

Response:

Employees in the ES&ER department do not track hours or code time sheets specifically spent on its NGT program on a project by project basis.[14] Rather, ES&ER department staff is asked to optimize their time and expertise in providing an end-to-end service to customers. To this end, staff does not track minutes spent with each individual customer as they could be working on a number of NGT programs at one time.

In the AES Inquiry Report issued by the Commission on December 27, 2012 the Commission provided guidelines on the business structure for the NGT Service in that CNG and LNG 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 (page 53 and page 62).

As such, FEI has segregated the forecasted costs of serving NGT customers into a Separate Class of Service, which serves to provide for an appropriate measure of cost allocation among classes of service.[15] This segregation of such costs, which among other items, captures the marketing overhead allocation from the O&M departments that directly engage in developing NGT programs and is therefore representative of their time (and related costs) spent on NGT programs.

As directed by the Commission, these costs are to be recovered through the Overhead and Marketing (OH&M) charge of $0.52 per GJ. The process to set the rate and the requirement to capture NGT activities in a separate class of service have provided the appropriate level of transparency in cost allocation. The OH&M charge has been determined by the Commission to be an appropriate charge for the time spent by staff, and for such staff members to then further engage in the tracking of time, on a program by program basis would only serve as an administrative burden that would be of no value to customers.

[14] BFI CPCN Order G-150-12 Compliance Filing at page 4, filed November 16, 2012.

[15] In FEI's Compliance Filing to Order G-150-12 FEI provided an estimate of the time spent on CNG/LNG fueling station activities for the period of 2012-2017.

113.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.6.3, p. 158; West Coast Project to Show Way for LNG Use in Canada's Marine Sector, http://www.newswire.ca/en/story/1173657/west-coast-project-to-show-way-for-lng-use-in-canada-s-marine-sector

ES & ER - NGT PROGRAMS

"Launched in late 2012, the West Coast Marine LNG project will conclude with the release of a final report in November 2013 documenting technology readiness, training, safe operations and regulatory requirements, and environmental and economic benefits from a Canadian point of view."

113.1 Please describe and provide the cost of FEI's participation in the West Coast Marine LNG project for 2012-2013.

Response:

This response also addresses BCUC IR 1.113.1.1.

To date, FEI has contributed $28 thousand toward the West Coast Marine LNG Project. This contribution was made by FEI in November 2012 for participation in the working group which is administered by the Canadian Natural Gas Vehicle Alliance. FEI, along with other industry associations, natural gas producers and suppliers, manufacturers, the BC Government, and Federal Government agencies have committed to addressing issues facing the development of LNG for marine vessels across Canada. The full list of participants is provided below. This initiative could potentially assist FEI and participants in other jurisdictions in bringing marine projects to reality. In addition, the project has been supplemented by Great Lakes and East Coast versions of the same sort of assessment, and at no incremental cost to the original West Coast participants.

FEI views this activity as industry advocacy and long term market development for potential benefits of increased system throughput for FEI's natural gas ratepayers via Rate Schedule 16. Thus no specific customer group should bear these costs. FEI has no marine LNG customers at this time and these activities are not related in any way to FEI's offering of CNG and LNG fueling stations for heavy duty vehicles. Thus the costs related to the West Coast Marine LNG Project are not being recovered from NGT customers. Should this activity lead to development of marine markets, FEI's customer base would benefit from the revenues and margins associated with LNG purchases.

There are 17 participating organizations (including FEI) from the private, public sectors, government as well as from academia. The project's participants are:

- American Bureau of Shipping
- BC Ferries
- BC Institute of Technology
- BC Ministry of Transportation – Pacific Gateway
- Canadian Natural Gas Initiative
- CSA Group
- Encana
- FortisBC
- Government of Canada (Transport Canada, Environment Canada, Natural Resources Canada)
- Lloyd's Register
- Port Metro Vancouver
- Rolls-Royce
- Seaspan
- Shell
- Teekay
- Wärtsilä
- Westport Innovations

113.1.1 Are these costs being recovered from NGT customers?

Response:

Please refer to the response to BCUC IR 1.113.1.

114.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Sections 3.8.3-3.8.4, pp. 169-171

Information Technology – FTE

114.1 Please provide the labour FTE, separated into permanent and temporary, by year, which equate to the labour dollars in Tables C3-21 (2010 Actual – 2013 Approved) and C3-22 (2013 Base – 2018 Forecast).

Response:

The IT department does not have any temporary FTEs. The number of FTEs in total for each of 2010 through 2012 is as follows: 2010 - 63 FTEs, 2011 – 72 FTEs, 2012 – 75 FTEs.

The increase FTEs in 2011 and 2012 is due to the IT support for the systems associated with the Customer Care Enhancement project.

No additional headcount are anticipated for 2013 through 2018 associated with the O&M costs in Table C3-22. Please refer to Section C3.8.3 of the Application for a description of related O&M costs.

114.2 For 2007-2014, please provide a breakdown of IT O&M expenditures by the following categories:

(i) Infrastructure Management
(ii) Applications Management
(iii) IT Project Portfolio Planning and Execution

Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Please refer to Attachment 114.2.

114.3 For 2007-2014, please provide the following:

(i) Annual licensing fees associated with software
(ii) Agreements with third parties for the support
(iii) Maintenance of the Company's applications

Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Please refer to Attachment 114.3.

114.4 For 2007-2014, please provide the number of laptops, workstations, and servers managed by Information Technology. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Please refer to Attachment 114.4 for the number of laptops, workstations and servers.

Note the increase in portable computer systems is due to increased use of mobile applications in the field.

114.5 For 2007-2014, please provide the average O&M cost per laptop and workstation.

Response:

Below is the average O&M cost per laptop and workstation.

Desktop/Laptop O&M per machine per year

	2007	2008	2009	2010	2011	2012	2013	2014
Desktop (Workstation)	$481	$487	$479	$456	$456	$473	$474	$474
Laptop	$556	$551	$543	$533	$526	$550	$559	$549

115.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.8.3, pp. 169-170

Information Technology (IT)

FEI states: "The decrease of $1.2 million from the 2013 Approved to 2013 Projection is primarily due to the following… $600 thousand increase in non-labour for consulting due to backfill for internal resources assigned to capital work and for backfill on overtime work." (p. 170)

115.1 Is this additional $600 million for consultants to perform backfill work related only to the 2013 period? Please discuss.

Response:

The $600 thousand increase in non-labour for consulting backfills is expected to continue over the PBR Term. Internal resources are engaged in project activity every year to ensure projects meet Company requirements, provide internal business and system knowledge and ensure knowledge transfer internally for ongoing support. The internal resources come from different parts of the IT organization depending on the project and using external temporary backfills is more cost effective because they can be procured for the specific skillset that is temporarily required for the duration of the project. The same is the case for overtime backfills, as it is not always the same areas of IT that require additional support after hours, and external resources provide flexibility for these situations. $600 thousand is what these temporary external backfills are expected to cost on an annual basis.

115.2 How long does FEI expect the internal resources to be assigned to capital work?

Response:

The Company expects internal resources to be assigned/allocated to capital work for the duration of this PBR period. Refer to the response to BCUC IR 1.115.1. The use of consulting resources for backfilling is expected to be $600 thousand in each year of the PBR period.

115.3 Would it be more appropriate to characterize this increase in O&M as a "temporary" incremental cost? Please discuss.

Response:

As indicated in the response to BCUC IR 1.115.1, these costs are expected to occur each year for the reasons indicated in that response. These costs are not temporary or incremental.

115.4 Please explain why this $600 thousand increase should form part of the 2013 Base as opposed to being removed from the 2013 Base so that the 2013 Base properly reflects permanent costs expected to be incurred over the 5-year PBR period.

Response:

Please refer to BCUC IR 1.115.1.

116.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.8.4, Table C3-22, pp. 170-171

Information Technology (IT) Forecast

FEI states: "In non-labour, IT is forecasting moderate increases primarily due to contractual obligations and incremental O&M related to IT Sustainment." (p. 170)

116.1 Please confirm that the increase in O&M in the 2014 Forecast over the 2013 Base, as shown in Table C3-22, reflects only the formulaic increase prescribed by FEI's proposed PBR formula.

Response:

The forecast O&M provided in Section C of the Application is not the same as the formula O&M that will be used to set delivery rates during the PBR Period.

As stated on page 121 of the Application, the 2014 through 2018 O&M forecasts included in the Application are for reference purposes only. They represent a high level forecast of future trends and upcoming challenges for FEI. The Company's proposed PBR Plan does not rely on the forecast O&M costs. Instead, it relies on a formula-based approach, as discussed in Section B of the Application.

As noted in Section B, the formula-based approach generates O&M costs for the 2014-2018 years that are below the Company's forecast O&M. FEI will therefore be required to find productivity improvements during the upcoming PBR Period in order to offset the costs it is forecasting in this section. The allocations of O&M between and among departments of the Company during the PBR will be the responsibility of FEI's management. The productivity challenge may not be uniform across all departments. Instead FEI's management will seek to find the most effective ways to manage the Company within the construct and incentives in the PBR.

116.1.1 If not confirmed, please explain why, and please indicate what the 2014 Forecast O&M would be using the proposed PBR formula.

Response:

Please refer to the response to BCUC IR 1.116.1.

117.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.13.3, Table C3-31, p. 191;

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

Finance & Regulatory Review

The historical average 5-year O&M in the Finance & Regulatory department is $11,804,000; whereas, the Projected 2013 O&M is $13,279,000. This represents a 12.5% increase over the historical 5-year average O&M. (Exhibit B-1-1, Appendix F6, p. 3)

117.1 Please explain why FEI believes it is reasonable to set the PBR Base O&M at an amount that is 12.5% higher than the historical 5-year average.

Response:

A review of the historical numbers shows that, for each of the past 5 years, with the exception of 2011, FEI's costs have increased. In the context of labour, benefit and non-labour inflation alone, it is not realistic to expect that the 2013 projection would be equal to the average of the previous 5 years. Rather, the expectation would be that the 2013 projection would be higher than the 2012 actual, all else equal. The average annual increase in the departmental O&M over the five year period is approximately 2.6%. At a minimum, the cost increase would be expected to be in line with this. But given the one-time efficiencies that are reflected in the historical numbers (the elimination of executive and support positions and unfilled vacancies), this historical average increase is understated when looking forward.

The factors that have caused the 2013 increase to be higher than 2012 are explained on page 191 of the Application relating to labour costs and external fees and other support costs increases.

As discussed, the 2013 Projection is still approximately $900 thousand less than the 2013 Approved; these savings are carried forward to the 2013 Base used for setting rates in the PBR Period.

117.2 Please re-create Table C3-31 separating the labour and non-labour costs between the finance function and the regulatory function.

Response:

The following is a copy of Table C3-31 which has been re-created separating the labour and non-labour costs between the finance and regulatory functions. The two tables are provided below.

Table C3-31: Finance & Regulatory O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Labour	$ 6,212	$ 6,550	$ 6,007	$ 6,783	$ 7,695
Non-Labour	5,965	5,514	6,142	6,496	6,490
Total O&M	$ 12,177	$ 12,064	$ 12,149	$ 13,279	$ 14,184

Finance O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Labour	$ 3,751	$ 4,000	$ 3,902	$ 4,230	$ 4,633
Non-Labour	3,652	3,411	3,712	4,239	4,239
Total O&M	$ 7,403	$ 7,411	$ 7,614	$ 8,469	$ 8,873

Regulatory O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Labour	$ 2,461	$ 2,550	$ 2,105	$ 2,553	$ 3,062
Non-Labour	2,313	2,103	2,430	2,257	2,250
Total O&M	$ 4,774	$ 4,653	$ 4,535	$ 4,809	$ 5,312

118.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.13.3, Table C3-31, p. 191

Finance & Regulatory Services

FEI states: "The department has managed an increasing number of major applications (average of 63 per year for the five years from 2005 to 2009 as compared to 72 in the three years from 2010 through 2012). In addition, the number of Information Requests responded to has increased (average of 2,500 for the five years from 2005 to 2009 as compared to 4,200 in the three years from 2010 through 2012)." (p. 191)

Per Table C3-31, the average O&M for the 2010-2012 period is $12,130,000. The Projected 2013 O&M is $13,279,000. This represents an increase of 9.4% over the average of the past three years.

118.1 Given that the department has already been managing the increased workload, as described above, with an average O&M expenditure of $12,130,000 annually, please explain why it is reasonable to expect that FEI requires a 9.4% increase to this annual O&M for 2013.

Response:

Please refer to the response to BCUC IR 1.117.1, which applies equally to this question.

FEI states: "When compared to the O&M costs of the department and number of employees, which has either held constant or declined, the direction to continue to do more with the same number of employees is evident." (p. 191)

118.2 Give that this department has historically remained constant in terms of staff and expenditures, please discuss whether it would be more appropriate to reduce the 2013 Projection so that it only reflects the standard increases related to inflation, labour and benefits.

Response:

The information provided for the Regulatory Department separately (the Regulatory Department is what has been referenced in the preamble) has been provided in the response to BCUC IR 1.17.2. From reviewing this information, it is apparent that the 2013 projection represents more of a return to normal staffing levels than an increase over historical levels. The 2013 projected O&M is only $35 thousand higher than the 2010 actual O&M. Although 2013 is $150 to $250 thousand higher than the intervening years, the decrease in those years should be considered an anomaly. FEI was unable to hire employees to fill vacant positions in those years, partly because of a reluctancy 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. In addition, as discussed in the response to BCUC IR 1.117.1 and in the Application, the complexity and level of regulatory filings has increased along with changes in energy policy and new service offerings, which has all resulted in a step change in requirements for regulatory applications and proceedings, and FEI will not be able to continue to operate at existing staffing levels for the next 5 years. Finally, FEI notes that the 2013 Projection is still $500 thousand less than the amount approved for that year.

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." (p. 191)

118.3 Please explain the amount of additional costs FEI anticipates incurring to prepare separate revenue requirements for the utilities.

Response:

Although FEI will be required to prepare separate revenue requirements for the utilities in the absence of amalgamation and the adoption of common rates, the filling of vacancies and the additional position are not solely related to revenue requirement applications. The bulk of the work will result from completing separate rate design and cost of capital applications and from filing applications and participating in processes to extend or modify FEI service offerings (customer choice, biomethane, NGT, etc.) to the other utilities.

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. Any incremental external costs are captured separately in deferral accounts and have not been included in any of the O&M amounts included in this Application.

118.4 Please explain if FEI plans to fill these vacant spots in advance of a determination on the FEU Amalgamation Reconsideration.

Response:

FEI is currently filling these positions using temporary employees. If the Commission does not approve the FEU's Amalgamation and Common Rates Reconsideration application, then these employees will be made permanent.

118.5 Please explain why it would not be more appropriate to remove any additional costs FEI has forecasted and included in the 2013 Base related to the outcome of the amalgamation proceeding, given that the reconsideration is still in process.

Response:

FEI has included these costs in the 2013 Base to ensure that the Commission has a full record on which to base its determination and that the 2013 Base includes the necessary resources to support the regulatory process for the upcoming 5 year period. As the original Amalgamation and Common Rates application was denied, it is appropriate to include the resources required as part of the 2013 Base.

118.5.1 Please explain why these incremental costs would not be more appropriately classified as "uncontrollable costs" and therefore excluded from the 2013 Base and from the PBR formula.

Response:

As the original application for Amalgamation and Common Rates was denied, FEI believes the costs are appropriately included in the 2013 Base.

119.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.14

Human Resources – FTE

"HR has 58 employees, a reduction of approximately 17 percent from previous years." (Exhibit B-1, Section 3.14.1, p. 193, line 1)

"In 2012, employee development, talent sourcing, labour relations, compensation administration, pension and benefits administration and corporate HR functions were integrated between gas and electric utilities." (Exhibit B-1, Section 3.14.3, p. 195, lines 30-32)

119.1 Please provide the labour FTE, separated into permanent and temporary, by year, which equate to the labour dollars in Tables C3-33 (2010 Actual – 2013 Approved) and C3-34 (2013 Base – 2018 Forecast).

Response:

The labour FTE in Human Resources which equate to the labour dollars in Tables C3-33 are listed in the table below.

Human Resources Average FTE in Relation to Table C3-33

Human Resources FTE Summary

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
FTE	96	103	66	58	58	58	58	58	58	58

The FTE figures above are not separated into regular and temporary (since they are FTE they already incorporate the impact of temporary employees). Human Resources does not maintain a budget for temporary employees. Temporary employees are brought in to assist Human Resources when required; for example, a temporary employee may be hired to cover a regular employee off on leave.

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.

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. Accordingly for purposes of this IR response, the FTE levels of 2013 Projection and 2014 Forecast going forward are being maintained at the level of 2012 Actuals.

It should be noted that the decrease in FTEs from 2011 to 2012 is not reflected in the costs shown in Table C3-33 for the same years. This is because previous to 2012, FEI employed a number of temporary employees ("Relief Clerks") who would be assigned by Human Resources to different parts of the company on a short-term basis. Relief Clerks were represented in the FTE count for HR, but their salaries and wages were paid by the departments in which they worked. Since mid-2012, departments have employed their own temporary employees, and FEI no longer maintains a pool of Relief Clerks.

120.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.14. p. 192

Human Resources

On page 192 of Exhibit B-1, FEI states that, "the overall goal of Human Resources (HR) is to ensure that the Company's workforce, now and into the future, has the level of skill and capacity to achieve its business goals and objectives. The Human Resources department performs and provides different services to support management of the workforce to ensure effective and efficient alignment with business plans."

120.1 Does FEI participate in a human resources benchmarking group or engage consultants to benchmark FEI'S operational performance? If so, please elaborate.

Response:

FEI participates in various industry groups as HR professionals. While the performance metrics reviewed in those groups are considered, their relevance is dependent on the specific details of the specific metric.

Annually, FEI creates a corporate scorecard to measure different elements of operational performance. In addition, FEI's departments set operational goals and objectives that support corporate objectives. FEI then measures its operational performance against itself, year over year.

120.2 Please submit any documents used to evaluate FEI's operational performance produced over the last five years; e.g., HR Metrics, Benchmarking Studies, Strategic Plans, Progress Reports, etc.

Response:

FEI's primary measure of operational performance is its corporate scorecard.

In addition, since 2003, FEI has committed to maintaining specified levels of service as measured by ten SQIs. These SQIs reflect areas of service that are important to FEI customers. They are measured and compared to benchmarks on an annual basis. FEI also includes two directional indicators that do not have benchmarks but are designed to give an understanding of trends that may develop in these areas relating to customer service.

Please refer to Attachment 120.2 for copies of FEI's corporate scorecards and SQI results for the years 2008-2012.

121.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.14.3-3.14.4

Human Resources – Cross charges Gas-Electric

"The increase in non-labour is a result of cross charges from electric to gas where electric employees support programs across utility lines, contract services for training development and delivery and employer branding initiatives which support recruitment efforts. Additional non-labour costs are also assigned to leadership development, business acumen training and documentation for knowledge transfer in support of workforce planning activities." (Exhibit B-1, Section 3.14.3, p. 196, lines 13-17)

121.1 Please provide the amount of forecast cross charges from electric to gas in non-labour shown in Table C3-34.

Response:

The amount of cross-charging from electric to gas included in the 2013 Base (Non-Labour) found in Table C3-34 is $312,000. The amount of cross-charging for subsequent years (2014 – 2018) is based on the 2013 figure, plus inflation.

121.2 Please explain where the forecast cross charge revenue from gas to electric can be seen in the Application.

Response:

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.

121.3 Please confirm, or otherwise explain, the HR employees charge from gas to electric and from electric to gas under the Mutual Shared Services Agreement in Appendix F1.

Response:

Confirmed. The agreement governing sharing of services between FortisBC Inc. (electric) and FortisBC Energy Inc. (gas) is found at the end of Appendix F-1.

122.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.16

Corporate – Non-Labour

122.1 Please provide the Non-Labour dollars in Tables C3-37 (2010 Actual – 2013 Approved) and C3-38 (2013 Base – 2018 Forecast) separated, by year, into the categories described in Section 3.16.1 on page 200.

Response:

Please refer to the table below for a breakdown of Corporate Non-Labour dollars in Tables C3-37 (2010 Actual – 2013 Approved) and C3-38 (2013 Base – 2018 Forecast).

Breakdown of Corporate Non-Labour ($ thousands)
2010 Actual - 2013 Approved

Categories	Actual 2010	2011	2012	Projected 2013	Approved 2013
FEI's portion of the Corporate Services fee	$ 3,528	$ 3,759	$ 4,549	$ 4,408	$ 4,910
FEI's portion of the Board of Directors costs	733	600	617	711	711
FEI's portion of the cost of the President & CEO's office	1,509	3,332	1,902	1,011	652
Recoveries from FAES	(500)	(500)	(842)	(854)	(854)
Shared Services recoveries from FEVI, FEW, Fort Nelson and CMAE	(9,623)	(9,997)	(11,681)	(12,170)	(11,770)
Executive cross charges	287	551	530	568	568
Total	$ (4,065)	$ (2,254)	$ (4,925)	$ (6,326)	$ (5,784)

Breakdown of Corporate Non-Labour ($ thousands)
2013 Base - 2018 Forecast

Categories	Base 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
FEI's portion of the Corporate Services fee	$ 4,408	$ 4,540	$ 4,677	$ 4,817	$ 4,961	$ 5,110
FEI's portion of the Board of Directors costs	711	725	740	755	771	787
FEI's portion of the cost of the President & CEO's office	1,286	1,306	1,330	1,354	1,378	1,403
Recoveries from FAES	(854)	(870)	(889)	(907)	(926)	(946)
Shared Services recoveries from FEVI, FEW, Fort Nelson and CMAE	(12,410)	(12,800)	(13,065)	(13,365)	(13,674)	(14,053)
Executive cross charges	568	579	591	603	616	629
Total	$ (6,292)	$ (6,520)	$ (6,616)	$ (6,743)	$ (6,874)	$ (7,069)

123.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.6.3, p. 156;

Commission Letters L-33-13A, L-34-13; Exhibit A2-3

Customer Information System (CIS)

FEI states that it has in-sourced the Customer Information System, and its billed consumption database is facilitated by this CIS.

In a letter to the Commission in response to Letter L-33-13A (Exhibit A2-3), FEI described its CIS as new and that the only way to refund over-collection as a result of rate decrease is with the use of rate riders, as opposed to a credit adjustment. FEI also mentioned that there is significant complexity and cost implications with respect to the investigation, planning, programming, and testing required in order to determine if mass retroactive billing capability should be considered for implementation in the future.

123.1 Is the inability of the new CIS to issue credit adjustment due to a capability issue of the new CIS compared to the old system? Or is it due to the lack of time to reconfigure or re-program the billing system to meet the new delivery rate implementation date?

Response:

The new CIS system is capable of refunding customers with a credit adjustment. For details on the cost and time required to implement this feature, refer to the response to BCUC IR 1.123.2.1.

123.2 Is FEI aware of the ability of BC Hydro and PNG to issue credit adjustments for over-collection?

Response:

FEI is aware of the abilities of both BC Hydro and PNG to issue credit adjustment for over-collection.

123.2.1 Please provide an estimate of the significant cost implications mentioned in FEI's letter.

Response:

The estimated cost of implementing the bill credit adjustment based on the instructions identified in the correspondence related to Letter L-22-12A is $188,000. The duration to design, develop and test the solution is expected to take approximately four months from the time the Company is notified that an adjustment is required.

123.3 Does FEI believe that a regulatory policy should be put in place to determine how a refund or under-collection following the granting of permanent rates will be addressed? If so, please describe the circumstances and the conditions. If not, please explain why not.

Response:

FEI does not believe a regulatory policy is required to determine how refunds or under-collections are handled. The Commission has the discretion to request specific methods as circumstances require, or to let the utilities propose methods based on their experience with their customers and their respective CIS systems. FEI does not believe that a one size fits all prescriptive policy is in the best interest of customers as the circumstances related to the refund could vary.

124.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Tab C, Section 3.4.2.1, p. 136

Business Drivers for Operations Department

FEI states: "Also, customers regularly call regarding concerns ranging from emergency type activities such as gas odours to financial type activities such as billing inquiries."

124.1 While the above statement is obvious, would it not be correct that the substantial efforts that FEI has invested in to have such inquiries handled more efficiently at the point of first customer contact should lead to reduced costs in handling such calls?

Response:

Emergency type activities such as gas odour calls, house fires and carbon monoxide investigations, generally speaking, continue to require a field resource to investigate. The contact centre is able to pre-screen, evaluate and prioritize these types of calls somewhat; however, the level of activity has remained fairly steady at roughly 20,000 to 21,000 calls per year and the field visit is still required to physically assess the customer's concern.

In terms of the financial/billing type of activities, there have been some reductions to these types of activities. This includes a reduction in the "meter to cash" type of activities such as lock-offs and reconnects, the costs of which have generally been recoverable from individual customers through the tariff reconnection fee. While the costs and activities have been reduced, the revenues from reconnects have also reduced in parallel.

125.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Tab C, Section 3.4.2.3, p. 137

Business Drivers for Operations Department

FEI states: "Since 2007, the Company has hired Distribution Apprentices (96) as part of its resource plan to respond to challenging demographics in the field workforce."

125.1 Since this activity has been ongoing since 2007, would it not be embedded in the O&M cost structure rather than being a new cost driver?

Response:

This is not a new cost driver but an ongoing cost driver for the Operations group which is expected to continue at various levels until such time as the challenging demographics of the field workforce are lessened.

The business drivers for the Operations Department discussed in section C.3.4.2 of the Application (and, similarly, the business drivers described for all the other departments in section C.3 of the Application) are the ongoing business drivers, not new business drivers.

126.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Tab C, Section 3.4.2.4, p. 137

Business Drivers for Operations Department

FEI states: "Fuel gas is used to run drivers for compressor units and to provide heat for the vaporizers at the LNG plant."

126.1 With declining peak day throughput, does FEI expect this cost to decline during the PBR period?

Response:

The cost of fuel gas is not expected to decline during the PBR period with declining peak day throughput.

The forecast cost of fuel gas is based on historical fuel gas requirements for average annual conditions which are more representative of normal annual load, together with a forecast of natural gas prices. Actual system load variability is primarily weather dependent and FEI seeks continuation of the current deferral account treatment of company use gas variances whereby price and volume variances between the forecast and actual amounts are booked against and managed through the Midstream Cost Reconciliation Account (MCRA).

127.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Tab C, Section 3.4.3, p. 138

Business Drivers for Operations Department

Table C3-6 sets out the historical O&M for Operations.

127.1 Total O&M rose by 16.65 percent over the three-year period. This increase of more than 5%/yr does not seem sustainable. What can FEI do to reduce it back to something less than inflation?

Response:

The following table summarizes the historical and forecast Operations O&M dollars from 2010 to 2018 together with the annual percentage increases.

	Operations O&M ($000s)									
	2010	**2011**	**2012**	**2013**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
	Actuals	**Actuals**	**Actuals**	**Projection**	**Base**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**
Distribution	$ 40,989	$ 41,864	$ 45,680	$ 48,295	$ 52,949	$ 54,282	$ 55,450	$ 56,829	$ 58,423	$ 60,443
Transmission	$ 7,010	$ 8,209	$ 9,117	$ 9,369	$ 9,813	$ 10,017	$ 10,231	$ 10,466	$ 10,716	$ 11,007
Plant Operations	$ 6,444	$ 5,683	$ 5,009	$ 5,845	$ 6,253	$ 6,763	$ 7,617	$ 7,789	$ 8,114	$ 8,199
Operations Total	$ 54,443	$ 55,756	$ 59,806	$ 63,509	$ 69,015	$ 71,062	$ 73,298	$ 75,084	$ 77,253	$ 79,649
% Change	5.4%	2.4%	7.3%	6.2%	8.7%	3.0%	3.1%	2.4%	2.9%	3.1%

Although the forecast Operations O&M increases continue to exceed current composite inflation factors for 2014-2018 ranging between 2.3 % and 2.4% per year (Exhibit B-1, Tab C, Table B6-7, page 63), the increases are only slightly above inflation and reflect the efforts of the Operations group to control spending in the face of the ongoing pressures in labour and benefit and other costs. For rate setting purposes, the overall company O&M will be inflated at the formula-driven rate, including a productivity factor. As part of the PBR, FEI will be working to manage its overall Company costs to this level, even though the costs in the Operations department are forecast to increase at a rate slightly greater than inflation.

Although not directly relevant to the rates that FEI will be proposing during the PBR period, FEI provides a high level summary below of the kinds of pressures it will be facing and how it will continue to work to manage them over the coming 5 years.

Approximately 69% of the 2014 forecast Operations O&M is for company labour. Labour and benefits inflation included in the forecast are between 2.2% and 3.7% annually (Exhibit B-1, Tab C, Table C3-3, page 127). Labour and benefits inflation, is primarily a non-discretionary cost required to fund expected increases for employees. Pension and OPEB forecast expenses, which impact the overall benefits challenge, are based upon recent actuarial estimates and are a significant challenge for Operations due to the large number of employees in this group. The increase from 2013 Projection to 2013 Base (8.7%), exclusive of a small incremental PST amount, is directly related to pension and OPEB forecast pressures.

In the Plant Operations sub-group there are higher than inflationary increases in forecast O&M in 2014 and 2015 due to the ramp-up and inclusion of incremental labour and non-labour costs required to support production of LNG and the revenues from Rate Schedule 16 volumes. For rate setting purposes, these amounts are treated outside of the PBR formula and will be subject to re-forecast and review at each Annual Review.

In the Distribution sub-group there is also a minor incremental increase in 2014 for residential meter exchange activities driven by known Measurement Canada compliance sampling changes.

In the Transmission group, there are no incremental pressures forecast other than inflation and benefits pressures.

The Operations group continues to look for ways to reduce spending below forecasted and inflationary levels while maintaining and improving customer satisfaction, safety and reliability. Productivity initiatives, process and program reviews and resource optimization are on-going in Operations and embedded in a continuous improvement employee culture. Any additional code changes, changes in the scope of Operations type activities are expected to be offset with future productivity realizations.

127.2 Please restate Table C3-6 to show actual and approved O&M/ customer.

Response:

Provided below is a restated Table C3-6 to show actual and approved O&M/Customer.

Operations O&M Per Customer

	2010 Actual	2011 Actual	2012 Actual	2013 Approved
Total O&M ($ thousands)	$ 54,444	$ 55,756	$ 59,806	$ 63,189
Total Average Customers	839,017	845,282	834,888	840,721
O&M per Customer	$ 65	$ 66	$ 72	$ 75

127.3 Please indicate the actual O&M/customer in 2007, the projected O&M/ customer in 2013, the proposed PBR base O&M/ customer for 2013 (Table C3-10), and the average annual increase in O&M/customer from 2007 to the 2013 PBR Base.

Response:

The appropriate basis of comparison for the 2013 Projected O&M is the 2013 Approved O&M. The 2013 Approved O&M was subject to a full hearing and the costs that were included in that figure are at an appropriate level to compare the 2013 Projections (and 2013 Base) that form the basis for the 2014 delivery rates. The 2007 Actual O&M provided below reflects a different set of accounting classifications between O&M and capital, and a different set of circumstances than 2013.

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

Operations O&M Per Customer

	2007 Actuals	2013 Projected	2013 Base
Total O&M ($000s)	$44,244	$63,509	$69,016
Total Average Customers	816,427	840,721	840,721
Operations O&M Per Customer ($)	$54	$76	$82

The increase in Operations O&M per customer from 2007 to 2013 PBR Base is $28 per customer. The difference between the 2013 Base and 2013 Projected is the OPEB/pension adjustments related to Operations O&M. The average annual increase is $28 divided by 6 years or $4.7 per customer per year.

127.4 Please provide a table of the actual O&M/ customer for the Operations Department for each year of the last 2004-2009 PBR.

Response:

Please refer to the response to BCUC IR 1.127.3 for a discussion of why these figures from 10 years ago are not relevant to the Commission's review of the 2013 projections included in this Application.

Operations O&M Per Customer (2004 - 2009)

	2004 Actuals	2005 Actuals	2006 Actuals	2007 Actuals	2008 Actuals	2009 Actuals
Total O&M ($000s)	$42,154	$42,849	$42,370	$44,244	$48,730	$51,661
Total Average Customers	779,779	791,593	802,743	816,427	825,696	832,751
Operations O&M Per Customer ($)	$54	$54	$53	$54	$59	$62

128.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Tab C, Section 3.4.3, p. 139

Business Drivers for Operations Department

FEI states: "Labour versus Non-Labour – The Projected 2013 shift of Distribution group O&M labour to non-labour resources of approximately $1.8 million reflects expected use of contractor resources in 2013 and the level of actual internal and contractors resources used in 2012."

128.1 Why was there such a large shift to contractor resources in 2013 projected compared to 2013 approved?

Response:

The statement above from page 139 incorrectly attributes $1.8 million of the shift from labour to non-labour as being contractor resources. The correct amount is $0.4 million. The largest component of the shift to non-labour is a reduction in revenues as summarized below.

The table below summarizes the changes in Distribution non-labour 2013 Projected versus non-labour 2013 Approved by BCUC Activity code. FEI is projecting an increase in non-labour (contractor) costs of approximately $0.4 million for Operations (BCUC Activity Code 110-23) below for leak survey and bridge crossing repair activities. The additional leak survey costs are for contractors to complete surveys at addresses which have been difficult to survey during regular surveys. The bridge crossing repairs are identified through inspection surveys and not typically a skill the company maintains in-house. The repairs are required to maintain gas assets at the bridge crossings in a safe operating condition.

The largest component of the projected 2013 shift of Distribution group O&M labour to non-labour (BCUC Activity Code 110-24 and 110-42 below) of approximately $1.8 million is the reductions in reconnect and system damage revenues. Lock-off and unlock field activities (part of the credit and collections bad debt management process), together with offsetting reconnection revenues, have decreased relative to approved amounts. Similarly, emergency management (system damage) revenues, a non-labour item, and repair costs have been steadily decreasing relative to approved values. System damages are decreasing due to higher awareness levels of BC One Call and decreased construction activity.

Distribution Non Labour 2013 Projected versus 2013 Approved ($000s)

BCUC Activity View	BCUC Activity Code	2013 Projection	2013 Approved	Variance
Distribution Supervision	110-11	$ 3,114	$ 3,088	$ 26
Distribution Supervison Total	**110-10**	**$ 3,114**	**$ 3,088**	**$ 26**
Operation Centre	110-21	$ 2,050	$ 2,076	$ (26)
Preventative Maintenance	110-22	$ 894	$ 1,163	$ (269)
Operations	110-23	$ 3,621	$ 3,235	$ 386
Emergency Management	110-24	$ (310)	$ (767)	$ 457
Field Training	110-25	$ 798	$ 1,048	$ (250)
Meter Exchange	110-26	$ 713	$ 777	$ (64)
Distribution Operations Total	**110-20**	**$ 7,766**	**$ 7,532**	**$ 234**
Corrective	110-31	$ 2,055	$ 2,047	$ 8
Distribution Maintenance Total	**110-30**	**$ 2,055**	**$ 2,047**	**$ 8**
Account Services	110-41	$ 211	$ 138	$ 73
Bad Debt Management	110-42	$ (840)	$ (2,232)	$ 1,392
Distribution Meter to Cash	**110-40**	**$ (629)**	**$ (2,094)**	**$ 1,465**
Distribution Total	**110**	**$ 12,306**	**$ 10,573**	**$ 1,733**

129.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Tab C, Section 3.4.3, p. 139

Business Drivers for Operations Department

Table C3-8 shows very large increases from 2010 through 2013 projected.

129.1 What were the annual percentage increases and why?

Response:

	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%

As stated in the response to other IRs, the appropriate basis of comparison for the 2013 Projected O&M is the 2013 Approved O&M. The 2010 actual O&M reflects a different set of accounting classifications between O&M and capital as well as Integrity Management Plan (IMP) code and regulation changes introduced, reviewed and approved in the 2010-2011 RRA and the 2012-2013 RRA.

Primary contributors to the increase from 2010 to 2011 were materials (signage and marker placements; $400 thousand), vegetation management and TPIP (Transmission Integrity Management Plan; $600 thousand) and COPE salaries (one additional headcount and increased O&M inspection activities; $200 thousand).

Primary contributors to the increase from 2011 to 2012 are TPIP and vegetation management costs ($800 thousand), and corrective maintenance costs (washouts; $110 thousand).

The vegetation management requirements on the right of ways have been more extensive than planned and are required on an on-going basis to maintain visibility and access to the pipelines so that regular line patrols can be conducted efficiently and access to pipelines is straight forward.

Primary contributors to the forecast increase from 2012 to 2013 Projection is for depth of cover management. A number of areas in the Interior have been identified in which the depth of cover on the pipeline no longer meets industry code and these need to be remedied.

129.2 Please provide the Transmission O&M / customer costs for 2007, 2013 Projected and 2013 PBR Base (Table C3-12) and please indicate the average annual percentage increase between 2007 and 2013 PBR Base.

Response:

The 2007 Actual O&M provided below reflects a different set of accounting classifications between O&M and capital, and a different set of circumstances than 2013. For example, several CSA Z662 code and regulation changes (i.e. asset security, integrity management plans) impacting Transmission Operations were implemented in 2010/2011.

Please refer to the response to BCUC IR 1.127.3 for a discussion of why actuals from 2007 are not relevant to the Commission's review of the 2013 projections included in this Application.

Transmission Operations O&M per Customer

	2007 Actuals	2013 Projected	2013 Base
Transmisssion O&M ($000s)	$6,965	$9,369	$9,813
Average Customers	816,427	840,721	840,721
Transmission Opns O&M Per Customer ($)	$9	$11	$12

The increase in Transmission O&M per customer from 2007 to 2013 was $3 per customer or 36.8% and the average annual percentage increase was 36.8% divided by six years or 6.1% per year. The 4.7% increase from 2013 Projection to 2013 Base is for pension, OPEB and PST.

130.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Tab C, Section 3.4.4, pp. 141-143

Business Drivers for Operations Department

Tables C3-10 through C3-13 show increases from 2013 Approved and Projected to the 2013 PBR Base.

130.1 Please provide a Table showing the Total O&M for each of Operations, Distribution, Transmission, and Plant Operations for each of 2013 Approved, Projected, and PBR Base.

Response:

Please refer to the table below.

	Operations O&M ($000s)		
	2013 Approved	**2013 Projected**	**2013 Base**
Distribution	$ 48,635	$ 48,295	$ 52,949
Transmission	$ 8,803	$ 9,369	$ 9,813
Plant Operations	$ 5,751	$ 5,845	$ 6,253
Total Operations	$ 63,189	$ 63,509	$ 69,015

130.2 Why are the 2013 PBR Base costs significantly higher than the expected 2013 costs?

Response:

The 2013 PBR Base costs are $5.5 million or 8.7% higher than the 2013 Projected Operations O&M costs. A reconciliation of the 2013 Projection to the 2013 Base was provided in Table C3-2 for the Operations department and an explanation of the adjustments was provided in Section B6.2.4.1 of the Application. The adjustments include $137 thousand for the reintroduction of PST, $3.667 million for pension and OPEB expense incurred in 2013 that was captured in a deferral account, and $1.704 million to allocate Operations' share of retiree pension and OPEBs. The allocation of the $5.5 million between the Distribution, Transmission, and Plant Operations areas is provided in the table below.

Operations O&M ($000s)

	2013 Projected	2013 Base	Difference	% Change
Distribution	$ 48,295	$ 52,949	$ 4,654	9.6%
Transmission	$ 9,369	$ 9,813	$ 444	4.7%
Plant Operations	$ 5,845	$ 6,253	$ 408	7.0%
Total Operations	$ 63,509	$ 69,015	**$ 5,506**	8.7%

2013 Deferrals:	
PST	$ 135
Pension Variance	$ 3,667
	$ 3,802
Accounting Changes	
Retiree pension/OPEBs	$ 1,704
Summary of Difference	**$ 5,506**

131.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.7, p. 162; FEU 2012-2013RRA, FEU Final Submission, p. 36

ENERGY SUPPLY AND RESOURCE DEVELOPMENT BUDGET

On page 36 of the FEU Final Submission in the FEU 2012-2013 RRA, FEU stated: "The FEU are seeking approval of the consolidated Core Market Administration Expense (CMAE), and allocation percentages, for FEI, FEW, and FEVI as set out in Section 5.2 of the Application."

131.1 Please confirm that the CMAE budget for the 2012 and 2013 test years was reviewed and approved as part of the FEU 2012-2013 Revenue Requirements Application. If not confirmed, please explain.

Response:

Confirmed.

131.2 Please provide the total approved CMAE budget for each of the 2012 and 2013 test years and the respective allocation percentages for FEI, FEW and FEVI.

Response:

The approved CMAE budgets for 2012 and 2013 were $4,374 thousand and $4,519 thousand, respectively. The approved CMAE budget amounts reflect the forecast costs net of the forecast Energy Management Services revenues from non-affiliated third parties, and other cost recoveries related to work performed by the Gas Supply group for power supply group at FortisBC Inc, and for propane supply management on behalf of the Furry Creek and Sun Peaks propane utilities.

The approved CMAE allocations for both 2012 and 2013 remained at 90% to FEI (including FEW) and 10% to FEVI.

On page 162 of the Application FEI states "the CMAE budget for 2014 will be submitted for Commission approval as part of the Company's regular gas cost reporting and rate setting process."

131.3 Please confirm that seeking approval of the CMAE budget as part of the Company's regular gas cost reporting is a new request.

Response:

Not confirmed.

Although requests for approval of the most recent CMAE budgets were sought and approved as part of the 2010-2011 and the 2012-2103 revenue requirements processes, 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.

Specifically, the 2006 CMAE budget and allocations were filed and reviewed as part of the Company's 2005 Fourth Quarter Gas Cost Report, dated December 5, 2005; subsequently approved pursuant to Commission Order G-131-05, dated December 13, 2005.

The 2007 CMAE budget and allocations were filed and reviewed as part of the Company's 2006 Fourth Quarter Gas Cost Report, dated December 4, 2006; subsequently approved pursuant to Commission Order G-167-06, dated December 15, 2006.

The 2008 CMAE budget and allocations were filed and reviewed as part of the Company's 2007 Fourth Quarter Gas Cost Report, dated December 3, 2007; subsequently approved pursuant to Commission Order G-150-07, dated December 7, 2007.

The 2009 CMAE budget and allocations were filed and reviewed as part of the Company's 2008 Fourth Quarter Gas Cost Report, dated December 4, 2008; subsequently approved pursuant to Commission Order G-187-08, dated December 11, 2008.

131.3.1 Should this request be added to the list of approvals sought by FEI in this proceeding?

Response:

No. The 2014 CMAE budget and allocations will be submitted for Commission review and approval as part of the FEI 2013 Fourth Quarter Gas Cost Report, anticipated to be filed in early December 2013.

FEI anticipates that during the PBR period it would seek Commission approval of its annual CMAE budgets and allocations as part of its Fourth Quarter Gas Cost Reports (typically filed in early December). This process is consistent with that followed during the previous PBR period, as discussed in the response to BCUC IR 1.131.3.

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.

131.3.1.1 If not, please explain.

Response:

Please refer to the response to BCUC IR 1.131.3.1.

131.3.1.2 If so, please state the requested approval being sought.

Response:

Please refer to the response to BCUC IR 1.131.3.1.

131.4 Please describe which "regular gas cost reporting and rate setting process" FEI anticipates will include the requests for approval of the CMAE budget for each of the years from 2014 through 2018 and the expected filing date of each of these filings.

Response:

Please refer to the response to BCUC IR 1.131.3.1.

131.5 Should the Commission conduct a regulatory review of the CMAE revenue requirement and the allocation percentages for FEI, FEW and FEVI separate from the proceeding for this Application? Please explain the response.

Response:

Please refer to the responses to BCUC IR 1.131.3.1 and 1.131.8.

131.6 Please explain why FEI is proposing to change the mechanism for review and approval of the CMAE costs.

Response:

Please refer to the responses to BCUC IR 1.131.3, 1.131.3.1 and 1.131.3.8.

131.7 Does FEI agree that the CMAE consists largely of controllable expenditures? If not, please explain.

Response:

The CMAE consists of both labour-related expenses and non-labour expenses. FEI agrees that the labour expenses are largely controllable. The non-labour expenses, however, can vary significantly from year to year and are difficult to forecast.

An example is the expenses related to upstream regulatory activities in which FEI participates to help minimize potential adverse cost impacts for core customers. The level of activity from year to year depends on outside factors that are largely beyond FEI's control and the associated costs are difficult to forecast. An example of the upstream regulatory activities in which FEI may directly participate is the recent Komie North proceeding discussed in the responses to BCUC IRs 1.133.2 and 1.133.2.1. As discussed in the response to BCUC IR 1.133.5, FEI anticipates that there may be several upstream regulatory proceedings over the duration of the PBR period where it may be necessary for the Company to participate.

Other examples of unforeseen expenses include third party costs related to Commission-directed reviews related to Gas Supply programs or applications. For example, in 2010, FEI was directed to conduct a review of its hedging objectives and strategy. After consultation with Commission staff, FEI used an experienced industry consultant to help with this review. As another example, in 2011 FEI was directed to conduct a review of its Gas Supply Mitigation Incentive Program (GSMIP) and recommended it engage an outside consultant to help in this regard which also resulted in unplanned costs.

Please also refer to the responses to BCUC IRs 1.131.8.5 and the 1.133 series.

131.8 Please provide the rationale for excluding the CMAE from the O&M expenses that the PBR formula will apply to.

Response:

The CMAE costs are excluded from the Company's O&M as these costs relate to securing and managing the gas supply for the Core Market and, as such, are more appropriately recovered from those customers via gas cost recovery rates. Pursuant to Commission Order G-37-94 and the 1994-1995 Revenue Requirements Application Phase 1 Decision, the Commission approved that the CMAE costs be segregated from the O&M cost category for the 1994-1995 period. Subsequently, pursuant to Commission Order G-99-95 and the Decision related to the Company's 1996-1998 revenue requirements, the Commission accepted the Negotiated

Settlement which included the CMAE costs being allocated to cost of gas commencing 1996. This treatment of CMAE costs have been in place since that time.

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.

Applying a PBR formula to the CMAE budget on a stand-alone basis is not appropriate. As discussed in the response to BCUC IR 1.131.7, the non-labour costs within the CMAE are largely due to FEI's response to events that are outside its control and can vary significantly from year to year. Further, 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.

It is appropriate that the CMAE budget is reviewed in the context of the forecast activities, including any inflationary pressures and efficiency savings. Commission review of the annual CMAE budget requirements in the context of managing the gas supply portfolio on behalf of Core Market customers, including the impacts related to the significant and dynamic changes occurring in the natural gas marketplace, remains appropriate and is consistent with the process followed during the prior PBR period as well as during the 2010-2011 and 2012-2013 revenue requirements periods.

132.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.7, p. 162; Commission Order E-18-12 dated July 26, 2012

ENERGY SUPPLY AND RESOURCE DEVELOPMENT BUDGET

On page 162 of the Application FEI states: "The main activities for the Gas Supply team funded through the CMAE budget include completing as commodity procurement, providing intra-day balancing supply (required primarily due to weather changes) for core customers, facilitating all gas scheduling and nominations on Company and third party pipeline transmission systems, mitigation activity based on buying and selling around excess resources and the management of relationships with financial and physical supply counterparties, storage operators and pipeline companies to the benefit of customers."

132.1 Please confirm that, as described in Commission Order E-18-12 dated July 26, 2012, FEI also provided Energy Management Services to Pacific Northern Gas (PNG) over the period from May 2003 to March 31, 2013. If not confirmed, please explain.

Response:

FEI provided Energy Management Services (EMS) to PNG from June 1, 2003 to March 31, 2013.

The initial EMS contract covering gas management services for the period June 1, 2003 to April 30, 2005 was dated May 7, 2003, and was accepted by the Commission via Order E-6-03.

132.2 Please confirm that the Energy Management Services agreement (EMS Agreement) with PNG was not renewed when it expired March 31, 2013.

Response:

Confirmed.

132.3 Please provide the amount of annual revenue provided to FEI under the PNG EMS Agreement in the final year of the EMS Agreement.

Response:

The length of the final term of the PNG EMS Agreement was actually 11 months instead of a year. The revenue provided to FEI under the last PNG EMS Agreement term from May 1, 2012 to March 31, 2013 was $15,500 per month, for a total of $170,500.

132.4 Please describe the allocation of resources in the Energy Supply & Resource Development (ES&RD) department required to provide the services set out in the PNG EMS Agreement prior to its expiry and the adjustments to ES&RD resourcing that were made to accommodate the expiry of the PNG EMS Agreement and the associated decrease in revenue.

Response:

The following services were set out in the PNG EMS Agreement:

- Gas supply planning and resource selection analysis
- Gas supply contract negotiation and administration
- Daily energy management services
- Monitor and report on credit, hedging positions, and gas prices

The above noted services provided by FEI were not performed by one individual but were part of the responsibilities of several people in the gas supply team in ES&RD, and the activities varied depending on the day or time of the year. For example, daily energy management services were performed by the Midstream group, which also manages FEI and FEVI's daily loads. Gas supply planning, contract negotiation, and market analyses were performed by the Commodity group, which also manages FEI and FEVI's gas supply planning, contract negotiation, and market analysis.

The expiry of the PNG EMS Agreement does not result in any redundant staffing resources, however does provide some capacity to reallocate responsibilities as part of on-going employee development and organization of the gas supply staff. It also provides capacity to allow FEI to continue to improve its processes and activities, respond to increased regulatory requirements, and position itself to respond to new challenges and opportunities resulting from the significant changes that are occurring in the regional natural gas marketplace without adding additional staff. Nevertheless, due to recent staffing changes and subsequent re-allocation of responsibilities within the group, and taking into consideration no longer having to perform the PNG EMS work, recent overall organizational changes have resulted in a reduction of one FTE within the ES&RD Core Market Administration Expense (CMAE), which will be reflected in the 2014 CMAE budget to be filed within the Company's 2013 Fourth Quarter Gas Cost Report.

132.5 Does the ES&RD department currently perform Energy Management Services for any other parties?

Response:

Yes, the ES&RD department continues to provide EMS related to management of the propane supply for Sun Peaks and Furry Creek.

132.5.1 If so, please describe the extent of such activities and the allocation of resources in the ES&RD department.

Response:

FEI provides the following services to support the Sun Peaks and Furry Creek propane operations:

- Propane supply contract negotiation and administration
- Management of payments and invoices

Unlike the EMS provided to PNG, FEI only provides limited services for the Sun Peaks and Furry Creek propane operations. The propane supply contract negotiation is managed by the Commodity group, which also manages FEI and FEVI's gas supply contract negotiation. Payment and invoices are managed by the Gas Supply back office, which also manages FEI and FEVI's gas supply payments and invoices.

Currently, a minimal amount of ES&RD resources are spent on activities related to Sun Peaks and Furry Creek.

132.6 Please confirm that the ES&RD department also performs Energy Management Services for FEW and FEVI, and currently allocates costs to these utilities based on allocation percentages approved in the FEU 2012-2013 RRA.

Response:

Since 2004 the CMAE activities performed within the FEI Gas Supply area have been provided on the basis of a single administrative function to serve core market customers within FEI, FEVI, and FEW. FEI would not characterize the integrated and harmonized gas supply function as a provision of EMS in the same context as PNG and the small propane utilities.

As discussed in the response to BCUC IR 1.131.8, CMAE costs are excluded from O&M and are a component of the cost of gas. The approved CMAE cost forecast is allocated to and included within the prospective gas costs used to set the gas cost recovery rates. Variances between the approved and actual gas costs, including the CMAE cost variances, are captured in the gas cost deferral accounts and refunded to, or recovered from, core market customers as part of future gas cost recovery rates. Consistent with the approved allocation percentages, the CMAE costs are currently allocated 90 percent to FEI (including FEW) and 10 percent to FEVI.

There has been no separate allocation of CMAE to FEW since 2009, as the Commission approved the amalgamation of the FEW and FEI natural gas portfolios commencing in 2010. Since 2010 the FEW and FEI combined share of the CMAE (e.g. 89% + 1% = 90%) has been included as part of the gas costs for the amalgamated gas supply portfolio; these costs have then been allocated to the various regions and core market rate classes as part of the rate setting process, based on the approved gas cost allocation methodologies. Prior to the amalgamation of the FEW and FEI gas portfolios, the allocation was 89% FEI, 10% FEVI and 1% FEW.

132.6.1 Please provide the allocation percentages used to allocate Energy Management Services costs to FEW and FEVI.

Response:

Please refer to the response to BCUC IR 1.132.6.

132.6.2 If not confirmed, please describe the arrangements for providing Energy Management Services to FEW and FEVI.

Response:

Please refer to the response to BCUC IR 1.132.6.

133.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.7, p. 163; National Energy Board NOVA Gas Transmission Ltd. Northwest Mainline Komie North Extension Application (https://www.neb-one.gc.ca/ll-eng/Livelink.exe?func=ll&objId=737909&objAction=browse&sort=-name&redirect=3)

ENERGY SUPPLY AND RESOURCE DEVELOPMENT BUDGET

On page 163 of the Application, FEI states, "Resource Development also monitors and participates in regional regulatory initiatives, such as proceedings involving other utilities and pipeline companies."

On the National Energy Board (NEB) website the following link provides further detail regarding FEI's involvement as an Intervener in the NEB NOVA Gas Transmission Ltd. Northwest Mainline Komie North Extension Application proceeding:

https://www.neb-one.gc.ca/ll-eng/Livelink.exe?func=ll&objId=811452&objAction=browse&sort=name

133.1 Please confirm that FEI participated directly in the NEB proceeding for the NOVA Gas Transmission Ltd. (NGTL) Northwest Mainline Komie North Extension application (Komie North Proceeding) established in NEB Hearing Order GH-001-12, including the provision of a Witness Panel and filing of Evidence.

Response:

Confirmed. FEI actively participated in that hearing.

133.2 Please describe the nature of FEI's past practice regarding FEI involvement in NEB hearings regarding NGTL infrastructure in Northeastern British Columbia and confirm that FEI's direct participation in the NEB Komie North proceeding was a departure from this past practice.

Response:

A review of the history of FEI's involvement in regulatory matters concerning developments in northeast BC that involved Westcoast Energy and TransCanada's NGTL system, shows that FEI has often directly intervened on issues. Such action is typically taken in circumstances where an issue is of significant and primary importance to FEI. As such, FEI's direct participation in the Komie North proceeding in 2012 was not a departure from this past practice, although much of the recent involvement in NTGL issues has been as part of the Western Export Group (WEG).

FEI has been actively involved in NEB regulatory matters concerning northeast BC since the early 1990s, when gas markets opened to competition. Initially this interest centred on Westcoast Energy, its tolls, and on the development of infrastructure required for the transmission of raw and processed gas in and from northeast BC. FEI was involved in a number of proceedings initiated by Westcoast Energy with the NEB. One of the more significant outcomes of this participation was the development of the Framework for Light-Handed Regulation in 1997 of the Westcoast Zone 1 (raw gas transmission) and Zone 2 (processing) facilities. This Framework remains in effect today.

FEI became increasingly involved in regulatory matters concerning TransCanada's NGTL system as that system undertook expansion plans into northeast BC from Alberta beginning with the Groundbirch Pipeline in 2008. Given the lower reliance on supply transported from Alberta, FEI participated in NEB hearings regarding NGTL infrastructure in northeast British Columbia and in Alberta primarily through WEG, which represents a number of gas and electric local distribution companies in BC, Washington State, Oregon, Idaho, Nevada, and California. Participation through WEG requires a consensus of its members. One of the significant proceedings WEG participated in that concerned infrastructure in northeast BC, was the Horn River Project hearing in 2010.

In the case of Komie North, the potential impact on the individual WEG members varied significantly and so the member companies did not participate as a single group. For example, as discussed in the response to BCUC IR 1.133.2.1, FEI's primary concerns were on the potential impact on the Westcoast System, which would be of limited interest to the California utilities who hold NGTL capacity to connect to Foothills BC and GTN at Kingsgate As a result of Komie North having a potential significant impact on FEI and its customers, FEI elected to actively participate on its own at the hearing.

133.2.1 Please describe the reasons for FEI's direct participation in the NEB Komie North Proceeding.

Response:

There were a number of reasons for FEI's direct participation that include:

- FEI receives about 85% of its gas supply via Westcoast Energy Inc. (Westcoast) and the Komie North extension had the potential to negatively impact the medium and longer term availability of supply, liquidity, and pipeline utilization, particularly on the Westcoast System.
- The project could have reduced flows on Westcoast'sT-South pipeline, and such a reduction would negatively impact the continued access to adequate gas supplies at Station 2, resulting in greater price volatility and higher overall gas costs to FEI's customers. Any reduced pipeline utilization would also negatively impact the toll paid for transportation by FEI.
- FEI was concerned about the sizing of the pipeline, average contract term, and inappropriate pricing signals to the marketplace. These issues could create the potential for overbuilding, or the inefficient development, of natural gas infrastructure in northeast BC while at the same time reducing the volume of gas flowing on to the Westcoast System.
- The project could cause underutilized and redundant facilities on Westcoast's systems resulting in higher tolling costs that would be borne by those transporting, distributing, and consuming natural gas.

In reaching its decision denying the application for the Komie North extension, the NEB relied in part on arguments raised by FEI as described above. The NEB did not accept that the Komie North section as proposed had sufficient commercial support for it to be economically feasible and acknowledged that an approval of the Komie North extension as proposed would have unacceptable commercial impacts on other parties. In particular the NEB took into consideration the potential negative impacts on Westcoast's existing transmission and gathering and processing facilities in northeast BC, as well as on existing shippers on its system.

FEI keeps the Commission informed on these types of developments and FEI's potential involvement on an on-going basis. A review of upstream regulatory developments and the potential impacts to FEI and its customers is provided annually as part of the FEI/FEVI's ACP and the Komie North development in particular was discussed in detail in both the 2012/13 and 2013/14 ACPs. In addition, FEI meets with Commission staff from time to time to inform them of upcoming issues when there are significant developments in other regulatory jurisdictions which could impact FEI and its customers. For example, in a meeting with Commission staff held on May 30, 2012 about NEB related issues, FEI provided background information about the proposed Komie North project and set out concerns this project raised. FEI also indicated that an intervention by FEI in the proceeding with the NEB was needed and that it would include third party expert witnesses as part of a Company panel. The potential cost of involvement in the proceeding was also discussed in general terms. FEI indicate that the cost would be significant given the importance of the issues Komie North raised and the need for involving third party expert witnesses.

133.3 Please provide an estimate of FEI's cost of participating in the Komie North Proceeding.

Response:

The estimated incremental cost to participate in the Komie North proceeding by FEI is $414,000. This amount is comprised of $248,000 of consulting costs, $153,000 of external legal services, and $13,000 in travel expenses.

133.4 Please describe the extent to which this cost was included in the CMAE budget that was approved in the FEU 2012-2013 Revenue Requirements Application.

Response:

The total cost of the Komie North proceeding was included as a CMAE expense in 2012, for which the budget was approved in the FEU 2012-2013 RRA.

The CMAE budget for 2012-2013 included a provision for potential upstream regulatory activities, such as those involving the Komie North proceeding. These costs are appropriately included as a CMAE expense because actively monitoring and participating in regional regulatory and market developments helps to minimize potential adverse cost impacts for core customers.

133.5 Does FEI anticipate participating to this extent in additional NEB proceedings over the period from 2014 through 2018?

Response:

FEI anticipates that there may be several proceedings in the period from 2014 to 2018 where it may need to participate to a similar extent to that necessary in the Komie North proceeding. This involvement is necessary as a result of an increasing level of pipeline activity by TransCanada/NGTL in northeast BC with the NGTL system extending further into the Horn River, Montney, and Liard basins.

At this time, FEI foresees that there may be up to three such hearings that could require it to participate again to this extent. These potential hearings include an extension by NGTL of the Groundbirch pipeline to an area north of Aitken Creek, a transportation by others agreement by NGTL associated with the proposed Coastal Gas Link pipeline, and an application by NGTL applying for a Horn River pipeline extension that may extend as far as the Liard basin. These hearings would likely be in the 2014 to 2016 timeframe with the North Montney Project expected to occur in 2014, assuming there is no delay in proceeding with the LNG projects that are a key driver for these TransCanada/NGTL applications. At this point in time, FEI is unable to determine what other potential hearings might arise during this period.

The level of participation in any proceeding will depend on the nature of the application, the potential for a positive outcome, and the principles at stake. This level of participation also determines the potential cost faced by FEI for each proceeding. As a basic rule of thumb, a typical proceeding that involves a Company panel, including third party expert witnesses and where external legal counsel is required to actively participate in the proceeding, is expected to cost in the range of $200,000 to $500,000 depending on the length of the proceeding. To the extent that FEI is able to participate with other parties with similar interests then this amount may be reduced.

133.5.1 If so, please provide an estimate of the number of such proceedings and an estimate of the costs of participating in each such further NEB proceeding.

Response:

Please refer to the response to BCUC IR 1.133.5.

134.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Application, Tab C, Section 3.7, p. 163

ENERGY SUPPLY AND RESOURCE DEVELOPMENT BUDGET

On page 163 of the Application, FEI states, "the on-system transportation services activities within Gas Supply (funded through O&M) include management of transportation and marketing services on the Company's pipeline system, and oversight of on-system gas transportation and industrial, commercial and marketer agent services. This includes coordinating nominations and scheduling third-party shipper requests onto the pipeline."

134.1 Please confirm that FEI manages the on-system transportation service activities of FEVI.

Response:

Confirmed.

134.2 Please confirm that the on-system transportation service activities on the FEVI system recently expanded to include the management of transportation service under the FEVI Rate Schedule Large Commercial Service No. 13 (LCS-13) General Firm Transportation Service when this rate schedule became effective March 1, 2013 under Commission Order G-33-13.

Response:

Confirmed. FEVI applied to the Commission to amend this Rate Schedule to include the terms and conditions necessary to pool customers and offer transportation services more effectively to FEVI customers and these amendments were approved, effective March 1, 2013, on an interim basis pursuant to Commission Order G-33-13, dated March 7, 2013.

134.3 Please provide an estimate of the incremental annual ES&RD shared services costs to be allocated from FEI to FEVI to account for the management of FEVI's on-system transportation services under Rate Schedule LCS-13 for the 2014 year.

Response:

The on-system transportation services activities performed by FEI to support the FEVI transportation services under Rate Schedule LCS-13 will be covered under the Shared Services Management Agreement between FEVI and FEI. The on-system transportation services costs forecast to be allocated to FEVI in 2014 are approximately $23,000.

Shared services costs are allocated based on a representative driver as approved by the Commission. In any given year there may be more or less specific work related to FEVI activities, but overall the allocation factor provides a reasonable basis for allocating costs.

134.4 Were any computer upgrades or revised business processes required for the ES&RD scheduling systems in order to accommodate the management of transactions under FEVI Rate Schedule LCS-13?

Response:

Yes, system upgrades were required to manage transactions under FEVI's Rate Schedule LCS-13.

134.4.1 If so, please describe the nature of the upgrades and/or enhancements and the cost of the upgrades and enhancements?

Response:

The gas management and nomination system known as WINS (which stands for Web Interface Nomination System) is used to manage and track gas supply requirements on the FEI and FEVI systems. In order to handle the business for shipper groups operating under the FEVI Rate Schedule LCS-13, WINS required two enhancements. First, an update to the existing Inventory

Report, and second, the generation of a Billing Report to track high end charges as they occur. The one-time cost for this work was approximately $6,500.

In addition, the SAP system handled by Industrial Billing required new configuration for the LCS-13 rate class, the addition of high end charges, and testing. The one-time cost for this work was $5,775.

Consistent with the existing business practice, the costs related to information technology system upgrades and enhancements are allocated between FEI and FEVI.

134.4.2 Please describe any additional staff resources that were required to support the management of this incremental transportation service.

Response:

No additional staff resources are required at this time.

135.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Tab C, Section 3.9.2 & 3.9.3, pp. 172-177

Engineering Services and Project Management

The 4 key Drivers are identified on page 172 and actual and forecast costs are shown on Tables C3-23 and C3-24.

135.1 The four key drivers seem to indicate a business as usual state but the costs in table C3-23 show substantial cost increases since 2010. Why?

Response:

It is expected that the nature of the business drivers that influence Engineering Services and Project Management should remain relatively consistent over time, however with varying levels of impacts. As an example, changes to standards, regulations, and industry standard practices may in some years have a significant impact to FEI's practices. In others, the impact may be insignificant. Likewise, as the Company's LTSP risk framework evolves, the 20-year view of potential infrastructure requirements is expected to evolve.

Increases since 2010 are due to pressures related to Codes & Regulations and Service Standards & Reliability, as recognized and approved by the Commission through the 2010-2011 RRA and 2012-2013 RRA Decisions. 2012 Actuals were lower than anticipated primarily due to insourcing of LTSP development as well as challenges experienced by FEI associated with hiring technical staff from the current labour markets.

135.2 Why are the 2013 PBR Base costs significantly higher than the Projected 2013 costs?

Response:

The reconciliation of the 2013 Projection to 2013 Base was provided for each department in Table C3-2 of the Application. The information in that table has been reproduced below specifically for the Engineering Services and Project Management department, with a split between the labour and non-labour lines. In addition, the nature of these items is explained in Section B.6.2.4.1 on pages 54-56.

	Labour	Non-Labour	Total
2013 Projection	**11,266**	**4,191**	**15,456**
PST		58	58
Retiree Pension/OPEB	477		477
Pension Variance	1,027		1,027
2013 Base	**12,769**	**4,249**	**17,018**

In summary, the difference between 2013 PBR Base costs and Projected 2013 costs do not reflect an increase in activity levels in Engineering Services and Project Management. Instead, the difference is solely due to the true-up of 2013 O&M to include 2013 O&M impacts from PST and Pension and OPEB amounts that are held in deferral accounts.

135.3 Why were the 2013 Approved costs 25 percent higher than Actual 2012 costs and the 2013 Projected costs 14 percent higher?

Response:

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.

The 2013 Projection is higher than 2012 Actual because 2013 includes successful hiring of technical staff and further LTSP development (as discussed in Section C3.9.3, "resources to conduct asset condition assessments and to develop more detailed asset mitigation plans"), offset by productivity enhancements as also described in that section of the Application.

135.4 What were the actual 2008 Engineering Services and Project Management costs compared to the 2013 PBR Base costs and what average percentage increase does that represent?

Response:

FEI provides below a comparison between 2008 costs and 2013 Projection, followed by an explanation at the end of the response for the difference between the 2013 Projection and 2013 Base. As stated in response to other IRs, the appropriate basis of comparison for the 2013 Projected O&M is the 2013 Approved O&M. The 2013 Approved O&M was subject to a full hearing and the costs that were included in that figure are at an appropriate level to compare the 2013 Projections (and 2013 Base) that form the basis for the 2014 delivery rates. The 2008 Actual O&M reflects a different set of accounting classifications between O&M and capital, and a different set of circumstances than 2013.

In 2008, the actual 2008 Engineering Services and Project Management costs were $8.959 million compared to the 2013 projection of $15.456 million. This represents an average annual percentage increase of 11.5%.

Primary contributors to the increase have been discussed and approved in prior Revenue Requirements applications, and included the following:

- Requirement for FEI to meet a changed requirement in the BC Safety Authority – Gas Safety Regulation to provide gas system information requested through BC OneCall within two days instead of three;
- Requirement for FEI to meet changed requirements in the CSA Z662 standard. CSA Z662 Annex N brought more formal and rigorous requirements to the integrity management of pipeline systems. Particular areas of impact included records management practices and training/competency requirements for staff performing elements of the Company's Integrity Management Program;
- Incremental maintenance and capital planning resources to manage increased workload for planning and prioritizing maintenance and capital investments;
- Establishing and maintaining a LTSP to ensure the Company's assets continue to meet customer needs today and into the future;
- Ensuring sufficient Engineering Services and Project Management resources to implement required activities identified through the LTSP and other asset planning processes;

- Ensuring sufficient resources to enable compliance with the Oil and Gas Activities Act (OGAA) that replaced the B.C. Pipeline Act and became law in October 2010; and
- Aligning FEI's GIS and Drafting practices to the CSA S250 Mapping Standard for Underground Utilities.

A reconciliation of the 2013 Projection to the 2013 PBR Base was provided in Table C3-2 and described in Section B6.2.4.1 of the Application. The amounts provided in Table C3-2 for the Engineering Services and PM department include $58 thousand for the reintroduction of PST, $1,027 thousand for pension and OPEB expenses that were held in a deferral account in 2013, and $477 thousand for an allocation of the retiree portion of pension and OPEB expenses.

136.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Tab C, Section 3.9.4, p. 176

Engineering Services and Project Management

FEI states that: "There is an increasing trend in the pipeline industry, in part driven by regulator expectations, for operators to fully understand and to demonstrate their utilization of both historic and current engineering data and records in operating decisions, such as maximum operating pressure calculations. To facilitate this, improved methods for data collection, data organization, and data use are being developed. Historic data collection and organization is particularly resource-intensive, an example being material properties (e.g. yield strength, tensile strength, chemical properties) dating from original pipeline construction. It is expected that pressures will be experienced over the 2014-2018 timeframe within Engineering Services and Project Management related to the effective capture and management of historic and current engineering data."

136.1 Isn't this work well underway in the Long Term Sustainment Plan and, therefore, not a significant cost driver during the proposed PBR period?

Response:

The LTSP risk framework has been developed and has led to the production of initial plans for asset replacement. These plans will be refined over time as discussed in Appendix C3, Section 3 of the Application (Exhibit B-1-1). A number of additional Threat and Consequence factors were identified during the LTSP development process and were ultimately deferred due to incomplete or missing asset data. As such, ongoing historical data collection and validation to support the LTSP and other asset data requirements is an anticipated pressure for FEI over the proposed 2014-2018 PBR Period.

Through the Gas Asset Records Project, FEI is improving records collection, retention, and management practices. To build on this work, and to remain current with industry standard practice, FEI is anticipating pressures over the 2014-2018 timeframe for such items as extraction and validation of selected historical data elements.

137.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Tab C, Section 3.10, pp. 177-181

Operations Support

On page 179, FEI states that: "Operations Support realized cost savings in 2012 of approximately $1.1 million as compared to the Approved O&M, and anticipates continuing this level of cost savings through 2013. These savings are directly attributed to lower than forecasted labour costs driven by adjustments to the sustainment capital plan which reduced activity levels, combined with the implementation of a variety of internal productivity enhancements throughout the department. Examples of the various productivity enhancements embedded within Operations Support include the following:

- Expansion of roles for existing employees in all areas of the department to enable employees to be re-directed where demand is the greatest;
- Automation of equipment within the mechanical and meter shops to reduce manual effort;
- Business process simplification through automation within Supply Chain Services, simplification of various physical processes within Materials Services to reduce cycle time and digitizing key documents within Measurement Services to reduce document management activities;
- Optimizing the use of 3rd party contractors to reduce logistics costs; and
- Continuing to pursue 3rd party revenue generation opportunities within Measurement Services, the Radio Network, ICS and Mechanical Services to offset operating costs.

137.1 In spite of these efficiencies the costs continued to rise in the 2010 – 2013 period and are expected to jump by 10.5 percent from Projected 2013 costs to PBR Base 2013. Why?

Response:

Between the period of 2010 – 2013, Operations Support costs have risen by an annual average of 2.18% compared to the approved annual average approved increase of 4.75% over the same time period. The increase in costs over this period was driven by government regulation, reliability standards and customer expectations, as discussed in FEI's 2010/2011 RRA and 2012/13 RRA. In particular, incremental costs were incurred to maintain 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. Finally, the department faced both labour and non-labour inflationary pressure throughout this period. As such, Operations Support has implemented productivity enhancements to mitigate these cost increases and will continue to explore opportunities to achieve operational efficiencies going forward.

A reconciliation of the 2013 Projection to the 2013 Base was provided in Table C3-2 for the Operations Support department and an explanation of the adjustments was provided in Section B6.2.4.1 of the Application. The adjustments include $69 thousand for the reintroduction of PST, $802 thousand for pension and OPEB expense incurred in 2013 that was captured in a deferral account, and $373 thousand to allocate Operations Support's share of retiree pension and OPEBs.

137.2 What were the actual 2008 costs for the Operations Support Department?

<u>Response:</u>

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

The appropriate basis of comparison for the 2013 Projected O&M is the 2013 Approved O&M. The 2013 Approved O&M was subject to a full hearing and the costs that were included in that figure are at an appropriate level to compare the 2013 Projections (and 2013 Base) that form the basis for the 2014 delivery rates. The 2008 Actual O&M provided reflects a different set of accounting classifications between O&M and capital, and a different set of circumstances than 2013, including some organizational changes that FEI was not able to restate to be fully comparable.

138.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Tab C, Section 3.11.3, p. 182

Facilities

Table C3-27 shows the actual, approved and projected costs of the Facilities.

138.1 Please explain the 53 percent jump in non-labour costs in 2012?

Response:

The explanation for this increase was provided in Exhibit B-1, Section C3.11.3 on page 182 starting at line 34 and is repeated below:

"In 2012, Facilities had an increase of $2.7 million in actual spending, which was equal to the approval level. $2.4 million of this increase was to support the two new contact centre spaces brought into service as a result of the insourcing of the Customer Service function. This increase in O&M was approved in the 2012-2013 RRA Decision. The remainder of $300 thousand was driven by lease contracts, service contracts, cyclical building maintenance and labour as discussed in the 2012-2013 RRA."

138.2 What were the actual 2008 costs for the Facilities Department?

Response:

The Facilities Department actual 2008 O&M was $5,890 thousand.

The appropriate basis of comparison for the 2013 Projected O&M is the 2013 Approved O&M. The 2013 Approved O&M was subject to a full hearing and the costs that were included in that figure are at an appropriate level to compare the 2013 Projections (and 2013 Base) that form the basis for the 2014 delivery rates. The 2008 Actual O&M provided reflects a different set of accounting classifications between O&M and capital, and a different set of circumstances than 2013, including some organizational changes that FEI was not able to restate to be fully comparable.

138.3 Please identify the number of employees in the Facilities Department in each year since 2008?

Response:

Please refer to the table below for the number of average FTEs in the Facilities Department since 2008. In 2010, Facilities was not able to fill vacancies due to job description re-writes for the maintenance roles which required a delay in hiring. Additionally, in 2010, 2011 and 2012, Facilities experienced challenges with retirements and hiring qualified trades people due to the high demand in the market. During these years, the vacancies were back filled by contractor service to ensure operations and maintenance was not impacted. However, in 2013 FEI was finally able to fill all vacancies to budgeted levels.

Summary of Facilities Average FTE

	2008	2009	2010	2011	2012	2013 Projection
Actual FTE	10	10	13	15	15	17

139.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Tab C, Section 3.11.4, p. 183

Facilities

139.1 Please provide the total number of buildings managed by Facilities for 2007-2014 by year.

Response:

The total number of buildings managed by Facilities for FEI for the years of 2007 -2014 is listed in the table below.

	2007	2008	2009	2010	2011	2012	2013	2014
Total Buildings	65	65	65	69	72	71	72	72

FEI's building count remained unchanged between 2007 and 2009. In 2010, the building count increased by four structures. This increase was a result of the purchase of a parcel of land at 6939 Tilbury Road, Delta which included three buildings in place and the purchase of a parcel of land for one of the Customer Contact Centre spaces located in Prince George. Both the Tilbury land acquisition and Customer Contact Centre were approved through Commission Orders G-68-10 and C-1-10, respectively. In 2011, FEI built two new shed structures for storage of operating tools and equipment at two interior facilities and added office space for the Lower Mainland Customer Contact Centre that was as approved within the 2012-2013 RRA. There have been minor changes since 2011 where the Tilbury surplus property was subdivided and sold and an additional shed structure was added in the Interior.

139.2 For 2010-2014, for the each of the regional offices (Prince George, Kamloops, Kelowna, Penticton, Cranbrook, Trail, and Vernon) and operations centres (Surrey and Burnaby) provide the following:

- The total number FTEs by function Operations (Distribution, Transmission and Plant Operations), Customer Service, Energy Solutions and External Relations, FAES, Biomethane, Information Technology, Finance and Regulatory Services, Engineering Services and Project Management, Environment, Health, and Safety, and Facilities
- The O&M, Depreciation and Property Taxes

Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Please refer to Attachment 139.2 for a working spreadsheet for the FTE, O&M, Depreciation and Property Tax for each regional office.

FEI was not able to provide the total number of FTE by function within each regional office, and submits that this information is not relevant to a review of the Facilities department. FEI has provided the total number of FTEs by regional office which FEI provides the relevant information for a review of Facilities' activities. The 2014 FTEs are not provided in the spreadsheet but expected to be consistent with 2013 projected levels.

The O&M costs include rental revenues and exclude administration costs such as postage, stationary and off-site record storage.

140.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Tab C, Section 3.11.4, p. 183

Facilities –Leases

140.1 For the FEI space leased at 1111 W. Georgia Street, Vancouver, please provide lease cost and square footage leased by year for 2007-2014. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Please refer to Attachment 140.1, which is a working spreadsheet that provides the requested square footage and lease costs for 1111 West Georgia Street, Vancouver by year from 2007 to 2014. In addition, FEI has provided the revenue received from third parties by year from 2007 to 2014. The revenue reduces the total cost of the lease to FEI.

"In addition, there are receivable leases scheduled to expire that will not be renewed, which will reduce revenue received."

140.2 For 2007-2013, please provide the lease revenues and square footage being leased by location. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Facilities' primary objective is to operate and maintain the office, shop, warehouse and yard space for the FortisBC group of Companies to ensure that the Companies and their employees have a suitable work environment and safe and efficient workspace. Over time, FEI has made operational changes that resulted in surplus space. At times when space becomes surplus, the Company has actively pursued lease opportunities in order to reduce the operating costs of its facilities. As such, within the period between 2007 and 2013, FEI leased space at various locations including: Cranbrook, Kamloops, Kelowna, Prince George, Vernon, Tilbury and 1111 West Georgia. This effort has resulted in lease revenue totaling $14,969,194 over the 7 year period. Please refer to Attachment 140.2 for the fully functioning electronic spreadsheet.

140.3 For each of the receivable leases scheduled to expire that will not be renewed, provide the location, the expiry date of the lease, the square footage being returned to FEI, and the reason why FEI requires the additional space. Include the requested information in the form of fully functioning electronic spreadsheet. If additional space will be used by FEI employees list the employees that will occupy the additional space. Include the requested information in the form of fully functioning electronic spreadsheet.

Response:

FEI did not state on page 183 that FEI requires the additional space for FEI employees but rather that there are receivable leases scheduled to expire and not expected to be renewed. As a Landlord, FEI faces the risk of vacancy and bad debt within its lease portfolio which may create O&M pressures within Facilities. Attachment 140.3 outlines the leases that have recently expired or are nearing expiry and the reason each lease will not be renewed.

140.4 Please provide the cost reduction due to the elimination of the lease cost for the North Vancouver muster site.

Response:

The cost reduction due the elimination of the lease cost for the North Vancouver muster site is $58,917 per annum. This cost reduction began in 2013 and therefore has been incorporated into the 2013 Projection and Base O&M for Facilities that forms the basis for the 2014 to 2018 delivery rates.

141.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Tab C, Section 3.12, pp. 184-189

Environment, Health and Safety (EH&S)

The costs of the EH&S Department have been flat since 2010 but FEI is forecasting an increase for 2013 PBR Base of 7 percent over 2013 Projected and the further increases throughout the PBR period.

141.1 Why is the 2013 PBR Base higher than the 2013 Projected?

Response:

The 2013 Projection to the 2013 Base has been reconciled on a department basis in Table C3-2 of the Application. The reasoning behind each of the adjustments is provided in Section B6.2.4.1 on pages 54-56 of the Application.

141.2 Are there not continued synergies during the PBR term that would continue to keep the EH&S Department costs flat rather than rising with inflation? Please explain.

Response:

The integration of the two utility divisions enabled the analysis of productivity opportunities. The bulk of integration synergies have been achieved, and the Company does not anticipate continual significant synergies to arise, given the current structure and ongoing, required operational requirements.

141.3 FEI identifies two areas it is currently monitoring (Species at risk & Greenhouse gas management). Are there any new EH&S regulations that FEI can identify that are certain to be implemented in the PBR period?

Response:

FEI closely tracks proposed new and/or amended EH&S related regulatory requirements that may impact operational schedules and budgets. Currently there are no new EH&S regulations to be implemented; however, this is a constantly evolving environment, and the company may be required to assess a variety of EH&S regulatory requirements during the PBR period.

141.4 Please provide the research coordinated in the department that tracks the annual effectiveness of the corporate safety planning activities.

Response:

The Company has in place several research instruments that track the annual effectiveness of planned corporate public safety planning activities. The company also maintains a Public Safety Manager role that closely monitors the efficacy of safety planning activities on a continual basis, liaising closely with the Communications department in the execution of annual strategies as related to the enhancement of public safety awareness.

The corporate safety planning activities for the company are aligned with key risk areas. Quantitative research is conducted via the 'Natural Gas Safety Awareness Tracking' telephone survey that has been designed to be statistically representative as related to the B.C. population.

The objective of this research is to:

- Measure British Columbians' current levels of natural gas safety awareness;
- Track the effectiveness of the current awareness and results as compared to historical awareness metrics;
- Determine and track levels of preparedness as related to the response to a natural gas odour; and
- Measure the level of awareness around excavation safety.

From this study, two indices are dervied that provide feedback as related to levels of preparedness among British Columbians with respect to the actions required by them during natural gas emergencies, namely the '*Safety Preparedness Index'* and the '*Excavation Safety*

Index'. The former instrument gauges the current levels of public awareness around natural gas odour recognition and the requirement to leave areas where gas odour is present. The latter measures the level of awareness and the requirements for safe excavation procedures and practices.

Qualitative studies are also conducted in the form of focus groups. Focus group feedback assists in the assurance of effectiveness in safety messaging and in the development of creative strategies that target any areas of weaker awareness response determined during the quantitative research phase.

Please refer to Attachment 141.4 for the research studies and reports.

141.4.1 If not included in the previous response, please provide the cost effectiveness of the corporate safety planning activities by year for 2007-2012 and Projected 2013.

Response:

With respect to the Company's monitoring of the cost effectiveness of the corporate safety planning activities for 2007-2012, the company reviewed annual programs via several instruments, as described in BCUC IR 1.141.4. The same process will be maintained in 2013.

The company has also developed partnerships with agencies that provide a conduit to large awareness channels. Mass media opportunities have served to garner significant economies of scale via the Corus Radio Network, for example. Furthermore, First Responder Awareness is delivered by employees to peer training partners among the First Responder agency groups. This is a cost effective delivery method in that fewer sessions are required and peer trainers can conduct the required training on their own training schedules.

Local festivals and community events are also venues through which safety based information can be distributed. Employees are in most cases volunteers with respect to the delivery of the school safety program at these events.

Increases in overall safety awareness levels have been tracked using research instruments as described in BCUC IR 1.141.4. The effectiveness of FEI's safety awareness programs in 2013 will be tracked as done in previous years and as described in the response to BCUC IR 1.141.4.

142.0 Reference: FORECASTS FOR THE PBR PERIOD

Exhibit B-1, Tab C, Section 3.12.2, p. 185

Environment, Health and Safety (EH&S)

FEI states that: "EH&S continues to focus on streamlining processes, integrating management systems, and optimizing all opportunities from the integration with the Electric utility in order to increase and support productivity opportunities.

In 2012 and 2013 EH&S integrated several functions involved in the provision of gas and electric services. Through integration, and the alignment of the electric and gas EH&S groups, service quality levels were maintained; EH&S has been able to manage additional workload within existing budgets during 2012 and 2013."

142.1 Won't the integration of functions of the electric and gas EH&S groups be expected to lead to further synergies and cost reductions into the PBR period?

Response:

The bulk of integration synergies between the electric and gas EH&S groups have been achieved, and the company does not anticipate continual significant synergies to arise, given the current structure and ongoing operational requirements.

FORECASTS FOR THE PBR PERIOD –CAPITAL

143.0 Reference: CAPITAL

Exhibit B-1, Tab C, Section 4.3.2, p. 205

Capital Expenditures-Historical

Table C4-1 provides historical FEI Capital Expenditures from 2010 through 2013.

143.1 Please add years 2007 and 2008 to the Table to provide a perspective from the last PBR period to the start of this proposed PBR period.

Response:

The years 2007 and 2008 have been added to the table below. For continuity, FEI has also included 2009.

