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August 23, 2013

Via Email
Original via Mail

British Columbia Public Interest Advocacy Centre
Suite 209 – 1090 West Pender Street
Vancouver, B.C.
V6E 2N7

Attention: Ms. Tannis Braithwaite, Acting Executive Director

Dear Ms. Braithwaite:

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 Public Interest Advocacy Centre on behalf of the British Columbia Pensioners' and Seniors' Organization *et al* (BCPSO) 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 BCPSO IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc: Commission Secretary
Registered Parties (e-mail only)

1.0 Reference: Exhibit B-1, page 40, Table B5-1 and page 42 (lines 3-10)

Preamble: Exhibit B-1, page 42:

"The Alberta Utilities Commission (AUC) PBR initiative as well as the Ontario Energy Board (OEB) renewed regulatory framework for power distributors, which were applicable to a number of utilities, were resolved by hearing."

1.1 Please clarify the nature of the Regulatory Proceeding associated with the OEB 4th Generation IR (Electricity) plan (Exhibit B-1, page 42). Was there a formal "hearing" before a panel of the Board?

Response:

The regulatory proceeding for the development of the OEB's 4th Generation IR framework was an OEB coordinated consultative process that included extensive stakeholder consultations, roundtables, conferences and written comments to determine the specific mechanics of the renewed regulatory framework for electric distributors. A written hearing was used to determine cost award matters such as cost eligibility and claims in relation to consultation activities for all eligible participants.

A timeline showing the steps in this regulatory proceeding can be found in the following link: http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory%20Proceedings/Policy%20Initiatives%20and%20Consultations/Renewed%20Regulatory%20Framework

2.0 Reference: Exhibit B-1-1, Appendix D1, pages 14 and 16

Preamble: Exhibit B-1-1, Appendix D1, page 14:

"The values for the productivity factor and stretch factor are not yet determined although a study has been filed and a decision for outstanding issues is due for mid-2013."

Exhibit B-1-1, Appendix D1, page 16:

"the OEB will engage stakeholders in further consultation on establishment of an "efficiency carry-over mechanism" in due course."

2.1 Please provide a copy of the study referenced in Exhibit B-1-1, Appendix D1, page 14 (last paragraph/last sentence).

Response:

The mentioned study can be found in the OEB's website under the following link:
http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/EB-2010-0379_PEG_Report_20130503.pdf

Please note that this report was later revised slightly. The link below includes the red-lined version of the revised report:
http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/PEG_Report_to_OEB_4Gen_%20IR_redline_20130531.pdf

2.2 Apart from the "efficiency carry-over mechanism", were there any other PBR-related regulatory mechanisms that the OEB indicated it would be engaging stakeholders on in due course (Appendix D1, page 16).

Response:

Page 61 of the OEB's "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" report states:

"Additional regulatory mechanisms may be necessary to achieve the objectives of the renewed regulatory framework. The Board will engage stakeholders in further consultation on the following in due course:

- *The establishment of an "efficiency carry-over" mechanism;*

- *Development of incentives to;*
  - *reward superior performance;*
  - *encourage innovation;*
  - *encourage asset optimization; and*
- *Potential consequences for inferior performance."*

In addition, the determination of X-factor and stretch factor values as well as the composite inflator was planned for mid-2013.

3.0 Reference: Exhibit B-1, Appendix D2, pages 1-2 and 10

Exhibit B-1, Appendix D9-3, pages 59-60

Preamble: Appendix D2, page 1:

"TFP is simply a measure of how efficiently a firm converts total inputs into total outputs."

Appendix D2, page 2:

"The analysis of TFP measures how efficiently the firm's output changes as the inputs are changed. TFP is positive when output changes faster than input and is negative when inputs change faster than output."

Appendix D2, page 2:

"A negative TFP means that costs are rising faster than inflation and a positive TFP means cost are changing slower than inflation."

Appendix D2, page 10:

"For each of the measures, input and output, the annual change is calculated and the difference between the changes represents the TFP for each particular output measure.

Appendix D9-3, page 59:

"In its report, NERA explained that productivity growth for a particular firm, by definition, is the difference between the growth rates of a firm's physical outputs and physical inputs."

Appendix D9-3, page 60:

"Accordingly, the Commission agrees with NERA that, in these circumstances, the purpose of the TFP study is to estimate the long term productivity growth of the industry in question."

3.1 Does FEI agree that TFP growth represents the difference between the growth rates of a firm's (or industry's) physical outputs and its physical inputs? If not, what does TFP growth represent?

Response:

B&V provides the following response.