HISTORICAL AND FORECAST FEI CAPITAL EXPENDITURES ($ THOUSANDS)

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2012 Approved	2013 Projection	2013 Approved
Sustainment Capital									
Meter Recalls/Exchanges	9,967	11,563	14,479	19,126	22,922	24,197	20,668	25,062	21,272
Transmission System Reinforcements	5,087	13,299	11,848	9,771	10,808	14,964	20,350	18,005	24,386
Distribution System Reinforcements	10,293	8,050	8,524	5,198	7,670	8,574	7,170	8,691	7,610
Distribution Mains & Service Renewals & Alt.	9,307	9,398	12,757	11,342	17,736	16,556	17,330	20,500	21,845
Total Sustainment Capital	34,653	42,309	47,608	45,437	59,137	64,291	65,517	72,258	75,114
Growth Capital									
New Customer Mains	8,087	10,983	6,133	4,538	4,510	5,374	6,127	5,033	6,500
New Customer Services	17,054	17,954	12,073	13,874	14,423	17,423	12,050	16,791	12,910
New Customer Meters	3,677	3,300	1,498	1,905	1,699	1,403	1,965	1,438	2,105
Total Growth Capital	28,818	32,237	19,704	20,317	20,632	24,200	20,142	23,262	21,515
Other									
Biomethane - Interconnect	-	-	-	504	-	-	1,015	1,100	1,015
Equipment	2,356	2,996	6,607	3,434	3,499	3,951	3,310	3,875	2,930
Facilities	3,159	1,988	2,805	4,177	5,840	1,996	8,424	7,549	4,124
IT	4,171	10,468	14,245	12,418	14,503	13,983	18,000	21,600	18,000
Total Other	9,686	15,452	23,657	20,533	23,841	19,930	30,749	34,124	26,069
Total Gross Capex	73,158	89,998	90,968	86,287	103,610	108,421	116,408	129,644	122,698
CIAC	(8,331)	(11,291)	(4,615)	(3,922)	(7,948)	(5,830)	(5,341)	(5,864)	(5,400)
Total Net Capex	64,827	78,707	86,353	82,365	95,662	102,591	111,067	123,781	117,298

143.2 Total expenditures on Sustainment Capital have grown by about 65% in 3 years. Given the conclusions in the Long Term Sustainment Plan related to the risk assessments of pipe and facilities, how could these expenditures have ballooned so much?

<u>Response:</u>

The increase in the level of sustainment capital spending has been previously approved by the Commission through an oral hearing in the 2012-2013 RRA and fully documented in that proceeding.

In the past 3 years, FEI has increased its expenditures on Sustainment Capital, while also recognizing the need to balance the rate impact on customers with those expenditures necessary to support the continued safe and reliable delivery of natural gas to its customers. The level of Sustainment Capital expenditures from 2010 through 2013 has been required to proactively address concerns identified at the time, and the subsequent conclusions in the LTSP do not change this conclusion. There are several drivers behind the escalation in capital expenditures over the period 2010 through 2013 that have been previously discussed in FEI's last two RRAs.

Overall, the increase in sustainment capital expenditures over the past 3 years is a result of FEI's transition from a reactive approach to a proactive, long-term approach in managing its natural gas assets, and also as a result of changing regulations and heightened public expectations regarding the safety of natural gas infrastructure. The sustainment capital expenditures relating to integrity and reliability, as well as mains replacements, were proposed to address known issues and integrity concerns and to avoid the potential of more costly repairs in the future. Another driver of expenditures was additional pipe replacements to accommodate the increased activities of municipalities and the Ministry of Transportation in upgrading their respective infrastructures. As discussed above, the reasons for the increased level of spending were provided in the 2012-2013 RRA and subsequently approved in Order G-44-12. FEI's actual expenditures for Sustainment Capital were within the levels forecasted and approved in that decision. As per the 2012-2013 RRA, Section 6.2.2:

> *"For this Application, sustainment capital spending budgets have been developed using existing sustaining capital and some enhanced asset management practices. It should be noted that FEU is also addressing hazards and risks that the Company believes require immediate attention. Over the longer term, FEU will continue to improve its asset management practices with the further development of a Long Term Sustainment*

Planning process. Asset replacement costs are expected to continue to rise in the future because the cost of new assets will be higher than that of the original equipment."

The conclusions of the LTSP continue to support the increased level of Sustainment Capital expenditure. FEI is responsible for gas transmission and distribution assets with a rate base value of approximately $2.6 billion and an approximate replacement value of $6.1 billion. Approximately 27% of distribution mains were installed over 40 years ago. The installation practices and materials used during that era mean that many of these pipes possess characteristics which have been demonstrated to be a concern, such as increased susceptibility to corrosion. Although the LTSP does not consider age to be a risk factor, the presence of corrosion over time does cause pipe condition to deteriorate. The LTSP enables FEI to concentrate on areas of interest and reduce asset risks more cost-effectively; it does not eliminate the need to replace assets. Given the higher costs and more stringent requirements to install new assets, this level of Sustainment Capital expenditures addresses only a tiny fraction of FEI's assets and is far less than the cost to replace assets reactively or on the basis of asset age alone.

144.0 Reference: CAPITAL

Exhibit B-1, Tab C, Section 4.3.2, p. 206

Capital Expenditures-Historical

Table C4-2 provides Base adjustments to the Capital Budget.

144.1 Why is the 2013 pension adjustment done? Will FEI be including pension costs as part of the PBR Period costs rather than seeking a flow through of pension and OPEB costs separately?

Response:

The Pension/OPEB adjustment of $2,241 thousand to arrive at 2013 Base Capital Expenditures shown in Table C4-2, page 206 consists of 2 amounts as broken down in Table B6-6, page 61.

$930 thousand, representing a shift from O&M to capital, pertains to an accounting change with respect to the allocation of retiree Pension/OPEB as discussed in Section D.3.1 on page 265.

$1,311 thousand represents an adjustment to include in 2013 Base Capital that portion of actual incurred 2013 pension/OPEB expense that is attributable to base capital and that is held in deferral accounts in 2013.

The reasons why these items are adjusted in the 2013 Base is found in Section B.6.2.4.1 (the discussion is regarding O&M but applies equally to capital).

As explained in Section 3.3.3.4 Labour and Benefit Inflation on page 126, Pension and OPEB expenses are included in the forecast labour inflation and benefit loadings that are applied to the forecast labour force. In this fashion, increases in labour and benefits are allocated between O&M and capital based on the chargeable hours forecast against O&M and capital activities.

Also refer to the responses to BCUC IR 1.12.1 and 1.12.1.1 that explain how the flow through of these items works and how the variance between the amount recovered in rates and the actual amounts incurred will continue to be captured in a deferral account, for both capital and O&M.

144.2 Why is the 2013 pension adjustment so large? Are any of these pension adjustments related to pensions funded entirely by ratepayers? Please explain.

Response:

The 2013 Pension Adjustment referred to in Table C4-2 in the amount of $2.241 million is comprised of 2 amounts. $1.311 million represents the capital portion of the Pension and OPEB variance deferral as discussed in Section B 6.2.4.1, page 56, and $0.930 million represents the accounting change dealing with the allocation of retiree Pension and OPEB as discussed in Section D 3.1, page 265.

The full amount of the Pension and OPEB variance deferred, in the amount of $12.607 million, as shown in Section B 6.2.4.1, page 56, will be included in rates over the approved amortization period.

145.0 Reference: CAPITAL

Exhibit B-1, Tab C, Section 4.3.3, p. 207

Capital Expenditures-Inflation Assumptions

FEI states that: "FEI's forecast capital expenditures over the PBR period have been prepared using a low inflation scenario, as noted in the sections that follow."

145.1 Please confirm that that inflation forecast is 2%/yr.

Response:

Confirmed.

146.0 Reference: CAPITAL

Exhibit B-1, Tab C, Section 4.3.3, p. 209

Capital Expenditures-Inflation Assumptions

Figure C4-1 provides cost trends for US pipelines.

146.1 Please provide equivalent Canadian data.

<u>Response:</u>

FEI is not aware of equivalent Canadian data that is publicly available.

147.0 Reference: CAPITAL

Exhibit B-1, Tab C, Section 4.6.4.1, p. 245

Capital Expenditures-Business Technology

Tables C4-21 and C4-22 provide the historic and forecast IT expenditures.

147.1 Why is the Application Sustainment 2013 Base cost estimated at $5,484,000 when the Approved 2013 cost is $2,700,000?

<u>Response:</u>

The approved number of $2,700,000 in Table C4-21 was an estimate of the spending on this category of IT capital based on previous years' experience. Previous years did not specifically identify projects as Application Sustainment, and costs were aggregated based on descriptions to develop the previous year's estimates. In 2013, Application Sustainment projects were defined and costs were tracked. The projection for 2013, as shown in Table C4-21, is $3,600,000.

The 2013 Application Sustainment Base also includes the software capitalization adjustment as detailed in Exhibit B-1, Section D.3.1, p. 265 and referenced in the response to BCUC IR 1.165.1. This has the effect of increasing the capital forecast by $1.8 million (from $3.6 million to $5.4 million) with an offsetting reduction in O&M by the same amount.

147.2 Why does this 2013 Base cost persist through the proposed PBR period when the average historic costs are so much less?

<u>Response:</u>

As indicated in the response to BCUC IR 1.147.1, the Application Sustainment Base is inclusive of the $1.8 million software capitalization adjustment and the planned software sustainment activities for new and existing enterprise applications such as SAP, Workforce Management, Contact Centre Technology, SharePoint, GIS and other key applications that will continue through the PBR period.

148.0 Reference: CAPITAL

Exhibit B-1, Application, Tab C, Section 4.6.4.1

Forecast IT Capital – 2014-2018

Table C4-22: Forecast IT Capital Expenditures ($ thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
IT Capital						
Businses Technology Transformation	5,941	5,940	5,940	5,940	5,939	5,938
Business Technology Enhancements	3,199	3,199	3,199	3,199	3,198	3,197
Infrastructure Sustainment	3,884	3,884	3,884	3,884	3,655	3,197
Desktop Infrastructure Sustainment	1,599	1,599	1,599	1,599	1,827	2,284
Application Sustainment	5,484	5,483	5,483	5,483	5,482	5,481
	20,107	20,105	20,105	20,106	20,102	20,098

(Exhibit B-1, Section C4.6.4.1, page 245)

148.1 Please explain further the logic for increasing the forecast IT capital for 2014-2018 using the composite PBR inflation instead of the sum of discrete projects, including whether this implies spending would occur on Business Technology Transformation and Enhancements irrespective of the business cases and benefits to be derived from such spending.

Response:

The IT Capital forecasts for 2014-2018 are based on a 5 year forecast of demand supported by business technology and infrastructure requirements within each of the portfolio categories. These requirements are identified in the programs and projects in the near to medium term that drive the estimates, resource requirements and technology dependencies within each of the areas. High-level estimates and trending is used to forecast for the long-term since technology and business needs are difficult to predict 4 to 5 years out.

However, in this Application FEI is seeking approval for customer rates based on the PBR formula. Therefore, the capital forecasts provided in the Application, including those found in Table C4-22, are for references purposes only. Each year the component of rates designed to recover capital expenses will adjust the previous years' amount by the formula which includes a productivity component. As such, the resulting capital amounts prescribed under PBR for Sustainment and Other Capital, in which IT expenditures are included, will be representative of the aggregate of FEI's total Sustainment and Other Capital spending for the respective year. How this expenditure level set under the PBR formula is allocated to IT related projects, including Business Technology Transformation and Enhancements, will be determined by FEI management based on justifiable business needs or opportunities in support of FEI's operations in accordance with IT's Benefits Management practice detailed in Appendix C4.

The purpose of the proposed PBR Plan is to provide a strong incentive for FEI to find efficiencies in its spending on both capital and O&M.

148.2 Please explain the financial impact to FEI if the forecast IT Capital for 2014-18 is inflated using the composite PBR inflation but capital spending is less due to the inability to meet the project benefit requirement.

Response:

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.

149.0 Reference: CAPITAL

Exhibit B-1, Application, Tab C, Section 4.6.4.1

IT Application Sustainment - Increase from 2013 Approved to 2013 Base

Table C4-2: 2013 Base Adjustments ($ thousands)

	2013	2013 Adjustments				2013
	Approved	PST	Pension	Vehicles	IT Cap	Base
Other						
IT	18,000	307	-	-	1,800	20,107

(Extract from Exhibit B-1, Table C4-2, p. 206)

"The increase of Application Sustainment capital from 2013 Approved to 2013 base by $2.8 million was discussed in Section C4.6.4.1." (Exhibit B-1, Section C4.6.4.1, p. 245, lines 21-22)

149.1 Please explain further the $2.784 million increase in Application Sustainment capital, from $2.700 million in 2013 Approved (as per Table C4-21) to $5.484 million in 2013 Base (as per Table C4-22), including exactly where this increase is explained in Section C4.6.4.1.

Response:

The reference to Section C4.6.4.1 was incorrect. The sentence should have read "The increase of Application Sustainment capital from 2013 Projection to 2013 Base by $1.8 million was discussed in Section D3.1 (page 265)."

Please refer to the responses to BCUC IRs 1.147.1 and 1.147.2 for an explanation of the increase from 2013 Approved to 2013 Base. FEI will correct this page in the next Evidentiary Update.

150.0 Reference: CAPITAL

Exhibit B-1, Application, Tab C, Section 4.6.4.1; Exhibit B-1-1, Appendix C4

Business Technology Transformation and Enhancements

Table C4-21: Historical IT Capital Expenditures ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
IT Capital					
Businses Technology Transformation	3,655	5,099	2,193	6,300	5,850
Business Technology Enhancements	800	1,085	3,968	4,500	3,150

(Extract from Exhibit B-1, Sec. 4.6.4.1, p. 245)

Table C4-22: Forecast IT Capital Expenditures ($ thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
IT Capital						
Businses Technology Transformation	5,941	5,940	5,940	5,940	5,939	5,938
Business Technology Enhancements	3,199	3,199	3,199	3,199	3,198	3,197

(Extract from Exhibit B-1, Sec. 4.6.4.1, p. 245)

"Since 2013 forms the base for the PBR Period spending, FEI is providing information on the 2013 portfolio in support of the Commission's Directive **regarding justification of spending requests.** Highlighted below is a list of the 2013 portfolio approved Business Technology projects driving a variety of quantitative and qualitative benefits. Several of these projects span multiple fiscal years but the **expected spend in 2013 is $11 million** which is in keeping with the 2013 Projection. Some of the projects have financial returns as seen in the Tangible (Financial) Benefits column …" (Exhibit B-1-1, Appendix C4, p. 2, lines 13-20) [Emphasis added]

150.1 Please confirm, or otherwise explain, that the Base 2013 and future years' capital expenditures include all projects started prior to 2013 that continue into 2013 and potentially future years, as well as projects to be started in 2013 and future years.

Response:

Confirmed. For IT Capital the base 2013 and future years' capital expenditures include all projects started prior to 2013 that continue to incur expenditures into 2013 and potentially future years, as well as projects to be started in 2013 and future years. The IT capital expenditures reflect when the expenditures are made, not when the projects are placed into service.

150.2 Please confirm, or otherwise explain that both Business Technology Transformation and Business Technology Enhancements are subject to the justification of spending requests.

Response:

This is correct. All Business Technology Transformation and Enhancement projects that have started in 2013 since the advent of the Benefits Management Practice are subject to the justification of spending requests.

151.0 Reference: CAPITAL

Exhibit B-1, Application, Tab C, Section 4.6.4.2; Exhibit B-1-1, Appendix C4

Business Technology - 2013 Project Portfolio Benefits

"As detailed in Table C4-22, FEI is forecasting annual expenditures of $5.9 million **for the PBR period on business technology transformation.** This area will fund any justifiable business requirement or opportunity in support of safety, customer service, reliability and productivity for FEI's operations in accordance with IT's Benefits Management practice detailed in Appendix C4." (Exhibit B-1, Section 4.6.4.2, p. 246, lines 2-6) [Emphasis added]

"As detailed in Table C4-22, FEI is forecasting annual expenditures of $3.2 million **for the PBR period on business technology enhancements.** This area will fund any system enhancements that are required. Enhancements to existing systems are initiated when a business requirement or opportunity arises that requires a long term solution. These enhancements do not generally include additional licenses or hardware, but do include configuration, minor integration and process modification to take advantage of a particular application's inherent functionality." (Exhibit B-1, Sec. 4.6.4.3, p. 247) [Emphasis added]

"Therefore, the Commission Panel directs the FEU in future RRAs to clearly identify either a shortcoming in current customer service levels or provide a fulsome budgeted O&M cost reduction, **including the year of realization of expected savings**, resulting from each significant IT Capital project in order to justify spending requests." (Exhibit B-1-1, Appendix C4, p. 1, lines 6-11) [Emphasis added]

"Financial Benefits. Degree to which the project serves to provide value to the organization, its customers and/or shareholders through financial benefits, such as **increased revenue generation, improved productivity (operating efficiencies), reduced costs,** and/or **cost avoidance**. Generally the benefits reflect a minimum of a five year analysis period." (Exhibit B-1-1, Appendix C4, p. 4, lines 23-27) [Emphasis added]

151.1 Please explain why Table C4-1: 2013 Project Portfolio Benefits does not indicate the expected savings for each project separated by the year of benefits realization, and whether FEI is able to provide this detail of information.

Response:

Table C4-1: 2013 Project Portfolio Benefits is a summary view of the benefits statements by project for the 2013 Business Technology Portfolio.

Provided below are the financial benefits and the category per project. These expected financial benefits are estimates based on assumptions and business factors at the time of the business casing. Any variances from these stated benefits will be monitored and reported in accordance with the benefits practice.

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.

Project Name	Value $ (000s)	Benefits: Financial Benefit Category	Total (000s)	2014 (000s)	2015 (000s)	2016 (000s)	2017 (000s)	2018 (000s)	2019 (000s)	2020 (000s)	2021 (000s)
GeoSpatial Program - eForms	$2,400	Cost Reduction	$3,080	$140	$350	$420	$490	$560	$560	$560	
Geospatial Program - GIS Toolset Refresh	$2,800	Cost Reduction	$2,556	$426	$426	$426	$426	$426	$426		
		Cost Avoidance	$1,352	$526	$526	$75	$75	$75	$75		
Customer Portal and Bill Redesign	$1,600	Cost Reduction	$3,300	$550	$550	$550	$550	$550	$550		
Knowledge Management Program - SharePoint Upgrade and Migration	$1,307	Cost Reduction	$1,769	$411	$436	$461	$461				
Knowledge Management Program - Integrated Intranet	$1,277	Cost Avoidance	$350		$70	$70	$70	$70	$70		
Financial Consolidation & Enterprise Reporting Solution	$1,148	Cost Reduction	$713	$113	$150	$150	$150	$150			
		Cost Avoidance	$680	$60	$280	$60	$280				
Incident Management System	$1,000	Cost Reduction	$10	$2	$2	$2	$2	$2			
		Cost Avoidance	$500	$100	$100	$100	$100	$100			
Knowledge Management Program - New Business Solutions	$800	TBC									
Knowledge Management Program - Small & Medium New Builds	$600	Cost Reduction	$761		$59	$117	$117	$117	$117	$117	$117
2013 Customer Service Enhancement	$1,971	Cost Reduction	$750	$150	$150	$150	$150	$150			
ClickSchedule Business Enhancement	$512	Cost Containment	$690	$138	$138	$138	$138	$138			
2013 SAP BI-BW Enhancement	$231	N/A									
2013 GIS (GE Smallworld) and Mobile GIS (Tensing) Enhancement	$225	N/A									
2013 Operations Enhancement	$220	N/A									
Contractor Access to Planning Systems	$143	N/A									
2013 Supply Chain Enhancement	$133	N/A									
2013 Finance Enhancement	$120	N/A									
2013 BC One Call Enhancements (includes DCRS)	$110	N/A									
2013 Meter Management Enhancement	$108	N/A									
Web optimization templates and mobile	$99	N/A									
2013 Filenet Enhancement	$90	N/A									
2013 Forecasting Enhancement	$85	N/A									
2013 WINS Enhancement	$55	N/A									
2013 Entegrate Enhancement	$25	N/A									
2013 McLaren Enterprise Engineer Enhancement	$22	N/A									
	$17,081		**$ 16,511**	**$ 2,616**	**$ 3,237**	**$ 2,719**	**$ 3,009**	**$ 2,338**	**$ 1,798**	**$ 677**	**$ 117**

151.2 Please explain why the financial benefits in Table C4-1 are not separated into the four financial benefit categories listed under the "Financial Benefits" project driver, and whether FEI is able to provide this detail of information.

Response:

Table C4-1 is a summary view of the benefits statements by project for the 2013 Business Technology Portfolio. The categories of the estimated financial benefit by project have been provided in the response to BCUC IR 1.151.1.

151.3 Please explain why the multi-year Gas Asset and BC One Call projects, other than $110 thousand for BC One Call, are not shown in Table C4-1: 2013 Project Portfolio Benefits in Appendix C4.

Response:

Table C4-1: 2013 Project Portfolio Benefits in Appendix C4 relates specifically to the Business Technology investment and related benefits statements for the 2013 Portfolio. The Gas Asset Project is a concurrent O&M Project managed outside of the Business Technology Portfolio and funded through as Deferral Account as approved in the 2012-2013 RRA. As such, it does appear in this table.

The BC One Call project did have a Business Technology component that was managed under and funded by the Business Technology Portfolio; however, this technology stream was concluded in early 2012 and therefore is not listed under Table C4-1: 2013 Project Portfolio Benefits, nor was additional funding requested as a part of the deferral account.

An enhancement totaling $110,000 was requested for 2013 to make various improvements to the way geographical data is stored and managed for the BC One Call process to ultimately improve the quality of the information provided to the underground utility information requestors through BC One Call service. This initiative is separate from that of the BC One Call project, and the primary focus is on improving the quality and the way information is provided to the information requestors. The ultimate goal is to improve on safety for the excavation community.

152.0 Reference: CAPITAL

Exhibit B-1, Tab C, Section 4.4.1, p. 210

Capital Expenditures - Sustainment

Table C4-4 provides 2010-2013 Sustainment Capital Expenditures.

152.1 Why is there such a large increase in Distribution Mains and Services in 2013 Approved and Projected? Are the Renewals/Alterations due Mains and Services reaching the end of their useful lives or are they being prematurely replaced?

Response:

The primary reason for the increase in “Distribution Mains and Services” category has been the implementation of the LTSP with a resulting increase in the amount of main and number of services being replaced due to their categorization as being of a higher concern than other mains and services (approximately $2 million). To a lesser extent in this category is also included an increase in spending for mitigating service line hazards (approximately $1 million) and the installation of a new station to provide additional capacity to a specific distribution system (approximately $0.5 million). These increases were approved as part of the 2012-2013 RRA.

FEI has experienced a slight increase in third party initiated relocations which often impact mains that are not old, so, in these cases they are likely being prematurely replaced. However, FEI has implemented into its capital planning a longer term view of the integrity of the distribution system and to avoid a large spike in replacement expenditures, when mains and services installed in the 1950s and 1960s reach approximately 60 years old, we have increased our mains replacement (renewal) program to proactively replace mains before they become a hazard to the public and reduce the reliability of the system. The mains and services selected for replacement often tend to be older as the original steel piping often suffers from a time dependent failure of coating or corrosion growth; however, these are not the only criteria used for identifying the mains and services of concern. A simple analysis of the mains being removed in 2013, prorated based on the length of the pipe segment being removed, indicates an average age of approximately 63 years.

152.2 Please explain what appears to be a step increase to the 2011 Distribution Mains & Services expenditures. Was there a permanent change to inspection code requirements?

Response:

There was no change to inspection code requirements. Reviewing the recorded details of our expenditures in 2010 and 2011, the following is noted in the table below:

Activity	2010 ($000)	2011 ($000)	Difference	% of increase	Comment
DP Mains Renewal - Receivable	2,024	3,101	1,077	17	Third party initiated.
DP Mains renewal – Not Receivable	2,473	3,793	1,320	21	Some of these are third party initiated (e.g. Ministry of Highways); however, a much more detailed analysis would be required to break this into company planned work vs. third party driven work)
IP Mains Renewal - Receivable	92	1,346	1,254	20	Third party initiated.
Service Line Hazards Mitigation	1,762	3,589	1,827	29	To address overbuilds of service lines, protection of meter sets, and venting of regulators.
Revelstoke Plant Upgrades	392	1,348	956	14	Primarily to address expansion of storage capacity.
Other	4,599	4,559	-40	-1	
	11,342	17,736	6,394	100	

As indicated above, at least 37% of the increase was due to third party requests which FEI cannot control.

152.3 Why are the 2012 and 2013 Approved Transmission System Reinforcements 36% and 35% higher than Actual and Projected for those years?

Response:

It was intended that additional transmission pipeline upgrade projects to address class location and lack of adequate cover be developed and undertaken in 2012 and 2013. We were not successful in confirming the sites needing to be addressed, prioritizing the work, and blending it into pre-existing plans to address other matters (such as pipeline valve upgrades and third party relocations). Overall, FEI's sustainment capital spending for 2012 and 2013 combined is less than 3% lower than approved levels.

152.4 Please show the approved budgets for both Transmission System Reinforcements and Distribution Mains and Services for the years 2010 and 2011, along with their percentage variance to Actual expenditures.

Response:

Please refer to the table below.

	2010 Actual	2010 Approved	% Variance	2011 Actual	2011 Approved	% Variance
Transmission System Reinforcements	9,771	9,546	+2.4	10,808	8,663	+24.8
Distribution Mains and Services	11,342	10,060	+12.7	17,736	9,810	+80.8

152.5 Please show the actual expenditures on these same categories of Sustainment Capital during the last PBR period 2004-2008.

Response:

Sustainment capital expenditures for the last PBR period 2004-2008 are provided in the table below. These spending levels are not directly relevant to the approvals sought in this Application. FEI submits that the 2012 and 2013 approved and actual/projected spending levels form the appropriate basis for a comparison of the 2013 Base which forms the basis for the sustainment capital to be included in rate setting for the PBR period. The figures below from the 2004 to 2008 do not represent the more recent information gained from the LTSP's development.

An improved understanding of asset health and the increasing issues identified through the LTSP requires additional investments in Sustainment Capital now and in the future. Operating the natural gas delivery system continues to be impacted by system and operating conditions, regulatory changes and increasing expertise in forecasting the work. In view of these factors, there is limited value in comparing the 2004-2008 period to the 2010-2013 period.

	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual
Sustainment Capital					
Meter Recalls/Exchanges	12,140	12,125	11,920	9,967	11,563
Transmission System Reinforcements	7,076	5,559	8,663	5,091	13,302
Distribution System Reinforcements	10,998	10,219	9,339	10,320	8,080
Distribution Mains & Service Renewals & Alt.	9,087	9,084	11,977	9,308	9,398
Total Sustainment Capital	39,301	36,987	41,899	34,686	42,344

153.0 Reference: CAPITAL

Exhibit B-1, Tab C, Section 4.4.1, p. 211

Capital Expenditures - Sustainment

Table C4-5 provides 2013-2018 Sustainment Capital Base and Forecasts.

153.1 Shouldn't the Base year 2013 for Transmission System Reinforcements have been reduced to account for the large underspend of approved budgets in both 2013 and 2012?

<u>Response:</u>

FEI is not requesting approval of the 2013 Base year for Transmission System Reinforcements or for any other line item specifically, but rather an overall 2013 Base capital for growth and for sustainment and other. It is the overall level of spending in 2012 and 2013 that needs to be reviewed to determine if the 2013 Approved level (after adjustments to the 2013 Base) remains appropriate as the starting point for a PBR formula.

The following discussion of Transmission System Reinforcements spending levels is provided below.

Projects that were budgeted in 2012 but were not spent have been moved to 2013 and outer years as a result of unforeseen circumstances. These include:

- Upgrades at the LNG Plant were deferred in order to evaluate the impact of potential plant expansion upon the projects.
- Funds identified for repairs to a transmission pipeline if a major washout had occurred were not required.
- Security upgrades at sites, such as the Oliver Y Control Station, were found to be less costly than anticipated leading to consideration of improvements at other sites.

As FEI continues with its investigation of transmission system condition and compliance and the development of longer term projects, it is expected that there will be upward pressure on the funding required to ensure the work is done in a timely manner. While there may be some variances in spending within certain categories of capital, FEI is on track to spending all but $2 million of the full approved amounts over the 2012-13 periods for total base capital.

153.2 Please further explain the substantial increases to the Distribution Mains and Services budgets throughout the PBR period and particularly in 2017 and 2018?

Response:

FEI has implemented into its capital planning a longer term view of the integrity of the distribution system and, to avoid a large spike in replacement expenditures when mains and services installed in the 1950s and 1960s reach approximately 60 years old, we have increased our mains replacement (renewal) program to proactively replace mains before they become a hazard to the public and reduce the reliability of the system. The mains and services selected for replacement often tend to be older mains as the original steel piping often suffers from a time dependent failure of coating or corrosion growth; however, these are not the only criteria used for identifying the mains and services of concern.

Overall sustainment capital is up approximately 4% in 2017. FEI has a limited amount of resources available to it, and in years where other categories of capital are forecasting reduced levels from 2016 (meter recalls/exchanges and transmission system reinforcements), FEI will be able to redeploy some resources to the distributions mains/services category of capital. Overall we seek to balance the total work between the various categories.

154.0 Reference: CAPITAL

Exhibit B-1, Tab C, Section 4.4.4, p. 217

Capital Expenditures - Meter and Regulator Exchanges

Table C4-6 provides historic data on Meter Exchanges and Regulator Evergreening.

154.1 Please explain the jump in 2013 Projected expenditures on Regulator Evergreening compared to 2013 Approved?

Response:

FEI has identified a number of customer locations where non-standard, obsolete and aging regulators need to be replaced (approximately 70,000 outstanding notifications or locations at the end of 2012). A combination of external and internal resources was utilized to complete the work and in 2011 and 2012 the average spend increased to $4.6 million annually.

Prior to 2010, resources were focused on higher risk hazards and the Company made slower progress on the regulator replacement work. Since 2010 (post Whistler conversion project), however, several external resources (gas-fitters) have been available to complete this prudent replacement of aging assets.

In 2013, due to delays in the timing of expected mains and services renewal work which would typically utilize these resources, the resources are able to eliminate additional quantities of the outstanding regulators. These resources are expected to be less available in the future to eliminate these notifications as larger mains and services renewal projects come on-stream, therefore the Company has taken the opportunity to deploy these resources to do the regulator replacements this year. The increased expenditures this year will result in reduced spending on this program in future years.

155.0 Reference: CAPITAL

Exhibit B-1, Tab C, Section 4.4.4, p. 219

Capital Expenditures - Meter and Regulator Exchanges

FEI states that: "Effective January 1, 2014, this sampling plan is changing and all utilities in Canada will be adjusting their meter fleet management strategies to meet the new requirements. The sampling plan, referred to as SS-06, incorporates tighter tolerances and stricter criteria for allowing meters to remain in service. For example, the current sampling plan assesses the performance of a group of meters based solely on the average of sample test results and excludes eligible outliers. Alternatively, the new sampling plan assesses the performance of a group based on the number of samples meters that exceed the allowable tolerances. Furthermore, the new sampling plan includes all outliers in the performance assessment of a group of meters. Therefore, by applying this new approach to determine meter performance, the potential for a given group to fall outside of Measurement Canada's requirements increases. As a result of this new sampling plan, gas utilities across Canada are expecting to experience a requirement to increase the number of scheduled meter exchanges."

155.1 Please confirm that the 2014 implementation date is mandatory.

Response:

Yes, the mandatory implementation date for the new statistical sampling plan S-S-06 is January 1, 2014. This date is documented within Specification S-02 (p5) Compliance Sampling section 5.1.4 subsection 1 issued by Measurement Canada.

155.2 Has FEI done statistical work to help develop its Incremental Recalls forecast in Table C4-9? Please explain.

Response:

Yes, FEI has performed the required analysis to establish the incremental recalls forecast in Table C4-9.

In order to forecast the impact of this change in sampling standard upon FEI's meter fleet, an approach was completed which combined the application of a statistical method developed by the Canadian Gas Association for use by all member utilities coupled with the company's own detailed analysis of historical compliance sample data. Through this process, FEI was able to develop a forecast which ensures the meter fleet continues to be managed in a manner which is reliable and cost effective.

156.0 Reference: CAPITAL

Exhibit B-1, Tab C, Section 4.4.4, p. 220

Capital Expenditures - Meter and Regulator Exchanges

FEI states that: "FEI has actively identified and replaced regulators since 2003. However, as of the end of 2012, there are still some 70,000 of these identified regulator replacements outstanding. The Company intends to eliminate these over the next three years at a rate of 15 to 20 thousand per year."

156.1 How many regulators were replaced in each of the years from 2003 to 2012?

Response:

Regulators are replaced under three different scenarios:

- at the time of a meter exchange, if required;
- as follow-on work to a notification raised by a field resource to identify an obsolete and/or aging regulator location; 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.

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.

156.2 Since FEI identifies this as "lower priority hazards," shouldn't the replacement program extend through the proposed PBR period?

Response:

The regulator replacement program is an ongoing program, albeit at substantially reduced levels beginning in 2017. The main issue with reducing the number of identified outstanding regulator replacement notifications in a timely manner has been lack of resources, both external and internal.

FEI currently has a window of opportunity to reduce the outstanding notifications utilizing a complement of external resources which are not expected to be available for this type of work in the long term as the company increases its system renewal work. Internal resources are also less likely to be available for this type of work in the near future as the same resource will be required to complete increased levels of meter exchange activity beginning in 2014.

157.0 Reference: CAPITAL

Exhibit B-1, Tab C, Section 4.4.5, p. 221

Capital Expenditures - Transmission System Reinforcement

FEI identifies the projects that involve the replacement of sections of pipelines due to adjacent development and are anticipated to exceed $1 million over the 2014-2018 forecast period.

157.1 For the 3 projects with pipe vintage of 1975 and 2000, please provide reasons for the expected replacement and why they weren't anticipated in the planning process. For the relocations of the Southern Crossing Pipeline why weren't these encroachments recognized in the planning stage of the Southern Crossing Pipeline?

Response:

When a new pipeline is proposed, or even a minor alteration of an existing pipeline is necessary, the potential development in the area of the proposed work is considered, since an increase in development adjacent to a pipeline necessitates a higher factor of safety, primarily due to a probable increase in third party activity around the pipeline. The designer, however, has a limited amount of information available in order to come to a conclusion about where development is likely to occur. Land use planning provided by municipalities can be considered and landowners may be willing to share their plans for development. There may also be obvious trends in the development growth in a particular area. However, if the municipalities are small and lack a development plan and landowners are not open about their plans for development, the designer is forced to make assumptions based on what exists at the time of design.

With regard to the 1975 vintage pipeline, at the time of construction, the pipeline was intentionally located in very remote and/or rural areas to avoid developed areas. It would have been very difficult to anticipate where development would occur that would justify altering the design of the pipeline. The fact that it has taken over 35 years for development to be a concern over very small lengths of the pipeline indicates that the assumptions made during the initial design were reasonable.

With regard to the Southern Crossing Pipeline constructed in 2000, analyses undertaken to project future development during the planning stage of this project indicated there were certain areas where future growth was anticipated. The analyses undertaken included a review of forecasts available pertaining to housing starts and also household formations, discussions with municipalities regarding development plans, and also discussions with landowners regarding their future plans for development (if they are willing to discuss such). The results of the analyses, together with consideration of a number of other factors that lead to the determination of wall thickness, led to the decision that approximately 10% of the 302.5 km long pipeline was to be constructed with heavy wall pipe that would be appropriate for increased adjacent development. However, over time, more extensive development than was anticipated occurred. In fact, one area, the development adjacent to the Moyie River, has seen more dwellings located there since the pipeline was constructed than the area was subdivided for. As a result two segments that were initially installed with a thicker pipe have been identified as requiring replacement.

158.0 Reference: CAPITAL

Exhibit B-1, Tab C, Section 4.4.5, p. 222

Capital Expenditures - Transmission System Reinforcement

FEI identifies the Pitt River Pipeline Crossing replacement for 2016.

158.1 What is the vintage of the existing pipe and what level of “moderate” seismic event has been calculated to lead to failure?

Response:

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).

159.0 Reference: CAPITAL

Exhibit B-1, Tab C, Section 4.4. 7, p. 225

Capital Expenditures - Distribution Mains, Service Renewals

FEI states that: "The plan to install a second source of supply to the City of Penticton has been in existence for many years. In about 1980 the site for the second gate station was purchased in the NE corner of Penticton. The estimated cost for installing an additional gate station and the distribution system improvements is $2.4 million (approx. 10 percent will be incurred in 2014)."

159.1 Will this project be delayed again?

<u>Response:</u>

The conclusion that the project was delayed is incorrect; an opportunity arose to acquire the property, knowing that at some point in the future the Company would identify the appropriate time for the installation of the station.

This project is scheduled to commence in 2014 and be completed in 2015; however, the timing of this and other projects will continue to be managed as part of FEI's overall capital program and assessment of priorities within that portfolio. If circumstances change such that it is necessary to defer this specific project in lieu of one that has a higher priority, that is a possibility. The annual capital expenditures included in delivery rates will be calculated under the PBR formula.

160.0 Reference: CAPITAL

Exhibit B-1, Tab C, Section 4.4.7, p. 225

Capital Expenditures – Distribution Mains, Service Renewals

FEI states that: "FEI may have to install a new pipeline on the new (Pattullo) bridge during 2015; however, this could be deferred as a result of decisions by other parties. The estimate for the total project is $2.7 million."

160.1 What is the current expected install date?

Response:

The current plan is for installation in late 2015, as indicated in the Application.

161.0 Reference: CAPITAL

Exhibit B-1, Tab C, Section 4.5.1, pp. 229 & 238

Capital Expenditures - Growth

Figure C4-6 provides the average unit cost/ service. Table C4-18 provides the forecast costs. FEI states that: "FEI expects that the overall services unit costs will be lower in 2013 than in 2012 and the 2014 -2018 period (excluding inflation) will follow this trend due to the shift to higher proportions of activity in the Interior where installation costs are typically lower."

161.1 Table C4-18 doesn't seem to show a reduction in unit costs ($/ service-riser). Please explain?

<u>Response:</u>

The statement above (from page 238) was in reference to the 2013 Projection for services unit costs (which formed the base for the 2014 to 2018 forecasts) being lower than the 2012 Actual. This can be seen in Table C4-17 and is also shown below.

When the forecasted inflation and the adjustments that are included in Table C4-2, namely PST of $220 thousand and Pension and OPEB expenses of $341 thousand, are factored out of the forecast 2014-2018 cost to achieve a consistent basis of comparison, the service line unit cost for 2014-2018 continues to be lower than the 2012 actuals, primarily due to a shift of the new service activity to the lower cost interior regions.

The following table confirms that the 2013-2018 unit costs are lower than the 2012 actual unit cost when the impact of inflation (2%) and the pension/OPEB/PST adjustment is removed from the service line unit cost forecast.

		Service Unit Costs 2012- 2018 ($/service)					
	2012	2013	2014	2015	2016	2017	2018
	Actuals	Projection	Forecast	Forecast	Forecast	Forecast	Forecast
Service Cost - Table C4-17/18	$ 2,206	$ 2,163	$ 2,280	$ 2,320	$ 2,363	$ 2,409	$ 2,462
Less: Pension/OPEB Impact	n/a	n/a	$ 73	$ 69	$ 67	$ 67	$ 74
Less: Inflation 2%/year	n/a	n/a	$ 44	$ 88	$ 133	$ 179	$ 225
Base Service Cost	$ 2,206	$ 2,163	$ 2,163	$ 2,163	$ 2,163	$ 2,163	$ 2,163

162.0 Reference: CAPITAL

Exhibit B-1, Tab C, Section 4.5.4, p. 239

Capital Expenditures- New Meters

FEI states that: "A blended unit cost of all customer types is used for forecasting new meter costs, although meter unit costs typically range from $75 to $10 thousand depending on the customer requirements."

162.1 Please provide a table of new meter costs showing the average meter cost and % of new customers based on the following classes, residential, small commercial, large commercial, institutional/ small industrial, large industrial.

<u>Response:</u>

Please refer to the table below. Average meter unit costs are not currently tracked by customer class and we do not believe a more granular approach would provide for more accurate forecasting of Meters Capital costs. Meters are not exclusively purchased as residential, commercial or industrial, although some specific meter types tend to be used for a particular customer type. Meter selection is made based on a set of requirements which include: cost of ownership, flow capacity requirements, pressure rating, long term availability and any particular requirements such as positive displacement or inferential measurement based on the specific application. Therefore, there is significant variability in the cost for each meter type and significant variability within each customer class as to meter type.

The blended meter unit cost includes the purchase and logistics of handling the meter as well as installation and in some specialized cases the design and prefabrication of the meter. Installation time varies widely from 0.5 hours for a typical residential meter to 2 weeks for a more complex commercial or industrial meter set.

In terms of meters, there are currently over fifty approved types of meters across the three main customer classes (residential, commercial and industrial) that are available through meter vendors.

In relation to residential meters, the purchase cost in 2013 would generally range from $60 to $156 and the average cost based on the planned device purchases in 2013 is $79.

In relation to commercial meters, the purchase cost in 2013 would generally range from $387 to $2,200 and the average cost based on the planned device purchases in 2013 is $509.

In relation to industrial meters, the purchase cost in 2013 would generally range from $2,400 to $56,000 and the average cost based on the planned device purchases in 2013 is $3,600.

	Forecast Customer Additions by Class and New Meters Costs 2014-2018)									
	2014		2015		2016		2017		2018	
Class	**Customer Additions**	**% of Total**	**Customer Additions**	**% of Total**	**Customer Additions**	**% of Total**	**Customer Additions**	**% of Total**	**Customer Additions**	**% of Total**
Residential	4,594	92%	4,955	93%	5,085	93%	4,972	93%	4,806	93%
Commercial	388	8%	373	7%	358	7%	372	7%	367	7%
Industrial	-	-	-	-	-	-	-	-	-	-
Total New Meters	4,982	100%	5,328	100%	5,443	100%	5,344	100%	5,173	100%
Blended Unit Cost	$ 334		$ 339		$ 345		$ 351		$ 360	
Total New Meters ($000s)	$ 1,664		$ 1,806		$ 1,878		$ 1,876		$ 1,862	

FINANCING, TAXES, ACCOUNTING POLICIES AND DEFERRALS

163.0 Reference: ACCOUNTING POLICIES

Exhibit B-1, Application, Tab D, Section 3.1, pp. 263-264

US GAAP

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." (p. 263)

163.1 Please discuss the process for becoming an SEC Issuer, including the estimated costs involved.

Response:

To become an SEC Issuer FEI would be required to list an existing investment grade, non-convertible debt instrument on the New York Stock Exchange (NYSE) and file a registration statement with the SEC. As an SEC Issuer FEI would continue to prepare and file financial statements in accordance with US GAAP for interim and annual periods beginning January 1, 2015, but would also fall under any applicable securities requirements specific to the SEC and NYSE, which have been summarized in FEI's response to BCUC IR 1.163.2.

At this point in time, based on FEI's understanding of the SEC registration process, the estimated one-time costs FEI would expect to incur during the process of becoming an SEC Issuer are approximately $250,000. The incremental ongoing annual costs that FEI expects to incur as an SEC Issuer would be approximately $230,000.

Please see the response to BCUC IR 1.163.2 for a discussion about why becoming an SEC Issuer still makes sense despite these costs.

163.2 Please discuss the future implications of FEI becoming an SEC Issuer, including whether or not there will be additional compliance and reporting requirements.

Response:

If FEI were to become an SEC Issuer, the future implications would be additional compliance and reporting requirements that may include, but not be limited to, the following:

a. The initial registration statement, as well as subsequent annual reports, would be filed on either a Form 40-F or a Form 20-F. FEI would also be required to furnish the SEC with current reports on Form 6-K.

b. FEI would be required to comply with the rules of the NYSE which include, but are not limited to, most of the corporate governance requirements of the NYSE, audit committee independence rules, annual certification requirements confirming compliance with such rules and disclosure on how Canadian governance rules differ from the U.S. rules.

c. FEI may be subject to most of the Sarbanes-Oxley (SOX) requirements including, but not limited to, the requirement that certain officers certify the annual report and the rules relating to disclosure controls and procedures and internal control over financial reporting, and potentially an attestation report of the company's independent auditor on the issuer's internal controls. Fortis Inc. would be subject to Sarbanes-Oxley so as a result, FEI would be required to be included in that testing as it is a material subsidiary.

Additionally, FEI could possibly be subject to other acts and requirements (such as XBRL reporting) as an SEC Issuer.

Even with the additional compliance and reporting requirements that would exist if FEI were to become an SEC Issuer the continuation of reporting under US GAAP which allows regulated entities to recognized regulatory assets and liabilities under ASC 980, *Regulated Operations*, is a better option than reporting under IFRS which currently does not have existing standards that permit similar treatment.

FEI states: "To consider adopting IFRS in 2015 or beyond would result in an additional one-time cost to implement." (p. 264)

163.3 Please discuss what FEI anticipates the one-time implementation cost of IFRS would be compared to both the one-time and recurring costs of becoming an SEC Issuer.

Response:

It is not possible to provide a reliable estimate of costs without an understanding of the differences between US GAAP and IFRS that would exist at the time of conversion in 2015 or later.

164.0 Reference: ACCOUNTING POLICIES

Exhibit B-1, Application, Tab D, Section 3.1, p. 265

Allocation of Retiree Pension and OPEBs

FEI states: "As a result of the adoption of US GAAP starting January 1, 2012 and the plan to continue using US GAAP as the basis of financial and regulatory accounting during the PBR Period, FEI is requesting to include both the current service and retiree portion of pension and OPEBs in benefit loadings, consistent with the practice prior to 2010." (p. 265)

164.1 Please explain why FEI did not request to make this change in its 2012-2013 RRA, since this was the period when FEI adopted US GAAP.

Response:

FEI did not request to make this change in its 2012-2013 RRA because at the time of both the filing and the proceeding the Company was still assessing all differences under US GAAP. 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 (which includes both the Current Service Cost and other components of pension expense, including retiree portion of pension and OPEBs) is the appropriate amount to be included in benefit loadings. This is supported by US GAAP references below.

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.

In support of the above, ASC 330-10-55-6, *Inventory-Implementation Guidance and Illustrations*, states the following: *In the aggregate, net periodic pension and other postretirement cost is viewed as an element of employee compensation. Therefore, when it is appropriate to capitalize employee compensation in connection with the construction or production of an asset, the net periodic pension and other postretirement cost applicable to the pertinent employees for the period (including interest cost), not individual components of that amount, is the relevant amount.*

164.2 Please describe FEI's treatment of the allocation of Retiree Pension and OPEBs prior to 2010.

Response:

FEI's 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.

164.2.1 What, if any, differences are there between the treatment prior to 2010 and FEI's proposed treatment going forward into the PBR Period?

Response:

There are no differences between the treatment prior to 2010 and FEI's proposed treatment going forward into the PBR Period beginning in 2014.

FEI states: "In 2010, FEI separated the current service portion and the retiree portion of both pension and OPEB expenses. This change was made in anticipation of the adoption of IFRS which allowed for the capitalization of only direct expenditures into benefits loadings and capital."

164.3 Please indicate which portion of pension and OPEB expenses were allowed to be capitalized into benefits loadings and capital under IFRS.

Response:

IFRS allows capitalization of only costs that are directly attributable to bringing an asset into the location and condition necessary for its intended use. This guidance has been interpreted broadly, and in 2010 the Company's view was that only the Current Service Cost portion of Net

Benefit Cost would be considered directly attributable under IFRS because this component of the expense relates to the services rendered by current employees during the period.

165.0 Reference: ACCOUNTING POLICIES

Exhibit B-1, Application, Tab D, Section 3.1, p. 265

Capitalization of Annual Software Costs

FEI states that it is "proposing to adopt a capitalization methodology for the treatment of annual software costs paid to vendors in support of upgrade capability." (p. 265)

165.1 Please explain if this proposed change in methodology is consistent with US GAAP treatment.

Response:

Yes, the proposed change is consistent with US GAAP treatment. 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.

165.1.1 If yes, please provide the US GAAP section which allows for this capitalization treatment.

Response:

The US GAAP section which allows for this capitalization treatment is ASC 350-40, *Internal – Use Software (Intangibles – Goodwill and Other)*, which states the following:

> *25-7 In order for costs of specified upgrades and enhancements to internal-use software to be capitalized…it must be probable that those expenditures will result in additional functionality.*

> *25-11 External costs incurred under agreements related to specified upgrades and enhancements shall be expensed or capitalized…If maintenance is combined with specified upgrades and enhancements in a single contract, the cost shall be allocated between the elements…*

165.1.2 If no, please explain why FEI considers it appropriate to capitalize these costs.

Response:

Not applicable. Refer to the response to BCUC IR 1.165.1.

165.2 Please explain what activities relate to "upgrade capability".

Response:

Upgrade capability allows the Company to use the newest version of software it owns when it is available at no additional costs over and above the cost paid as part of the annual fees. New versions generally include new or improved functionality that may be used to support evolving business needs.

165.3 Please explain what FEI means by the term "upgrade capability".

Response:

Please refer to the response to BCUC IR 1.165.2.

165.4 Please explain how the upgrades extend the life of the software assets.

Response:

Software is kept current and useful through continual upgrades. The annual investment in these upgrades generally extends the life of the software asset many years after the original investment is fully depreciated. Without these upgrades complete software replacements would need to be done regularly with a higher capital cost and increased business disruption.

165.5 Please explain how FEI proposes to estimate the portion of the software costs that relate to upgrades.

Response:

FEI has estimated the allocation of capitalized software costs based on a combination of the expected benefits to be derived from the software and the feedback provided by FEI's external vendors.

Based on information provided by the vendors of FEI's software solutions, it is estimated that at least 50 percent of their total annual fees add value and extend the life of the respective software asset and should be capitalized; the details are as follows:

1. 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.
2. It is estimated that at least 25 percent of annual costs paid to vendors should be considered a pre-payment of the next capital upgrade. Capital upgrades generally occur every 4 to 5 years at no additional costs for software versions due to these pre-payments.
3. It is estimated that 50 percent of the annual costs are for what would be considered purely maintenance and support and should be considered operating and maintenance costs.

Microsoft has provided feedback on their annual costs with a recommendation on how such costs could be allocated. Due to the nature of their software and their agreement they identify a smaller percentage specifically for licensing and maintenance; the details are as follows:

1. 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.
2. Microsoft identifies approximately 25 percent of server software costs (server operating systems, exchange, system management, databases) are specifically licensing & maintenance and the remaining 75 percent is related to upgrades and should be considered capital.

166.0 Reference: ACCOUNTING POLICIES

Exhibit B-1, Application, Tab D, Section 3.1, pp. 265-266

Purchases of Vehicles

166.1 Please explain why FEI historically has chosen to acquire the majority of its vehicles from a third party lessor.

Response:

As a result of the purchase of the Lower Mainland Gas Division assets from BC Hydro by Inland Natural Gas Co. Ltd. (the predecessor company to FEI) in 1988, FEI inherited a number of administrative and customer services contracts that existed between the Gas Division and BC Hydro. As the Gas Division was an operating department of BC Hydro, it relied on BC Hydro to provide it with a wide range of corporate support services, including vehicle lease and maintenance services. In 2005, BC Hydro advised FEI that it would no longer provide vehicle lease and maintenance services and terminated the vehicle lease and services arrangement. FEI decided to then partner with PHH Arval (PHH) to assume the vehicle services that BC Hydro had previously provided including lease and maintenance services.

166.2 Please explain why FEI now believes it is appropriate to change from a policy of leasing its vehicles to purchasing. What changes in circumstances have led to this decision?

Response:

The FortisBC companies continue to pursue opportunities for integration and process harmonization in order to simplify and reduce administrative activity. FortisBC now has common management of its fleet for its gas and electric operations. FEI's 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.

FEI states: "Purchasing vehicles would also ensure that FEI is not exposed to risks associated with the credit markets as was experienced in 2009 during the credit crisis." (p. 265)

166.3 Please describe the risks that FEI has been exposed to through leasing its vehicles.

Response:

From an asset replacement perspective, FEI was exposed to increased risk relating to a delay in the supply of vehicles resulting from the 2009 credit crisis. On this occasion, the third party lessor that provides lease services to FEI raised its funding through "asset-backed" debt which is typically in the form of commercial and term paper as commonly observed within the industry. As a result of the credit crisis, credit markets began to tighten and the third party lessor was not able to access the necessary capital to fund all the vehicles required by FEI causing a delay in replacements until the funding issue was resolved. Although the delay to the vehicle replacement program did not result in a material impact to FEI's operation, it did result in an increased awareness of the risks associated with the credit markets in relation to the company's vehicle fleet. More specifically, in the event that FEI did experience an extended delay in scheduled vehicle replacements, the impacts may include increased risk to employee and public safety resulting from inadequate access to the vehicles necessary for emergency response and increased operating expense resulting from additional repairs and down time.

166.4 Please explain what financial and other impacts the 2009 credit crisis had on FEI due to its leasing of vehicles.

Response:

Please refer to BCUC IR 166.3 for a discussion describing the impacts upon FEI's vehicle fleet resulting from the 2009 credit crisis.

166.5 Please discuss the pros and cons of purchasing versus leasing vehicles.

Response:

The pros of purchasing the vehicles have been discussed in Section D3.1 on pages 265 and 266 of the Application. FEI is not aware of any significant cons with purchasing vehicles versus leasing vehicles.

166.6 Please describe the financial analysis that FEI performed to make its determination to transition to an owned fleet.

Response:

FEI calculated the Net Present Value of the Cost of Service of FEI's vehicle fleet under three scenarios. The three scenarios considered were:

1. Transition the fleet over 1 year which entails purchasing the Fleet from PHH.
2. Transition the fleet over 10 years. As vehicles are retired and replaced they would be purchased by FEI.
3. Keep leasing the Fleet from PHH.

FEI's analysis indicates that scenario 2, transitioning the vehicle fleet to an owned status as the current leased vehicles are retired, has the lowest present value cost of service and thereby the lowest rate impact to customers.

There are three key items that differ between the scenarios. The present value of these items make up the difference between the scenarios considered.

1. Earned Return: There is a small difference in Earned Return between the scenarios based on the need for FEI to deem a portion of the leased fleet as being financed with capital (with an offset in short term debt).
2. PHH Management Fee: PHH charges a management fee as a percentage of the capital cost of the fleet when leased and uses a different fee structure if the vehicles are purchased.
3. Tax impacts on deductibility of CCA vs. lease payments: For leased vehicles, the lease payment is 100% tax deductible and for purchased vehicles, FEI is allowed CCA as a deduction for taxes.

Earned Return Calculation

When vehicles are owned, the earned return on their inclusion in rate base is calculated in the same fashion as other owned assets. Mid-year net book value funded with 38.5% equity at 8.75% ROE and 61.5% debt at long term interest rates. The mid-year net book value of our leased vehicles is approximately $14 million. The following table shows the Earned Return in a particular year as if they were owned.

If Owned				
Long Term Debt (new Issue 10 year)	8,610,000	61.50%	3.80%	**327,180**
Equity	5,390,000	38.50%	8.75%	**471,625**
Total Earned Return	14,000,000	100.00%	5.71%	**$ 798,805**

Under a lease scenario, the entire fleet is financed with interest through the lease payment. However, since the vehicles are included in Rate base, for FEI to maintain its approved equity ratio, 38.5% of the net book value of the vehicles is deemed to be financed with equity. Consequently, FEI creates a notional 38.5% offset in short term debt. The following table shows the Earned Return of the leased vehicles.

Lease Debt	14,000,000	100.00%	3.97%	**555,800**
Adjustment for Accounting Entries if Leased				
Lease Debt	14,000,000	100.00%	3.97%	**555,800**
Equity	5,390,000	38.50%	8.75%	**471,625**
Short Term Debt	(5,390,000)	-38.50%	1.75%	**(94,325)**
Total Earned Return	14,000,000	100.00%	6.67%	**$ 933,100**

Under a leased scenario 61.5% of the leased vehicles are financed at 5.36% ((555,800 – 94,325) / (14,000,000 * 61.5%)). Ownership of the vehicles is less expensive from a financing perspective by approximately $134,000 per year (933,100 – 798,805).

From an Earned return perspective, FEI finds that financing the fleet as owned would be the best option. The present value of the earned return for the three scenarios is as follows. Scenario 1 produces the lowest cost to customers.

Scenario	Description	Present Value of Earned Return
1	Immediate Transition	$ 4,629,000
2	Transition over Time	$ 5,271,000
3	Continue Leasing	$ 5,477,000

Lease Management Fee

PHH charges FEI a management fee on the book value of the leased vehicle portfolio. Under an ownership scenario, a different fee structure would be implemented.

The present value of the PHH management fee for the three scenarios is as follows. Scenario 1 has the lowest cost to customers.

Scenario	Description	Present Value Management Fee
1	Immediate Transition	$ 749,000
2	Transition over Time	$ 903,000
3	Continue Leasing	$ 1,350,000

Tax impacts on deductibility of CCA vs. lease payments

For tax purposes all leased vehicles are considered operating leases which results in 100% of the lease payment (depreciation plus interest) being deductible for calculating taxable income. Lease payments are structured to include straight line depreciation and since the lease payments are tax deductible, the straight line depreciation is deductible.

Under an owned scenario, Capital Cost Allowance (CCA) is tax deductible as a percentage of the Undepreciated Capital Cost (UCC) of the vehicles. Interest is also deductible for calculating taxable income. The CCA rate used for analysis purposes is that of class 10 vehicles at 30%.

For the current leased fleet, the depreciation built into the lease payments is larger than the CCA that could be taken if the leased fleet was transitioned to an owned status at its current net book value. Therefore, it is more of a tax benefit to continue to lease the current fleet.

However, new vehicles added to the fleet have a greater CCA deduction in the early years than the depreciation that is built into their lease payments. Therefore, new vehicles should be owned.

Scenario 2, continuing to lease the currently leased fleet and purchasing any replaced or added vehicles results in the greatest tax benefit for rate payers.

Scenario	Description	Present Value of Tax Expense
1	Immediate Transition	$ 1,146,000
2	Transition over Time	($ 2,323,000)
3	Continue Leasing	($508,000)

Financial Summary

Based on the three major components that affect the cost of service, the lowest cost of service and lowest cost to rate payers would be to transition FEI's current leased fleet to an owned status as the existing vehicles are retired and replaced. (Scenario 2).

	Description	PV of Cost of Service ($000) [2+3+4+5]	PV of Earned Return ($000)	PV of Manageme nt Fee ($000)	PV of Tax Expense ($000)	PV of Depreciatio n ($000)
		(1)	(2)	(3)	(4)	(5)
1	Immediate Transition	$34,639	$4,629	$749	$1,146	$28,116
2	***Transition over Time***	***$31,966***	***$5,271***	***$903***	***($2,323)***	***$28,116***
3	Continue Leasing	$34,435	$5,477	$1,350	($508)	$28,116

FEI states: "This option has the lowest present value cost of service (approximately $3 million over a 20 year analysis period), and therefore a lower rate impact to customers." (p. 265)

166.7 Please provide the above analysis in a working excel spreadsheet which shows how the lowest present value cost of service was determined.

Response:

Please refer to Attachment 166.7.

FEI states: "Since the existing vehicle lease is treated as a capital lease for financial and regulatory purposes, the change only results in what was previously shown as a capital addition now being shown as a capital expenditure (an actual cash outlay) in the financial schedules." (pp. 265-266)

166.8 Please describe the accounting and regulatory treatment for a vehicle under a capital lease versus a purchased vehicle.

Response:

FEI's accounting treatment for vehicles under capital lease and purchased vehicles is similar.

Capital leased vehicles are initially set up as capital leased assets and capital lease obligations (liability) at an amount equal to the present value of the minimum lease payments over the lease term. The capital lease asset is amortized over the term of the lease. During the lease term, the minimum lease payments are allocated between a reduction of the capital lease obligation and interest expense.

The accounting treatment for a purchased vehicle would be to capitalize the cost of acquiring the vehicle and to depreciate the vehicle over the estimated useful life of the vehicle. The vehicles would be purchased with a mix of equity, short term and long term debt.

FEI assumes that "regulatory" treatment from this IR means how the treatment between purchasing and leasing vehicles differs for "rate making purposes". Please see the Earned Return Calculation section in response to BCUC IR 1.166.6 for the difference between leased and owned vehicles for rate making purposes.

166.9 Please indicate if the change from being recorded as capital additions to capital expenditures will have any impact on rate-payers.

Response:

From a rate base perspective, under FEI's PBR proposal, FEI has included the 2013 Approved vehicle lease capital additions as the 2013 capital expenditure for the vehicles. For 2014-2018, this amount is included in the 2013 Base to which the formula is applied. Under either a vehicle lease or vehicle purchase scenario, this same approved amount would have been included in the 2013 Base to which the formula is applied. For this reason FEI concludes there is no difference to ratepayers in the rate base treatment.

Please refer to the response to BCUC IR 1.166.6 which discusses the earned return impacts of the change.

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)

166.10 Please confirm, or explain otherwise, that the average service life estimated for these vehicles and the depreciation rate is consistent with those applied by FEVI, FEW and FBC.

Response:

FEI confirms that the average service life estimated for these vehicles is consistent with that used in the Gannett Fleming study for FEVI, FEW, and FBC.

However, inclusion of net salvage and past gains/losses associated with this asset category will cause the depreciation rates (i.e. 17.72% for FEVI, 12.15% for FEW, 10.7% for FBC) to be different than a depreciation rate based solely on the estimated service life of a vehicle.

166.11 How many vehicle retirements and subsequent replacements does FEI anticipate occurring in 2014? Over the PBR Period?

Response:

Vehicle retirements and replacements are reviewed annually using a number of key criteria including: vehicle mileage, years of service, safety compliance and operational requirements.

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.

167.0 Reference: ACCOUNTING POLICIES

Exhibit B-1, Application, Tab D, Section 3.7, pp. 286-289; Exhibit B-1-1, Appendix F1

Capitalized Overhead

FEI states: “The Survey based approach suggests a 12 percent rate while the Mathematical based approach yielded an 11 percent rate.” (p. 288)

167.1 Please identify the customer rate impact which would result from reducing Capitalized Overhead from 14 percent to 12 percent, and from 14 percent to 11 percent.

Response:

The impact on delivery rates is approximately 0.4 percent for every 1.0 percent change in the other direction in the Capitalized Overhead rate. Consequently, reducing the Capitalized Overhead rate from 14 percent to 12 percent would increase customer delivery rates by approximately 0.8 percent and a reduction of the Capitalized Overhead rate from 14 percent to 11 percent would increase customer delivery rates by approximately 1.2 percent.

KPMG states in the Executive Summary to its report: “The Study utilized the BCUC approved 2013 FEI budget (the “2013 budget”) figures pursuant to BCUC order G-44-12.” (Exhibit B-1-1, Appendix F1, p. 5)

167.2 Please discuss whether or not FEI’s proposed accounting policy changes regarding Allocation of Retiree Pension and OPEBs, and Capitalization of Annual Software Costs would have had any impact on the calculation of the appropriate capitalization rate performed in the Capitalized Overhead Study.

Response:

The Allocation of Retiree Pension and OPEBs, and Capitalization of Annual Software Costs would have an impact on the calculation of the Capitalized Overhead rate.

In the case of the Retiree Pension and OPEBs, approximately $930 thousand would have historically been expensed but will now be capitalized, and the balance of approximately $4.9

million will be reallocated from the Corporate department to all the other departments' labour expense. The effect will be to increase the Capitalized Overhead rate because the Corporate department's Capitalization Rate is lower relative to the other departments.

The Capitalization of Annual Software Costs will have the opposite effect and reduce both the Information Technology departmental expense as well as the amount included in the Capitalization rate and lowers the overall Capitalization Rate.

The net effect results in a Capitalization Rate that is not materially different than was presented in the Study.

168.0 Reference: ACCOUNTING POLICIES

Exhibit B-1-1, Appendix F1, KPMG Overhead Capitalization Methodology Review, Section 7.2.2, Table 5, pp. 28-29

Capitalized Overhead

168.1 Please discuss why, under the Survey Model, the "Objectivity" evaluation criteria only "somewhat satisfies the evaluation criteria."

Response:

The Survey Model in the study was based on interviews and discussions using a standardized questionnaire across the various business units and corporate departments. The accumulated result is nonetheless the product of the views of the interviewees over the cost centres under their control. As such, the Model does not eliminate the risk of human bias which may be present in the overall results.

168.2 Please discuss why, under the Survey Model, the "Transparent and Supportable Methodology" evaluation criteria only "somewhat satisfies the evaluation criteria."

Response:

The Survey Model was conducted at a sufficient level of depth within the company to be able to make an informed estimate of the overhead capitalization rate, which has been documented through the survey process. However, the Model is less transparent and supportable than a process whereby the data, which currently is estimated through the interview process, is captured directly at the individual employee source level and subject to related periodic data checks and controls. Capturing data at the individual level is much less efficient, would result in increased costs and the result may not be materially different than the management survey process.

KPMG states in its report that it "finds the Survey-based model and underlying costs used in the model to be consistent with the cost allocation methodologies as proposed by FEI and guidance related to U.S. GAAP. Based on the results of the Survey Model, the estimated overhead capitalization rate is approximately 12 percent." (p. 35)

168.3 Please explain why it is not appropriate for FEI to change its overhead capitalization rate to 12 percent, as this rate has been evaluated and deemed appropriate by a qualified independent third party.

<u>Response:</u>

The Company does not think it would be appropriate to change its overhead capitalization rate to 12 percent for the following reasons:

1. The Survey Methodology is subjective in nature and therefore the rate is merely an estimate. In their Executive summary, KPMG states that the rate "is estimated to be approximately 12 percent", suggesting that the rate is indicative in nature, but not definitive;
2. As illustrated in Exhibit B-1, Section D.3.7, page 289, Table D3-9 the Company expects capital spending to increase over the period 2014 – 2018 and to lower the overhead capitalization rate would be counter to the trend;
3. Decreasing the estimated rate to 12 percent would have the negative effect of increasing customer delivery rates by about 0.8 percent; and finally,
4. The current capitalization rate of 14 percent is in the lower range compared to the utilities surveyed in the KPMG Overhead Capitalization Methodology Review Appendix A.

169.0 Reference: ACCOUNTING POLICIES

Exhibit B-1, Application, Tab D, Section 3.7, pp. 286-289

Capitalized Overhead

FEI states: "The Company is of the opinion that there has been no material change in utility operations since the 2012-2013 RRA that would require a change to the overheads capitalized rate." (p. 288)

The Commission stated in the FEU 2012-2013 RRA Decision: "Given the various changes in accounting standards and the desired expansion of the FEU's customer offerings and new business activities, the Commission Panel directs the FEU to update their capitalized overhead methodology…" (p. 78)

169.1 Please discuss the changes that have occurred since FEI's last capitalized overhead study which would likely impact the capitalized overhead rate, including new service offerings, separation of various service offerings, and other new business activities.

Response:

Changes such as new service offerings, separation of various service offerings, and other new business activities would have little, if any, effect on the capitalized overhead rate. The types of changes described involve a very small group of employees that direct charge their time to capital projects when working on them rather than being included in the capitalized overhead rate. Additionally, the majority of the new services are developer built and the Company simply purchases the assets so there is little of the conventional utility type work or involvement during the asset build when capitalized overhead would be applied. The nature and size of these expenditures in FEI has not materially increased from 2010 as the assets are being built or purchased in an affiliated company, FAES.

Changes in accounting standards can have an impact on the overhead capitalization rate as was evidenced in the 2010/2011 KPMG Overheads Capitalized Study prepared for the Company. That study applied a survey based methodology that yielded an estimated rate of 8 percent that was almost entirely due to assuming IFRS accounting guidance. Under IFRS, unless costs are directly attributable to capital projects the costs cannot be capitalized and therefore there had to be a direct casual linkage between the cost incurred and the capital project.

As discussed in some detail, the 2013 KPMG Study was prepared assuming US GAAP, FERC and BCUC accounting guidance that all provide for the capitalization of overhead that is indirectly attributable to capital work and supports a higher overhead capitalized rate than that determined under IFRS.

170.0 Reference: ACCOUNTING POLICIES

Exhibit B-1, Application, Tab D, Section 4

Deferral Accounts

170.1 Please complete the following three tables below:

Table 1:

	2011 (Actual)	2012 (Actual)	2013 (Projected)	2014 (Forecast)	2015 (Forecast)	2016 (Forecast)	2017 (Forecast)	2018 (Forecast)
Total Deferral Accounts - END OF YEAR ($'000)								
Total Deferral Accounts - End of Year as a % of total revenue requirements								

Table 2:

	2011 (Actual)	2012 (Actual)	2013 (Projected)	2014 (Forecast)	2015 (Forecast)	2016 (Forecast)	2017 (Forecast)	2018 (Forecast)
Total Deferral Accounts - MID YEAR ($'000)								
Total Deferral Accounts - Mid-Year as a % of rate base								

Table 3:

	2011 (Actual)	2012 (Actual)	2013 (Projected)	2014 (Forecast)	2015 (Forecast)	2016 (Forecast)	2017 (Forecast)	2018 (Forecast)
Total Deferral Accounts - AMORTIZATION ($'000)								
Total Deferral Accounts - amortization as a % of rate base								

Response:

For all tables provided in this response, information for 2011 and 2012 reflects the actual deferral account balances, rate base and revenue requirements for each year and 2013 through 2018 reflects the projection and forecasts as included in the July 16th Evidentiary Update to this Application (Exhibit B-1-3). Additionally, FEI has provided a fourth table which it believes, along with Table 2, most accurately reflect the impacts of deferrals accounts on revenue requirements given:

- The mid-year balances of deferral accounts are used to determine rate base (not the end of year balances) and;
- It is the amortization expense and earned return associated with the mid-year balance of the deferral accounts that are included in the revenue requirement, not the mid-year balance itself.

Table 1

	2011 (Actual)	2012 (Actual)	2013 (Projected)	2014 (Forecast)	2015 (Forecast)	2016 (Forecast)	2017 (Forecast)	2018 (Forecast)
Total Deferral Accounts - END OF YEAR ($'000)	$ (42,425)	$(20,242)	$ 4,281	$ 42,363	$ 67,664	$ 68,419	$ 60,597	$ 49,147
Total Deferral Accounts - End of Year as a % of total revenue requirements	-3.56%	-1.80%	0.39%	3.81%	6.03%	5.98%	5.23%	4.17%

Table 2

	2011 (Actual)	2012 (Actual)	2013 (Projected)	2014 (Forecast)	2015 (Forecast)	2016 (Forecast)	2017 (Forecast)	2018 (Forecast)
Total Deferral Accounts - MID YEAR ($'000)	$ (13,703)	$ 497	$ (7,981)	$ 36,676	$ 55,284	$ 68,042	$ 64,508	$ 54,872
Total Deferral Accounts - Mid-Year as a % of rate base	-0.53%	0.02%	-0.30%	1.32%	1.94%	2.35%	2.20%	1.85%

Table 3

	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**	**$ 29,970**	**$ 29,516**	**$ 33,195**	**$ 35,654**	**$ 37,552**
Total Deferral Accounts - amortization as a % of rate base	**-0.21%**	**0.44%**	**0.95%**	**1.07%**	**1.04%**	**1.15%**	**1.22%**	**1.27%**

Table 4

	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**	**$ 29,970**	**$ 29,516**	**$ 33,195**	**$ 35,654**	**$ 37,552**
Total Deferral Accounts - amortization as a % of total revenue requirements	**-0.44%**	**1.05%**	**2.31%**	**2.70%**	**2.63%**	**2.90%**	**3.08%**	**3.18%**

171.0 Reference: ACCOUNTING POLICIES

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

Deferral Accounts – 2014-2018 PBR Application

171.1 Please clarify if the proposed 2014-2018 PBR Application Deferral Account will be a rate-base deferral account or a non-rate base deferral account.

Response:

The proposed 2014-2018 PBR Application Deferral Account will be a rate-base deferral account.

171.1.1 Please explain why this treatment is appropriate.

Response:

This treatment is appropriate as it is consistent with the treatment of other application costs incurred historically including, but not limited to, the application costs for the FEI 2012-2013 RRA, the 2010-2011 RRA, and the 2004-2009 PBR Application. The simplest and most transparent way to achieve recovery of these costs from all customers is by including them in rate base and amortizing them directly into the delivery rates.

172.0 Reference: ACCOUNTING POLICIES

Exhibit B-1, Application, Tab D, Section 4.1.2, pp. 292-293;

Exhibit B-1-1, Appendix F5, Section 2.2, pp. 3-4

Deferral Accounts – TESDA Overhead Allocation Variance

FEI states: "This account will capture the difference between the currently forecasted amount of overheads recovered by FEI from thermal energy customers and any changes to the allocation that may result from the TESDA Report and the Transfer Pricing Policy/Code of Conduct review requested in the AES Inquiry to be undertaken with the Commission later in 2013." (Exhibit B-1, p. 292)

172.1 Please confirm that the proposed "TESDA Overhead Allocation Variance" deferral account is a separate deferral account from the "Thermal Energy Services Deferral Account (TESDA)."

Response:

Confirmed.

172.2 Please confirm that the 2013 addition to the TESDA is $854 thousand.

Response:

Correct as far as the addition that relates to the overhead allocation. The 2013 approved overhead allocation from FEI to the TESDA is $854 thousand.

172.3 Please confirm, or explain otherwise, that the purpose of this new deferral account is essentially to capture the difference between the "old" TESDA deferral account and the actual overhead recovery which will be determined at the completion of the above-mentioned proceedings.

Response:

Confirmed. To clarify, the purpose of this new deferral account is to capture the difference between the 2013 approved FEI overhead allocation to the TESDA of $854 thousand and, if applicable, a revised amount determined at the completion of the above-mentioned proceedings. This will ensure that the amount of costs allocated to the TESDA and being credited to natural gas ratepayers reflects the Commission-approved allocation methodology.

172.4 Please provide the following information regarding the TESDA deferral account:

(i) The current balance of the TESDA;
(ii) A listing of all the transactions recorded to the TESDA since its inception, by year and by project. This list should include all of the O&M costs allocated to the TESDA as well as any recoveries from customers which have reduced the balance; and
(iii) Evidence which shows that the amount of O&M allocation going into the TESDA each year is equal to the O&M reduction from the overall gross O&M of the natural gas business.

Response:

This response is being filed confidentially as it contains commercially sensitive information that should not be publicly disclosed, including to the COC which represents competitors of FAES.

172.5 When does FAES anticipate filing the TESDA Report? When does FAES anticipate filing the Transfer Pricing Policy/Code of Conduct review?

Response:

FAES anticipates filing the TESDA Report once the Transfer Pricing Policy/Code of Conduct review is complete. On pages 276 -277 of the PBR Application, FEI has indicated that the Company had agreed to start the Transfer Pricing Policy/ Code of Conduct review with the Commission in the fall of 2013. This proposed schedule was also described in an IR response to the Commission (FAES' Application for CPCN for the Kelowna District Energy System, BCUC IR 3.3.1) and is included as reference below:

> *"FAES understands that a review of the Code of Conduct and Transfer Pricing Policy will commence in the fall of this year.*

As set out in the FortisBC Energy Utilities' "Clarification Request Related to Upcoming Revenue Requirements" filed on February 20, 2013:

> *"The FEU and the Commission staff have tentatively agreed to start the COC/TPP review process in the Fall of 2013. This proposed timeframe considers the active participation of both the FEU and the Commission staff in numerous other regulatory proceedings in 2013. Subsequent to updating the COC/TPP, the FEU will file an application regarding allocation and recovery of TESDA. Without clarity on the COC/TPP and the resulting costs that will be allocated to the TESDA, an analysis of the forecasted* recovery from the TESDA is not possible."

Subsequently, in a recent discussion with Commission staff in July 2013, it was agreed to target Q1/Q2 of 2014 for FEU to file a proposed Transfer Pricing Policy and Code of Conduct update for review and approval by the Commission.

172.5.1 Will these reports/reviews be filed concurrently or in tandem?

Response:

Please refer to the response to BCUC IR 1.172.5.

172.6 Please explain why FEI believes this new TESDA Overhead Allocation Variance deferral account needs to be established at this time.

Response:

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 anticipates the determination of the recovery amount will be finalized as part of the Transfer Pricing Policy/Code of Conduct (TPP/COC) Review. 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.

FEI is of the view that the TESDA Report filing or the TPP/COC review would not be an appropriate place to request items such as new deferral accounts for FEI; therefore it has made the deferral account request in this Application so that parties to this proceeding understand FEI's intentions to keep customers whole.

172.6.1 Would it not be more appropriate to establish this account, if the need arose, during the Transfer Pricing Policy/Code of Conduct review? Please discuss.

<u>Response:</u>

Please refer to the response to BCUC IR 1.172.6.

172.7 Please discuss whether FEI believes that the entire balance in the TESDA should be allocated to rate-payers or if some of the balance should be allocated to share-holders.

<u>Response:</u>

FAES believes that the disposition of the TESDA should be dealt with as part of the TESDA Report. The TESDA is not part of FEI's rate base or the setting of its delivery rates, and therefore is not part of this proceeding. FEI has proposed a deferral account mechanism to deal with the allocation to the TESDA that is part of this proceeding.

173.0 Reference: ACCOUNTING POLICIES

Exhibit B-1, Application, Tab D, Section 4.2.4, p. 294

Deferral Accounts – Pension and OPEB Variance

FEI states that it "is requesting approval to extend the amortization period of this [Pension and OPEB Variance] account from the currently approved three year period to the Expected Average Remaining Service Life ("EARSL") of the benefit plans." (p. 294)

173.1 Please discuss the benefits and drawbacks of a shorter amortization period (i.e., the currently approved 3 year period) versus the longer proposed 12-year period.

<u>Response:</u>

The benefits of the longer proposed 12-year amortization period are two-fold. As discussed in Section D4.2.4 of the Application, extending the amortization period to the EARSL more appropriately allocates the costs over the future period to which they are applicable. The EARSL is an average of the employees' average expected time to retirement and would represent the period of time FEI would expect the employee, on average to be an employee. Additionally, as the nature of these costs is uncontrollable, large fluctuations in this account can occur from year to year. A longer amortization period allows for smoother rates for customers in future years that follow a year with high volatility in pension and OPEB costs. Conversely, a shorter amortization period has the benefit of recovering costs from customers sooner rather than later.

173.2 Please explain why the amortization period for this deferral account was originally approved to be three years.

<u>Response:</u>

This account was approved through Commission Order G-51-03 to capture pension variances only and to be amortized over one year. This account was modified starting in 2010 through Commission Order G-141-09 to also include OPEB variances from forecast and to extend the amortization period of the account to three years. This modification was required due to changes in market conditions and accounting practices that created additional volatility in the utility's pension and OPEB expenses. With this volatility, the deferral account was amended to avoid large fluctuations in recovered amounts from year to year.

173.2.1 What changes in circumstances have occurred which now lead FEI to believe that an amortization period based on the EARSL is more appropriate?

Response:

Since FEI filed its last revenue requirement in 2011 for 2012 and 2013, there has been a large increase in the pension expense which has resulted in a material variance in the Pension and OPEB variance account. Low interest rates in 2011 through 2013 have resulted in a higher pension expense than forecast. The low interest rates lower the discounting of the liability which, in turn, results in higher expenses each year. The discount rate is set in reference to Corporate AA bond and the rate used is beyond the control of FEI. As a result, the annual variances recorded in the deferral are significant and, for the reasons discussed in the response to BCUC IR 1.173.1, FEI believes that an amortization period to recover these balances based on the EARSL is more appropriate.

173.3 Please explain how often the accounting valuation is performed to determine the EARSL for the defined benefit pension plan and the OPEBS.

Response:

While accounting valuations are done each year to determine the pension and OPEB expense for accounting purposes, the EARSL for each of the pension plans and OPEBs is determined when an actuarial valuation is done for each plan. Actuarial valuations are typically only done once every three years, as required under the current pension legislation, but the actuarial valuation may be done more often if deemed necessary.

173.4 If the Commission were to approve the use of the EARSL to determine the amortization period for this deferral account, how often would FEI propose to update the amortization period to reflect the most up-to-date EARSL?

Response:

As discussed in Section D4.2.4 of the Application, if the Commission were to approve the use of EARSL to determine the amortization period for this deferral account, FEI would use the calculated 12 year EARSL for the entire term of this PBR. This prevents FEI from having to re-calculate and implement various amortization periods for a single account during the term of a PBR period. EARSL is generally not subject to change materially from one actuarial valuation period to the next. Considering actuarial valuations are required to be done once every three years, this potentially means there could be only one future valuation period during the five year term of this PBR and it is unlikely that it would create a material change to the requested EARSL period.

Additionally, the requested 12 year EARSL amortization period would likely be adjusted in the next revenue requirement application based on the calculation of EARSL at that time.

173.5 Please explain why FEI believes it is most appropriate for this deferral account to have an amortization period that will be periodically subject to change.

Response:

As discussed in the response to BCUC IR 1.173.4, using the EARSL to determine the amortization period for this account will only potentially result in a change to the actual amortization period of the deferral account during each successive revenue requirement application. This is not any different than other deferral accounts where the utility has the potential to request a change to the existing approved amortization period of a deferral account in the next Revenue Requirement Application. For example, please refer to Table D4-5 of this Application where FEI has requested to modify the amortization period for two other existing deferral accounts with previously approved amortization periods (the Midstream Cost Reconciliation Account and the Revenue Stabilization Adjustment Mechanism account).

173.6 Please discuss why FEI believes it is appropriate for this deferral account to be included in rate base and therefore earning a return based on FEI's Weighted Average Cost of Capital (WACC)?

Response:

FEI believes that the deferral account should attract a return based on WACC regardless of whether is it in rate base or not. That is, the same principle should apply to rate base deferrals and non rate base deferrals, and that principle is articulated in response to BCUC IR 1.173.7.

FEI's preference is to hold deferral accounts as part of rate base to keep as much consistency as possible in treatment of deferrals, and normally only requests non-rate base deferrals due to timing issues or to stream costs to a particular customer group. In this case, neither of these conditions exist.

173.7 Please discuss whether the amounts recorded in this deferral account are capital or non-capital in nature, and whether FEI believes this should impact the type of return the deferral account should earn.

Response:

The amounts recorded in this deferral account are both capital and non-capital in nature. That is, some amounts would normally be capitalized as part of the labour loadings for those employees that perform capital work, and some would be expensed for those employees that do not.

However, as stated in other recent applications of the FortisBC Utilities, FEI believes that the nature of the amounts (capital or non-capital) should not impact the type of return the deferral account should earn. This is because the moment an item is placed into a deferral account for future recovery or refund, it ceases to become a "non-capital" item. It has now become akin to a capital item in that costs are being incurred in one period and not being recovered from ratepayers until a future period. In fact, even non-capital (or operating items) that are expensed and recovered within the same test year receive a rate base return through the working capital component to the extent there is a time lag in their recovery during the year.

It is not relevant whether an item was originally of a capital nature or not, because the nature of the expenditure has been changed by recording it into the deferral account. Allowing deferrals to attract a rate base rate of return recovers the costs associated with the timing difference when there is an outlay of funds and when those costs are recovered from ratepayers. A rate base rate of return is the only logical and consistent approach to be applied; providing consistency between those deferrals that are in rate base and those that are held outside of rate base.

173.8 Please indicate what the rate impact would be for 2014 if the Pension and OPEB Variance deferral account continued to be amortized over three years. How does this compare to the impact of changing the amortization period to 12 years?

Response:

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.

174.0 Reference: ACCOUNTING POLICIES

Exhibit B-1, Application, Tab D, Section 4.2.5, pp. 294-295

Deferral Accounts – Customer Service Variance Account

FEI states that it "believes that a five year amortization period is appropriate because it smoothes the rate impacts of the significant credits held in the account over the term of the PBR." (p. 295)

174.1 Please indicate why it is important to smooth the rate impacts over the term of the PBR.

<u>Response:</u>

FEI believes it is important to smooth the rate impacts over the term of the PBR in order to prevent unnecessary fluctuations in rates and provide rate stability for customers. FEI adopts this approach for many of its deferral accounts, regardless of whether the funds are returned to customers or recovered from customers. In the case of the Customer Service Variance Account, it is also appropriate to amortize the account over five years, from 2014 to 2018, to better align with the amortization period of the existing 2010/2011 Customer Service O&M and Cost of Service deferral, which is amortized over eight years from 2012 to 2019. The annual amortization costs to customers of approximately $2.9 million per year for the 2010/2011 Customer Service O&M and Cost of Service deferral would be almost fully offset by the forecasted amortization credit of $2.7 million per year for the Customer Service Variance Account.

The benefit of amortizing the balance over a shorter period compared to the proposed five year period is that the funds are returned to customers sooner. However, for the reasons described above and the further analysis provided in the response to BCUC IR 1.174.3, FEI believes a five year amortization period is appropriate for this account.

174.2 Please discuss the pros and cons of amortizing the balance over a shorter period versus the proposed 5-year period.

<u>Response:</u>

Please refer to the response to BCUC IR 1.174.1.

174.3 Please provide the rate impact of amortizing the balance over: (i) the proposed 5 years, (ii) 3 years, (iii) 2 years, (iv) 1 year.

Response:

The table below provides the FEI cumulative delivery rate impacts from 2014 through 2018 for each of the amortization scenarios identified for the Customer Service Variance Account.