TFP in its most formal economic definition measures the growth in output not accounted for by the growth in inputs. In the context of the TFP analysis for estimating the X-Factor, the measure is the difference between the rate of growth in outputs minus the rate of growth in inputs as we have defined it in the TFP Report in Appendix D-2.

3.2 Does FEI also agree that TFP growth can be represented as:

TFP Growth (%) = Physical Output Growth (%) – Physical Input Growth (%)

If not, please provide a similar formulaic representation of what FEI considers TFP growth to represent.

Response:

Yes. Please refer to the response to BCPSO IR 1.3.1.

3.3 Please reconcile the two statement referenced above from Appendix D2 (page 2) as each appears to provide a different definition of TFP.

Response:

B&V provides the following response.

Neither of the two statements is a definition of TFP but rather an explanation of the impact of TFP as it relates to the costs of providing utility service. Please also refer to the response to BCPSO IR 1.3.4.

3.4 Please explain how "negative TFP means that costs are rising faster than inflation and positive TFP means that cost are rising slower than inflation"?

Response:

B&V provides the following response.

These are just mathematical conclusions based on the logic of TFP. If we assume constant input prices and the quantity of inputs rises then mathematically costs increase faster than the rate of inflation because prices were assumed to be constant to illustrate this point. Likewise the opposite is also true.

4.0 Reference: Exhibit B-1, page 51

4.1 Please provide the actual values used to create Figure B6-1 and the references supporting each value.

Response:

The table below includes the actual TFP values and their respective references used to create Figure B6-1.

State/ Province	Utility	Sector	Term	Measured TFP	Reference
CA	PacifiCorp	Electric	2011-13	0.50%	Decision 10-09-010
CA	Sierra Pacific Power	Electric	2009-11	0.50%	Decision 09-10-041
CA	San Diego Gas and Electric (SDG&E)	Gas	2000-02	2000-1.08% 2001-1.23% 2002-1.38%	Decision 99-05-030
CA	SDG&E	Electric	1999-2002	2000-1.32% 2001-1.47% 2002-1.53%	Decision 99-05-030
MA	Berkshire Gas	Gas	2004-11	0%	Docket D.T.E. 01-56
MA	NSTAR	Electric	2006-12	0%	Docket D.T.E. 05-85
MA	Boston Gas	Gas	1997-2001	0.50%	Docket D.P.U. 96-50-C (Phase I)
ME	Bangor Gas	Gas	2000-12	0%	Docket 970795
ME	Central Maine Power	Electric	2009-2013	1.0%	Docket 2007-215
ME	Central Maine Power	Electric	2001-2007	2.0%-2.9%*	Docket 99-666
Ontario	All utilities	Electric	2010-2013	0.72	EB-2007-0673
Ontario	All utilities	Electric	2000-2003	1.25%	RP-1999-0034
Ontario	All utilities	Electric	2006-2009	1.00%	EB-2006-0089
Ontario	Union Gas	Gas	2001-2003	1.10%	RP-1999-0017
CA	SoCAL Gas	Gas	1997-2002	1.50%	Decision 96-09-092

* Gradual increase over the 8 years term of the plan.

Please refer to Attachment 4.1 for the working excel spreadsheet of this table as well as the calculations that are used to construct the Figure B6-1.

4.2 What difference (if any) is there between "approved TFP" (used in the title of the Figure) and "measured TFP" as used in the legend for the Figure? Are these the TFP (X-factor) values approved for use in PBR plans or the measured TFP values calculated as input into the determination of the X-Factor for various PBR plans?

Response:

In the context of Figure B6-1 there is no difference between the approved and measured TFP values. These are the TFP values approved by the regulators either as the approved X-factor value (where TFP equals X-factor) or as a part of the approved X-factor value (in case the X-factor also includes an additional stretch factor).

4.3 Please identify those US gas transmission/distribution utilities that are currently operating under PBR plans and indicate the approved X-Factor for each. Note: In those cases where there is an approved "stretch factor" as well as X-Factor, please also report the Stretch Factor.

Response:

Based on the Commission's staff letter dated April 18, 2013 our survey for active PBR plans was limited to Canadian distributors. Given the number of gas utilities in the U.S., FEI may not be aware of all the active PBR plans in the US gas industry. Please refer to the response to BCPSO IR 1.4.1 for a list of US utilities with active PBR plans between 2000 and 2012. Please also refer to Attachment 4.3 for a copy of the April 18, 2013 letter.

5.0 Reference: Exhibit B-1, page 48 (lines 23-24) and page 52 (lines 13-15)

5.1 Specifically what were the business conditions that FEI expected would "affect BC's natural gas utility industry during the PBR term" (page 48)?