FEI Cumulative Delivery Rate Impact	2014	2015	2016	2017	2018
5 year amortization	-0.72%	-0.68%	-0.64%	-0.60%	-0.56%
3 year amortization	-1.09%	-1.02%	-0.95%	0.00%	0.00%
2 year amortization	-1.54%	-1.44%	0.00%	0.00%	0.00%
1 year amortization	-2.90%	0.00%	0.00%	0.00%	0.00%

174.4 Please indicate if FEI will continue to record amounts in the Customer Service Variance Account beyond 2013.

Response:

No, FEI will not continue to record amounts to the Customer Service Variance Account beyond 2013.

174.5 Please confirm, or explain otherwise, that the Customer Service Variance Account is a rate base deferral account.

Response:

Confirmed. The Customer Service Variance Account is a rate base deferral account.

175.0 Reference: ACCOUNTING POLICIES

Exhibit B-1, Application, Tab D, Section 4.2.9, p. 297

Deferral Accounts – Generic Cost of Capital Application

FEI states that it is "seeking approval for a rate base deferral account to record the forecast costs related to the GCOC Stage 1 proceeding, less the amounts recovered from other affected utilities." (p. 297)

175.1 Please explain why FEI believes it is reasonable to include this deferral account in rate base.

Response:

FEI has included this deferral account in rate base as this treatment is consistent with past practice for deferral accounts that hold costs related to regulatory proceedings, and in particular costs related to cost of capital proceedings. Whether a deferral account is in rate base or not, it is subject to a rate base rate of return, and therefore there is no difference to customers between the two treatments. Please refer to the response to BCUC IR 1.173.7 for a discussion of the appropriate return for deferral accounts.

FEI states: "No Stage 2 proceeding is required for FEI itself." (p. 297)

175.2 Please clarify whether the proposed Generic Cost of Capital Application deferral account will contain costs related to the Stage 2 proceeding.

Response:

No, in FEI, the Generic Cost of Capital Application deferral account will not contain costs related to the Stage 2 proceeding.

175.2.1 If yes, please discuss the types of costs FEI anticipates incurring for Stage 2 which would be included in the deferral account.

Response:

Please refer to the response to BCUC IR 1.175.2 where the response was no.

176.0 Reference: ACCOUNTING POLICIES

Exhibit B-1, Application, Tab D, Section 4.2.10, pp. 297-298

Deferral Accounts – Amalgamation and Rate Design Application Costs

FEI states that it is "requesting to continue accumulating residual costs related to that [Common Rates, Amalgamation and Rate Design] Application, and the subsequent reconsideration application that was filed on April 26, 2013, in this deferral account and to transfer FEI's portion of the accumulated balance to rate base beginning January 1, 2014." (p. 298)

176.1 Please indicate what "residual costs" FEI is incurring related to the above application.

Response:

To clarify, FEI has not incurred any "residual" costs that it is aware of. This request was made to ensure any late invoices received or any potential late PACA requests could be captured in this deferral account.

176.1.1 Approximately how much are the "residual costs"?

Response:

Please refer to the response to BCUC IR 1.176.1.

176.2 Please provide an update on the status of the reconsideration application.

Response:

On June 26, 2013, the Commission issued Order G-100-13 establishing Phase Two for the FEU Common Rates, Amalgamation and Rate Design Reconsideration Applications filed separately by the Commercial Energy Consumers Association of British Columbia (CEC) and the FEU on April 17 and 26, 2013 respectively. Order G-100-13 set out a Regulatory Timetable which included the filing of Evidence on July 10, 2013 and a round of Information Requests (IRs) on the Applications and Evidence filed. The proceeding is currently in the discovery stage awaiting response to IRs.

Evidence was filed by the FEU, CEC, and Mr. Robinson. IRs were filed by the Commission to the FEU, Mr. Robinson, CEC and the Ministry of Energy and Mines, and Mr. Robinson and the Association of Vancouver Island and Coastal Communities filed IRs to the FEU.

On July 25, 2013, the Commission issued letter L-45-13, amending the Regulatory Timetable setting the date for IR responses to Wednesday, August 14, 2013. Further process beyond the response to IRs has not yet been determined.

176.3 Please explain why it would not be more appropriate to create a separate deferral account related to costs incurred for the reconsideration application.

Response:

FEI does not believe it is appropriate to capture costs incurred for the Reconsideration Application separately from the costs incurred for the Common Rates, Amalgamation and Rate Design Application as they relate to the same initial application. Costs incurred for the Reconsideration Application are solely the result of issues with the Commission Decision related to the initial Common Rates, Amalgamation and Rate Design Application, so they must be considered as one and the same group of costs.

FEI also does not see the value in separating these costs into two separate deferral accounts if both are to be recovered from customers over the same period of time.

176.4 Please indicate why FEI believes a three-year amortization period is appropriate for this deferral account.

Response:

FEI has chosen a three-year amortization period for this deferral account to satisfy competing factors.

FEI did not choose a shorter amortization period as, due to the costs of that proceeding, there is the potential to produce moderate rate fluctuations through high amortization costs in those years.

Conversely, FEI did not choose a longer amortization period as it did not want amalgamated customer rates to be negatively impacted by these application costs for a significant period of time.

177.0 Reference: ACCOUNTING POLICIES

Exhibit B-1, Application, Tab D, Section 4.2.11, pp. 298-299

Deferral Accounts – Residual Delivery Rate Riders

177.1 Please provide the residual balances for each of the three deferral accounts proposed to be combined in the Residual Delivery Rate Riders deferral account.

Response:

The residual balances of the three individual deferral accounts proposed to be combined into the Residual Delivery Rate Riders deferral account are shown below:

Commodity Unbundling - Rate Rider 8		($93,022)
Earnings Sharing/Capital Incentive Mechanism - Rate Rider 3		84,383
Delivery Rate Refund Rider - Rate Rider 4		(29,383)
Total	$	(38,022)

177.2 Please explain why it is appropriate to include the Earnings Sharing/Capital Incentive Mechanism deferral account in the Residual Delivery Rate Riders account given that the Earnings Sharing/Capital Incentive Mechanism account is rate base and the residual account is non rate base.

Response:

To clarify, the existing approved Residual Delivery Rate Riders account is a rate base deferral account. The account was created as part of the FEU 2012-2013 RRA to transfer three residual non-rate base deferral accounts, that originally used riders to recover the balance in the account, into rate base and amortize the balance to customers. The proposal in this Application is similar in that FEI is requesting to combine two residual non-rate base deferrals and one residual rate base deferral, each of which also used riders to recover the balance in the account, into the Residual Rate Riders account.

FEI acknowledges that the alternative request of seeking a one year amortization period for the Earnings Sharing/Capital Incentive Mechanism, and not transferring the balance, would achieve the same result as the request for this specific account included in this Application. However, FEI believes the latter alternative is the best approach as it serves to reduce the number of deferral accounts and continues the precedent of combining residual rider deferrals for ease of returning or recovering the balance from customers.

177.3 Please explain why FEI believes it is appropriate for these three particular deferral accounts to be combined into one deferral account.

Response:

Please refer to the response to BCUC IR 1.177.2.

178.0 Reference: ACCOUNTING POLICIES

Exhibit B-1, Application, Tab D, Section 4.3.1, p. 299

Deferral Accounts – On-Bill Financing Program

FEI states that it is "seeking approval to transfer the balance of this account as at December 31, 2014 to rate base on January 1, 2015 and to continue to recover the balance from OBF pilot program customers over approximately a ten-year period until the account is fully recovered." (p. 299)

178.1 Please confirm, or explain otherwise, that FEI's proposed treatment is consistent with the treatment discussed in Order G-163-12 and in the accompanying Reasons for Decision.

<u>Response:</u>

FEI's proposed treatment is consistent with the treatment discussed in the On-Bill Financing Pilot Program Application. In that Application, FEI requested creation of this deferral account as a non-rate base account, attracting AFUDC, and then requested "Effective January 1, 2015, the Utilities are seeking approval to transfer these deferrals into their respective rate bases and include the balances as part of their respective revenue requirements applications starting in 2015".

In the resulting Order G-163-12 and in the accompanying Reasons for Decision, the Commission approved the new account as follows "OBF Financing Deferral Account: a new non-rate base deferral account attracting AFUDC, to capture, on a net-of-tax basis, the principal loan balances provided to participating customers of the OBF Pilot Program and the applicable interest charges and recoveries".

Since no determination was made on the second part of FEI's request, FEI has requested it in this Application instead.

178.2 Please provide the current balance of this deferral account and the forecast balance of the account at the end of 2014.

Response:

There is currently no balance in this deferral account. As provided in Appendix E of the On-Bill Financing Pilot Program Application, the anticipated balance in this account at the end of 2014 is $541 thousand.

179.0 Reference: ACCOUNTING & FINANCIAL MATTERS

Exhibit B-1-1, Appendix F5, Section 2.4, p. 4

KORP Feasibility Costs

179.1 Please confirm, or explain otherwise, that the KORP Feasibility Costs deferral account is not currently earning any return, including AFUDC.

Response:

Confirmed. The Commission deferred its determination on the return treatment for this account in its Decision G-101-12 and FEI has not yet requested a determination be made. For a discussion of the topic please refer to BCUC IR 1.173.7 which provides FEI's views on why this account should earn a WACC return.

180.0 Reference: ACCOUNTING & FINANCIAL MATTERS

Exhibit B-1-1, Appendix F6, Resource View, Line 15

Recoveries & Revenue

180.1 Please provide the breakdown of "Recoveries & Revenue" for the 2013 Approved and 2013 Projection amounts.

Response:

Provided below is a breakdown of "Recoveries & Revenue" for the 2013 Approved and 2013 Projection amounts.

Breakdown of Recoveries & Revenue ($ thousands)

	Approved 2013	Projection 2013
Shared services	(11,089)	(11,090)
Rent recoveries	(1,566)	(1,400)
Customer Service recovery	(2,918)	(2,497)
Reconnect fees	(2,675)	(1,240)
System damages recovery	(1,775)	(1,133)
Recoveries on 3rd party work and others	(751)	(1,696)
Total	$ (20,774)	$ (19,055)

Shared Service recoveries are as per Shared Service Agreements for FEVI, FEW, and CMAE and as per BCUC Order G-44-12 for FAES.

Rent recoveries include recoveries from subleasing of 1111 West Georgia and revenue from leasing available space, such as Tilbury and some regional facilities.

Customer service recoveries include bad debts recovered by collection agencies and amounts charged to Gas marketers to offset costs to administer the Customer Choice program.

Recoveries from reconnect fees are collected from customers to unlock meters and reactivate gas flow downstream of the meter. Meter lock-off is the last step in the credit and collection process that allows customers to unlock when their gas account is back in good standing.

System damage recoveries are amounts collected from third parties, such as excavators, to recover emergency response and repair costs for damages to gas system assets.

Other recoveries include amounts collected from third parties for various miscellaneous services rendered.

180.2 Are any of the "Recoveries" amounts received from FAES or from the TESDA?

Response:

Yes, line 15 (Recoveries) includes amounts received from FAES.

$500 thousand was recovered from thermal energy customers in each of 2010 and 2011 as approved by BCUC Order G-141-09.

$842 thousand was recovered from thermal energy customers via the amount being charged to TESDA in 2012 and $854 thousand will be recovered in 2013 as approved by BCUC Order G-44-12. As discussed in Section D4.1.2 of the Application, the 2014 through 2018 Forecasts include the same amount as was approved for 2013, with a deferral account proposed to capture the difference between this amount and the amount ultimately recovered.

In addition, costs incurred on behalf of FAES (formerly Terasen Energy Services) are direct charged and recovered through continuing services and departments directly charge to the TESDA for the work they perform. These amounts offset the labour costs in FEI and are not included in the Resource View line 15 - Recoveries & Revenue.

181.0 Reference: APPENDICES

Exhibit B-1-1, Appendix F1

Shared Services Agreements

Schedule "B"
Shared Service Fee

Cost Allocation Drivers

Department	**Allocation Method**
Engineering Services and Project Management	# of Customers Specific Allocation %
Operations	# of Customers # of Employees Specific Allocation %

Note 1: Does not include Timesheet (or Direct Charge) allocations.
Note 2: The Shared Service Fee may be amended from time to time by the written agreement of the parties.

3.786 FEI and FEVI Shared Services Agreement (Cost Sharing) Final.doc SCB-1

181.1 Please confirm, or otherwise explain that the allocation method for the Shared Services Agreements is to Direct Charge amounts using Timesheets and then allocate the remaining amount to be charged for Shared Services using the allocation methods listed on Schedule "B".

<u>Response:</u>

FEI confirms that where costs are directly attributable to FEVI/FEW, the costs will be allocated using timesheets. These costs are excluded from the Shared Services Agreement.

For other shared costs which are covered by the Shared Services Agreement, they are captured in departmental cost pools and then allocated based on allocation factors such as the number of customers, number of employees and a specific allocation percentage.

181.2 Please explain further how the "Specific Allocation %" is applied for Engineering Services and Project Management and for Operations, including how this works with the "# of Customers" and "# of Employees" allocation methods.

Response:

The use of the Specific Allocation percentage as an allocation method is not new and was previously approved for use by the Commission in prior RRA agreements (i.e. 2010/2011 and 2012/2013).

The Specific Allocation percentage method is applied in only a couple of situations where it is more accurate to allocate specific dollars included in the department cost pools than using cost drivers such as the number of customers and employees.

For Operations, the Specific Allocation percentage method is used for the Field Dispatch and Pre-requisite departments where the number of employees specifically performing work for FEVI/FEW can be identified.

For Engineering Services and Project Management, most of the shared services costs are allocated using the number of customers. For a small portion of the shared services costs in the Drafting department where the costs can be specifically identified with FEVI, the Specific Allocation percentage method is used.

182.0 Reference: ACCOUNTING AND FINANCIAL MATTERS

Exhibit B-1-1, Appendix F2

Corporate Services Study and Agreements

Table 5.5 – 2013 FI FTEs, Labour and Non-labour Costs Allocated

Service	FTEs	Labour	Non-Labour	Total
Executive	5.0	4,778,000	-	4,778,000
Treasury and Taxation	2.0	361,000	116,000	477,000
Investor Relations	2.0	335,000	1,348,000	1,683,000
Financial Reporting	7.0	1,057,000	680,000	1,737,000
Internal Audit	1.1	290,000	461,000	751,000
Board of Directors	-	1,764,000	305,000	2,069,000
Other*	1.0	481,000	2,099,000	2,580,000
Less: Fortis Properties Management Fee Revenue	-	-	(1,500,000)	(1,500,000)
Total	**18.1**	**9,066,000**	**3,509,000**	**12,575,000**

(Exhibit B-1-1, Appendix F2, p. 13)

182.1 Please explain the position(s) title(s) and the work performed by the one FTE in "Other" which results in the $481,000 of labour to be allocated.

Response:

The one FTE in "Other" should be included in Internal Audit rather than in" Other". The remaining labour costs in "Other" represent group/health benefits for employees.

183.0 Reference: FINANCING, TAXES, ACCOUNTING POLICIES AND DEFERRALS

Exhibit B-1, Tab D, Section 4.4.3, p. 305, Lines 22-37; Exhibit A2-6, Compliance Filing to Commission Order G-68-10 - Potential Revenue Opportunities from Land North of Tilbury Road, p. 3; Order G-181-11

Tilbury Property Purchase (Subdividable Land)

In Exhibit B-1, page 305 FEI states: "As discussed in the FEI Tilbury Land Sale Application dated October 12, 2011 and approved through Commission Order G-181-11, FEI has subsequently sold this land and recorded the proceeds of sale against the balance of this deferral account. Additionally, as discussed in that Application, FEI has also recorded incremental rental revenue from the property over and above what was forecast in the 2012-2013 RRA.

After accounting for the above items, the net forecasted balance at the end of 2013 is a credit balance, to be returned to customers, of $164 thousand."

183.1 Please provide all the financial transactions that have resulted in the net forecasted credit balance of $164 thousand in the Tilbury Property Purchase (Subdividable Land) deferral account.

<u>Response:</u>

The table below shows the derivation of the $164 thousand credit forecasted in the account at the end of 2013. It should be noted that the rent recoveries are currently one-month behind which explains the eight months of rent recoveries in 2012 compared to the nine months included in Exhibit A2-6. In light of this, the revised forecast for this account should be a credit of $196 thousand. FEI will update this forecast either during the next Evidentiary Update for this Application, or through the financial schedules filed once a Final Decision is issued by the Commission.

Actual Activity (2010 through 2012)	
Allocation of Subdividable Area	$ 3,300,000
Proceeds from Parcel Sale	(2,743,764)
Income Tax Benefits	(470,620)
Legal costs	123,417
Consulting fees	34,655
Commission & PACA costs	13,879
Interest	180,661
Admin costs	1,133
Rent Recoveries ($31,746 x 8)	(253,969)
Forecast 2013 Activity	
Rent Recoveries ($31,746 x 11)	(349,208)
Total Forecasted Ending Balance in Account	$ (163,815)

The amounts above include the items from Directive 2 (net proceeds and related income tax benefits) and Directive 3 (rent recoveries).

> Directive 2 of Order G-181-11 states: "The net proceeds from the sale and subdivision (estimated at $3.2 million) are to be credited to the deferral account established pursuant to Commission Order G-68-10, with the disposition of the deferral account to be addressed in FEI's next revenue requirements application. The actual proceeds of the transactions will be adjusted by the related income tax benefits, calculated at the tax rate applicable to the year that the losses are deducted for income tax purposes."
>
> Directive 3 of Order G-181-11 states: "Expansion of the deferral account to include any incremental revenue on a net of tax basis received from the Tilbury Property for the years 2012 and 2013 over and above what has been forecast in its 2012-2013 Revenue Requirements and Natural Gas Rates Application is approved."
>
> Commission staff has also filed Exhibit A2-6, which is FEI's Compliance Filing in accordance with Order

G-68-10, Directive 7. On page 3 of the Compliance Filing, FEI states:

"The costs to realize the revenue of $1,581,936.62 have been minimal and included some minor repair and operating costs on site prior to tenancy for $5,918.02 and the real estate broker fee of $55,706.66.

All of these revenues have been returned to customers. The original lease amount of $27,853.33 per month was forecast as a reduction to O&M in FEI's 2012-2013 Revenue Requirement Application. The lease amendment which resulted in a further $ $31,746.17 per month of revenue has been included in FEI's Tilbury Property Purchase deferral account pursuant to Commission Order G-181-11. In its Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 to 2018, FEI has proposed to return the balance in this deferral account to customers in 2014." [Emphasis Added]

183.2 In reference to Commission Order G-181-11, please provide all the transactions in the Tilbury Property Purchase (Subdividable Land) deferral account that relate to Directives 2 and 3.

Response:

Please refer to the response to BCUC IR 1.183.1.

183.3 In reference to the Compliance Filing (Exhibit A2-6) and Commission Order G-181-11, please show how the deferral account transactions reconcile with the $164 thousand balance in the deferral account.

Response:

In reference to the Compliance Filing (Exhibit A2-6), the lease revenues are broken up into two categories in that filing – original lease revenues of $947,013 and amended lease additional revenues of $634,923. The amended lease additional revenues are included in the Tilbury Property Purchase (Subdividable Land) deferral as shown in the response to BCUC IR 1.183.1 at $603,177 plus the additional $31,746 to be updated. It is only the additional revenues that FEI included in the deferral account, pursuant to Commission Order G-181-11:

"Expansion of the deferral account to include any incremental rental revenue on a net of tax basis received from the Tilbury Property for the years 2012 and 2013 over and above what has been forecast in its 2012- 2013 Revenue Requirements and Natural Gas Rates Application is approved."

183.4 In reference to the Compliance Filing (Exhibit A2-6), please provide a detailed explanation of the above underlined excerpt: "[a]ll of these revenues have been returned to customers."

Response:

The excerpt in the Compliance Filing was intended to confirm to the Commission that the revenues that were directed to be returned to customers have been returned. In reviewing the transactions in the deferral account, FEI realized that, although the vast majority of the revenues were returned to customers, the statement was not entirely accurate. In fact, all of the amended lease additional revenues (at $31,746 per month) are being returned to customers through the deferral account, and the 2012 and 2013 original lease revenues were also included as a reduction of the approved O&M in FEI's 2012-2013 RRA and returned to customers in that manner. However, since rates for 2011 had already been set when the 2011 original lease revenues were realized, they were not anticipated in setting rates for that year.

183.4.1 Please provide the references from the 2012-2013 Revenue Requirements to show how the original lease amount of $27,853.33 per month was returned to customers. In other words, provide references to show where the amount of $27,853.33 was a reduction to O&M in FEI's 2012-2013 Revenue Requirement Application.

Response:

Within the Facilities O&M Section for the FEU 2012-2013 RRA, page 241 identifies "Facilities is responsible for a wide range of services including:

- Lease Revenue – Facilities acts as the Landlord to tenants at 8 facilities. Lease revenue, similar to lease contracts, have stepped rate increases, renewals and expiries that affect the required operating costs for the various facilities."

Further on page 244, the paragraph below refers to the Tilbury rent received as a reduction to the O&M forecast for 2012/2013.

“Lease revenue increases of $425 thousand including tenant contract stepped rate increase at the Kelowna Regional Office, tenant expiry and removal of one lease at the Kamloops Regional Office, and a new tenant contract at the Tilbury location.”

183.4.2 Please show the total net amount returned to customers in the 2012-2013 test period.

Response:

The total net amount returned to customers in the 2012-2013 test period is as described in Exhibit A2-6. Included in the test period O&M forecasts was a reduction to O&M of $640 thousand representing 23 months of original lease revenue from the tenant at a rate of $27,853 per month.

183.5 In reference to the Compliance Filing (Exhibit A2-6), please indicate how the revenue of $1,581,936.62, less the minor repair and operating costs on site prior to tenancy for $5,918.02 and the real estate broker fee of $55,706.66, coincide with the net forecasted credit balance of $164 thousand at the end of 2013.

Response:

As explained in the responses to BCUC IR 1.183.1 and 1.183.3, of the revenues of $1,581,936 .62 shown in the Compliance Filing, $634,923.40 for the amended lease addition revenue will be recorded in the Tilbury Property Purchase (Subdividable Land) deferral while the remaining $947,013.22 in original lease revenue was included in the actual O&M. The minor repair and operating costs on site prior to tenancy of $5,918.02 and the real estate broker fee of $55,706.66 have also been included in FEI’s O&M costs. Therefore, only the amended lease additional revenue can be used in the reconciliation of the $164 thousand forecasted credit balance of the Tilbury Property Purchase (Subdividable Land) deferral.

183.6 Please confirm that if FEI enters a lease agreement with a third party or if a third party renews the lease agreement for the property north of Tilbury Roard (6939 Tilbury Road), future rental revenues would be captured in Other Revenues as a benefit to ratepayers.

Response:

Future rental revenues would only be to the benefit of ratepayers to the extent that they are forecasted in Other Revenues in the Annual Reviews to this Application. Alternatively, FEI is open to the Commission continuing the use of the Tilbury Property Purchase (Subdividable Land) deferral account to capture any variances from forecasts related to these revenues.

184.0 Reference: FINANCING, TAXES, ACCOUNTING PROLICIES AND DEFERRALS

Exhibit B-1, Application, Tab D, Section 1.1.1, pp. 254-255

Long-Term Debt

"Debt financing costs include the interest expense on issued debt as well as interest expense on new issuances that are forecast. Debt consists of both Long-term Debt and Short-term (Unfunded) Debt."

184.1 Please provide a continuity schedule of FEI's long-term debt with information that includes the total amount outstanding, individual debt issues and corresponding interest rates and maturity dates.

Response:

Please refer to Section E, Schedule 62 of the financial schedules included in the July 16th Evidentiary Update for this Application (Exhibit B-1-3) for a listing of all FEI long-term debt outstanding through 2014. In addition, FEI has included the same schedule for 2018. Please refer to Attachment 184.1.

184.2 Please replicate Table D1-1 using information for the years 2008 to 2014.

Response:

The requested table is provided below.

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
30 YR GOC	4.05%	3.84%	3.77%	3.30%	2.44%	2.75%	3.25%	3.75%	4.00%	4.00%
Indicative Spread	2.10%	2.18%	1.44%	1.46%	1.39%	1.40%	1.40%	1.40%	1.40%	1.40%
New Issue Rate	**6.15%**	**6.02%**	**5.22%**	**4.76%**	**3.83%**	**4.15%**	**4.65%**	**5.15%**	**5.40%**	**5.40%**

Source: Data from 2008 to 2012 – CIBC World Markets

The data for 2008 to 2012 is based on average weekly indicative credits spreads for FEI and the benchmark Government of Canada long bond.

185.0 Reference: FINANCING, TAXES, ACCOUNTING POLICIES AND DEFERRALS

Exhibit B-1, Application, Tab D, Section 4.2.9, p. 297

Rate Base Deferral Account Related to Generic Cost of Capital Stage 1 proceeding

In Stage 1 of the Generic Cost of Capital proceeding, FEI incurred application costs related to legal fees, costs for witnesses and consultants, miscellaneous facilities, stationery and supply costs.

The recovery of the Commission's direct costs was set out in Order G-47-12 and the allocation of PACA costs was determined in Order G-72-12.

FEI is seeking approval for a rate base deferral account to record the forecast costs related to the GCOC Stage 1 proceeding, less the amounts recovered from other affected utilities. FEI proposes to amortize the balance in the account over two years beginning in 2014.

185.1 Does FEI now have the actual (as opposed to forecast) costs related to the GCOC Stage 1 proceeding? If so, please provide the total amount that is related to FEI's share. If not, please provide the latest forecast cost that is related to FEI's share.

Response:

Yes, FEI now has the actual costs as it is not anticipating any further costs related to the GCOC Stage 1 proceeding. The total amount related to FEI's share of the costs is $2.304 million and is all included in the deferral account FEI is seeking approval for.

185.2 Please provide a breakdown of the above total costs into: (a) FEI incurred costs such as legal fees, witnesses and consultants, and miscellaneous facilities, stationery and supplies costs; (b) Commission's direct costs that are recoverable from FEI through its levy; and (c) FEI's share of PACA funding costs.

Response:

The following table addresses BCUC IRs 1.185.2 and 1.185.2.1.

	Total paid by FEI	Chargeouts to Other Participants	FEI portion of charges
Legal costs	$ 590,586	$ -	$ 590,586
Expert witnesses and consultants' fees and expenses	994,522	(173,107)	821,415
Miscellaneous	46,038	-	46,038
Commission's direct costs that are recoverable from FEI through its levy *	500,000	-	500,000
PACA funding costs	477,650	(131,511)	346,139
Total	$ 2,608,797	$ (304,618)	$ 2,304,179

*Amount provided by the BCUC and stated in GCOC Phase 1 Proceeding BCUC IR 1.120.3

185.2.1 For the FEI incurred costs in (a) above, please provide a further breakdown into (a) legal; (b) expert witnesses and consultants' fees and expenses; and (c) miscellaneous.

Response:

Please refer to the response to BCUC IR 1.185.2.

185.2.2 Please provide comparative data of the expert witnesses' and consultants' fees in the GCOC proceeding with the costs incurred in the 2009 ROE proceeding.

Response:

The expert witnesses' and consultants' fees costs from the 2009 ROE proceeding were $377,118 (comparable to the second line provided in the response to BCUC IR 1.185.2).

The 2009 ROE proceeding was brought as a discrete application by the FEU (FEI, FEVI and FEW), and while the resulting decision affected all utilities which have their ROE set off the benchmark, it was not a generic proceeding.

The GCOC Stage 1 proceeding covered a greater number of issues, had more active interveners and participants, involved the filing of much more evidence, resulted in many more information requests which required responses, convened a lengthy oral hearing, and thus resulted in much higher costs for the GCOC Stage 1 proceeding than were incurred in the 2009

ROE proceeding. FEI, the benchmark, was the focus of the greater number of IRs and longer hearing as compared to 2009.

186.0 Reference: ACCOUNTING POLICIES FINANCING, TAXES, ACCOUNTING POLICIES AND DEFERRALS

Exhibit B-1, Application, Tab D, Section 3.5.1, pp. 269-270; 2012-2013 FEU RRA Decision, p. 90

ASSET LOSSSED - DIRECTIVE RE ASSETS NOT IN USE

"As a result, the only reasonable alternative is to continue to keep these assets available for future service until such time as there is no expectation that they will be used in the future. FEI therefore does not believe any action should be taken regarding the assets that are not in use." (Exhibit B-1, pp. 269-70)

186.1 By account (473, 475), please provide a schedule showing the in-service date, the location, the gross plant, accumulated depreciation and net book value of all assets that are not in use.

Response:

The information has been provided in the two tables below, one for Account 473 and one for Account 475.

Inactive Mains (475) ($ thousands)

Region	In Service Date	Cost	Acc Depr	NBV
Lower Mainland East	1960s and prior	1	(1)	-
	1970s	3	(2)	1
	1980s	22	(10)	12
Lower Mainland West	1960s and prior	307	(112)	195
	1970s	53	(24)	29
	1980s	30	(9)	21
	1990s	48	(15)	33
	2000s	17	(1)	16
North Okanagan	1960s and prior	1	(1)	-
East Kootenays	2000s	84	(9)	75
TOTAL		**566**	**(184)**	**382**

Inactive Services (473) ($ thousands)

Region	In Service Date	Cost	Acc Depr	NBV
Lower Mainland East	1960s and prior	176	(75)	101
	1970s	251	(104)	148
	1980s	314	(131)	183
	1990s	688	(262)	426
	2000s	216	(37)	179
	2010's	26	(1)	25
Lower Mainland West	1960s and prior	194	(86)	109
	1970s	386	(164)	222
	1980s	386	(153)	232
	1990s	574	(212)	362
	2000s	285	(43)	242
	2010's	80	(6)	74
Central Okanagan	1960s and prior	123	(31)	91
	1970s	50	(14)	35
	1980s	674	(247)	427
	1990s	778	(234)	544
	2000s	38	(8)	30
	2010's	4	(0)	4
North Okanagan	1960s and prior	84	(41)	42
	1970s	14	(5)	10
	1980s	423	(174)	249
	1990s	331	(119)	212
	2000s	38	(7)	31
	2010's	14	(0)	14
Southern Okanagan	1960s and prior	14	(14)	(0)
	1970s	14	(10)	4
	1980s	349	(211)	138
	1990s	296	(115)	181
	2000s	32	(6)	25
	2010's	11	(1)	10
East Kootenays	1960s and prior	55	(25)	30
	1970s	56	(25)	30
	1980s	233	(106)	127
	1990s	244	(90)	154
	2000s	70	(15)	55
	2010's	4	(0)	4
West Kootenays	1960s and prior	437	(162)	275
	1970s	60	(23)	38
	1980s	200	(69)	131
	1990s	352	(101)	251
	2000s	40	(7)	33
	2010's	102	(4)	98
Thompson	1960s and prior	100	(106)	(6)
	1970s	37	(27)	10
	1980s	948	(555)	392
	1990s	737	(283)	453
	2000s	150	(33)	117
	2010's	31	(2)	29
Northern	1960s and prior	26	(18)	7
	1970s	19	(14)	5
	1980s	670	(396)	275
	1990s	583	(215)	368
	2000s	180	(39)	141
	2010's	1	(0)	1
TOTAL		**12,198**	**(4,827)**	**7,371**

Note - The presented regions include the following locations:

- **Lower Mainland East**: Abbotsford/Matsqui, Chilliwack, Delta, Harrison, Hope, Kent, Langley, Maple Ridge, Mission, Pitt Meadows, Surrey and White Rock.
- **Lower Mainland West**: Anmore, Belcarra, Burnaby, Coquitlam, New Westminster, North Vancouver, Port Moody, Port Coquitlam, Richmond, University Endowment Lands, Vancouver, West Vancouver, and Squamish.
- **Central Okanagan**: Kelowna, Winfield, Peachland and Westbank.
- **North Okanagan**: Vernon, Armstrong, Lumby, Falkland, Coldstream, Spallumcheen, Sorrento, and Revelstoke.
- **Southern Okanagan**: Penticton, Summerland, Okanagan Falls, Naramata, Osoyoos, Oliver, Keremeos, and Princeton.
- **East Kootenays**: Cranbrook, Creston, Kimberley, Sparwood and Fernie.
- **West Kootenays**: Trail, Rossland, Warfield, Fruitvale, Montrose, Castlegar, Nelson, Salmo, Grand Forks, Christina Lake, Greenwood and Midway.
- **Thompson region**: Kamloops, Savona, Chase, Merritt, Logan Lake, 100 Mile House, Lac La Hache, Cache Creek, Ashcroft, Clinton, Salmon Arm, Enderby and Grindrod.
- **Northern Region**: Prince George, Quesnel, Williams Lake, Mackenzie, Chetwynd, Hudson Hope, and Fort Nelson.

> “Therefore, the Panel finds that a reasonable timeframe for the first customer to connect to a main and begin consuming gas is one year after construction of the main extension is completed.
>
> **.Given that no customers have attached to the West Coast Road extension since construction was complete on June 1, 2009, the Commission Panel determines that it is not ‘used and useful.’”** (2012-2013 FEU RRA Decision, p. 90)

186.2 Given that the Commission Panel has found one year to be a reasonable timeframe for the the first customer to connect to a main and begin consuming gas, please explain why assets that are not in use should be included in rate base.

Response:

FEI does not believe that the Commission Panel's ruling that one year is a reasonable timeframe for the first customer to connect to a main and begin consuming gas, applies to the assets not in use, which are being discussed here. For the services and mains assets listed in the response to BCUC IR 1.186.1, FEI believes they meet the definition of "used and useful" and that it is appropriate that they continue to be included in rate base.

The assets listed as not in use consist primarily of services lines that are not being used currently to serve customers but are still connected to the gas system, cathodically protected, and regularly maintained. Unlike the West Coast Road extension situation where no customers were attached and consuming gas, these service lines have had gas flowing through them in the past suggesting a reasonable expectation of potential future use (note that at the time of 2012-2013 RRA Decision was made, there was already a customer consuming gas on West Coast Road. Therefore that asset actually was used and useful even according to the Commission's definition.). While there is no gas flowing currently, these assets are available to have gas flowing through them. Further, in FEI's view, these service lines represent extensions of an overall integrated system to provide a utility service and that it is normal to have varying degrees of system utilization in various locations at different points in time as is the case being discussed here.

Given the above, FEI believes the noted services and mains assets meet the definition of used and useful and should continue to be included in rate base, providing for a return on investment and recovery of the assets costs through depreciation.

187.0 Reference: ACCOUNTING POLICIES FINANCING, TAXES, ACCOUNTING POLICIES AND DEFERRALS

Exhibit B-1, Application, Tab D, Section 3.5.1, p. 269-270; Exhibit A2-7, Exhibit A2-4

MAIN EXTENSIONS

"The Panel is concerned that the FEU may be constructing high cost main extensions without adequate assurance that customers will connect to the extensions. The FEU are reminded that the primary purpose of the extension and connection policies is to promote fair and equitable treatment of customers and, more specifically, to ensure that existing customers are not adversely affected by the addition of a new customer or customers (2007 System Extension Decision, 19)." (2012-2013 FEU RRA Decision, p. 91)

187.1 Please provide the MX test forecast 20-year NPV of each of the five highest cost FEI main extensions in Exhibit A2-7 for the years 2008-2011.

Response:

The "20-year NPV" of each of the five highest cost FEI main extensions are the PI results of the Main Extension Test performed when the customer originally inquired about service. This information is currently provided on pages 26 to 109 of the 2012 MX Report submitted March 28, 2013, included as Attachment 187.1. As can be seen throughout the Report, all the forecast profitability index (PI) values for the main extensions are above the 0.8 threshold in accordance with Order G-52-07.

FEI disagrees with the characterization that it is constructing high cost main extensions without adequate assurance that customers will connect. The Main Extension Test and the associated Tariff pages have been approved by the Commission and the Company abides by the Tariffs and approvals. Using the available information at the time, the Company administers the MX test, and attaches customers that meet the MX Test parameters and the associated tariff pages and policies.

The original MX tests in question, when run, produced positive results, enabling the Company to proceed with construction of the mains in question. The MX Annual Report shows the original test as well as a snap shot in time of where the PI is within the first five years. However, the only time at which the Company, or any other party, can know definitively that a main is profitable is by performing a forensic accounting of the costs and revenues of the main, and all its attachments, at the end of the useful life of the main. Any reporting done prior to that using the MX test, re-run, provides indications of profitability.

Exhibit A2-7, pages 97-103 show that the five highest cost FEI main extensions installed in 2008 and all have a Profitability Index (P.I.) below the minimum P.I. of 0.80 for an individual main extension.

187.2 Should asset impairment be recognized for main extensions with an actual Profitability Index of less than 0.8 five years after the main has been installed (i.e. the 2008 main extensions in 2013)? Please explain why, or why not.

Response:

No, asset impairment should not be recognized for main extensions with an actual Profitability Index of less than 0.8 five years after the main has been installed because the performance of a main extension cannot be properly evaluated until the end of the life of the asset which is after forty to fifty or more years. The assets will remain used and useful over the economic life, providing service to customers. The assets were prudently incurred. As such FEI is entitled to earn a return of and on this capital.

The results included in the 2012 Main Extension Report represent a snap shot in time only and are not definitive with respect to the final impact of a main extension on ratepayers. In fact, due to the 20 year DCF (Discounted Cash Flow) time frame of the Main Extension Test, the re-forecasting methodologies required by BCUC Staff and the variances between forecast and actual consumption values, many results reviewed by the Commission should only be considered to be preliminary in nature. The impacts of these reporting issues are discussed further below.

The current MX Test itself is structured in such a way that it lends itself to being viewed as a short-term measure based on the maximum twenty-year discounted cash flow of all main extension projects. Because the vast majority of the Companies' assets last well beyond twenty years, the MX Test may not accurately portray the final, economic impact of a main extension project on rate payers as it assumes customers simply disappear from the FEU systems at the end of twenty years. In reality, many customers' homes at this time are undergoing renovations or their neighbourhoods are undergoing renewal. A prime example would be the demographic shift in Vancouver's residential neighbourhoods where coach homes are being added in addition to existing single family dwellings. This represents unanticipated additional consumption on a pre-existing main and would translate into an improved PI, well after the twenty year PI calculated in the Companies' current Main Extension Test. Furthermore, many main extensions spawn additional main extensions which are not translated back, or have an effect on, the original system extension (due to the current five year window of forecasting attachments). This additive effect can serve to make original main extensions even more positive than would be shown in current reporting. Therefore the only way to truly asses the viability of a main extension is at the end of the life of the asset. The annual MX reports provided to the Commission thus represent a "snap shot" in time view of a main extension or group of main extensions based on a 20 year DCF time frame and a BCUC requested reporting methodology which does not reflect the final impact of a main extension on ratepayers.

The majority of main extensions included in the 2012 Main Extension Report continue to add customers year after year. However, these actual attachments are, in most cases, misaligned with original forecasts due to the difficulties in determining exactly when a home in a given subdivision will be planned, constructed, sold and the meter activated. These ongoing and potential future customer connections support the notion that the PI at any given time on an existing main is generally representative of that point in time only. When considered in conjunction with re-forecasting methodologies where unrealized attachments are assumed to have disappeared forever (the methodology requested by the BCUC), the PI becomes even less representative of the long-term potential economic impacts on existing customers.

There is a legal perspective on this as well. The prudence test is not applied using the benefit of hindsight. The main extensions have been undertaken in accordance with approved guidelines based on facts known at the time. Even if the PI is less than anticipated, there is no basis to impair the assets as the Company is entitled to recover prudently incurred capital.

187.2.1 If the Commission directed FEI to recognize asset impairment for main extensions with a P.I.<0.8, should the net book value of the main extensions be removed from plant in service and transferred to a non-rate base interest bearing deferral account and amortized over 10 years? Please explain why, or why not.

Response:

The Company does not believe that the Commission should recognize asset impairment for main extensions with a PI < 0.8 for the reasons provided in response to BCUC IR 1.187.2. As such, the existing treatment of main extensions remains the most appropriate and the Commission should not adopt the suggested approach that would result in prudently incurred costs that provide benefits to customers being afforded something other than a rate base return. Recognizing impairment for assets that provide benefits to customers and were prudently incurred would violate the fair return standard, as it would have the effect of precluding FEI from earning a fair return on its prudently invested capital.

"The Companies are expected to use the existing MX Test as established by Order G-152-07 to meet this directive, and since the EES [EES Consulting] Report does not do this, it does not fulfill the requirements of the PI reporting directive; the Commission makes no determination on the EES Report itself at this time." (Appendix 2-4, p. 2)

187.3 Please provide the cost of the EES Report.

Response:

The cost of the EES Report included as Appendix C of the 2012 Main Extension Report was $51,444.84. Please refer to the response to BCUC IR 1.187.1 for a copy of the full Main Extension report.

187.3.1 Given that the EES Report did not fulfill the requirements of the PI reporting directive, should the cost of the report be excluded from recovery in rates? Please explain why, or why not.

Response:

The Company submits that the statement contained within this question is inaccurate. The Company believes that the EES report fulfills the clarification in reporting as requested by BCUC letter L-60-12. The EES Report fulfills the requirements of the PI reporting directive and has been paid for through existing 2013 Approved O&M. Excerpts from the Companies' response to Commission Letter L-32-13 and to the Commission Letter dated July 8, 2013 are provided below for further explanation.

In addition, whether or not the Commission agrees that the EES report meets or does not meet the clarification in Letter L-60-12 to Order G-152-07, the cost was fully incurred in 2013. FEI's rates for 2013 have been set, and the Company's decision to spend dollars during 2013 was within its full discretion as the funds essentially came out of the revenue that would otherwise flow to the shareholder. For the Commission to now inquire about the prudence of this expenditure represents an exercise in retroactive ratemaking, which is precluded by the UCA.

FEU Response to Commission Letter L-32-13 dated June 5, 2013, follows:

The Companies submitted the EES Report to specifically comply with the direction to include "a plan". To provide a plan that addresses the appropriate PI threshold level on a go-forward basis requires the Companies to review the existing MX test and policies as a whole. This is a complex task as the Companies need to consider multiple issues, including the interests of the existing and future customers, the impacts of technology and efficiency, changes to the economic and housing market environments, the tests of other jurisdictions, and intergenerational equity among new and existing customers. As such, the Companies engaged recognized experts in system extension policy (i.e. EES Consulting) to conduct a thorough review, including the PI threshold.

The Companies' "plan" provides more than just a potential adjustment to the low PIs as found by the EES Report, the low PIs are a symptom of larger issues with the Companies' system extension policies. Thus, the EES Report provides a framework for an examination of several components of the Companies' system extension policy, as shown in Appendix C to the 2012 MX Report. Further,

- *The Companies believe that the current reporting practices do not adequately reflect the results of the Companies' system extension portfolio. For instance, as discussed in section 3 of the 2012 MX Report, the PI results reflect a snapshot in time and are not indicative of the overall impact of a main extension on existing ratepayers. The overall impact can only be determined after the useful life of the asset is reached at 40 to 50 years. Therefore, the reported PI for any given year is only a directional indicator, nothing more.*
- *As a directional indicator, the PIs in the 2012 MX Report do show the effect of lower consumption from new customers as compared to existing customers. While only directional at this point, this variance is, in part, driving the desire of the Companies to review their system extension policies.*

The Companies recognize that there seems to be some confusion in the 2012 MX Report in terms of the Companies' view on whether the PI threshold needs to be adjusted on a go-forward basis. This may have prompted the statement in the Letter that "[a] separate process to review the MX Test and MX historical results is required to vary the MX Test methodology and its reporting requirements." ***The Companies believe that the current existing PI threshold of the aggregate main extensions and the minimum PI for individual PIs, should remain until such time as a new system extension and customer connection application is filed by the Companies and approved by the Commission.***

FEU Response to Commission Letter (log No. 43347) dated July 8, 2013 follows:

The Companies respectfully disagree with the Commission's statement that the Companies have not provided a go-forward plan to adjust the aggregate PI threshold as required by Order G-152-07. As stated in the Companies' letter of June 26, 2013, the Companies have submitted a plan to address our system extension policies more broadly. The EES Report provides a framework to review the Companies' system extension policies on a go forward basis, which can include a consideration of the appropriateness of PI threshold levels established. Whether or not the Commission agrees with the plan submitted by the Companies is, in and of itself, not a matter of compliance. Indeed, as the Commission itself has recognized before, the Commission will leave the determination of the merits of the EES Report to another day.

188.0 Reference: ACCOUNTING POLICIES FINANCING, TAXES, ACCOUNTING POLICIES AND DEFERRALS

Exhibit B-1, Application, Tab C, Section 3.1.2, p. 122; Exhibit B-1-1, Appendix F6; BCUC Uniform System of Accounts (USoA) Report, BCUC 1.1, 1.6

BCUC UNIFORM SYSTEM OF ACCOUNTS

188.1 Please provide an electronic copy of the latest FEI code of accounts.

<u>Response:</u>

Please refer to Attachment 188.1 for the latest FEI code of accounts.

In the response to BCUC 1.1 FEI states: "the publication of notices for regulatory applications and proceedings is not recorded as an O&M expense. These costs are instead recorded in the various deferral accounts relevant to the application(s) in question. However, FEU is able to report on how much is spent on these costs through separate tracking within the deferral accounts as requested." (USoA Report, BCUC 1.1)

188.2 For 2007-2013, please provide the annual costs for the cost elements listed below:

63303 Communications, Public Relations
63304 Communications Employees
63401 Advertising Media
63402 Advertising Printed Matter
63403 Miscellaneous Advertising

<u>Response:</u>

Below is a summary of annual costs for the above mentioned cost elements.

Annual Costs for Communications and Advertising ($ thousands)

Cost Element	Description	2007	2008	2009	2010	2011	2012
63303	Communications, Public Relations	1,097	205	146	193	42	44
63304	Communications, Employees	7	26	53	68	19	1
63401	Advertising Media	3,800	3,605	1,273	2,261	2,361	4,324
63402	Advertising Printed Matter	1,472	536	381	491	549	856
63403	Miscellaneous Advertising	264	530	811	1,918	1,968	1,146
Total		6,640	4,902	2,665	4,931	4,939	6,372

Please note that these costs may include O&M, capital, and deferral items. Since the FEU do not have individual settlement accounts at the lowest level, the O&M portion of the above items is not separately available. Please refer to the response to BCUC IR 1.1.8 that was provided in the review of the FEU's filing of the BCUC Uniform System of Accounts (USoA) Report where this is described further.

Increases to advertising costs for years 2010 to 2012 are mainly attributed to increased safety awareness spending and EEC market awareness.

In the 2010-2011 RRA, the FEU requested and received approval for $1 million in safety awareness spending, primarily to increase the public's awareness of how to identify and respond to a gas leak. Additional funding of $750 thousand in 2012 and $850 thousand in 2013 was approved in BCUC Order No. G-44-12 for the 2012-2013 RRA.

In the 2010-2011 RRA, the FEU also requested and received approval for the continuation of the residential and commercial EEC program and new funding for the interruptible industrial programs and innovative technologies.

188.2.1 Please provide the cost for "the publication of notices for regulatory applications and proceedings" for 2007-2013.

Response:

Provided below is a summary of costs for publication of notices for regulatory applications and proceedings from 2007-2013. The costs will vary for each year depending on the number of applications filed, the number of service territories involved, and the publications used as directed by the Commission. In all instances, FEI seeks to minimize the amount of costs while conforming with the Commission's directives.

As noted in the preamble, these costs are generally captured in the specific application cost deferral account. However, they have been included in Account 63401 listed in response to BCUC IR 1.188.2 which includes deferred costs as well as O&M and capital items. In addition, it should be noted that the summary below is for all FEU companies, not just FEI.

Summary of Publication of Notices for Regulatory Applications and Proceedings

Year	Project name	Cost	Total
2007	Fortis Acquisition Regulatory Ad	37,157.26	
2007	Liquefied Natural Gas Storage application	18,575.40	
2007	Fort Nelson service area	975.00	56,707.66
2008	Fort Nelson service area	975.00	
2008	2009 Whistler Revenue Requirements	1,525.96	2,500.96
2009	Lionsgate biogas	1,750.98	
2009	ROE & Capital structure	20,878.73	
2009	Customer Care	20,878.73	
2009	2010/2011 TGI Revenue Requirements	20,878.73	
2009	2010/2011 TGVI revenue requirements	15,303.30	
2009	2010/2011 Whistler Revenue Requirements	1,076.40	80,766.87
2010	Long term resource plan	7,215.00	
2010	Kootenay River Crossing	981.50	
2010	CNG & LNG Service for Vehicles	9,888.00	
2010	2011 Fort Nelson revenue application	529.55	
2010	Victoria office	12,039.30	30,653.35
2011	Mt Hayes Ownership interest	16,251.20	
2011	Price Risk Management plan	14,638.40	
2011	2012/2013 FEU Revenue requirements	22,662.78	
2011	AES inquiry	52,919.52	
2011	Delta School District	2,437.12	108,909.02
2012	Rate Amalgamation	77,435.70	
2012	Tsawwassen Springs	1,320.90	
2012	PCI Marine Gateway	1,649.34	
2012	Alternative Energy Services	2,905.98	83,311.92
2013	2014-2018 FEI Revenue requirements	13,018.60	13,018.60
Total		$375,868.38	$375,868.38

The BCUC Uniform System of Accounts for Distribution Stales and Promotions – Operation includes the accounts listed below.

Account 700 – Supervision
Account 701 – Advertising
Account 702 – Demonstration and Selling Expense
Account 709 – Other Sales Promotion Operation

188.3 Please provide 2010-2013 FEI expenses by year for accounts: 700, 701, 702 and 709.

Response:

FEI is unable to provide expenses by year for the original BCUC Uniform System of Accounts: 700, 701, 702, and 709.

By way of Order G-153-07 the Commission approved FEI's request to depart from using a portion of the Uniform System of Accounts for recording its O&M in Accounts 600 – 999, and to prepare reports using the New Code of Accounts. This applies to the period subsequent to 2006.

Also, by way of BCUC letter of December 3, 2012, Log No. 41494, the FEU were granted permission to adopt an alternative approach (a refreshed view of the New Code of Accounts) to the BCUC Uniform System of Accounts for the next Revenue Requirements Application starting with 2014.

While under the BCUC Uniform System of Accounts, the business segment 'Distribution Sales Promotion – Operations' included Accounts 700 - Supervision, 701 - Advertising, 702 – Demonstration and Selling Expense, and 709 – Other Sales Promotion Operation, under the alternative approach this segment of the business is now referred to as 'Energy Services and External Relations' and includes Accounts 310-11 – Energy Solutions & External Relations Supervision, 310-12 – Energy Solutions, 310-13 – Energy Efficiency, 310-14 – Corporate Communications and External Relations, and 310-15 – Forecasting, Marketing & Business Development. The amounts for these four accounts for the requested years have been provided in Appendix F6 to the Application.

In BCUC 1.6, FEI states: "Customer education encompasses a broad category of activities which is carried out through various mediums and is not a distinct and mutually exclusive activity. For this reason, it cannot be successfully and accurately segregated."

188.4 Given that FEI cannot segregate customer education costs from other activities, please explain how FEI can determine the effectiveness and efficiency of its customer education expenditures.

Response:

While customer education costs are not captured as a separate line item in either the resource or activity view of the current O&M view of reporting, FEI does track the success, effectiveness and efficiency of such activities. Measures and metrics for such efforts will typically differ from event to event, and from activity to activity, as they are contingent on the type of event or action undertaken.

Specific examples of these measures are provided as they relate to corporate safety planning activities in response to BCUC IR 1.141.4 and to the monitoring of conservation education and outreach programs in response to BCUC IR 1.230.1.

189.0 Reference: DEFERRAL ACCOUNTS

Exhibit B-1-1, Appendix F4, p. 1; FEU 2012-2013 RRA, BCUC 1.81.1, p. 231

SCP Mitigation Revenues Variance Account

FEU states in response to BCUC 1.81.1 of the 2012-2013 FEU RRA: "The rationale for the three-year time period selected was to align the amortization period of the SCP Mitigation Revenues Variance Account with other margin related deferral accounts such as the Midstream Cost Reconciliation Account and the Revenue Stabilization Adjustment Mechanism."

189.1 Please explain why FEI is not requesting to adjust the amortization period on the SCP Mitigation Revenues Variance Account to two years, given that FEI has proposed to change the amortization periods on the RSAM and the MCRA to two years in the current Application?

Response:

FEI has not requested an adjustment of the amortization period on the SCP Mitigation Revenues Variance Account because this account was not directly subject to the US GAAP requirement to modify the recovery period, unlike the Midstream Cost Reconciliation Account and the Revenue Stabilization Adjustment Mechanism account. However, if the Commission makes the determination that a two year amortization period to align the SCP Mitigation Revenues Variance Account with the other margin related deferral accounts is appropriate, FEI is not opposed to making this change.

189.2 Does FEI agree that it would be more appropriate and consistent to change the amortization period from three years to two years for the SCP Mitigation Revenues Variance Account? If not, please explain why not.

Response:

Please refer to the response to BCUC IR 1.189.1.

190.0 Reference: FINANCING, TAXES AND ACCOUNTING POLICIES

Exhibit B-1, Application, Tab D, Section 4.2.1, p. 293; Commission Letter L-40-11 dated May 19, 2011

CHANGE IN MCRA AMORTIZATION PERIOD

On page 293 of the Application FEI notes it is "requesting to modify the amortization period for the MCRA to amortize one-half of the cumulative MCRA deferral balance at the end of the year into the next year's midstream rates." FEI notes further that "This change is the result of US GAAP requirements relating to revenue recognition for rate-regulated entities with alternative revenue programs" and that US GAAP defines an alternative revenue program as a program that adjusts "billings for the effects of weather abnormalities or broad external factors …"

Commission Letter L-40-11 dated May 19, 2011 sets out the Guidelines for setting of gas commodity rate and states:

"One-third of the cumulative MCRA deferral balance at the end of each year will be amortized into the next year's midstream rates. This amortization methodology has the net effect of dampening the year-to-year rate change impacts by elongating the amortization period related to any individual year's deficit or surplus and smoothes the annual weather-related MCRA variances. Over a multiyear period the annual weather variations would be expected to offset themselves as the weather will trend to normal over the long run."

190.1 Please describe the manner in which the Midstream Cost Reconciliation Account (MCRA) adjusts rates for the effects of weather abnormalities.

Response:

Under the Essential Services Model, the commodity providers (FEI commodity and unbundling marketers) provide baseload gas and the FEI midstream is responsible for balancing the supply and demand volumes of the FEI gas supply portfolio. Unlike the Commodity Cost Reconciliation Account (CCRA), which is basically only subject to commodity price-related variances on the baseload volume, the MCRA is subject to price-related variances on all of its individual components as well as the volume-related variances between the forecast and the actual consumption for the entire gas supply portfolio. Variations from the normal weather used to develop the forecast are a primary driver of the volume-related variances. Thus, the effects of warmer or colder than normal weather are captured in the MCRA deferral balance.

190.2 Please confirm that the current amortization of the cumulative MCRA deferral balance outstanding at the end of the year is one-third of the cumulative MCRA deferral balance amortized into rates for the next year and that this is recovered through a rate rider (Rate Rider 6 for Rate Schedule 1 Residential Service) for all rate schedules with a Midstream Cost Recovery component.

<u>Response:</u>

Confirmed. To clarify, the MCRA balance is not “amortized” into the cost of service rates as is done with many other deferrals. Rather, the MCRA is recovered from or returned to customers through Rate Rider 6.

190.3 Please confirm that this amortization arrangement was established in Commission Order L-40-11 as the result of a directive from the Commission in the letter accompanying Commission Order G-106-10 for FEI to investigate the possibility of improving the MCRA forecasting capability and the rate setting methodology.

<u>Response:</u>

Confirmed.

190.3.1 Please confirm that the change to a three year amortization period was recommended in order to provide reduced volatility in Midstream Cost Recovery related charges.

<u>Response:</u>

Confirmed.

190.3.1.1 If not confirmed, please explain.

Response:

Please refer to the response to BCUC IR 1.190.3.1.

190.4 Please confirm that the current Rate Rider 6 was set at a credit of $0.082 per gigajoule for Rate Schedule 1 Residential Service customers effective January 1, 2013.

Response:

Confirmed.

190.5 All else equal, please calculate the Rate Rider 6 that would have been effective January 1, 2013 if the proposed change to the amortization had been in effect at that time.

Response:

If the Rate Rider 6 effective January 1, 2013 had been calculated based on a two year amortization period, the Rate Schedule 1 Rate Rider 6 for the Lower Mainland, Inland, and the Columbia service areas would have been a credit amount of $0.123 per gigajoule.

190.6 Does FEI agree that one would expect that the proposed change will result in greater rate volatility in regard to the Midstream Cost Recovery related charges? If not, please explain.

Response:

All else being equal, the proposed change in the amortization period from three years to two years for the cumulative MCRA deferral balance at the end of each year will result in greater rate volatility for Rate Rider 6. However, the change in the amortization period will not affect the setting of the Midstream Cost Recovery Charge component of the overall midstream rates as this component of the midstream rates will continue to be established on a 12-month prospective cost and recovery basis.

For example, the midstream rate effective January 1, 2013 for a Lower Mainland residential customer was $1.192 per gigajoule (comprising two components – a Midstream Cost Recovery Charge of $1.274 per gigajoule and a Rate Rider 6 credit amount of $0.082 per gigajoule). As is evident with this example, the proposed change to the recovery period of Rate Rider 6 only represents a small portion of the overall net midstream costs collected from customers.

BALANCED SCORECARD BENCHMARKING

191.0 Reference: BALANCED SCORECARD BENCHMARKING

Exhibit B-1-1, Appendix C2, Section 4.1, p. 3

Financial Key Performance Indicators

Table C2-1 shows the Financial KPIs of peer companies.

191.1 Has FEI considered adding O&M/ customer, Debt/Equity ratio and EBITDA to its financial KPIs? If not, why not since they are readily available statistics?

Response:

In 2012, the Company revised its scorecard measures. Instead of using 10 measures in the four categories of Financial, Customer, Key Processes and Employee, as was used in 2011 and prior years, the Company moved to four categories of measures; Financial, Safety, Customer and Regulatory with six different measures chosen to assess performance. The different measures reflect the key areas of focus.

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.

Additionally, as the scorecard is an important communication tool to improving organizational alignment, clarity and understanding of a measure, for employees and other stakeholders, is an important consideration. The measure Net Earnings is a readily understood financial metric.

192.0 Reference: BALANCED SCORECARD BENCHMARKING

Exhibit B-1-1, Appendix C2, Section 4.2, p. 4

Customer Key Performance Indicators

Table C2-2 shows the Customer KPIs of peer companies.

192.1 Has FEI considered expanding its Customer survey to include new clients satisfaction rate and industrial clients satisfaction survey? If not, why not?

<u>Response:</u>

Feedback from new customers is already captured in two ongoing studies: the Service Quality Measurement (SQM) and the Customer Satisfaction Tracking Survey (CSTS). A separate survey focused exclusively on new customers would duplicate the research already being undertaken.

FEI's key account managers are in frequent contact with industrial clients and FEI is also in the midst of supplementing this feedback with regular in-depth interviews conducted by a third party research vendor. These various activities are discussed below.

The SQM study is focused on recent customer contact center interactions. SQM completes each survey within 72 hours after a customer has called the contact center. About 1,300 surveys are undertaken each month. "Move-ins" for both new and existing clients is one call type classification that is tracked and evaluated.

The CSTS study evaluates several complex interactions including new service applications (i.e., running a service line and meter to new premises). This survey is typically undertaken after a customer has completed the entire process – from initial request through gasification, so that the Company can monitor, evaluate and adjust procedures if necessary.

As noted, FEI key account managers are regularly in contact with industrial customers, and their feedback is provided to the relevant part of the organization. FEI believes this is the most effective way of obtaining feedback from the relatively small number of industrial customers. A quantitative survey similar to the residential and commercial customer surveys would be difficult to achieve due to the small number of customers in the rate classes.

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.

193.0 Reference: BALANCED SCORECARD BENCHMARKING

Exhibit B-1-1, Appendix C2, Section 4.3, p. 5

Safety Key Performance Indicators

Table C2-3 shows the Safety KPIs of peer companies.

193.1 Has FEI considered expanding its Safety KPIs to include the percentage of planned maintenance completed? If not, why not?

<u>Response:</u>

As outlined in the response to BCUC IR 1.191.1, in determining the scorecard categories and measures to use, the Company seeks not only to select the appropriate success measures but also the optimal number of measures (i.e. how many). At this time, the six scorecard measures used best represent the overall priorities for the Company.

While tracking planned maintenance activities is of value in terms of public safety, we have selected the public safety metric "Public Contacts with Pipelines" as a higher priority metric in this area as it drives improvement from both the Company and the public to reduce the unplanned emergencies (hit lines) that have the most impact on public safety.

Planned maintenance activities have a broad spectrum of maintenance cycles from monthly to quarterly to annual to every fifth year and so on. Tracking the metric on a monthly basis as a public safety KPI may not be an optimal time period given that required completion dates may be exceeded when resources have been allocated to higher priority work such as emergencies. While a month-end date may be missed, over the course of an operating year, planned maintenance dates are met. The true value of this type of metric is therefore at year-end. However, for scorecard measures, the Company needs to have metrics which can be reviewed with employees and stakeholders more frequently.

194.0 Reference: BALANCED SCORECARD BENCHMARKING

Exhibit B-1-1, Appendix C2, Section 4.4, p. 6

Employee Key Performance Indicators

Table C2-4 shows the Employee KPIs of peer companies.

194.1 Has FEI considered expanding its Employee KPIs to include the measures for leadership effectiveness, succession readiness, workforce planning effectiveness, turn over and recruitment? If not, why not?

Response:

FEI has considered expanding its Employee KPIs to include measures such as leadership effectiveness, succession readiness, workforce planning effectiveness, turnover and recruitment. For FEI, turnover is an Employee KPI which is monitored at the departmental level, while internally filled positions are monitored monthly by HR. Additional employee KPI measures may be found on individual scorecards which reflect areas of focus at the department/individual level for M&E staff.

Absenteeism information is monitored by HR and distributed at the departmental level quarterly. Absenteeism is managed at the departmental level, a corporate attendance management program is supported by HR.

After reviewing the measures in place at the departmental level, and also considering the resources that would be required to measure additional Employee KPIs, the decision was made against expanding the KPIs currently being measured.

Refer to the response to COPE IR 1.6.3 for a complete review of FEI's most recent analysis of some of the Employee KPIs noted above.

LONG TERM SUSTAINMENT PLAN (LTSP)

195.0 Reference: LONG TERM SUSTAINMENT PLAN (LTSP)

Exhibit B-1-1, Appendix C3, p. 2

FEI states that: "During the course of the project the team developed a fundamentally different approach towards the concept of "aging infrastructure". In gaining an understanding of asset condition and the impact of age, the team realized that in fact age is not the causal factor which affects the probability of failure. Rather, the probability of failure is determined by the presence of threats such as corrosion or natural forces which act on the pipe. Corrosion is dependent on factors including coating and mitigating measures such as cathodic protection. Steel pipe that is properly coated and has effective cathodic protection has little threat of corrosion and can last virtually forever. 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. Thus an asset's risk is dependent on the presence of threat factors which the project team has identified through literature, experience and expert knowledge."

195.1 How much of FEI's steel pipe is considered to be at significant risk?

<u>Response:</u>

It is challenging to determine precisely how much of FEI's steel pipe is considered to be at significant risk, for a number of reasons. The implementation of the LTSP has enabled FEI to compare the relative risk level of its assets on a consistent basis. It does not provide an absolute measure of probability, consequence and risk. In addition, FEI constantly monitors the condition of its assets through a number of preventative maintenance programs, such as In-Line Inspection and Natural Hazard Mitigation programs, and through those programs any assets that are deemed to be at imminent risk of failure are addressed immediately.

Steel pipelines which FEI considers to be at the highest **relative** risk are the unprotected mains and services in the Lower Mainland region, and the 508mm OD Coquitlam to Vancouver Intermediate Pressure Pipeline. Unprotected mains refer to pipes that cannot be cathodically protected due to very poor coating. A program has been underway since 2012 to replace them. The LTSP has enabled these mains to be easily identified and prioritized. Presently, there is approximately 13.2 km of unprotected steel mains left in the Lower Mainland region. The 508mm OD Coquitlam to Vancouver IP pipeline is approximately 20 km long and will be addressed in a separate CPCN as discussed in Section C4.7.2 of the Application.

As FEI's Asset Management team gathers additional knowledge and feedback regarding its sustainment capital projects and refines its models, FEI may be able to define appropriate risk threshold levels in future iterations of the LTSP. But, presently it is impractical to correlate the relative risk score developed through the LTSP to an absolute measure of risk and then define a level of significance.

195.2 Is PE pipe only at risk for stress related failure such as in Quesnel? Please explain in the context of the table on page 8.

Response:

No, PE pipe is not only at risk for stress related failure. As FEI collects more data and feedback, trends may emerge which may reveal previously unknown issues or failure modes. Other important considerations include installation practices of different eras, operating history and conditions. These considerations are explained in the context of the table on Page 8 of Appendix C3 below:

Corrosion: Corrosion does not occur on PE pipe, and therefore PE pipe is not considered to be at risk of failure under the threat of corrosion.

Equipment Malfunction: PE valves are one example of equipment that is considered to have a risk for the threat of equipment malfunction, although at a lower risk when compared to steel valves.

Material/Joint Failure: Much like welding on steel pipe, the installation techniques/procedures and training for PE fusion have changed over time. Experience has shown that PE fusion that took place during the initial introduction of PE pipe was not as thorough as current practices and has increased risk of failure. Therefore, PE pipe installed in certain eras using fusion methods of the day are considered to have a slightly higher risk of failure.

Excavation/Third Party Damage: Third party activity occurs around PE pipe, increasing the likelihood of the pipe being hit or punctured.

Natural Forces: PE pipe is vulnerable to stress related failures induced by external loads such as ground movement.

Leak History: Regardless of whether a pipe is steel or PE, an increasing number of leaks experienced on a particular segment of pipe correlates to an increased likelihood of additional leaks occurring on that same segment.

Loss of Supply: When debris is in the system, it tends to accumulate in certain areas, depending more on factors such as direction of flow and pipe pressure rather than pipe material. Therefore PE pipe is considered to be at risk of failure under the threat of Loss of Supply.

195.3 Has FEI considered extending its average life depreciation rates for both steel and PE pipe? If not, why not?

<u>Response:</u>

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."*

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.

196.0 Reference: LTSP

Exhibit B-1-1, Appendix C3, p. 9

FEI provides a table of Consequences of Failure.

196.1 How does FEI rate the consequences of failure between the categories identified? For example how is a "difficulty of repair" evaluated against "Public Safety"?

<u>Response:</u>

In estimating the consequence of failure for a particular asset, FEI developed a score for each of the categorized consequence factors (Financial, Public Safety, Difficulty of Repair, Security of Supply, Regulatory Intervention) and then applied a weighted average to then estimate an overall consequence of failure. The consequences of failure and the relative weightings for each of those consequences were defined through consensus by the project team, based on their collective experience, knowledge and limited reference material, and were developed to support the FEI vision of providing safe, reliable, economically efficient energy to its customers. The weightings applied to each consequence factor are listed below:

- Financial 10%
- Public Safety 40%
- Difficulty of Repair 15%
- Security of Supply 30%
- Regulatory Intervention 5%

197.0 Reference: LTSP

Exhibit B-1-1, Appendix C3, p. 13

FEI states that: "The reality is that a significant proportion of the FEU's assets, due to the technology and practices used in the era of installation, do possess characteristics which have been demonstrated through experience to be a concern so replacement may be more reasonable than repairs and mitigation."

197.1 Please further explain this statement and define what constitutes a "significant proportion"?

<u>Response:</u>

In developing an understanding of asset condition and the impact of age on infrastructure, the LTSP project team developed a different approach towards the concept of "aging infrastructure". Instead of replacing assets on the basis of age alone, the project team identified the underlying threats which directly result in a failure. The technology and practices used to install a pipeline determines the threat factors that the pipe is vulnerable to and the potential mitigating actions that are possible. The term "significant proportion" refers to the approximately 27% (6000 km) of FEI's distribution mains which are over 40 years old (please see Exhibit B-1, Section C4, Figure C4-2) and which were installed in eras in which the technology and practices used have proven to be problematic.

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.

Pipe coatings such as coal tar from even earlier eras have not been identified as problematic. However, other considerations would include the welding processes used during the era or the level of cathodic protection available prior to 1970. Due to the technology and materials available at the time of install, these assets possess characteristics that lead to a higher relative risk score than assets installed with newer technology and materials. Thus more assets from earlier eras will have a high relative risk score and the nature of the underlying concerns may support replacement. Given that these assets represent over a quarter of its distribution system, FEI is of the view that this constitutes a significant portion of its assets.

198.0 Reference: LTSP

Exhibit B-1-1, Appendix C3, pp. 2, 13

FEI states that: "Steel pipe that is properly coated and has effective cathodic protection has little threat of corrosion and can last virtually forever. 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."

FEI states that: "FEI has challenges in obtaining resources to execute an increased level of sustainment capital in 2014. Therefore, for 2014 FEI forecasts maintaining the same level of sustainment capital expenditure as in 2013. For 2015-2018, FEI is forecasting to gradually increase sustainment capital by an average of $1 million per year starting in 2015 to a total of $82.3 million in 2018."

198.1 Wouldn't the level of sustainment capital be declining into the future now that much data has been collected and the risks assessed (i.e. given that the life expectancies of properly coated steel pipe and PE? Please explain.

Response:

The purpose of the LTSP was to assist FEI in identifying and prioritizing capital work over the long term on the basis of asset condition and attributes, enabling FEI to become more proactive and cost-effective in mitigating risk – as opposed to replacing assets reactively or based on age alone. The LTSP does not suggest that the amount of sustainment capital work should be reduced. Although FEI has determined that properly coated and protected steel pipe has an extended life expectancy, FEI has also determined certain types of materials and installation practices used in certain eras to be a concern. These concerns, after further analysis, led to the development of the proposed sustainment capital expenditures that are required to address issues identified by the LTSP and to avoid even more costly repairs in the future.

Please note that FEI's proposed capital expenditures are only sufficient to replace a relatively small fraction of FEI's total assets. FEI is responsible for gas transmission and distribution assets with a rate base value of approximately $2.6 billion and an approximate replacement value of $6.1 billion. Over a quarter of FEI's assets are over 40 years old, installed before the advent of cathodic protection systems. Some of these assets were installed with materials and practices which are now known to be a concern, such as increased susceptibility to corrosion. Given the higher costs and more stringent requirements to install new assets, FEI's proposed level of Sustainment Capital is relatively low and is far less than replacing assets reactively or on the basis of asset age alone.

199.0 Reference: LTSP

Exhibit B-1-1, Appendix C3, p. 15

FEI states that: "This is the first iteration of the entire risk assessment process and FEI expects that all elements of the LTSP will continue to evolve and improve as more experience and knowledge is gained. For example, a number of additional *Threat* and *Consequence* factors were identified during the development process, but were ultimately deferred due to incomplete or missing data, or time constraints. One such Threat Factor would be to use slope grade as a proxy for possible landslide hazards."

199.1 Please list the additional threat and consequence factors that were identified for future consideration.

Response:

FEI is currently considering three additional threat and consequence factors for potential inclusion in future iterations of the risk assessment process:

- Slope Grade (threat),
- Environmental Impact (consequence),
- Customer Retention (consequence).

As stated in Exhibit B-1-1, Appendix C3, p. 15, slope grade is being considered as a proxy to gauge the potential threat of landslide hazards. FEI is also considering a factor which provides a measure to enable a comparison of the different environmental impacts across the province that could result from a failure. 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.

Although the above three factors are those under consideration for potential inclusion in future iterations of the risk assessment process, FEI intends to review all elements of the LTSP and as more experience and knowledge is gained, revisions and/or additions will be made to ensure the LTSP continues to evolve and improve over time.

NATURAL GAS FOR TRANSPORTATION

200.0 Reference: NATURAL GAS FOR TRANSPORTATION

Exhibit B-1, Application, Tab A, p.7; Exhibit B-1-1, Appendix H, p. 17; Commission Order C-6-12

NATURAL GAS FOR TRANSPORTATION – BFI COSTS AND RECOVERIES

On page 7 of the Application, FEI lists the "BFI Costs and Recoveries" Deferral Account as an account FEI is seeking approval to discontinue.

On page 17 of Appendix H of the Application, FEI states:

"In accordance with Commission Orders C-6-12 and G-150-12, FEI is to include all other amounts paid by BFI for volumes in excess of the 'take or pay' commitment in a new rate base deferral account separate from the deferral account approved in the Waste Management Decision. The deferral account is to capture incremental CNG Service recoveries received from actual volumes purchased in excess of minimum take or pay commitments, with the disposition to be determined at a future date.

BFI is in a class of service for which natural gas ratepayers are not accountable. BFI has a station refuelling rate contracted for seven years. Therefore, it is no longer necessary to accumulate a deficiency or surplus in this deferral since all deficiencies or surpluses related to BFI will be accounted for in the Non-GGRR CNG Class of Service and be to the account of the shareholder and not FEI's traditional natural gas ratepayers."[Emphasis Added]

In Commission Order C-6-12 FEI was directed as follows:

> "d. FEI is to establish a rate base deferral account to capture the revenues associated with volumes in excess of BFI's "take or pay" commitment which may be credited back to BFI in the event that BFI is required to pay the un-depreciated capital cost of the fuelling station (i.e. amounts collected in excess of the "take or pay" commitment representing one half of the applicable capital rate).
>
> e. FEI is to include all other amounts paid by BFI for volumes in excess of the "take or pay" commitment in the existing rate base deferral account approved in the Waste Management Decision to capture incremental CNG and LNG Service recoveries received from actual volumes purchased in excess of minimum take or pay commitments, for refund to all non by-pass customers."

200.1 Please confirm that prior to Order G-150-12, Order C-6-12 required FEI to establish two deferral accounts for the capture of excess revenue associated with volumes in excess of BFI's "take-or-pay" commitment rather than one deferral account.

Response:

Not confirmed. Refer to the response to BCUC IR1.200.2.

200.2 Please confirm that the deferral account referred to as "BFI Costs and Recoveries" which FEI is seeking Commission approval to discontinue includes excess revenue from both the deferral accounts that FEI was directed to set up under Commission Order C-6-12. If not confirmed, please clarify.

Response:

Confirmed.

Commission Order C-6-12 and Decision ordered FEI to create two new deferral accounts[16]. One account to capture 2012 and 2013 costs and recoveries up to the minimum take or pay volume and one to capture the Capital component of recoveries in excess of minimum. The Order also directed FEI to use one existing deferral account[17] to capture the O&M component in the existing CNG and LNG Recoveries account approved in Order G-128-11.

1. "FEI establish a rate base deferral account for all revenues from the BFI Project excluding revenues in excess of the "take or pay" commitment;[18]

2. "FEI establish a rate base deferral account for all costs for the BFI Project.[19]"

3. "FEI is to establish a rate base deferral account to capture the revenues associated with volumes in excess of BFI's "take or pay" commitment which may be credited back to BFI in the event that BFI is required to pay the un-depreciated capital cost of the fuelling

[16] Directive 5(d) and 6
[17] Directive 5(e)
[18] Order C-6-12, Directive 6(a)
[19] Order C-6-12, Directive 6(b)

station (i.e. amounts collected in excess of the “take or pay” commitment representing one half of the applicable capital rate).[20]”

Subsequently, pursuant to Order G-150-12 the Commission determined that “Given the creation of a separate class of service for CNG, on an interim basis pending the outcome of the AES Inquiry, the Panel varies Order 5(e) to state: “FEI is to include all other amounts paid by BFI for volumes in excess of the 'take or pay' commitment in a **separate rate base deferral account from the one approved in the Waste Management Decision** to capture incremental CNG Service recoveries received from actual volumes purchased in excess of minimum take or pay commitments. Disposition of this deferral account will be determined at a future date.””[21] [Emphasis added].

FEI interpreted the G-150-12 determination to mean that FEI was to capture all revenues in excess of minimum (Capital and O&M components) in the rate base deferral account ordered in C-6-12, directive 5(d) [item 3 above]. In addition to this interpretation, and pursuant to the Commission’s directive to account for BFI in a separate class of service, FEI believed it was logical to account for the BFI costs and minimum recoveries [items 1 and 2 above] within the same deferral account since the Commission had afforded all of the BFI deferrals the same treatment – rate base with an undetermined disposition. Consequently, all BFI deferrals are being accounted for in the “BFI Costs and Recoveries” account.

Given that BFI is in a separate class of service, that all customers within this class of service have contracted station rates lasting at least seven years, and that deferrals within this class of service cannot be collected from these customers due to their contracted rates, FEI has proposed to discontinue the use of the BFI Costs and Recoveries account settling the balance to the Non-GGRR CNG Class of Service. If BFI were to not renew their contract, FEI will still be able to calculate excess capital recovery as a credit against the net book value of the station assets.

200.3 Please confirm that the deferral account FEI was directed to establish under item “d.” of Order G-6-12 was separate from the deferral account to be established under item “e.” of Order C-6-12 due to the contractual provision that FEI would be required to repay this excess revenue to BFI in the event BFI

[20] Order C-6-12, Directive 5(d)
[21] Appendix A to Order G-150-12 Page 9 of 9

elected to buy the refueling facility rather than renew the Fueling Station License and Use Agreement.

Response:

It is confirmed that these two amounts were ordered to be held in two separate deferral accounts. Additionally, please refer to the responses to BCUC IR 1.200.1 and 1.200.2.

200.4 Please provide the projected balance in the BFI Costs and Recoveries deferral account at December 31, 2013.

Response:

The projected balance of the BFI Costs and Recoveries deferral on December 31, 2013 is a debit $41,033. The projection includes a credit amount related to item "d" of Order C-6-12 of $25,886 and a credit amount related to item "e" of Order C-6-12 of $17,988.

200.4.1 Please provide the allocation of this projected deferral account balance between the two categories of excess volume revenue as described in item "d" and item "e" of Order C-6-12.

Response:

Please refer to the response to BCUC IR 1.200.4.

200.5 Please confirm that, In the event BFI chooses to not renew the Fueling Station License and Use Agreement, the excess revenue referred to in item "d" of Order C-6-12 to be credited back to BFI will be paid for by the shareholder.

Response:

The excess revenue referred to in item "d" of Order C-6-12 will be credited against the termination payment owed to FEI from BFI. As it is expected that the termination payment will exceed the amount of excess revenue collected, no cash disbursement to BFI from FEI will be required. In the unlikely event that the excess revenues do exceed the termination payment and BFI's resulting termination payment is calculated to be zero, BFI will not be required to pay a termination fee to FEI and no cash disbursement from FEI to BFI will be made. FEI will redeploy or write-off the station assets with the loss accounted for in the Non-GGRR CNG Class of Service.

201.0 Reference: NATURAL GAS TRANSPORTATION

Exhibit B-1-1, Appendix H, 16; Order G-118-11, Appendix A, Page 5 of 8; Application for Approval to Amend Rate Schedule 16 on a Permanent Basis, Reply Argument, pp. 2-3

NATURAL GAS FOR TRANSPORTATION-Classes of Service

"Pursuant to the BFI Decision and the AES Inquiry Report, FEI is accounting for its existing CNG and LNG stations in the Non-GGRR CNG and LNG classes of service. FEI was directed to account for BFI in this manner and **although not directed to**, FEI believes that it is appropriate to account for its other Non-GGRR stations in the spirit of both the BFI Decision and AES Inquiry Report." Underlined for emphasis. (Exhibit B-1-1, Appendix H, p. 16)

201.1 Please confirm that FEI is seeking approval to include the stations listed below in the Non-proposed Non-GGRR CNG and LNG classes of service. If yes, please update the Approvals Sought.

Proposed Non-GGRR CNG and LNG classes of service stations

Name	Filing Date	Order	Approval /Issuing Date
Waste Management	December 1, 2010	G-128-11	July 19, 2011
Surrey Operations CNG Pump	July 8, 2011	G-165-11A	September 26, 2011
Burnaby Operations CNG Pump			
BFI CNG Station	February 29, 2012	C-6-12	April 30, 2012
Vedder Transport LNG Station **interim basis**	July 13, 2012	C-11-12	October 5, 2012
AES Report	May 24, 2011	G-201-12	December 27, 2012

(Exhibit B-1-1, Appendix H, p. 16)

Response:

Not Confirmed. FEI is proposing to include in the Non-GGRR CNG and LNG classes of service the stations listed in the following table and will update the Approvals Sought accordingly.

Station	Class of Service
Waste Management CNG Station	Non-GGRR CNG
BFI CNG Station	Non-GGRR CNG
Surrey Operations CNG Pump	Non-GGRR CNG
Burnaby Operations CNG Pump	Non-GGRR CNG
Vedder Transport LNG Station	Non-GGRR LNG

201.2 When did FEI receive Commission approval to provide service from the Burnaby Operations CNG Pump?

Response:

FEI has not received Commission approval to provide public fueling service from the Burnaby Operations CNG Pump nor is FEI providing public fueling service from the Burnaby Operation's CNG Pump at this time. This pump is used solely to fuel FEI's own fleet vehicles and is presently not configured to provide fueling services to the general public.

However, if in the future, FEI is able to make the Burnaby Operation's CNG pump available to the public, FEI will apply for rate and fueling services approval with the Commission at that time.

201.3 Given that the permanent rates for the Vedder Transport LNG Station have not been established, please explain why it is appropriate to include the Vedder Station in the Non-GGRR CNG and LNG class of service?

Response:

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. Given the Commission's recommendations, FEI believes that this treatment at this time is the most clear and simple method to account for these stations as it enables FEI to account for similar stations in the same fashion. Whether all stations are in the natural gas class of service or segregated into separate classes, FEI believes that similar stations should be treated in a similar fashion.

By including the Vedder Station in the Non-GGRR LNG class of service, regardless of whether the permanent rates have been established or not, FEI is providing transparency that the station's cost of service is excluded from FEI's traditional rate payer's revenue requirement.

201.4 Please provide the incremental CNG and LNG recoveries received from actual volumes purchased in excess of minimum contract take or pay commitments to be refunded to all non-bypass customers by year and station for 2011-2013. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

Please refer to Attachment 201.4 for the fully functioning electronic spreadsheet.

201.5 Please provide the incremental CNG and LNG recoveries received from actual volumes purchased in excess of minimum contract take or pay commitments to be refunded to all non-bypass customers by year and station for 204-2018, if the Commission approves/does not approves the inclusion of the existing CNG and LNG stations in the Non-GGRR CNG and LNG classes of service. Include the requested information in the form of a fully functioning electronic spreadsheet.

Response:

FEI is unable to accurately predict future consumption in excess of contract volume for existing CNG and LNG customers as their consumption is dependent on factors in the customer's control. As such, FEI does not forecast consumption of CNG and LNG greater than contracted demand. This forecasting method is consistent with FEI's Industrial customer classes where FEI forecasts exclusively either the contracted demand (firm) or the demand from each customer as indicated in their survey responses. However, as stated in the response to BCUC IR 1.201.4, BFI, Waste Management, and Vedder have all consistently consumed more than their minimum take-or-pay quantities. If this continues in the future, there will be excess revenues from these three customers.

The excess revenues will flow back to all non-bypass customers if the Commission does not approve the inclusion of the existing CNG and LNG stations in the non-GGR CNG and LNG classes of service.

If the Commission does approve the inclusion of the existing CNG and LNG stations in the non-GGRR classes of service then the excess station revenues will remain in the non-GGRR classes of service and not flow back to non-bypass customers.

> **"The Panel sees the outcome of this proceeding as being applied in a forward looking manner and not impinging on past or current ongoing proceedings."** (Order G-118-11, Appendix A, p. 5)
>
> "5. Ferus LNG ignores the distinction between directives and recommendations in the AES Inquiry Report. The structure of the AES Inquiry Report and, in particular, Appendix "H", makes a clear distinction between "directives" and "recommendations". If recommendations were meant to be binding directives, then they would not have been distinguished in this manner." (Application for Approval to Amend Rate Schedule 16 on a Permanent Basis, Reply Argument, pp. 2-3)

201.6 The FEI proposal to include for its existing CNG and LNG stations in the Non-GGRR CNG and LNG class of service appears to be inconsistent with the Panel's statement in Order G-118-11, Appendix A, Page 5 of 8 and FEI's statement in its Rate 16 Reply Argument. Please explain.

Response:

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.

THERMAL ENERGY/FORTISBC ALTERNATIVE ENERGY SERVICES (FAES)

202.0 Reference: THERMAL ENERGY

Exhibit B-1, Application, Tab C, Section 3, pp. 121-202

Thermal Energy Services – O&M

202.1 Please describe in detail how employees in each of the O&M departments track their time related to TES. Does it continue to be based on Internal Order numbers and time sheets for employees and general allocation or estimation for senior management and board functions?

Response:

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.

202.2 In the FEU 2012-2013 Revenue Requirements and Rate proceeding, the FEU indicated that the FEU's policy under which employee's track their time related to TES was communicated verbally to employees and that no written policy exists. Please confirm whether this is still the case or whether there is a written policy. If a written policy exists, please provide that policy. (Transcript Volume 3, pp. 392-3)

Response:

On an annual basis (for 2012 and 2013), the FEU reminds all employees via an announcement on "pipeline", the company's intraweb, about compliance with its Code of Conduct and Transfer Pricing Policy. While this is not a written policy, it reminds all employees about the Transfer Pricing and Code of Conduct Policy and has a link to both of these policies. The written policy is the existing Transfer Pricing and Code of Conduct Policy and on an annual basis, employees are reminded about the policy.

202.3 Please show a detailed account of all costs that all of the O&M departments incurred for TES-related activities in 2012 and 2013.

Response:

The following table shows the total labour costs by O&M department (in thousands of dollars) charged to the TESDA in 2012 and to June 2013. Some of the charges below are included in capital projects that have been approved as CPCNs rather than general business development costs.

Labour 2012 to June 2013			
Sum of $ (000)		**Year**	
O&M Department	**Description**	**2012**	**June Ytd 2013**
Business Development	Bus Development/AES	1,421.8	408.4
Energy Solutions	Commercial & Industrial Sales	0.3	0.0
	Interior Sales	15.3	10.9
	Residential Sales	53.8	8.7
	Customer Management	0.0	0.3
	Community Energy Sales	124.3	6.8
	FEVI Sales	0.2	0.0
ES&ER-EEC	Energy Efficiency	0.0	0.9
ES&ER-Bus Dev	Business Development	138.9	73.5
ES&ER-Comm	Communications	0.1	0.0
ER&RD	Gas Control	1.1	0.0
Fac Ops Supp-Supply	Manufacturing Serv Mgr	0.1	0.1
	Procurement	0.4	0.0
HR-Recruiting	Relief Pool	0.1	0.0
Inc-Legal	Inc Legal	11.8	4.1
Ops & Eng	Garp Proj	0.0	0.8
Trans-FEVI	Transmission-VI (Pipeline,Right of Way, Measurement)	0.2	0.0
Grand Total		**1,768.2**	**514.6**

203.0 Reference: THERMAL ENERGY

Exhibit B-1, Application, Tab C, Section 3.6.1, p. 153

Thermal Energy Services – Cost Allocation

The FEU state: "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)."

203.1 When were the costs related to TES (AES) customers and associated activities moved to FAES?

Response:

The FEI non rate base deferral account related to thermal energy services (TESDA) has been in place since 2010. Amounts are allocated to FAES from the TESDA, and as projects are approved, the related capital costs are moved to FAES. Any further disposition of the TESDA balance will be dealt with as part of the TESDA Application to be filed in 2014, after the updates to the Code of Conduct and Transfer Pricing are completed.

203.2 Please explain how costs related to serving TES customers are captured in FAES when the FEU is requesting a deferral account to ensure natural gas ratepayers are held whole.

Response:

FAES is a separate legal entity where the assets for TES customers are captured and put into service. Currently FAES utilized certain FEI staff to assist with the development and operation of these assets. Those employees' time is either directly charged to FAES or is captured in the TESDA for subsequent allocation to FAES. As part of the AES Inquiry, FEI was directed to undertake a review of its Transfer Pricing Policy and Code of Conduct. In a recent discussion with Commission staff in July 2013, it was agreed to commence work on the TPP/COC this fall and target Q1/Q2 of 2014 for FEU to file a proposed Transfer Pricing Policy and Code of Conduct update for review and approval by the Commission. If any variances arise as a result of this review they would be captured in this deferral account. 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.

203.3 Please provide the financial statements for FAES to corroborate the statement that costs related to serving TES customers and associated activities "are not included here".

Response:

FAES' first regulated project (Delta School District) for FAES went into service part way through 2013. The AES Inquiry decision was released in last December 2012 and FEI had accumulated the costs for the Delta School District in the TESDA pending the release of the AES Inquiry decision. So as of December 31, 2012, none of the costs related to serving TES customers were transferred to FAES but rather these costs were captured in the TESDA. The TESDA account was set up to capture costs related to TES customers and the costs associated with TESDA are not included in this Application, which is for FEI gas customers.

203.4 Please provide a table showing FAES' number of employees, FTEs and headcount for each of 2012 and 2013.

Response:

FAES did not have any direct employees in 2012 and 2013 so it has zero FTEs and headcount for each of these years.

203.4.1 In the 2012-2013 FEU Revenue Requirement and Rates proceeding the FEU confirmed that there were between 12 and 14 individuals working in the TES area (Transcript Volume 3, p. 385). Were all these individuals moved to FAES? If so, when? If not, what are the position(s) of those employees remaining in FEI?

Response:

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.

203.5 Please specify the services FAES obtains from the FEU and show a detailed cost accounting for each of these costs since the date TES costs were moved to FAES.

Response:

FEI employees charge thermal energy customers in two ways. First, as outlined in the response to BCUC IR 1.202.1, FEI employees charge time to TESDA via timesheets for those employees who are directly involved in the TES business. Additionally, FEI natural gas customers recover an overhead charge from TES customers via a charge of approximately $854 thousand which includes the components for facilities and other overheads typically charged via the Transfer Pricing Policy. Lastly, a number of the projects that are in service, like the Delta School District, have had amounts charged to both their capital and operations and maintenance expense in FAES. The costs charged to the TESDA have been provided in response to BCUC IR 1.172.4.

In terms of a more detailed cost accounting of how and what costs in the TESDA are recovered from FAES' TES customers, the information is not relevant to this Application as it doesn't affect FEI's rates in any way. FAES can provide more details in the TESDA Recovery application.

203.5.1 Please provide the policy (i.e. Code of Conduct, Transfer Pricing) under which FAES purchases Shared Services from FEI.

Response:

Please refer to Attachment 203.5.1 for the current Code of Conduct and Transfer Pricing policies.

203.6 Does the FEU believe it is complying with Directive 25 of Order G-44-12 by capturing the costs related to TES in FAES?

Response:

Yes. Please refer to the response to BCUC IR 1.205.1.

204.0 Reference: THERMAL ENERGY

Exhibit B-1, Application, Tab C, Section 3.6.1, p. 153

Energy Solutions and External Relations

The FEU state: "The Energy Solutions team works closely with potential and existing industrial, commercial and residential natural gas customers (including builders, developers, large and small businesses, homeowners, municipalities, school districts and other government organizations), to find the right energy solution to meet their energy needs. The group is responsible for managing key customer accounts, developing and implementing activities to add new customers and natural gas load, identifying and assisting in developing service enhancements for existing customers, and communicating with customers regarding service options and available programs, including participation in EEC programs."

204.1 Please describe the Energy Solutions Department's role in promoting TES.

Response:

The Commission issued the AES Report on December 27, 2012 which recommended that TES Projects are most appropriately undertaken through an Affiliated Regulated Business. Since that time, the FEU have undertaken to achieve greater separation between FEI and FAES.

At a practical level this means 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. The FEU expect to transfer these staff out of FEI starting in January 1, 2014 in order to achieve greater separation. FEI prefers to move employees into the affiliated company at the start of each fiscal year as it avoids negative tax consequences to both the Company and employee.

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.

204.2 Of the current or planned TES projects being under taken by FAES (i.e. SOLO), please specify for which projects the initial customer contact was undertaken by the Energy Solutions and External Relations Department.

Response:

Please refer to the response to BCUC IR 1.204.1.

204.2.1 How were these projects or project leads transferred to FAES?

Response:

Please refer to the response to BCUC IR 1.204.1.

204.2.2 How are project leads in general transferred from the Energy Solutions and External Relations department to FAES?

Response:

Please refer to the response to BCUC IR 1.204.1.

204.3 Please provide the FAES capital additions by year and project from 2012-2013.

Response:

Please refer to the response to BCUC IR 1.172.4.

205.0 Reference: THERMAL ENERGY

Exhibit B-1, Application, Tab D, Section 3.6, pp.276-278, p. 293; Exhibit B-1-1, Appendix C-1, p. 1

Thermal Energy Services – Order G-44-12, Directive 25

Directive 25 of Order G-44-12 – FEU 2012-2013 Revenue Requirement and Rates Decision states, in part: “Further, the Commission Panel directs the FEU to break activities of the FEU entities into two, distinct parts:

- Those of traditional gas operations, and
- Those of TES offerings so that costs attributable to each entity of the FEU can be clearly broken down by their TES component.”

FEU state on page 278: “As a result of these other ongoing processes [TESDA and Code of Conduct/Transfer Pricing Policy], 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. However, FEI has confirmed through its work on the shared and corporate service models that using the Massachusetts Formula for allocating corporate services costs to the TES offerings results in a much lower cost allocation (i.e. less than $100 thousand per year) than the placeholder that has been included. The Massachusetts Formula has been employed for the traditional natural gas business to allocate corporate services costs (i.e. it is approved currently for use in allocating FHI corporate services costs to the FEU). The Massachusetts Formula is extensively used in industry and is composed of the arithmetical average of (1) operating revenue, (2) payroll, and (3) average net book value of capital assets plus inventories. The use of these factors represents the total activity of all business segments as a means to allocate costs that cannot be directly assigned.”

FEU state on pages 292-293: “This account will capture the difference between the currently forecasted amount of overheads recovered by FEI from thermal energy customers and any changes to the allocation that may result from the TESDA Report and the Transfer Pricing Policy/Code of Conduct review requested in the AES Inquiry to be undertaken with the Commission later in 2013. The amount of O&M currently forecasted to be recovered from thermal energy customers in the 2013 O&M Base is $854 thousand, as approved by Commission Order

G-44-12. This amount will be inflated by the O&M formula for the PBR Period. FEI will address the disposition of any amounts recorded in this deferral account [TESDA Overhead Allocation Variance] in its first Annual Review to be held in 2014.”

205.1 Please comply with Directive 25 of Order G-44-12 and provide financial schedules to show the activities of the FEU entities broken down into: i) traditional gas operations; and ii) TES.

Response:

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. The final resolution of the amount to be allocated between traditional gas operations and TES activities will result from the Transfer Pricing Policy and Code of Conduct review and FEI has proposed a deferral account so that amounts are appropriately allocated as between TES and traditional gas operations over the term of the PBR.

205.2 Please provide financial statements for FEI showing complete removal of all TES operational costs.

Response:

The FEI annual December 31, 2012 consolidated financial statements “Note 8 Regulatory Assets and Liabilities” highlight alternative energy project balances, which include the TESDA deferral account. The FEI income statement operation and maintenance expenses do not include FAES operational costs.

205.2.1 On a summary line basis, what would be the reduction in costs and resulting reduction in rate impact if all costs (operational and other) related to TES were removed from the FEU?

Response:

FEI considers that all costs related to TES are recovered by being charged to the TES business, for recovery from TES customers and removing the net costs would not impact the rates at all.

However, if the amount of the allocation to the TESDA is changed, the revenue requirement could vary as this difference would be captured in the TESDA Variance Deferral account. The amount of variance may not be large enough to affect the delivery rates.

205.3 Please confirm whether the FEU is proposing to allocate corporate and shared services for TES offerings to the requested TESDA Overhead Allocation Variance deferral account or the TESDA.

Response:

Under FEI's proposal, the delivery rates for 2014 through 2018 will be set using a credit/recovery of $854 thousand as the base for the amounts included in the PBR O&M formula.

FEI will charge the TESDA with the amount of overhead allocation that results from the TPP/COC review. The difference between this amount and the formula-driven O&M calculation amount will be credited to the TESDA Overhead Allocation Variance deferral account.

Natural gas ratepayers will therefore receive credit for the formula-driven O&M recovery amount through the O&M and an adjustment to that amount through the amortization of the TESDA Overhead Allocation deferral account.

TES customers will receive their share of the costs in the TESDA that reflect the revised TPP/COC.

205.4 Please quantify the amount the FEU is expecting to allocate to the requested TESDA Overhead Allocation Variance deferral account for each of 2014-2018.

Response:

FEI is unable to forecast how much the variance account might be. FEI has requested the variance account in order to allow for the update of the Code of Conduct and Transfer Pricing Policy to occur as directed by the AES Inquiry and to capture any variance as an outcome of this review in the variance account. By setting up the variance account, both the natural gas customers and thermal energy customers are kept whole.

205.4.1 On what basis would the FEU allocate costs to the requested deferral account for TES? The Massachusetts Formula? If not, what is the placeholder amount based on?

Response:

The placeholder amount is based on the amount charged that was approved in BCUC Order G-44-12. As a result of the AES Inquiry, FEI will be undertaking a review of the Code of Conduct and Transfer Pricing Policy and any variance in this charge would be put into the deferral account. As submitted in the 2012-2013 RRA, 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.

205.5 Please show the direct charges the FEU made to the TESDA in each of 2012 and 2013.

Response:

Please refer to the response to BCUC IR 1.172.4 for a summary of the dollars of labour directly charged to TESDA in 2012 and to June 2013.

206.0 Reference: THERMAL ENERGY

Exhibit B-1, Application, Tab D, Section 3.6, p. 277; AES Inquiry Report, pp. 15, 25, 33

Thermal Energy Services – Cost Allocation

On page 278, FEU state: "As a result of these other ongoing processes [TESDA and Code of Conduct/Transfer Pricing Policy], 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.

Page 15 of the AES Inquiry Report states: "the Commission Panel confirms that there must be no cross-subsidization when a utility purports to enter a competitive market."

Page 25 of the AES Inquiry Report states: "the Panel finds a greater reliance on structural separation as opposed to the use of accounting will minimize the potential for abuse. Such separation will make it easier for the Commission to assess whether the allocation of costs and risk has been undertaken in a fair and reasonable manner."

Page 33 of the AES Inquiry Report states: "For those new business activities provided through a Regulated or Non-Regulated Affiliated Business or a Separate Class of Service, costs are to be allocated to the new business or shareholder, on the basis of the higher of market price or the fully allocated cost, and be free of all forms of cross-subsidization from the traditional utility. These costs include both direct costs and a fair allocation of the parent utility costs required to provide the product or service. An exception to this rule would be any cost handling which has been prescribed by legislation, regulation or special direction."

206.1 Please confirm that the Commission found TES to be a competitive market in the AES Inquiry Report.

<u>Response:</u>

In Appendix H of the AES Report, the Commission found that Thermal Energy Services are regulated services:

"Thermal Energy Services

Directives and Determinations:

1. Thermal Energy Services are regulated under the UCA.

2. The $0 CPCN Threshold for TES Projects is maintained.

3. TES comprise a fundamentally different line of business, occurring beyond the gas distribution meter, and cannot therefore be considered an extension of the utility distribution system.

4. Commission Staff will conduct consultation on a scaled regulatory framework for TES utilities. The resulting framework will be brought to the Commission for approval.

Recommendations:

a. Until such time as the UCA is amended, exemptions from regulation should be sought for Discrete Energy Systems with no monopoly characteristics or need for consumer protection. Where such exemptions are granted it would be appropriate for FEU to pursue Discrete Energy Systems through a stand-alone Non-Regulated Business that is separate from the traditional gas distribution utility.

b. TES Projects (that are not exempt from regulation) are most appropriately undertaken through an Affiliated Regulated Business. "

While the AES Report did indicate that the Commission believed that the TES market is competitive, particularly competition for the market, FAES submits that natural monopoly does not mean that competition is eliminated, nor that the existence of competition means that natural monopoly does not exist. In other words, natural monopoly and competition are not mutually exclusive terms. For example:

"…if the minimum efficient scale of plant is less than total market demand, there is obviously room for competition. Moreover, in a dynamic society the presence of a natural monopoly at one time does not ensure that those same conditions will exist forever."[22]

Or

"Close approximations to pure or perfect competition are thought to be rarely, if ever, found in manufacturing or trading industries. On the other hand, even incumbent public utilities may face severe competitiveness from two sources: (1) existing rivals, typically of a substitute-product type, with respect to a large, perhaps even major, fraction of their services; and (2) perhaps even more importantly from potential entrants in those contestable markets where there is nearly frictionless and costless entry and exit."[23]

[22] Bonbright, Principles of Public Utility Rates, page 43
[23] Bonbright, Principles of Public Utility Rates, page 17

206.2 Please confirm that FAES pays the higher of the market price of the fully allocated cost for FEI services it uses. Please provide evidence to support this confirmation, including how any market price or fully allocated cost was determined.

Response:

For the allocation to the TESDA, FEI is currently charging a Commission-determined amount of $854 thousand.

For other services provided (i.e. business development), FEI believes it is in compliance with the existing TPP pricing rules for services provided to FAES with the Transfer Price for such services set at either the full cost or where feasible and practical, the Competitive Market Price, whichever is greater. FEI's approach to compensation and benefits is to provide its employees with competitive base salaries and wages, incentive compensation, benefits and paid time-off. 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.

206.3 Please explain how the FEU's request for a deferral account for TES accords with the Commission's finding that a greater reliance on structural separation as opposed to the use of accounting will minimize the potential for abuse and will make it easier for the Commission to assess whether the allocation of costs and risk has been undertaken in a fair and reasonable manner.

Response:

The TES business is in transit moving towards greater structural separation as directed in the AES Inquiry. 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. Any changes to the O&M costs allocated to the TESDA or FAES that result from the review of the Code of Conduct and Transfer Pricing policy would be placed in this deferral account to keep both the natural gas customers and TES customers whole.

206.4 Please confirm whether the FEU plans complete operational segregation of TES into FAES. If so, when does the FEU plan to complete this segregation?

Response:

The AES Inquiry Report was issued on December 27, 2012 recommending that the FEU provide TES in a separate regulated affiliate. Since that time the FEU have dedicated a number of FEI personnel to work solely on TES for FAES. The FEU anticipate that on January 1, 2014, those personnel will be transferred out of FEI into an affiliate entity.

The FEU will continue to provide corporate and administrative services to FAES as it is currently doing.

206.5 Please confirm that the planned Code of Conduct/Transfer Pricing Policy will examine and set the "rules" for how costs are allocated between FEI and FAES and at what price. If not, please explain the FEU's understanding of what these proceedings will determine.

Response:

FEI confirms that as part of the upcoming planned Code of Conduct and Transfer Pricing Policy update as recommended by the Commission in the AES Inquiry Report, it will be following a collaborative process to update the Code of Conduct and Transfer Pricing governing the interactions between Affiliated Regulated and non-regulated Businesses. As part of the review, FEI confirms that it will review the rules governing how costs are allocated and at what price they are allocated between FEI and FAES, with recommendations provided on the rules.

ENERGY EFFICIENCY AND CONSERVATION

207.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1-1, Appendix I, p. 4; BC Energy Plan, p. 5

Regulatory guidance in setting the funding envelope

On page 4 of Appendix I to the Application, FEU state: "The FEU's EEC proposals are designed to implement all cost-effective (as defined by the Demand-Side Measures Regulation) demand-side measures...The FEU's EEC programs will...lead to...reductions in greenhouse gas emissions."

The BC Energy Plan states on page 5, "...the plan supports utilities in British Columbia and the

BC Utilities Commission pursuing all cost effective and competitive demand side management programs."

207.1 Does FEU consider that the interests of gas customers overall would generally not be negatively affected if the EEC programs resulted in lower overall bills, even if rates increased? Please explain why/why not.

<u>Response:</u>

The legal framework that the Commission must consider when reviewing the Companies' proposed portfolio of EEC activity and associated proposed expenditures in this proceeding is laid out in Section 2.1 of Exhibit B-1-1, Appendix I. The FEU have endeavored to answer this question in the context of this legal framework, and this proceeding.

The portfolio of EEC activity proposed by the FEU over the test period 2014-2018, which is the subject of this proceeding, is cost-effective as defined by the Demand Side Measures Regulation, provided as Attachment 207.1, which governs DSM activity in British Columbia. Cost-effectiveness of DSM activity in British Columbia is determined on the basis of whether or not a portfolio of activity has a combined TRC/MTRC of 1.0 or greater. Provision is made in the Regulation for the Utilities Commission to use, amongst other approaches, the Utility Cost Test if it sees fit to do so. In their decision in the 2012-2013 Revenue Requirements proceeding, the Commission affirmed the portfolio-level approach to cost-effectiveness screening on page 174 of the Decision, as excerpted below:

"With the assurance that FEU will continue to monitor EEC programs on a monthly basis to ensure the EEC portfolio meets an MTRC of 1 or greater, the Commission approves the assessment of cost-effectiveness on a portfolio basis…"

As can be seen on page 6 of Exhibit B-1-1, Appendix I, Attachment I1, the proposed portfolio has a combined Portfolio TRC/MTRC ratio of 1.30, and a Utility Cost Test ratio of 1.30. As is the case with all DSM activity, perspectives on participants and non-participants in the FEU's EEC initiative are provided by the Participant Cost Test and Ratepayer Impact Measure respectively. For the portfolio of activity proposed for the test period, the Participant Cost Test ratio is 2.33 and the Ratepayer Impact Measure ratio is 0.49. This indicates generally that participants will see a net benefit from EEC activity, while non-participants will see a net increase in utility bills. The DSM Regulation states the following: "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." Thus, based upon the guidelines established by Regulation for British Columbia, the proposed portfolio of activity is cost-effective.

With respect to the quote from the Application in the preamble to the IR, please refer to the response to COPE IR 1.8.2.

207.1.1 Does FEU consider it would be reasonable or not reasonable to place limits on the amount of EEC activities FEU undertakes which both decreases emissions and decreases total customer bills, provided that FEU strives to provide equitable access to EEC programs for all its customer classes? Please explain why/why not.

<u>Response:</u>

The portfolio of EEC activity proposed for the test period decreases emissions in British Columbia and as such, is consistent with BC's Energy Objectives, as detailed in Section 2.2 of Exhibit B-1-1, Appendix I. A discussion of the genesis of the proposed overall expenditure level can be found in the response to BCUC IR 1.224.1. The approach taken by the Companies in requesting funding approval places an annual limit on EEC expenditures. The portfolio of activity that is the subject of this proceeding is cost-effective as defined by British Columbia's Demand Side Management Regulation, both decreases emissions and at a portfolio level, has a positive Utility Cost Test result, and provides equitable access to EEC programs for all customer classes.

207.2 Would FEU consider it reasonable to use EEC programs to reduce emissions, even where it could increase overall bills (i.e. accept EEC programs that fail the Utility Cost Test (UCT) on the basis of emission reduction benefits)? Please explain why/why not.

Response:

The portfolio of EEC activity proposed for the test period has the effect of decreasing GHG emissions and also has a positive UCT ratio. The portfolio of activity proposed by the Companies for the test period complies with the existing guidelines established for British Columbia. The Companies have not contemplated EEC activity outside the guidelines, such as undertaking EEC initiatives that have the sole criteria of reducing emissions.

207.2.1 Does FEU consider that, in determining the extent, if any, to which FEU should use EEC to decrease emissions, the following should be considered: (i) an equitable contribution by gas customers to the cost of reducing BC emissions, and (ii) the cost effectiveness of using EEC to reduce BC emissions compared to other alternative approaches of reducing BC emissions? Please explain why/why not.

Response:

In determining the extent to which it proposes to undertake EEC activities, the FEU complies with the relevant requirements of the UCA and the cost-effectiveness tests in the DSM Regulation and follows the FEU's EEC Guiding Principles. 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. The FEU are also taking other approaches to support British Columbia's GHG emission reduction goals. Natural Gas for Transportation and Renewable Natural Gas are two primary examples. At this time, the FEU have not found that any of these approaches are mutually exclusive or otherwise had a reason to compare the cost-effectiveness of the various alternatives to reduce GHG emissions.

Please also refer to the response to BCUC IR 1.207.2.

208.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

***Clean Energy Act* (CEA), Section 2**

BC Energy Objectives

The *Clean Energy Act* (section 2) includes BC energy objectives: "(g) to reduce BC greenhouse gas emissions...(k) to encourage economic development and the creation and retention of jobs; (h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia; ..."

208.1 Is BC forecast to meet its BC greenhouse gas emission targets over the PBR period? Please explain.

Response:

The FEU do not track or evaluate the Province's progress on meeting the Provincial GHG emission reduction targets it has set. This question should be directed to the Province of BC.

While the FEU are committed to supporting Provincial efforts to reduce GHG emissions, there are no legislated emission reduction targets set out specifically for the FEU or their customers. EEC is one area in which the FEU are supporting Provincial efforts. Our high carbon to low carbon fuel switching program, renewable natural gas and NGT initiatives are other important areas of support for GHG emission reductions. FortisBC continues to examine the feasibility of other initiatives that can support GHG emission reductions.

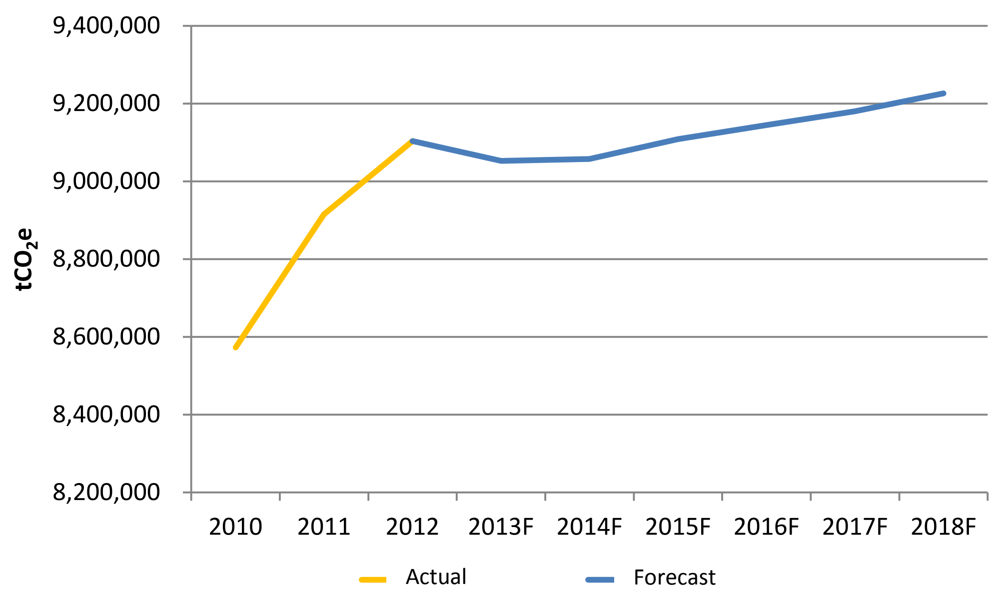
208.1.1 Please provide a graph showing total carbon equivalent emissions from FEU commodity sales for domestic consumption since 2007, and forecast over the PBR period for (i) emissions included in the carbon tax, and (ii) total 'cradle to grave' gas related emissions (including venting, flaring and fugitive). Please provide a breakdown of this data by customer class.

Response:

Since the commodity sales forecasts for FEVI and FEW are not part of the PBR application and are not yet available, this response can only be provided for FEI's commodity sales.

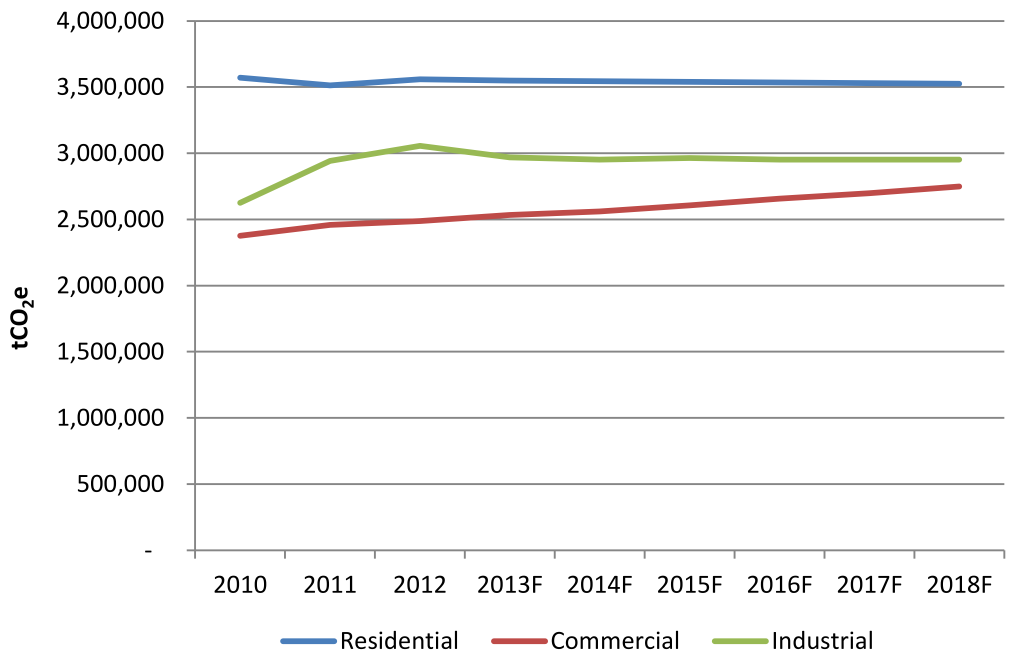
Figure 1 shows CO2e emissions[24] from FEI's commodity sales subject to the carbon tax from 2010 to 2012 and forecast commodity sales through the PBR period. Figure 2 shows the same information by industrial, commercial and residential customer class. Emissions are based on actual, historic GJ sales and forecast GJ sales that are weather normalized.

Figure 1: Total CO2e Emissions from Natural Gas Commodity Sales to FEI Customers



[24] A GHG emissions factor source of 0.051 tCO2e/GJ was used. Source: Greenhouse Gas Emission Assessment Guide for British Columbia Local Governments. 2008.

Figure 2: CO2e Emissions from Natural Gas Commodity Sales to FEI Customers by Customer Class



The 2010 BC Greenhouse Gas Inventory Report aggregates oil and gas emissions, showing emissions for 25 different oil and gas emission sources for well drillings and completions, upstream and gathering, and processing and transmission activities.[25] However, it is not possible to determine what proportion of emissions from each emission source ends up in FEI's commodity sales as opposed to in oil and gas used for other industrial processes, internal industrial consumption and energy exports. To add, according to the B.C. Ministry of Finance, of the 30 percent of B.C.'s carbon emissions that are not derived from burning fuel, fugitive emissions comprise approximately 10 percent and "cannot be accurately measured."[26] For these reasons, FEI is not able to provide total 'cradle to grave' gas-related emissions including venting, flaring and fugitive emissions.

[25] http://www.env.gov.bc.ca/cas/mitigation/ggrcta/reporting-regulation/emissions-reports-qa.html, accessed Aug. 7, 2013.

[26] http://www.fin.gov.bc.ca/tbs/tp/climate/A6.htm, accessed Aug. 7, 2013.

208.1.2 Please provide a table showing what percentage of FEU's forecast growth in gas consumption is expected to be met by EEC programs over the PBR period.

Response:

The table below provides a comparison of the annual forecast growth in annual customer demand from the short term natural gas demand forecast for FEI contained in the PBR Application, to the annual savings from planned EEC programs reported in the EEC Plan for the PBR period. Planned annual energy savings will more than offset forecast annual demand growth during the period.

Planned Natural Gas Savings from EEC as a Percentage of Forecast Demand Growth

FEI	GJ					
Year	2013F	2014F	2015F	2016F	2017F	2018F
Annual Demand	177,412,000	177,619,400	178,559,300	179,269,400	180,102,500	180,959,700
Growth in Annual Demand		207,400	939,900	710,100	833,100	857,200
Estimated Annual Savings from EEC Programs		637,255	1,255,547	1,733,589	2,265,196	2,787,418
EEC Plan GJ Savings as a Percentage of Total Demand Growth		307%	134%	244%	272%	325%

208.2 Does FEU consider that the CEA requirement to 'encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in BC' applies to existing infrastructure only, or should it also apply to new builds? Please explain why/why not.

Response:

The Companies are not proposing any EEC activity in the <u>EEC portfolio</u> that addresses fuel switching. The expenditure to support high-carbon fuel switching activity that is proposed by the Companies is classified as O&M, and is discussed on pages 157 and 161 of Exhibit B-1. From a practical perspective, this high-carbon fuel switching activity has historically only occurred around existing buildings as it is restricted to switching from oil and propane.

208.2.1 Does FEU consider that it should try to avoid EEC programs which could have an indirect consequence discouraging customers from switching to a renewable fuel? Please explain why/why not.

Response:

The FEU are not aware that any of the EEC programs which are the subject of this proceeding, covering the 2014-2018 EEC Plan and time frame, could have an indirect consequence of discouraging customers from switching to a renewable fuel. Ultimately it is the customer that will make the decision as to the type of energy system that is installed, and uses of renewable solutions such as solar hot water are too costly for all but a few customers.

208.3 In evaluating alternative programs, does FEU give additional emphasis to programs which support economic development and the creation of jobs? If yes, please explain how.

Response:

No, the FEU do not consider economic development and the creation of jobs when evaluating alternative programs. It would be too challenging and costly to try to quantify the different economic benefits resulting from different programs. The FEU have, however, evaluated the economic benefits of EEC activity generally as part of their last Conservation Potential Review, in a report called, "Impact of CPR-2010 Natural Gas Savings on the B.C. Economy (2010-2030)", provided as Attachment 208.3. The conclusions from this report are excerpted below.

"The analysis determined that the net impacts of DSM programs are overwhelmingly positive for the regional economy as measured by output, GDP, and employment…

- *The net impacts on output, GDP, and employment are all positive across all sectors for every scenario. This occurs because the DSM program shifts spending from low multiplier industries to industries with higher multipliers.*
- *Annual impacts increase over time and are larger for the aggressive achievable scenarios. This arises due to the accumulation of energy savings from measures installed in prior years.*

- *The residential sector, in every scenario, accounts for the greatest share of economic impacts. This is most likely due to the early replacement measures in this sector.*
- *By 2021, the net employment gains from CPR activities will range between 362 - 682 jobs, depending on scenario. This translates to between 5.8 – 6.7 jobs per $1 million invested in DSM that year.*
- *By 2031 the net employment gains from CPR activities would grow to between 580 - 881 jobs, depending on scenario. This translates to between 9.6 – 10.0 jobs per $1 million*
- *invested in DSM that year. The increase in number of jobs per $1 million invested in 2031 includes the beneficial effects of DSM investments made in prior years.*
- *Benefits will continue to accrue after 2030, due to investments made in prior years, until the effective life of the installed program measures has been exceeded. "*

209.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1-1, Appendix A, p. 3; Exhibit A2-1, page 3-1

EEC Objective

On page 3 of Appendix A to the Application, FEI states: "Demand Side Management [DSM], defined as 'any utility activity that modifies or influences the way in which customers utilize energy services.'" From FEI's perspective, the primary objectives of DSM are to increase the overall economic efficiency of the energy services it provides to customers and maintain the competitive position of natural gas relative to other energy sources."

"Aligning Utility Incentives with Investment in Energy Efficiency" (2007) paper (Exhibit A2-1) defines energy efficiency as "The use of less energy to provide the same or an improved level of service to the energy consumer in an economically efficient way." (p. 3-1)

209.1 Would FEU object to defining the objective of EEC as "The use of less energy to provide the same or an improved level of service to the energy consumer in an economically efficient way?" Please explain why/why not.

Response:

For the FEU, the EEC initiative encompasses not only energy efficiency, which can be described as "the use of less energy to provide the same or an improved level of service" but also conservation, which can be described as reducing or going without a level of service in order to reduce energy use". The distinction can be made as follows: upgrading a furnace from a standard model to a high-efficiency model constitutes energy efficiency; putting on a sweater and turning down the heat constitutes conservation. It is the goal of the FEU to provide the Companies' customers with EEC services in an economically efficient way; however the assessment of the cost-effectiveness of a utilities' portfolio of DSM activity is governed in BC by the DSM Regulation as described in the response to BCUC IR 1.207.1.

209.2 Does FEU consider that a goal of 'maintaining the competitive position of natural gas relative to other energy sources' is not an EEC objective, but relates to the conflict between FEU undertaking both EEC activities and its traditional gas provider services. Please explain why/why not.

Response:

There is no conflict created by the FEU undertaking both EEC activities and other natural gas provider services. The provision of EEC initiatives is in fact complementary to the provision of cost effective natural gas service, since the FEU are optimally positioned to deliver EEC services to its customers.

209.2.1 Does FEU consider that it can maintain the competitive position of gas relative to other energy sources if a customer's average bill did not increase, even though the gas rate increased (i.e., customers become more efficient in how they use gas)? Please explain why/why not.

Response:

The Companies believe that *one way* that the FEU can help customers to manage their energy bills is to provide them with access to energy efficiency and conservation opportunities. This has the effect of protecting customers from a potential future rise in the delivered cost of natural gas. There are many other factors that affect the energy marketplace, and natural gas's competitive position within it, however. Some of these are within the FEU's control, and some are not. Some of these include the need for the FEU and for other energy sources to: replace aging infrastructure; the need to bring on new sources of supply; and the continental and international supply and demand for natural gas and for other energy sources.

209.3 Do any of FEU's existing and proposed EEC programs fall outside of the DSM definition contained in the *Clean Energy Act*? If yes, please explain.

Response:

No; all of the FEU's existing or proposed EEC programs fall within the definition for "Demand Side Measure" contained within the Clean Energy Act.

210.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit A2-1, p. 1-3; Demand Side Management Incentives in Canada, Pembina Institute, 2004, p. 9[27]; Exhibit B-1-1, Tab C, Section 1.6, p. 115

Existing DSM Incentives

"Aligning Utility Incentives with Investment in Energy Efficiency" (2007) paper (Exhibit A2-1) includes Table 1-1 on page 1-3 titled Utility Financial Concerns.

Pembina Institute August 2004 paper titled "Demand Side Management Incentives in Canada" states on page 9: "Two of BC's utilities, Terasen (gas) and FortisBC (formally Aquila Networks Canada, electric), are currently operating under a PBR that includes DSM financial mechanisms and incentives. Targets are set for DSM savings and, if the utility exceeds these targets, it receives credit for a percent of total savings in its next rate decision. Both utilities are allowed to amortize DSM program costs over a multi-year period that provides a further incentive to operate DSM programs. Terasen also has a revenue stabilization adjustment that prevents the utility from benefiting from increased sales in the residential and commercial (but not industrial) sectors."

On page 115 of the Application, FEI states: "For residential and commercial customers, any variation in the customer demand from what has been forecast in rates has no impact on the gross margin earned from a new customer because of the [Revenue Stabilization Adjustment Mechanism]."

210.1 Please add three additional columns to Table 1-1 from Exhibit A2-1, p. 1-3 to identify and describe which of the potential solutions were/are being used to address potential FEU EEC related utility financial concerns (i) in 2004, (ii) currently, and (iii) as proposed in the 2014-2018 PBR application.

Response:

FEI provides the following response as the 2014-2018 PBR application is not a FEU application, similarly 2004 would only apply to FEI.

Potential Impact issues and Potential Solutions identified in Exhibit A2-1, Table 1-1 have been addressed in 2004, and remain essentially the same currently, and in the FEI's proposal for the 2014-2018 PBR Application. In the table below the symbol, '√'is used to identify how the Potential Impact issues and solutions have been used. 'N / A' is used in the table to indicate which solutions have not been applied. The BCUC has approved the FEU to include

[27] http://www.pembina.org/pub/174

DSM/Energy Efficiency costs in a Rate Base deferral account which allows the utility to earn a return on its investment and to recover the expenditures by allowing the amortization expense to be included in the utility's revenue requirements. Currently and which is also proposed for the 2014-2018 PBR Application, EEC expenditure that exceeds a threshold amount of $15 million is charged to a non-rate base deferral account. However, since the costs charged to the non-rate base deferral account attract AFUDC this approved financial treatment will keep the investors of FEI whole with respect to earning its allowed rate of return.

Exhibit A2-1, Table 1-1: Utility Financial Concerns + added columns

Potential Impact	Potential Solutions	2004	Current	Proposed 2014-2018 PBR Mechanism
Energy efficiency expenditures adversely impact utility cash flow and earnings if not recovered in a timely manner.	• Recovery through general rate case • Energy efficiency cost recovery surcharges • System benefits charge	√ N / A N / A	√ N / A N / A	√ N / A N / A
Energy efficiency will reduce electricity or gas sales and revenues and potentially lead to under-recovery of fixed costs.	• Lost revenue adjustment mechanisms that allow recovery of revenue to cover fixed costs • Decoupling mechanisms that sever the link between sales and margin or fixed-cost revenues • Straight fixed-variable (SFV) rate design (allocate fixed costs to fixed charges)	N / A √ √	N / A √ √	N / A √ √
Supply-side investments generate substantial returns for investor-owned utilities. Typically, energy efficiency investments do not earn a ret6urn and are, therefore, less financially attractive.	• Capitalize efficiency program costs and include in rate base • Performance incentives that reward utilities for superior performance in delivering energy efficiency	√ N / A	√ N / A	√ N / A

The decoupling mechanism, for FEI, originating from the 1993 Phase B Rate Design, was created to sever the link between sales and margin. Initially, it was described as a Weather Stabilization Adjustment Mechanism and then later modified in the 1990's to the current Revenue Stabilization Adjustment Mechanism. By severing the link the utility was protected from the potential impact of reduced revenues from reduced sales (Residential, Small Commercial and Rate Schedule 3 Large Commercial) and transport volumes (Large

Commercial Rate Schedule 23) from residential and commercial customers which was not planned for in the determination of the utility's customers' energy use rates and revenues. Any reduced revenues as a result of actual use per customer being lower than Commission approved use per customer could be recovered in subsequent years through the RSAM rider. Conversely, if actual UPC is higher than forecast these customers will recover the excess revenue by a credit in the RSAM Rate Rider in subsequent years. One of the impacts of the RSAM decoupling mechanism is that FEI earnings would be unaffected by subsequent volume impacts from energy efficiency investments on customer energy use rates.

One of the outcomes of the RSAM mechanism is that it strips away any incentive to deliberately under or over forecast customers' energy use rates. Coupled with the Commission's ability to review annually customer consumption behavior and any ongoing changes over time, the Commission can determine if FEI's customer consumption forecast is reasonable and fair.

In regard to industrial firm service, the majority of the revenues to recover fixed costs come from Demand Charges, monthly Basic Charges and monthly Administration Charges (Rate Schedules 5, 25, 22A and 22B). These revenues do not vary with changes in volume of gas delivered and while they might not be technically a straight-fixed variable rate design it would definitely emulate a SFV rate design. Even though the majority of customers and volumes under Rate Schedule 22 are served under interruptible T-Service and charged a variable Delivery Charge rate, this tariff does allow for customers to negotiate a firm service Demand Charge (which would be subject to Commission approval before being effective) for a firm Daily Transportation Quantity (DTQ). FEI does have a few large industrial customers with negotiated fixed demand charges which is the predominant component of the revenues.

As can be seen in the response to BCUC IR 1.57.2 a 1% variance in the volume demand would only result in variance of the revenues (after tax) of approximately $250 thousand. FEI considers this, and believes the Commission considers this, to be an acceptable level of risk that could modestly impact FEI's earnings.

210.2 Please describe the current impact on FEU shareholder earnings if annual EEC gigajoule (GJ) energy savings exceed forecast while EEC spend remains the same (i.e. EEC $/GJ cost of energy savings decreases) for (i) residential customers, (ii) commercial customer, and (iii) industrial customers.

Response:

There is no impact to FEU shareholder earnings if the annual energy savings either exceed or are under the forecast amount, and EEC spend remains the same. Refer also tp the response to BCUC IR 1.210.1.

210.2.1 Please describe the effect of the scenario above under (i) the PBR mechanism in place in 2004 and (ii) the PBR mechanism proposed for 2014-2018.

Response:

Please refer to the response to BCUC IR 1.210.1.

211.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1-1, Appendix I, pp. 19-20; Commission Decision G-44-12, pp. 185-186;

Need to review existing DSM Incentives

On pages 19 and 20 of the Appendix I to the Application FEU state: "Due to the length of the period the EEC plan covers, the Companies require the flexibility to be able to adjust to new information, program results and opportunities through the test period without the need for a full Commission review."

On pages 185-186 of its 2012-2013 FEU Revenue Requirement Application Decision (G-44-12),[28] the Commission states: "In the view of the Panel, the issue is how to get the most value for the dollars being expended on DSM programs... The Commission Panel believes that it is appropriate that these questions be explored in a separate review process."

211.1 Does FEU consider that, in order to move to a lighter handed regulatory regime for EEC, it is important that (i) proper utility incentives are in place to provide economically efficient EEC, and (ii) appropriate checks/balances are in place such that ratepayers and the regulator have confidence in the EEC results reported? Please explain.

<u>Response:</u>

It is not clear to the FEU what is being referred to as a "lighter handed regulatory regime for EEC".

As discussed in the response to BCUC IR 1.213.1, the matter of utility incentives to pursue DSM has been extensively canvassed in previous proceedings and the proper utility incentives to support cost-effective EEC expenditures are in place.

As discussed in the response to BCUC IR 1.236.1, the group with responsibility for EM&V for EEC activity is separate from the groups responsible for EEC Program Design and EEC Program Delivery, and reports to a different Director so that the EM&V group is independent of the EEC Program Design and Delivery groups.

The matter of EEC checks and balances and accountability mechanisms has also been canvassed in previous proceedings, and the Companies believe that the appropriate accountability mechanisms for EEC activity and expenditure are in place, and that these

[28] http://www.bcuc.com/Documents/Proceedings/2012/DOC_30355_04-12-2012-FEU-2012-13RR-Decision-WEB.pdf

mechanisms support continuing with the existing regulatory regime for EEC as is being proposed in the current proceeding. Please refer to Attachment 211.1 for a discussion of accountability mechanisms, which provides excerpts of the FEU's response to BCUC IR 1.205 series in the 2012-2013 RRA proceeding, and the Commission's discussion of the EEC Framework from their Decision in the 2012-2013 RRA proceeding. It can be seen in the Application, Table I-2 in Exhibit B-1-1, Appendix I that the Companies have complied with all the Commission's Directives related to accountability mechanisms in as provided in Attachment 211.1.

211.1.1 Does FEU consider that the existing EEC organizational structure and shareholder incentive mechanism supports a move to a more light-handed regulatory regime? Please explain why/why not.

Response:

If the reference to a more light-handed regulatory regime is referring to the FEU's request to be able to launch new programs without preapproval from the Commission as stated on page 20 Appendix I in Exhibit B-1-1, then, yes, the FEU believes the existing structure and mechanisms support this request.

Please refer to the response to BCUC IR 1.211.1.

211.1.2 Does FEU support a review of the existing EEC organizational structure and shareholder incentive mechanisms? Please explain why/why not. If yes, please suggest a recommended approach.

Response:

No, the FEU do not support a review. As noted in the response to BCUC IR 1.213.1, it is the view of the FEU that the EEC framework, including the organizational structure and shareholder incentive mechanisms are understood and are functioning well. The FEU do not believe these matters need to be reviewed given that they have recently been established over the last 5 years.

211.2 Does FEU consider that EEC is different in nature from its traditional core/monopoly activities, in that it is focused on competing for customers' discretionary dollars (i.e. to persuade customers to invest in EEC rather than on vacations or retirement savings) and time? Please explain why/why not.

Response:

No, the FEU consider that the provision of Energy Efficiency and Conservation services to its customers is a part of its core utility activities.

212.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1-1, Tab A, Section 5.1, p. 19, Tab C, Section 1.3.5, p. 96

Issues with existing incentive mechanisms

On page 19 of the Application, FEU states: "The FEU use a Balanced Scorecard approach to deliver on a number of key success measures critical to the business."

On page 96 of the Application, FEU states: "The forecast for Industrial Customer Additions assumes no net change in the number of customers over the forecast period except where specific knowledge has been received by the Company."

212.1 Please explain why FEU has a Revenue Stabilization Adjustment Mechanism for residential and commercial customers, but not for industrial customers?

Response:

A RSAM for industrial customers has not been applied for by the Company nor ordered or approved by the Commission.

A decoupled RSAM mechanism is unnecessary for industrial customers as the variable revenues from this group of customers are at a level that variances in volumes would not significantly affect the revenues of FEI (refer to the response to BCUC IR 1.57.2). This is because, unlike Residential and Commercial classes where the vast majority of the revenues are directly linked to gas volumes delivered this is not the situation for firm service industrial customers.

The structuring of the firm industrial rates is to ensure the majority of the revenues is fixed through monthly Deamnd and Basic Charges. These revenues are delinked from the volumes delivered. The other purpose of the rate structure and rate level is to ensure continuity of firm industrial revenues to pay for fixed cost investment related to the rate base assets for provision of capacity that enables the delivery of energy. It is important, for rate design reasons, that a straight-fixed variable form of rates be charged for firm and interruptible service that does not incent firm industrial customers to decontract (this is particularly important for firm Large Volume Industrial customers served under Rate Schedules 22, 22A and 22B) which would cause a shift in revenue responsibility from the industrials to smaller volume customers such as residential and commercial customers in an embedded cost of service study.

Please also refer to the BCUR IR 1.67.2 for an explanation of the problems with applying the RSAM to interruptible service industrial customers.

212.1.1 Please describe any other customers that are excluded from the Revenue Stabilization Adjustment Mechanism (customer classes, regions etc).

Response:

The following table lists the Rate Schedules and service area that are excluded from RSAM which are comprised of seasonal service or industrial firm and interruptible sales and T-service customers.

	Service Area		
Rate Schedule	**Lower Mainland**	**Inland**	**Columbia**
Rate Schedule 4 – Seasonal Firm Gas Service	√	√	√
Rate Schedule 5 – General Firm Service	√	√	√
Rate Schedule 6/6A/6P – NGV/Vehicle Refuelling/Public Service – NGV Refuelling	Rate 6 - √ Rate 6A/P - √	Rate 6 - √ Rate 6A/P – N/A	Rate 6 - √ Rate 6A/P – N/A
Rate Schedule 7 – General Interruptible Service	√	√	√
Rate Schedule 11B – Biomethane Large Volume Interruptible Sales	√	√	√
Rate Schedule 16 – Interruptible LNG Sales & Dispensing Service	√	N/A	N/A
Rate Schedule 22 – Large Volume Transprtation	√	√	√
Rate Schedule 22A – Transportation Service (Closed)	N/A	√	N/A
Rate Schedule 22B – Transportation Service (Closed)	N/A	N/A	√
Rate Schedule 25 – General Firm Transportation Service	√	√	√
Rate Schedule 26 – NGV Transportation Service	√	√	√
Rate Schedule 27 – General Interruptible Transportation	√	√	√

212.1.2 For industrial customers and any other customers identified above, does FEU consider that exclusion from the Revenue Stabilization Adjustment Mechanism results in a disincentive for FEU to provide EEC programs to these customers? Please explain why/why not.

Response:

The absence of a RSAM for these customers in the Rate Schedules listed in response to BCUC IR 1.212.1.1 does not result in a disincentive for FEU to provide EEC programs to these customers. For the relative small number of customers involved in industrial manufacturing, FEI devises customer tailored energy efficiency applications and for those customers that are larger commercial type customers (included in Rate Schedules 4, 5, 7 & 27). FEI already has energy efficiency programs related to HVAC and Efficient Boilers.

212.1.3 Please explain the effect on the FEU shareholder if new (not forecast) industrial customers were to decrease energy consumption as a result of a FEU EEC program (compared to no FEU EEC program being offered).

Response:

As a point of reference, as indicated in the response to BCUC IR 1.57.2, a 1% reduction in volumes to all non-RSAM customers only has a relatively minor impact of approximately $250 thousand (after tax) on reduced margin for FEI (before PBR 50/50 sharing).

In responding to this question, FEI is assuming, that the new industrial customers have already become customers and then subsequently, shortly afterwards have reduced its energy demand requirements as a result of an EEC Program/Initiative and that this reduction in energy was not forecasted or planned for. Also, FEI is assuming the higher volumes and revenues were planned for in the revenue requirements forecast for setting customer rates that are now approved by the Commission.

Any adverse impact from the scenario described above would be limited to at most a one year period, until the revenue and cost impact would be included in the next revenue requirement application or annual review.

Such a scenario is also unlikely to occur:

- Generally speaking, there is significant time required for industrial customers to establish a capital plan for an energy efficiency upgrade, and to apply for and receive approval for an EEC incentive, and then to implement the energy efficiency upgrade. Given this timeframe, the customer will be able to forecast the reduced volumes as part of the Industrial Survey for that year of the PBR and as such the lower volumes would be incorporated into the future year forecast. Therefore there is no disincentive from the Company perspective in providing EEC incentives from the perspective of forecast volumes and rate design.
- Industrial customer additions do not occur frequently and the Company usually has ample time to forecast consumption prior to attachment.
- It is unlikely that a new industrial customer would attach and also require EEC as their facilities would already be new, and presumably would be efficient for competitive reasons.

212.2 Is there an incentive for the FEU shareholder to focus on EEC programs encouraging the attachment of new residential and commercial customers (for example, by providing incentives for gas heat/hot water where the customer may otherwise have selected electricity heat/hot water)? Please describe why/why not.

<u>Response:</u>

The benefit to the shareholder of investing in EEC activity is the same for programs that may bring about new customer attachments as those that are aimed at existing customers. This is the same under the proposed PBR as it was under regular cost of service-based revenue requirements applications. The benefit to the shareholder of investing in EEC is that EEC expenditures are included in utility rate base and earn a fair return as the expenditures are amortized in rates[29].

[29] High carbon fuel switching programs such as the Switch and Shrink program are an exception and do not earn a return (as per BCUC Order G-44-12, Reasons for Decision, pages 161 and 162). Arguably the Switch and Shrink program, which involves new customer attachments as consumers switch to natural gas from heating oil or propane, has less incentive for the Company than other EEC programs which attract a return.

There are several reasons why an EEC program aimed at new customer attachments does not provide any extra benefit to the shareholder relative to EEC programs for existing customers. First, a new customer attachment brings both revenues and costs. In the first year of service for a new customer (regardless of whether EEC funding has been provided or not) costs and revenues tend to be similar in magnitude and are largely offsetting. Since volumes, revenues and customer counts are reforecast annually under the PBR, the contribution of new customers to volumes, revenues and customer counts will be blended into the next forecast (and revenue implications are thereby "rebased"). The second reason that customer additions derived from EEC new construction programs do not provide any additional benefit to the shareholder is that the residential and commercial revenues are subject to a revenue decoupling mechanism – the RSAM. Under the RSAM the use per account for the residential and commercial classes is trued up to the forecast use per account in these customer classes. The use rates of new customers in a particular rate class will affect the overall average use rate as they are added to the rate class.

The programs aimed specifically at new construction in the proposed portfolio are proposed to be offered in conjunction with electric utilities, as can be seen on pages 28 (New Home Program – Residential) and 48 (Customer Equipment Upgrade Program – Commercial) of Exhibit B-1-1, Appendix I, Attachment I1. However, despite incentives available from both the gas and electric utilities for new construction programs, ultimately, it is the customer who will choose the energy source that makes the most sense for them.

212.3 Does FEU include any EEC related key success measures on its Balanced Scorecard? Please explain why/why not.

Response:

The FEU currently do not have any specific key success measure on its Scorecard related to EEC performance. EEC related key success measures are included in individual employee objectives and performance plans, where applicable

As discussed in the response to BCUC IR 1.191.1, in determining the scorecard categories and measures to use, the Company seeks not only to select the appropriate success measures but also the optimal number of measures (i.e. how many). At this time, FEI believes the six scorecard measures used best represent the overall priorities for Company.

212.4 Does FEU consider that the requirement to undertake EEC initiatives increases shareholder business risk? Please explain why/why not.

Response:

Please refer to the response to BCUC IR 1.212.5.

212.5 Does FEU consider that being the provider of EEC services to customers (rather than, for example, gas EEC being provided by a third party provider) enhances FEU's corporate image, which in turn reduces FEU business risk? Please explain why/why not.

Response:

EEC has both directionally favourable and directionally unfavourable impacts on FEI's business risk.

The provision of EEC services by the FEU is beneficial to the Company in the sense that many customers expect the Company to make EEC available as part of providing comprehensive energy solutions. Rather than being tied to branding, *per se*, FEI would characterize the directionally favourable impact on business risk as being related to the fact that providing comprehensive energy solutions can make staying with, or choosing, natural gas more attractive.

The counteracting effect is that EEC is contributing to declining throughput over time by virtue of its effect on UPC. Declining throughput is one of the most significant challenges facing the utility. Over the long term, the declines in UPC and throughput associated with EEC and other developments external to FEI result in upward pressure on delivery rates. This increases the competitive challenges FEI faces, and directionally contributes to the Company's overall business risk.

On the whole, FEI regards EEC as a good thing for the Company in the long term. While it will not reduce FEI's business risk in absolute terms from where it stands today, it will (along with other initiatives aimed at providing comprehensive energy solutions) help to mitigate increasing risk.

This has been canvassed in great detail in the GCOC Stage 1 proceeding.

212.6 Please provide a table and a graph showing the growth in EEC funding since FEU first undertook EEC to the end of the PBR forecast period. Please include in the table a column showing, for each year, total EEC funding as a percentage of FEU revenues.

Response:

Table 1 shows the approved and requested level of FEU EEC funding from 2010 to the end of the PBR forecast period as well as the actual 2010 through 2012, and the 2013 projected, FEU EEC spending. The same information is also shown for FEI separately. These EEC funding amounts are also shown as a percentage of FEU and FEI revenues, respectively. As the FEVI and FEW revenue requirements for the forecast period are not available, this table shows only total FEI funding as a percentage of FEI revenues for the forecast period. Please also note that it is the amortization of the existing EEC balances into the cost of service that needs to be recovered from customers through revenues and rates, not the current year funding additions to the deferral accounts.

Table 1: Comparison of Annual EEC Funding to Company revenue

	FEU EEC Funding				FEI EEC Funding			
Year	Approved & 2014-2018 Requested [1] (million)	Actual & 2013 Projected [2] (million)	Approved & Requested as a % of Approved FEU Revenue	Actual & 2013 Projected as a % of Actual & Projected FEU Revenue	Approved & 2014-2018 Requested [1] (million)	Actual & 2013 Projected [2] (million)	Approved & Requested as a % of Approved & Requested FEI Revenue [3]	Actual & 2013 Projected as a % of Actual & Projected FEI Revenue
2010	$29.5	$17.4	1.8%	1.2%	$25.8	$15.7	1.7%	1.2%
2011	$33.8	$15.7	2.0%	1.2%	$29.6	$13.2	1.9%	1.1%
2012	$29.1	$23.8	2.0%	1.8%	$25.9	$20.7	2.1%	1.8%
2013	$35.6	$27.9	2.4%	N/A	$31.7	$25.1	2.5%	2.2%
2014	$34.4	-	not available		$30.5	-	2.7%	-
2015	$37.3	-	not available		$33.1	-	3.0%	-
2016	$37.4	-	not available		$33.1	-	2.9%	-
2017	$37.7	-	not available		$33.3	-	2.9%	-
2018	$39.0	-	not available		$34.6	-	3.0%	-

Notes:

- Slight differences from previously reported values due to rounding

[1] - 2010/2011 approved funding as provided in Table K-1, page 2, Appendix K of the 2012/2013 RRA. 2012/2013 approved funding per Order G-44-12, Page 169 approving the 2012/2013 RRA - the FEU has allocated the approved amounts 89% to FEI, 10% to FEVI and 1% to FEW. 2014 through 2018 requested funding are amounts, including inflation, as reported in Attachment I-1, Appendix I, FEU EEC 2014 - 2018 Plan, Pg 5, Exhibit 1. All years exclude High Carbon Fuel Switching to allow a consistent comparison.

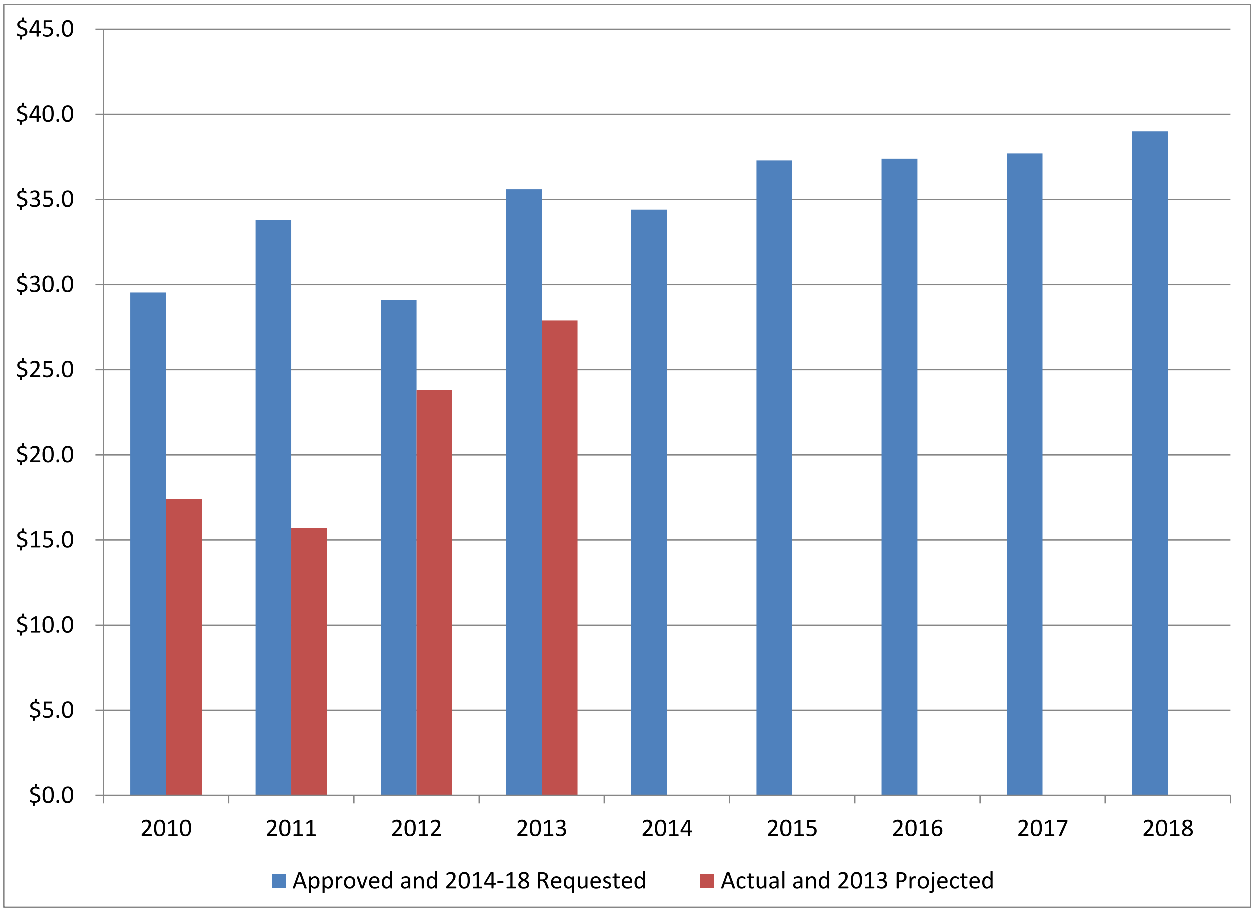
[2] - 2010-2012 funding are actuals as reported in Table I-3 of Appendix I in this Application. 2013 funding is based on a revised forecast by the FEU, found in the response to CEC IR 1.80.1, and is allocated 90% to FEI and 10% to FEVI. All years exclude High Carbon Fuel Switching to allow a consistent comparison.

[3] - Projected revenues for 2014-2018 are from 2014-2018 PBR Application Table C1-5: Forecast Sales Revenue at Existing Rates, p. 111.

The information in Table 1 shows that during this period, the approved level of funding has been relatively consistent leading into the PBR period. The growth in actual EEC expenditures in earlier years to match approved levels has been the result of ramping up program design and implementation, as well as in customer awareness and uptake.

Figure 1 demonstrates that the requested EEC funding also remains consistent during the PBR period, peaking in 2018 at $39.0 million (after inflation).

Figure 1: Stable FEU EEC funding Envelope 2010-2018



212.6.1 Does FEU agree that the growth in EEC activities could mean that the utility EEC incentive mechanisms considered appropriate in the past may no longer be appropriate? Please explain why/why not.

Response:

The level of funding approval being requested by the FEU is consistent with previously approved amounts, rather than constituting growth as the question states.

The FEU do not agree. As noted in the responses to BCUC IR 1.211.1 and BCUC IR 1.213.1, the FEU believe that the current financial treatment for EEC activity is appropriate and is common to the three utilities delivering demand side management services to customers in

British Columbia. This topic has been canvassed extensively in past proceedings. The Companies position has remained consistent throughout including as discussed in BCUC IR 1.213.1 and BCUC IR 1.213.1.1. The current financial treatment is consistent with section 60(b)(ii) of the UCA, which applies regardless of the extent of EEC activities.

213.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1-1, Tab A, Section 1, p. 1; Exhibit A2-1, pp. ES-3, 6-1, 6-2; Exhibit A2-2, p. 32

Performance Incentives

On page 1 of its Application FEI states:

"FEI's primary objectives for its PBR Plan are:

1. To enforce FEI's productivity improvement culture, while ensuring safety and customer service requirements continue to be met; and
2. To create an efficient regulatory process for the upcoming years, allowing the Company to focus on effectively managing business priorities and minimizing costs for customers."

Exhibit A2-1 provides an overview of EEC performance incentives page ES-3, and a summary of performance incentive mechanisms used in other jurisdictions on pages 6-1 and 6-2.

Exhibit A2-2 provides on page 32, Table 6, three types of metrics which have found common use in evaluating policies (direct impacts, cost of saved energy, energy efficiency spending).

213.1 Please describe the mechanism currently used to reduce or eliminate incentives for FEU to prefer supply-side investments over EEC investments.

Response:

The matter of the financial incentive for the FEU to pursue EEC activity has been canvassed extensively over multiple regulatory proceedings, most notably the 2010-2011 and 2012-2013 RRAs and the original EEC proceeding in 2008-2009. The Companies continue to believe that the currently approved methodology, described on pages 150 and 151 in the Commission Decision in the 2012-2013 RRA, and excerpted below, is the appropriate financial treatment for EEC activity, and provides for equal treatment of EEC and supply-side investments.

"The Commission Panel is satisfied that the proposal for $15 million on a net of tax basis to be added to an EEC Rate Base Deferral account in both 2012 and 2013 is in the public interest. The FEU have been ramping up their EEC expenditures over the past two years as programs are implemented and begin to take hold. This is expected to continue into the current test period and there is no evidence to suggest that an amount less than the proposed $15 million is likely to be spent. The Panel has considered the

proposal to create an EEC Non-Rate Base deferral account to capture the remaining portion of the EEC costs to a maximum of the approved EEC expenditure amount less the $15 million threshold to be recovered over a ten year period with the method of recovery to be determined as part of the next revenue requirements. We are satisfied that the methodology will allow all applicable costs to be captured and at the same time protect the interests of ratepayers by keeping the majority of forecast costs out of rates until the expenditures have been made.

As noted later in Section 8.7.4 in this Decision, the Commission Panel and some of the Interveners concerned with how best to amortize these expenditures and over what term. The Panel is not persuaded that a ten-year amortization period is necessarily appropriate but the issue was not canvassed thoroughly enough in this Proceeding to warrant a change. To assist in understanding this issue, the FEU are directed to provide a report detailing the rate impact of a number of amortization scenarios which will be helpful in determining a long term solution. For the 2012/2013 test period, the Commission Panel is satisfied that the proposed 10-year amortization period for the rate base deferral account is reasonable as is the FEU's proposal to allocate costs based upon the average number of customers served by each Company. Accordingly, the Commission Panel approves the following:

1. *EEC rate base additions of $15 million in both 2012 and 2013 to be included on a net-of-tax basis and amortized in rates over a 10-year period.*
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.*
4. *The creation of an EEC Non-Rate Base deferral account, attracting AFUDC, to capture the additional EEC costs as incurred on an actual spend basis to a maximum of the total approved EEC expenditures less $15 million in 2012 and 2013. No determination on amortization rates will be made at this time."*

Note that BC Hydro uses a 15 year amortization period and FortisBC Inc., the FEU's sister electric utility, has proposed a 15 year amortization period in their 2014-2018 Performance-Based Rate Application.[30] The Companies have provided an analysis of the rate impacts of

[30] http://www.bcuc.com/Documents/Proceedings/2013/DOC_35094_B-1-1_FBC_Submitting-Appendices.pdf, pages 18-19.

expensing EEC expenditures and amortizing over 5, 10 and 15 years; it is Exhibit B-1-1, Appendix I, Attachment I3.

It should be further noted that the *Utilities Commission Act*, in clause 60 (1) (b) (ii) states that in setting a rate under the Act, the Commission must "provide to the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demand…"[31] It is the view of the Companies that the currently approved financial treatment for EEC expenditures provides such a fair and reasonable return.

213.1.1 Please explain why FEU has not proposed a performance based incentive mechanism for EEC as part of its PBR Application. In the response, please describe the advantages and disadvantages of moving to a performance based incentive mechanism for EEC.

Response:

The Companies have not proposed a performance-based incentive mechanism for EEC activity in this proceeding because (1) we believe that the previously—approved mechanism is working well in that there are no dis-incentives to the FEU pursuing EEC activity under the current mechanism and (2) the financial treatment previously approved and currently applied to the FEU's EEC activity is the same as the financial treatment applied by the electric utilities in British Columbia, with the exception of the amortization period.

Please refer to Attachment 213.1.1, which consists of the Companies' responses to BCUC IR 1.193.3 and 1.193.4 and Attachment 193.3 of the FEU's 2012-2013 RRA proceeding. The Companies continue to hold the positions outlined in Attachment 213.1, and these positions would the same regardless of the type of performance based incentive under consideration, including all those outlined in the response to BCUC IR.1.213.2.

213.1.1.1 Please explain how a reduction or increase in the amortization period would affect FEU's incentives to invest in EEC compared to supply side resources.

[31] http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/00_96473_01, page 39.

Response:

Because the financial treatment of EEC activity includes a fair return on EEC expenditures which is comparable to the treatment of capital expenditures on supply side resources, there is an appropriate incentive for the company to pursue EEC activities in keeping with government policy and legislation such as the UCA and Clean Energy Act. The amortization period is not relevant to our decision-making criteria other than the impact that differing amortization periods can have on customer rates.

213.2 Please provide FEU's position on replacing the existing rate of return incentive with each of the following performance measures (refer Table 6 in Exhibit A2-1):

- Share of net economic benefits up to 10 percent of total EEC spending (Arizona).
- Share of net benefits (Georgia – 15 percent, Hawaii – 5 percent).
- Management fee of 1 to 8 percent of program costs (before tax) for meeting or exceeding predetermined targets. One percent initiative is given to meet at least 70 percent of the target, 5 percent for meeting the target, and 8 percent for 130 percent of the target (Connecticut).
- Up to 2 percent added ROE on EEC investments if performance targets are met with one percent penalty otherwise (Indiana).
- 5 percent of the program costs if savings targets are met on a program-by-program basis (Kansas, Massachusetts).
- Specific share of net benefits based on cost-effectiveness test is given back to the utilities. At 150 percent of savings target, 30 percent of the conservation expenditure budget can be earned (Minnesota).

Response:

FEU's general understanding of the DSM incentive mechanisms in other jurisdictions is that they have been designed to overcome the general disincentive for utilities to pursue DSM because DSM activities in those jurisdictions are not treated on an equal footing with supply side activities, and DSM in those jurisdictions will reduce the use of utility product and utility returns. The financial treatment for DSM activity approved and adopted in BC for the FEU and for the electric utilities effectively addresses the disincentive to DSM expenditure found in other jurisdictions. This approved treatment is consistent with the requirements of section 60(1)(b)(ii) of the UCA, whereas the performance measures listed above are not. The FEU believe the current approach in BC is appropriate and does not need to be changed.

Please refer also to the responses to BCUC IR 1.213.1 and 1.213.1.1.

214.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1-1, Appendix I, Section 7, p. 1, Section 8, pp. 15-16

Evaluation, Measurement and Verification (EM&V) - Independence

Appendix I-7 of the Application states: "Measurement and Verification (M&V) studies are conducted mainly to assess pilot programs, demonstration projects, and custom programs." (p. 1)

Appendix I-8 of the Application states: "Evaluations will be conducted or managed by staff who are independent from the program managers and other staff responsible for designing and implementing the program...External consultants will be retained whenever increased levels of evaluation activity above the base level are such that they cannot be completed by internal staff..." (pp. 15-16)

214.1 Please provide an overview of FEU's approach to EEC evaluation, measurement and verification. Please include in this overview: who is responsible for which tasks, their expertise and place within the organization, reviews/checks undertaken of EM&V results, and the level of independence of the reviewer.

Response:

The FEU's approach to EEC evaluation, measurement and verification is described in Sections 2.2 "Evaluation Objectives" and 2.3 "Evaluation Principles" in the EM&V Framework, Appendix I-8 to the Application, Exhibit B-1-1. Staff responsible for EM&V activities have separate lines of reporting from those of staff responsible for program development and implementation.

Table 1 summarizes the key FEU staff responsible for Evaluation, Measurement & Verification. Please refer to the response to BCUC IR 1.214.1.1 for the corresponding organizational chart.

Table 1

EEC Evaluation	Expertise & Experience	Responsibilities
Evaluation, Measurement & Verification (EM&V) Specialist	• Bachelor of Arts, Economics (B.A. Econ) • Legal Secretary Diploma • Natural Gas consumption analysis and modeling • Customer and demand forecasting • DSM program evaluation process and reporting • Project Management **Completion of the following DSM evaluation related training courses:** • Association of Energy Engineers (AEE): Fundamentals of Measurement & Verification for IPMVP • Principles of Research & Evaluation (EM&V) • UBC Clean Energy Engineering: Demand-Side Energy Efficiency & Conservation.	• Initiates and manages evaluation studies. • Manages the budget and direction for Evaluation studies. • Manages the design and implementation of evaluation studies. • Develops evaluation plans and budgets. • Manages consultant selection, RFP process and scope of work. • Gathers and manages the use of consumption and other data. • Ensures adherence to industry standards and protocols. • Participates in the review of inputs to the cost effectiveness analysis

The EM&V Specialist reports directly to the Manager, Integrated Resource Planning and EEC Reporting, who approves evaluation plans, budgets and reports, and oversees the implementation of any changes to cost effectiveness test inputs that result from evaluation activities.

EEC Measurement & Verification	Expertise & Experience	Responsibilities
Energy Utilization Managers (EUM)	**3 Energy Utilization Managers with the key personal certificates & designations:** • 2 – Professional Engineers (PEng) • Master of Engineering (MEng) • Master of Applied Science (MASc) • LEED AP O+M (Existing Building) • 2 – CMVP[32] certification. • Class "A" gas ticket, BCSA • Refrigeration Electrical (RE) Endorsement • BC 4th Class Power Engineering Certificate • BC Certificate of Qualification, Refrigeration – Journeyman Refrigeration Mechanic Interprovincial Red Seal • Applied Science Technologist (Mechanical), Applied Science Technicians and Technologists of BC (ASTTBC)	• Develop and complete M&V plans • Measurement equipment specification, selection and monitoring • Measurement equipment configuration • Data management and quality review • Data Analysis and Reporting • Site visits and project scoping • Review of technical reports and information • Review of inputs to the cost effectiveness analysis

The Energy Utilization Managers report directly to the Manager, Business Performance & Technical Solutions, who is responsible for approval of M&V Plans and oversees the implementation of changes to the inputs to cost effectiveness tests that result from M&V activities.

Both the Manager, Integrated Resource Planning and EEC Reporting, and the Manager, Business Performance and Technical Solutions report to the Director, Market Development, who is responsible for setting overall objectives for EM&V activities and ensuring the independence of EM&V staff from EEC staff responsible for program development and implementation.

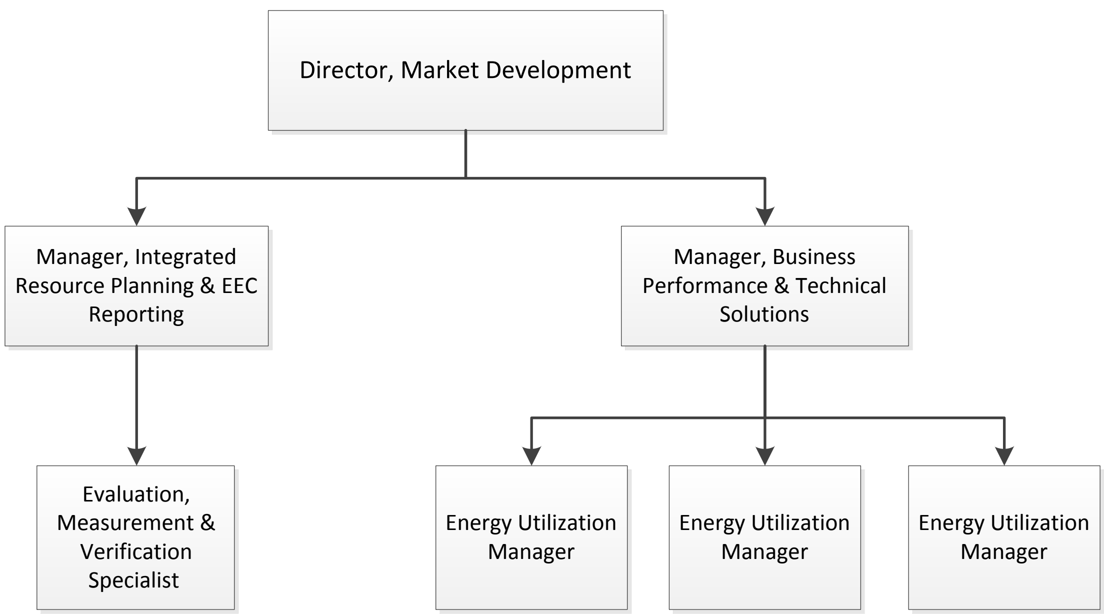
[32] CMVP is an accreditation from EVO and the AEE awarded to qualified professionals in the field of M&V within the energy industry. The right to use CMVP designation is granted to those who demonstrate proficiency in M&V knowledge of the IPMVP by passing an exam and metering the required academic and practical qualifications. A CMVP is recognized to have demonstrated the necessary capabilities to write an M&V Plan that adheres to the IPMVP. www.aeecenter.org/certificates or www.evo-world.org.

214.1.1 Please provide an organization chart showing FEU EEC EM&V activities and reporting lines.

Response:

The following organizational chart shows the reporting lines for all FEU EM&V staff. Please refer to the response to BCUC IR 1.214.1 for the EM&V activities of these positions.

FEU EEC EM&V Organization Chart



214.1.2 Did the (i) TLC Furnace/Fireplace 2011 and 2012 Sentis/TNS and (ii) Furnace Replacement Pilot Program 2013 IPSOS studies provide assurance as to the energy savings achieved? Please explain.

Response:

(i) No, the TLC Furnace/Fireplace 2011 and 2012 Sentis/TNS evaluations are not impact studies and did not evaluate the energy savings achieved. Rather, these investigations are process evaluations, the objectives of which were to assess the program satisfaction among the end users and to assist in improving program implementation and program delivery. The outcome from the key findings helped promote the Furnace Replacement Pilot Program by encouraging contractors to leverage on the relatively easy-to-access TLC program to promote furnace upgrades. The FEU will not be conducting impact evaluations to verify savings directly attributed from the TLC program, as there are no savings attributed to that program. Please refer to the response to BCUC IR 1.217.4.1 for a description of other benefits of the TLC program (shown in the EEC Plan as the Residential Appliance Service Program).

(ii) No, the Furnace Replacement Pilot Program 2013 IPSOS is not an impact study and did not evaluate the energy savings achieved. This study is also a process evaluation intended to gauge program satisfaction among the customers and to provide feedback for program improvements and implementation. A billing analysis will be conducted in 2014 to verify energy savings. This impact evaluation will incorporate the in-depth customer and contractor feedback evaluations with 12 months pre and post gas consumption data. This pre and post consumption data is critical for evaluating the impact of the pilot. Please refer to Exhibit B-1-1, Appendix I, Attachment I-5, p7-8 Furnace Replacement Pilot and Program from the Application for further details on evaluation studies.

214.1.3 What is the process for determining which programs and factors are evaluated?

Response:

All EEC programs will be evaluated on a program by program basis. For program evaluations, the process for determining which factors to evaluate and thereby what type of evaluations to conduct is to review each program for the following:

- Program objectives and whether or not the companies intend to measure and attribute energy savings to the program
- Stage of program life cycle

- Appropriate timing for evaluation activities to ensure meaningful results
- Size of the investment in the EEC program being evaluated
- Program target markets and market penetration objectives
- Adequate program participant levels for obtaining a meaningful sample size
- Budget and resource constraints

In the case of existing programs, this review is conducted annually, although generally both evaluation and program staff have an ongoing awareness of program evaluation needs. In the case of new programs, these aspects are examined during the program design stages in order that appropriate evaluation design parameters and budgets are incorporates prior to program launch.

More detail on the types of evaluations that are conducted during a program's life cycle and the factors to be examined is provided the Companies' EM&V (draft) Framework, Exhibit B-1-1, Appendix I, Attachment I-8 to the Application.

Evaluation activities are conducted to look at a program as a whole to determine its effectiveness. The scope of the evaluation studies should be practical and feasible within the confines of resources, cost and time available and should also align with the program's objectives.

The Evaluation staff ensure that evaluation requirements specific to the program objectives and target market are developed at and incorporated into program design. Projected participant levels will help to determine the extent and timing for when evaluations studies can be conducted. Assessment of an adequate sample size and data is required to obtain meaningful results. In addition to the program objectives and target, the size of the investments in the EEC program and budget levels help to determine the evaluation scope and schedule. This early consideration of evaluation requirements set the guideline for the timing and retrieval of relevant information that may be required to conduct the evaluation studies. Please refer to the response to BCUC IR 1.215.3.1 for further details on the importance of timing for when evaluations are conducted to obtain meaningful results.

For measurement and verification activities that examine pilot studies or custom programs, or support the evaluation of prescriptive programs, the selection of factors to study is guided by the International Performance Measurement and Verification Protocol as described in Section 3.5 of the FEU's EM&V Framework.

214.1.3.1 Do any outside stakeholders have input into (i) the selection of programs for evaluation and/or (ii) evaluation study design? If yes, please describe.

Response:

Yes. The selection of programs for evaluation and evaluation study design is guided by the EM&V Framework, which the EEC Advisory Group (please refer to the response to BCUC IR 1.216.1 for a description of the EECAG) has reviewed and provided input on. The EEC Advisory Group has also had an opportunity to review and comment on the proposed evaluation plan for the 2014 to 2018 period. Additionally, this group will have an opportunity to review evaluation summaries and, if requested, any member of the EECAG will be able to review evaluation reports. Any comments received from the EECAG with regard to the EM&V Framework, the evaluation plan or the review of evaluation results and reports has been or will be considered in future planning and design of evaluation activities. Finally, comments and feedback received from stakeholders during program design workshops (please refer to the response to BCUC IR 1.216.2) can also inform the design of evaluation studies.

In designing evaluation activities, the FEU may also consult with program partners, other utilities and third party experts, who all have a greater level of program evaluation expertise than that expected of the EECAG, on an as needed and case by case basis.

214.1.3.2 Do the Advisory Groups have any role in guiding the evaluation process? If yes, please describe.

Response:

While the FEU do provide an opportunity for the EEC Advisory Group to review and provide input into Evaluation activity (refer to the response to BCUC IR 1.214.3.1), guiding evaluation activities is not a key role for this group. The EECAG was established to provide insight and feedback more broadly on the Companies' portfolio of DSM activities (please refer to the response to BCUC IR 1.216.1 for further explanation of the EECAG's role) and are not expected to have expertise in evaluation activity specifically. In previous EECAG workshops, some members expressed the viewpoint that the design and management of evaluation activities is not something the EECAG have the time or the scope to be involved in, that they feel these activities are best managed by the FEU, and that they are satisfied with opportunities to review evaluation results.

214.2 Does FEU consider that there is a potential conflict of interest in a utility both undertaking EEC activities and being responsible for EEC EM&V? Please explain why/why not.

Response:

No. The FEU do not consider that there is a potential conflict of interest. The FEU's EM&V activities are appropriately segregated to avoid any such conflict of interest situation that could arise between the development and implementation of EEC programs and the evaluation of those programs within the utility. This has been achieved by way of its organizational structure, following the principles and guidelines laid out in the EM&V Framework (including the principle of transparency) and by acting in an ethical manner in accordance with the Companies' Business Ethics Policy. Further detail is provided below.

The organizational separation by function between EEC Program staff and EEC Evaluation, Measurement & Verification staff is an important measure to avoid any potential conflict of interest. The evaluation activities are managed and conducted by staff who are independent from the program managers and staff responsible for designing and implementing DSM programs. Evaluation staff ensure that evaluation requirements are defined at the program design stage and set evaluation requirements independent of the Program Managers for which studies may be successfully conducted. Such segregation enables the development and completion of unbiased EM&V reports which then serve as a valuable tool for which to make enhancements and changes to future EEC program delivery. Evaluation studies are conducted on a program by program basis and adhere to sections 2.2 “Evaluation Objectives” and 2.3 “Evaluation Principles” in the draft EM&V Framework, Appendix 1-8 to the Application, Exhibit B-1-1.