Response:

In the context of the X-factor determination, the review of business conditions is specifically related to those conditions that affect FEI's output measures (customers and capacity) as defined by the B&V TFP report in Appendix D-2 of the Application. Input business conditions are expected to be reflected by the proposed I-Factor.

5.2 What business conditions are expected to be the same during the period used to measure TFP (2007-2011) and during the term of the PBR plan (2014-2018), per page 52? In particular, please address the extent to which the economic conditions (e.g. GDP growth) are expected to be the same in the two periods.

Response:

The business conditions related to output measures, namely customers and capacity are expected to be relatively the same in the two periods. For instance, the growth rate of customer additions during the 2007-2011 period is similar to the forecast rate of customer additions during the PBR period (with the expected growth rate during the PBR term slightly lower). Input conditions are expected to be reflected by the proposed I-Factor.

FEI did not claim that the economic conditions such as GDP growth are expected to be the same (but rather business conditions specific to BC's natural gas utility industry). B&V indicates that, since FEI's output measures are not related to volumetric indices (as opposed to AUC TFP calculation), the macro economic conditions do not have the same material impact on FEI's productivity as measured by capacity as the output.

6.0 Reference: Exhibit B-1, page 49 (lines 7-9)

Exhibit B-1, page 47 (lines 14-16)

6.1 Does FEI consider its proposed inflation factor to be representative of input price escalation for the natural gas transmission/distribution industry or, in principle, should the X-Factor for the proposed plan also include an adjustment "for any difference between the inflation index used in the PBR index formula and the rate of inflation for the regulated sector" (page 49)?

Response:

B&V provides the following response.

The inflation factor or the I-Factor under PBR is an estimate of the expected price increases associated with inputs for the LDC. That factor has both a general inflation component and a labor inflation component designed to track the price increases expected by FEI. In general, the I-Factor may be a general measure of inflation or a utility specific measure based on actual utility input cost changes. Since a general index of inflation will not precisely match the actual inflation for utility inputs some econometric studies develop an adjustment for the difference between the general index of inflation and the actual inflation rates for the utilities in the TFP study. In essence, this estimated difference is an attempt to develop an industry specific measure of inflation defined as the sum of the general inflation and the calculated adjustment factor. Under this method, the adjustment factor would be added to the X-Factor along with the TFP estimate and if applicable a stretch factor. Since we are using the composite inflator that tracks input price increases the adjustment is not required.

6.2 What was the average annual rate of growth in FEI's proposed inflation factor (page 47) over the period 2007-2011? Please provide a supporting schedule setting the calculation of the historical annual increases for this period.

Response:

The average annual rate of growth in FEI's proposed composite inflation factor over the period 2007-2011, using the same methodology that was applied to determine the composite inflation factor for the proposed PBR from 2014-2018, is summarized in the table below:

FEI Net O&M (Formula Based)	2006	2007	2008	2009	2010	2011
BC-AWE	2.90%	3.41%	2.56%	0.81%	2.80%	1.50%
BC-CPI	2.20%	2.00%	2.20%	2.00%	1.40%	2.30%
Labor	55%	55%	55%	55%	55%	55%
Non-Labour	45%	45%	45%	45%	45%	45%
Composite I-Factor	2.59%	2.78%	2.40%	1.34%	2.17%	1.86%

1

2

7.0 Reference: Exhibit B-1, page 52 (lines 21-27)

Exhibit B-1-1, Appendix D2, page 10

7.1 Please provide documentation that clearly explains the "Kahn" methodology.

Response:

Please refer to the response to CEC IR 1.81.18 which includes the testimony of Alfred E. Kahn.

7.2 Please clarify, if not done so in response to the previous question, whether the "expenses" that were deducted from Operating Revenue in the Kahn methodology were just O&M expenses and Gas costs or whether they also included depreciation (page 52, lines 23-25).

Response:

B&V provides the following response.

The Kahn method applied to oil pipelines so there was no gas costs included in the operating expenses. The measure operating expenses includes both O&M and General expenses (See FERC Form 6). Depreciation expense is recorded in General Expenses as account 540.

7.3 Please indicate how the Kahn methodology was used in setting the price cap index for the oil pipelines regulated by FERC. In doing so, please confirm whether:

a) The Kahn methodology was used to establish the historical annual increase in costs (per unit of output) for the industry,

b) The historical differential between cost escalation for the industry and escalation in the Producer Price Index for Finished Goods (PPI-FG) was determined, and

c) The price cap formula was then based on the future escalation in the PPI-FG index less the differential.

If not, how was it used?

Response:

B&V provides the following response.

The Kahn Method was used to determine the X-Factor in the formula for the price cap applicable to oil pipelines.