Secondly, the FEU have developed a comprehensive EM&V Framework to guide its EM&V activities (see Exhibit B-1-1, Appendix I, Attachment I-8). The framework has been developed by reviewing industry guidelines and common practices for EM&V activities. One of the FEU's evaluation principles contained in the Framework is that of providing transparency both internal and external to the FEU with respect to EM&V activities. External stakeholders, such as members of the RPAG may request to view final evaluation reports, if they so wish. The regulatory review process by which the FEU receive approval for their EEC funding provides additional transparency for external stakeholders.

Also outlined in the EM&V Framework, the FEU's reliance on independent third party consultants to conduct the majority of the EM&V activities is a common industry practice. These consultants are selected by the EM&V staff and independent of the EEC Program Managers. They are chosen based on a combination of their relevant experience, the level of detail required for the each evaluation project, and the size of the program being evaluated in combination with the consultant's capacity and previous work history. Once selected, the consultant then develops the detailed evaluation plan based on the scope of work provided by the Evaluation staff. When the plan has been approved by the Evaluation staff, the consultant typically develops any necessary market research (for example with participants and with the relevant trade allies), conducts the analysis and develops a report. The independent third party consultants adhere to the industry guidelines, engineering calculations and methodologies, survey reporting analysis and the industry code of ethics for all evaluation activities conducted.

Please refer to the response to BCUC IR 1.214.1 for a description of EM&V activities and BCUC IR 1.214.1.1 for the EEC EM&V Organizational Chart.

214.2.1 How does FEU ensure that there is no incentive to (i) generate overly optimistic measurement results (for example, to overstate benefits or understate costs), and (ii) hide the results of poorly performing EEC programs, instead of learning from them? Please explain.

Response:

The FEU ensure there is no incentive in this regard through the adequate segregation of duties, its organizational structure and the processes and procedures in place that provide additional assurance that biases are not introduced. Please refer to the response to BCUC IR 1.214.2 for a discussion of the organizational structure, procedures and the avoidance of any potential conflicts of interest on EM&V activities.

Further, the FEU do not believe that there is an incentive to generate false results or to hide results about the evaluation of EEC Programs. EEC Programs help consumers make better energy efficiency decisions and the Companies' commitment to provide reliable information and choices for the consumers rely on our ability to deliver supportive and meaningful evaluation results. FEU EM&V Staff and EEC Staff value both the positive and negative evaluation results as it provides input and improvement for program design and implementation.

Among the main objectives of evaluation activities is to determine if programs are being effective, identify possible improvements and/or determine if ineffective programs should be ended. The objectives of measurement and verification activities include helping to confirm energy savings and properly design EEC programs. Program managers take the feedback they receive as a result of EM&V activities into account in the management of their programs and portfolios. Generating overly optimistic results or hiding negative results would not serve any of these objectives.

All final evaluation reports and evaluation summaries are transparent and available to the BCUC and other Stakeholders upon request. All evaluation assumptions, calculations, and methodologies are documented and auditable. All results, positive or negative, are valued and will be used to provide input for future program design and implementation. Indications of poorly performing programs or pilots will provide input to make improvements or may provide justification to discontinue a program.

214.3 Please estimate the cost of annual EM&V review of the FEU EEC EM&V reports by a Commission retained consultant, and indicate what percentage of the EEC budget this would represent.

Response:

This response addresses BCUC IR 1.214.3, 1.214.3.1 and 1.214.3.2.

The FEU are not in a position to calculate the annual cost of an additional review of completed EM&V reports by a Commission retained consultant. The FEU have managed EM&V activities in a prudent manner and achieved the desired objective of EM&V activities. Any further review would place an unnecessary burden on rates.

It is also not industry standard practice to conduct additional third party review of completed EM&V studies. The Companies asked E Source, a leading industry expert on energy efficiency practices, to investigate the incidence of this practice. E Source was only able to identify three utilities whose EM&V studies were subjected to third party review on a regular basis. The E Source response is provided in Attachment 214.3. Note that the FEU interpret the Ontario example cited in the E Source response to be similar to the FEU's current practice.

214.3.1 Does FEU consider it industry standard not to subject EEC EM&V results to independent review? Please explain.

Response:

Please refer to the response to BCUC IR 1.214.3.

214.3.2 If there was to be an independent review of EM&V results, please describe the alternative groups that could be responsible for hiring the consultant (for example, the Commission, FEU EEC Stakeholder Advisory Group etc.), and describe the advantages/disadvantages of alternative approaches.

Response:

Please refer to the response to BCUC IR 1.214.3.

214.4 Is M&V (i) required for every custom program and (ii) used in impact evaluations for non-custom programs?

Response:

(i) Yes, M&V is generally a required component in all the Companies' custom incentive programs. The FEU custom programs include the Commercial Custom Design - New Construction, Commercial Custom Design – Retrofit, and Industrial Technology Retrofit Projects. In the Commercial programs, the extent and degree of M&V will vary from project to project based on factors such as the project size, the incentive amount, or the type of measure being implemented. M&V would not be required for projects where energy savings are derived largely from proven technologies that the Companies are familiar with such as boilers. Projects in the Industrial Custom programs on the other hand (Technology Retrofit custom projects) are often complex, site and technology specific, and therefore will require M&V for every project.

(ii) M&V may be used as part of impact evaluations for non-custom (otherwise referred to as prescriptive) programs, but is not required in all cases. This is because for prescriptive programs, sufficient information regarding energy savings is often available from existing sources such as pre and post consumption data for participants, results from similar programs in other, similar jurisdictions, previously completed third party energy savings studies and in some cases pilot study results, from which a proper impact evaluation can be performed.

214.4.1 What is the process for determining and updating claimed savings for non-custom programs?

Response:

The FEU's response to BCUC IR 1.218.1 explains generally how all of the inputs into the TRC/mTRC calculation are determined and updated, including claimed energy savings. Updating of claimed energy savings is done when new, reliably sourced information becomes available. The best source of technical information will come from impact evaluations, typically conducted by third party consultants, in which energy savings are verified. Programs need to be in market for a sufficient period in order to conduct impact evaluations. Other sources of information that might be considered in estimating and updating energy savings estimates when an impact evaluation has not been conducted might be a review of similar programs in other jurisdictions, results from pilot studies or other technical research, impact evaluation studies from similar programs in other similar jurisdictions or advice from industry experts and consultants.

214.5 Please confirm that all EEC programs planned for 2014-2018 are included in the EM&V Evaluation Plan.

Response:

Confirmed.

214.5.1 Has FEU finalized the EM&V Framework? If yes, please identify any changes to the draft framework filed.

Response:

No, the FEU have not yet finalized the EM&V Framework. The FEU consider the Framework to be largely complete and plan to finalize it by the fall of 2013. At this time there have been no changes to the draft version of the Framework filed with the Application, and the FEU are not anticipating significant changes prior to finalizing. Once finalized, the EM&V Framework will be updated from time to time in consultation with industry and stakeholders as industry practices evolve and are adopted by the Companies.

214.5.2 In developing the Evaluation Plan, how did FEU select the appropriate methodology from the list of evaluation methodologies listed in the EM&V (Draft) Framework?

Response:

The Evaluation Plan for 2014-2018 was developed to reflect the program specific objectives while meeting industry standards in conducting EM&V activities. Staff assessed evaluation needs using the information available to date from existing and planned programs based on the following aspects: program objectives, years the program has been running (program life cycle), the program participant level, previous program evaluation studies, budget constraints, program targets, available resources, and the amount of data and information anticipated to be available to conduct the evaluations. Please also refer to the response to BCUC IR 1.214.1.3 for a description of the process of selecting appropriate evaluation types and methodologies to perform on EEC programs.

The Evaluation Plan for 2014-2018 has been developed to align with the Companies' EM&V budget spending guidelines, evaluation methodologies and approach contained within the EM&V Framework. Within this Framework, the plan will be adjusted as necessary to adapt to new information regarding existing EEC programs and as new programs that are planned but not yet designed or developed.

214.5.2.1 How do evaluation staff identify appropriate indicators and measures for evaluating programs?

Response:

Evaluation staff identify appropriate indicators and measures for evaluation by carefully reviewing program objectives and meeting with program staff to understand the program design and, for existing programs, the program history. Where a program is in its life cycle will in part determine the type of evaluation that needs to be completed (refer to Section 3 of the draft EM&V Framework, Attachment I-8 to Appendix I in Exhibit B-1-1), which in turn helps to identify the types of parameters that should be examined. Once the type of evaluation is determined, staff – often with the involvement of third party consultants who will be conducting all or a portion of the evaluation study - will examine available program, market and/or energy consumption data (depending on the type of evaluation) relevant to the program. This information, in conjunction with a review of the evaluation methodologies that can be employed (refer to Section 3.6 of the draft EM&V Framework), is used by evaluation staff to identify the indicators and measures that will be evaluated. Please also refer to the response to BCUC IR 1.214.1.3.

214.5.3 Please describe the nature of stakeholder feedback on the EM&V Framework. Were there any key points of disagreement? If yes, please describe.

Response:

The FEU received numerous comments from the EEC Advisory Group as well as from program and evaluation partners (BC Hydro and FortisBC Inc. (electric)) that helped the Companies to refine the original draft of the EM&V Framework. Overall the feedback and comments were supportive of the FEU's EM&V Framework and were largely around matters of clarification. There were no key points of disagreement identified.

214.5.4 Are the results of evaluations linked to any performance incentives of EEC program staff? If yes, please describe.

Response:

No, the results of evaluations are not linked to any performance incentives of EEC program staff.

215.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1-1, Appendix I, Section 8, p. 8

Impact Evaluations

The draft EM&V Framework (Appendix I-8 to the Application) states: "generally, impact evaluations are conducted between two and three years following a program's launch" (p. 8).

215.1 Please provide all EM&V reports completed since the last FEI revenue requirement application was filed.

Response:

The FEU interpret this request to be referring to impact evaluation reports as indicated in the preamble to this series of questions.

To date, 5 impact evaluation studies have been completed since the last FEI revenue requirement application filed in May 2011. Many programs have not reached maturity and therefore impact evaluations have not yet been conducted. FEU has plans to conduct impact evaluations to verify savings as more programs reach maturity and sufficient participation rates and energy consumption data are available to properly assess program impact.

Please refer to Attachment 215.1 for the final impact evaluation reports as follows.

a. Efficient Boiler Program (Retrofit) 2011
b. Efficient Boiler Program (Retrofit) 2012
c. Fireplace Timer Pilot Project 2012
d. Energy Specialist Pilot Program Energy Savings Audit 2012
e. Switch N Shrink Program Technical Analysis 2012

Note that while the Switch N Shrink program is not currently part of the EEC portfolio, that impact study evaluates program activity that occurred prior to the Commission's direction to move funding for the program into O&M.

215.2 With respect to past impact evaluations of FEU's EEC programs, what has been the average realization rate at the first impact evaluation?

Response:

The FEU define the realization rate as the ratio of measured savings to the audit predicted savings. It is usually expressed as a percentage. If the predicted and measured savings match exactly, the realization rate would be equal to 100%. When measured savings exceed predicted savings, the realization rate is greater than 100%.

The FEU have completed five impact evaluation studies since the last FEI revenue requirement application filed in May 2011 (refer to the response to BCUC IR 1.215.1). To date, the Efficient Boiler Program is the only program with more than one impact evaluation conducted. As more programs mature, the FEU will have plans to conduct updated impact evaluations for those programs.

The FEU can only calculate the average realization rate at the first impact evaluation for 2 programs based on evaluation studies conducted since the last FEI revenue requirement application. The table below shows the realization rate for the Efficient Boiler Program and the Fireplace Timer Pilot Program at the first impact evaluation. This data results in an average realization rate of 138% A summary of the realization rate calculations for all five impact evaluation studies is provided in the response to BCUC IR 1.215.2.2.

Realization Rate at First Impact Evaluation for Programs Evaluated Since the Last Revenue Requirement Decision.

Evaluation Name (1st Impact Evaluation)	Annual Target Savings as indicated in Business Case	Annual Measured Savings as indicated in Impact Evaluation Report	Realization Rate
Efficient Boiler Program Impact Evaluation 2011	**15%** of pre retrofit consumption	**16%** of pre retrofit consumption	107%
Fireplace Timer Pilot Program 2012	**3** GJ/participant	**5.1** GJ/participant	170%
Average Realization Rate			138%

215.2.1 What percentage of the programs have had an impact rate of greater than 100 percent?

Response:

Since the last FEU revenue requirement filed in May 2011, the FEU have completed five impact evaluation studies. (Please refer to the response to BCUC IR 1.215.1.) As more programs reach maturity, the FEU will conduct more impact evaluations. To date, 60 percent (3 out of the 5) of the programs show a realization rate greater than 100 percent. For the other two programs, a realization rate could not be calculated as energy savings estimates were not established in the program design and objectives. Please refer to the response to BCUC IR 1.215.2.2 for a summary of all past EEC program impact evaluations since the last FEU revenue requirement, with impact evaluations and a realization rate greater than 100 percent, and further details on the two impact evaluations for which a realization rate could not be calculated.

215.2.2 Please provide a summary table listing all past EEC programs with impact evaluations that shows realization rate and the number of months between program inception and the date the study was performed.

Response:

Since the last FEU revenue requirement application filed in May 2011, the FEU have completed five impact evaluations. Please refer to the response to BCUC IR 1.215.1 and Attachments 215.1a through 215.1e for the final reports.

The table below provides a summary of the realization rates, number of months between the program's launch date and the evaluation study start date.

Evaluation Name	Annual Target Savings as indicated in Business Case	Annual Measured Savings as indicated in Impact Evaluation Report	Realization Rate	Program Launch Date	Evaluation Study Start Date	Number of Months between program launch date and evaluation study start date
Efficient Boiler Program Impact Evaluation 2011*	**15%** of pre retrofit consumption	**16%** of pre retrofit consumption	107%	2005	September 2010	60
Efficient Boiler Program Impact Evaluation 2012*	**15%** of pre retrofit consumption	**19.4%** of pre retrofit consumption	129%	2005	January 2012	84
Fireplace Timer Pilot Program 2012	**3** GJ/participant	**5.1** GJ/participant	170%	November 2009	April 2012	31
Switch N Shrink	N/A	**4.63** GJ/participant**	N/A	January 2010	March 2012	27
Energy Specialist Pilot Program Energy Savings Audit 2012	N/A	**8,742** GJ total for 2011 & 2012	N/A	May 2010	July 2012	28

* The Efficient Boiler Program has been in the market since the early 90's and revisions had been made in 2005 and 2012 to suit the objectives of the EEC Program.

** Results considered directional due to small sample size

The realization rates for the Switch N Shrink, and Energy Specialist Pilot Program could not be calculated as energy savings estimates were not established in the program design and objectives for the following reasons. The Switch N Shrink program was an EEC funded program up until 2011 and is currently part of the O&M expenditures. The purpose of the Carbon Emissions and Cost Savings Analysis was to quantify the savings from switching from oil to gas. The realization rate could not be calculated since the heating oil data was not available for the initial target savings assumptions. The FEU have not claimed savings directly from the Energy Specialist Pilot Program. The Energy Savings Audit was conducted to assess the possibility of claiming savings for energy efficiency projects that are not attributed from a current FEI incentive program.

215.2.3 Has there been any correlation between the timing of impact evaluations and the realization rate?

Response:

There is insufficient data available with respect to the FEU's impact evaluations upon which to draw any statistical conclusions about the relationship between impact evaluation timing and realization rate. The FEU stress that in order to conduct a meaningful analysis and obtain meaningful results, sufficient time must be allowed between program launch and evaluation for program uptake and for energy consumption information to become available following the installation of measures. Typically, the best timing for impact evaluations is two to three years following program launch. Beyond this general guideline, the selection of timing for impact evaluations is not an exact science, but rather a balancing of competing factors, resource needs and data collection requirements.

215.3 If an impact evaluation conducted after three years of program activity demonstrated a realization rate substantially lower than 100 percent, what effect would this have on: (i) cost-effectiveness results (both UCT and TRC/mTRC); (ii) program cost-recovery; (iii) shareholder return on equity from rate-base deferral accounts; (iv) ratepayer bill and rate impacts; and (v) future program design decisions?

Response:

If an impact evaluation showed a program result markedly different from that projected during program planning and launch either above or below planning assumptions, cost-effectiveness tests would be rerun and program design adjusted to provide optimal results. If impact evaluation showed program results that were greater than those originally projected, cost effectiveness would be higher than originally projected but there would be no change to the methodology of program cost recovery or shareholder return on rate-base deferral accounts. Similarly, if impact evaluations showed program results that were lower than those originally projected, cost effectiveness would be lower than originally projected, but there would be no change to the methodology of program cost recovery or shareholder return on rate-base deferral accounts. If, for example, the volume of customer participation and therefore of expenditures made by the utility on a particular program was higher or lower than originally projected, the dollar value of shareholder return would vary up or down in proportion to the variation in actual customer participation as opposed to projected customer participation. However, the impacts of this would only be recognized in the next revenue requirement application as customer rates and shareholder return on rate base for the existing period are set on a forecast basis.

In terms of customer bills and bill impacts from a specific program perspective, more participants in a program results in collectively lower bills for participants, and results in collectively higher costs for non-participants, and fewer participants in a program results in fewer customers benefiting from lower bills and lower costs to be recovered from all customers.

Program designs are modified as a regular course of EEC business activity for a number of reasons, including such elements as lower equipment costs resulting from economies of scale, equipment penetration levels, contractor familiarity with equipment, changes to net-to-gross ratios, the introduction of efficiency regulations and standards, changes to program partner plans, and many other factors.

215.3.1 To what extent would any of the above effects been affected if impact evaluations were conducted soon after program launch?

Response:

The Companies are unable to speculate as to the potential results of an impact evaluation conducted soon after program launch. In order for expenditures on impact evaluations to provide value to the EEC initiative, and therefore to ratepayers, a program being evaluated must have enough participants to provide a meaningful sample size. Impact evaluations often involve billing analysis, so in order to provide meaningful billing analysis, some time must elapse after the installation of an energy efficiency measure. Generally speaking, adequate participation levels for a meaningful sample size, and adequate time elapsed after measure installation occurs two to three years after program launch.

215.4 Does FEU consider the benefits of waiting to conduct impact evaluations until two or three years following the program launch outweigh the potential effects on ratepayers and shareholders? Please explain why or why not?

Response:

In order for expenditures on impact evaluations to provide value to the EEC initiative, and therefore to ratepayers, a program being evaluated must have enough participants and energy use data to facilitate meaningful analysis. In following with the principles set out in the EM&V Framework, the timing of impact evaluation must allow sufficient period of program operation for implementation and uptake, including the adoption of process improvements that might be identified during the early program period. Generally, impact evaluations are conducted between 2 to 3 years following a program's launch to allow sufficient program uptake and time for program adjustments and data capture for meaningful analysis. Conducting impact evaluations prior to having relevant data and information would not be a prudent use of customer money. Please also refer to the response to BCUC IR 1.215.3.1.

216.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1-1, Appendix I, Section 2, pp. 18-19, Section 8, p. 16

EEC Advisory Group

On page 18 of the 2012 FEU EEC Annual Report (Appendix I-2 to the Application), FEU states: "...the [Terms of Reference for the Energy Efficiency and Conservation Advisory Group] was finalized in Q1, 2013...The objective of this advisory body is to provide insight and feedback on the Companies' EEC activities and related issues." (pp. 18-19)

Exhibit B-1-1, Attachment I, Section 8 (page 16) states: "Advisory group members are not expected to have a high level of expertise in EM&V and are not expected to provide input on individual evaluation or measurement and verification projects. The Advisory Groups will have access to evaluation report summaries and members may request to see any of the full EM&V reports that are prepared once they are final."

216.1 Please provide an overview of the make-up of the Advisory Group, the selection process, and provide the terms of reference. Please provide a breakdown by interest group.

<u>Response:</u>

The EEC Advisory Group (EECAG) Terms of Reference ("ToR") and current list of EECAG members are contained in Attachment 216.1.

As of the time of filing, the EECAG was made up of 29 members from organizations representing the following areas originally described in the Companies' 2008 EEC Application:

- Provincial, municipal, and First Nations governments
- Non-governmental organizations
- Consumer advocates representing residential customers
- Affordable housing advocates
- Commercial customers
- Trade organizations
- Equipment manufacturers
- Other utilities

Section 5 of the ToR (Membership) provides the following revised description summary of EECAG membership:

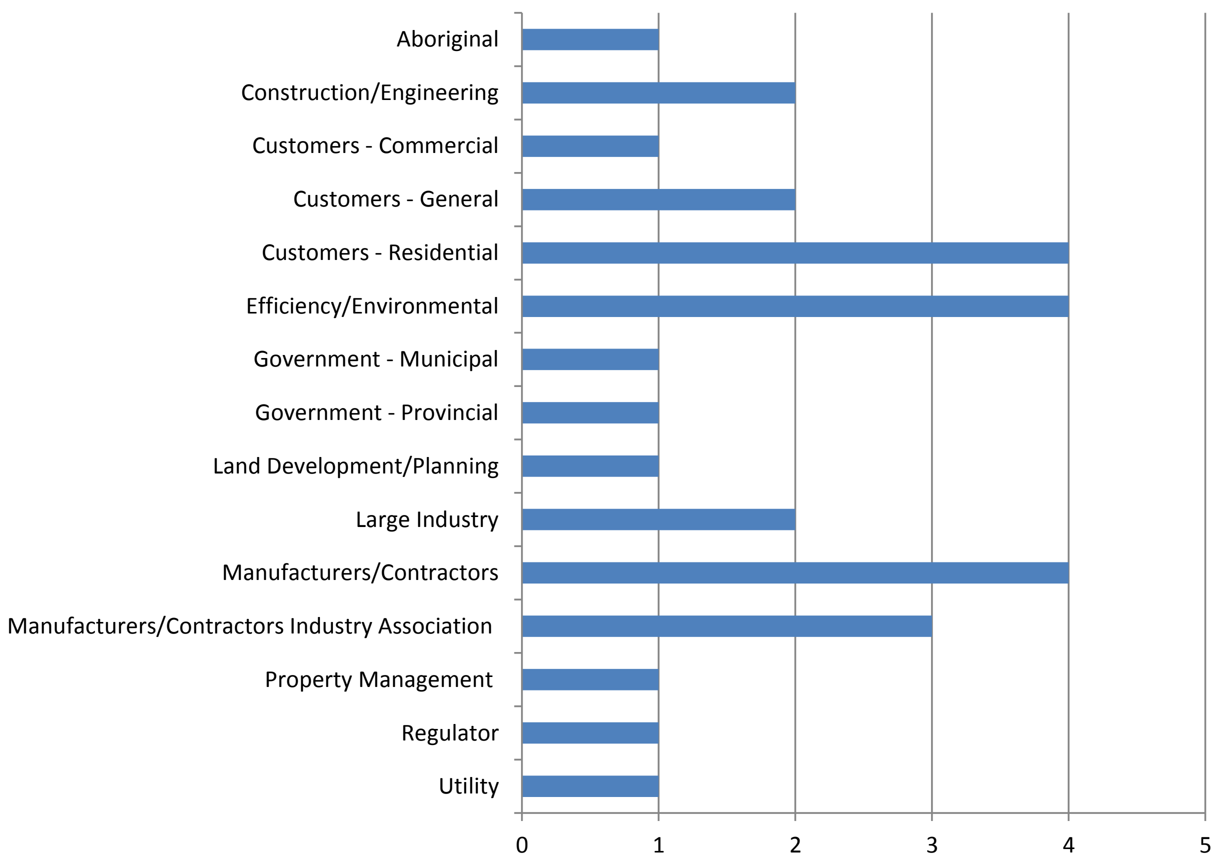
> *"The EECAG is intended to be a consortium representing the broad constituency of FEU stakeholders. Members may be appointed based on their personal capacity (i.e. independent experts), representation of a common interest shared by stakeholders or representation of a particular organization/group (including but not limited to governments, regions, First Nations, customers, suppliers, industries, non-government organizations and research institutes).*
>
> *While the number of members and interest groups they represent are not specifically set, a periodic review will be conducted to assess the adequacy and appropriateness of representation within the EECAG."*

The FEU initiated an EECAG Membership Review in 2013 in order to assess the adequacy and appropriateness of interest group representation. This review, ongoing at the time of filing this response, is being carried out in collaboration with an EECAG Independent Facilitator. The engagement of an Independent Facilitator was initially proposed by the EECAG in 2012 in order to provide neutral, third-party advice and facilitation. The Independent Facilitator is helping the FEU to conduct the EECAG Membership Review, which consists of the following broad steps:

1. Define key interest groups on the EECAG
2. Review current EECAG membership to assess:
    a. Overrepresentation of interest groups
    b. Underrepresentation of interest groups
    c. Need to replace uninterested/inactive members, if applicable
    d. The approximate number of new members sought
3. Identify potential new EECAG members, focusing on:
    a. Underrepresented interest groups
    b. Stakeholders with notable experience/expertise related to EEC
    c. Potential members suggested to FEU and/or potential members expressing interest in joining the EECAG
4. Invite new members to join the EECAG

5. Update EECAG on status/results of Membership Review at subsequent meetings
6. Formalize membership of EECAG group through signing of EECAG ToR
7. To initiate the Membership Review the FEU created an initial breakdown of EECAG members, identifying the key interest group each may represent (see Figure 1).

Figure 1: FEU Breakdown of the EECAG by Interest Group



Although this simple breakdown of the EECAG by interest group may be useful, it was recognized that:

1. EECAG members may represent more than one interest;
2. EECAG members bring a wide range of backgrounds and expertise to the group;

3. It is difficult for the FEU to assess the interests/expertise of the EECAG without input from the group.

For these reasons, the FEU chose to survey the EECAG in order to allow members to assess themselves. In June 2013 a brief online survey was emailed to the group. Results from this survey are depicted in Figures 2 and 3. The differences between the FEU's breakdown of EECAG interest group representation and the results of the survey highlight the fact that this exercise is somewhat subjective and open to interpretation.

Figure 2: EECAG Membership Review Survey Question #1:

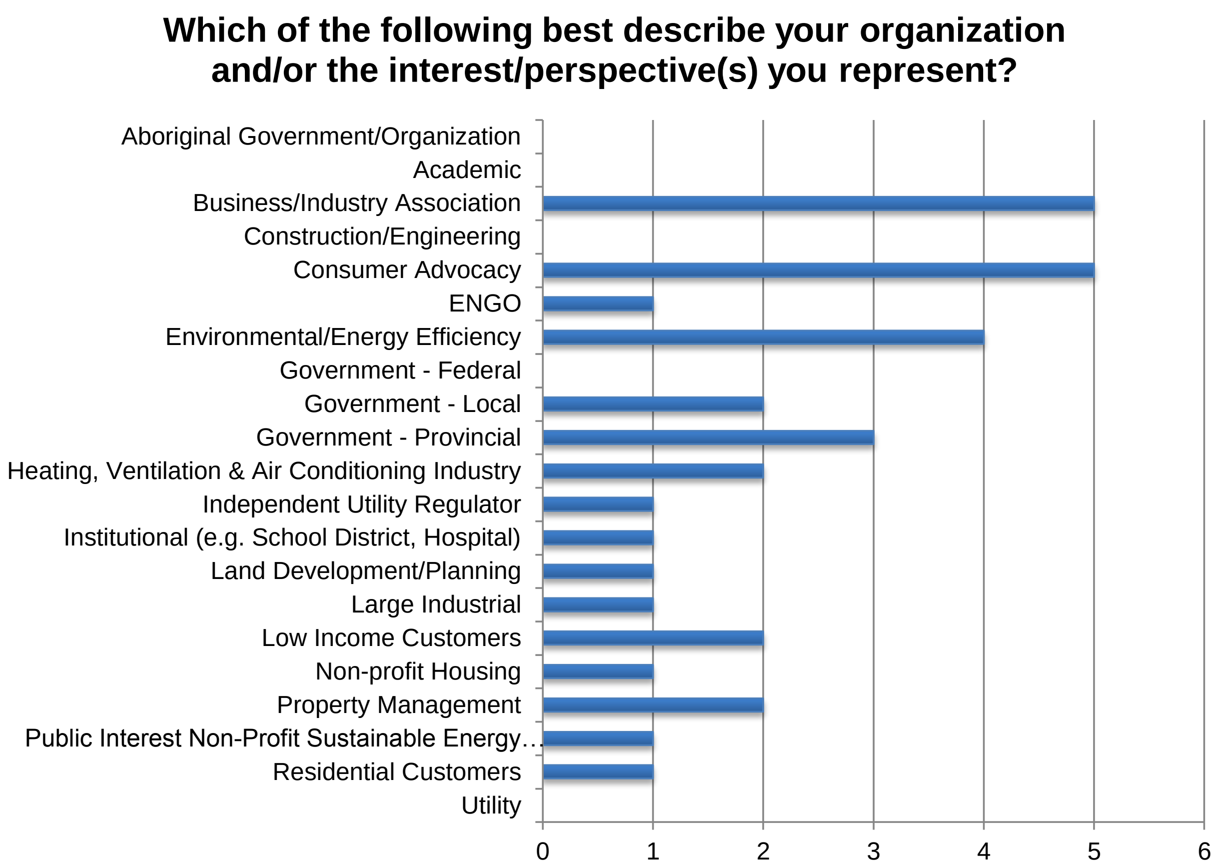
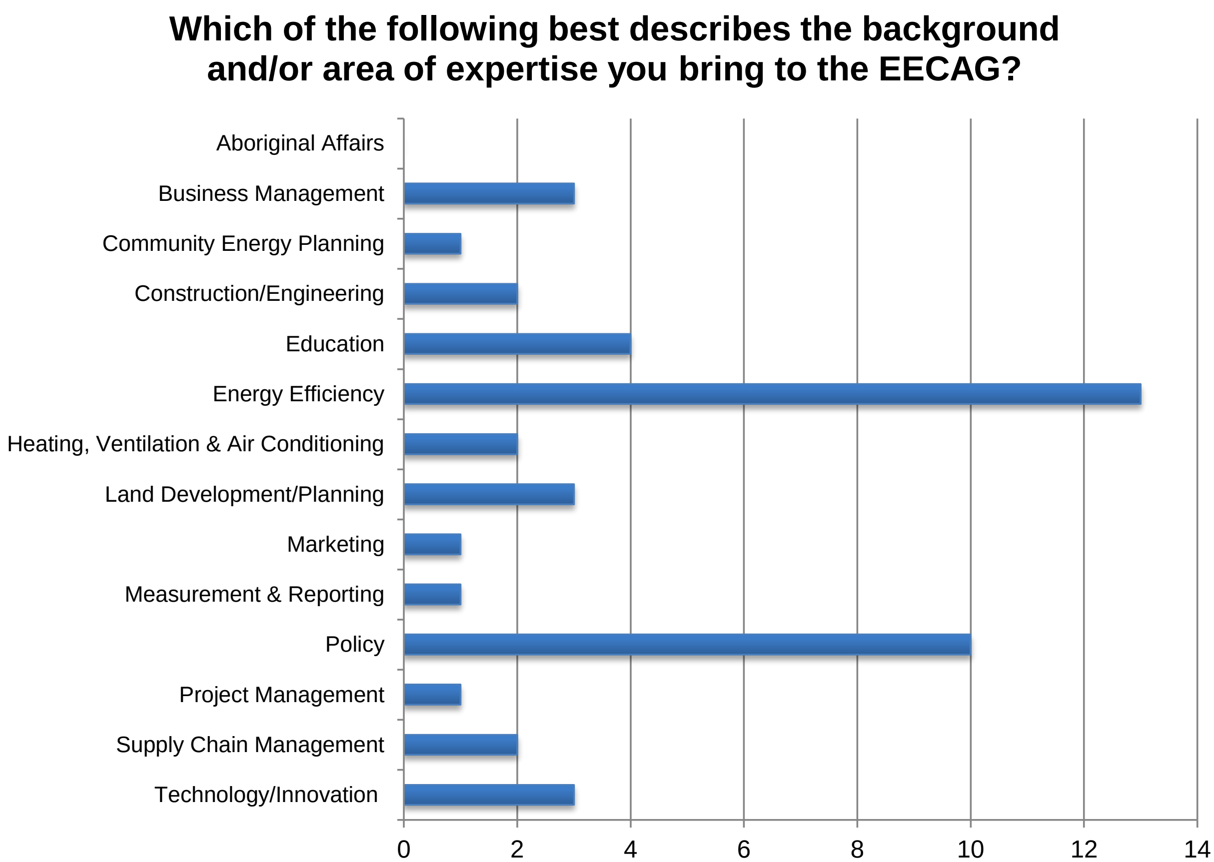


Figure 3: EECAG Membership Review Survey Question #2



The results of the survey were discussed during an EECAG Web Conference held on July 17, 2013. During this web conference EECAG members had the opportunity to comment on the survey results and provide additional input.

These results will only be used for guidance during the Membership Review process. Twenty of the 29 EECAG members responded to the survey, meaning that the results may not accurately reflect the full make-up of the group.

Section 5 of the ToR provides additional guidance on EECAG member selection and will also be used to guide the Membership Review, particularly the selection of new members.

> *"The optimum number of EECAG members is 35... Only one person from any one organization may typically sit as a member of the EECAG. Membership to the EECAG cannot be transferred by members, though members may occasionally appoint someone from their own organization to attend in their place with prior notification to FEU.*

Once the initial EECAG membership is set following the adoption of the final ToR, the process for identifying and inducting new members is:

- *Prospective members will submit in writing (letter or email) a request to join the EECAG, stating their name, organization, contact information and reasons for wanting to join the EECAG.*
- *Prospective members will be considered by FEU. Input from the Independent Facilitator (See Section 6) and/or EECAG members will be considered, but the final decision will rest with FEU.*
- *Membership will be formalized by the signing of these ToR*
- *In the case where a member leaves the organization they are representing a review will be conducted by FEU to determine:*
  - *If that person should remain a member of the EECAG*
  - *If an alternative person from that organization should be chosen to join the EECAG (with prior agreement by both that organization and FortisBC and providing the membership requirements are met)*
  - *If that seat should be vacated and made available for a potential new member*

FEU recognizes that in some cases it is the participation of an influencer within an organization that is important to the FEU-EECAG objectives, while in other cases it may be the expertise and experience of an individual that is desired, provided that individual remains engaged in the energy efficiency field. This aspect will be considered in the review.

Members who are consistently absent, fail to participate or do not adhere to these ToR may be asked to leave the EECAG."

The membership review process is ongoing. The FEU, with the help of the EECAG Independent Facilitator, is in the process of assessing the make-up of the group and identifying potential new members.

216.2 Please describe the product design stages where feedback is sought from the EEC Advisory Group, and the mechanisms FEU uses to solicit feedback from the Advisory Group.

Response:

This response addresses both this IR and BCUC IR 1.216.2.1. The FEU interpret the term "product design stages" to refer to EEC program design.

Seeking Program Design Feedback

Because the backgrounds, interests and expertise of members of the EECAG are so broad, it is not typically appropriate to seek program design input from this group as a whole. Rather, where stakeholder input is needed for program design, a review of interest groups specific to that program area is conducted to select stakeholders for an invitation to a program design forum such as a program design workshop. Unlike EECAG workshops, which are typically held biannually and may cover a wide range of topics, program design workshops allow the FEU and stakeholders to focus in on the issues unique to a program. These workshops are typically attended by individuals with expertise in the area in question and are considered a more efficient and cost-effective way to gather program-specific input than EECAG workshops. The FEU have implemented the practice of informing the EECAG of any program design forums in which stakeholder feedback is being sought and inviting interested EECAG members to attend those forums. In addition, the EECAG are encouraged to bring program ideas forward from their organizations, interest groups and their own experiences for consideration by the FEU.

The nature of program design forums and the mechanisms for seeking feedback will vary depending on the information needed from stakeholders to help complete program design. The FEU may seek third party, expert assistance with designing/conducting effective stakeholder input forums and feedback mechanisms (both in terms of costs and results), and will continue to survey the industry for innovative, cost effective ways to achieve effective stakeholder feedback on program design.

Mechanisms to Solicit Feedback from the EECAG

The FEU may use a variety of mechanisms to gather feedback on issues brought before the EECAG including, but not limited to workshops and facilitated break-out sessions, facilitated question and answer sessions, surveys, written comments on draft documents and more. EECAG forums may be conducted in person, by phone, via the internet or through electronic communication. Since retaining a third party facilitator as recommended through EECAG feedback, the FEU generally seek ideas and advice from that facilitator on designing workshops and other feedback mechanisms to ensure adequate opportunity for each member to participate and for the FEU to capture feedback, all in accordance with the ToR.

216.2.1 What other mechanisms does FEU use to solicit feedback from third parties on program design, and is the Advisory Group process considered a cost-effective way for FEU to obtain this input compared with other mechanisms (for example, program specific workshops)?

Response:

Please refer to the response to BCUC IR 1.216.2.

217.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Guide to the Demand-Side Measures Regulation, BC Ministry of Energy and Mines, p. 4[33]; Adventures in Tweaking the TRC: Experiences from British Columbia, BC Ministry of Energy and Mines, FEU and FortisBC, 2012[34]

Purpose of Total Resource Cost Test

Page 4 of the BC Ministry of Energy and Mines Guide to the Demand-Side Measures Regulation states:

> "...s. 4(1.1) requires that the commission 'must make determinations of cost effectiveness by applying the total resource cost test' as modified by a set of instructions...The TRC test is a cost-benefit calculation in which one of the benefits is the avoided cost of the energy saved by the DSM. In a TRC test this is typically valued at the marginal cost of that energy to the utility.
>
> One of the principal components of the MTRC is the use of the price signal for a zero-emission energy supply alternative (ZEEA) as the avoided cost of energy for DSM. Section 4(1.1)(a) specifies that the ZEEA value for avoided natural gas from DSM be BC Hydro's long run marginal cost (LRMC) of acquiring electricity generated from clean or renewable resources in BC."

A joint BC Ministry of Energy and Mines, FEU and FortisBC paper titled "Adventures in Tweaking the TRC: Experiences from British Columbia" states in the conclusion: "By tweaking the TRC, the BC government hopes to achieve a positive outcome for its emission reduction and energy savings targets...Unfortunately, the complexity of the topic...have resulted in a very complex regulation. This complexity has increased the likelihood of interpretation errors and unintended consequences."

217.1 Please describe how FEU calculates both the Total Resource Cost Test (TRC) and the Modified TRC (mTRC).

<u>Response:</u>

The FEU calculate the Total Resource Cost (TRC) Test as a benefit-cost ratio of the discounted total net benefits of the program to the total net costs over a specified time period. The benefits calculated in the TRC are the avoided supply costs of the gas that would otherwise be delivered to the customer in the absence of the program (refer to the response to BCUC IR 1.218.2 for an

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33 http://www.empr.gov.bc.ca/EEC/Strategy/EEA/Documents/Guide%20to%20the%20DSM%20Regulation%20August%202012.pdf

34 http://www.aceee.org/files/proceedings/2012/data/papers/0193-000258.pdf

explanation of the avoided cost of gas in the conventional TRC). The costs in this test are the incremental costs (the cost to install the incented equipment over what would otherwise have been installed in the absence of the program) and the administration costs for the program. All incremental costs such as equipment costs, installation, operation and maintenance, cost of equipment removal no matter who pays for them, are included in this test.

The Modified TRC calculation has the same methodology as TRC calculation with only two alterations. The first alteration is that the value of the discounted total net benefits of the program is calculated based on 50% of BC Hydro's long term marginal cost for acquiring electricity generated from clean or renewable resources in BC rather than the cost of regular gas supply as used by TRC calculation. The second alteration is a 15 percent adder added on top of the total net benefits in lieu of additional non-energy benefits such water savings and job creation that result from the program being in the market.

Please note: In the course of responding to this IR and reviewing evidence related to the MTRC subject matter, FEI have noted that there was an error on page 13 of Exhibit B-1-1, Appendix I1 related to the application of the MTRC to the Innovative Technologies program area. The statement on that page under Directive 75 should have read "The expenditures in this Innovative Technologies Program Area..... are not subject to the 33 percent cap for expenditures that do not pass the MTRC test as written in the DSM Regulation as discussed in Section 8.2." FEI will update this page in its next Evidentiary Update.

217.2 Does FEU consider that the purpose of the TRC/mTRC could be described as identifying whether there would be a BC benefit from encouraging customers to change their investment decisions or behaviors in a way that provides similar or improved level of service from the energy consumed? Please explain why/why not.

<u>Response:</u>

Please refer to page 6-6 of the paper "Understanding Cost-Effectiveness of Energy Efficiency Programs", provided in Attachment 217.2:

> *"The primary purpose of the TRC is to evaluate the net benefits of energy efficiency measures to the region as a whole…The TRC is useful for jurisdictions wishing to value energy efficiency as a resource not just for the utility, but for the entire region…The TRC may be considered the sum of the PCT [Participant Cost Test] and the RIM [Ratepayer Impact Measure], that is the participant and non-participant cost-effectiveness tests.*

> *The TRC is also useful when energy efficiency might fall through the cracks taken from the perspective of individual stakeholders, but would yield benefits on a wider regional level."*

The FEU concur with this interpretation of the TRC, namely that the TRC evaluates whether or not British Columbia generally is better or worse off from EEC activity that encourages customers to change their investment decisions or behaviours. As referred to in the response to BCUC IR 1.209.1, the Companies' EEC activity incorporates not only energy efficiency but also conservation, so the level of service resulting from a change in energy use or an equipment upgrade may decline if, for example, a customer decides to turn down the thermostat and put on a sweater instead.

The use of the MTRC results from a government regulation, so the Companies refer back to material created by government to support stakeholders in interpreting the Demand Side Measures Regulation, such as the Guide to the Regulation referred to in the Information Request. As can be seen on page 7 of "Overview of the DSM Regulation", also provided in Attachment 217.2, the MTRC is intended to "provide a consistent avoided supply cost that reflects a zero greenhouse gas emitting source".

217.2.1 Does FEU consider that the optimal EEC portfolio may not be the one with the highest overall TRC/mTRC, for example, where energy efficiency investment costs are high as the product is new, or is there a onetime opportunity to make a deep (rather than shallow) EEC investment? Please explain why/why not.

Response:

Yes, the FEU would concur that the optimal EEC portfolio may not be the one with the highest portfolio TRC/MTRC. In addition to the examples in the Information Request of high upfront costs, or a onetime opportunity for a deep retrofit, a key principle for the Companies is that programs must be available for all customers. It can be seen from the 2014-2018 EEC Plan, Exhibit B-1-1, Appendix I, Attachment I1, page 9 that the Residential and Low Income Program Areas have Program Area TRC results of below one. If the Companies were to design a portfolio of EEC activity to maximize TRC/MTRC, that portfolio would be very heavily focused on the Commercial and Industrial Program Areas.

217.3 Does FEU consider that the mTRC is a refined version of the TRC as it includes (i) a proxy for the long-term benefit to BC of any reduced gas emissions resulting from the behaviour/investment change, and (ii) an estimate of additional non energy benefit the customer may receive from making the investment (such as comfort, improved health, reduced noise etc.)? Please explain why/why not.

Response:

The FEU would describe the MTRC as a modified version of the TRC, rather than using the word "refined". The FEU would consider the MTRC to incorporate a wider view of the benefits of the FEU's EEC activity, given that such activity results in GHG emission reductions.

217.3.1 Does FEU agree that, if the long-term value of emission reduction or non-energy benefits is overstated in the mTRC (but the program passes the UCT), the parties adversely affected are the program participants and not non-participating utility customers? If no, please explain why not.

Response:

No. Program participants benefit as do all British Columbians from GHG emission reductions. The use of the MTRC and the associated values given to GHG emission reductions is established by government regulation.

217.4 Please identify any programs which FEU has been unable to demonstrate will pass the TRC/mTRC and where the reason is not related to a difficulty in identifying annual gas savings.

Response:

This response addresses both this IR and BCUC IR 1.217.4.1.

There is only one program within the 2014-2018 EEC Plan that the FEU have not been able to show passes the TRC (or the MTRC in cases where the program does not pass the TRC), and where the reason is not related to a difficulty in identifying annual gas savings:

- Low Income ECAP

The ECAP program is designed to be very similar to best-in-class programs offered in other jurisdictions to low income customers. Since the FEU have partnered with BC Hydro on the ECAP program, it is being offered in a cost efficient way while maintaining adequate assurances for safety and customer satisfaction. The benefits of enabling cost savings through energy efficiency to this customer segment are many and a portion of these benefits, including some benefits that serve the broader Province of BC, are not recognized by TRC even with the 30% benefit adder to the TRC calculation. It should be noted that the BCUC approved the Low Income ECAP program as part of the FEU's EEC portfolio in the 2012-2013 Revenue Requirements Proceeding.[35] Further, while the Low Income ECAP program individually fails the TRC, overall, the FEU's portfolio of EEC Programs does pass the TRC and MTRC. As discussed in Section 6.1.1, pages 23-24, of Appendix I of Exhibit B-1-1, the portfolio-level analysis of cost-effectiveness testing has been consistently approved by the Commission and there are good reasons to continue with this approach.

217.4.1 For programs identified above, please provide an explanation as to why FEU considers that undertaking this measure should provide a net benefit to BC

Response:

Please refer to the response to BCUC IR 1.217.4

[35] BCUC Decision in the Matter of the FortisBC Energy Utilities, 2012-2013 Revenue Requirements and Rates proceeding, April 12, 2012, page 148.

217.4.2 For programs were FEU has been unable to demonstrate will pass the TRC/mTRC as a result of difficulty in identifying annual gas savings, please identify the steps FEU is taking, if any, to improvement the measurement of annual gas savings.

Response:

For all other programs identified within the 2014-2018 EEC Plan that the FEU have been unable to demonstrate passing the TRC or the MTRC, the reason for not passing the TRC or the MTRC is in whole or in part a result of difficulty in identifying or measuring the annual gas savings from that program. These programs or program areas are:

- Residential Appliance Service Program
- Residential Financing Pilot
- Conservation Education and Outreach (all programs)
- Commercial Energy Specialist Program
- Low Income REnEW Program
- Enabling Activities

These activities show annual energy savings of zero in the Summary of Savings and Cost Effectiveness Results tables provided in the EEC Plan. In some cases the difficulty in identifying savings arises because the annual 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. In all cases, these are important programs for supporting the overall portfolio and the FEU believe that the reported or estimated energy savings from the portfolio are understated as a result of not being able to determine an energy savings value from these programs. An explanation of the steps, if any, that the FEU are taking to improve measurement and reporting of energy savings for each of these programs / program areas follows.

The **Residential Appliance Service Program** provides customer education related to the importance of regular appliance maintenance to ensure efficient operation of natural gas appliances. 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. The FEU do not expect to try to measure the energy savings from this program as separating the impact of this program on customer knowledge of energy efficiency and on contractor ability to influence energy equipment choices from the influence of other programs is too difficult.

The **Residential Financing Pilot Program** is still under program development and as such, so is the methodology for estimating and measuring energy savings.

For the **CEO Program Area**, the FEU has no plan at this time to measure and attribute energy savings. Due to the behavioral nature of many of these program objectives, the associated energy savings are difficult to estimate, track and measure. The companies previously attempted to identify some savings from these programs; however, the savings they were able to identify were too small to further justify the costs of calculating and evaluating. If the Companies identify examples from the industry where savings from these types of activities have successfully been tracked and measured or estimated with confidence, they may re-investigate attributing some savings in the future.

The FEU hired a third party engineering firm to conduct an annual energy audit for the **Commercial Energy Specialist Program** (see the response to BCUC IR 1.215.1 for a copy of the audit). That study identified some energy savings that the FEU were able to include in the overall portfolio savings, and recommendations were made for improved tracking of Energy Specialist activities and results for improved project and energy consumption data, in order to calculate program level savings. The energy savings attributable to this program are from any ad hoc projects undertaken by the Specialists, making it difficult to forecast such savings (see also the response to BCUC IR 1.227.3).

The FEU do not expect to be able to measure and attribute energy savings for the **REnEW Program**. This is a training program that provides graduates with skills and knowledge about energy efficiency that they will use in a myriad of ways and occupations in their new employment ventures. This makes the tracking and quantification of resulting energy savings too difficult.

Enabling Activities are a range of initiatives that support the overall portfolio and the delivery and effectiveness of other programs. Where the energy savings for these initiatives can be identified and tracked, the FEU will continue to explore appropriate methodologies for doing so. For example, the FEU are exploring the identification and attribution of energy savings from codes and standards work and intend to claim those savings when an appropriate and defendable methodology is identified. In some other cases, the benefits that result from enabling activities that support other programs are inherent in the energy savings attributed to those programs.

217.5 Please confirm that the TRC/mTRC does not include the cost of the incentive provided by the utility as this is a wealth transfer. For example, if an energy efficiency investment cost $1,000 before any incentive and the incentive was $400, the TRC/mTRC calculation would either (i) include the $1,000 as the BC cost, or (ii) include $600 as the BC cost plus the cost of the incentive of $400 for the same total amount as $1,000.

Response:

The FEU can confirm that the TRC/mTRC calculation does not include the cost of the incentive provided by the utility.

217.5.1 Does FEU agree that increasing the FEU EEC incentive (for example from 5 percent of the product price to 100 percent of the product price) will generally not affect the TRC/mTRC result?

Response:

The FEU agree that increasing the FEU EEC incentive will generally not affect the TRC/mTRC result.

217.5.2 Does FEU consider that the effect identified above means that the TRC/mTRC should generally not be used as the only measure to determine the cost effectiveness of EEC programs? If no, please explain why not.

Response:

As explained in Section 6 of Appendix I to the Application, Exhibit B-1-1, the FEU consider that the appropriate way to determine the cost effectiveness of EEC programs is to apply the TRC / mTRC test at the Portfolio level. It is also useful to calculate and monitor other cost effectiveness tests both at the portfolio and individual program levels (and have thus been consistently reporting a range of cost effectiveness test results in its EEC Annual Reports), but these other tests should not be applied to determine whether a program is implemented or not. Other cost effectiveness tests can provide information about the impacts of EEC programs from different perspectives. However, the benefits of EEC investments are better optimized by having a robust portfolio of programs working together to provide all customers with access to programs while achieving energy savings. Setting additional cost effectiveness rules at the program level could result in the removal of important supporting programs or could reduce accessibility to programs, compromising the effectiveness of the portfolio as a whole.

Further, the appropriate way to set program incentive levels is by using market research and good program design approaches, rather than by applying additional cost effectiveness hurdles at the program or portfolio levels. This approach will allow incentives to be set based on the objectives of the program and challenges in the market place to program success, rather than by their impact on rigid cost effectiveness rules. The strength of the program design and approval process that the FEU has in place and the transparency with which EEC activities are reported will both continue to ensure that incentive levels are set appropriately.

Since the TRC/mTRC examine the cost effectiveness of EEC Programs from the societal perspective, the FEU believes that the current, approved approach of determining the cost effectiveness of EEC programs by using the TRC/mTRC at the portfolio level remains appropriate for the 2014-2018 EEC Plan period.

217.5.3 Does FEU consider that the TRC/mTRC is more of a pass/fail test (i.e. an initial screening tool), or does FEU consider it should maximize its TRC/mTRC portfolio results? Please explain.

Response:

The FEU consider that at the portfolio level the TRC/mTRC is a pass/fail test, but are unsure of the Commission's intended meaning about its use as an initial screening tool. There are many factors that go into deciding the programs and activities that will make up an optimal EEC portfolio, and the FEU did not stop improving their portfolio based on its cost effectiveness result.

At the program level, the FEU seek to design programs to maximize the TRC/mTRC results, as this will lead to improved TRC / mTRC results at the portfolio level and thus a more optimal use of EEC expenditures, while including considerations such as:

- fair access to programs by all customers,

- the importance of supporting activities for which energy savings cannot be attributed, and
- overhead costs such as labor, training, transportation, capacity building and consulting services that are essential for an effective EEC effort.

217.5.4 Does FEU consider that free rider/spillover estimates have a greater effect on the UCT than the TRC/mTRC as, with the exception of 'program administration costs/participant,' the TRC/mTRC can be calculated on the investment/behaviour the utility is looking to incentivize, rather than the EEC program itself? Please explain why/why not.

Response:

The FEU do agree that, if the free rider rate does not fully offset the spillover effects (or vice versa), their inclusion in the cost effectiveness tests will generally have a bigger impact on the UCT than the TRC. The reason for this difference is that free riders and spillover are applied to both the benefits and the costs (except for administration costs) in the TRC/mTRC calculation, but only to the benefits in the UCT. The intended meaning of the distinction that this request is drawing between "the investment/behavior" and the "EEC program itself" is unclear to the FEU.

218.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1-1, Tab C, Section 4.3.1, p. 204; Exhibit B-1-1, Appendix I, p. 24; Conservation and Demand Management Cost Effectiveness Guide, Ontario Power Authority, 2010, p. 6[36]

TRC – Key Inputs

FEU described the Total Resource Cost (TRC) Test on page 24 of Appendix I to the Application.

On page 204 of the Application, FEU states: "Sustainment Capital – Consists of...system reinforcements to the distribution and transmission systems to maintain capacity to meet existing and forecast load."

The Ontario Power Authority 2010 Conservation and Demand Management Cost Effectiveness Guide states on page 6: "Inventive costs may include cash payments, in-kind contributions and/or tax benefits that the program-sponsoring institution provides to participating customers..."

218.1 Please identify the inputs into a TRC/mTRC calculation, and provide an overview of the methodology used to calculate the value of these inputs.

Response:

TRC:

The typical inputs into a TRC calculation are as follows:

- incremental costs (the cost to install the incented equipment over what would otherwise have been installed in the absence of the program),
- value for energy savings, based on the avoided cost of natural gas (TRC),
- amount of energy savings per measure,
- number of participants,
- free rider rate,
- spillover rate (if applicable),
- measure life,
- program non-incentive costs, and the
- discount rate based on the weighted average cost of capital.

[36] http://www.powerauthority.on.ca/sites/default/files/OPA%20CDM%20Cost%20Effectiveness%20Test%20Guide%20-%202010-10-15%20F.pdf

For measure attributes such as incremental costs, energy savings per measure, free rider rates and measure life, there are a number of ways in which the value of the inputs might be determined, depending on the availability and quality of information. At the program design stage, the program designer conducts a review of available market information, technical studies and experience of DSM providers in similar jurisdictions. The program designer may also call on assistance from internal energy utilization managers or external expert consultants to assist with this review. Market information will be obtained from surveys, secondary market research, program experience from similar jurisdictions and other useful sources and can be used to develop estimates for participation, free riders and spillover (if applicable) and measure life. Forecasted administration costs are estimated based on previous program data or experience with similar programs. The identification of any or all of these inputs may be aided by the inclusion of industry and customer stakeholders in a design development workshop or other program design tools for refinement. As the program is in market, key information is obtained from participant feedback on application forms, surveys and ultimately, consumption analysis. The FEU have set up a process led by staff responsible for EM&V activities, to review the estimated values for these inputs, assumptions and information sources and ensure that the inputs are reasonable based on the best available information.

At various stages of the life cycle of a program, these inputs will be subjected to different types of evaluations (see the FEU's EM&V Framework, Attachment I-8 to Appendix I, Exhibit B-1-1), or new market information may become available. In each case, this new information may lead to adjustments to the inputs. These updates will be reported in the compliance filing Annual EEC Report.

Program non-incentive costs are estimated using the best available information at the design stage and revised based on actual recorded costs once the program is in market. The methodology for determining the Companies' avoided cost of gas is described in the response to BCUC IR 1.218.2. The discount rate used to discount future values in the calculation is updated annually and represents the Companies pre-tax weighted average cost of capital, adjusted for inflation (see the responses to BCUC IRs 1.218.6 and 1.220.2).

MTRC:

The inputs into the MTRC calculation are the same as those for the TRC except for the value of the avoided energy consumption and a value that represents additional, non-energy benefits not included in the TRC. The methodologies for determining these values are defined by the BC Demand-side Measures Regulation. Currently, the avoided cost of energy in the MTRC calculation is set at 50% of BC Hydro's long run marginal cost for clean renewable power (also referred to as the zero emission energy alternative or ZEEA), and the non-energy benefits are included by increasing the benefits side of the calculation by 15%.

218.2 Please provide evidence to support the long-run marginal cost of gas used in the TRC calculation.

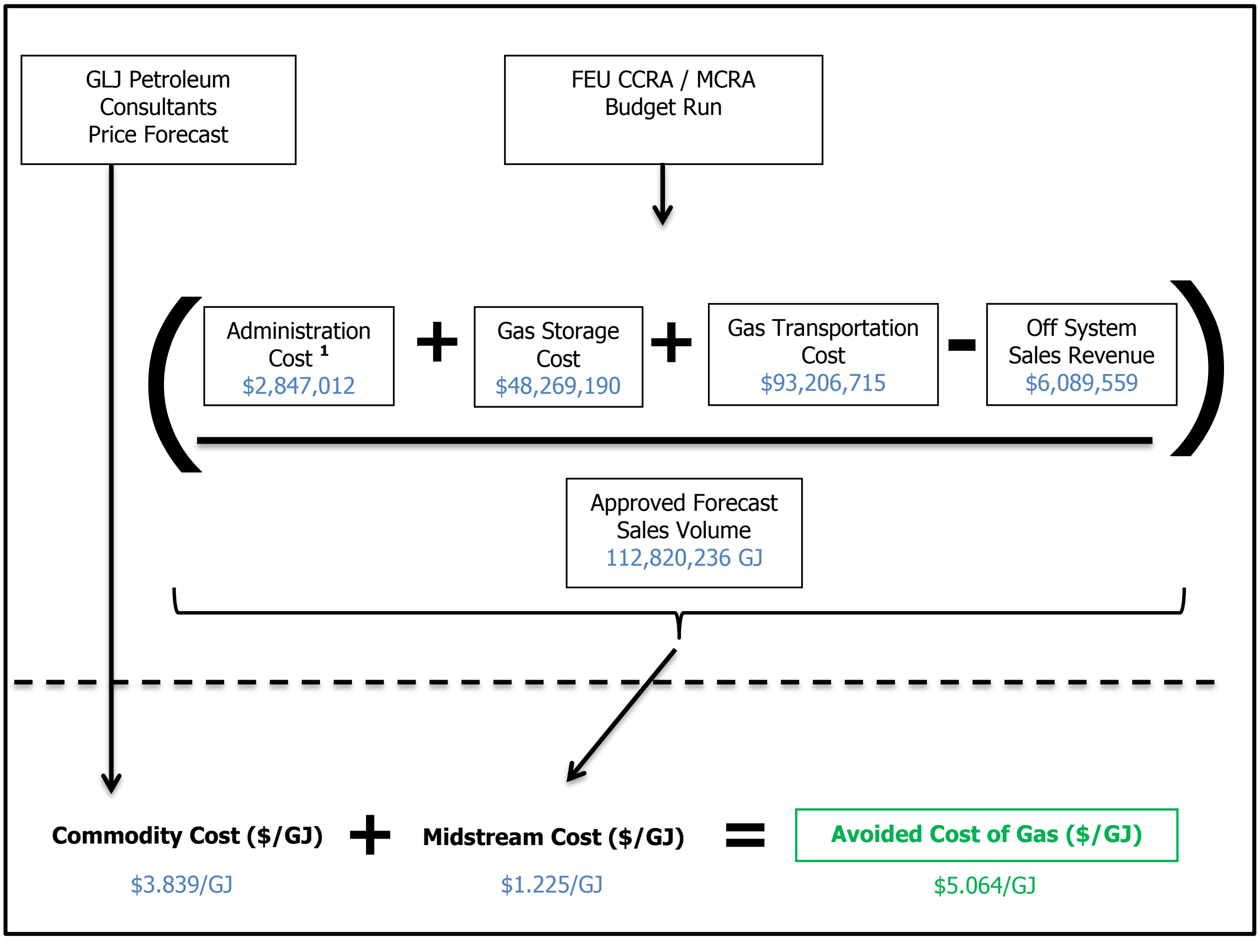
Response:

This response also addresses BCUC IRs 1.218.7 and 1.220.3, and provides the explanation requested in BCUC IR 1.218.2.1.

The FEU use an avoided cost of gas based on gas commodity and midstream transportation and storage costs in the TRC calculation. The figure below 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 volume[37] (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.

[37] The approved forecast sales volume is composed of sales volumes for Rates Schedules 1 – 7 for FEI and sales volumes for FEW

Avoided Cost of Gas Calculation



[1] The administration cost used is the Core Market Administration Expense for managing midstream costs

To date, the FEU have not included the benefit of long range avoided capital costs related to system capacity expansion in the avoided costs of the TRC calculation. The reason for this omission is twofold: 1) the timing of and preferred options for capacity expansion projects beyond the next few years is uncertain, creating a broad range of potential costs, and 2) EEC programs are not expected to reduce peak demand sufficiently to defer capacity expansion projects by more than a few years at most, and confirming such impacts is difficult. Therefore the benefit of reduced annual gas demand on a customer's bills is expected to outweigh the benefit of avoided capital costs. It should also be noted that capital costs for system sustainment would not be impacted by EEC programs as maintaining the system infrastructure is necessary, regardless of trends in overall energy demand.

218.2.1 Is there any difference between the gas product used to determine the long-run marginal cost of gas (for example, delivery location, shape, firmness, environmental attributes, take-or-pay requirements) and the gas product effectively obtained through EEC? Please explain.

Response:

No. Please refer to the response to BCUC IR 1.218.2.

218.3 Please provide evidence to support the ZEEA value used in the mTRC calculation.

Response:

Please refer to Section 6.1.3.1, page 25, of Appendix I (Exhibit B-1-1) for a discussion of the ZEEA value used by the FEU in the MTRC calculation. As indicated there, the Companies have used a value of $129/MWh x 0.5 for the ZEEA and BC Hydro has confirmed that this is the value for the Long Run Marginal Cost of clean or renewable power. The source for the figure is BC Hydro's October 2010 Report on the RFP Process for the Clean Power Call Request for Proposal. Please refer to Table 3-5 on page 12 of Attachment 218.3.

Subsequent to the development of the Plan, on August 8, 2013 BC Hydro held a workshop with Commission staff and Interveners, at which it was indicated that BC Hydro's Long Run Marginal Cost of clean or renewable power may be changing. BC Hydro staff indicated during that session and in an email to the FEU's Director, EEC, that a value of $85-$100 may be more appropriate.

218.3.1 Does FEU consider that the ZEEA is a proxy for the long-run marginal cost (LRMC) of gas plus long-run marginal cost of emissions?

Response:

As stated on page 24 of Appendix I of Exhibit B-1-1, the FEU consider that the use of the ZEAA recognizes that avoiding natural gas use has similar GHG emission reduction benefits to that of employing clean electricity to meet that energy need.

218.3.1.1 How would a change in BC Hydro's LRMC (either up or down) affect FEU's EEC's activities during the PBR period? Please explain, and include in your response if FEU considers that a significant changes in BC Hydro's LRMC could affect the ability of ZEEA to remain a reasonable proxy for the LRMC of gas plus LRMC of emissions.

Response:

The table below shows the impact that changes in the LRMC for clean renewable power have on programs in the 2014-2018 EEC Portfolio. The value used to calculate the "MTRC (Std.)" results was the value used in the 2014-2018 EEC Plan originally generated - $129/MWh.

Programs affected by varying levels of LRMC

Program and Service Territory	Benefit/Cost Ratios					
	TRC	MTRC ($190/MWh)	MTRC ($160/MWh)	MTRC (Std.)	MTRC ($100/MWh)	MTRC ($70/MWh)
* Furnace Replacement Program (Residential)						
FEI	0.50	2.03	1.71	1.41	1.07	0.75
FEVI	0.51	2.08	1.75	1.44	1.09	0.76
Total	0.50	2.04	1.72	1.41	1.07	0.75
* ENERGY STAR® Water Heater Program (Residential)						
FEI	0.62	2.54	2.14	1.76	1.34	0.93
FEVI	0.64	2.59	2.18	1.80	1.36	0.95
Total	0.63	2.54	2.14	1.77	1.34	0.94
* New Home Program (Residential)						
FEI	0.40	1.62	1.36	1.12	0.85	0.60
FEVI	0.41	1.66	1.40	1.15	0.87	0.61
Total	0.40	1.62	1.36	1.12	0.85	0.60
* New Technologies Program (Residential)						
FEI	0.37	1.49	1.26	1.04	0.79	0.55
FEVI	0.37	1.51	1.27	1.05	0.80	0.56
Total	0.37	1.50	1.26	1.04	0.79	0.55
* Customer Engagement Tool for Conservation Behaviours (Residential)						
FEI	0.86	3.69	3.11	2.56	1.94	1.36
FEVI	0.85	3.68	3.10	2.55	1.94	1.35
Total	0.86	3.69	3.11	2.56	1.94	1.36
* Continuous Optimization Program (Commercial)						
FEI	0.82	3.41	2.87	2.37	1.79	1.26
FEVI	0.77	3.21	2.71	2.23	1.69	1.18
Total	0.82	3.40	2.86	2.36	1.79	1.25

* Program requires t **Note:** Whistler (FEW) is included in the FEI service territory

* Program requires the MTRC in order to pass the economic screen

It can be seen in the table above that lowering the ZEEA value affects Residential customers. A ZEEA value using $100/MWh as the LRMC for clean renewable power causes the New Home and New Technologies program to drop out of the portfolio of activity, and a ZEEA value that uses $70/MWh as the LRMC for clean renewable power causes two more Residential programs, the Furnace Replacement and Energy Star® Water Heater programs, to drop out of the portfolio of activity.

As referred to in the response to BCUC IR 1.218.3.2, the ceiling price for biomethane is currently $16.87/GJ. The Companies continue to believe that the ceiling price for biomethane is an appropriate figure to use for the ZEEA for natural gas DSM activity, as it represents the value of an environmentally benign gaseous fuel. Please refer to Attachment 218.3.1.1 for further discussion on the use of biomethane as the avoided cost for natural gas DSM.

218.3.2 Please provide a comparison of the ZEEA value used in the mTRC calculation (in $/GJ) with the cost of biomethane.

Response:

In the FEU 2012-2013 RRA proceeding, the FEU had proposed to use the ceiling price of biomethane as the avoided cost of energy input to the cost benefit tests. The current value for the ceiling price of biomethane is $16.87/GJ. In comparison, the ZEEA value used in the MTRC calculation is 50 percent of $129/MWh, or $18.32/GJ.

218.4 Please provide an estimate of the volume of carbon equivalent emissions for each GJ of gas consumed (i) including all emissions subject to carbon tax (ii) including all 'cradle to grave' emissions such as venting, flaring and fugitive. Please include all assumptions made.

Response:

Please refer to the response to BCUC IR 1.208.1.1.

218.5 Please describe how FEU treats non-FEU incentives in the TRC/mTRC calculation. Specifically, is the customer cost grossed up for any non-FEU incentives received (such as LiveSmart)?

Response:

The FEU do not include non-FEU incentives in the TRC/mTRC calculation. The TRC/mTRC calculation does not include the cost of any incentive provided by either the utility or a third party as this is a wealth transfer.

218.6 What discount rate has FEU used for the TRC/mTRC calculation?

Response:

The discount rate that the FEU use for the TRC / MTRC calculation is the utility's pre-tax weighted average cost of capital (WACC) adjusted for inflation. For 2013, these values are 6.44% for FEI and 6.57% for FEVI.

Since the submission of the EEC Plan as Attachment I-1 to Appendix I in Exhibit B-1-1 to the Application, the FEU have identified an error in the discount rate value entered into the model used to develop the cost effectiveness and net present value of energy savings results presented in the EEC Plan. The entered values were 6.82% and 6.52% for FEI and FEVI respectively and were transferred from an earlier run calculation of the rate, rather than the final run which was based on the approved 2013 rate base and debt and equity figures for the Companies. The FEU do not believe that this error will have a noticeable impact on the cost effectiveness test results reported in the 2014 – 2018 EEC Plan, but are continuing to re-examine those results. If there are any changes needed to the tables filed in the Application as part of the EEC Plan as a result, the FEU will provide updated tables within the next evidentiary update to the application.

218.6.1 Please state if there could be any negative impact to non-participants of using a societal discount rate for the TRC/mTRC (provided the program passes the UCT).

Response:

Using a societal discount rate in the TRC calculation will allow some programs to pass the cost effectiveness hurdle and become part of a utilities DSM portfolio that would not otherwise do so.

For non-participants who are customers of the utility, a program that is implemented based on a TRC using a societal discount rate and which does not pass the TRC using a traditional discount rate will put additional upward pressure on rates that would not occur using the traditional discount rate. Energy costs for these customers will therefore be higher than they would if traditional discount rates are used to set the portfolio cost effectiveness boundaries, and these customers will not get the benefit of lower energy consumption, and thus lower energy costs, that result from implementing the measure.

The use of the cost for a zero emission energy alternative as the avoided cost, and a 15 percent adder to the benefits side of the equation for those programs that fail the TRC, up to 30 percent of the EEC portfolio, has a similar effect in the mTRC as that of a societal discount rate used in the TRC calculation.

218.7 Does FEU include in the TRC/mTRC a credit for avoided transmission, distribution or gas peak day capacity infrastructure costs? Please explain why/why not, and if these benefits are included please provide supporting evidence.

Response:

Please refer to the response to BCUC IR 1.218.2.

218.8 How does FEU treat incentives in kind (such as free or subsidized installation) in calculating the TRC/mTRC? Please explain.

Response:

Incentive costs are not part of the TRC/mTRC calculation. The costs entered into the TRC calculation are the incremental costs (including installation costs for new equipment or measures), regardless of who incurs them and program administration costs. Where installation costs are incremental to what would otherwise have been installed in the absence of the program, they are captured in the TRC / mTRC calculation regardless of whether or not these costs are covered by a utility or program partner incentive.

219.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

BC Ministry of Energy and Mines Guide to the Demand-Side Measures Regulation, p. 4[38]; Reality Check: The State of Climate Progress in Canada, National Round Table on the Environment and the Economy, 2012, p. 97[39]; Exhibit B-1-1, Appendix I, p. 21

Purpose of the Utility Cost Test

Page 4 of the BC Ministry of Energy and Mines Guide to the Demand-Side Measures Regulation states: "...s. 4(1.8) allows the commission to determine (with some exceptions) that a demand-side measure that fails the UCT is not cost-effective."

A 2012 National Round Table on the Environment and the Economy report titled "Reality Check: The

State of Climate Progress in Canada" states on page 97: "Our analysis suggests that all emission reductions available in Canada up to $150 per tonne must be achieved to meet the [federal government's] 2020 target."

FEU includes as an EEC Guiding Principle "EEC expenditures will have a goal of non-incentive costs not exceeding 50 percent of the expenditure in a given year." (Exhibit B-1-1, Appendix I, p. 21)

219.1 Please describe how FEU calculates the Utility Cost Test (UCT).

Response:

The FEU calculate the UCT test as the ratio of the total net benefits of a program, discounted by the net to gross ratio to address free riders and spillover where applicable, to the total costs for the utility over some specified time period. The benefits of the test are similar to the TRC benefits which are the net avoided gas supply costs (refer to the response to BCUC IR 1.218.2 for a description of the avoided cost of gas). The costs for the test are the total program costs incurred by the administrator including the incentives paid to the customers, the marketing cost, the operational cost and evaluation costs etc.

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[38] http://www.empr.gov.bc.ca/EEC/Strategy/EEA/Documents/Guide%20to%20the%20DSM%20Regulation%20August%202012.pdf

[39] http://www.bcuc.com/Documents/Proceedings/2013/DOC_34653_A2-14-NRT-RealityCheck-StateClimate.pdf

219.2 Does FEU consider that the purpose of the UCT could be described as identifying whether, once the TRC/mTRC has identified that customers are making suboptimal investment/consumption decision from a BC perspective, it would be cost effective for the utility to step in and mitigate the problem rather than supply the additional energy that would otherwise be required? Please explain why/why not.

Response:

Please refer to pages 6-2 to 6-4 of Attachment 217.2 provided in response to BCUC IR 1.217.2, where the Program Administrator Cost Test (another term for the UCT) is discussed. The UCT provides an estimate of energy efficiency costs as a utility resource so in that sense, it could be stated that the UCT indicates whether it is cost-effective from the utility's perspective to reduce demand rather than increasing supply.

219.2.1 Does FEU consider that, as a general rule, the higher the UCT result, the higher the benefit to FEU ratepayers overall? Please explain why/why not.

Response:

Speaking very generally, the FEU would agree in theory that the higher the UCT, the more cost-effective it is for the utility to reduce demand rather than increasing supply The perspective on the benefit or cost to FEU ratepayers overall, as British Columbians, is more optimally provided by the TRC/MTRC, as can be seen on page 6-6 of Attachment 217.2a in response to BCUC IR 1.217.2, where the title of Table 6-4 is given as “Benefits and Costs from the Perspective of All Utility Customers (Participants and Non-Participants) in the Utility Service Territory.”

219.2.2 Does FEU consider that the optimal EEC portfolio may not be the one with the highest overall UCT, for example where energy efficiency investment costs are high as the product is new, or there is a onetime opportunity to make a deep (rather than shallow) EEC investments? Please explain why/why not.

Response:

Please refer to the response to BCUC IR 1.217.2.1. As is the case with the TRC, the optimal EEC portfolio may not be the one with the highest overall UCT. Such a portfolio would lean very heavily toward the Commercial and Industrial Program Areas, and it is the goal of the Companies to make EEC services available to all customer classes.

219.3 To what extent, if any, is the value to ratepayers of emissions reduction from EEC programs reflected in the UCT? Please explain.

Response:

The avoided cost of energy used by the FEU in the UCT calculation incorporates $1.50/GJ for B.C.'s carbon tax. That is the extent of the value of emissions reductions incorporated into the UCT.

219.3.1 If emissions reduction benefits are not included, does FEU consider that the EEC UCT results could understate the benefit to ratepayers of the EEC programs? Please explain why/why not and how this should affect the interpretation of the UCT program results.

Response:

To the extent that the carbon tax is incorporated into the avoided cost of gas, emissions reductions benefits are included in the FEU's UCT calculations. As noted in the response to BCUC IR 1.219.2.1, it is the Companies' view that the effect of EEC activity on all ratepayers is best evaluated through the application of the TRC test. The MTRC component of the combined TRC/MTRC test "provide a consistent avoided supply cost that reflects a zero greenhouse gas emitting source", as noted in the response to BCUC IR 1.217.2.

219.3.2 Does FEU consider that a lower threshold than 1.00 could be used for the UCT to reflect the value of emissions reduction? If yes, please suggest what threshold should be used and why.

Please include in your response whether a long-run cost of carbon estimate (such as $150/tonne used in the National Round Table on the Environment and the Economy report) could be used as an input in developing the threshold.

Response:

It is the view of the FEU that the TRC/MTRC is a more appropriate vehicle to use to reflect the value of emissions reductions. The TRC/MTRC is intended to capture the effects of EEC activity on all British Columbians, rather than just on the <u>utility</u>, as the UCT is intended to do. The Companies have used the carbon tax value of $1.50/GJ in the UCT as it is a price on carbon introduced by the Government of British Columbia for this jurisdiction. The Companies do not have any further position on appropriate UCT thresholds, nor on inputs to and applications of the various cost-benefit tests that are not either a) established by the Demand Side Measures Regulation; b) the result of previous Commission Decisions; or c) those outlined in Attachment 217.2a in response to BCUC IR 1.217.2.

219.4 Does FEU consider that EEC programs which fail the UCT but result in a reduction in overall gas emissions could be considered similar to a ‘renewable portfolio standard,’ in that the overall cost of the gas portfolio is higher than it would otherwise have been, but the emissions generated from gas consumption are lower? Please explain why/why not.

Response:

In concept, the <u>outcomes</u> of a having a “Renewable Portfolio Standard” in place and operating natural gas EEC programs that fail the UCT are similar, in that doing so may result in a higher overall cost for the provision of utility services while reducing emissions.

219.5 Please explain why FEU has a goal of non-incentive costs not exceeding 50 percent of the expenditure in a given year. Please include in your response if there are any scenarios where this restriction could result in sub-optimal outcomes (for example, where the market barrier is not the cost of the EEC measure, but customer awareness or lack of enforcement of codes/standards).

Response:

Please refer to Attachment 219.5, which is the Companies' response to BC Hydro IR 1.4 series in the original EEC proceeding. The FEU's 50% maximum non-incentive goal is for the overall EEC portfolio as a whole. At an individual program level, non-incentive costs could exceed 50% of the individual program budget, depending on the barrier that the program is intended to address. The Companies originally set the 50% maximum non-incentive portfolio level expenditure in order to provide a balance between the funds received directly by customers in incentives, and non-incentive costs such as overhead, labour, program administration, communications and evaluation.

219.6 Please provide a table listing for each FEU EEC program:

- total FEU EEC $ requested over PBR period, and $ requested as a percent of total EEC funding requested;
- total expected GJ energy saved over the PBR period, and GJ energy saved as a percent of total GJ energy saved;
- TRC/mTRC;
- UCT, expressed as both a ratio and $/GJ.

Response:

The table below provides the requested information for each FEU EEC program. Note that the natural gas savings are net of free ridership and spillover. Further, only savings from 2014-2018 are presented. Therefore please note that programs that include measures with longer lifetimes also result in a significant amount of savings outside of this period.

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%**	**0.71**	**2.01**	**1.15**	**7.66**
Energy Efficient Home Performance Program	7,901	4.4%	618,980	6.4%	1.07	3.00	2.88	3.15
* Furnace Replacement Program	16,705	9.4%	468,527	4.8%	0.50	1.41	0.90	9.85
Enerchoice Fireplace Program	5,823	3.3%	215,973	2.2%	1.55	4.37	0.96	9.03
Appliance Service Program	2,281	1.3%	0	0.0%	0.00	0.00	0.00	n/a
* ENERGY STAR® Water Heater Program	6,275	3.5%	207,105	2.1%	0.63	1.77	1.10	8.18
Low-Flow Fixtures	1,450	0.8%	192,375	2.0%	3.00	8.49	2.81	2.99
* New Home Program	4,677	2.6%	122,125	1.3%	0.40	1.12	0.98	9.45
* New Technologies Program	1,556	0.9%	24,216	0.2%	0.37	1.04	0.35	23.79
* Customer Engagement Tool for Conservation Behaviours	4,428	2.5%	513,000	5.3%	0.86	2.56	0.86	8.60
Financing Pilot	1,105	0.6%	0	0.0%	0.00	0.00	0.00	n/a
Non-Program Specific Expenses	2,700	1.5%	0	0.0%	0.00	0.00	0.00	n/a
COMMERCIAL (ALL PROGRAMS)	**54,144**	**30.4%**	**4,296,483**	**44.3%**	**1.05**	**3.00**	**1.69**	**5.11**
Space Heat Program	10,066	5.7%	848,671	8.8%	2.50	7.05	3.03	2.99
Water Heating Program	1,442	0.8%	215,798	2.2%	1.14	3.21	3.88	2.21
Commercial Food Service Program	2,448	1.4%	215,842	2.2%	1.78	5.03	2.38	3.61
Customized Equipment Upgrade Program	12,272	6.9%	771,502	8.0%	1.07	3.01	2.30	3.97
EnerTracker Program	964	0.5%	218,078	2.2%	1.57	5.04	1.51	4.42
* Continuous Optimization Program	9,214	5.2%	1,780,325	18.4%	0.81	2.34	1.94	3.94
Commercial Energy Assessment Program	2,339	1.3%	231,267	2.4%	1.00	3.02	0.72	10.11
Energy Specialist Program	9,882	5.6%	0	0.0%	0.00	0.00	0.00	n/a
Mechanical Insulation Pilot	16	0.0%	15,000	0.2%	5.60	15.78	29.45	0.31
Non-Program Specific Expenses	5,500	3.1%	0	0.0%	0.00	0.00	0.00	n/a
INDUSTRIAL (ALL PROGRAMS)	**12,896**	**7.2%**	**2,192,299**	**22.6%**	**3.03**	**8.55**	**4.09**	**2.08**
Industrial Optimization Program	9,148	5.1%	1,552,971	16.0%	2.86	8.07	3.84	2.19
Specialized Industrial Process Technology Program	2,438	1.4%	639,328	6.6%	4.66	13.12	7.30	1.19
Non-Program Specific Expenses	1,310	0.7%	0	0.0%	0.00	0.00	0.00	n/a
LOW INCOME (ALL PROGRAMS)	**15,223**	**8.6%**	**406,432**	**4.2%**	**0.94**	**n/a**	**0.72**	**12.19**
Energy Savings Kit	651	0.4%	136,063	1.4%	5.33	n/a	3.43	2.38
Energy Conservation Assistance Program	10,240	5.8%	118,065	1.2%	0.43	n/a	0.32	26.98
REnEW	405	0.2%	0	0.0%	0.00	n/a	0.00	n/a
Low Income Space Heat Top-Ups	394	0.2%	36,766	0.4%	2.92	n/a	3.09	2.91
Low Income Water Heating Top-Ups	77	0.0%	10,742	0.1%	1.39	n/a	3.29	2.58
Non-Profit Custom Program	1,931	1.1%	104,796	1.1%	2.72	n/a	2.02	4.50
Non-Program Specific Expenses	1,525	0.9%	0	0.0%	0.00	n/a	0.00	n/a
CONSERVATION EDUCATION AND OUTREACH (ALL PROGRAMS)	**12,000**	**6.7%**	**0**	**0.0%**	**0.00**	**0.00**	**0.00**	**n/a**
Residential Education Program	4,950	2.8%	0	0.0%	0.00	0.00	0.00	n/a
Commercial Education Program	2,250	1.3%	0	0.0%	0.00	0.00	0.00	n/a
School Education Program	3,600	2.0%	0	0.0%	0.00	0.00	0.00	n/a
Non-Program Specific Expenses	1,200	0.7%	0	0.0%	0.00	0.00	0.00	n/a
INNOVATIVE TECHNOLOGIES (ALL PILOTS)	**6,086**	**3.4%**	**435,173**	**4.5%**	**1.71**	**4.81**	**2.23**	**4.01**
ENABLING ACTIVITIES (ALL ACTIVITIES)	**22,740**	**12.8%**	**0**	**0.0%**	**0.00**	**0.00**	**0.00**	**n/a**
ENTIRE PORTFOLIO	**177,991**	**100.0%**	**9,692,688**	**100.0%**	**0.93**	**2.49**	**1.30**	**6.68**

Note: Whistler (FEW) is included in the FEI service territory

* Program requires the MTRC in order to pass the economic screen

219.7 For each measure which FEU has been unable to demonstrate will pass the UCT, and which is not the result of difficulty quantifying annual gas savings, please provide an explanation as to why FEU considers that undertaking this measure should provide a net benefit to its ratepayers.

Response:

As stated in the response to BCUC IR 1.219.2.1, the perspective on the benefit or cost to FEU ratepayers overall, as British Columbians, is more optimally provided by the TRC/MTRC.

Please see listed below each of the programs presented in the FEU's 2014-2018 EEC Plan which have a UCT under 1.0 and an explanation as to why FEU considers that undertaking this program should provide a net benefit to British Columbians. The MTRC ratio is listed for each program where required/applicable. The TRC ratio is listed for the programs that do not require or are not applicable to the MTRC.

Furnace Replacement Program (UCT = 0.90, MTRC = 1.41)

This 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.

Note that the marginal UCT for this program may be able to be improved through reduced program administration costs in future years such as through transition to online application forms, review of contractor incentives, and reduced marketing costs once the program is further established.

Enerchoice Fireplace Program (UCT = 0.96, TRC = 1.55)

This program provides the following net benefits to British Columbians:

- Fireplace manufacturing in BC creates jobs and benefits the BC economy.
- BC households have more natural gas fireplaces than any province in Canada.
- The program provides the opportunity to educate customers about the benefits of energy efficient zone heating and messaging regarding choosing warmth with ambience.
- Enables the FEU to further strengthen relationships with contractors, distributors, retailers and trade associations.
- Enables the FEU to be involved in codes and standards, testing procedures and market transformation of energy efficient fireplaces.
- In new construction, the program encourages builders to install higher quality appliances that are energy efficient rather than low cost base models.

Note that the marginal UCT for this program may be able to be improved through reduced program administration costs in future years such as through transition to online application forms, review of dealer incentives, and reduced marketing costs once the program is further established.

New Home Program (UCT = 0.98, MTRC = 1.12)

This program provides the following net benefits to British Columbians:

- Enables the FEU to further educate builders, developers, architects and engineers on the benefits of using natural gas efficiently and building higher quality, energy efficient homes that will benefit occupants for many decades.
- Enables the FEU to be involved in building codes and how natural gas fits into the goal of Near Net Zero housing by 2020.
- The program encourages builders to install higher quality appliances that are energy efficient rather than low cost base models.
- Energy labeling requirement (EnerGuide Rating) provides an opportunity for builders to work with Certified Energy Advisors and through the blower door test educate builders / onsite trades people about basic practices such as air sealing and draft proofing.

Note that the marginal UCT of this program may be able to be managed through reduced program administration costs in future years.

New Technologies Program (UCT = 0.35, MTRC = 1.04)

This program provides the following net benefits to British Columbians:

- Introduction of new innovative technologies that are high cost but provide energy saving opportunities, where costs will come down as the market is transformed.
- Further relationships with manufacturers and distributors such that FEU is able to identify new product introductions for energy efficiency.
- In collaboration with trade associations, provide training to trades as new products are introduced to ensure customers receive quality installation so savings potential is realized.