Items (a), (b) and (c) are confirmed.

7.4 Did the price cap formula used by FERC for the oil pipeline industry include both an inflation factor and an X-factor?

Response:

Yes. The FERC price cap formula includes both an inflation factor (Producer price index for finished goods or PPI-FG) and an X-factor. For further information on the X factor please refer to the response to BCPSO IR 1.7.3.

7.5 Does FEI consider the input price increases it experienced during the 2007-2011 period to be similar to those experienced by the US gas utilities used in B&V's study over the same period? If not, were FEI's experienced input price increases higher or lower and why?

Response:

There has been no study of the input price increases for FEI since FEI was not part of the sample. B&V explains that the differences between the escalation of prices would not inform the analysis of TFP since the PBR Plan uses local measures of inflation that would not necessarily apply to the US sample of gas LDCs. The essential element of the TFP Report is that the TFP measures productivity not absolute price changes.

8.0 Reference: Exhibit B-1-1, Appendix D2, Schedule 2

8.1 Did B&V review the reasonableness of the data before using it in the TFP analysis?

Response:

Yes.

8.2 A number of utilities (e.g. Alabama Gas, Atlanta Gas Light and Baltimore Gas) report year over year decreases in installed capacity. Please explain how such decreases could occur.

Response:

B&V provides the following response.

This could occur where the infrastructure replacement is determined on the basis of expected future loads and a pipe segment and a smaller size of pipe is adequate based on the impact of any number of external factors such as conservation, zoning changes, building code changes, and so forth. For example, there are a number of cases where old manufacturing sites in urban areas have been converted to condominiums with a substantial reduction in design day load requirements. This would result in smaller diameter pipe being able to serve the load and a reduced cost for customers.

8.3 Please provide Schedule 2 in a working Excel file.

Response:

Please refer to the response to CEC IR 1.81.1.

9.0 Reference: Exhibit B-1-1, Appendix D2, Schedule 2

9.1 Please confirm whether the values reported in column H include O&M costs and Gas Commodity costs but not Depreciation expense.

Response:

B&V provides the following response.

Column H includes all expenses including depreciation and gas cost.

9.2 Please confirm that column Z is a measure of the change in total costs, including the impact of both inflation (i.e. increases in the price of inputs) and changes in the quantity of inputs used. If not, please explain why not and what it does provide a measure of.

Response:

B&V provides the following response.

The value in column Z includes the items in question as well as changes in the quality of inputs.

9.3 Please confirm that Columns AD, AF and AG represent the difference between the change in physical output (measured various ways) and the change in costs (including the impact of both changes in physical inputs and change in the cost of inputs). If not, please explain why not and what the columns do represent.

Response:

B&V provides the following response.

Please refer to the response to BCPSO IR 1.9.2. These columns represent the differences between composite measures of outputs and inputs.

9.4 Please explain how/why the values calculated in Columns AD, AF and AG are consistent with the definition of TFP as used in the PBR formulation set out at Exhibit B-1, page 32.

Response:

Please refer to the response to BCPSO IR 1.9.3.

9.5 Wouldn't incorporating a TFP factor based on the results from Columns AD, AF or AG into a PBR formula that also included a inflation factor result in double counting the impact of inflation? If not, why not?

Response:

B&V provides the following response.

No. The measures are an ex-post composite measure of inputs and outputs and as such do not include a measure of inflation.

10.0 Reference: Exhibit B-1, Page 32, lines 6-9

Preamble: In lines 6-9 of page 32, FEI states:

"PBR plans (both price cap and revenue cap) are typically further categorized into two subgroups based on their rate base assessment methodology and the role of (I–X) mechanism in forecasting their costs. These are termed the "building-block" approach and the "total expenditure" approach."

The BCPSO requires an understanding of how the proposed PBR model is used in other jurisdictions.

10.1 Please provide a list of other jurisdictions where such a building block approach is used. In the response, please provide referenced to actual decisions and dockets where the concept was discussed and approved.

Response:

Extensive work would be required to determine which plans in other jurisdictions fit the building block approach, since each would have to be reviewed in detail to make this assessment. However FEI is aware of the following. FEI's previous PBR plans which were approved by the Commission are based on a building-block approach, meaning that the capital and operational expenditures were treated in two different blocks. The OEB's 4th Generation IR includes an option called "Custom incentive rate-setting" under which customized PBR plans such as the building-block approach are allowed. Most recently Enbridge Gas applied this option to its current PBR application and proposed a building-block approach.