Note that the cost benefit inputs for this program were provided as placeholders for Residential New Technologies that may be introduced over the next five years. Since it is expected that these will be innovative with low market adoption, their costs may be such that they fail traditional cost benefit tests. However, once program parameters are more defined over time, the UCT may be able to be managed through reduced program administration costs in future years.

Note also that pursuant to Section 4(1.8) of the DSM Regulation, the Commission may not use the UCT to determine that a specified demand-side measure, including a technology innovation program, is not cost-effective.

Customer Engagement Tool for Conservation Behaviours (UCT = 0.86, MTRC = 2.56)

This program provides the following net benefits to British Columbians:

- An energy visualization tool that will allow customers to understand their natural gas consumption in relation to their neighbours.
- An additional marketing platform to introduce rebate offers and energy savings tips.
- Enable the FEU to gather customer intelligence about homes, appliances and provide opportunities to target relevant marketing messages more effectively.

Note that as the Customer Engagement Tool project has yet to be delivered, the exact costs have yet to be determined.

Commercial Energy Assessment Program (UCT = 0.72, TRC = 1.00)

By providing participants with an energy assessment of their buildings this program makes it easier for participants to subsequently take action to reduce consumption, as well as participate in one or more of FEU's other incentive programs. The benefits which may be attributed directly to this program are limited, however, by customers who do in fact participate in another EEC program. In such a case, for example a customer who receives an assessment and then participates in the Efficient Boiler Program, the resultant natural gas savings are recorded only under the Efficient Boiler Program. The benefits which are attributed to the Commercial Energy Assessment Program represent only savings resulting from the implementation of measures with no subsequent follow up in another EEC program. This necessarily impacts the cost effectiveness of the program. Regardless, the Commercial Energy Assessment program provides value to participants and serves as a funnel to participation in other more cost effective incentive programs. As such, it occupies a well deserved place within the context of a cost effective portfolio of programs.

ECAP (UCT = 0.32, TRC = 0.43)

ECAP is the FEU's flagship Low Income Program in terms of having the potential to create significant and lasting savings for FEU's low income customers. By creating savings for low income customers, there are many non-energy benefits that impact the broader society and rate payers but that are difficult to quantify. One example benefit is improved health. The energy efficiency retrofit work implemented through the ECAP program can improve air quality which can lead to improved health of the occupants and therefore reduce the burden on health care systems which all FEU ratepayers help support through their tax dollars.

The ECAP program is very similar to, and leverages best practices from, programs offered to low income customers in many other Provinces and States and is the best example of meeting FEU's EEC portfolio adequacy requirement of offering programs to Low Income customers. Because of the programs important role in FEU's EEC portfolio and because of the many non-energy benefits that arise from the program, it is believed the UCT is an insufficient gauge of the program's merits.

Pursuant to Section 4(1.8) of the DSM Regulation, the Commission may not use the UCT to determine that a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption is not cost effective.

220.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1-1, Tab C, Section 4.3.1, p. 204

UCT – Key Inputs

"Sustainment Capital – Consists of...system reinforcements to the distribution and transmission systems to maintain capacity to meet existing and forecast load."

220.1 Please identify the inputs into a UCT calculation, and provide an overview of the methodology used to calculate the value of these inputs.

Response:

Typical inputs are:

- energy savings,
- program incentives,
- number of participants,
- free rider rate,
- spillover rate
- measure life and
- program administration costs.

Please refer to the response to BCUC IR 1.218.1 for the process through which these inputs are determined.

220.2 What discount rate is used for the UCT calculation, and is this discount rate the same discount rate used to evaluate utility supply side investments?

Response:

The discount rate that the FEU use for the UCT calculation is the utility's pre-tax weighted average cost of capital (WACC), adjusted for inflation. For 2013, these values are 6.44% for FEI and 6.57% for FEVI.

No, this is not the same discount rate used to evaluate supply side investments. Supply side investments are generally evaluated using an after tax WACC. The FEU use a pre-tax WACC in the EEC cost effectiveness calculations because the cost and benefit inputs to the calculations are also entered on a pre-tax basis. This treatment is consistent with industry practice.

Since the submission of the EEC Plan as Attachment I-1 to Appendix I in Exhibit B-1-1 to the Application, the FEU have identified an error in the discount rate value entered into the model used to develop the cost effectiveness and net present value of energy savings results presented in the EEC Plan. The entered values were 6.82% and 6.52% for FEI and FEVI respectively and were transferred from an earlier run calculation of the rate, rather than the final run which was based on the approved 2013 rate base and debt and equity figures for the Companies. The FEU do not believe that this error will have a noticeable impact on the cost effectiveness test results reported in the 2014 – 2018 EEC Plan, but are continuing to re-examine those results. If there are any changes needed to the tables filed in the Application as part of the EEC Plan as a result, the FEU will provide updated tables within the next evidentiary update to the application.

220.3 Does FEU include a credit for avoided transmission, distribution or gas peak day capacity infrastructure costs in the UCT? Please explain why/why not, and if these benefits are included please provide supporting evidence.

Response:

Please refer to the response to BCUC IR 1.218.1. The FEU use the same avoided cost of gas in both the TRC and the UCT.

220.4 Please explain how FEU estimates program uptake, free-rider, spillover and rebound estimates.

Response:

Please also refer to the response to BCUC IR 1.218.1 for a general description of how the inputs to cost effectiveness calculations are determined and updated.

Program Uptake (number of participants):

For new programs, the FEU use their program development experience and work with program partners, industry stakeholders and/or industry consultants to determine a reasonable estimate of the first few years of participation. For existing, in-market programs the FEU examine previous performance and give consideration to any program adjustments made that may affect participation levels.

Free Riders

Estimates of free ridership generally need to be done on a program-by-program basis, as they can vary significantly between programs. A number of different approaches have been used by FEU to estimate the free ridership rates:

1. In cases where the FEU have operated a program which has been evaluated, the free rider rate from the evaluation has been used. In the evaluations, the FRR has typically been determined by a combination of information from: a customer survey; a trade ally survey; or in some cases by discrete choice analysis modeling using participant and nonparticipant data.
2. For other programs, the approach has been to estimate the ratio of existing energy efficient products sold prior to the program launch and the estimated program sales after the launch.
3. In some cases, other utilities have operated similar programs in the same or similar marketplaces. In this case, the FRR from the other utility program might be used.
4. In other cases, judgment has been applied based on the opinion of industry experts outside of the utility or FEU field staff who work closely with the trades and major customers.

Spillover

Please refer to the response to BCUC IR 1.226.10. For the one program that the FEU have estimated spillover for, the spillover estimate was developed in consultation with the program partner who has experience estimating spillover for that program's electricity participants. For all other programs in the plan, the FEU have used a zero value for spillover in the plan forecast analysis. The FEU will update the spillover estimates on a program by program basis as appropriate methodologies and suitable data are identified with which to do so.

Rebound

The FEU have not included rebound estimates at this time but will continue to examine the merits of doing so and the availability of appropriate methodologies and suitable data with which to do so.

220.4.1 How sensitive does FEU consider that UCT results generally are to the estimates referred to above?

Response:

Program Uptake (Number of Participants)

The FEU consider that, holding other inputs constant, the UCT results are somewhat sensitive to the level of program uptake. Since the incentive costs are typically greater than non-incentive costs and since both the incentive costs and the energy savings benefit vary with the number of participants, the impact of program uptake on the benefit to cost ratio in this test will be somewhat muted.

Free Riders, Spillover and Rebound

These estimates are interrelated in their impact on the UCT results. The relative size of the estimate of each factor, and the extent to which these factors offset one another, will determine how much impact they have on the UCT results. If, for example, the free rider rate or the rebound effect for a program is high, and the spillover is low, there can be a substantial impact on the UCT results. However, if the estimates for these factors are all low, or if they otherwise largely offset one another, the impact will be low. To date, since the FEU have been including free riders in the UCT calculation, but not in most cases either spillover or rebound, the UCT results have been more sensitive to free rider estimates than to the other factors cited in this IR.

220.4.2 Please explain how FEU ensures these estimates are not subject to bias.

Response:

The FEU have set up a review process led by staff responsible for EM&V activities, to review the estimated inputs, assumptions and information sources for the inputs to the cost effectiveness tests and ensure that the inputs are reasonable based on the best available information. Please also refer to the response to BCUC IR 1.214.2 with respect to potential conflict of interest and the role of EM&V staff.

220.5 Does FEU agree that a program with a high estimated free-rider rate is an indicator that the program is not an effective means of addressing the market failure identified through the TRC/mTRC, and that other alternative programs should be considered? Please explain why/why not.

Response:

The Companies' views on free-ridership and spillover have been well-canvassed in previous proceedings. Please refer to Attachment 220.5 which is the FEU's response to BCUC IR 1.210 series in the 2012-2013 Revenue Requirements proceeding. Attachment 210.3 in response to BCUC IR 1.210.3 in the 2012-2013 Revenue Requirements proceeding, "Maximizing Societal Uptake of Energy Efficiency in the New Millenium: Time for Net-to-Gross to Get Out of the Way?" is included as Attachment 235.3 in the response to BCUC IR 1.235.3 in the current proceeding. It is the view of the Companies that free-ridership and spillover are both highly subjective, that they cancel each other out, and that the appropriate approach is to use the gross energy savings as the benefit in the benefit-cost calculations.

A program with a relatively high free rider rate may indicate that a program needs to be modified or discontinued in favour of an altered or alternative program.

220.5.1 Does FEU consider that a program with a high estimated spillover rate indicates that the program is addressing other EEC market failures as well as the one for which it is intended? Please explain why/why not.

Response:

A program with a relatively high spillover rate may indicate that a program needs to be modified or discontinued in favour of an altered or alternative program. A high spillover rate may indicate a need for a focus on education and the provision of information to consumers related to a specific action or piece of equipment, rather than the provision of an incentive. However, relying solely on subjective inputs such as free-ridership and spillover in designing and modifying programs is too narrow an approach. Other inputs to the optimal program design to address the market failure under consideration, such as customer, contractor and distributor commentary, should also be considered.

220.5.2 How does FEU deal with changing levels of participation, free-rider and spillover estimates over time in undertaking the UCT estimate?

Response:

The FEU monitor the cost-effectiveness of all their EEC activity monthly in a management report that details the results of all the cost-effectiveness tests, including the UCT. As new information becomes available, all of the inputs to all of the cost-effectiveness tests are modified, including the free-rider and spillover effects and savings per participant in the UCT, and are monitored by the Director, EEC, on a monthly basis as the Companies committed to do in the 2012-2013 Revenue Requirements Proceeding.[40]

The FEU provide transparent estimates of all of the cost-effectiveness tests including all assumptions and all sources for same in their extensive EEC Annual Reports.

220.5.3 How does FEU deal with changing assumed levels of participant GJ savings over time (for example, as the 'status quo' investment becomes more efficient) in undertaking the UCT estimate?

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[40] http://www.bcuc.com/Documents/Arguments/2011/DOC_29217_12-02-2011_FEU-Final-Submission.pdf, page 185

Response:

Please refer to the response to BCUC IR 1.220.5.2.

221.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

FEU 2010 Conservation Potential Review;[41] Exhibit B-1-1, Appendix I, Attachment I-1, p. 105

Identification of Market Failures/ Conservation Potential Review

FEU included its 2010 Conservation Potential Review as Appendix K-2 of its 2012 and 2013 Revenue Requirements and Natural Gas Rates Application.

FEU has budgeted $500,000 for an update of the Conservation Potential Review (CPR) in 2015. The update is planned in collaboration with FortisBC (electric) and BC Hydro. (Appendix I, Attachment I-1, p. 105)

221.1 Would Fortis agree that the aim of the CPR is to identify customer investments and behaviours which are sub-optimal from a societal perspective (for example, where they would not pass the TRC/mTRC)? Please explain why/why not.

Response:

The aim of the CPR is to provide a planning document that the FEU can use as an ongoing reference tool to:

- Develop a long-range energy efficiency strategy
- Design and implement energy efficiency programs
- Assess the impact of energy efficiency programs on both peak and annual loads
- Set annual energy efficiency targets and budgets
- Determine contributions energy efficiency programs can make towards meeting greenhouse gas (GHG) reduction targets

The FEU use the CPR to identify potential energy efficiency opportunities, the majority of which are not being readily adopted by FEU customers. This helps to inform the development of the FEU's programs. However, it should be emphasized that this report does not aim to either set specific program targets or provide program design.

To be considered for review in the CPR, measures must be technically proven and commercially available but not fully adopted within the applicable utility service territories.

[41] http://www.bcuc.com/Documents/Proceedings/2011/DOC_28081_B-1_FEU-2012-2013-RRA-REDACTED-Public-Version-R.pdf pdf page 1453.

Therefore, they present EEC opportunities to address customer investments and behaviours which are sub-optimal from a societal perspective. However, what the CPR does not address are the specific market failures that have lead to the sub-optimal societal decisions.

At this point, the FEU have not decided if it will use the TRC or mTRC as the screening tool to determine the measures eligible for the CPR Economic Potential Forecast.

In terms of behaviour measures, there are a wide number of behaviours that homeowners and building occupants can undertake that affect natural gas consumption. For the CPR study, the number of behaviours will be narrowed by looking at the potential size of the impact, the availability of information, and by consulting with applicable DSM program personnel.

221.1.1 Does FEU agree that the CPR is the starting point in the development/review of a portfolio of EEC programs? Please explain why/why not.

Response:

The CPR could be considered as a starting point for the development of new EEC programs but not for the review of existing EEC programs. Existing EEC programs are constantly reviewed by the respective program teams and formally reviewed through an evaluation report.

The CPR provides a foundation for the development of demand side management (DSM) strategy and programs. It provides a detailed view of DSM opportunities by end use, technology and sub markets. FEU plans to use the CPR for directional input into program development to help determine where there may be new opportunities for DSM programs. FEU will also use the CPR results to help assess the future potential of existing programs to help guide expenditures for those programs.

221.1.2 How does FEU ensure that the results of the 2010 CPR are still valid?

Response:

The 2010 CPR was a snapshot of the energy efficiency potential at the time the study was carried out and it helped guide the development of the FEU's current program offerings. The FEU believe that a five-year interval is reasonable for refreshing this data and ensuring that it is as current as possible. As such, the FEU plan to invest in another CPR in 2015, in conjunction with the electric utilities and the province.

221.1.3 Does the 2010 CPR include non-energy benefits and the value of emission reductions? If no, could it understate the amount of EEC which could provide a societal benefit to BC?

Response:

The 2010 CPR did not include analysis of non-energy benefits or the value of emission reductions as this was not part of the scope of work for the 2010 CPR. The 2010 CPR examined only the potential natural gas savings, greenhouse gas emission savings and economic impact of EEC. It was not tasked with establishing a value on emission reductions or with providing an estimate of the societal benefit that EEC could provide. The 2010 CPR only examined measures through the Total Resource Cost (TRC) test. Therefore, the 2010 CPR provided no statement on the amount of EEC which could provide a societal benefit to BC.

Since the 2010 CPR did not include non-energy benefits and the value of emission reductions, it likely does understate the amount of EEC which provides a societal benefit to BC.

221.1.4 Does the 2010 CPR exclude the administration related costs of addressing the identified investment/behaviour change? If no, please describe how it is incorporated into the cost/benefit results. If yes, is the CPR more of an initial screening tool to determine which programs should then be subject to the TRC?

Response:

The 2010 CPR did not include the administration related costs of addressing the identified technology upgrades or conservation behaviours. The benefit/cost analysis conducted through the 2010 CPR only considered the costs of the identified technology upgrades.

Administration cost estimates are determined during the program design phase. While a CPR can provide input into program design, program design is not a component of a CPR. Therefore, administration related costs were not incorporated into the TRC test results listed in the 2010 CPR. The CPR can however act as an initial screening tool to help determine which technology upgrades and/or conservation behaviours should be pursued through to the program design phase.

221.2 Please explain why the 2010 CPR deals with customer investments only, and not customer behaviors.

Response:

The 2010 CPR did address customer behaviours. Please see *Exhibit B-1, FEU-2012-2013 RRA REDACTED Public Version R*[42], *page 1476* and *Exhibit B-9-1, FEU 2012-2013RRA BCUC IR1 Attachments*[43]*, page 413 to 421*.

221.2.1 What process does FEU use to identify customer energy related behaviors which are sub-optimal from a BC perspective?

Response:

FEU uses the CPR to identify behaviours that homeowners and building occupants can undertake that affect natural gas consumption. FEU generally focuses on natural gas space and water heating related behaviours which have minimal or zero costs to the customer. FEU also

[42] http://www.bcuc.com/Documents/Proceedings/2011/DOC_28081_B-1_FEU-2012-2013-RRA-REDACTED-Public-Version-R.pdf page 1476

[43] http://www.bcuc.com/Documents/Proceedings/2011/DOC_28092_B-9-1_FEU_2012-2013RRA_BCUC_IR1_Attachments.pdf page 413 to 421.

uses its discretion in focusing on behaviours that customers will find simple to implement, will be most likely to follow through with and are within their control.

An example of a behaviour that FEU encourages customers to adopt is taking 5 minute showers, which has zero costs to the customer, involves installation of a simple piece of equipment (an hourglass or other form of timer) where controls are not required, and is within the customer's control. Lastly, FEU will seek opportunities to reduce customer barriers to adopting a behaviour, in the case of 5 minute showers, such as distributing shower timers during outreach events.

221.2.2 Does FEU plan to include customer behaviors in the 2015 CPR update?

Response:

Yes, FEU intends to include customer behaviours in the 2015 CPR.

221.3 Please describe the extent of collaboration FEU intends to undertake with FortisBC and BC Hydro for the 2015 CPR update (for example, would one BC CPR be developed?)

Response:

At this point, only preliminary discussions have occurred between the FEU, FortisBC Inc. and BC Hydro on what the extent of a 2015 CPR collaboration would be. In-depth discussions will likely not take place until 2014. At this time though, it is FEU's intent to pursue developing one 2015 CPR study in collaboration with FortisBC Inc., BC Hydro and the Province which would examine natural gas conservation potential within the FEU's service territories and electricity conservation potential within FortisBC and BC Hydro's service territories with appropriate budget contributions from each utility based on respective utility size.

222.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit A2-2, p. 69; FEU 2010 Conservation Potential Review, p. 21; Exhibit B-1-1, Appendix I, Attachment I-2, p. 21

Design of Programs to Address CPR Identified Market Failures

Exhibit A2-2 states: "A true break-through in scaling-up the market for energy efficiency will only occur by better coordination and cooperation among all the market actors in the energy chain (technology providers, financial institutions, contractors, energy providers, and customers)" (p. 69).

FEU included on page 21 (Exhibit 12) of the 2010 CPR a table titled "Most Likely Achievable Natural Gas Savings for the Total FortisBC Service Area by Technology and Milestone Year, (1000 GJ/yr.), Residential Sector."[44]

FEU states on page 21 of Exhibit B-1-1, Appendix I, Attachment I-2 to the Application: "Other feedback indicated a strong interest in increased collaboration with First Nations, open dialogue and improved clarity on how feedback is being utilized. The Companies take this feedback seriously and are working hard to make improvements for 2013."

222.1 Please provide an updated table similar to Exhibit 12 in the 2010 CPR for FEU residential customers and include the following:

- End use – please include all end-uses identified in the 2010 CPR and any additional end-uses FEU has identified.
- Measure – please include all measures identified in the 2010 CPR and any additional measures FEU has identified.
- Potential energy savings – GJ/year of potential energy savings from each measure for 2015, 2020, 2025 and 2030 as identified in the 2010 CPR, and for any additional measures/behaviour changes to the extent information is available.
- Percent Savings 2030 relative to total 2030 (from 2010 CPR).
- Average benefit/cost ratio (from 2010 CPR).

Response:

The FEU cannot determine a way to provide a meaningful potential energy savings comparison between forecasted natural gas savings in the 2010 CPR and forecasted achievable potential savings from the EEC Plan 2014-2018. Therefore, measures identified in the 2010 CPR and

[44] http://www.bcuc.com/Documents/Proceedings/2011/DOC_28081_B-1_FEU-2012-2013-RRA-REDACTED-Public-Version-R.pdf, pdf page 1453.

measures identified in the EEC Plan have been listed separately in Tables 1 and 2 below, along with the energy savings and TRC data available.

Table 1 lists the end-uses and measures identified in the 2010 CPR. Only those measures that passed the Total Resource Cost (TRC) test were included in Exhibit 12 of the 2010 CPR. At that time, the remaining measures could not be included in programs until amendments were made to DSM regulations. All measures evaluated in the CPR have been included in Table 1 along with their average weighted TRC values for FEI and FEVI; however, those not included in Exhibit 12 of the 2010 CPR do not have estimates of achievable gas savings.

Table 1: DSM Measures Identified in the 2010 CPR, Residential, all Service Territories

End Use	Measure	2015	2020	2025	2030	% Savings 2030 Relative to Total 2030 Savings	Average TRC	
							FEI	FEVI
Domestic hot water (DHW)	DHW Pipe Insulation	11	18	20	20	0.6%	16.9	13.3
Domestic hot water (DHW)	Showerheads	35	49	47	38	1.1%	9.6	7.5
Space heating	Prog. Thermostats	198	292	303	256	7.7%	6.5	4.3
Domestic hot water (DHW)	Faucet Aerators	21	29	28	22	0.7%	5.0	3.9
Fireplace	Gas Fireplaces	23	111	336	391	11.7%	3.3	2.4
Pool & spa heaters	Solar Pool Heaters	12	50	116	210	6.3%	1.2	1.2
Space heating	Wall Insulation	8	24	46	74	2.2%	0.9	0.6
Domestic hot water (DHW)	DHW Tank Insulation	2	4	5	5	0.1%	0.9	0.7
Space heating	Attic Insulation	44	85	123	159	4.8%	0.9	0.6
Space heating	Basement Insulation	25	71	136	217	6.5%	0.9	0.7
Space heating	Homeowner Air Sealing	60	116	169	218	6.6%	0.8	0.6
Domestic hot water (DHW)	ESTAR Clothes Washers	11	29	36	26	0.8%	0.9	0.8
Space heating	Early Retire Gas Furnaces	294	780	1,134	1,693	50.8%	0.3	0.1
Space heating	Slab Insulation (Unfinished Basements)	n/a				n/a	0.1	0.1
Space heating	Crawlspace Insulation						0.3	0.2

End Use	Measure	2015	2020	2025	2030	% Savings 2030 Relative to Total 2030 Savings	Average TRC	
							FEI	FEVI
Space heating	Professional Air Sealing/Weather Stripping/Caulking						0.5	0.3
Space heating	Air Leakage Sealing and Insulation (Old Homes)						0.6	0.4
Space heating	Zoned-Up Windows: (ENERGY STAR®) Rating for a Colder Zone						0.2	0.2
Space heating	Super High-Performance Windows						0.6	0.4
Space heating	High-Performance Homes (EGH 80/R2000/ENERGY STAR®)						0.0	0.0
Space heating	Net-Zero Ready Energy Homes						0.3	0.2
Space heating	High-efficiency Condensing Gas Furnaces						0.3	0.2
Space heating	Condensing Gas Boilers						0.2	0.2
Space heating	Solar Pre-Heated Make-Up Air Systems (e.g., SolarWall®)						0.2	0.1
Space heating	High-efficiency Heat Recovery Ventilators (HRVs)						0.3	0.2
Space heating	Gas-Fired Air-Source Heat Pumps						0.0	0.0
Space heating	Integrated Heating and DHW (Forced Air Heating)						0.2	0.1
Space heating	Integrated Heating and DHW (Hydronic Heating)						0.3	0.2
Domestic hot water (DHW)	Condensing Gas Water Heaters						0.3	0.2
Domestic hot water (DHW)	Point-of-Use (Tankless) Water Heaters (Gas)						0.4	0.3
Domestic hot water (DHW)	Active Solar Water Heating Systems						0.2	0.2

End Use	Measure	2015	2020	2025	2030	% Savings 2030 Relative to Total 2030 Savings	Average TRC	
							FEI	FEVI
Domestic hot water (DHW)	DHW Heat Traps						0.0	0.0
Domestic hot water (DHW)	Wastewater Heat Recovery Systems						0.5	0.4
Domestic hot water (DHW)	DHW Recirculation Systems (e.g. Metlund D'MAND®)						0.6	0.5
Domestic hot water (DHW)	High-Efficiency (ENERGY STAR®) Dishwashers						0.3	0.3
Other	High-Efficiency Gas Clothes Dryers						0.0	0.0
Other	Insulating Pool Covers						0.9	0.9
Other	Heat Pump Pool Heaters						4.9	4.9
Other	High-Efficiency Gas-Fired Pool Heaters						0.1	0.1
Other	Micro-Combined Heat and Power (CHP)						0.4	0.4
Grand Total		744	1,658	2,500	3,329	100.0%		

Table 2 lists the end-uses and measures included in the EEC Plan 2014-2018. Although there have been no additional end uses identified since the 2010 CPR, additional measures have been identified since the introduction of the MTRC. The MTRC enabled additional measures to be included in the Residential Program portfolio.

Table 2: DSM Measures Identified in the EEC Plan 2012-2013, Residential, all Service Territories

End Use	Measure	Average TRC	
		FEI	FEVI
Domestic hot water (DHW)	ESTAR 0.67 EF Storage Tank	0.8	0.8
Domestic hot water (DHW)	Non-Condensing Tankless	0.9	0.9
Domestic hot water (DHW)	Condensing Tankless	0.7	0.7
Domestic hot water (DHW)	Hybrids	0.4	0.4

End Use	Measure	Average TRC FEI	Average TRC FEVI
Domestic hot water (DHW)	Condensing Storage Tank	0.1	0.1
Space heating	EnerChoice Fireplace (Retrofit)	1.7	1.8
Space heating	EnerChoice Fireplace (New Construction)	1.2	1.2
Space heating	Furnace Service	0.0	0.0
Space heating	Fireplace Service	0.0	0.0
Space heating	Air Sealing and Draft-Proofing	0.8	0.9
Space heating	Attic Insulation	1.1	1.1
Space heating	Basement Insulation	1.0	1.0
Space heating	Wall Insulation	1.9	1.9
Space heating	Champion Bonus	0.7	0.8
Space heating	Standard Efficiency Furnace	0.6	0.6
Space heating	Mid-Efficiency Furnace	0.3	0.3
Space heating	Boilers	0.3	0.3
Space heating	SFD-Home Performance Rating	0.3	0.3
Space heating	Townhouse-Home Performance Rating	0.9	0.9
Space heating	Condensing Boiler	0.5	0.6
Domestic hot water (DHW)	Low-Flow Fixtures	3.0	3.0
Various	New Technologies	0.4	0.4
Various	Home Energy Reporting	0.8	0.9
Various	Interest Rate Buy downs	0.0	0.0

222.2 Please list all 2012 residential EEC programs, and any additional EEC programs proposed for the PBR period, and map them to the appropriate measure (there may be more than one EEC program per measure). Where a program addresses more than one measure, please identify the percentage allocation of the program between the two or more measures.

Response:

The FEU interpret "percentage allocation of the program between two or more measures" to mean the estimated percentage distribution of energy savings within a program by measure.

The table below lists all 2012-2018 Residential EEC programs along with their eligible measures. Most programs and their corresponding measures were in place in 2012; however, several have been updated in the 2014-2018 EEC Plan.

The percentage allocation of energy savings provided in the table below is based on the percentage of cumulative energy savings for each measure from 2014-2018 within total estimated program energy savings during that period.

Residential EEC programs by measure, 2012-2018

Residential EEC Programs	Measures 2012	Measures Added 2014-2018	% Allocation of Energy Savings
ENERGY STAR® Water Heater Program	ESTAR 0.67 EF Storage Tank		18%
	Non-Condensing Tankless		6%
	Condensing Tankless		64%
	Hybrids		10%
	Condensing Storage Tank		2%
Enerchoice Fireplace Program	EnerChoice Fireplace (Retrofit)		72%
	EnerChoice Fireplace (New Construction)		28%
Appliance Service Program ("Give your Furnace/Fireplace Some TLC" – Service Campaign)	Furnace Service		n/a
	Fireplace Service		n/a
Energy Efficient Home Performance Program (LiveSmart BC)	Air Sealing and Draft-Proofing		14%
	Attic Insulation		40%
	Basement Insulation		10%
	Wall Insulation		23%
		Champion Bonus	13%
ENERGY STAR® Washers and Other Measures for DHW Conservation	ENERGY STAR® Washing Machines	Program Discontinued	n/a
Furnace Replacement Pilot Program	Standard Efficiency Furnace		85%
	Mid-Efficiency Furnace		12%
	Boilers		3%

Residential EEC programs by measure, 2012-2018 (continued)

Residential EEC Programs	Measures 2012	Measures Added 2014-2018	% Allocation of Energy Savings
New Home Program (New Construction - EnerGuide 80 and Energy Efficient Appliances)	SFD Home Performance Rating		66%
	Townhouse Home Performance Rating		26%
	Condensing Boiler		8%
Financing Pilot		Interest Rate Buy Downs (OBF)	n/a
		Interest Rate Buy Downs (Financial Institutions)	n/a
Low-Flow Fixtures		Low-Flow Fixtures	100%
New Technologies Program		New Technologies	100%
Customer Engagement Tool for Conservation Behaviours		Home Energy Reporting	100%

222.2.1 Please provide a comparison of FEU forecast 2015 GJ savings per measure relative to the 2015 annual most likely achievable savings included in the 2010 CPR and explain any significant differences.

Response:

The table below provides a comparison of achievable savings from the CPR on a sub sector-by-sub sector basis with the achieved and forecasted savings from the programs that the FEU have put in place and are planning to put in place from 2010-2015. This approach results in a reasonable comparison of the natural gas savings and demonstrates how EEC programs are expected to perform relative to the achievable savings that were forecasted in the CPR. Note however that the FEU do not use the CPR to set specific program targets. Rather, the CPR identifies savings opportunities, establishes their relative magnitude, provides context with cost-benefit screening, and further describes the likelihood of achieving savings with specific opportunities within the various market segments. This information is then used by the Program Managers as one of the primary inputs to their program development work.

Note also that measures in the CPR have not been compared to programs that have been implemented by the FEU for several reasons. For instance, CPR measures are intended to be representative, both in terms of the technologies being presented and their savings estimates. In practice, the measures being implemented and their associated savings are likely to be much more diverse. This is especially true in the commercial and industrial sectors, where building sizes and loads vary considerably. In addition, the structures of the FEU's EEC programs and the measures that have been included in these programs have changed considerably. Another factor that makes it difficult to compare measure level savings is changes to regulations and minimum energy performance standards that have occurred since the CPR report was issued. These changes are obviously not captured in the CPR results.

Comparing actual and forecasted savings to most likely achievable savings shows a significant difference only in the commercial program area. This is attributable to two items: first, an underestimation of the savings achievable through commercial measures such as high efficiency boilers and water heaters; second, the launch of the Commercial Custom Design Program for retrofit projects. This program, which targets energy conservation measures custom designed to suit each participant's facility, was not analyzed in the CPR, which necessarily focuses on readily identifiable measures. The program is expected to generate significant natural gas savings in the forecast years.

Comparison of 2010 CPR Most Likely Achievable Savings with Actual and Forecasted EEC Natural Gas Savings, 2010-2015

	Actual Natural Gas Savings (1000 GJ/yr), FEU (2010 EEC Annual Report)	Actual Natural Gas Savings (1000 GJ/yr), FEU (2011 EEC Annual Report)	Actual Natural Gas Savings (1000 GJ/yr), FEU (2012 EEC Annual Report)	Forecast Natural Gas Savings (1000 GJ/yr), FEU (Revised Forecast)	Forecast Natural Gas Savings (1000 GJ/yr), FEU (EEC Plan 2014-2018)	Forecast Natural Gas Savings (1000 GJ/yr), FEU (EEC Plan 2014-2018)	Estimated Cumulative Natural Gas Savings (1000 GJ/yr), FEU	Most Likely Achievable Natural Gas Savings (1000 GJ/yr.), FEU (2010 CPR)
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2010-2015**	**2015**
Residential	62	17	202	131	190	142	744	744
Commercial	104	157	163	291	368	305	1,387	930
Industrial	0	0	70	108	110	142	430	500
Grand Total	166	174	435	530	668	589	**2,561**	**2,174**

222.3 Please provide a similar updated table and comparison of 2015 forecast GJ natural gas savings to that included in the 2010 CPR for each Commercial Sector program (refer Exhibit 23, page 29 in the 2010 CPR) and for each Industrial Sector program (refer Exhibit 33, page 37).

Response:

Please refer to the response to BCUC IR 1.222.2.1.

222.4 Please describe the process used by FEU to identify the market barriers causing customers to make sub-optimal investment/usage decisions (for example, lack of information, pay-back period).

Response:

In developing EEC programs, FEU identifies market barriers that hinder energy efficient upgrades and behaviour change through multiple research methods. As applicable to each specific program, FEU conducts market research through one or more of the following research methods: hosting a program design workshop with attendance from relevant stakeholders and subject matter experts, completion of a market research study through an independent consultant, secondary research (i.e. through submission of an E Source inquiry), direct consultation with key market influencers such as associations, and/or consultation with other natural gas utilities.

222.4.1 In undertaking this analysis, does FEU segment customers in order to better tailor its offerings? If yes, please describe. If no, please explain why not.

Please include in your response whether FEU has tailored its programs to reflect any differences in the following customer segments: (i) cold vs. warm climate, (ii) renter/landlord/owner-occupier, (iii) First Nations, (v) low-income, (vi) rural vs. urban, (vii) language/culture differences (viii) environmentally conscious customers (ix) size of dwelling, (x) age of home.

Response:

The FEU segment customers when performing market analysis and determining communication strategy but has yet to undertake customer segmentation extensively to the point of tailoring programs to any specific sub segment of the market. Challenges of undertaking extensive customer segmentation include ensuring that FEU remain within its guiding principles of universal and uniform program offerings. In addition, targeted marketing such as direct mail can be expensive and the ability to target bill inserts is limited at this stage of the new FEU billing system. However, it is the FEU's intent to use customer segmentation more in the future such as through the Customer Engagement Tool for Conservation Behaviours Program which will be a means for capturing customer information and segmenting relevant messages.

The following outlines how the FEU currently tailor programs to reflect differences in the following customer segments:

(i) **cold vs. warm climate** – To date programs have been offered province-wide to allow access for all customers.

(ii) **renter/landlord/owner-occupier** – All Residential program offerings are equally accessible to renter, landlords and owner-occupants. Low Income programs have alternative application procedures and accommodations for renters vs. owners.

(iii) **First Nations** – The ECAP program has a program stream specifically designed for First Nations that is now also used for other non-profit building societies to help make the program application procedure easier. It also provides these parties with value added reporting on their building stock, how it has been modified as a result of the program participation, and other observations made during the implementation of the program. In addition to the tailored First Nations program stream in the ECAP program, the FEU have also signed a funding agreement through the Energy Specialist Program with the First Nations Energy and Mines Council to support this organization with employing an Energy Specialist. This Energy Specialist will focus on identifying opportunities for First Nation communities to utilize natural gas efficiently and take advantage of FEU EEC programs.

(iv) **low-income** - The three low income programs that are currently available to the FEU's low income customers are all tailor-made programs specifically designed to help this customer segment save energy and lower their energy bills.

(v) **rural vs. urban** - To date programs have been offered province-wide to allow access for all customers. The Kootenay, East Kootenay and Rossland Energy Diets though are programs that the Residential program area contributes to that target a more rural setting.

(vi) **language/culture differences** – The FEU have recently begun to transcribe some of its program materials to meet the needs of specific ethnic segments. The FEU have also executed some limited non-English marketing campaigns such as print ads in ethnic newspapers and is in the process of building out key sections of fortisbc.com to suit the needs of various ethnic groups. In addition, the FEU's Conservation Education and Outreach program area is funding Empower Me, a new one-year pilot program delivered by Quality Program Services, in 2013 targeting South Asian and Chinese speaking residential customers residing in the Lower Mainland. The pilot is designed to educate residential ethnic customers on behaviour change, encourage installation of low flow efficiency measures, and increase their participation in EEC rebate programs. Empower Me is delivered through a peer modeling and local champion network of local energy mentors.

(vii) **environmentally conscious customers** - The FEU engage in events and outreach activities that promote energy efficiency and conservation to environmentally conscious customers. The FEU recently partnered with VanCity on a Home Energy Rebate program where VanCity provided a $2,000 top-up to qualifying FortisBC rebate participants who signed up for a new mortgage during the promotional period. In addition, activities such as supporting the Climate Smart education for small to medium sized businesses, the Canadian Home Builders' Association of British Columbia's Department G awards, regional Commercial Building Awards in energy efficient buildings category, and exhibiting at events such as EPIC Vancouver are how FEU reaches environmentally conscious residential and business customers.

(viii) **size of dwelling** – To date no programs or program communications have specifically targeted size of dwelling.

(ix) **age of home** - To date no programs or program communications have specifically targeted age of home. However, this is a strategy that FEU has investigated and intends to pursue for program communications in the future.

222.4.1.1 Which programs does FEU have, or which programs does FEU plan to develop, that address the unique market barriers to EEC of (i) First Nation communities and (ii) renters?

Response:

The Low Income Programs have had significant and meaningful success in engaging First Nations communities especially in the ECAP program. Wherever possible this program seeks to leverage First Nations Housing Coordinators in engaging the community in the ECAP program. In some cases the ECAP program has been fortunate enough to have someone from the First Nations community accompany ECAP staff in order to gain the participation of their community members. Through the FEU's ECAP design workshop held in Q1 2013 the FEU also gained some valuable feedback on how future First Nations community engagement can be improved further such as including the First Nations community logo on program materials to reinforce the collaboration and instill trust through familiarity.

In addition, the FEU have also signed a funding agreement through the Energy Specialist Program with the First Nations Energy and Mines Council to support this organization with employing an Energy Specialist. This Energy Specialist will focus on identifying opportunities for First Nation communities to utilize natural gas efficiently and take advantage of FEU EEC programs.

Renters are able to participate in any of the Low Income and Residential programs and can also benefit from select Commercial programs as applicable to multi-family buildings. In particular though, the new Low Income programs proposed in this Application are specifically suited to non-profit multi-unit complexes which would include benefits (direct or indirect) to low income renters in the participating buildings. Please also refer to the response to BCUC IR 1.239.1, Table 2 and the response to BCSEA IR 1.15.1.

222.4.2 In undertaking this analysis, does FEU consider all market actors along the energy value chain (e.g., lenders, manufacturers, retailers)? If yes, please describe. If no, please explain why.

Response:

Yes. The FEU have developed strong relationships with natural gas contractors through the Contractor Program, industry associations, distributors, manufacturers and retailers. When launching new programs or extending existing programs the FEU request feedback from industry partners through conference calls and where feasible through program design workshops.

222.5 Please describe the general process used by FEU to develop and evaluate potential EEC programs.

Response:

The process used by the FEU to develop and evaluate potential EEC programs generally involves the following:

1. Market opportunities are identified through a Conservation Potential Review.
2. The potential energy savings of various customer segments are cross referenced with the potential savings of various technologies to prioritize markets for further investigation.
3. More in depth analysis is then performed via market characterization and technical analysis of any proposed energy saving measures.
4. Potential programs are identified.
5. Offerings of other utilities are reviewed to determine if there are any pre-existing programs which may be copied or adapted to suit EEC's needs.
6. Assumptions for benefit/cost inputs are determined.
7. Market influencers who are likely to be impacted by a proposed program are contacted to contribute their input to the proposed program.
8. Program development is finalized by formalizing eligibility criteria, terms, conditions, applicable technologies, etc.
9. The program is made available to the target market.
10. Programs are updated as required after receiving feedback from key influencers, process evaluation studies and/or energy saving verification studies.

222.6 What actions does FEU take to generate new EEC program ideas?

Response:

There are several actions that the FEU undertake to generate new EEC program ideas. These actions include the following:

- Review and analysis of the most recent Conservation Potential Review.
- Research into program offerings at utilities similar to FEU.
- Collaborative discussions with potential program partners such as other BC utilities and government.
- Attendance at energy efficiency related conferences and industry working groups to keep abreast of new programs and program developments from other areas of North America.
- Seeking feedback from various market players including suppliers, distributors, contractors, associations, consultants and potential program participants.
- Seeking feedback from the EEC Advisory Group.
- Seeking feedback from customer facing FEU departments.
- Evaluation of new and emerging technologies through the Innovative Technologies program area.
- Review of pending codes and standards.

222.7 Does FEU lead by example with regard to EEC investments and behaviors in its own property, plant and equipment? Please describe.

Response:

In terms of investments in energy efficiency the Companies believe that they do lead by example. Some specific examples of how this is achieved are provided below:

1. Lighting upgrades to all buildings at the Companies' Surrey Operations Centre will be completed in 2013. This project will reduce electricity consumption and has qualified for an incentive from BC Hydro Power Smart.

2. Lighting upgrades to FEI's Prince George Regional Office, replacing older T12 fixtures with newer high efficiency lighting, will be completed in 2013. This project will reduce electricity consumption and has qualified for an incentive from BC Hydro Power Smart.

3. In 2012 FEVI completed construction of the new Victoria Area Regional Office. This building has been built according to LEED standards. The site's mechanical systems make use of geoexchange technology coupled with high efficiency boilers, as well as high efficiency lighting supplemented by daylighting.

4. In 2011 FEI leased space for the new Willingdon Contact Centre. This space is located in a LEED Gold certified building.

5. In 2011 the companies performed an energy audit of the Surrey Operations Centre. FEI is currently proceeding with the recommendation to install a dedicated RTU to provide space conditioning to areas occupied outside of normal business hours, thereby reducing both gas and electricity consumption.

6. In 2010 FEI purchased a building to house its Prince George Contact Centre. FEI subsequently invested in the replacement of both the Heating Ventilating and Air Conditioning (HVAC) and lighting systems. Improvements to the HVAC system included the installation of a new high efficiency (97% combustion efficiency) boiler while lighting improvements included high efficiency light fixtures, substantial use of daylight and control by occupancy sensors in occupied areas.

7.

222.8 To what extent does FEU leverage off its access to customer gas consumption data in the design and delivery of EEC programs?

Response:

The Companies have not historically leveraged access to individual customer gas consumption data to design and deliver EEC programs. Individual customer consumption data in and of itself is not useful to EEC activity, since it is only a consumption number, and does not indicate how the energy is being used in the building. Without additional information such as building size, insulation levels, appliances, occupancy levels, usage patterns or demographic information from customers, the Companies cannot use customer consumption information to design or deliver EEC programs. It is conceivable that the Companies might in the future access aggregated customer data to target programs to, for examples, locations with clusters of high gas consumption.

222.8.1 Could this data be made available to third parties wishing to provide EEC services to customers? Please explain what mechanisms would be required to protect customer privacy.

Response:

Customer permission would need to be obtained in order for individual customer consumption data to be provided to third parties wishing to provide EEC services to customers. Obtaining customer permission is a very resource-intense process, so the Companies have no plans to provide customer consumption data, either on an individual or on an aggregated level to third parties engaged in the provision of EEC services on any widespread basis at this time. The Companies do, however, provide customers with access to information about entities engaged in the provision of products and services. An example of this would be the Efficiency Partners Program which is described on page 104 of Exhibit B-1-1, Appendix I, Attachment I1, and which provides customers with the names of gas contractors should the customer so wish.

The Companies do provide consumption data to third parties for the purposes of conducting studies and undertaking reports. An example of this would be impact evaluations for residential programs. After having obtained customer permission, program participant consumption data is provided to the third party evaluation contractor in order to perform billing analysis to determine energy savings.

223.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

BC Energy Plan, p. 5-9; Exhibit B-1-1, Appendix I, Attachment I-1, p. 10;

Attachment I-2,

Coordination with other agencies

The BC Energy Plan states: "Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia" (p. 5) and on pages 6 to 8 refers to Energy Efficient Buildings, the Community Action on Energy Efficiency Program and the Industrial Energy Efficiency Program.

Appendix I-1 to the Application, FEU states: "The longer term vision for residential programs is to continue to seek partnerships with electric utilities and governments. This will allow us to build a common rebate administration and marketing platform..." (p. 10)

The Memorandum of Understanding (MOU) Report Executive Summary is included in the Application as Appendix A to Attachment I-2 of Appendix I. Under "Next Steps" it states: "The utility partners are currently working on creating consistent key performance indicators (KPIs) …."

223.1 How does FEU coordinate with providers of other EEC programs (such as BC Hydro, LiveSmart) in ensuring that a coordinated approach is undertaken in (i) program development (for example, to identify market barriers which may not be addressed by the existing suite of programs offered by different providers) and (ii) incorporating feedback from existing programs to better tailor program design?

Response:

The FEU coordinate with other providers of energy efficiency incentive programs through a variety of formal and informal means. In terms of program development, the FEU and other providers generally begin by identifying priority programs for inter organizational collaboration. The MOU between the FEU and BC Hydro is an example of how these decisions are formalized. MOUs or less formal means may be used with other organizations. Subsequently, the program teams at the respective organizations work to develop coordinated programs and hold regular update meetings to track progress and discuss any difficulties or issues. Such meetings may take place over the phone or in person. Finally, when programs are in market the program teams continue to hold regular meetings in order to gauge success, review any feedback or issues, and take action to correct issues or enhance a program if needed. This process is applied in each FEU EEC program area.

For example, the Residential program area participates in bi-weekly meetings with program partners to discuss operational issues, program design opportunities, market needs, communications plans and future program planning. A LiveSmart BC Program Design Workshop is being undertaken in the fall of 2013 to obtain feedback from key influencers as to the future direction of the home retrofit program. In addition, BCHydro has commissioned a Whole Home Performance Study which will be shared with the FEU and will suggest a five year plan to develop a sustainable BC-based Home Performance industry. For the New Home program, utility partners are co-funding a Home Energy Modeling study to understand the impact of the December 2014 BC Building Code updates on future program design. Plans for a builder/developer workshop on the impacts of the new building code as well as the introduction of NRCan's New Home Energy Rating System are being discussed.

Another example of the FEU's coordination with providers of other EEC programs is the FEU's Conservation Education and Outreach program area which corresponds frequently with FortisBC Inc. (electric) through email, regular phone calls and written business cases on a variety of EEC programs including school programs, partnerships, outreach and energy conservation initiatives that occur in the joint FEU and FortisBC Inc. service territory. The FEU are also collaborating closely with BC Hydro on six outreach events throughout 2013 and share event evaluations and feedback, as well as discuss new partnership and outreach opportunities as they arise.

223.1.1 Please describe any progress FEU has made towards developing a common rebate administration and marketing platform for EEC residential programs across utilities.

Response:

The FEU and electric utilities share a common administration platform where possible for all programs as demonstrated in the following table.

Program	Administrative Platform
LiveSmart BC (listed as Energy Efficient Home Performance Program in 2014-2018 EEC Plan)	Currently Ministry of Energy and Mines provides program administration based on NRCan data files. LiveSmart BC program partners are discussing options for a common rebate administration platform for 2014 program deployment.

Program	Administrative Platform
New Home Program	The FEU and BC Hydro share a common database and administration platform that is outsourced to Consumer Response Marketing Ltd. Surrey, BC (CRM). The FEU and FortisBC Inc. rebates are administered by FortisBC Inc. / FEU staff.
Washer Program	BCHydro oversees program administration that is outsourced to CRM. FortisBC Electric rebates are administered by FortisBC staff. The washer program will not be continued in 2014.
FEU Stand-Alone Programs	The FEU administration (and most BCHydro administration) is outsourced to CRM. An online customer enrollment project is under development for 2013-2014 which will streamline costs, provide more accurate data, and improve customer experience. This online process is a first step a shared administration platform.

The utility partners' communications teams have developed co-branding guidelines as the first step in collaborative marketing initiatives. The branding guidelines include the theme "*Working together to help BC save energy"*. This establishes a consistent and creative platform for co-branded Power Smart and FortisBC communication materials. The platform aligns the Power Smart and FortisBC brands, without diluting either brand. With a similar creative approach, tone, look and feel, this new marketing platform will help British Columbians recognize energy efficiency programs and highlight the collaboration between utilities. The FEU's longer term vision is to work with partners in developing a Home Energy Efficiency Web Portal.

223.1.2 Please provide the BC Hydro and FortisBC EEC MOU key performance indicators.

Response:

The BC Hydro and FortisBC EEC MOU key performance indicators have not been developed yet. The need for a formalized evaluation strategy has been identified as a priority going forward but is still in development. Both utility partners are currently engaging their respective evaluation teams to develop a plan to quantify the deliverables of our partnership, and are working cooperatively to identify a consistent, shared approach.

223.2 Does FEU participate in and support the (i) Community Action on Energy Efficiency Program (page 7 of the BC Energy Plan); (ii) Industrial Energy Efficiency Program (page 8 of the BC Energy Plan); and/or (iii) Energy Efficient Buildings: A Plan for BC (page 6 of the BC Energy Plan)? If no, please explain why not. If yes, please describe.

<u>Response:</u>

The Companies are not aware of any active processes currently being conducted by the Government of British Columbia associated with the Community Action on Energy Efficiency Program or the Energy Efficient Buildings initiative. The FEU's EEC programs generally support enhancements in community and building efficiency. The Companies are currently engaged to some degree with Government in the Industrial sector, exploring how both the FEU and BC Hydro's activity in DSM for the industrial sector aligns with Government's interest in promoting the ISO 50001 standard.

223.3 Has FEU developed attribution rules for all integrated programs with partner organizations? If yes, please provide them and describe how they were developed. If no, when and how does FEU plan to develop and complete them?

<u>Response:</u>

The FEU have begun investigating appropriate attribution rules for energy savings to apply to integrated programs with other partners, but have not yet completed developing these rules. These attribution rules will be completed by the end of 2013. The process for completing these rules will be to survey the industry for similar rules in other jurisdictions, continuing to work with program partners to discuss and examine appropriate rules, developing draft rules for review by program partners and the EECAG, and finalizing the rules based on our examination of potential conflicts and any feedback received.

224.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

DSM In North American Gas Utilities, Navigant, 2004, p. 13;[45] BC Energy Plan, p. 5; Exhibit B-1-1, Appendix I, Attachment I-1, p. 5; Exhibit A2-2, p. 64

Setting the EEC Funding Envelope

The Navigant "DSM in North American Gas Utilities" paper states on page 13: "The general principle in the budget and target setting process used in many jurisdictions surveyed could be loosely characterized as 'Set a reasonable budget and do the best you can with the money.'"

The BC Energy Plan states on page 5 "...the plan supports utilities in British Columbia and the BC Utilities Commission pursuing all cost effective and competitive demand side management programs."

FEU are requesting $185m in EEC funding over the PBR period. (Attachment I-1, p. 5)

A 2013 International Energy Agency report on Energy Provider-Delivered Energy Efficiency (Exhibit A2-2) states on page 64: "DSM programmes need to be developed and conducted in a phased manner over a period of years. This makes it possible to capture synergies with other activities and adapt in response to changing market, funding, social and even political conditions."

224.1 Please describe the general approach used by FEU in setting the $185m EEC funding envelope.

Please include in your response if the approach could be considered (i) a 'zero based budgeting approach,' where the level of EEC spending is not based on the previous year's budget but uses the CPR (as updated for cost inputs/new technologies/changes in existing building stock and plants as the starting point; (ii) an approach which uses the previous year's EEC budget as a starting point to develop an EEC funding envelope the utility considers reasonable; or (iii) an alternative approach – if so please describe.

Response:

The approach that the FEU took to establishing annual EEC expenditure levels for the test period is closest to point (ii) above. As noted in Section 5 of Exhibit B-1-1, Appendix I, "Many of

[45] http://www.indeco.com/www.nsf/602920ce130253a08525764e007a6418/abbfd4c9e05d712085256e38006d76b3/$FILE/EGD%20Report%20on%20DSM%20Jurisdictions.pdf

the programs are continuations of previously-approved programs that the FEU are currently running…" As noted on page 18 of Exhibit B-1-1, Appendix I, "It can be seen…that the funding levels being requested for most program areas are relatively stable." Given that many of the proposed programs were continuations of previously approved programs, the Commission approved funding levels for existing programs in 2012 and 2013 was considered to be indicative of the levels that were appropriate to maintain over the test period. The appropriateness of the Plan and its associated level of funding was also supported by the fact that the members of the Energy Efficiency and Conservation Advisory Group that participated in the conference call held May 1 to discuss the 2014-2018 EEC Plan did not indicate that any major "course corrections" were necessary.

The process that the FEU undertook in arriving at program budgets, and therefore the overall EEC budget is further described in Section 1.2 of the 2014-2018 EEC Plan, Exhibit B-1-1, Appendix I, Attachment I1:

> *"The information presented in this report was compiled in a similar manner as the FortisBC Energy Utilities 2012-2013 EEC Plan filed in 2011. The process involved a collaborative working effort between FortisBC EEC program personnel and ICF Marbek staff that employed the following steps:*
>
> - *FortisBC program managers identified and provided a description of the individual programs included within their respective portfolios, including eligible measures, target markets and potential delivery partners.*
> - *Drawing on a combination of previous FortisBC EEC market experience, relevant technology and market studies, and, in some cases, professional estimates, FortisBC EEC managers completed Profiles for each program within their portfolio. Individual Profiles are included in the body of this report.*
> - *ICF Marbek staff worked from the Program Profiles provided by FortisBC staff and populated the cost-effectiveness model. Initial results were generated at the level of total EEC program portfolio, program area (e.g., Residential, Commercial, etc.) and individual program.*
> - *The initial results were reviewed collaboratively and revisions were made, as necessary.*
> - *The final results were compiled into the current report."*

Each of the individual program profiles includes a program budget, and there is funding allotted for various Enabling Activities, which are described in Section 9 of Plan Exhibit B-1-1, Appendix I, Attachment I1.

224.1.1 If the EEC funding envelope was increased by (i) 10 percent and (ii) 50 percent from that proposed by FEU, does FEU consider it could develop and implement new programs and/or expand existing programs to spend the EEC budget which would (i) pass the TRC/mTRC (ii) pass the UCT, and (iii) provide an equitable level of EEC funding to each customer class? Please explain.

Response:

No. The level of funding and activity has in fact been ramping up and programs phased in since the original EEC Application was approved in 2009, as can be seen in Table I-3 in Exhibit B-1-1, Appendix I. 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.

224.1.2 If FEU response to any of the above scenarios was 'yes,' please explain why FEU has limited the requested EEC budget to $185m. Please include in your response if an increase in the EEC budget would displace higher utility gas costs over the long term.

Response:

Please refer to the response to BCUC IR 1.224.1.1.

224.2 Please explain how FEU has arrived at the EEC funding split between residential, commercial and industrial customer.

Response:

A discussion of the process that the FEU undertook in determining funding levels can be found in the response to BCUC IR 1.224.1. It can be seen in the response to BCUC IR 1.234.5 that the planned EEC expenditure breakdown for residential, commercial and industrial customers in, for example, 2014 is 31% for residential customers, 32 percent for commercial customers and 6% for industrial customers. This breakdown results from evolution of the EEC activity since 2009, and the proposed expenditure is based on existing, previously approved activity.

224.2.1 Please explain to what extent, if any, the level of FEU funding for EEC changes as a result of changes in the total level of BC Hydro and LiveSmart EEC funding.

Response:

The level of FEU funding does not change as a result of changes in the total level of BC Hydro and LiveSmart funding.

225.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

DSM in North American Gas Utilities, Navigant, 2004, p. 51;[46] Exhibit A2-2, pp. 33, 89

Use of the Market to Discover and Deliver Cost Effective EEC

Navigant paper titled "DSM in North American Gas Utilities" states on page 51: "Low income customers of [Vermont Gas] are referred to the Champlain Valley Weatherization Service (CVWS) for energy efficiency programs. The CVWS determines the customer's income status and eligibility, performs the energy audit, submits the recommended measures to VGS for screening, and coordinates the installation of the cost-effective energy saving measure. VGS shares the costs of the program..."

A 2013 International Energy Agency report on Energy Provider-Delivered Energy Efficiency (Exhibit A2-2) discusses EEC White Certificates on page 33 and an EEC Block Bidding Program on page 89:

225.1 Does FEU partner with any social agencies in the delivery of its low-income EEC programs? If yes, please explain. If no, does FEU consider there could be a net benefit of exploring this option? Please explain why/why not.

<u>Response:</u>

The FEU do work with several social agencies in the delivery of our Low Income programs; however, the scope of engagement that is assigned to the social agencies that the FEU work with is different from the scope that Champlain Valley Weatherization Service performs for Vermont Gas. Champlain Valley Weatherization Service is a non-profit organization and the FEU are unaware of any provincial non-profit organizations that have the expertise to perform the role that Champlain Valley Weatherization Service performs in Vermont. The role that various non-profits and social agencies play in the FEU's programs is described below.

Residential Energy and Efficiency Works – REnEW for short - is a training program, in partnership with BC Hydro and FBC that trains marginalized individuals to work in the emerging field of energy efficiency. To date, the REnEW training program has been delivered in partnership with five social service providers - John Howard Society of the Central and South Okanagan, Aboriginal Community Career Employment Services Society, Prince George Metis Housing Society, Cariboo Friendship Society and the Sto:Lo First Nation. Each of these agencies played a central role in delivering the REnEW program in their community including

[46] http://www.indeco.com/www.nsf/602920ce130253a08525764e007a6418/abbfd4c9e05d712085256e38006d76b3/$FILE/EGD%20Report%20on%20DSM%20Jurisdictions.pdf

marketing the program, recruiting participants, performing all administration associated with offering the training in their community, and leveraging their networks to gain additional financial contributions from organizations such as BladeRunners, Service Canada, Province of British Columbia, Community Living, and the Ministry of Advanced Education and Labour Market Development.

The Energy Conservation Assistance Program (ECAP) and Energy Savings Kit (ESK) program are collaborative initiatives between the FEU, BC Hydro and more recently FBC. Together, the utilities have built strong partnerships to assist with the communication of low income programs, as well directly reach FEU's target market through a "hands on" approach. The FEU have collaborated with many partners, some of which are listed below along with a brief explanation of the collaborative approach.

Organization Name	City	Tactics
Ministry of Social Development (MSD)	Fraser Region	Promotional Partner- posting and promoting ESK marketing materials to clients ESK/ECAP on-site** event Low Income article in internal newsletter Bill insert distributed with their monthly cheque run
Family and Youth Pilot Program (MSD)	Province Wide	Promotional Partner - promoting ESK to clients they work with. Leaving marketing material for clients
DIVERSEcity	Surrey	ESK on-site** Partner - Handing out ESK to qualified clients
Surrey Food Bank	Surrey	Promotional Partner - posting and promoting ESK marketing material to clients Summer on-site** event- handed out ESK to clients Summer dish soap* handout Initiative - promoting ESK to hamper clients
Abbotsford Food Bank	Abbotsford	Promo Partner - posting and promoting ESK marketing material to clients Christmas Hamper Initiative - promoting ESK to hamper clients
Cause we Care	Vancouver	Mother's Day Initiative -brochures and CFLS put in 60 hampers
Surrey Urban Mission (Surrey Connect)	Surrey	On-site** Event- Handed out ESK/ECAP applications to qualified clients

Organization Name	City	Tactics
Chilliwack Connect	Chilliwack	On-site** Event- Handed out ESK/ECAP applications to qualified clients
Vancouver Food Bank	Burnaby/Van	Summer dish soap* - promoting ESK to hamper clients with dish soap
Collingwood Neighbourhood house	Burnaby	Promo Partner - posting and promoting ESK marketing material to clients
BC211	Lower mainland	Workshop- ESK/ECAP workshop provide for employees
Foodshare	Kitimat	ESK on-site** Event - Handing out ESK to qualified clients Promotional Partner - posting and promoting ESK/ECAP marketing material to clients
Network of Inner City Community Service Society (NICCSS)	Campbell River	Promo Partner - posting and promoting ESK marketing material to clients ESK On-site** Partner - Handing out ESK to qualified clients
Capital Regional District (Parks and Rec)	Victoria	Promo Partner - posting and promoting ESK marketing material to clients Workshop- ESK/ECAP presentation about programs to CRD staff
Salvation Army Victoria (addictions/rehabilitation)	Victoria	Promo Partner - posting and promoting ESK/ECAP marketing material to clients
Bright Family Futures	Vancouver	Workshop- On ESK and energy efficiency behaviors to clients
North Vancouver Family Services	North Vancouver	Promo Partner - posting and promoting ESK marketing material to clients Christmas Hamper Initiative - promoting ESK to hamper clients with dish soap
Chilliwack &District Senior Resources Society	Chilliwack	Tax Clinic Partner - promoting ECAP to tax clinic clients
Volunteer Terrace	Terrace	ESK on-site** Event - Handing out ESK to qualified clients Promotional Partner - posting and promoting ESK/ECAP marketing material to clients
Saanich Parks & Recreation	Victoria	Promotional Partner - posting and promoting ESK/ECAP marketing material to clients

Organization Name	City	Tactics
BC Non Profit Housing Association	Province-wide	Participation in BCNPHA annual conference Mutual referrals to PowerSmart/PowerSense programs ECAP email blast to members
Desert Gardens Community Centre / Senior Outreach Centre	Kamloops	Promotional Partner - posting and promoting ECAP marketing material to clients
Intercultural Society of the Central Okanagan	Kelowna	Promotional Partner - posting and promoting multi-lingual ECAP marketing material to clients
South Okanagan Immigrant & Community Centres	Penticton	Promotional Partner - posting and promoting multi-lingual ECAP marketing material to clients
Burnside Gorge Community Association	Victoria	Promotional Partner - posting and promoting ECAP marketing material to clients
Central Vancouver Island Multi-Cultural Society	Nanaimo	Promotional Partner - posting and promoting multi-lingual ECAP marketing material to clients
Douglas Care Community	Victoria	Promotional Partner - posting and promoting ECAP marketing material to clients
Immigrant Welcome Centre, Campbell River	Campbell River	Promotional Partner - posting and promoting multi-lingual ECAP marketing material to clients
Immigrant Welcome Centre, Comox Valley	Courtenay	Promotional Partner - posting and promoting multi-lingual ECAP marketing material to clients
James Bay Community Project	Victoria	Tax Clinic Partner - promoting ECAP to tax clinic clients Promotional Partner - posting and promoting ECAP marketing material to clients
Lake Cowichan District Seniors Association	Lake Cowichan	Promotional Partner - posting and promoting ECAP marketing material to clients
Mustard Seed	Victoria	ESK/ECAP on-site** event Christmas Hamper Initiative - promoting ESK to hamper clients Promotional Partner - posting and promoting ESK/ECAP marketing material to clients
Nanaimo Loaves and Fishes Food Bank	Nanaimo	ESK/ECAP on-site** event; Promotional Partner - posting and promoting ESK/ECAP marketing material to clients
Saanich Neighbourhood Place	Victoria	Promotional Partner - posting and promoting ECAP marketing material to clients
Kamloops Food Bank	Kamloops	Promotional Partner - posting and promoting ECAP marketing material to clients

Organization Name	City	Tactics
Salvation Army - Alberni Valley Ministries	Port Alberni	Promotional Partner - posting and promoting ECAP marketing material to clients
1Up Victoria Single Parent Resource Centre	Victoria	Promotional Partner - posting and promoting ECAP marketing material to clients
Salvation Army Community & Family Services - Comox Valley Centre	Courtenay	Promotional Partner - posting and promoting ECAP marketing material to clients
Salvation Army Stan Hagen Center for Families	Victoria	Christmas Hamper Initiative - promoting ESK to hamper clients Promotional Partner - posting and promoting ESK/ECAP marketing material to clients
Valley Seniors Organization	Duncan	Promotional Partner - posting and promoting ECAP marketing material to clients
**Dish soap bottles are stickered with information to promote free ESKS that will help the low income families save money and make their homes more comfortable. **On-site Event: These events are physically located at the partner's location, this allows eligible customer to sign up for ESK, as well learn about ECAP and receive an application to fill out.*		

225.2 What process would FEU follow if an individual or company brought forward an idea for a possible DSM project, for example, a school education program? Please explain if and how this idea would be evaluated.

Response:

Typically, third party DSM project ideas are funneled through either the Innovative Technologies program area or Conservation Education and Outreach program area as these two program areas are responsible for capturing and evaluating ideas for new DSM technology measures and behaviourial programs respectively. The process for accepting and reviewing DSM project ideas for Innovative Technologies works as follows:

- Individual/company is required to provide a third party engineering report supporting their technology DSM claim.
- Individual/company is required to formally present their DSM idea to FEU either in person or through a conference call.

- The FEU then assesses whether the idea has a market which could directly or indirectly result in significant reductions of energy use that is cost effective and meets the DSM definition.
- The FEU will determine the priority and assign resources to develop a business case which is then submitted to the Director, EEC for approval.

Please refer to the response to BCUC IR 1.230.1.2 for information on how an idea for a Conservation Education and Outreach program such as a school education program is evaluated.

Note also that the FEU occasionally receive requests for program collaboration that consists basically of a co-marketing partnership to drive participation in existing EEC programs. Typically these requests come to the Residential program area. An example of this would be the VanCity Home Energy Rebate where VanCity provides a $2,000 top-up to qualifying FortisBC rebate participants who signed up for a new mortgage during the promotional period. FEU assesses these types of proposals based on how they would benefit customers and the internal resource requirements that would be required for implementation.

The FEU take into consideration the biases of individuals or companies that submit DSM project ideas. DSM project ideas are often brought forward by individuals or companies to further their own agenda in some way, rather than pursuing what is best for the market as a whole. Because of this, the FEU often do not implement ideas proposed by outside sources, especially vendors.

225.2.1 If FEU did not wish to pursue the idea brought forward, what process would be available to the individual/company to challenge this?

Response:

The FEU strive to support requests in whole or in part that they believe would be beneficial to customers. Individuals/companies are welcome to re-state their DSM project ideas for reconsideration so long as the proposal includes new information not included in the original proposal. Currently, the formal process by which an individual or company could challenge a decision of the FEU would be to file a complaint with the BCUC or intervene in a proceeding such as the present one.

225.3 What process, if any, does FEU use to actively solicit ideas from individual and companies regarding potential cost-effective EEC programs?

Response:

FEU does not actively solicit ideas for new EEC programs from third party individuals and companies. To date, FEU has focused its resources more on designing and implementing the existing DSM programs that were identified as opportunities in the 2006 and 2010 Conservation Potential Review (CPR) studies which acted as a comprehensive and unbiased review of the natural gas conservation potential within FEU's service territories.

However, as stated in the response to IR 225.2, FEU does actively review and consider DSM project ideas from third parties as they are submitted. FEU also actively consults with program partners and key EEC stakeholders throughout the program design and implementation process in order to ensure that all expert perspectives are captured and considered when designing and rolling out an EEC program. In being active participants in trades associations, workshops and working with government and utilities FEU feels they are readily accessible to hear from key influencers and will consider proposals that are received that have merit to ratepayers, communities or trades engagement and training.

225.3.1 Please discuss the advantages/disadvantages of an EEC 'standing offer program,' where FEU agrees to purchase energy savings from third parties at a specified $/GJ price (similar to White Certificates/BC Hydro's Standing Offer Program).

Response:

BC Hydro's Standing Offer Program and a white certificate program are not examples of a standard offer program. A standard offer program meets the definition supplied above, where a utility offers a specific price per kWh or GJ of energy savings that a customer or energy service company (ESCOs) achieves. BC Hydro's Standing Offer Program is an electricity purchase agreement program, by which BC Hydro secures clean, renewable energy from small developers to supply electricity to ratepayers.

White certificates, also referred to as white tags, operate similarly to renewable energy credits. They certify that an entity achieved a specified amount of energy savings and then the certificates can be sold based on prices set on a white certificate market.

Some of the advantages and disadvantages of standard offer programs are listed below.

Advantages of standard offer programs:

- Standard offer programs allow a utility to set the price they are willing to pay for energy savings, providing the opportunity to acquire energy savings at a lower $/energy unit than prescriptive programs.
- Standard offer programs can vary prices for energy savings based on measure type, market segment, or depth of savings to align with internal utility/program goals.
- Competitive programs allow customers and energy service companies (ESCOs) greater flexibility to select projects that will generate energy savings at a lower project cost, offering the potential to uncover efficiency savings not currently being realized.

Disadvantages of standard offer programs:

- Customers, contractors, and/or engineers will need training on how to accurately calculate energy savings and incentives.
- Participants are likely to target the lowest hanging fruit, unless program administrators value energy savings based on measure type or set limits on the amount of savings that can come from the lower cost, higher return projects.
- The customer's perceived risk may be greater than with a prescriptive program because they have to calculate expected savings and determine the incentive which could negatively impact participation.
- Standard offer programs rarely address "market transformation" barriers such as a lack of information about a specific energy efficiency opportunity or impediments in the supply chain.

225.3.2 Please discuss the advantages/disadvantages of an EEC 'reverse auction,' where FEU invites EEC suppliers to bid to supply EEC, and awards contracts to the lowest bidder (similar to a Block Bidding Program/BC Hydro's Clean Energy Call).

Response:

There are a few competitive processes by which utilities (or other agencies) award funds for cost effective energy efficiency projects, such as reverse auctions, competitive bids and request for proposals (RFPs). The following addresses the advantages and disadvantages of these competitive programs.

Advantages of competitive programs:

- Competitive bid programs allow utilities to set a ceiling on the price they are willing to pay for energy savings, providing the opportunity to acquire energy savings at a lower $/energy unit than prescriptive programs.
- Competitive programs allow a utility greater flexibility to select projects that align with internal program goals.
- Bid programs are usually offered supplemental to other prescriptive and custom programs, thereby offering customers a greater variety of ways to receive incentives for energy savings.
- If designed appropriately, competitive programs can encourage the installation of comprehensive measures, or emerging technologies, since these often less cost effective measures can be paired with highly cost effective measures.

Disadvantages of competitive programs:

- Customers, contractors, and/or engineers will need training on how to submit a bid.
- Competitive bid programs may require the utility to conduct more administrative work and project tracking to ensure projects are meeting deadlines as well as expected energy savings.
- Due to their large scope (i.e., project costs in excess $250,000), competitive projects require commitment from upper level management at the project site – an added hurdle to securing projects and energy savings.
- Participants are likely to target the lowest hanging fruit, unless program administrators value energy savings based on measure type or set limits on the amount of savings that can come from the lower cost, higher return projects.

- Competitive bid programs rarely address market transformation barriers such as a lack of information about a specific energy efficiency opportunity or impediments in the supply chain.

Please note that BC Hydro's Clean Energy Call is not an example of an energy-efficiency reverse auction or competitive bidding program. It is an electricity purchase agreement program, by which BC Hydro secures clean, renewable energy to supply electricity to ratepayers.

225.4 How does FEU ensure that ideas/feedback from the educational conferences and workshops that FEU holds and attends to highlight new technologies and program offerings and exchange best practice information are incorporated into the decision making process regarding which EEC opportunities to pursue?

Response:

Generally speaking, the EEC Program Managers responsible for EEC program design attend conferences and workshops with content applicable to their individual program areas, and learnings from those conferences and workshops are incorporated into the design of the Companies' EEC programs by the Program Managers. Further, the EEC group has a practice of requiring EEC Program Managers returning from conferences to do a short presentation on the learnings gleaned as a result of attending the conference to the larger EEC group at the regular bi-weekly meetings the group holds.

In terms of determining which EEC opportunities to pursue, those decisions are made by the EEC Management team consisting of the Director and Program Managers in consultation with ICF Marbek, the consultant that prepared the Companies' 2010 Conservation Potential Review and 2012-2013 and 2014-2018 EEC Plans, with input from various stakeholders, including governments and other utilities as well as customer groups and industry associations.

225.5 Have there been any EEC contracts awarded for the delivery of EEC programs to suppliers who do not have an arms-length relationship with FEU, its affiliated companies, its staff or directors? If yes, please explain.

Response:

No, the Companies have not awarded any contracts for the delivery of EEC programs to suppliers who do not have an arms-length relationship with the FEU, its affiliated companies, its staff or directors.

225.5.1 How does/would FEU address the conflict of interest issue in awarding EEC contracts under the above scenario? Please describe.

Response:

The FEU have not encountered any conflicts of interest to date. However the business activity of the FEU is governed by corporate policies. Two corporate policies are provided in Attachment 225.5.1 – the Business Ethics Policy and the Procurement Policy. It can be seen on page 3 of the Business Ethics Policy that "Relationships with vendors must always be arms length, consistent with accepted business practices, the Company's policies, and in accordance with applicable laws." Should the Companies encounter such a conflict of interest, the Companies' actions would be guided by these policies.

225.6 Please describe the delivery agents used by FEU to deliver EEC services, and the process used by FEU to determine which services should be provided by a third party and to procure these services.

Response:

The FEU do not "deliver" EEC activity beyond the activity described in the response to BCUC IR 1.237.1. Examples of other EEC activity delivery models in the 2014-2018 EEC Plan are provided below; however, it is the FEU's customer who chooses who they deal with to access EEC opportunities.

Most of the residential EEC activity being proposed for the test period is actually "delivered" by contractors of various sorts, working directly with residential customers to undertake activities that qualify for the Companies' EEC incentive programs (either stand-alone or offered in partnership with other utilities and governments as identified in the detailed Program Profiles provided for each Program Area in the 2014-2018 EEC Plan, Exhibit B-1-1, Appendix I, Attachment I1), under program terms and conditions. One exception to this would be the “Customer Engagement Tool for Conservation Behaviours”, described on pages 32 and 33 of Exhibit B-1-1, Appendix I, Attachment I1, for which the Companies are currently undergoing a procurement process led by the FEU’s IT department.

The same is true for much of the activity in the Commercial Program Area, with a few exceptions. For the Customized Equipment Upgrade Program described on pages 48 and 49 of Exhibit B-1-1, Appendix I, Attachment I1, the Companies underwent a procurement process to develop a list of engineering companies and consultants from which customers can select an entity to undertake the detailed energy study funded by the FEU in order to enter the program. For the EnerTracker Program described on pages 50 and 51 of Exhibit B-1-1, Appendix I, Attachment I1, the Companies underwent a procurement process in order to select the providers of the Energy Management Information Systems from customers can select. The Companies are currently in the procurement process for vendors for the Commercial Energy Assessment Program described on pages 54 and 55 of Exhibit B-1-1, Appendix I, Attachment I1.

In the case of the Low Income Program Area, BC Hydro is the “lead” utility on both the Energy Savings Kits and Energy Conservation Assistance Program, and was responsible for selecting vendors.

225.7 Does FEU consider that it can generally deliver its EEC programs more cost effectively than LiveSmart or PowerSmart? Please explain why/why not.

Response:

The portfolio of EEC activity proposed for the FEU over the test period is cost effective as defined by the Demand Side Management Regulation, as it has a combined TRC/MTRC of over 1.0. The Companies do not know what the cost-effectiveness of the overall LiveSmart portfolio, or the BC Hydro Power Smart portfolio is over the same time period. The FEU enjoy significant collaborative efforts with BC Hydro Power Smart and with various municipal and provincial governments on programs such as LiveSmart, as detailed in the Program Profiles, and these collaborative efforts serve to keep EEC costs down for customers.

226.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1-1, Appendix I, Attachment I-1, p. 15

Residential Programs – EEC Plan overview

226.1 Please describe the results FEU considers would be obtained if there was an increase in available EEC funding for each residential EEC program with a positive UCT.

Response:

The following response addresses BCUC IRs 1.226.1, 1.227.1, 1.228.1 and 1.232.2.2

An increase in available funding may allow the inclusion of more measures in a program, the provision of greater incentives, or increased marketing investments which may in turn increase program participation and result in greater realized savings. However, FEU believes that the requested funding envelope provides a good balance of opportunities for customers to achieve energy savings while at the same time being mindful of customer rate impact. This is outlined further in the response to BCUC IR 1.224.1 and 1.224.1.1.

226.2 What heating source for FEU assume is displaced by the Enerchoice Fireplace Program (for example, is it assumed that customers are using ornamental fireplaces to heat their homes)?

Response:

Yes. The FEU assume that the EnerChoice incentive persuades customers about to install a natural gas fireplace to choose an efficient EnerChoice model that can provide zone heating rather than a less efficient decorative natural gas fireplace that provides ambience.

226.3 Please explain how the Appliance Service Program results in energy savings to the customer.

Response:

The FEU do not claim direct energy savings for The Appliance Service Program. However, the FEU believe that educating customers about the benefits of efficient equipment maintenance, while creating opportunities to further educate customers about energy saving behaviours and programs opens the door to future natural gas savings. Intuitively, a heating system that is well-maintained will run more smoothly and consume less energy.

226.3.1 Does FEU consider that this program is undertaken primarily or partly to improve customer satisfaction around gas appliance safety concerns? Please explain why/why not.

Response:

The FEU acknowledge that The Appliance Service Program addresses safety concerns but this is not the primary intention of the program. Respondents in the "TLC Furnace/Fireplace 2011" and "TLC Furnace/Fireplace 2012" participant surveys described on page 87 of the 2012 Annual Report, Exhibit B-1-1, Appendix I, Attachment I2, identified "peace of mind/knowing its safe", "improved efficiency", and "lower gas bills/saving money" as the top three benefits of servicing their appliances annually.

226.3.1.1 If yes, does FEU consider that all or part of the costs should not be categorized as EEC expenditures?

Response:

The FEU believe it is reasonable for the Appliance Service Program to be wholly categorized as EEC expenditures since non-energy benefits can be captured in EEC programs. Furthermore, this popular EEC program provides the FEU with a relatively low-cost opportunity for all customers to engage in an EEC rebate that can lead to further high efficiency appliance upgrades.

226.3.2 Does FEU consider that this is a cost-effective means of encouraging customers to replace inefficient furnaces/fireplace boilers? If yes, please explain why.

Response:

Yes, in addition to program benefits noted in the response to BCUC IR 1.226.3.1, the Appliance Service Program is a cost-effective means for contractors to engage customers on the benefits of upgrading to energy efficient appliances. The table below outlines that during the furnace service 13-16% of responders were advised to upgrade their furnace while during the fireplace service 10-11% of responders were advised to upgrade their fireplace. Problems (including gas leaks) were discovered in 6-11% of furnaces and 4% of furnaces.

Appliance Service Evaluation Results 2010 through 2012

Appliance survey participant responses (%)	Program Year		
	2010	2011	2012
Did contractor discuss efficiency of appliance during service visit?	48	60	50
Furnace Service	48	42	33
Fireplace Service	NA	9	18
Both Serviced	NA	10	NA*
No discussion regarding efficiency of appliance	52	40	50
Furnace Upgrade Advised	15	13	16
Fireplace Upgrade Advised	NA	11	10
Problems Discovered including gas leaks - Furnace	10	11	6
Problems Discovered including gas leaks - Fireplace	NA	4	4

*In 2012, customers were asked about only their furnace or fireplace, not both in the same survey.

226.3.2.1 Does FEU train the employees/contractors performing the service to provide information to customers on the energy savings from upgrading inefficient furnaces/fireplaces? Please explain.

Response:

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.

Contractor communications for this program included the following:

- a mail-out to the BC Safety Authority (BCSA) database including a letter, brochure, and Spring Contractor newsletter that discussed all EEC programs,
- an email to Contractor program members announcing the program,
- education regarding BCSA's gas permits and appliance service checklists, and
- promotion at Contractor Program registration drives and other events

Customer communications included:

- call out to hire an accredited contractor,
- what to look for in a furnace or fireplace service, and
- benefits of a furnace or fireplace service

226.4 Are the estimated TRC/mTRC and UCT of the NewTechnologies Program 'placeholders' only (i.e. not supported by underlying data).

Response:

Yes, at this time, the estimated TRC/mTRC and UCT of the New Technologies Program are placeholders and are not supported by underlying data. Those were derived as best guess estimates in determining the average incentive and GJ savings numbers for a five year outlook. The FEU plan to update these numbers once measures are defined and savings and market data become available through pre-feasibility studies and pilots.

226.4.1 Please describe how FEU arrived at the requested budget for the New Technologies Program.

Response:

The budget was determined as a placeholder to support emerging water and heating technologies being transferred from the Innovative Technologies Program Area. The budget amount requested is reasonable based on annual adoption rates of 200-300 customers.

At this time, details surrounding which technologies would be included into the New Technologies Program is uncertain as they are required to be successfully filtered through the technology selection and implementation process as referenced in Exhibit B-1-1, Appendix I, Attachment I1, page 96. This process includes several steps whereby the technology may be rejected if it does not meet the DSM regulation criteria or by demonstrating acceptable levels of technical performance and cost-effective energy savings. Once the technologies have passed the Innovative Technology screen, the FEU plan to present them for inclusion into the New Technology program to the EECAG stakeholders as well as notify the BCUC through the FEU's compliance filings. One of the technologies under consideration is integrated heat and water heating systems (combi-systems) for which a pre-feasibility study is under development.

The budget amount requested is reasonable and will provide more customers with the opportunity to adopt new energy saving appliances.

226.4.2 Please describe the process FEU intends to undertake to identify and evaluate new technologies that may be eligible to receive this funding.

Response:

Technologies considered for inclusion within the New Technologies program will be required to be screened through the Innovative Technology Program Area. This includes ensuring that the technologies meet the definition of a Demand-Side Measure and have demonstrated acceptable levels of technical performance and cost-effective energy savings. Furthermore, the technology must have an approved business case including a third party evaluation of the market need and energy savings potential. Upon business case approval, the FEU intend to present the new measure to the EECAG Stakeholders for feedback as well as notify the BCUC through compliance filings. This process will be refined further upon funding approval for a New Technologies program.

226.4.3 Do stakeholders have any assurance that new technologies that could result in an increase in overall gas consumption are not given preference for funding by FEU over new technologies that would result in an overall decrease in gas consumption? If yes, please describe how FEU will offer this assurance.

Response:

New technologies that could result in an increase in overall gas consumption do not meet the definition of the demand-side measure set out in section 1 (1) of the Clean Energy Act and therefore would be rejected for inclusion into the New Technologies program. Part of the eligibility requirements set out in the response to BCUC IR 1.226.4.2 assures that only technologies that meet the definition of a DSM will be included in this program.

226.5 For the Customer Engagement Tool for Conservation Behaviours, how will customers see their energy consumption comparison with their neighbours (for example, will it be on the bill or a customized bill insert)?

Response:

The FEU are currently finalizing business requirements and evaluating vendors for the Customer Engagement Tool program. For that reason, the final decision regarding deployment of neighbor comparisons through an “Energy Visualization” tool has yet to be made. One option under consideration is to provide all customers access through their FortisBC Account Online. In order to drive awareness of this online Energy Visualization tool, regions will be selected as pilots to be mailed or emailed neighbour comparison reports. At this time, the billing system does not allow for regional targeting of bill inserts and the latest bill redesign project does not include a requirement for neighbor comparisons.

226.5.1 Has FEU researched alternative methods of making customers aware of how their consumption compares to their neighbours? If no, why not. If yes, please describe why the proposed approach was selected.

Response:

Yes the FEU are currently researching alternatives for an Energy Visualization Tool. As discussed in the response to BCUC IR 1.226.5, the FEU are evaluating vendors in order to identify the tool that we believe provides the most value for our customers. An approach has not yet been finalized, but the FEU plan to have a pilot program, if approved, in market in 2014.

226.5.2 Please explain why the measure life is only one year. Does this mean that FEU only expects customer responses to this information (behaviour changes, investment changes) to last one year?

Response:

Yes. A one year measure life was assumed to be the average persistence of the energy savings across all participants selected to receive reports as referenced in the FEU 2012-2013 RRA proceeding, Exhibit B-67, FEU Response to BCUC IR 3.1.2.1 (Page 15). The response would be a bell curve with some targeted participants achieving zero energy savings, while others would be activated to engage in home retrofits and achieve substantial savings over time. The average persistence per participant is deemed to be one year after receiving reports.

These tools are relatively new and as such, information on persistence is limited. Recent evaluations suggest that a measure life of 1.6 years is achievable based on two-thirds of the savings continuing after mailed reports are stopped. This is based on the research paper “Keep the Change: the Persistence of New Energy Behaviours” presented at the Consortium of Energy Efficiency Summer Program Meeting. This research was conducted by Puget Sound and Sacramento Municipal Utility District, through evaluation of the OPOWER tool. Please refer to Attachment 226.5.2 for the report.

Once the program is established, the FEU will conduct ongoing evaluation, and update cost benefit assumptions in their compliance filings, as they gain experience and user feedback with the selected tool.

226.6 Please provide an update of the results of the financing pilot program and describe the flexibility FEU has in the design of this program.

Response:

This program is being managed by FortisBC Inc. on behalf of the FEU in the South Okanagan. To date, FortisBC Inc. has had twenty-three enquiries on the financing pilot program, and has one approved loan.

The FEU's provision of the financing pilot program is mandated by the Improvement Financing Regulation, issued by the Government of British Columbia July 24, 2012, and amended September 13, 2012; both the original Regulation and the Amendment are provided in Attachment 226.6.

The FEU would describe the flexibility that it has resulting from the Improvement Financing Regulation as low. The regulation and subsequent amendment prescribe the following:

- the type of buildings eligible for loans ("specified building");
- persons eligible for loans ("eligible persons");
- the credit criteria that must be met for customers to be eligible for loans ("2c" and "2d");
- the maximum interest rate that customers must be offered (4.5%);
- the minimum term of the loan (5 years);
- the improvements eligible for financing;
- the requirement for participants to engage a Qualified/Certified Energy Advisor and have an Energy Report completed;
- the requirement for contractors used by participants to undertake the eligible improvements to have attended a Ministry of Energy and Mines information session; and
- the qualifications needed by contractors to undertake the eligible improvements.

226.6.1 Does FEU package this financing program with other programs (for example, the Furnace Replacement Program) when it comes to selling the financing program to customers? Please explain why/why not.

Response:

No, the Companies have not packaged the financing pilot program with other programs. The financing pilot program is available in a limited geographical area (the South Okanagan). Customer research conducted by the FEU and BC Hydro prior to the implementation of the Improvement Financing Regulation, and provided in Attachment 226.6.1, indicated that customers generally would prefer to self-interest, or use their lines of credit, rather than participate in a utility financing offering, so with limited human resources to deploy in the EEC group to a financing pilot, efforts were focused on promoting EEC programs through other means (primarily through contractor communications, print media, radio and social media).

226.6.2 Please describe the advantages/disadvantages of FEU funding and administering the financing project, compared to the funding being provided and administered by a third party (such as a bank).

Response:

The primary disadvantage of having the FEU administering the financing pilot project is that the utility is not a financial institution. The Companies are not set up to administer a financing program, have no expertise in doing so, and no back-end administrative processes to support utility financing for customers. The customer research in Attachment 226.6.1 in response to BCUC IR 1.226.6.1 shows that customers preferred to self-finance or use the offerings from their financial institutions such as lines of credit.

226.6.2.1 Does FEU consider that there is an overall benefit to customers, in terms of lower interest costs, of FEU being able to reduce credit risk by disconnecting customers in the event of default, compared to a third party (such as a bank) taking on the credit risk? Please explain why/why not.

Response:

No; if a third party such as a bank takes on credit risk associated with financing, there is no cost and no resultant risk to utility customers in the event of default.

226.6.3 Does FEU consider that there is a risk of overall reduced customer satisfaction with FEU if FEU disconnected customers in response to non-payment of EEC related charges under this program? If yes, please explain how FEU would address this concern.

Response:

The financing pilot program does not have adequate participation at this time for the FEU to be able to provide a fact-based answer to this question. Without any research as to the potential nature and reasons for reduced customer satisfaction, the Companies are unable to respond in any definitive way. However, there may be a risk of overall reduced customer satisfaction if the FEU disconnected customers in response to non-payment of EEC related charges under this program, especially amongst any customers disconnected.

226.7 Does FEU consider that it has a gas theft issue, and if yes does FEU consider that this could be addressed through an EEC program? If yes, please describe.

Response:

Although lost gas related to known incidents of gas theft have occurred on the distribution system, the FEU do not consider that gas theft is a material issue at this time. The FEU actively investigate reports of gas theft where they do occur and do not believe that these instances could be addressed through EEC programs.

226.8 Does FEU offer any non-cash incentives to customers as part of EEC programs (such as Air Miles)? If yes, please describe.

Response:

Yes, there are select EEC programs where the FEU offer non-cash incentives to customers. These programs and their non-cash incentives are listed below:

- **Energy Savings Kit** – A bundle of free measures is provided including low-flow fixtures, water heater pipe wrap, caulking, draft proofing tape, outlet gaskets and window film.
- **Energy Conservation Assistance Program** – A bundle of customized free measures is provided which may include low-flow fixtures, water heater pipe wrap, professional draft proofing, outlet gaskets, window film, insulation, improved ventilation and CO detectors.
- **Appliance Service Program** (also known as "Give your Furnace/Fireplace Some TLC" – Service Campaign) – Provided Save-On Foods gift cards as an incentive from 2010 through 2012. However, note that in 2013 this program began offering rebate cheques instead in order to simplify controls and improve customer service.
- **Commercial Energy Assessment Program** – Offers a walk through energy assessment and accompanying report. These are provided at no charge to the participant. FEU directly reimburses the consultant conducting the work.
- **MURB Program** - Offers low flow showerheads and kitchen and bathroom aerators to customers in multifamily buildings. These showerheads and aerators are provided to the customer at no charge.

Note that in 2012 the Conservation Education and Outreach program area operated a pilot program which offered Air Miles as a reward to customers. This pilot program encouraged customers to undertake behavioural actions by pledging to reduce their energy consumption and to sign up for the EEC electronic newsletter, The Conserver, in order to receive Air Miles rewards for their participation. However, for the purposes of 2012 EEC Annual Report this was not reported as an "incentive" expenditure but instead as a non-incentive expenditure same as with all other Conservation Education and Outreach expenditures.

226.9 Has FEU considered regional targeted EEC programs so that it can treat clusters of properties at the same time? If no, why not. If yes, please describe.

Response:

Please refer to the response to BCUC IR 1.222.4.1.

226.10 Please explain why FEU has evaluated the spillover effect of one program only.

Response:

To date, the FEU have evaluated the spillover effect for only one program because spillover effects are notoriously subjective (as with free rider rates) and therefore difficult to accurately measure and study. The FEU have been examining opportunities and alternatives for measuring spillover, but as yet have not been able to do so. Evaluation of spillover for the LiveSmart program has been possible as a result of BC Hydro's experience and work on evaluating spillover effects for this program as described in Section 6.2.1 of Appendix I to the Application, Exhibit B-1-1.

The FEU have been required to estimate and include free rider rates in its cost effectiveness analysis and consider that including free riders but not spillover has resulted in conservative program design and evaluation. Under the current circumstance where the FEU are required to include the subjective effects of free riders, it is the Companies intention to include the development of spillover rates for use in cost effectiveness analysis in program design and evaluation studies going forward on a program by program basis as described in Section 6.2.1 of Appendix I of Exhibit B-1-1, and to continue monitoring the industry for examples and best practices in doing so. However, it remains the Companies' position that as both free riders and spillover effects are very subjective and tend to cancel each other out, a preferred approach is to use gross energy savings as the benefit in cost effectiveness analysis instead of using any spillover or free rider effects. Please refer to the response to BCUC IR 1.235.3 for studies examining the challenges inherent in applying a net to gross ratio in the cost effectiveness analysis of DSM programs.

226.10.1 Please provide the evaluation results of LiveSmart BC if available, including the estimated spillover effect. If not yet available, please estimate when these results will be available.

Response:

The Final version of the LiveSmart BC Evaluation report is currently not available. BC Hydro, as the lead utility on this evaluation, is unable to provide an estimated time when these results will be available.

227.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1-1, Appendix I, Attachment I-1, p. 41

Commercial Programs – EEC Plan overview

227.1 Please describe the results FEU considers would be obtained if there were an increase in available EEC funding for each commercial EEC programs with a positive UCT.

<u>Response:</u>

Please refer to the response to BCUC IR 1.226.1.

227.2 For the Commercial Energy Assessment Program, please explain why (i) an increase FortisBC brand permeation is included as an objective of this program and (ii) only one year of measure life is assumed.

<u>Response:</u>

(i) In its current form, Commercial Energy Assessment Program reports are not formatted as FEU documents. Adopting a FEU formatted and branded report template is expected to resolve the following issues:

- Consistency of reports: In order to ensure fair market value and deliver top quality reports, the assessments will be prepared by several different service providers. Creating FEU report templates will ensure these documents are consistent in their formatting and presentation to the participant.

- Confusion surrounding who to contact with questions or concerns: By adopting FEU branded and formatted reports participants will be more obviously prompted to contact the FEU with any additional questions they may have about energy efficiency projects or incentives.

- Awareness of other FEU offers and incentives: The FEU want to ensure that participants are aware of all FEU incentive dollars which may be available to them. FEU branded reports more effectively illustrate the programs available from the FEU and establish a link between energy efficiency projects and FEU EEC incentives.

(ii) In the 2012-2013 Revenue Requirements and Natural Gas Rates Application, BCUC IR 2.97.1, Table 2.7, the FEU detail the one year measure life assumption (excerpt below for ease of reference):

> *"It may be argued that a longer measure life is appropriate for the measure life of the savings attributable to participation in the Energy Assessment Program however the Companies have opted for a very conservative approach. This is due to the inherently diverse nature of the recommendations made, as well as the variable rate of implementation."*

227.3 Please explain why no savings are attributable to the Energy Specialist Program.

Response:

Please refer to Exhibit B-1-1, Appendix I, Attachment I1, p. 56, footnote 5 which states:

> *Although energy savings will be reported from this program as indicated in the program description, these energy savings come from unique ad hoc projects undertaken by energy specialists and therefore cannot be forecast.*

227.4 Please explain why FEU has included assumed gas savings of 50,531 GJ for the Mechanical Insulation Pilot, and yet has not budgeted any costs for this program.

Response:

The Mechanical Insulation project was a pilot program of limited scale, intended to establish whether or not a cost effective program based on the measure could subsequently be deployed. The pilot would have seen bare heating pipes, valves, and fittings in existing Multi-Unit Residential buildings provided with insulation per the building code and best industry practice. At the time of writing the FEU EEC 2014-2018 Plan the FEU believed that project startup would occur, and the bulk of the costs incurred in 2013. Since that time, however, the FEU have been unable to conclude an agreement on terms satisfactory to the FEU with a 3rd party contractor to deliver the project. At present the FEU do not have a formal plan to pursue this pilot further.

227.4.1 Please describe all assumptions used in estimating the TRC/mTRC and UCT for this program.

Response:

At present the FEU no longer have a plan to pursue this pilot. Please refer to the response to BCUC IR 1.227.4 for additional details.

227.4.2 Please explain how FEU has determined the optimum budget size for this program in order to maximize overall benefits for BC and its customers.

Response:

At present the FEU no longer have a plan to pursue this pilot. Please refer to the response to BCUC IR 1.227.4 for additional details.

227.5 For the Space Heat Program, does FEU assume that the customers' existing space heat assets are at the end of their life? If yes, please explain why. If no, how does FEU factor in early retirement of these assets into its TRC/mTRC and UCT calculations?

Response:

Yes, the FEU assume that the customer's existing space heat assets are at, or very near, the end of their service life. Commercial boilers and rooftop units are large, expensive pieces of equipment and their installation can be time consuming, costly, and disruptive. Boilers for example are not easily replaced, nor are they replaced on a regular basis within any particular building. Installation of new boilers necessarily involves replacing other ancillary items such as pipes, pumps and valves, while removal of existing boilers can come with unforeseen difficulties, in some cases requiring asbestos removal, or the demolition of architectural features. Moreover, stakeholders have not indicated to the FEU that early retirement occurs on a regular basis in order to reduce natural gas consumption. As such, the FEU believe that it is reasonable and prudent to consider that customers replace space heating equipment at, or very near, the end of their useful service life.

227.6 For the EnerTracker Program, please explain how FEU arrived as the estimated gas savings per participant of 245.5 GJ/year and measure life of one year.

Response:

The EnerTracker Program is a pilot program and is based on the premise that if provided with access to timely, usable consumption data through an energy management information system (EMIS), participants will take action to reduce energy waste and save money.

For the pilot program, the level of savings that could be achieved was evaluated by first establishing a target participant group from a broad range of customer types. For this target group, the average annual consumption was determined to be 12,275 GJ. A subset of the group was then evaluated more closely to identify ESOs in their natural gas consumption profiles. ESOs were established by using an EMIS to develop a predictive baseline of natural gas consumption for each customer in the subset based on their past consumption history. The EMIS was then used to compare each customer's predicted consumption to their actual consumption in a specific year. Where actual consumption exceeded the predicted amount, an ESO (attributable to things such as scheduling inefficiencies, or improper maintenance) was identified. Performing this analysis across the subset group indicated that capturing potential savings of 3.4%±1.2% of a customer's annual consumption was possible. As this is a pilot program which has yet to be evaluated, the FEU have chosen to conservatively estimate savings at 2% of total annual natural gas consumption. When applied to the target participant group's average annual consumption of 12,275 GJ, this 2% yields gas savings per participant of 245.5 GJ/year. Note that during the pilot stage the FEU plan to assess the accuracy of the assumptions described above annually and readjust as necessary.

The measure life is based on the one year duration of the EMIS software license. The participant is expected to maintain the level of savings derived by using the software to identify building inefficiencies or energy savings opportunities for as long as they have access to the EMIS. In the absence of the information provided by the EMIS or any accompanying recommissioning work such as is provided under the continuous optimization program, it is assumed that the natural gas savings will no longer be obtained.

227.6.1 Why has FEU not assumed in the budget that this program would continue past the pilot stage if the estimated mTRC and UCT are positive?

Response:

The FEU are not assuming the program will not continue past the pilot stage. Rather it has been assumed that if the pilot proves successful, the FEU will first critically evaluate the Continuous Optimization Program and commercial program area budgets to determine if funds sufficient to allow the continuation of the EnerTracker Program are available within the approved funding envelope. If insufficient funds are available within the approved funding envelope, the FEU will seek approval from the Commission for additional funding as required.

227.7 For the Continuous Optimization Program, why has FEU assumed a measure life of five years – does this reflect the length of expected gas savings?

Response:

As a part of the program, the FEU provide participants with access to an EMIS. Natural gas savings are assumed to persist as long as access to the EMIS is supported by the FEU, as the EMIS allows participants to track and maintain the performance of their building subsequent to completion of the recommissioning work. Support for the EMIS is provided for up to 4 years. The FEU further assume that the savings will persist for 1 year after utility support for access to the EMIS is withdrawn. Overall, this is conservative in comparison with the five year persistence[47] often applied to recommissioning savings, especially when access to an EMIS is provided to help assure continued building optimization.

[47] Mills, Evan, Building Commissioning: A Golden Opportunity for Reducing Energy Costs and Greenhouse Gas Emissions. Lawrence Berkeley National Laboratory, July 21, 2009, p. 22, cx.lbl.gov/2009-assessment.html.

228.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1-1, Appendix I, Attachment I-1, p. 63

Industrial Programs – EEC Plan overview

228.1 Please describe the results FEU considers would be obtained if there was an increase in available EEC funding for each of the industrial EEC programs with a positive UCT.

<u>Response:</u>

Please refer to the response to BCUC IR 1.226.1.

228.2 Please explain why the measure life for the Industrial Energy Audit, Industrial Assessment, and Industrial sector Study is only one year.

<u>Response:</u>

As there are no savings attached directly to the Industrial Energy Audit, Industrial Assessment or Industrial sector Study measures and costs are incurred as one time lump sums, the measure life value does not influence the program's overall benefits. However, a one year measure life is used by the Companies simply to ensure the measures' costs are accounted for in the Industrial Optimization Program's cost effectiveness calculations.

228.3 Please provide a description of each of the specific EEC initiatives FEU plans to fund through the Industrial Optimization Program and the Industrial Process Technology program over the PBR period.

<u>Response:</u>

1. Industrial Optimization Program

Through the Industrial Optimization Program, the Companies provide financial incentives towards identifying, assessing and implementing customized cost-effective energy-efficiency projects for industrial processes using natural gas as an energy source.

The Companies offer its industrial clients five initiatives under the Industrial Optimization Program, three options to identify energy saving opportunities and two options to provide funding towards the implementation of energy efficiency capital improvement projects.

1.1. **Industrial Assessment:** This measure encourages industrial customers to perform a one day walkthrough assessment to identify, at a high level, natural gas saving opportunities.

1.2. **Industrial Energy Audit** This measure provides funds to industrial customers to hire a consultant to perform a comprehensive audit of their industrial process and/or facility to identify energy efficiency improvements.

1.3. **Industrial Sector[48] Study:** This measure encourages industrial customers to hire a consultant to study efficiency improvements of a specific sector, system or piece of equipment inside an industrial facility. It differs in this respect from the Industrial Energy Audit option which tends to focus on a whole plant approach.

1.4. **Technology Implementation**: This measure provides eligible industrial customers with funding to encourage the implementation of any cost effective retrofits or new industrial processes using natural gas as process heat or energy source. The expected energy savings, measures, incentives, measure cost and life will necessarily vary depending on the customer, though each project is subjected to a TRC test and must be approved by the utility.

1.5. **Small Industrial Implementation:** This measure, proposed in response to feedback received from small and medium sized industrial companies, will provide a program and incentive structure more specifically tailored to the needs of this group. As with the Technology Implementation measure for larger customers however, the FEU plan to submit each project to a TRC test to approve only cost effective projects.

2. Specialized Industrial Process Technology program

This program provides prescriptive incentives to Industrial customers to encourage the implementation of specific technologies and best practices targeted at particular industrial processes using natural gas as an energy source.

The Companies plan to offer measures focused on three groups:

[48] Sector refers to a specific area, system, process or piece of equipment affecting the consumption of natural gas within an industrial facility that can be analyzed individually (e.g. boiler, dryer or heat exchanger). The measures' names and structure were selected to pair with BC Hydro's assessment, audit and sector study offerings to simplify identification and understanding of the FEU's programs for industrial customers.

2.1. **Steam Distribution:** This prescriptive measure, targeted at facilities using steam for industrial processes, will encourage surveys and the optimization of the steam distribution system by encouraging the repair of leaks, steam traps and pipe insulation.

2.2. **Process Boiler System:** This prescriptive measure, targeted at industrial customers using boilers for steam or hot water generation, will encourage customers to increase the efficiency of their boilers through retrofits or complete replacement.

2.3. **Wood Drying Process:** This prescriptive measure, targeted at wood drying facilities, will provide funds towards control systems and heat recovery units to increase the efficiency of wood drying process.

228.3.1 Please explain why FEU determined that two Industrial Optimization Programs (and not a greater or lesser number) should be available to small, medium and large Industrial customers.

Response:

The FEU's intent is to offer two programs, providing support for many different natural gas saving measures. The Companies believe that this structure will provide more clarity to industrial customers seeking support to engage in energy efficiency projects. The two programs are described in general terms below:

1. The Industrial Optimization Program is offered to industrial customers seeking to identify and implement customized capital upgrade projects.
2. The Specialized Industrial Process Technology program offers funds towards prescriptive measures focused on a particular process or system within an industrial facility.

For more specific details on each of these programs please refer to the response to BCUC IR 228.3.

228.4 To what extent does FEU ensure that industrial EEC programs are available to all of its industrial customers? Please explain.

Response:

The FEU's current offerings suit industrial customers in a wide variety of sectors and industries. Customized capital upgrade projects are eligible, regardless of the participant's industry, for funding from the Industrial Optimization program as long as the projects increase the efficiency of the industrial facility and are cost effective.

Further, the FEU are expanding their program offerings to address energy efficiency measures and projects that are not well served by the Industrial Optimization program. All of these programs are available to assist industrial customers with diverse industrial processes and applications.

For more specific details on each of these programs please refer to the response to BCUC IR 1.228.3.

Finally, in order to ensure that all industrial customers are aware of and can participate in the industrial EEC programs, the Companies communicate through several forms of direct and indirect marketing:

1. The FEU have dedicated a specific address within their website to EEC's industrial programs, where all industrial customers can review details about the industrial EEC offerings.
2. The Companies design a yearly communications plan to promote EEC's industrial programs and its website through various communication channels targeting industrial customers, energy service companies (ESCOs), and energy management and electromechanical consultants and auditors.
3. The FEU's industrial account managers and EEC's industrial program manager promote EEC's industrial programs by establishing direct contact with industrial customers.

229.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1-1, Appendix I, Attachment I-1, p. 18

Low-income Programs – EEC Plan overview

On page 18 of the Appendix I to the Application, FEU states: "Finding potential participants for ECAP is difficult, and getting past the barriers of enrolling them has been hard as this customer group can be mistrustful and is focused on getting through the day-to-day rather on the energy matters."

229.1 For the Residential Energy Efficiency Works (REnEW) program, please explain why the free training provided to participants is considered a program administration cost and not treated in the same way as a cash incentive.

Response:

The free training provided to participants is considered a program administration cost because these costs are generally tied to things like the cost of trainers, tools, transportation, nutritious meals, etc., which are typically considered administration type costs. Participants do not receive a monetary incentive.

229.1.1 Please explain why energy savings are not estimated for this program.

Response:

Energy Savings are not estimated for the REnEW program due to difficulty in measuring the savings. Through the training, graduates are better suited to enter or return to the work force. The energy efficiency lessons and skills the participants learn through the training can be implemented in a broad spectrum of ways in their new employment ventures. This makes tracking and quantifying the energy savings that result from the program too difficult.

229.2 Does FEU consider that a lower UCT threshold is appropriate for EEC programs targeted at low-income customers? Please explain why/why not.

Response:

A "UCT threshold" does not exist for EEC programs targeted at low-income customers. The Demand Side Measures Regulation provides for the use of the Total Resource Cost test with a 30% bonus applied to the benefits considered in the test for EEC programs targeted at low-income customers and states at Section 4(1.8)(c) that the Commission may not apply the Utility Cost Test to programs for low-income customers in determining whether the programs are cost-effective.

230.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1-1, Appendix I, Attachment I-1, p. 89

Conservation Education and Outreach Initiatives – EEC Plan overview

230.1 How does FEU monitor the performance of its conservation education and outreach initiatives?

Response:

The FEU monitor the performance of its conservation education and outreach initiatives through a variety of methods which are listed in the table below:

Initiative by Program	Monitoring Methods
Residential Education	Event evaluations, occasional event evaluation conducted by a third party, on-site audits conducted randomly at events, web analytics, electronic newsletter analytics, ongoing progress reports, participation in regular conference calls with program partners, and through an ongoing corporate communications study.
Commercial Education	Event evaluations, on-site audits conducted randomly at events, web analytics, workshop surveys, ongoing progress reports, and participation in regular conference calls with program partners.
School Education	Ongoing progress reports, on-site audits, and participation in regular conference calls with program partners.

230.1.1 How does FEU incentivize its staff/contractors to excel in CEO program design and delivery?

Response:

The FEU do not provide additional monetary compensation to incentivize staff and contractors in excelling in CEO program design and delivery. Staff who work directly on CEO programs are incentivized through their respective performance plans, while with contractors, all terms, project deliverables, and cost of services are included during the request for proposal process or contract negotiations.

230.1.2 If a third party has an idea for a CEO program, how would FEU evaluate their submission?

Response:

If a third party has an idea for a CEO program, the FEU will ask them to detail their idea through a written submission. As most ideas also generally request funding support, the FEU will require a proposal or a completed Education and Behaviour Funding Request application form. Please refer to Attachment 230.1.2 for a copy of the Education and Behaviour Funding Request application form. The Education and Behaviour Funding requests generally come from Energy Specialists; however, other third parties are permitted to make a request for funding of their project idea utilizing that form. Project ideas are then evaluated through an internal process of assessing the market opportunity and ensuring it meets the basic criteria and considerations, which ultimately leads to a signed business case.

Submissions must include the following basic criteria:

- related to natural gas conservation education
- meets EEC guiding principle of universality, offering access to energy efficiency and conservation for all (as applicable) residential, commercial and industrial customers
- targets FEU customers, or students in FEU service territory

Submissions are also evaluated using the following criteria:

- availability of financial resources
- availability of internal human resources to manage the initiative
- complements existing EEC programs in the market
- meets FEU policies (eg. procurement) and business priorities
- proportion of proposed program directly related to natural gas conservation vs. other sustainability subject areas, for example, electricity, alternative energy, waste, and/or transportation

231.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1-1, Appendix I, Attachment I-1, p. 96

Innovative Technologies Program Area – EEC Plan overview

231.1 In the Innovative Technologies Program area, does FEU include EEC products/services that are generally unknown/untested in the marketplace, or EEC products/services that are unknown/untested to FEU EEC staff?

Response:

Technologies that are considered for inclusion within the Innovative Technology program area may include measures that are both generally known and unknown to EEC staff, as well as both tested and untested in the marketplace Further, as per Footnote 8 to Section 8.1 of Exhibit B-1-1, Appendix I, Attachment I1, in order for an EEC product or service to be included in the Innovative Technologies program area, the product or service must meet the definition of a Technology Innovation program as given in the DSM Regulation. That is, it must be a technology, a system of technologies, a building design or an industrial facility design that is not commonly used in British Columbia and the use of which could directly or indirectly result in significant reductions of energy use, or significantly more efficient use of energy. Thus a technology could be known to the marketplace, and tested as well, but if it is not widely adopted, it could be eligible for the Innovative Technologies program area. An example of such an instance would be solar hot water for residential customers. While the Companies do not have any plans to include solar hot water for residential customers in the Innovative Technologies portfolio over the test period, solar hot water in residential applications is not unknown in the Companies' service territory, nor is it untested. It not commonly used in British Columbia (has a low adoption rate) and should therefore qualify, hypothetically, for inclusion in the Innovative Technologies portfolio.

231.1.1 Does FEU plan to put in place programs to mitigate market barriers to these innovative technologies (other than pilot programs) between 2014 and 2018? If no, please explain why not. If yes, please explain how they will be funded.

Response:

Yes, in that the pilot programs proposed for the test period would incorporate activities to mitigate such market barriers as weak supply chains (lack of replacement parts for example), lack of installation training, the development of codes and standards and public education for innovative technologies that may be new to the marketplace, untested, unknown and/or have a low adoption rate. Prefeasibility studies and pilot programs help to uncover these market barriers and to find solutions to them.

231.2 Once a technology has been determined cost-effective through the innovative technology program, what is the process to bring it into the standard efficiency offerings?

Response:

The Innovative Technologies Program focuses on determining whether the proposed technologies meet the DSM Regulation definition of a Technology Innovation Program, validating the technical performance of these proposed technologies, and determining their cost effectiveness. As a by-product of screening technologies for these metrics through prefeasibility studies and pilot programs, the Innovative Technologies program area gathers market data on the technologies including noted information on market barriers as noted in the response to BCUC IR 1.231.1.1). As such, the Innovative Technologies program area assembles a variety of data for the standard efficiency program managers to determine the feasibility of a technology.

Attachment 231.2 contains an excerpt from the Companies' response to BCUC IR 2.103.2 in the 2012-2013 RRA proceeding, explaining that the Innovative Technologies program area identifies and screens innovative technologies using a varying range of methods for gathering information. If sufficient information on a technology is available, the Innovative Technologies program area uses a consistent framework for submitting this information to the non-Innovative Technology EEC program managers. Attachment 231.2 also contains an excerpt from the Companies' response to BCUC IR 2.114.1 in the 2012-2013 RRA proceeding, which further describes that the framework does not require pilot projects in all cases and applies these where other screening measures do not yield sufficient reliable information. This framework assembles three types of data:

1. The FEU technical solutions group, or an independent consultant, provides validated cost-benefit inputs and information on any technical issues that may arise during the installation or operation of the technology in question.
2. The FEU long-term resource planning group calculates the cost-effectiveness of the technology based on the validated inputs.

3. The innovative technologies group prepares noteworthy market data, such as customer acceptance behavior or information on adoption barriers and strategies to overcome these.

All three groups conduct a joint presentation to the relevant non-Innovative Technology EEC program managers. On the basis of this presentation, the non-Innovative Technology EEC program managers determine the feasibility of including innovative technology filtered measures into the FEU's non-Innovative Technology EEC offerings.

If the non-Innovative Technology EEC program managers decide to incorporate a product or service evaluated under the Innovative Technologies program area into an approved Program Area, the FEU will include a program update in their annual EEC report to the Commission.

231.3 Are there any innovative technologies listed that FEU already has programs to address? If yes, please explain why these technologies are also included here.

Response:

Yes, there are three innovative technology activities listed during the test period that the FEU already have programs to address:

First, the Residential High-Efficiency Water Heaters are listed in Innovative Technologies because the pilot for this technology will incur residual expenses associated to measurement and verification of $10,000 during the 2014 calendar year only. Interim findings from this pilot supported the launch of an incentive program for tankless, hybrid, and condensing storage tank water heaters via the ENERGY STAR® Domestic Hot Water "DHW" Technologies Program in July of 2012 in the residential program area. [49]

Second, the ENERGY STAR® 0.67 Storage Tank Water Heaters are listed in Innovative Technologies because the pilot for this technology will incur residual expenses associated to measurement and verification of $3,000 during the 2014 calendar year only. Interim results of this pilot enabled the launch of an incentive program for this technology via the ENERGY STAR® Domestic Hot Water "DHW" Technologies Program in September of 2012 in the residential program area.[50]

[49] Exhibit B-1-1, Appendix I, Attachment I2, p. 25.
[50] Exhibit B-1-1, Appendix I, Attachment I2, p. 25.

Third, the Condensing Gas-Fired Ventilation Units are listed in Innovative Technologies because the pilot which screens this technology will incur its full expenditures during the 2014 and 2015 calendar years. In Exhibit B-1-1, Appendix I, Attachment I1, p. 42, the Commercial Space Heat Program lists incentives for condensing rooftop units as a placeholder only. The non-Innovative Technology EEC program manager will only make a decision on disbursing these incentives and claiming the related savings after the Innovative Technologies program area screens condensing rooftop units via the aforementioned pilot.

The first two cases highlight that Innovative Technology pilots may still have to conclude measurement and verification activities after their results are communicated to the non-Innovative Technology EEC program managers. As such, pilots may incur residual expenses of low magnitude after their results have already led to the launch of programs into FEU's non-Innovative Technology EEC offerings.

231.3.1 Are there any technologies now being offered as part of the standard set of programs that were identified through the innovative technology program? If so, please identify them.

Response:

Please refer to the response to BCUC IR 1.231.3.

232.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1-1, Appendix I, Attachment I-1, p. 103

Enabling Activities– EEC Plan overview

232.1 Does FEU consider that the enabling activities described in Appendix I-1 (chapter 9) of the Application consist of (i) EEC programs (such as Efficiency Partner Program; Codes and Standards; Home Energy Efficiency Web Portal; Energy Management Education Funding), and (ii) EEC overheads? Please explain.

<u>Response:</u>

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 believe that the enabling activities described in Appendix I-1 (chapter 9) of the Application could be further categorized as follows:

1. EEC programs that support multiple program areas:
    a. Efficiency Partners Program
    b. Codes and Standards
    c. Home Energy Efficiency Web Portal
    d. Energy Management Education Funding
2. EEC portfolio level research studies:
    a. Conservation Potential Review
    b. Residential End-Use Study
    c. Commercial End-Use Study
    d. Market Saturation Study
    e. New Homes Study
3. EEC portfolio level overhead:
    a. EEC Labour
    b. TrakSmart Maintenance

232.1.1 Please provide an estimate of how the individual program TRC/mTRC and UCT ratios would change if EEC overhead costs were allocated out to individual programs. For example, would a typical program with a 1.0 UCT result drop to a 0.95 UCT result?

Response:

For the purposes of this response, the FEU have deemed EEC overhead costs to include costs for both Enabling Activities and Non-Program Specific Expenses. To determine the impact of allocating these costs to individual programs, the appropriate costs were allocated to two sample programs from the Residential program area and two sample programs from the Commercial program area. EEC Overhead costs were allotted based on spending for each of the programs. As summarized in Table 1 below, this resulted in increases of about 19% and 26% for the sample residential and commercial programs, respectively. The increase is larger for the commercial programs since Non-Program Specific Expenses represent a larger portion of the overall Commercial program area spending.

Table 1

Program and Service Territory	Utility Expenditures ($1000s)		Apportioned Expenditures ($1000s)			Revised Utility Expenditures ($1000s)	
	2014-2018	% of Total	Enabling Activities	Non-Program Specific	Total	2014-2018	% Increase
Energy Efficient Home Performance Program	7,901	4.4%	1,062	409	1,470	9,371	18.6%
* New Home Program	4,677	2.6%	628	242	870	5,547	18.6%
Space Heat Program	10,066	5.7%	1,431	1,138	2,569	12,635	25.5%
Commercial Energy Assessment Program	2,339	1.3%	333	264	597	2,936	25.5%

* Program requires the MTRC in order to pass the economic screen

The cost effectiveness results for these programs were recalculated based on the revised expenditures noted in Table 1. A comparison of the cost effectiveness results is shown in Table 2. TRC ratios were found to decrease by between approximately 7% and 26%, with the impact being more pronounced with Commercial programs. This is likely due to the fact that revised Commercial program expenditures were impacted more by the allocation of EEC Overhead costs, as noted above. Similarly, UCT results were found to decrease by between approximately 14% and 22%. Again, the impact was more pronounced with Commercial programs.

Table 2

Program and Service Territory	Benefit/Cost Ratios			Benefit/Cost Ratios, Including EEC Overhead			Benefit/Cost Ratios, % Change		
	TRC	MTRC	Utility	TRC	MTRC	Utility	TRC	MTRC	Utility
Energy Efficient Home Performance Program (Residential)									
FEI	1.06	N/A	2.87	0.99	2.80	2.42	-6.5%	N/A	-15.8%
FEVI	1.09	N/A	2.94	1.02	2.87	2.47	-6.5%	N/A	-15.8%
Total	1.07	N/A	2.88	1.00	2.81	2.42	-6.5%	N/A	-15.8%
* New Home Program (Residential)									
FEI	0.40	1.12	0.98	0.37	1.04	0.82	-7.1%	-7.1%	-15.8%
FEVI	0.41	1.15	1.00	0.38	1.07	0.85	-7.1%	-7.1%	-15.8%
Total	0.40	1.12	0.98	0.37	1.04	0.83	-7.1%	-7.1%	-15.8%
Space Heat Program (Commercial)									
FEI	2.48	N/A	2.99	2.01	N/A	2.33	-19.0%	N/A	-22.1%
FEVI	2.58	N/A	3.13	2.28	N/A	2.69	-11.7%	N/A	-13.9%
Total	2.50	N/A	3.03	2.07	N/A	2.42	-17.1%	N/A	-20.0%
Commercial Energy Assessment Program (Commercial)									
FEI	1.00	N/A	0.72	0.74	2.23	0.57	-26.2%	N/A	-20.3%
FEVI	1.00	N/A	0.71	0.74	2.23	0.57	-26.2%	N/A	-20.3%
Total	1.00	N/A	0.72	0.74	2.23	0.57	-26.2%	N/A	-20.3%

Note: Whistler (FEW) is included in the FEI service territory
* Program requires the MTRC in order to pass the economic screen

232.2 Please explain how FEU arrived at the EEC budget for the following programs: Efficiency Partner Program; Codes and Standards; Home Energy Efficiency Web Portal; Energy Management Education Funding.

Response:

An explanation for how the FEU arrived at the EEC budget for each of these programs is listed below:

Efficiency Partners Program

The Efficiency Partner Program formed in 2009 to consolidate and enhance existing service and supplier relationships to provide a delivery pathway to customers for all EEC programs. In 2009 and 2010, program focus was on evaluating and developing a new Contractor program for B-ticket contracting companies, while maintaining Centra Gas' 'Qualified Dealer' legacy program and respective co-op advertising activities for contractor members in the FEVI service area. Total expenditures in 2009 and 2010 were approximately $27,000 and $93,000 respectively. The focus of activity through 2011 was to roll out the new Contractor program and extend co-op advertising funding to Contractor program members province-wide. Total expenditures in 2011 were approximately $267,000. As program activity continued to ramp-up through 2012, expenditures for this year reached $334,000. Projected spending in 2013 is estimated at $450,000. Therefore, an annual budget of $500,000 in the Efficiency Partners Program is reasonable as the FEU continue to grow and maintain activity in this program area.

Codes and Standards

This forecast expenditure was derived by assessing the increased involvement that the FEU foresee in code and appliance standard development and in the provision of education and training, including sponsorship of such activities with key stakeholders in the forecasted period, over the 2012 and 2013 levels.

Home Energy Efficiency Web Portal

In late 2011, the Utility Partners (FEU, FortisBC Inc., and BC Hydro) commissioned Communicopia to develop a Digital Vision for the BC Utility Partnership Residential Rebate Portal and web portal IT requirements. Through these discussions, the FEU determined that an annual contribution of $100,000 for the development and ongoing support of this project was reasonable.

Energy Management Education Funding

In 2013, the FEU will be contributing $100,000 to UBC's Masters in Clean Energy program as part of a three year funding agreement signed in 2012. FEU will also be contributing $50,000 in 2013 to the BCIT Sustainable Energy Management Advanced Certificate program as part of a funding agreement to move the program to an online environment. As the FEU plan to explore similar funding for Douglas College's Building Energy and Resource Management program it was deemed appropriate to maintain a budget of $150,000 per year for this Enabling Activity area.

232.2.1 For each of the programs above, does FEU consider that they address an identified market barrier to cost effective EEC investment/behaviour change?

Response:

Yes, each of the programs cited address an identified market barrier to cost effective EEC investment/behaviour change. Further explanation is provided below for each program.

Efficiency Partners Program

The decision point for FEU customers for investing in EEC technology and/or behavior often occurs when interacting with a natural gas contractor. If contractors are not supportive of EEC investments/behaviours then it is unlikely that the customer will be. The Efficiency Partners Program develops and manages a contractor network to promote EEC programs and energy efficiency massaging to service contractors who may otherwise not be aware of FEU's program rebates and initiatives. This industry group has significant influence with the end use residential and commercial customers and therefore provides a delivery pathway to FEU customers.

Codes and Standards

Codes and Standards work helps addresses the market barrier of transitioning EEC technologies to market transformation. Codes and Standards aid in market transformation by increasing awareness and providing knowledge and training, supporting effective adoption and implementation, and aiding in development of future codes and standards.

Home Energy Efficiency Web Portal

Due to the fact that government and utility rebate offers come in and out of market, FEU has received positive feedback that a centralized, up-to-date rebate offers portal would be advantageous to customers and assist contractors with promoting EEC programs. However, the best go-to market strategy that works for all partners has yet to be determined.

Energy Management Education Funding

Before EEC began to invest in energy management through the Energy Specialist Program and Energy Management Education Funding, most energy management professionals were primarily educated on electricity EEC measures. This resulted in energy management professionals focusing on implementing these types of measures in the market and thereby typically neglecting potential natural gas EEC measures. By partnering with local energy management education programs, FEU has been able to ensure that natural gas EEC is included as part of the curriculum and therefore enable an energy management market where natural gas EEC is starting to become more of a focus.

232.2.2 For each of the programs above, please describe what the effect would be if there was an increase in the EEC budget.

Response:

Please refer to the response to BCUC IR 1.226.1.

232.2.3 For the other FEU enabling activities, please explain why FEU has not allocated out these costs as overhead.

Response:

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.

232.3 Please explain how FEU arrived at the $35,000/year budget request for proposed work to help advance national, provincial and municipal level codes and standards. Specifically, was this request the result of discussions with national, provincial and municipal governments to establish a cost effective funding level for FEU?

Response:

The budget was derived independent of any consultation with government. It was derived by assessing the increased involvement that the FEU foresee in code and appliance standard development and in the provision of education and training, including sponsorship of such activities with key stakeholders in the forecasted period.

232.3.1 Has FEU considered providing EEC funding for enforcement of codes and standards? If no, please explain why not. If yes, please describe the results.

Response:

The Companies have no jurisdiction over the "enforcement" of codes and standards in the Province. Codes and standards enforcement is the role of the respective Municipal, Provincial and Federal regulatory agencies. The role of the utility can be better characterized as compliance rather than enforcement. The FEU have helped the Ministry of Energy and Mines (MEM) fund a Compliance Enhancement Coordinator role. The role of this coordinator was to assist with the transition of the new Energy Efficiency Standards Regulation, specifically as it pertains to compliance for the following products: fenestration (windows, doors, skylights), lighting, water heaters and residential gas furnaces.

232.4 Please describe the process that will be used by FEU, FortisBC and BC Hydro to commission the reviews/studies FEU intended to undertake during 2014-2018 (as identified in Appendix I-1 (chapter 9) of the Application).

Response:

The FEU have not yet formally agreed to a process with FortisBC inc. and BC Hydro for commissioning the reviews/studies the FEU intend to undertake during 2014-2018 (as identified in Appendix I-1 (chapter 9) of the Application). The FEU's intent though would be to select a vendor for each study through a RFP process and to have all three utilities provide input into this process.

233.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1-1, Appendix I, Attachment I-2

2012 EEC Annual Report

233.1 For each EEC program, please provide a comparison of plan 2012 UCT (using plan expenditures and plan energy savings) to actual 2012 UTC (using actual expenditures and actual energy savings). Please explain any significant variances.

Response:

Tables 1 through 4 below provide a comparison of program UCT results from the FEU 2012-2013 EEC Plan with program UCT results from the 2012 EEC Annual Report for the Residential, Industrial, Low Income and Commercial program areas respectively.

This question is not applicable to the CEO program area, which does not have UCT results. The Innovative Technologies program area was also excluded from this response as its activities in 2012 differed from those listed in the FEU 2012-2013 EEC Plan, making a comparison of little use. The Innovative Technologies program area had only one project that produced direct savings and cost-effectiveness test results in 2012.

Table 1: Actual 2012 Residential program UCT results vs. UCT results from the EEC Plan 2012-2013

Program and Service Territory	UCT Benefit/Cost Ratio		Variance	Explanation of Variance (where necessary)
	2012 Annual Report	EEC Plan 2012-2013		
ENERGY STAR® Domestic Hot Water "DHW" Technologies				The UTC was lower than projected due to the higher proportion of non-incentive spend than forecasted. This was due to the fact that the program was new in market. Program start-up costs were incurred mid-year and program participation was just starting to ramp up.
FEI	0.9	1.2	-26%	
FEVI	1.3	1.3	3%	
Enerchoice Fireplace Program				n/a
FEI	1.3	1.4	-4%	
FEVI	1.3	1.4	-6%	
"Give your Furnace/ Fireplace Some TLC"				n/a
FEI	No	0.0	n/a	

1

Program and Service Territory	UCT Benefit/Cost Ratio 2012 Annual Report	UCT Benefit/Cost Ratio EEC Plan 2012-2013	Variance	Explanation of Variance (where necessary)
FEVI	Direct Savings	0.0	n/a	
LiveSmart BC - April 1, 2011 through March 31, 2012				n/a
FEI	3.2	3.1	5%	
FEVI	3.0	3.2	-5%	
LiveSmart BC - April 1, 2012 through March 31, 2013 1				n/a
FEI	3.2	3.1	5%	
FEVI	3.4	3.2	7%	
ENERGY STAR® Washers and Other Measures for DHW Conservation				FEU reduced energy savings per participant from 1.5 GJs to 1.0 GJ to reflect market transformation and the increased efficiency of the base line washer. Incremental costs were reduced accordingly
FEI	1.2	2.9	-58%	
FEVI	1.4	3.0	-53%	
Furnace Replacement Pilot Program				n/a
FEI	0.9	n/a	n/a	
FEVI	0.8	n/a	n/a	
New Construction - EnerGuide 80 and Energy Efficient Appliances				The program was in a start-up phase and the actual Benefit Cost ratios will improve over time with greater participant uptake and reduced non-incentive spend.
FEI	0.3	1.8	-84%	
FEVI	0.8	2.4	-66%	
Enabling Activities				n/a
FEI	No Direct Savings	0.0	n/a	
FEVI		0.0	n/a	
On-Bill Financing				n/a
FEI	No Direct Savings	n/a	n/a	
FEVI				
ALL PROGRAMS				
FEI	**1.8**	**1.9**	-6%	
FEVI	**1.5**	**2.0**	-26%	
Total	**1.8**	**1.9**	-7%	

Table 2: Actual 2012 Industrial program UCT results vs. UCT results from the EEC Plan 2012-2013

Program and Service Territory	UCT Benefit/Cost Ratio		Variance	Explanation of Variance (where necessary)
	2012 - Actual	2012-2013 EEC Plan		
Technology Retrofit Program				The 2012 plan anticipated four participants and only one materialized. The UTC was lower because the project that was funded in 2012 had the highest incentive amount of all four projects planned.
FEI	4.9	7.5	-34%	
FEVI	0.0	0.0	n/a	
Energy Audit & Analysis Program				This program had no cost-effectiveness test results. It does not include direct savings as the incentives are aimed only at identifying energy saving opportunities. Incentives are applied for under the Technology Retrofit Program.
FEI	No Direct Savings	4.9	n/a	
FEVI		0.0	n/a	
Process Heat Program				Program development activities were initiated in 2012 and the FEU anticipate launching this program in 2013.
FEI	No Direct Savings	4.7	n/a	
FEVI		4.8	n/a	
Customer Energy Analysis				n/a
FEI	No Direct Savings	n/a	n/a	
FEVI		n/a	n/a	
Total				
ALL PROGRAMS				
FEI	**4.7**	**6.5**	**-28%**	
FEVI	**0.0**	**0.0**	**n/a**	
Total	**4.7**	**6.5**	**-28%**	

Table 3: Actual 2012 Low Income program UCT results vs. UCT results from the EEC Plan 2012-2013

Program and Service Territory	UCT Benefit/Cost Ratio: 2012-Actual	UCT Benefit/Cost Ratio: 2012-2013 EEC Plan	Variance	Explanation of Variance (where necessary)
Residential Energy Efficiency Works (REnEW)				n/a
FEI	No Direct Savings	0.0	n/a	
FEVI		0.0	n/a	
Total				
Energy Saving Kit (ESK)				Due to beneficial cost sharing arrangements with BC Hydro, incurred marketing and administrational costs were lower than anticipated.
FEI	3.8	2.2	76%	
FEVI	5.8	2.1	172%	
Total				
Energy Conservation Assistance Program (ECAP)				n/a
FEI	0.2	0.3	-29%	
FEVI	0.2	0.3	-31%	
Total				
ALL PROGRAMS				
FEI	**1.6**	**0.4**	300%	
FEVI	**4.0**	**0.4**	926%	
Total	**1.9**	**0.4**	375%	

Table 4: Actual 2012 Commercial program UCT results vs. UCT results from the EEC Plan 2012-2013

Program and Service Territory	UTC Benefit/Cost Ratio: 2012-Actual	UTC Benefit/Cost Ratio: 2012-2013 EEC Plan	Variance	Explanation of Variance (where necessary)
Efficient Boiler Program				New Construction numbers are highly variable as participation is fairly limited, allowing any 1
New Construction				

Program and Service Territory	UTC Benefit/Cost Ratio 2012-Actual	 2012-2013 EEC Plan	Variance	Explanation of Variance (where necessary)
FEI	3.7	3.6	2%	participant to have an undue effect on the results. In this case there were only 3 New Construction participants in FEVI in 2012, of which 1 participant had estimated savings of only 36 GJ/year. This necessarily reduced the average savings per participant and correspondingly, the UTC.
FEVI	1.1	3.8	-71%	
Retrofit				
FEI	3.3	3.6	-9%	
FEVI	3.1	3.8	-17%	
Light Commercial Boiler Program				This program was operated until May of 2012, when it was folded into the revised Efficient Boiler Program. In that time only 1 participant was recorded in the FEVI retrofit market. Due to a low pre-retrofit average annual natural gas consumption, the savings for this participant amounted to an estimated 23 GJ/year savings; much lower than the average annual savings per participant which would have been expected had the program operated longer and generated more participants.
New Construction				
FEI	6.1	7.1	-14%	
FEVI	n/a	7.6	n/a	
Retrofit				
FEI	6.0	7.1	-15%	
FEVI	2.5	7.6	-67%	
Efficient Commercial Water Heater Program				The FEU need to correct the UCT value for the FEVI, New Construction market. The total program savings of 108 GJ/yr, net of free ridership, was used in the Benefit Cost calculations for this market, as opposed to the correct average savings per participant of 38 GJ/year. The corrected UCT is 0.8. This is lower than expected, as this market only produced 3 participants, with comparatively low natural gas savings.
New Construction				
FEI	2.5	2.9	-13%	
FEVI	6.8	2.9	134%	
Retrofit				
FEI	3.6	2.9	25%	The FEI Retrofit market saw larger water heating plants than predicted participate. While incremental costs were correspondingly higher than anticipated, increased savings led to a higher than expected UCT result.
FEVI	2.8	2.9	-4%	
Commercial Energy Assessment Program				The actual average cost to perform an assessment was higher than predicted in the EEC Plan 2012-2013, negatively impacting the UCT result. The average assessment cost experienced upward pressure due to an 8% increase in the standard assessment cost, and
FEI	1.1	1.7	-34%	

Program and Service Territory	UTC Benefit/Cost Ratio 2012-Actual	UTC Benefit/Cost Ratio 2012-2013 EEC Plan	Variance	Explanation of Variance (where necessary)
FEVI	1.1	1.7	-34%	greater participation from sites that were either significantly larger or that required more travel had been previously been experienced. These sites incurred additional travel and/or assessment costs.
Spray Valve Program				n/a
New Construction				
FEI	0.0	2.4	n/a	
FEVI	0.0	2.4	n/a	
Retrofit				
FEI	2.1	2.4	-12%	
FEVI	2.1	2.4	-13%	
Commercial Custom Design Program				The New Construction version of the program was launched, as a joint program offered in partnership with the BC Hydro New Construction Program, in January of 2012. As of December 31st, 2012 no participants had completed construction of a new building, thus natural gas savings could not yet be claimed. The Retrofit version of the program remained in Beta Testing in 2012. The test participants had not completed implementation of Energy Conservation Measures by the end of 2012, thus natural gas savings could not yet be claimed.
New Construction				
FEI	0.0	2.2	n/a	
FEVI	0.0	2.5	n/a	
Retrofit				
FEI	0.0	2.2	n/a	
FEVI	0.0	2.5	n/a	
Continuous Optimization Program				The EEC Plan 2012-2013 made use of an annual savings per participant, averaged over a participant's multiyear involvement in the program. The FEU 2012 EEC annual report used the specific natural savings actually observed in 2012. As only 3 out of 164 participants had implemented Energy Conservation Measures by the end of 2012, the actual savings in 2012 were low compared to the averaged value used in the EEC Plan. Refer to BCUC IR 1.233.7 for additional clarification.
FEI	0.1	3.2	-97%	
FEVI	0.1	3.1	-97%	
Efficiency à la Carte (Commercial Kitchen Program)				This program was made available in September of 2012. Participation was light by the end of the

Program and Service Territory	UTC Benefit/Cost Ratio 2012-Actual	UTC Benefit/Cost Ratio 2012-2013 EEC Plan	Variance	Explanation of Variance (where necessary)
New Construction				year, limiting natural gas savings, while the majority of the program development and roll out cost were concurrently born in this year, significantly increasing the administrative costs. These two factors negatively impacted the UCT in this first year of program operation.
FEI	0.2	1.9	-89%	
FEVI	0.8	1.7	-53%	
Retrofit				
FEI	0.0	1.9	n/a	
FEVI	2.5	1.7	45%	
MURB Program				A limited scale pilot program was in market in 2012. This pilot was only offered in the FEI service territory for retrofit applications.
New Construction				
FEI	0.0	1.9	n/a	
FEVI	0.0	1.9	n/a	
Retrofit				
FEI	2.0	1.9	6%	
FEVI	0.0	1.9	n/a	
Fireplace Timers Pilot Program				The EEC Plan 2012-2013 presumed that a full program roll out would occur subsequent to an evaluation of the pilot stage results. Savings from the measure have not yet been proven conclusively however. There is some evidence to suggest that energy consumption may have been shifted to another source. Program roll out has therefore not occurred.
FEI	No Direct Savings	2.1	n/a	
FEVI		2.1	n/a	
Radiant Tube Heaters Pilot Program				This pilot program was not actively promoted, and did not garner additional participation or natural gas savings in 2012. The pilot now falls under the Innovative Technologies program area.
FEI	0.0	4.5	n/a	
FEVI	0.0	n/a	n/a	
EnerTracker Program				n/a
FEI	No Direct Savings	n/a	n/a	
FEVI		n/a	n/a	
Energy Specialist Program				n/a
FEI	0.0	0.0	n/a	
FEVI	0.0	0.0	n/a	

Program and Service Territory	UTC Benefit/Cost Ratio 2012-Actual	UTC Benefit/Cost Ratio 2012-2013 EEC Plan	Variance	Explanation of Variance (where necessary)
PSECA Program				
FEI	No Direct Savings	n/a	n/a	n/a
FEVI		n/a	n/a	
ALL PROGRAMS				
FEI	**1.5**	**2.7**	-44%	
FEVI	**1.7**	**2.6**	-34%	
Total	**1.5**	**2.7**	-44%	

233.2 For the Residential Energy Star Water Heater Program (Appendix I-2, p. 25), what baseline technology and efficiency was assumed?

Response:

The baseline technology assumed for the Energy Star Water Heater program is a standard 151 liter (40 US gallons) storage tank with an Energy Factor (EF) of 0.62 based on current BC Efficiency Act Standards. This standard is based on the Ministry of Energy, Mines and Petroleum Resources ' (MEMPR) Enforcement Bulletin 09-05. BC Efficiency Act Standards: Gas and Propane-Fired Water Heaters which came into effect September 1, 2010.

233.3 The proposed savings from a residential new EnerChoice Fireplace are almost 50 percent higher than the savings for a high-efficiency furnace assuming a mid-efficiency furnace baseline (Appendix I-2, p. 26). Please provide the savings calculations and assumption for each of these measures.

Response:

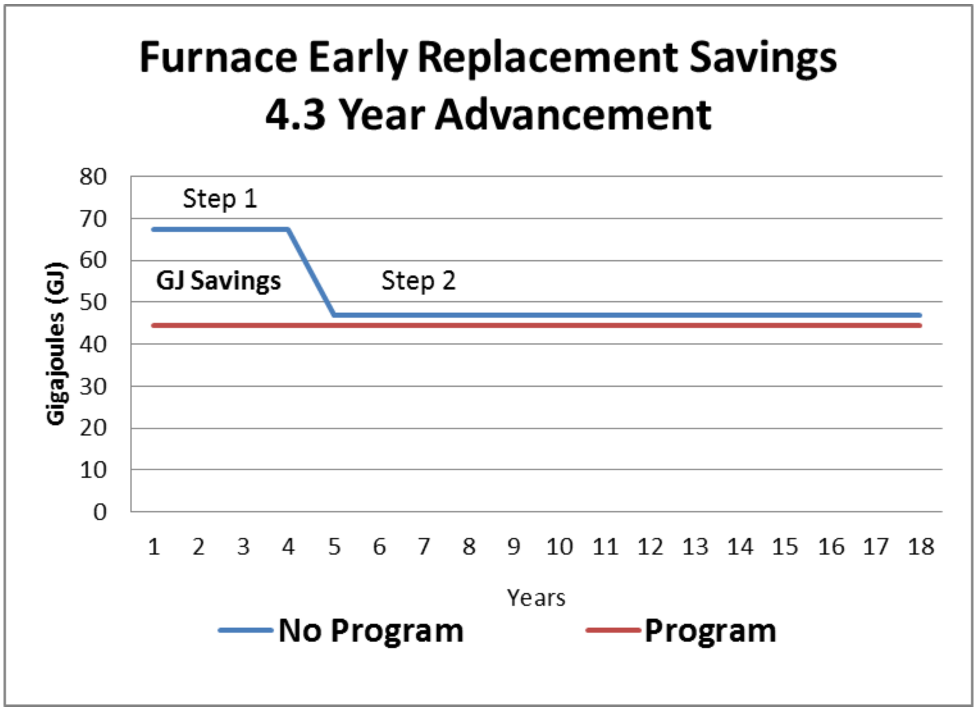
The difference in savings are due to the fact that the energy savings calculations for the EnerChoice Fireplace and the Furnace Replacement program use different methodologies because while the EnerChoice Fireplace program uses traditional DSM methodology for savings calculations, the Furnace Replacement Program employs an early replacement calculation.

The EnerChoice Fireplace represents annual savings of 7.75 GJs across the 15 year measure life of the appliance. This savings estimate was developed utilizing HOT2000 modeling by Innes Hood based on assumptions provided by Habart & Associates' report on the Impact of Terasen Gas Pilot Fireplace Program (2004). An impact evaluation was to be initiated in 2012, however, a sufficient sample size of EnerChoice program participants with at least one year post installation was not yet available. Now that the program has been in market for a sufficient duration of time, an impact evaluation is planned for late 2013 or 2014.

Early replacement methodology was employed in the Furnace Replacement program due to the existence of the minimum efficiency regulation governing gas furnaces. Analysis of a traditional rebate offering at furnace failure was determined to be not cost-effective. Rather, the program required the savings generated from early replacement described in the following paragraph. As noted in the 2010 CPR, early retirement of gas furnaces had the highest achievable potential savings of the measures that were reviewed.

In the Furnace Replacement program, savings calculations for upgrading standard and mid-efficiency furnaces are based on an early replacement methodology. Referring to Figure 1, the energy savings are calculated in two steps. Step 1 accounts for the savings incurred for the period the purchase decision was advanced (4.3 years) and represents the difference between the replaced furnace and the new high-efficiency furnace. Step 2 accounts for the savings incurred when the program incents the homeowner to purchase a more efficient furnace than they normally would have without a program. The savings are based on the NPV over the life of the appliance and are calculated based on the advancement of 4.3 years. For upgrades from mid-efficiency to a high efficiency furnace, the annualized savings (NPV) are calculated as 5.5 GJs, and for upgrades from a standard-efficiency to a high efficiency furnace, the annualized savings are calculated as 10 GJs. Please refer to the response to BCSEA IR 1.4.4. for a more in-depth discussion of the early replacement methodology, and to the response to BCSEA IR 1.4.12 for the program evaluation report that provides a more in-depth analysis of these savings claims.

Figure 1



233.3.1 What was the baseline technology assumed for the EnerChoice Fireplace program? If a standard wood-burning fireplace, what avoided costs were used in the cost-effectiveness calculation?

Response:

The baseline technology assumption for the EnerChoice Fireplace program is that customers are about to install a base efficiency, decorative style gas log set chosen for ambience rather than a high efficiency model for zone heating (2010 CPR). The FEU assume that the participant who is replacing a standard wood-burning fireplace has already decided to convert to a natural gas model. The rebate is then used to incent the customer to choose an energy efficient EnerChoice model rather than the base efficiency model. Therefore the same cost-effectiveness test is used whether or not participants are converting from wood-burning fireplaces to natural gas or upgrading their natural gas fireplace.

233.3.2 From the summary table for the EnerChoice Fireplace, it appears that the incentive being offered is twice the incremental cost of the fireplace. Is this the case? If so, please explain why it is appropriate for the customer incentive to be greater than the incremental cost of the measure.

Response:

Yes, the incremental cost of the EnerChoice fireplace is deemed to be $150 while the customer incentive value is $300.

Incremental cost for the EnerChoice program was determined through discussions with industry and members of the Hearth, Patio and Barbecue Association of Canada (HPBAC). Through these discussions, it was determined that fireplace cost is not directly correlated with efficiency. Rather, cost has more to do with decorative features such as the flame, the rock or log set, and mantle design, whereas with other program measures such as furnaces, higher efficiency is directly correlated with increased costs. The FEU, in discussions with consultants, determined that a more reasonable way to propose incremental costs was to use manufacturer's cost for the energy efficient components. Discussions with a BC manufacturer during 2010 CPR development and EnerChoice Fireplace program development suggested that their incremental cost was approximately $150.

The $300 incentive value was determined through discussions with the HPBAC, and through the experience gained in earlier program iterations. The 2009 program provided a $50 dealer incentive but no customer incentive. This was problematic in that there was only limited customer data available with this approach. In July, 2010, a $150 customer rebate was introduced. However, year over year participation declined. Discussions with HPBAC led to the introduction of a $300 rebate in 2011. The HPBAC felt that this rebate amount would be effective in motivating the customer to purchase EnerChoice models rather than the decorative models. At that time, a $50 dealer incentive was re-introduced as a means to further engage dealers in EnerChoice education and promoting the EnerChoice brand to their customers. Program participation targets are being met at this incentive level.

233.4 The Commercial Energy Assessment Program (Appendix I-2, p. 46) includes an onsite walkthrough, resulting in a report describing observed inefficiencies. Claimed savings for the program could represent a fairly large portion of customers' gas use (488 GJ saved for customers with total usage greater than 2,000 GJ, or as much as 25 percent). How is the claimed savings value of 488 GJ derived?

Response:

The value is derived from program evaluations conducted by the FEU in both 2008 and 2010. Excerpts from the FEU responses in the 2012-2013 RRA proceeding, BCUC IR 3.17.1 and BCUC IR 3.17.1.2 illustrate how the savings are derived and then attributed to participants (excerpts below for ease of reference):

"The FEU are claiming savings for this program as a portion of the program participants, most notably manufacturers, do in fact implement at least one of the recommended energy conserving measures (ECM) outlined in their energy assessment report. The implementation of recommended ECMs generated actual energy savings which were demonstrated by first performing a billing analysis of past program participants to quantify the reduced natural gas consumption of these participants. A participant survey subsequently sought to identify and account for factors other than the implementation of a recommended ECM to which any savings may be attributable…While we can never be certain that any particular individual receiving an energy assessment will implement a recommended ECM, many programs participants do implement ECMs as a result

of the energy assessment. The two program evaluation studies demonstrate a clear and direct link between participation in the program and the generation of tangible natural gas savings for program participants in the aggregate."

"The FEU's approach to reporting natural gas savings attributable to this program has been to develop a reasonable estimate of average participant savings and apply this value to the participant total in a given year to yield a reasonably representative estimate of savings attributable to the Commercial Energy Assessment program specific to that year. In the estimation of average savings for the Commercial Energy Assessment program, participation in other programs is factored out."

The FEU response in the 2012-2013 RRA proceeding, BCUC IR 3.17.3.1 further details how the savings value is derived (excerpt below for ease of reference):

"…the FEU weighted the average savings in each sector (ie. MURBs, Offices, Care Homes) by the number of participants in each sector to assess the average savings per

> *customer. This method assigns greater weight to the average savings of sectors with higher participation, as opposed to simply those with greater average savings. The weighted average determined as described above was combined with the average reported previously*[51] *to generate a number more consistent with a reasonable long term average. The FEU believe that this provides a reasonable estimate of per participant average savings attributable to this program."*

Based on the average of the results of the 2008 and 2010 Evaluation Studies, it is estimated that, on average, participants save 488 GJ/yr.

233.4.1 What percentage of recommended measures was assumed to be implemented?

<u>Response:</u>

The FEU have not assumed a percentage of implementation of recommended measures in the derivation of the average annual savings per participant. The value was determined instead by performing detailed billing analysis and follow-up phone surveys with past program participants. Please refer to the response to BCUC IR 1.233.4 for more information.

233.4.2 What steps does the program take to increase the likelihood of the recommended measures actually being implemented?

<u>Response:</u>

A six month follow-up is conducted by an FEU Commercial & Industrial Account Manager, EEC Energy Solutions Manager, or the energy assessment consultant. During the follow-up, the FEU representative and the participant review the energy assessment report and any plans to implement any recommended energy conservation measures, as well as discuss any EEC incentives which may be available to help defray a portion of the costs of implementation.

[51] Average annual savings from 2008 Program Evaluation: 299 GJ/participant. Average annual savings from 2010 Program Evaluation: 677 GJ/participant.

233.4.3 Are there follow-ups with the customers to see how many of the recommended measures were installed?

Response:

Yes, follow-ups are conducted. Please refer to the response to BCUC IR 1.233.4.2.

233.5 Please provide the costs and savings for commercial boilers (Appendix I-2, p. 44) and commercial water heaters (Appendix I-2, p. 46) by market (i.e., new construction vs. retrofit) and size class.

Response:

The FEU believe that the requested information is provided in Exhibit B-1-1, Appendix I-2, p.43, 44 and 46. For your convenience, excerpts of the tables have been consolidated below. All numbers provided below are based on actual participant data recorded over the course of the year, as opposed to purely deemed values.

Commercial boilers and water heaters range continuously in size from input ratings as low as 75,000 Btu/hr to in excess of 6,000,000 Btu/hr. As such, a nearly infinite number of size classes may be defined. If requested to do so within specific size class boundaries, the FEU will extract the pertinent information from its 2012 program data.

Efficient Boiler Program (Excerpt from Exhibit B-1-1, Appendix I-2, Table 7-2, p. 43)

	FEI		FEVI	
	Retrofit	**New Construction**	**Retrofit**	**New Construction**
Incremental measure cost	$18,107	$33,452	$17,164	$12,317
Incentive amount	$12,786	$16,694	$12,175	$9,218
Savings per participant	570 GJ	818 GJ	461 GJ	129 GJ

Light Commercial Boiler Program (Excerpt from Exhibit B-1-1, Appendix I-2, Table 7-2, p. 44)

	FEI		FEVI	
	Retrofit	**New Construction**	**Retrofit**	**New Construction**
Incremental measure cost	$6,101	$6,225	$5,133	0
Incentive amount	$1,067	$1,338	$630	0
Savings per participant	88 GJ	110 GJ	23 GJ	0 GJ

Efficient Commercial Water Heater Program (Excerpt from Exhibit B-1-1, Appendix I-2, Table 7-2, p. 45)

	FEI		FEVI	
	Retrofit	**New Construction**	**Retrofit**	**New Construction**
Incremental measure cost	$8,460	$9,232	$5,319	$1,216
Incentive amount	$1,748	$3,496	$1,788	$710
Savings per participant	121 GJ	149 GJ	88 GJ	38 GJ

233.6 The Application states that despite having paid out incentives and incurred some costs, there are no savings attributable to the Customer Design Program in 2012. Does this mean that the incentives are paid out before the savings are realized?

Response:

Yes, a portion of the incentives are paid out before savings are realized. The Commercial Custom Design program makes incentives available to program participants in several stages. First, an Energy Study incentive is paid to program participants who successfully complete a detailed energy study that conforms to the program's requirements[52]. Next, when a participant successfully implements program approved ECMs, the participant is paid Capital Incentives. Finally, if the customer implements enough ECMs to deliver more that 50% of the approved GJ savings, an Implementation Bonus is paid. For a description of how each incentive is determined please refer to the response to BCUC IR 1.233.6.1. This structure aligns with BC Hydro's Power Smart Partner and New Construction Programs. The Commercial Custom

[52] Note: The objective of the energy study is to identify and analyze implementable energy conserving measures (ECMs) specific to the Participants building.

Design Program has been designed to be made available to customers in tandem with BC Hydro's offerings.

Incentives and costs incurred in the program in 2012 are attributable to customers passing through the energy study phase of the program and receiving Energy Study incentives. As these participants subsequently implement ECMs natural gas savings will begin to accrue.

233.6.1 What process is used to determine the incentive size before the project is developed and installed?

Response:

Please refer to the response to BCUC IR 1.233.6 for a description of the incentives made available to participants in this program.

The Energy Study incentive and Implementation Bonus are determined as follows:

1. Program participants have their desired engineering consultant submit an Energy Study proposal for review. The proposal outlines the scope of the proposed energy study as well as the cost.
2. Program staff review the proposal, and if found to be reasonable the proposed cost is approved and becomes the basis of both the Energy Study incentive and the Implementation Bonus. Each of these represents 50% of the approved cost, to a maximum of $25,000 each.
3. If the proposed cost is found to be unreasonable the FEU may either request modifications to the proposal, approve a lesser amount, or reject the proposal outright.

Capital Incentives are determined as follows:

1. Based on the approved Energy Study, each proposed (ECM) is first subjected to a TRC screening. If the TRC score of a given measure exceeds 1.0 it is deemed to be cost effective.

2. Cost effective measures are bundled with uneconomical measures (i.e. TRC<1.0) while maintaining an overall project TRC in excess of 1.0. Providing the project has a TRC score of 1.0 or greater it may receive Capital Incentives[53].
3. Incentives are determined per ECM. The maximum possible incentive per ECM is defined as the implementation cost, less the dollar value of one year's worth of natural gas savings, evaluated at the participant's current rate.
4. The annual GJ savings are multiplied by ½ of the expected measure life in years. The maximum number of years is limited to 10 and the GJ savings are discounted to account for future uncertainty.
5. The product of the above is multiplied by 5 $/GJ.
6. Note that participants must implement all cost effective ECMs in order to be eligible to receive Capital Incentives for uneconomical measures.

233.7 This Continuous Optimization Program's savings per participant (Appendix I-2, p. 50) is less than 5 percent of that of the Energy Assessment program, despite a much lower gas usage eligibility threshold and a requirement that all low-payback measures be implemented. Please give all assumptions and calculations behind the savings claim.

Response:

The observed natural gas savings per participant is a value calculated solely to conduct cost-benefit analysis for 2012. Due to the fact that the program occurs over a seven year period for each participant, it is challenging to demonstrate a realistic cost-benefit analysis in the frame of a specific year. Because costs are incurred at various stages throughout the seven year period, and savings are only realized in the later years, the savings observed and the cost-benefit tests for 2012 are necessarily low. As more participants implement their bundle of measures in the later years of the program, both the observed savings and cost-benefit tests will increase. The average expected annual natural gas savings per participant of 1,074 GJ/year as provided in Exhibit B-1-1, Appendix I, Attachment I-2, Table 7-8, Page 50, is a much better indicator of the

53 For an example of bundling, refer to: Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers, November, 2008. Section 3.2.1, pg. 3-9, available at: http://www.epa.gov/cleanenergy/documents/suca/cost-effectiveness.pdf.

natural gas savings which may be expected from program participants. To better illustrate why this is so, provided below is a description of how the average observed savings for 2012 was calculated.

The total natural gas savings for the program in 2012 is equivalent to 3,400.76 GJ/year. These savings are entirely attributable to 3 of the 164 participants. These 3 have successfully completed the program-required implementation of a bundle of energy conservation measures and have been provided with access to an energy management information system ("EMIS"). The savings for these 3 participants is composed of 3,052 GJ derived from the implementation of the bundle of measures as reported in the investigation report provided by BC Hydro[54], and 348.76 GJ (57,174 GJ * 1%[55] * 61%[56]) of savings from the EMIS. When averaged over all 164 participants for the purposes of inputting a value into cost/benefit analysis spreadsheets, this becomes 20.74 GJ per participant per year. When the 3,400.76 GJ/year is divided by the 3 participants who are actually generating savings however the average savings per participant becomes 1,134 GJ/year, similar to the expected value of 1,074 GJ/year.

Note that the remaining 161 participants are not yet generating natural gas savings for the program, but can be expected to do so over the next few years when they implement their own bundle of energy conservation measures. At such time the total savings and average savings per participant will be higher, along with the cost/benefit scores.

233.7.1 The Application states "the savings in these types of programs occur in later years while some program costs are incurred at the outset." (Appendix I-2, p. 50) Please describe the type of savings from this program that occur years after the study occurs.

54 These savings estimates are used until the final recommissioning report is received from BC Hydro, at which point the savings derived from that report are recorded.

55 The savings derived from the EMIS are calculated in a similar way to the EnerTracker program (please refer to the response to BCUC IR 1.227.6 for a detailed explanation). A lower savings estimate of 1% of total annual consumption is used to reflect that the savings derived from the continuous optimization of a building using an EMIS will be lower following a recommissioning project than if the EMIS is utilized on its own.

56 Proration of EMIS savings based on how long the participants have had the EMIS for in 2012 (post-implementation of the bundle of measures).

Response:

The savings are largely attributable to the implementation of a recommended bundle of energy conservation measures identified in the recommissioning study. Measures typically focus on operational or maintenance improvements to reduce energy consumption. Participants must commit to implementing a bundle of measures with up to a 2 year payback, to a maximum investment determined via negotiations with BC Hydro prior to program enrolment.

The program also provides participants with access to an Energy Management Information System (EMIS) which helps to ensure that the savings from implementing the bundle are maintained over time. As with the EnerTracker Program, access to an EMIS can further help participants identify energy saving opportunities on an ongoing basis. The FEU believe that 1 percent of the participant's annual consumption represents an appropriatet estimate of the potential savings attributable to the EMIS following a recommissioning study and the implementation of the bundle of energy conservation measures.

233.7.2 Please explain why the incremental cost and the incentives are incurred for seven years.

Response:

Continuous Optimization is by definition not a discreet event. It is an ongoing process which occurs over years. The incremental costs and incentives are incurred for up to seven years because as the participant proceeds through the various phases of the program they incur different costs along the way. These consist of:

- A gas meter upgrade in order to accommodate the installation of an AMR or pulse hand off device. Note: This is not required at all sites.
- The installation of an AMR or pulse hand off device onto the gas meter.
- Annual gas meter fees such as cellular communications charges, pulse hand off inspections, and AMR battery replacements.
- Recommissioning consultant fees.
- Provision of access to the EMIS including annual natural gas EMIS software license fees.

- Participant costs incurred by the installation of the bundle of energy conservation measures.

Please refer to the table below for a breakdown of which incremental costs and incentives are incurred by an average participant as they move through the program to completion. Note that there is some degree of variability in the timing indicated, but the sequence provided is generally what can be expected by the participant.

Continuous Optimization Program Cost Timetable

Year	Cost
1	Meter upgraded
	AMR installed
2	Recommissioning consultant - study conducted
	Annual gas meter fees
3	Participant costs - bundle of energy conservation measures installed
	Recommissioning consultant - post-implementation work conducted
	Annual gas meter fees
4	Recommissioning consultant - coaching conducted
	EMIS installed
	Annual EMIS license
	Annual gas meter fees
5	Annual EMIS license
	Annual gas meter fees
6	Annual EMIS license
	Annual gas meter fees
7	Annual EMIS license
	Annual gas meter fees

233.8 In 2012, FEU had only one industrial participant implement an energy saving project (Appendix I-2, p. 68). How many industrial customers does FEU have in its service territory?

Response:

The Companies have close to 380 accounts that fit the FEU's industrial customer definition provided below:

> *Industrial customers and their associated process loads use natural gas as an input to a manufacturing/transformative process where raw materials are transformed into finished goods (industrial production) with the use of machines, tools and labor for the purpose of resale. Process loads do not include space heating or domestic hot water for the purpose of maintaining human comfort or sanitation.*

Although in 2012 only one industrial customer received incentives towards the implementation of an energy efficiency project in the Technology Retrofit program, the FEU believe that the EEC industrial programs uptake is entirely reasonable given the complex nature of industrial energy efficiency projects, and the time at which the Industrial Program area started.

The EEC industrial program area was staffed in Q2 of 2010, close to one year later than EEC's residential and commercial program areas. Since Q2 of 2010, the FEU have developed and launched industrial programs, identified and contacted potential participants, and have had eligible customers enrolled.

Once enrolled, program participants have to hire qualified consultants to identify efficiency opportunities in their facilities, implement the energy efficiency projects, and have the results subsequently validated by the Companies. Industrial energy efficiency projects tend to be more complex and diverse than those in other program areas. These projects require specialized consultants, as well as parts and equipment custom designed and manufactured for each application. Program enrollment contracts or agreements generally require some customization to suit each project as industrial projects usually present differing technical and financial conditions. Hence, a significant timeframe is required to move a project through to the point of incentive pay out. In 2013, the FEU expect to validate the commissioning of three new energy efficiency projects that will have a lead time from initial contact to commissioning of one to two and half years.

Please refer to the response to BCUC IR 1.233.8.1 for a description of the FEU's activities to achieve higher levels of participation among its industrial customers.

233.8.1 What is FEU doing to achieve higher levels of participation among its industrial customers?

Response:

The FEU have seventeen industrial customers participating in EEC's industrial programs. Three industrial customers have been preapproved for implementation funds and will most likely receive incentives before the end of 2013. Also, fourteen industrial customers have been approved for funds towards an energy audit and the FEU expect to provide incentives for these audits within the next nine months.

To generate participation from Industrial account managers, the EEC industrial program manager and EEC technical support team have been promoting EEC industrial offerings and analyzing potential energy efficiency projects to more than thirty nine industrial customers.

In addition, broadening the funding options towards identifying energy efficiency opportunities, as well as making programs available for more prescriptive measures as provided in the EEC Plan Exhibit B-1-1, Appendix I, Attachment I1, Section 5, will help the Companies accelerate the uptake of EEC industrial programs.

Finally, the Companies also seek to achieve higher participation by collaborating with FortisBC Inc. and BC Hydro. The Companies and FortisBC Inc. jointly approach industrial customers to offer funds towards a single audit process for customers inside FortisBC Inc.'s service region. Further, the FEU and BC Hydro plan to offer its industrial customers a single process when applying to receive funds towards assessments, audits and specific studies.

233.8.2 Does FEU offer industrial customers financial incentives for energy assessments, technical studies, and retro-commissioning services?

Response:

The Companies offer its industrial customers financial incentives for energy assessments and technical studies to identify energy efficiency capital improvement projects as provided in the EEC Plan Exhibit B-1-1, Appendix I, Attachment I1, Section 5.4.1. The FEU do not currently offer incentives towards retro-commissioning services.

233.8.3 Has FEU considered offering special initiatives for municipal facilities, especially for technologies related to wastewater treatment plants and warm asphalt mix?

Response:

No. The FEU have not considered offering programs specifically directed at wastewater treatment plants, asphalt plants or any specific sector. To date, the Companies have focused on designing offerings to suit industrial customers in all sectors. Industrial customers with cost effective energy efficiency capital projects in wastewater treatment plants and asphalt mix plants are eligible to participate in the Industrial Optimization Program.

233.9 Does FEU offer incentives for steam trap replacement and automatic steam trap maintenance? Please explain.

Response:

No. To date, the FEU do not offer incentives specifically for steam trap surveys, replacements or maintenance. However, the Companies requested approval to include a steam distribution prescriptive measure as provided in the EEC Plan Exhibit B-1-1, Appendix I, Attachment I1, Section 5.4.2, that will include measures to increase the efficiency of steam distribution systems.

233.10 Does FEU offer incentives aimed at retrofits for large steam boilers, such as condensing economizers, blow-down heat recovery, and oxygen trim controls? Please explain.

Response:

No. To date, the FEU do not offer incentives specifically for large steam boilers, such as condensing economizers, blow-down heat recovery, and oxygen trim controls. However, the Companies requested approval to include a process boiler prescriptive measure as provided in the EEC Plan Exhibit B-1-1, Appendix I, Attachment I1, Section 5.4.2, that will include measures to increase the efficiency of process boilers and water heaters.

234.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1-1, Appendix I, Attachment I-1, Attachment I-2

Data Analysis of EEC Actual and Forest Results

234.1 Please provide electronic spreadsheet versions of Exhibits 4 through 7 and 9 through 14 in Attachment I-1 to Appendix I.

Response:

Electronic spreadsheet versions of Exhibits 4 through 7 and 9 through 14 in Attachment I-1 to Appendix I, are provided in Attachment 234.1.

234.2 Please provide a breakdown of all EEC 2012 and forecast 2013 incentives where the total incentive provided to any one customer (or group of related companies) was in aggregate $100,000 or higher. Please describe the reason for the incentive.

Response:

Please refer to Attachment 234.2. Tables 1, 2 and 3 provide a breakdown of all EEC 2012 and forecast 2013 incentives where the total incentive provided to any one customer (or group of related companies) was in aggregate $100,000 or higher, along with the reason for the incentive.

Table 1: Residential EEC incentives over $100,000, 2012-2013

Customer	Program	Year	Incentive Amount	Incentive Amount per Year	Total Incentive per Customer	Explanation
Quadra Homes	Quadra Homes - New Construction Pilot Program - 1st Installment	2012*	$130,688	$135,188	$154,171	This EnerGuide 80 Row Home Pilot was initiated in 2010 in order for the FEU to gain experience on the EnerGuide 80 building process, energy labeling requirements, and to obtain cost benefit inputs for efficient natural gas appliances in new homes. A total of 151 units were completed over several years. Units are EnerGuide 80+ and include Tankless water heaters, Electronic ignition fireplaces and High Efficiency furnaces.
	Quadra Homes - New Construction Pilot Program - 2nd Installment		$4,500			Second installment of Quadra Homes - New Construction Pilot - paid through the New Home Program (invoiced by BC Hydro at the time).
	Quadra Homes - New Construction Pilot Program - 3rd Installment	2013	$18,983	$18,983		Third installment of Quadra Homes - New Construction Pilot.

Table 2: Industrial EEC incentives over $100,000, 2012-2013

Customer	Program	Year	Incentive Amount	Incentive Amount per Year	Total Incentive per Customer	Explanation
Quesnel River Pulp Mill (QRP)	Technology Retrofit Program	2012	$250,000	$250,000	$350,000	This amount was paid to Quesnel River Pulp Mill (QRP) after validating the commissioning of an approved energy efficiency project. The amount is a quarter of the total funding approved for this project. By implementing the approved energy efficiency project, QRP is estimated to save 70,000 gigajoules per year.
		2013	$100,000	$100,000		Estimated second installment to be paid to QRP that will be calculated from the savings achieved by the energy efficiency project in the first year after its commissioning.
Canfor Pulp Limited Partnerships (CPLP)	Technology Retrofit Program	2013	$112,500	$112,500	$225,000	This amount was paid to Canfor Pulp Limited Partnerships (CPLP) after validating the commissioning of an approved energy efficiency project. The amount is a quarter of the total funding approved for this project. By implementing the approved energy efficiency project, CPLP is estimated to save 38,000 gigajoules per year.
			$112,500	$112,500		Estimated second installment to be paid to CPLP that will be calculated from the savings achieved by the energy efficiency project in the first six months after its commissioning.

1 **Table 3: Commercial EEC incentives over $100,000, 2012-2013**

Customer	Program	Year	Incentive Amount	Incentive Amount per Year	Total Incentive per Customer	Explanation
BC Housing	Energy Specialist Program	2012	$60,000	$60,850	$141,490	Provided funding for one Energy Specialist.
	Light Commercial Boiler Program		$850			Provided one incentive for a boiler installation.
	Efficient Boiler Program	2013	$4,440	$80,640		Will provide one incentive for a boiler installation.
	Energy Assessment Program		$16,200			Provided eleven energy assessments.
	Energy Specialist Program		$60,000			Will fund the Energy Specialist position for 2013.
Bird Construction	Efficient Boiler Program	2013	$118,800	$118,800	$118,800	Will provide one incentive for boiler installations.
City of Burnaby	Energy Assessment Program	2012	$13,500	$73,500	$138,400	Provided nine energy assessments.
	Efficient Boiler Program		$60,000			Provided one incentive for a boiler installation.
	Efficient Boiler Program	2013	$57,600	$64,900		Three boiler incentives are projected.
	EnerTracker		$7,300			Ten applications were submitted.
District of North Vancouver	Energy Assessment Program	2012	$8,100	$71,495	$182,415	Provided five energy assessments.
	Efficient Boiler Program		$2,400			Provided one incentive for a boiler installation.

Customer	Program	Year	Incentive Amount	Incentive Amount per Year	Total Incentive per Customer	Explanation
	Efficient Comm. Water Heater Program	2012	$995	$71,495	$182,415	Provided one incentive for a water heater installation.
	Energy Specialist Program		$60,000			Provided funding for one Energy Specialist.
	Efficient Boiler Program	2013	$48,000	$110,920		Provided one incentive for a boiler installation.
	Energy Specialist Program		$60,000			Will fund the Energy Specialist position for 2013.
	EnerTracker		$2,920			Four applications submitted.
Fraser Health Authority	Energy Assessment Program	2012	$14,850	$14,850	$115,185	Provided eight energy assessments.
	Continuous Optimization Program	2013	$95,955	$100,335		Eleven applications submitted.
	EnerTracker		$4,380			Six applications submitted.
Interior Health Authority	Continuous Optimization Program	2012	$14,486	$156,836	$220,593	Provided six incentives.
	Energy Assessment Program		$82,350			Provided forty two energy assessments.
	Energy Specialist Program		$60,000			Provided funding for one Energy Specialist.
	Continuous Optimization Program	2013	$2,762	$63,757		Three applications submitted.

Customer	Program	Year	Incentive Amount	Incentive Amount per Year	Total Incentive per Customer	Explanation
	Efficient Comm. Water Heater Program		$995			Provided one incentive for a water heater installation.
	Energy Specialist Program	2013	$60,000	$63,757	$220,593	Will fund the Energy Specialist position for 2013.
Ivanhoe Cambridge II Inc.	Continuous Optimization Program	2013	$8,466	$177,466	$177,466	Two applications submitted.
	Efficient Boiler Program		$169,000			Provided three incentives for boiler installations.
Northern Health Authority	Commercial Custom Design Program - Retrofit Projects	2012	$33,640	$95,333	$251,050	Incented 50% of two energy studies.
	Continuous Optimization Program		$1,693			One application submitted.
	Energy Specialist Program		$60,000			Provided funding for one Energy Specialist.
	Continuous Optimization Program	2013	$7,758	$155,717		Three applications submitted.
	Commercial Custom Design Program - Retrofit Projects		$73,459			A capital incentive and implementation bonus is projected.
	Efficiency a la Carte		$2,500			Provided one incentive for a food equipment installation.

Customer	Program	Year	Incentive Amount	Incentive Amount per Year	Total Incentive per Customer	Explanation
	Efficient Boiler Program		$12,000			Provide one incentive for a boiler installation
	Energy Specialist Program		$60,000			Will fund the Energy Specialist position for 2013.
Pacific National Exhibition	Efficient Boiler Program	2013	$180,000	$180,000	$180,000	Provided one incentive for boiler installations.
Provincial Health Authority	Energy Specialist Program	2012	$60,000	$60,000	$113,127	Provided funding for one Energy Specialist.
	Continuous Optimization Program	2013	$7,397	$53,127		Three applications submitted.
	Energy Specialist Program		$45,000			Will fund the Energy Specialist position for 2013. Part year funding due to hiring a new specialist.
	EnerTracker		$730			One application submitted.
School District 36 - Surrey	Continuous Optimization Program	2012	$72,455	$202,443	$312,552	Provided fourteen incentives.
	Efficient Boiler Program		$129,988			Provided seven incentives for boiler installations.
	Continuous Optimization Program	2013	$14,369	$110,109		Thirteen applications submitted
	Efficient Boiler Program		$24,940			Provided one incentive for a boiler installation.
	Energy Assessment Program		$10,800			Submitted eight applications.
	Energy Specialist		$60,000			Will fund the Energy Specialist position for 2013.