The 2009 report commissioned by the European Commission and prepared by KEMA consultants indicates that in the case of European natural gas transmission operators the majority of regulators used the various forms of building-block approach (Page 44, Table 6)[1]. Both Australia and New Zealand use the building block approach for both gas and electric utilities.

[1] http://ec.europa.eu/energy/gas_electricity/studies/doc/gas/2009_12_gas_transmission_and_balancing_annex_fact_sheets.pdf

11.0 Reference: Exhibit B-1, PBR Principles, Section B-6.1

Preamble: In Section B-6.1 of its Application, FEI discusses five principles of PBR. The BCPSO requires information to understand the intent and purpose of the FEI principles.

11.1 Please confirm that one of the purposes of a PBR is to break the direct link between revenues and costs. If not confirmed, please fully explain.

Response:

More precisely, the purpose of PBR is to break the link between prices and costs. The level of revenue is another matter separate and apart from the PBR Plan. As has been noted the PBR Plan must still provide a reasonable opportunity for the utility to earn the allowed return which also includes the revenue component. Failure to provide that opportunity would not result in just and reasonable rates even though PBR makes pricing independent of costs.

11.2 Please confirm that, under cost of service regulation, there is an incentive to increase rate base. If not confirmed, please fully explain.

Response:

FEI is aware of the economic theory that suggests that there is an incentive to increase rate base if the allowed return exceeds the market cost of capital over time. In practice, FEI does not believe this incentive exists as suggested. FEI believes that the prudence test and the used and useful test as well as competitive rate pressure all act as a clear disincentive for excess investment. Cost of service regulation in the context of FEI has led to prudent investment to expand and maintain its system.

11.3 Please confirm that one of the principles of PBR is to emulate the incentive forces that are experienced under a competitive market in order to improve efficiencies. If not confirmed, please fully explain.

Response:

In the Alberta PBR proceeding, the AUC identified the emulation of competitive market forces, to the greatest extent possible, as a principle for their PBR Plan in AUC Decision 2012-237. Specifically, Principle 1 on page 7 of AUC Decision 2012-237 reads:

> *"A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market quote"*

FEI considers the emulation of incentive forces under competitive market conditions to improve efficiencies as more of a result of a comprehensive PBR plan than a principle. PBR effectively decouples prices from the cost of service and therefore creates the intended PBR incentives for utilities to optimize the various inputs of production to operate efficiently, similar to firms in competitive markets. However, certain regulatory safeguard mechanisms that are essential to PBR plans, (such as deferrals, SQI's and off-ramps), do not conform to competitive market behavior. Therefore, FEI believes that emulating efficiency incentives as those experienced in competitive markets, to the greatest extent possible, is implicit in a comprehensive PBR plan.

11.4 Please confirm that, under PBR, one of the intents is to provide an incentive for the utility to optimize the various inputs of production, including operating versus capital. If not confirmed, please fully explain.

Response:

B&V provides the following response.

Theoretically, this may be the case. However, as a practical matter this cannot be confirmed. There are at least three issues that make this view incorrect as it relates to utility regulation. The first issue is the issue of sunk costs. Prior decisions that represent sunk investment in capital cannot be changed after the fact regardless of the efficiency of the decision based on current prices. In this case, there may be a more efficient combination of input resources available with current technology and prices but the implementation of that efficiency would increase not decrease costs because of the sunk costs involved in the system. The second issue is the lumpy nature of capital investment. Given the sunk cost nature of capital investments just discussed, a utility will not acquire just the current efficient level of a productive input. Instead, the utility will invest in the input based on the expected life and potential changes in the output requirements in the future related to this investment. Third, as noted above, the existence of regulation does not guarantee an efficient firm the market based cost of capital. Therefore, the efficient level of capital may not be used even under PBR. All of this contrasts

with outcomes under the competitive model where there are no sunk costs, no lumpy investments and the market cost of capital is earned in equilibrium. It is for this reason that theoretical models of economics cannot be easily applied to regulated industries. In the real world certain basic assumptions do not apply. In the context of PBR, utilities are encouraged to make efficient decisions related to actions at the margin where the utility controls the decision as to all of the factors of production. This is not a global efficiency but a relative efficiency.

11.5 If item 1.4 above is confirmed, please fully explain how the FEI PBR proposal provides the incentive to FEI to optimize the various inputs of production, including operating versus capital.

Response:

Under the proposed five-year PBR plan, rates are set annually to recover the set level of expenditures prescribed by the PBR formula for the given year. Each year the component of rates designed to recover O&M and Capital expenses will adjust the previous years' amount by the PBR formula which includes a productivity factor. With the utility's prices separated from the cost to provide service, an incentive is created for the utility to improve efficiencies via cost reductions and other measures in the context of meeting SQIs and providing reliable service. To the extent savings that result from efficiency measures are reflected in an ROE higher than the allowed, they will be shared with the customer over the PBR term. Please also refer to the response to BCPSO IR 1.11.4.