Customer	Program	Year	Incentive Amount	Incentive Amount per Year	Total Incentive per Customer	Explanation
	Program					
School District 37 - Delta	Efficient Commercial Water Heater Program	2012	$3,000	$63,000	$123,000	Provided one incentive for a water heater installation.
School District 37 - Delta	Energy Specialist Program	2012	$60,000	$63,000	$123,000	Provided funding for one Energy Specialist.
	Energy Specialist Program	2013	$60,000	$60,000		Will fund the Energy Specialist position for 2013.
School District 38 - Richmond	Continuous Optimization Program	2012	$36,745	$181,065	$268,990	Provided six incentives.
	Efficient Boiler Program		$84,320			Provided six incentives for boiler installations.
	Energy Specialist Program		$60,000			Provided funding for one Energy Specialist.
	Continuous Optimization Program	2013	$22,525	$87,925		Submitted five applications.
	Energy Assessment Program		$5,400			Submitted four applications.
	Energy Specialist Program		$60,000			Will fund the Energy Specialist position for 2013.
School District 41 - Burnaby	Efficient Boiler Program	2012	$29,728	$89,728	$272,556	Provided two incentives for boiler installations.
	Energy Specialist Program		$60,000			Providing funding for one Energy Specialist.

Customer	Program	Year	Incentive Amount	Incentive Amount per Year	Total Incentive per Customer	Explanation
	Efficient Boiler Program	2013	$122,828	$182,828		Provided five incentives for boiler installations with one projected.
	Energy Specialist Program		$60,000			Will fund the Energy Specialist position for 2013.
School District 63 - Saanich	Continuous Optimization Program	2012	$22,829	$22,829	$145,409	Provided three incentives.
	Continuous Optimization Program	2013	$6,872	$122,580	$145,409	Provided two incentives.
	Efficient Boiler Program		$60,708			Provided two incentives for boiler installations with one pending application.
	Energy Specialist Program		$55,000			Will fund the Energy Specialist position for 2013. Part year funding due to hiring a new specialist.
Simon Fraser University	Continuous Optimization Program	2012	$28,001	$91,451	$153,939	Provided five incentives.
	Efficient Commercial Water Heater Program		$750			Provided one incentive for water heater installation.
	Energy Assessment Program		$2,700			Provided two energy assessments.
	Energy Specialist Program		$60,000			Provided funding for one Energy Specialist.
	Continuous Optimization Program	2013	$2,488	$62,488		Four applications were submitted.

Customer	Program	Year	Incentive Amount	Incentive Amount per Year	Total Incentive per Customer	Explanation
	Energy Specialist Program		$60,000			Will fund the Energy Specialist position for 2013.
UBC/UBC Properties Trust	Commercial Custom Design Program - New Construction Projects	2012	$13,450	$173,572	$311,504	Incented 50% of an energy study.
	Continuous Optimization Program	2012	$96,072	$173,572	$311,504	Provided thirty three incentives.
	Energy Assessment Program		$4,050			Provided three energy assessments.
	Energy Specialist Program		$60,000			Provided funding for one Energy Specialist.
	Continuous Optimization Program	2013	$25,236	$137,932		Provided twenty two incentives.
	Energy Assessment Program		$2,700			Provided one energy assessment.
	Efficient Boiler Program		$46,006			Provided two incentives for boiler installations.
	Efficient Commercial Water Heater Program		$3,990			Provided one incentive for a water heater installation.
	Energy Specialist Program		$60,000			Will fund the Energy Specialist position for 2013.

Customer	Program	Year	Incentive Amount	Incentive Amount per Year	Total Incentive per Customer	Explanation
Vancouver Coastal Health Authority	Continuous Optimization Program	2012	$21,132	$86,532	$161,810	Provided four incentives.
	Energy Assessment Program		$5,400			Provided two energy assessments.
	Energy Specialist Program		$60,000			Provided funding for one Energy Specialist.
	Continuous Optimization Program	2013	$13,278	$75,278		Submitted fifteen applications.
	Efficiency a la Carte	2013	$2,000	$75,278	$161,810	Provided two incentives for installing foodservice equipment.
	Energy Specialist Program		$60,000			Will fund the Energy Specialist position for 2013.
Vancouver Island Health Authority	Continuous Optimization Program	2012	$113,833	$405,136	$618,759	Provided fourteen incentives.
	Commercial Custom Design Program - Retrofit Projects		$10,597			Incented 50% of an energy study.
	Efficiency a la Carte		$2,000			Provided an incentive for installing foodservice equipment.
	Energy Assessment Program		$12,150			Provided eight energy assessments.
	Efficient Boiler Program		$80,556			Provided three incentives for boiler installations.

Customer	Program	Year	Incentive Amount	Incentive Amount per Year	Total Incentive per Customer	Explanation
	Efficient Commercial Water Heater Program		$6,000			Provided one incentive for water heater installation.
	Energy Specialist Program		$180,000			Provided funding for three Energy Specialist positions.
	Continuous Optimization Program	2013	$21,347	$213,623		Five applications were submitted.
	Energy Assessment Program		$2,700			Provided one energy assessment.
	Efficient Boiler Program	2013	$9,576	$213,623	$618,759	Submitted one application for a boiler installation.
	Energy Specialist Program		$180,000			Will fund three Energy Specialist positions for 2013.

234.3 Please provide a graph of actual/forecast (i) total FEU EEC spend, and (ii) total FEU EEC spend as a percentage of FEU revenues from 2008 to 2018. Please explain any significant changes.

Response:

1. The data from which this response is developed is contained in Table 1 of the FEU's response to BCUC IR 1.212.6.

(i) Figure 1 below shows that approved funding levels for 2010 through 2013 and requested funding levels for 2014 through 2018 have remained consistent. Figure 2 shows that the only significant change in actual EEC expenditures during this period is related to the ramp-up of actual EEC activities and spending to meet the expected funding levels that have consistently been found to be an appropriate level of EEC funding for the FEU. The graph in Figure 2 is the same information shown in Figure 1 of BCUC IR 1.212.6.

(ii) Figure 3 shows that FEI spending as a percentage of FEI revenue reflects the same ramping up changes apparent in the actual spending data. This information cannot be provided for the FEU in total as the revenue forecasts for FEVI and FEW are not yet available.

Figure 1: FEU Approved EEC Funding for 2010 – 2013 and Requested Funding for 2014 - 2018

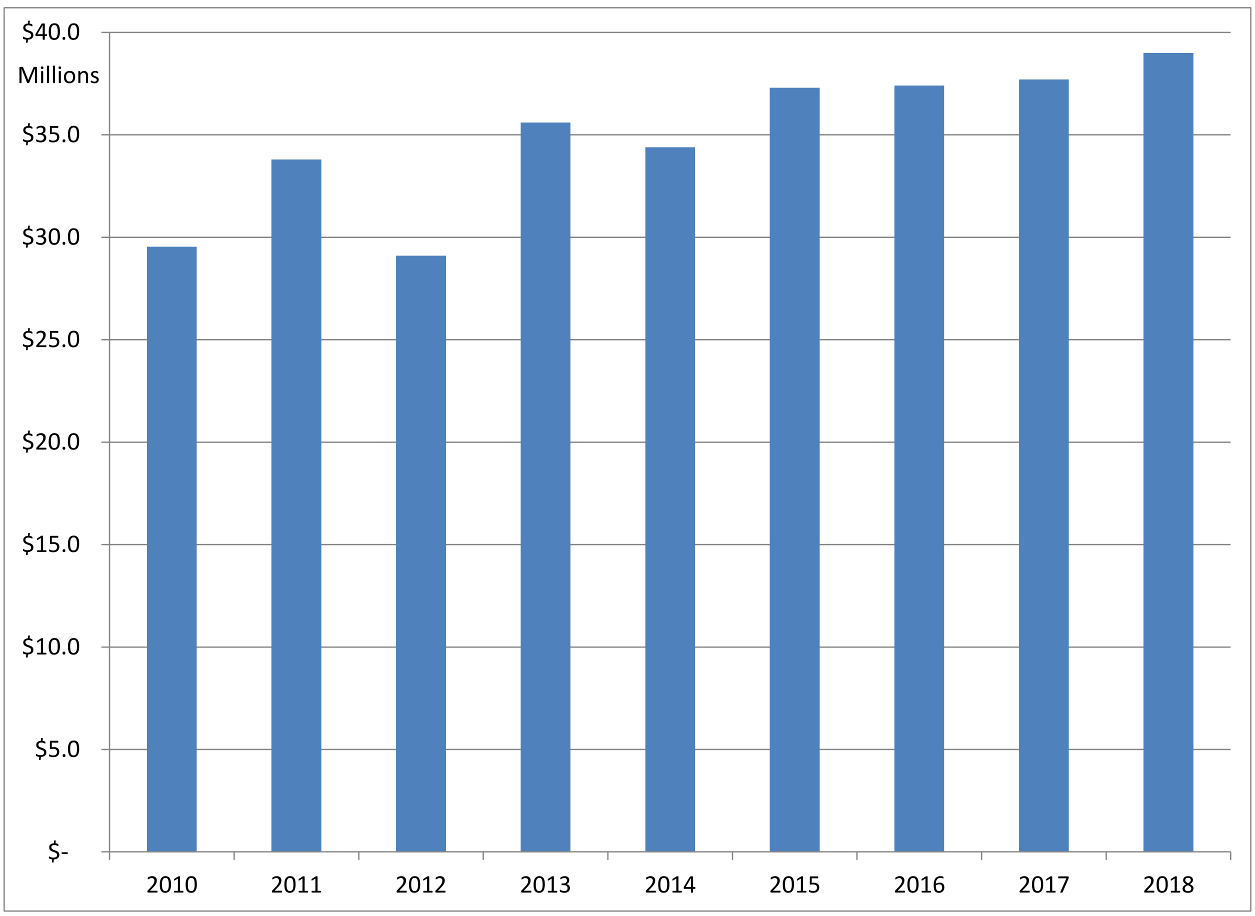


Figure 2: FEU Actual EEC Funding for 2010 – 2012, Projected Funding for 2013 and Requested Funding for 2014 – 2018

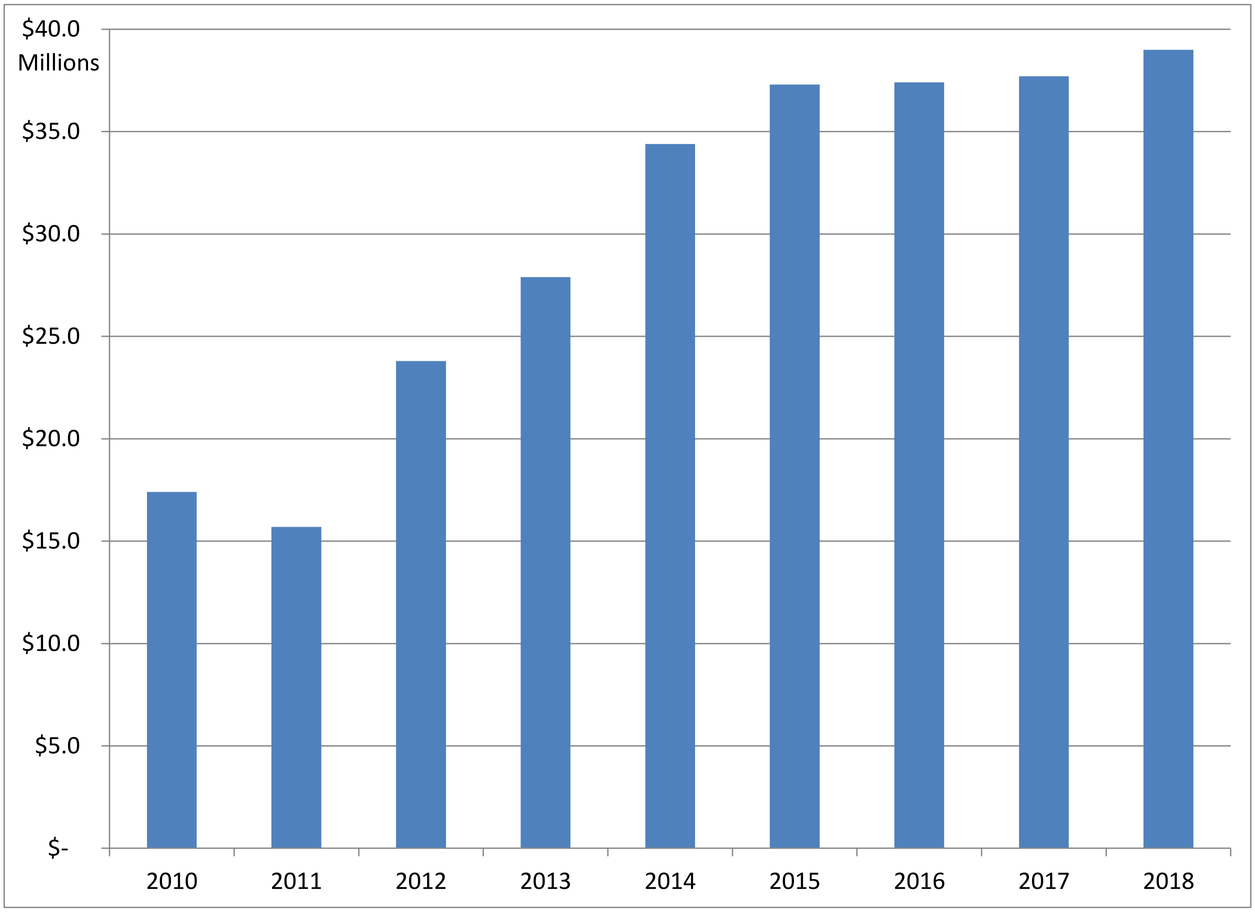
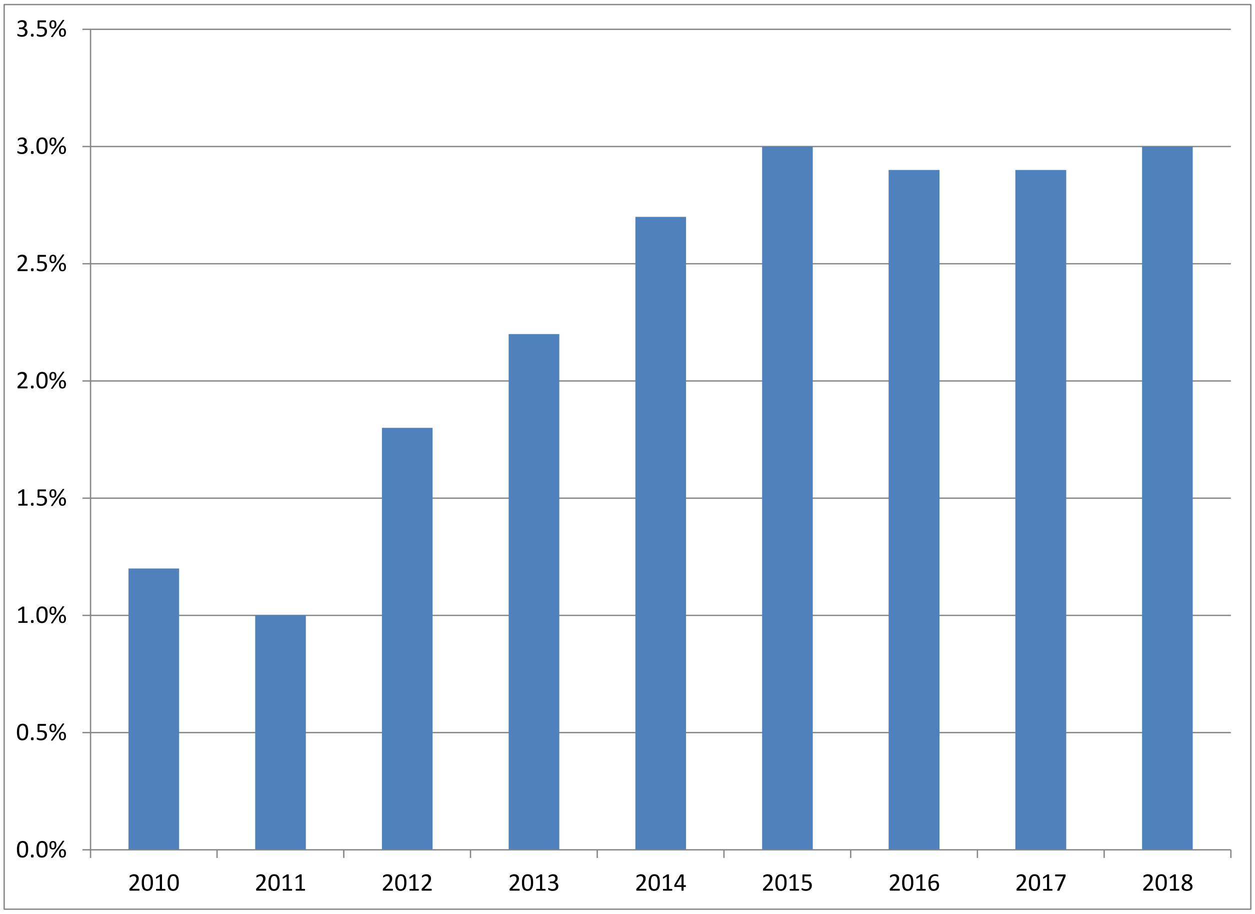


Figure 3: FEI Actual (2010 – 2012), Projected (2013) and Requested (2014 – 2018) Funding as a Percentage of FEI Revenue



234.4 Please complete the following tables for each year for 2012 (actual), 2014 and 2018. 'Total Spend' is the total utility EEC spend for that year on the program. Please explain any significant differences between years.

	Total EEC Spend - FEI	Total EEC Spend - FEVI	Total EEC Spend - FEW	Total

________Program (*Fill in for each program with sub-totals by customer class)*	$________ (______% of program total)	$_______ (______% of program total)	$_______ (%_____ of program total)	$______ (%_____ of program total)

Response:

Please refer to Attachment 234.4. This analysis incorporates the responses to both BCUC IR 1.234.4 and 1.234.8.

Note that Portfolio Level Activities as listed in the 2012 EEC Annual Report and Enabling Activities as listed in the 2014-2018 EEC Plan have not been included in this analysis as free-rider, spillover, non-energy benefits and lifespan of asset are not applicable to these activities. In terms of expenditure allocation by service territory for these activities, Portfolio Level Activities expenditures were reported as $3,454,000 for FEI and $581,000 for FEVI for a total of $4,045,000 in 2012. Enabling Activities expenditures are forecast to be $4,109,000 for FEI and $406,000 for FEVI in for a total of $4,515,000 in 2014 and $3,972,000 for FEI and $393,000 for FEVI for a total of 4,365,000 in 2018. Note that for these figures FEW has been included in FEI.

Also note that the category "persistence of savings assumed" has not been included in the analysis. The FEU have not accounted for any savings that persist after the lifetime of the equipment and are assuming that the lifespan of the asset (also known as "measure life") is the same as the persistence of energy savings.

234.5 Please complete the following table for each year for 2012 (actual), 2014 and 2018. Please explain any significant differences between years.

		Program		
		Residential	**Commercial**	**Industrial**
FEI	**Total EEC spend -FEI**	$_______ (______% of total FEI EEC spend)	$__________ (______% of total FEI EEC spend)	$________ (_______% of total FEI EEC spend)

	Total EEC spend as a % of customer class revenues	____%	____%	____%
FEVI (as above)				
FEW (as above)				

Response:

The table below provides a summary of actual (2012) and forecasted (2014 and 2018) EEC expenditures and revenues. Please note that FEW has been calculated as 1 percent of EEC FEI expenditures, consistent with the FEU's previous EEC Plans. Forecasted 2014-2018 revenues are not yet available for FEVI and FEW; consequently, forecasted total EEC expenditures as a percentage of customer class revenues are only available for FEI.

The only significant difference between years is a slight decrease in the relative percentage of EEC expenditures on Residential program between 2012 and 2014. This is due simply to changes to the EEC portfolio made in the 2012-2013 EEC Plan.

1 **Analysis of EEC expenditures and revenues, 2012, 2014 and 2018**

		2012			2014			2018		
		Residential	Commercial	Industrial	Residential	Commercial	Industrial	Residential	Commercial	Industrial
FEI	Total EEC spend - FEI ($000s)	$10,097	$3,906	$344	$9,374	$9,521	$1,721	$10,187	$8,347	$2,682
	% of total FEI EEC spend	49%	19%	2%	31%	32%	6%	32%	26%	9%
	Total EEC spend as a % of customer class revenues	1.4%	1.0%	0.5%	1.4%	2.6%	2.3%	1.5%	2.1%	3.5%
FEVI	Total EEC spend - FEVI ($000s)	$1,096	$920	$10	$1,089	$1,515	$174	$1,093	$1,620	$274
	% of total FEVI EEC spend	36%	30%	0%	28%	39%	5%	27%	40%	7%
	Total EEC spend as a % of customer class revenues	1.7%	0.9%	0.0%	n/a	n/a	n/a	n/a	n/a	n/a

		2012			2014			2018		
		Residential	Commercial	Industrial	Residential	Commercial	Industrial	Residential	Commercial	Industrial
FEW	Total EEC spend - FEW ($000s)	$102	$39	$3	$95	$96	$17	$103	$84	$27
	% of total FEW EEC spend	49%	19%	2%	31%	32%	6%	32%	26%	9%
	Total EEC spend as a % of customer class revenues	2.8%	0.5%	n/a	n/a	n/a	n/a	n/a	n/a	n/a
FEU	Total EEC spend - FEU ($000s)	$11,295	$4,865	$358	$10,588	$11,132	$1,912	$11,383	$10,051	$2,983
	% of total FEU EEC spend	48%	20%	2%	31%	32%	6%	32%	28%	8%
	Total EEC spend as a % of customer class revenues	1.4%	1.0%	0.4%	n/a	n/a	n/a	n/a	n/a	n/a

234.6 Please complete the following tables for each year for 2012 (actual), 2014 and 2018 for the following customer classes. Please explain any significant differences.

	FEI UCT	FEVI UCT	FEW UCT
Residential			
Commercial			
Industrial			

Response:

The table below provides a summary of UCT results for the Residential, Commercial and Industrial EEC Program Areas by service territory. Results for 2012 are actual UCT results from the 2012 EEC Annual Report, while those for 2014-2018 are forecasted results from the EEC Plan 2014-2018.

The FEU chose to present a combined UCT results for 2014-2018 for a variety of reasons. In order to break the UCT down by year, the FEU would need to employ the services of ICF Marbek. ICF Marbek confirmed that there would be a significant amount of work involved in addressing this IR since the model they created is not currently structured to provide benefits based on the implementations of a measure in a particular year. Rather, the model currently provides all of the benefits that occur in a particular year, which is often a result of implementations in previous years as well. Although it is possible to pull the numbers apart and calculate the cost-effectiveness results on an annual basis, it was estimated that this alone would involve 2.5 days of work at a significant cost.

ICF Marbek is also of the opinion that representing the UCT as a 2014-2018 average is a more appropriate analysis and better representation of the average impact on utility rates. Annual results for both 2014 and 2018 are expected to be lower than the average in many cases. In 2014 programs may be ramping up, possibly resulting in lower participation rates and higher administration costs. Conversely, in 2018 programs may be ramping down, possibly resulting in lower participation rates and higher evaluation costs. As such, the results for each of the years 2014 and 2018 are likely to be skewed in most cases.

UCT Results by Program Area and Service Territory, 2012[57] and 2014-2018[58]

Program Area	Service Territory	Utility Cost Test (UCT) 2012	Utility Cost Test (UCT) 2014-2018	Variation %
Residential	FEI	1.8	1.2	-36%
	FEVI	1.5	1.2	-22%
	FEW	n/a	n/a	n/a
Commercial	FEI	1.5	1.7	12%
	FEVI	1.7	1.8	3%
	FEW	n/a	n/a	n/a
Industrial	FEI	4.7	4.1	-13%
	FEVI	n/a	4.2	n/a
	FEW	n/a	n/a	n/a

For the purposes of this IR the FEU have defined a “significant difference” as +/- 25%. Only the results for the Residential Program Area – FEI were significantly different (-36%) between 2012 and 2014-2018. The decline in UCT is mostly attributable to the fact that in 2012, 44% of residential expenditures were attributed to LiveSmartBC a high UCT program of over 3.0. In the 2014-2018 period this high UCT program only accounts for 13% of the overall spend. All other programs are in alignment.

The Industrial Program Area – FEVI had no UCT results for 2012, although a UCT of 4.2 is forecasted in the EEC Plan 2014-2018. The decline in UCT is mostly attributable to the fact that in 2012 Industrial Program Area savings came from a single participant in the Technology Retrofit program that received an incentive that was higher than the average incentive estimated for all measures used in the UCT calculation for the 2014-2018 period. This single participant met the program’s general terms and conditions applicable to all participants. Hence, the participant received a higher incentive due to its project’s above average size.

[57] FEU Energy Efficiency and Conservation Program – 2012 Annual Report, p.10, Table 2-2. http://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/130328_FEU_2012_EEC_Annual_Report.pdf

[58] FortisBC Energy Performance Based Ratemaking Revenue Requirements 2014-2018. Exhibit B-1-1. Attachment I1 FEU EEC Plan 2014-2018, p.9, Exhibit 5. http://www.bcuc.com/Documents/Proceedings/2013/DOC_34888_B-1-1_FEI-2014-18-PBR-Application-Vol-2.pdf

234.7 Please complete the following table for 2012 (actual), 2014 and 2018 for each main customer class (residential, commercial, industrial). Please explain any significant variances.

Customer Class		**FEI**	**FEVI**	**FEW**	**Total**
Residential /Commercial /Industrial	Number of Customers				
	Number of customers as a % of FEU total				
	Total GJ sold to these customers				
	GJ sold as a % of total GJ sold to all customers.				
	EEC budget for this customer class				
	EEC budget above as a % of total EEC budget				

Response:

The following table provides a summary of EEC data by main customer class for 2012, 2014 and 2018. Please note that FEW expenditures have been calculated as 1 percent of EEC FEI expenditures, consistent with the FEU's current and previous EEC Plans. Forecasted 2014-2018 data is not yet available for FEVI and FEW; consequently, customer and usage data are only available for FEI.

The only significant difference between years is a slight decrease in the relative percentage of EEC expenditures on Residential program between 2012 and 2014. This is due simply to changes to the EEC portfolio made in the 2012-2013 EEC Plan.

EEC analysis by customer class, 2012, 2014 and 2018[59]

Customer Class		2012				2014				2018			
		FEI	FEVI	FEW	Total	FEI	FEVI	FEW	Total	FEI	FEVI	FEW	Total
Residential	Number of Customers	759,712	92,067	2,271	854,050	768,622	n/a	n/a	n/a	788,440	n/a	n/a	n/a
	Number of Customers as a % of FEU total	80.6%	9.8%	0.2%	90.6%	91%	n/a	n/a	n/a	91%	n/a	n/a	n/a
	Total TJ sold to these customers	68,328	3,588	222	72,138	69,500	n/a	n/a	n/a	69,100	n/a	n/a	n/a
	TJ sold as a % of total TJ sold to all customers	34.6%	1.8%	0.1%	36.5%	39.1%	n/a	n/a	n/a	38.2%	n/a	n/a	n/a
	EEC budget for this customer class ($000s)	10,097	1,096	102	11,295	$9,374	$1,089	$95	$10,588	$10,187	$1,093	$103	$11,383
	EEC budget above as a % of total EEC budget	49%	36%	49%	48%	31%	28%	n/a	31%	32%	27%	n/a	32%
Commercial	Number of Customers	78,430	9,021	341	87,792	79,133	n/a	n/a	n/a	80,603	n/a	n/a	n/a
	Number of Customers as a % of FEU total	8.3%	1.0%	0.0%	9.3%	9.3%	n/a	n/a	n/a	9.3%	n/a	n/a	n/a
	Total TJ sold to these customers	49,310	7,901	503	57,714	50,200	n/a	n/a	n/a	53,900	n/a	n/a	n/a
	TJ sold as a % of total TJ sold to all customers	25.0%	4.0%	0.3%	29.2%	28.3%	n/a	n/a	n/a	29.8%	n/a	n/a	n/a

[59] See 2014-2018 PBR Application Appendix E2 for forecasting tables.

Customer Class		2012				2014				2018			
		FEI	FEVI	FEW	Total	FEI	FEVI	FEW	Total	FEI	FEVI	FEW	Total
	EEC budget for this customer class	$3,906	$920	$39	$4,865	$9,617	$1,515	n/a	$11,132	$8,431	$1,620	n/a	$10,051
	EEC budget above as a % of total EEC budget	19%	30%	19%	20%	32%	39%	n/a	32%	26%	40%	n/a	28%
Industrial	Number of Customers	919	8	0	927	919	n/a	n/a	n/a	919	n/a	n/a	n/a
	Number of Customers as a % of FEU total	0.1%	0.0%	0.0%	0.1%	0.1%	n/a	n/a	n/a	0.1%	n/a	n/a	n/a
	Total TJ sold to these customers	59,605	7,928	0	67,533	57,900	n/a	n/a	n/a	57,900	n/a	n/a	n/a
	TJ sold as a % of total TJ sold to all customers	30.2%	4.0%	0.0%	34.2%	32.6%	n/a	n/a	n/a	32.0%	n/a	n/a	n/a
	EEC budget for this customer class	$344	$10	$3	$358	$1,738	$174	n/a	$1,912	$2,709	$274	n/a	$2,983
	EEC budget above as a % of total EEC budget	2%	0%	2%	2%	6%	5%	n/a	6%	9%	7%	n/a	8%

234.8 Please complete the following table for FEU for 2012 (actual), 2014 and 2018. Please explain any significant variances.

Program	**Free-rider %**	**Spillover %**	**Non-energy benefits (% of total benefit)**	**Lifespan of asset**	**Persistence of savings assumed**
________Program *(Fill in for each program, with sub-totals by customer class)*					

Response:

Please refer to the response to BCUC IR 1.234.4 and Attachment 234.4.

234.9 Please provide a table showing the following costs, for each program, for 2012 (actual), 2014 and 2018: (i) program incentive; (ii) program administration; (iii) program comm. and (iv) program evaluation. Please present costs as a percentage of total program EEC costs. Please also include a brief description of the type of costs included in each category.

Response:

Please refer to Attachment 234.9 for tables showing a breakdown of EEC expenditures by program, program area and total portfolio for 2012, 2014 and 2018 into the following categories: incentives, administration, communications and research and evaluation.

- Incentives include all EEC incentive payments made to customers;
- Communications includes marketing expenditures such as advertising and marketing collateral;

- Research & Evaluation includes expenditures on research studies and program evaluations; and
- Administration includes all other non-incentive expenditures not included in the categories above.

Costs are presented as total expenditures ($000s), percentage of program area spending and percentage of total portfolio spending.

235.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1-1, Appendix I, Attachment I-1, Appendix I, Attachment I-2

Benchmarking data

235.1 Please provide a comparison of $ EEC spending as a percentage of revenue for FEU against other utilities. Please explain any significant differences.

<u>Response:</u>

Please see Table 1 below.

This table is taken from the first draft of a report that the Canadian Gas Association is preparing on the state of natural gas DSM in Canada. It can be seen from the table that EEC expenditures as a percentage of distribution revenues have been ramping up since 2009. In 2012, the FEU expenditures on EEC were 1.7% of distribution revenues, compared with the Canadian average of 2.7%. In 2011, the FEU expenditures on EEC were 1% of distribution revenues, compared with the Canadian average of 2.5%. In 2010, the FEU expenditures on EEC were 1.1% compared with the Canadian average of 2.4%.

It should be noted that this data is gleaned from the first draft of this report, and that there will be differences in the methodologies that the different utilities across the country use to report distribution revenues, and expenditures on DSM that will make direct comparisons difficult. It should further be noted that many of the natural gas utilities shown in the table have fairly mature DSM programs with fairly stable levels of funding in recent years.

Table 1: Comparison of DSM Expenditure as a Percentage of Distribution Revenue for Canadian Natural Gas Utilities

Utility	ATCO		Enbridge		Fortis Energy Utilities		Gaz Metro		Manitoba Hydro		Sask Energy		Union		All Utilities	
Year	$ (millions)	Fraction of Distribution Revenue	$ (millions)	Fraction of Distribution Revenue	$ (millions)	Fraction of Distribution Revenue	$ (millions)	Fraction of Distribution Revenue	$ (millions)	Fraction of Distribution Revenue	$ (millions)	Fraction of Distribution Revenue	$ (millions)	Fraction of Distribution Revenue	Total $ (millions)	Fraction of Distribution Revenue
2012	0	n/a	30.9	0.031	23.80	0.017	17.75	0.034	6.10	0.095	1.20	0.011	27.67	0.040	100.14	0.027
2011	0	n/a	26.7	0.027	15.70	0.010	15.46	0.030	9.10	0.093	1.41	0.013	18.88	0.028	91.33	0.025
2010	1.7	0.003	25.5	0.026	17.40	0.011	15.26	0.029	9.79	0.085	1.19	0.011	14.78	0.022	88.86	0.024
2009	1.9	0.004	24.3	0.025	6.07	0.004	14.08	0.026	9.82	0.073	2.26	0.020	15.84	0.023	77.34	0.022
2008	1.3	0.003	23.1	0.024			13.41	0.026	9.56	0.058	2.27	0.020	13.79	0.020	63.42	0.018
2007	0.95	0.002	22	0.023			14.40	0.031	7.79	0.051	1.89	0.018	9.89	0.016	56.92	0.017
2006	1.7	0.004	18.9	0.020			13.50	0.030	5.18	0.035	1.60	0.016	9.75	0.015	50.64	0.015
2005	2.5	0.007	19	0.022			8.54	0.019	1.55	0.011	0.52	0.005	5.44	0.008	37.55	0.012
2004	2.8	0.008	13.6	0.016			6.43	0.014					4.27	0.007	27.10	0.009
2003	1.6	0.005	11.5	0.014			3.80	0.009					2.35	0.004	19.24	0.006
2002	0.95	0.003	10.9	0.014			3.21	0.008					1.55	0.002	16.61	0.006
2001			10.5	0.013			1.45	0.003					2.44	0.004	14.40	0.006
2000			6	0.008			1.00	0.002					2.21	0.005	9.82	0.005
1999			4.7	0.006									2.24		7.52	0.005
1998			4.8	0.007									2.03		8.82	0.006
1997													1.47		2.89	0.006

235.2 Please provide a comparison of FEU $ EEC spending on EM&V as a percentage of total EEC spending, against other utilities. Please explain any significant variances.

Response:

The FEU defines EM&V spending to include the annual cost of activities and staffing related to Evaluation, Measurement and Verification of EEC Programs. Table 235.2 below shows EM&V spending as a percentage of total EEC spending for the FEU and a number of other utilities in 2012. The FEU's spending on EM&V appears at the low end of the range of percentage of spending on DSM activity among these utilities; however, since EM&V spending necessarily lags behind program spending, and the FEU's EEC spending has ramped up in recent years, the FEU does expect annual EM&V spending to increase somewhat over the planning period. In keeping with general industry practice and in alignment with the EM&V Framework, the FEU plan EM&V budgets not to exceed 10 percent of overall DSM spending, and are targeting annual EM&V budgets to make up from 3 to 6 percent of the overall EEC portfolio spending.

Utility	Evaluation Spending	DSM Portfolio Spending	% spending on EM&V for 2012
FEU	$ 469,000	$ 23,760,000	2%
BC Hydro	$ 4,959,756	$ 175,250,000	3%
Consumers Energy	$ 2,506,196	$ 67,369,007	4%
Pacific Power (CA)	$ 198,519	$ 2,088,986	10%
Pacific Power (WA)	$ 751,468	$ 10,058,439	7%
Rocky Mountain Power (ID)	$ 796,620	$ 3,415,752	23%
Rocky Mountain Power (WY)	$ 92,046	$ 3,771,271	2%
Xcel MN	$ 1,830,599	$ 89,403,232	2%
APS	$ 1,929,312	$ 73,498,198	3%
PG&E	$ 21,163,063	$ 418,706,251	5%
SCE *	$ 13,653,593	$ 301,286,112	5%
SDG&E *	$ 5,684,012	$ 232,741,602	2%
SoCalGas *	$ 5,590,493	$ 188,514,346	3%
Xcel CO	$ 514,379	$ 79,441,169	1%
		Average % Spending on EM&V for 2012	**5%**

*based on a 3 year expenditure

Source:

FEU data is based on the figures from the Energy Efficiency and Conservation Program – 2012 Annual Report, Appendix I – 2 to the Application. BC Hydro provided FEU with the spending on EM&V for the fiscal year 2012. All other data provided by E Source based on a collection of DSM Reports in the USA.

Overall, the percentage spending on EM&V ranges from 1 to 23% with an average 5% EM&V spending for the utilities examined. There appears to be one significant variance among the utilities wherein Rocky Mountain Power (ID) spent 23% of its 2012 annual DSM expenditure on EM&V. However, in that case the overall DSM expenditure is smaller and, while the FEU have not determined the basis of that utility's EM&V spending, they would expect small variations in EM&V spending from year to year to cause a greater variance in the percentage of a smaller total DSM spending figure. Therefore this variance may not be as significant as it appears.

235.3 Please provide research papers on use of spillover and free rider estimates in EEC evaluations.

Response:

Please refer to Attachment 235.3 for the following three research papers on use of spillover and free rider estimates in EEC evaluations.

a. ***Custom Free Ridership and Participant Spillover Jurisdictional Review, Navigant, 2013:*** This report provides information to support a sub-committee of Ontario's Technical Evaluation Committee in its deliberations on the appropriate approach to Net-to-Gross (NTG) values in Ontario. Through a jurisdictional review of the approach to net savings, and a review of researched NTG values for programs comparable to Union and Enbridge's custom Commercial and Industrial gas programs, Navigant provides an assessment of the various approaches to NTG.

b. ***A National Review of Best Practices and Issues in Attribution and Net-to-Gross: Results of the SERA/CIEE White Paper, Skumatz and Vine, 2010:*** This study used interviews, a literature review, and analysis from around the United States to examine technical, research, and policy issues associated with the attribution of savings to programs – including NTG rations and its components, free ridership, spillover, and other issues.

c. ***Maximizing Societal Uptake of Energy Efficiency in the New Millennium: Time for Net-to-Gross to Get Out of the Way, Friedman, 2007:*** This report describes the NTG ratio currently applied within California and provides some thoughts on how to improve it.

236.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

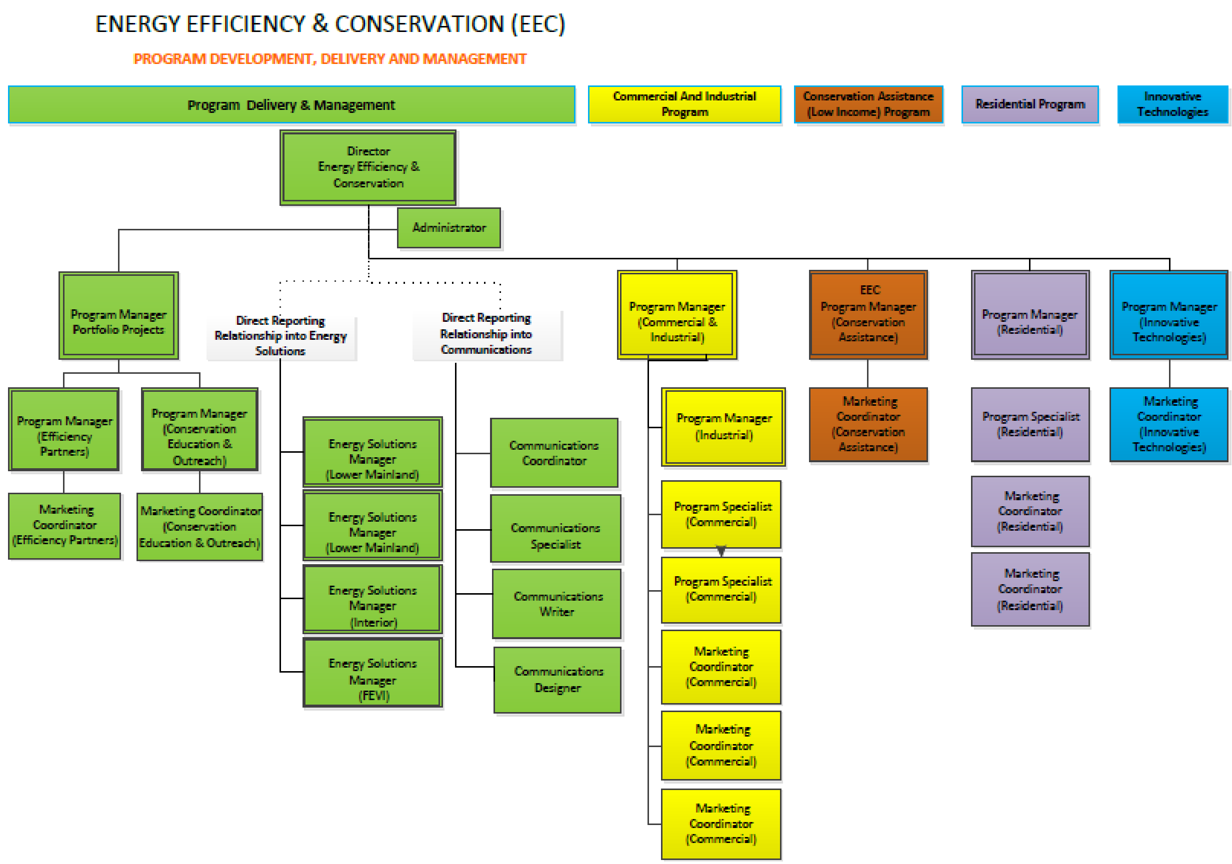
Exhibit B-1-1, Appendix I, Attachment I-1, p. 104

Staff levels and costs

236.1 Please provide a staff organization structure chart(s) for FEU departments responsible for EEC functions.

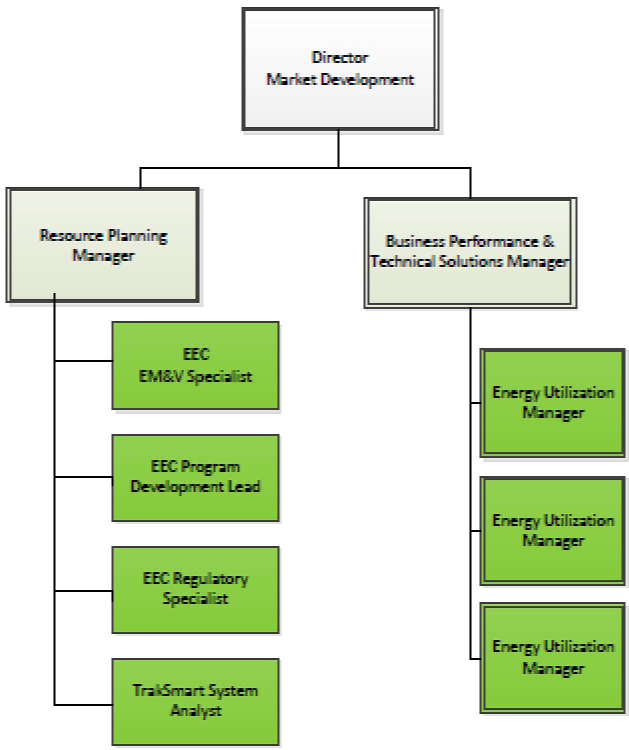
Response:

Please find below the current organizational charts for EEC functions.



ENERGY EFFICIENCY & CONSERVATION (EEC)

EVALUATION, MEASUREMENT AND VERIFICATION, PROGRAM TRACKING and EEC REPORTING



236.2 Please provide annual data from 2008 to 2012, together with forecast for the PBR period, for the following categories. Where compensation data is included, please describe what it included (for example, bonus, cashed-out vacation, pension etc.). Please include percentages to assist in identifying year over year variances, and describe the reason for any significant differences:

236.2.1 The number, total compensation, and average compensation per employee of FEU (i) full-time equivalent (FTE) employees and (ii) head counts working on EEC related projects, split by function.

Response:

This response pertains to BCUC IRs 236.2.1 and 236.2.2

The FEU have provided data back to 2010 in response to this IR as these periods provide for a meaningful comparison. The FEU received a decision from the Commission on its EEC expenditure levels on April 16, 2009, (Order No. G-36-09 the "EEC Decision"), which approved an increase in expenditure for the Companies' DSM Programs. This funding represented a significant increase from what had been previously allocated for DSM activities, and thereby much of 2009 was spent on the gathering of resources required for program delivery, which included some organizational restructuring along with external recruiting. By 2010 these resources were in place for effective EEC program delivery.

(i) The table below shows total compensation, FTE and average compensation from 2010 to 2018.

Item	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Total Compensation (000's)*	$ 1,320	$ 1,881	$ 2,759	$ 2,829	$ 2,834	$ 2,908	$ 2,995	$ 3,085	$ 3,177
FTE	19	26	37	36	36	36	36	36	36
Average Compensation (000's)	$ 70	$ 72	$ 74	$ 79	$ 79	$ 81	$ 83	$ 86	$ 88
Year Over Year % Change		2%	3%	7%	0%	3%	3%	3%	3%

* Total compensation includes base salary and short term incentive pay

The increase of 7% in average salary in 2013 Projection is the result of EEC administrative staff being moving from M&E to the COPE affiliation. This resulted in, on average, increases in base salary levels for these staff members, as their salaries were adjusted to the COPE salary structure. The move to the COPE bargaining unit was retroactive to September 2012.

(ii) The table below shows the 2013 projected FTE and the headcounts working on EEC related programs, split by function.

Function	2013 Projected FTE	2013 Projected Headcount
Program Development, Delivery & Management	14	14
Commercial and Industrial Programs	7	7
Residential Programs	4	4
Conservation Assistance (Low Income) Programs	2	2
Innovative Technologies	2	2
Evaluation, Measurement & Verification, Program Tracking & EEC Reporting	7	9
Total	**36**	**38**

Of these headcount, there are three staff members who work exclusively on EEC programs with compensation packages greater than $100 thousand, where compensation includes base pay and short term incentive.

236.2.2 The number of FEU (i) FTEs and (ii) headcounts working on EEC related projects with total compensation packages exceeding $100,000 per year.

Response:

Please refer to the response BCUC 1.236.2.1.

236.2.3 The number and average payment to contractors working on EEC projects at FEU, split by function.

Response

This response pertains to BCUC IRs 1.236.2.3 and 1.236.2.5. Please refer to the table below.

The FEU have provided data back to 2010 in response to this IR as these periods provide for a meaningful comparison. The FEU received a decision from the Commission on its EEC expenditure levels on April 16, 2009, (Order G-36-09, the EEC Decision), which approved an increase in expenditure for the Companies' DSM Programs. This funding represented a significant increase from the expenditure that had been previously allocated for DSM activities, and thereby a large portion of 2009 was spent ramping up EEC activities for effective EEC program delivery and therefore the years 2010 and onwards provide for comparable years of EEC program delivery.

Please note that for the purposes of this table, Evaluation, Measurement and Verification, Program Tracking and EEC Reporting expenditures have been attributed to the specific program areas which they supported and therefore have been included under the appropriate functions listed.

Function		2010 Actual	2011 Actual	2012 Actual
Program Development, Delivery & Management	Total Payment (000's)	$ 713	$ 712	$ 591
	Total Count of Contractors	33	48	58
	Average Payment (000's)	$ 22	$ 15	$ 10
Commercial and Industrial Programs	Total Payment (000's)	$ 86	$ 328	$ 583
	Total Count of Contractors	9	25	29
	Average Payment (000's)	$ 10	$ 13	$ 20
Residential Programs	Total Payment (000's)	$ 263	$ 563	$ 632
	Total Count of Contractors	14	23	21
	Average Payment (000's)	$ 19	$ 24	$ 30
Conservation Assistance (Low Income) Programs	Total Payment (000's)	$ 228	$ 245	$ 381
	Total Count of Contractors	17	23	15
	Average Payment (000's)	$ 13	$ 11	$ 25
Innovative Technologies	Total Payment (000's)	$ 120	$ 40	$ 234
	Total Count of Contractors	2	9	23
	Average Payment (000's)	$ 60	$ 4	$ 10
GRAND TOTAL	Total Payment (000's)	$ 1,410	$ 1,889	$ 2,421
	Total Count of Contractors	75	128	146
	Average Payment (000's)	$ 19	$ 15	$ 17

236.2.4 The number of contractors working on EEC projects with total compensation packages exceeding $100,000 per year.

Response:

The FEU assumes compensation package is referring to payment made by the FEU to the contractor.

Year	Contractor Count
2010	2
2011	4
2012	6

236.2.5 Total payments to consultants, split by function.

Response:

Please refer to the response to BCUC IR 1.236.2.3.

236.3 Please provide specific details of the incentive payment scheme for the Vice President responsible for EEC.

Response:

This response has been filed confidentially as it contains compensation information regarding an identifiable employee holding a particular position in the Company.

236.3.1 What is the 2014-2018 EEC budget for bonus/incentive pay?

Response:

Forecast Item ($ 000's)	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Short Term Incentive Pay	362	372	383	394	406

The specific details how the short term incentive pay are determined are provided in response to BCUC IRs 1.79.3 for M&E and 1.80.1.2 for COPE employees.

236.4 How does FEU determine total compensation packages for employees working on EEC functions?

Response:

Compensation packages for employees working on EEC programs is no different than that for employees working in the rest of the organization. A combination of M&E and COPE employees work on EEC functions and their respective total compensation packages are described in the responses to BCUC IR 1.79.3 for M&E and BCUC IR 1.80.1.2 for COPE.

237.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Energy Conservation and Demand Management – Annual Report of London Hydro's 2011 Activities & Achievements, 2012, p 70[60]

EEC Sales Focus

A Report by London Hydro (EM-12-04) states:

"London Hydro has traditionally approached [Conservation and Demand Management (CDM)] as a —sales activity and indeed all staff receives sales training (from outside experienced facilitators) with ongoing workshops to reinforce these skills."

237.1 How does FEU bundle together its EEC programs, both internally and with other service providers, to provide a 'package' of EEC service for customers?

<u>Response:</u>

The FEU interpret the question to mean "how do the FEU provide EEC services to customers", as program "bundles" and programs delivered in collaboration with other utilities and entities are described in the 2014-2018 EEC Plan, Exhibit B-1-1, Appendix I, Attachment I1. EEC services are delivered to customers through a number of channels.

For commercial and industrial customers, the Companies' Commercial/Industrial Account Managers were given EEC program participation targets starting in 2013, and their focus on helping commercial and industrial customers into the FEU's EEC program offerings was significantly strengthened.

The EEC Energy Solutions Managers are also focused on uncovering EEC opportunities with commercial customers, and helping those customers participate in the Companies' EEC offerings. The role of the EEC Energy Solutions Managers was discussed in the 2010 EEC Annual Report:

"Central to this will be the role played by the Companies' new energy solutions managers. The energy solutions managers will be increasing awareness of and participation in Energy Efficiency and Conservation programs by actively participating in industry associations, hosting workshops for commercial customers and seminars for energy managers, and educating small commercial customers through the Service Line newsletter. They will also work one-on-one with current and future commercial customers to increase participation and ease the program's application process."[61]

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[60] http://www.londonhydro.com/@assets/uploads/pages-270/cdm_annualreport2011_final.pdf

[61] 2010 EEC Annual Report, page 59

Further, the Companies fund Energy Specialists in a number of large commercial customers. This program is discussed on pages 56-57 of the 2014-2018 EEC Plan, Exhibit B-1-1, Appendix I, Attachment I1. The matter of EEC Energy Solutions Managers and Energy Specialists, and program delivery was canvassed in the FEU 2012-2013 RRA proceeding, and the Companies response to BCUC IR 1.217 series in that proceeding is provided below.

"217.1Parts 11.2.4 and 11.3 of the Report describe how the FEU has funded energy solutions managers in each major service territory and has developed a pilot to fund energy specialist positions in large commercial customers. The total expenditures in this program in 2010 were $460,000 and are planned to increase to $1.684 million in 2011. Do other jurisdictions employ specific EEC or DSM managers who are focused on sales activities dedicated to increasing participation in EEC programs? Please specify.

Response:

Yes; the practice of having positions focussed on sales activities dedicated to increasing participation in EEC programs is quite common. In BC, BC Hydro, for example, has their Key Account Managers, one of whose key roles is garnering commercial, industrial and institutional customer participation in BC Hydro's PowerSmart initiatives. In Ontario, Enbridge Gas Distribution has Energy Solutions Consultants who work with commercial, industrial and institutional customers to increase participation in Enbridge's DSM initiatives.

217.1.1Do the energy solutions managers target all customer classes or focus on a specific class?

Response:

The Energy Solutions Managers are targeting all commercial customers, with a focus on larger customers, although they have done work directly with some Rate Schedule 2 customers to assist those customers with entry into the Companies' commercial EEC programs.

217.2Please explain why the FEU chose to fund energy specialist positions with customers that already have established BC Hydro-funded energy managers. Why did the FEU not train the existing BC Hydro-funded energy managers in natural gas DSM measures? What would the cost of training the managers have been versus funding new positions?

Response:

The Energy Specialist pilot program was developed and deployed in close collaboration with BC Hydro. For the FEU pilot program, Energy Specialists have been placed at organizations where the BC Hydro-funded Energy Manager did not have the capacity to take on natural gas DSM measures in addition to their other electricity-related projects required under the BC Hydro Energy Manager program. This lack of capacity caused a need for an additional individual to work on natural gas DSM measures. In addition, given that it is a BC Hydro directed program, there was concern from FEU that the

Energy Managers would continue to focus their efforts on primarily pursuing electricity DSM solutions if a co-funding approach was taken versus funding a separate position. Due to this lack of capacity on the part of the BC Hydro-funded Energy Managers to take on natural gas DSM measures and the entrenched focus on electricity DSM solutions, the FEU in close collaboration with BC Hydro made a decision to fund a pilot program to place FEU-funded, natural gas focussed Energy Specialists in some organizations where BC Hydro-funded Energy Managers are already in place.

FEU chose to fund Energy Specialist positions with customers that already have established BC Hydro-funded Energy Managers in order to take advantage of opportunities where established energy management practice was already in place. This would enable the Energy Specialist to learn from the established Energy Manager and act on energy saving project development/implementation rather than spending a majority of their time on change management.

217.2.1Please provide a list of the 20 customers who were approved for energy specialist positions in 2010 and a detailed breakdown of the estimated energy savings associated with the position being implemented in each customer.

Response:

The following organizations were approved for Energy Specialist positions as part of the Energy Specialist Pilot Program in 2010:

	Approved Organizations	# of Energy Specialist Positions Filled in 2010
1	BC Apartment Owners & Managers Association	0
2	BC Housing	1
3	British Columbia Institute of Technology	1
4	Cadillac Fairview	1
5	Capilano University	1
6	City of Richmond	1
7	City of Vancouver	0
8	District of North Vancouver	1
9	Fraser Health Authority	0
10	Harmony Group	1
11	Interior Health Authority	0
12	Northern Health Authority	1
13	School District #37 (Delta)	1
14	School District #38 (Richmond)	1
15	School District #41 (Burnaby)	1
16	School District #43 (Coquitlam)	0
17	Simon Fraser University	0
18	University of BC	1
19	Vancouver Coastal Health Authority	0
20	Vancouver Island Health Authority	1

Note that some of the organizations who were not able to fill their Energy Specialist positions in 2010 have filled them in 2011. The Energy Specialist Program is defined as an enabling activity and as such supports the FEU's EEC program development and delivery but does not have energy savings directly associated with it. However, as part of the pilot program, the FEU is investigating ways to credit Energy Specialists directly for their contribution to attaining energy savings for their respective organizations.

217.2.2 If the energy specialist program is a pilot, are there plans to phase out the positions once DSM measures are implemented? If not, until when does the FEU expect to fund these positions?

Response:

The FEU's intent is to continue to fund Energy Specialist positions to the extent that the Energy Specialists can show that they are producing results in line with the Energy Specialist program's goals and objectives, and have future natural gas DSM projects to work on. Currently, the FEU sign one-year funding agreements with participating Energy Specialist Program organizations. Prior to renewing these one-year agreements, Energy Specialists are asked to provide a project plan for the following year. The FEU review the Energy Specialist's quarterly reports to date as well as this project plan to determine if continued funding is warranted. If it is apparent that there are no further natural gas DSM measures to implement at the organization then the FEU will discontinue funding for that Energy Specialist position."[62]

For residential customers, EEC services are delivered primarily through the Efficiency Partners network described on page 82 of the 2014-2018 EEC Plan, Exhibit B-1-1, Appendix I, Attachment I1.

237.1.1 Does FEU offer EEC 'while quantities last/for a limited time only' sales. If no, please explain why not. If yes, please describe.

Response:

Yes, the FEU may offer EEC initiatives "while quantities last/for a limited time only" to promote program participation. Past program examples are described in the following paragraphs.

The 2012 Residential Furnace Replacement pilot program, which ran at the start of heating season, utilized a "limited time only" sales mechanism and only offered rebates on heating systems purchased from September to the end of October, 2012 to collect important program

[62] Response to BCUC IR 1.217 series, FEU 2012-2013 RRA proceeding

information within a limited time period. The 2013 iteration of the Furnace Replacement pilot program further utilized a "limited time only mechanism" with pre-qualification codes only available to customers from April to July 1. The limited time only approach was utilized in the instance of the Furnace Replacement pilot program in order to restrict participation to manage a pilot with a limited budget, to encourage early replacement outside of the heating season, rather than emergency replacement at failure during heating season, and to support gas contractor businesses outside the prime heating season.

The Residential Appliance Service program utilizes a limited time only mechanism outside of heating season, when contractors are less busy. This assists the contractor network with seasonal trends and provides a cost-effective means for contractors to engage customers on the benefits of upgrading to energy efficient appliances outside of the heating season. In this instance, the limited time only approach was adopted to support gas contractor businesses outside the prime heating season, giving gas contractors more time to spend with customers discussing other energy efficiency upgrade opportunities.

Furthermore, pilot programs in the Innovative Technologies program area can utilize a "limited time only/while quantities last" to adhere to the monitoring methodology, sample size and time period established within the pilot measurement and verification plan. For instance, the pilot measurement and verification plan may have a requirement to monitor the pre-upgrade conditions and energy consumption during the heating season prior to installing the efficiency upgrade. In this instance, the Companies may adopt the limited time or while quantities last approach to drive participation for that predefined period of time. If the Companies do not drive the participation during that heating season, the Companies will have to wait another year until the next heating season in order to monitor the pre-upgrade conditions.

Thus it can be seen that the Companies use this approach for a variety of reasons.

237.2 Does FEU incentivize its staff, contractors and third party providers, (for example, through bonuses, commissions) to decrease the effective $/GJ cost of energy obtained through EEC? If no, please explain why not. If yes, please describe.

Please include in your response whether FEU incentivize its staff, contractors and third party providers to: (i) reduce EEC selling costs; (ii) bring forward ideas to change existing program design/selling techniques in order to increase EEC sales; (iii) bring forward ideas for potential new EEC products/services; (iv) sell more 'high margin' EEC projects (i.e. those with a lower $/GJ).

Response:

No, the Companies do not incentivize staff, contractors and third party providers for any of the reasons described in the Information Request above. The Companies are proposing to provide contractors with an incentive in two residential programs over the test period:

Furnace Replacement Program:	$50
EnerChoice Fireplace Program – Retrofits only:	$50

It is the case, however, that FEU staff have annual performance goals based on their specific business unit objectives, and on the performance of the Companies overall, on which part of their compensation is based.

238.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1-1, Appendix I, p. 18

New EEC Programs

On page 18 of the Appendix I to the Application, FEU states: "In the EEC Plan, FEU is requesting funding for 6 new programs."

238.1 Please provide the business case for each new program proposed. Please ensure it includes the following:

- The market failure the program is trying to address, and the TRC/mTRC (including key inputs) results which demonstrate that there is a BC benefit from addressing this market failure.
- Why FEU considers that it is best positioned to address this market failure.
- The research undertaken by FEU to determine what market barriers are causing this market failure (for example, short pay-back period required by customers, lack of awareness, landlord/tenant split incentive).
- A high level description of the proposed program, including: why FEU considers the program is an optimal way to address the market failure, how the incentive level was set, how FEU plans to sell this program to its customers and how FEU plans to ensure the program is updated/refined in response to actual results
- Identification of any other FEU, BCH, LiveSmart and other EEC programs which are also addressing this market failure, and how FEU ensures that the programs complement each other.
- Any difference in marketing/availability/expected uptake of each program between FEI/FEVI/FEW regions, and the rationale for the split of the budget between FEI/FEVI and FEW.
- The extent to which the program is cost effective for FEU's ratepayers. Please include in the explanation the results of the UCT and include all key inputs and assumptions.
- How FEU arrived at the uptake assumption, $/GJ saving per participant, free-rider/spillover estimate and measure life.
- Estimated payback period for a typical customer in the absence of this program, and when participating in this program.
- EM&V plan, and whether it is subject to third party review.
- Any incentives FEU has put in place for staff/contractors to maximize the uptake and cost-effectiveness of delivery of the program.

Response:

FEU does not have a finalized business case developed yet for any of the new programs proposed in the EEC Plan other than the Mechanical Insulation Pilot. FEU is awaiting Commission approval to pursue these programs before investing the time and resources required to craft a full business case and program plan. A full program profile for each new program proposed has been provided in the EEC Plan. The Program Profile for the Specialized Industrial Process Technology Program[63], and for the Low Income Space Heat Top-Up[64], Low Income Water Heating Top-Up[65] and the non-Profit Custom Program[66] provide the assumptions used to arrive at the cost-effectiveness projections included in the EEC Plan. At this time, no further information is available.

Please also note that at present FEU does not have a formal plan to pursue the Mechanical Insulation Pilot further. Therefore, the business case is not being presented here. Please refer to the response to BCUC IR 1.227.4 for additional details. Unlike the other new programs proposed in the EEC Plan, a business case had been produced for the Mechanical Insulation Pilot because it was originally set to launch in 2013.

[63] Pages 62, 63, 66 and 67 of Exhibit B-1-1, Appendix I, Attachment I1
[64] Pages 70, 71, 78 and 79, Ibid
[65] Pages 70, 71, 80 and 81, Ibid
[66] Pages 70, 71, 82 and 83 Ibid

239.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1-1, Appendix I, pp. 6, 7

Specified EEC Measures/Prescribed Undertakings

239.1 Please provide a mapping of FEU's EEC projects, together with their 2014-2018 budgets, and TRC/mTRC and UCT forecasts, which meet the following definitions:

- A demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption.
- A demand-side measure intended specifically to improve the energy efficiency of rental accommodations.
- An education program for students enrolled in schools in the public utility's service area.
- An education program for students enrolled in post-secondary institutions in the public utility's service area.

<u>Response:</u>

The following tables provide a mapping of the FEU's EEC programs, including their 2014-2018 projected expenditures and TRC, MTRC and UCT forecasts, which meet the definitions listed above. These programs meet the adequacy requirements set out in Section 3 of the Demand-Side Measures Regulation[67].

Table 1 outlines the FEU's demand-side measures intended specifically to assist residents of low-income households to reduce their energy consumption. These include all of the programs in the FEU's Low Income Program Area.

Table 1: 2014-2018 demand-side measures intended specifically to assist residents of low income households to reduce their energy consumption

Program Area	Program/Category	Service Territory	TRC	MTRC	UTC	Projected Expenditure* ($000s) 2014	2015	2016	2017	2018	Total
Low Income	Residential Energy Efficiency Works (REnEW)	FEI	0.0	n/a	0.0	41	81	81	41	81	324
		FEVI	0.0	n/a	0.0	41	0	0	41	0	81
		Total	0.0	n/a	0.0	81	81	81	81	81	405
	Energy Saving Kit (ESK)	FEI	5.1	n/a	3.3	122	110	99	89	81	501
		FEVI	5.9	n/a	3.7	37	33	30	27	24	150
		Total	5.3	n/a	3.4	159	143	129	116	105	651

[67] http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/10_326_2008

Program Area	Program/Category	Service Territory	TRC	MTRC	UTC	Projected Expenditure* ($000s)					
						2014	2015	2016	2017	2018	Total
	Energy Conservation Assistance Program (ECAP)	FEI	0.4	n/a	0.3	1507	1659	1829	2010	2210	9216
		FEVI	0.4	n/a	0.3	167	184	203	223	246	1024
		Total	0.4	n/a	0.3	1675	1844	2033	2234	2456	10240
	Low Income Space Heat Top-Ups	FEI	2.9	n/a	3.1	70	77	85	68	54	355
		FEVI	3.0	n/a	3.2	8	9	9	8	6	39
		Total	2.9	n/a	3.1	78	86	94	78	60	394
	Low Income Water Heating Top-Ups	FEI	1.4	n/a	3.3	14	15	16	3	12	69
		FEVI	1.4	n/a	3.3	2	2	2	1	1	8
		Total	1.4	n/a	3.3	15	16	17	15	13	77
	Non-Profit Custom Program	FEI	2.7	n/a	2.0	285	313	344	379	417	1738
		FEVI	2.8	n/a	2.1	32	35	38	42	46	193
		Total	2.7	n/a	2.0	316	348	383	421	463	1931
	Non-Program Specific Expenses	FEI	n/a	n/a	n/a	268	268	268	268	268	1342
		FEVI	n/a	n/a	n/a	37	37	37	37	37	183
		Total	n/a	n/a	n/a	305	305	305	305	305	1525
	All Low Income Programs	**FEI**	**0.9**	**n/a**	**0.7**	**2,307**	**2,524**	**2,723**	**2,869**	**3,123**	**13,545**
		FEVI	**1.1**	**n/a**	**0.9**	**322**	**299**	**319**	**378**	**360**	**1,678**
		Total	**0.9**	**n/a**	**0.7**	**2,629**	**2,822**	**3,042**	**3,247**	**3,483**	**15,223**

Table 2 outlines the FEU's demand-side measures intended specifically to improve the energy efficiency of rental accommodations. These include all of the programs in the FEU's Residential Program Area, as well as several programs in the Commercial Program Area that target rental accommodations.

Table 2: 2014-2018 demand-side measures intended specifically to improve the energy efficiency of rental accommodations

Program Area	Program/ Category	Service Territory	TRC	MTRC	UTC	Projected Expenditure* ($000s)					
						2014	2015	2016	2017	2018	Total
Residential	Energy Efficient Home Performance Program	FEI	1.1	n/a	2.9	1,279	1,354	1,403	1,503	1,652	7,190
		FEVI	1.1	n/a	2.9	126	134	139	149	163	711
		Total	1.1	n/a	2.9	1,405	1,488	1,542	1,651	1,815	7,901
	Furnace	FEI	0.5	1.4	0.9	3,053	3,040	3,040	3,040	3,030	15,202

Program Area	Program/ Category	Service Territory	TRC	MTRC	UTC	Projected Expenditure* ($000s) 2014	2015	2016	2017	2018	Total
	Replacement Program	FEVI	0.5	1.4	0.9	302	301	301	301	300	1,503
		Total	0.5	1.4	0.9	3,355	3,340	3,340	3,340	3,330	16,705
	Enerchoice Fireplace Program	FEI	1.5	n/a	1.0	1,156	1,103	1,051	730	677	4,716
		FEVI	1.6	n/a	1.0	271	259	247	171	159	1,106
		Total	1.6	n/a	1.0	1,427	1,361	1,298	901	835	5,823
	Appliance Service Program	FEI	0.0	n/a	0.0	415	415	415	415	415	2,076
		FEVI	0.0	n/a	0.0	41	41	41	41	41	205
		Total	0.0	n/a	0.0	456	456	456	456	456	2,281
	ENERGY STAR Water Heater Program	FEI	0.6	1.8	1.1	998	1,340	1,105	1,019	1,249	5,711
		FEVI	0.6	1.8	1.1	99	133	109	101	124	565
		Total	0.6	1.8	1.1	1,096	1,472	1,215	1,120	1,372	6,275
	Low-Flow Fixtures	FEI	3.0	n/a	2.8	264	264	264	264	264	1,320
		FEVI	3.0	n/a	2.8	26	26	26	26	26	131
		Total	3.0	n/a	2.8	290	290	290	290	290	1,450
	New Home Program	FEI	0.4	1.1	1.0	943	943	943	714	714	4,256
		FEVI	0.4	1.2	1.0	93	93	93	71	71	421
		Total	0.4	1.1	1.0	1,036	1,036	1,036	784	784	4,677
	New Technologies Program	FEI	0.4	1.0	0.4	239	262	282	305	329	1,416
		FEVI	0.4	1.1	0.4	24	26	28	30	32	140
		Total	0.4	1.0	0.4	262	287	310	335	361	1,556
	Customer Engagement Tool for Conservation Behaviours	FEI	0.9	2.6	0.9	520	635	763	905	1,161	3,984
		FEVI	0.9	2.6	0.9	58	71	85	101	129	444
		Total	0.9	2.6	0.9	578	706	848	1,006	1,290	4,428
	Financing Pilot	FEI	0.0	n/a	0.0	112	174	235	276	309	1,105
		FEVI	0.0	n/a	0.0	0	0	0	0	0	0
		Total	0.0	n/a	0.0	112	174	235	276	309	1,105
	Non-Program Specific Expenses	FEI	n/a	n/a	n/a	491	491	491	491	491	2,457
		FEVI	n/a	n/a	n/a	49	49	49	49	49	243
		Total	n/a	n/a	n/a	540	540	540	540	540	2,700
Commercial	Space Heat Program	FEI	2.5	n/a	3.0	1,347	1,381	1,606	1,606	1,653	7,592
		FEVI	2.6	n/a	3.1	439	450	523	523	538	2,473
		Total	2.5	n/a	3.0	1,786	1,831	2,128	2,128	2,191	10,066

Program Area	**Program/ Category**	**Service Territory**	**TRC**	**MTRC**	**UTC**	**Projected Expenditure* ($000s)**					
						2014	2015	2016	2017	2018	Total
	Water Heating Program	FEI	1.1	n/a	3.9	206	241	244	265	288	1,245
		FEVI	1.2	n/a	4.0	33	38	39	42	46	198
		Total	1.1	n/a	3.9	239	279	283	307	334	1,442
	Commercial Energy Assessment Program	FEI	1.0	n/a	0.7	414	419	438	414	419	2,105
		FEVI	1.0	n/a	0.7	46	47	49	46	47	234
		Total	1.0	n/a	0.7	460	466	487	460	466	2,339
	All Rental Programs	**FEI**	**n/a**	**n/a**	**n/a**	**11,437**	**12,062**	**12,280**	**11,947**	**12,651**	**60,375**
		FEVI	**n/a**	**n/a**	**n/a**	**1,607**	**1,668**	**1,729**	**1,651**	**1,725**	**8,374**
		Total	**n/a**	**n/a**	**n/a**	**13,042**	**13,726**	**14,008**	**13,594**	**14,373**	**68,748**

Table 3 outlines the FEU's EEC education program for students enrolled in schools in their service areas. These include both K-12 and post-secondary in class programs and presentations.

Table 3: 2014-2018 education programs for students enrolled in schools/post-secondary institutions in the FEU's service area

Program Area	**Program/ Category**	**Service Territory**	**TRC**	**MTRC**	**UTC**	**Projected Expenditure* ($000s)**					
						2014	**2015**	**2016**	**2017**	**2018**	**Total**
Conservation, Education & Outreach (CEO)	School Education Program	FEI	0.0	n/a	0.0	648	648	648	648	648	3,240
		FEVI	0.0	n/a	0.0	72	72	72	72	72	360
		Total	0.0	n/a	0.0	720	720	720	720	720	3,600
	All Education Programs	**FEI**	**0.0**	**n/a**	**0.0**	**648**	**648**	**648**	**648**	**648**	**3,240**
		FEVI	**0.0**	**n/a**	**0.0**	**72**	**72**	**72**	**72**	**72**	**360**
		Total	**0.0**	**n/a**	**0.0**	**720**	**720**	**720**	**720**	**720**	**3,600**

240.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

G-44-12-FEU 2012-2013 Revenue Requirements and Rates Decision, p. 183;

Exhibit B-1-1, Appendix F, Attachment F-5, p.4

EEC Incentives For AES Projects

Directive No.80 of the 2012-2013 RRA Decision states (Commission Order G-44-12): "The Commission directs the FEU to hold all EEC incentives that are provided for AES or TES technologies for projects in which the Companies are a participant in a separate deferral account. The recovery of this deferral account will be left to the Panel which hears the next FEU revenue requirements application. That Panel will have a benefit of the Panel's decision in the AES Inquiry."

In Attachment F-5 to Appendix F, FEU states: "FEI will continue accumulating EEC incentive costs relating to AES/TES activities in this deferral account and will propose disposition of this account in its first Annual Review to be held in 2014." (p. 4).

240.1 Please describe the "Annual Review" which FEU makes reference to above.

Response:

The Annual Review is described in Section 6.8 on pages 78-79 of Exhibit B-1.

240.2 Please confirm that in those instances where the Company is providing capital equipment to a project that is receiving DSM or other incentive funds, those incentive funds are being used to reduce the capital costs of the FEU assets.

Response:

The Companies cannot confirm this. On page 88 of its Report on the Inquiry into the Offering of Products and Services in Alternative Energy Services and Other New Initiatives, issued December 27, 2012, the Commission Panel found the following:

"To prevent the possibility of the utility potentially earning a double return, the Commission Panel is of the view that the presumption should be that incentive funds are used to reduce the capital costs of the FEU assets, in those instances where the

> *Company is providing capital equipment to a project that is receiving DSM or other incentive funds. In practice, this will require FEU to rebut this presumption. Where this is not done, the Panel recommends that the costs of these capital assets be reduced prior to being added to rate base."*

Since the Directive above was issued, 2 sets of EEC incentives have been paid to FAES customers: approximately $116,000 to the Delta School District, and approximately $4,000 to Glen Valley. It should be noted that it is the customer that receives the incentive funds, regardless of thermal energy services provider, not FEU or FAES. Those amounts are currently sitting in a deferral account that does not attract the FEU's rate of return, thus none of the Fortis entities are earning a double return. It is the intent of the Companies to bring forward a plan for the disposition of those funds in the first Annual Review in 2014, after consultation with customers, the Commission and other interested parties, as to how to address this Directive.

241.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

G-201-12-FEI Report on AES Inquiry, p.87; Appendix I-4, p. 7

Approval/Administration of DSM And Incentive Funds From Which FEU May Benefit

On page 87 of the Report on the AES Inquiry states: "...the FEU are directed to bring forward a proposal for mechanisms for approval and administration of funds by a neutral third party where the FEU may be involved in providing capital or services to a project receiving DSM or other incentive funds and/or there is a potential for FEU to benefit, either directly or indirectly, from that funding."

Price Waterhouse Coopers' (PwC) proposal is included as Attachment I-4 to Appendix I of the Application. PwC's proposal states: "In addition to third party administration of EEC program activities, 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...The applicable TES incentive programs include: Efficient Boiler Program, Commercial Water Heater Program, and the Commercial Custom Design Programs for New Construction and Retrofit." (page 1)

241.1 Please describe the process FEU undertook to select and engage the proponent (PwC) to develop their proposal? Was the process a competitive bid process?

Response:

PwC are the "fairness advisor" to the Companies' NGT program enabled by the the GGRR. The Companies underwent a competitive bid process in selecting PwC as the fairness advisor to the NGT program. Since the functions of the fairness advisor to the NGT program, and the functions associated with the fulfilling the Commission's directive for third party approval and administration of EEC funds associated with thermal energy projects are very similar, there was no need to go incur the expense and time associated with repeating the competitive bid process.

In the competitive bid process associated with selecting the fairness advisor to the NGT program, FEI issued an RFP, (please refer to Attachment 241.1) and received responses from 3 potential vendors. The vendors were rated on the following selection criteria: understanding and approach to scope of work; expertise (team); comprehensiveness of proposal; experience with similar work; and past performance with FEI. PwC emerged with the highest rating, and was therefore selected as vendor.

241.1.1 Please provide the criteria used to make the selection decision, and indicate the weight given to each criterion.

Response:

The criteria and weighting are provided in the table below.

Scoring Criteria for Fairness Advisor

Fairness Advisor Proposal Scoring	
Understanding and Approach to Scope of Work	30%
Expertise (Team)	20%
Comprehensiveness of proposal	10%
Experience with similar work	20%
Past performance with FEI	10%
Cost	10%

241.2 Has FEU compared PwC's proposed costs for third party program administration to costs in other jurisdictions and industries? If yes, how does PwC's proposal compare?

Response:

No, the Companies have not compared the proposed costs for third party program administration to other jurisdictions and industries. The hourly rate proposed by PwC was found to be competitive in the selection process for the fairness advisor to the NGT program.

241.3 Please provide the terms of reference for the contract between FEU and PwC, including time duration and cost of the contract.

Response:

A contract has not been established for the third party review of EEC incentives for thermal energy services, as the Commission has not yet accepted the Companies' proposal for meeting the Commission directive. However, the time duration would presumably be the same as the test period, and the cost of the contract would be dependent on the number of projects reviewed. An estimate of the Annual Cost Range can be found on page 6 of Exhibit B-1-1, Appendix I, Attachment I4. PwC estimates that the Annual Cost Range for their proposal is $141,300 to $258,300.

241.4 Please describe the process required to assess an application for eligibility to receive EEC funding.

Response:

Program process diagrams are provided in Exhibit B-1-1, Appendix I, Attachment I4, Appendix A – Business Process Diagrams. Please refer to Attachment 241.4 for a copy of these diagrams for your reference.

The process is dependent upon the program to which a customer has applied. Prescriptive programs such as the Efficient Boiler Program tend to have a fairly simple process, while customized incentive programs can be significantly more involved. Generally speaking the process consists of receiving and reviewing the program specific application documents to ensure that all required information has been provided and that the eligibility criteria, terms and conditions have been respected. Where details are unclear or questionable follow up is required in order to obtain clarification. Some programs may require some technical analysis, in which case coordination with qualified individuals is required. Finally a decision to either award an incentive or reject an application is made.

Note that the process to assess a custom incentive can be significantly more involved. In addition to the general tasks discussed above, custom incentives require meetings with participants and their chosen consultants, detailed energy studies, energy study technical reviews and approvals, benefit/cost analysis, customized incentive determination, and in some cases assistance with the development of a measurement and verification plan. Moreover, these projects may undergo a considerable amount of change during both the energy study and implementation stages, especially in the New Construction market, and all changes must be actively managed. Upon completion, the actual costs must be compared to the expected costs, and adjustments made to the incentive as required. Finally each project must generally undergo a post completion project inspection, normally performed via an in person site visit. Any deficiencies must be noted and the incentive adjusted accordingly. Each task in the process requires the investment of a considerable amount of effort in due diligence and in coordinating with all parties involved, including the participant, the participant's consultant, utility partners, and 3rd party technical reviewers.

241.4.1 Please justify why PwC have proposed an annual level of effort per applicant of (i) 6.5 for Commercial Custom Design Program-New Construction and (ii) 12 days for funding from the Commercial Custom Design Program-Retrofit.

Response:

As noted on page 6 of Exhibit B-1-1, Appendix I, Attachment I4, these are estimates of the level of work required, and are based upon PwC's experience in delivering similar programs. Should the Commission accept the FEU's proposal for third party review of EEC incentives for thermal energy services, and the FEU engage PwC in this capacity, contract terms will state that PwC will bill only for actual time spent on review, not on these estimates.

241.5 Please describe ways FEU can reduce the estimated annual costs of PwC's proposed services while still achieving the direction of the AES Inquiry.

Response:

At this time, without the benefit of understanding what actual costs will be incurred and without any experience in administering the process, the Companies are unaware of any ways of reducing costs associated with meeting this Commission directive.

241.6 Does PwC's proposal relate to the approval and administration of EEC programs, including the administration of incentives and grants, for all projects involving a TES provider, whether that provider is FEI/FEVI/FEW/FAES or a third party?

Response:

Yes. In the interests of fairness and transparency, to ensure that EEC funds are being distributed consistently to projects involving a thermal energy services provider, regardless of whether the thermal energy services provider is FAES or a third party, the Companies are proposing that all EEC applications with a third party thermal energy services component be reviewed. Should the Commission accept the proposal for third party review, the FEU will start to ask EEC commercial program applicants up front whether their project either has in place or contemplates third party ownership of thermal assets.

241.6.1 Please confirm that under PwC's proposed mechanism, customers would apply directly to PwC for funding for their eligible project.

Response:

The program flows can be found in Appendix A to to PWC's proposal (Exhibit B-1-1, Appendix I, Attachment I4). The entity to whom the customer applies varies from program to program. In the case of the Custom Design Program for New Construction, the customer applies to BC Hydro. In the case of the Custom Design Program for Retrofits, the customer applies to PwC. In the case of the Efficient Boiler Program, it is contemplated that the customer would speak first with a FortisBC Energy Solutions Manager, then if it is discovered that the boiler project was going to be incorporated into a thermal energy project, the customer would then deal with PwC who would confirm that the project meets the program terms and conditions and determine the incentive amount. Similarly, in the case of the Residential New Homes Program, it is contemplated that if an applicant is going to be involved in a thermal energy project, the customer would then deal with PwC who would then confirm that the project meets the program terms and conditions and determine the incentive amount.

241.6.2 How does PwC's proposal ensure that customers will not be biased towards selecting FEI/FEVI/FEW/FAES as the service provider for their eligible project?

Response:

As customers may have a previous "bias" or preference for a thermal energy services provider for their project, either towards or against FAES, the Companies interpret the question to mean "how does PwC's proposal ensure that customers will not be <u>influenced</u> towards selecting FAES as the service provider for their eligible project".

The Companies were directed by the Commission to bring forward a proposal for approval and administration of funds by a neutral third party where EEC incentive funds might be distributed to a project where FAES might be the thermal energy services provider. The PwC proposal meets this directive. As can be seen in Appendix D to Exhibit B-1-1, Appendix I, Attachment I4, the individuals involved in the proposal have previous experience in the third party administration of various programs and funds, some of which activity is ongoing. The FEU do not consider it reasonable to suggest that PwC would inappropriately influence program outcomes

241.6.3 Does PwC propose to administer each of four identified Programs in their entirety, or just those projects within the program that have a TES service provider component?

Response:

PwC's proposal is to administer each of the four identified programs for just those projects within the program that have a thermal energy services provider component, regardless of who that provider is, not for the programs in their entirety.

241.6.4 Please explain how FEU may be involved in providing capital or services to a project receiving DSM or other incentive funds and/or there is a potential for FEU to benefit, either directly or indirectly, from that EEC funding for each of the four programs identified in PwC's proposal.

Response:

FAES (not the FEU) may provide capital or thermal energy services to a project receiving DSM funds. The PwC proposal is intended to ensure that there is a "level playing field" for customers to benefit equally from access to EEC incentive funds for projects where there is a thermal energy services component, regardless of thermal energy services provider.

241.6.5 Are there any additional programs within FEU's proposed EEC portfolio that were not identified by PwC, but may have projects where there could be the potential for FEU to be involved in providing capital or services to a project receiving DSM or other incentive funds and/or where there is a potential for FEU to benefit, either directly or indirectly, from that funding? If yes, please identify them. Of those identified, please indicate which of these have a TES component, and which of these do not.

Response:

No. The four programs outlined in the PwC proposal are the programs that have the potential to include projects where FAES or other third party thermal services providers may be involved in the provision of capital or services to such projects. Should the Companies find that other programs involve projects with thermal energy services elements, projects in those other programs would also be subject to neutral third party review, regardless of thermal energy services provider.

241.7 Please explain why FEU has engaged PwC for an annual review of all EEC program activities involving a third party TES provider completed within the past two years. Please include in your response the benefit FEU anticipates from this annual review.

Response:

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 <u>subsequently</u> become part of a thermal energy services provider's project, and the two year time period is required as a result of the two directives below. In the Commission's Decision on the FEU 2012-2013 RRA, Directive 80 on page 14 of Appendix A to the Decision stated:

> *"The Commission directs the FEU to hold all EEC incentives that are provided for AES or TES technologies for projects in which the Companies are a participant in a separate deferral account. The recovery of this deferral account will be left to the Panel that hears the next FEU revenue requirements application. That Panel will have the benefit of the Panel's decision in the AES inquiry."*

Further, in the Commission's 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, dated May 11, 2012, the Commission writes:

> *"In the second point of clarification, the FEU note that not all EEC distributions can be immediately associated with projects in which an FEU company is a participant. As such, the FEU propose that funds should be held in accordance with the Decision for up to one year from the point EEC funds are issued for projects that are or become part of a TES or AES project. On this point of clarification, the Commission acknowledges that these projects are not 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…"*