11.6 Please fully explain how FEI proposes its principles be used in evaluating the FEI PBR plan as applied for.

Response:

FEI proposes its principles be used as a guide in evaluating the FEI PBR plan as applied for. FEI's objective is to achieve the principles to the extent reasonably possible. B&V believes that all of the general principles and objectives that have been articulated in testimony, reports and academic literature are relevant to and inform the discussion of any PBR Plan (refer to the response to BCUC IR 1.2.2). B&V also believes that the principles articulated by FEI represent the most complete set of standards for assessing the FEI Plan based on FEI's prior experience with successful plans.

12.0 Reference: Exhibit B-1, FEI Application, page 45, lines 24 and 25

Preamble: In lines 24 and 25, FEI discusses an annual review process and a midyear review process. The BCPSO requires an understanding of the differences between the annual and midterm processes.

12.1 Please fully explain the differences between the annual review and midterm review that FEI would envision.

Response:

The Annual Review is discussed in detail in Section B6.8 (pages 78 and 79) of the Application. There are two main purposes of the Annual Review. First, the Annual Reviews will have the purpose of reviewing the results of PBR for the current year, including, among other things, projected financial results and earnings sharing, and FEI's performance with respect to the service quality indicators. Secondly, the Annual Reviews will have the purpose of setting rates for the coming year. Delivery rates will be set according to the I-X provisions affecting O&M and capital expenditures and forecast flow-through items, as well as any exogenous factors that are brought forward to be considered in the Annual Review and approved by the Commission.

The Mid-term Review is discussed in detail in Section B6.7.1 (pages 76 and 77) of the Application. The following quote from Section B6.7.1 describes the intent of the Mid-term Review

> *"The Mid-term review as part of the third Annual Review is intended to be a "checkpoint" to permit stakeholders to review the performance over the first three years and to address specific and discrete flaws with an otherwise workable plan. This limitation is important. Off-ramps exist for more fundamental flaws with the PBR Plan as a whole, and short of triggering those off-ramps, the PBR Plan should be allowed to play out unless there is consensus that an element of the plan is capable of being improved for the mutual benefit of stakeholders."*

The Annual Review can therefore be characterized as a key element of the normal yearly cycle of setting rates and communicating with customers about how the PBR is unfolding. The Mid-term Review is more of a high level review of the performance of the PBR during the first three year with an opportunity to "tweak" the plan if unforeseen circumstances or issues can be resolved to the mutual benefit of customers and the Company.

12.2 In the response, please fully explain why a midterm review is needed given that there is an annual review.

Response:

As described in the response to BCPSO IR 1.12.1 FEI believes the Mid-term Review serves a different purpose than the Annual Review. On this basis FEI believes the Mid-term Review should be included in the PBR Plan as a separate element from the Annual Review process.

13.0 Reference: Exhibit B-1, FEI Application Section B-6.2.2.1, I Factor

Preamble: In Section B-6.2.2.1 of its Application, FEI discusses its proposed I-Factor. FEI proposes a weighted I-Factor with a weighting of 55% of BC Average Weekly Earnings (AWE) and 45% of BC CPI. AWE are to represent labour input costs, and CPI is to represent the cost of labour, and CPI is to represent the cost of non-labour. BCPSO is aware of the Electric Utility Construction Price Index (EUCPI) for electric utilities. The BCPSO requires information to understand the choice of indices and the weightings.

13.1 Is FEI aware of any gas utility construction price indices such as EUCPI for electric utilities? If so, please provide the indices and the data for 2011, 2012, 2013 and forecast for 2014.

Response:

FEI is not aware of a gas utility construction price index that exists for natural gas utilities, such as the Electric Utility Construction Price Index (EUCPI) that exists for electric utilities.

13.2 Please provide actual labour and supplies for 2008-2012 for each of O&M and Capital, and the calculation of actual ratio of labour and non labour input costs.

Response:

Provided below is a breakdown of O&M and Capital Expenditures into actual labour and non-labour for 2008-2012. The O&M split can be found in Exhibit B-1-1, Appendix F6.

O&M Summary ($ thousands)

	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual
Labour	82,641	88,318	94,443	98,084	122,163
Non-Labour	103,098	103,628	112,075	115,522	97,541
Total	185,739	191,946	206,518	213,606	219,704

	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual
Labour	44.5%	46.0%	45.7%	45.9%	55.6%
Non-Labour	55.5%	54.0%	54.3%	54.1%	44.4%
Total	100%	100%	100%	100%	100%

Capital Summary ($ thousands)

	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual
Labour	20,039	20,849	20,045	21,633	26,008
Non-Labour	70,012	70,118	66,242	81,977	82,413
Total	90,051	90,967	86,287	103,610	108,421

	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual
Labour	22.3%	22.9%	23.2%	20.9%	24.0%
Non-Labour	77.7%	77.1%	76.8%	79.1%	76.0%
Total	100%	100%	100%	100%	100%

As indicated in the Application, FEI utilized the 2012 O&M figures to determine the ratio as it was reflective of the figures used in the AUC proceeding and tends to have less variability than the capital ratio. In addition, the capital figures tend to include a much greater percentage of contract labour which although included in the non-labour line above, are also be expected to be subject to similar labour inflation as the BC-AWE. The data shows that the ratio of labour and non-labour are fairly consistent from 2008 to 2011 for O&M. The increase in O&M labour for 2012 is mainly due to the repatriation of the Customer Care department and therefore reflects the structure going forward into the PBR period.

14.0 Reference: Exhibit B-1, FEI Application, Figure B6-1

Exhibit B-1-1, FEI Application, Appendix D, Black and Veach &V) Report

Preamble: In Figure B6-1 of its Application, FEI provides TFP Values for the period 2000-2012. The BCPSO requires information to understand the TFP.

14.1 Please fully explain why Figure B6-1 only starts in the year 2000.

Response:

The data in Figure B6-1 was taken from B&V's survey of TFP studies. B&V provides the following response.

As discussed elsewhere, the latest TFP studies represent a more relevant time frame to review.

14.2 Please provide a table similar to Figure B6-1 that contains data for each year from 1980-2000

Response:

FEI cannot provide a similar figure for the period between 1980 and 2000. FEI's position regarding the downward TFP trend is related to the more recent period. In addition, B&V notes that the use of PBR plans and TFP studies for determination of X-factor for natural gas and electricity utilities were rare in North America during the 1980s and that the majority of the related PBR plans were started after 1995.

14.3 Please provide a list of other TFP studies conducted by B&V for regulated utilities, including the proceeding that the study was filed in.

Response:

Please refer to the response to CEC IR 1.81.3.

15.0 Reference: Exhibit B-1, FEI Application, Section B-6.2.4, O&M under PBR

Preamble: In Section B-6.2.7 of its Application, FEI provides a discussion of O&M costs. In Table B6-4, FEI provides a reconciliation of 2013 Decision O&M. The BCPSO requires information to assess the adjustments to O&M

15.1 Please provide a detailed analysis of the costs included in Sustainable Savings of $14,670,000.

Response:

Please refer to the response to BCUC IR 1.83.1.

15.2 Please provide the amount of (i) PST, (ii) BCUC Fees and Insurance, and (iii) Pension (O&M Portion) that is already included in the 2013 Decision O&M of $213,003,000.

Response:

To clarify, as shown in Table C3-1 of this Application, the 2013 Approved Gross O&M is actually $236,003,000.

The 2013 Approved O&M includes $0 for PST expenses as the 2012-2013 Revenue Requirement Application included HST which is a flow-through tax and not an additional cost to the utility. The amount shown in Table B6-4 for PST of $762 thousand relates to a full year impact of PST that will be incurred in 2014 O&M costs whereas nothing was approved in 2013 O&M costs.

The 2013 Approved O&M includes $1.404 million related to BCUC Fees and $4.617 million related to Insurance. The $1.016 million shown in Table B6-4 for BCUC Fees & Insurance costs represents expected actual costs incurred and recorded to deferral accounts in 2013 over and above the amounts approved in 2013 O&M.

The 2013 Approved O&M includes $15.638 million in Pension & OPEB expenses as shown in Table C3-4 of this Application. The $10.605 million shown in Table B6-4 for Pension (O&M Portion) represents the O&M portion of expected actual costs incurred and recorded to deferral accounts in 2013 over and above the amounts approved in 2013 O&M.

15.3 Please provide a reconciliation of the amounts included in Table B6-4 and in response to 5.2 above.

Response:

Please refer to the response to BCPSO IR 1.15.2.

16.0 Exhibit B-1, FEI Application, Figure B6-2

Preamble: FEI provides Figure B6-2, that contains a comparison of PBR O&M and Forecast O&M. The BCPSO requires information to assess the forecasts, and understand the impact of PBR on forecast costs.

16.1 Please provide the actual data for the years 2008-2012 for Figure B6-2.

Response:

In the course of responding to this IR, a minor discrepancy was noted between the Forecast O&M in Figure B6-2 and the Forecast O&M in Table C3-5 of page 133 of the Application. As Table C3-5 reflects the accurate Forecast O&M for 2014 to 2018, the figure in this response has been corrected accordingly. 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 total O&M in each year is not directly comparable. FEI will update this page in its next Evidentiary Update.

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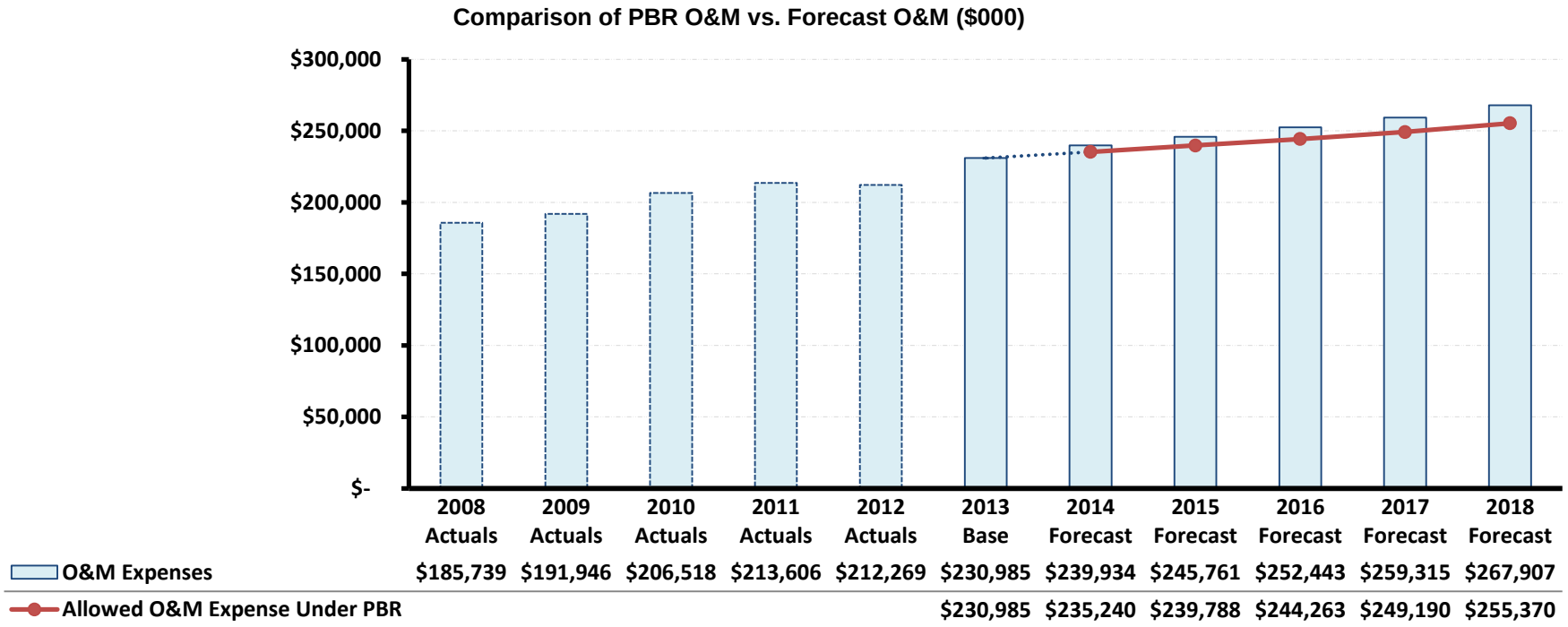
Comparison of PBR O&M vs. Forecast O&M ($000)
$300,000
$250,000
$200,000
$150,000
$100,000
$50,000
$-
2008 Actuals
2009 Actuals
2010 Actuals
2011 Actuals
2012 Actuals
2013 Base
2014 Forecast
2015 Forecast
2016 Forecast
2017 Forecast
2018 Forecast
O&M Expenses
$185,739
$191,946
$206,518
$213,606
$212,269
$230,985
$239,934
$245,761
$252,443
$259,315
$267,907
Allowed O&M Expense Under PBR
$230,985
$235,240
$239,788
$244,263
$249,190
$255,370

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4

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16.2 Please provide a figure similar to Figure B6-2 that contains O&M per customer for the years 2008-2018.

Response:

In the course of responding to this IR, a minor discrepancy was noticed between the Forecast O&M in Figure B6-2 and the Forecast O&M in Table C3-5 of page 133 of the Application. As Table C4-5 reflects the accurate Forecast O&M for 2014 to 2018, the O&M per Customer calculated in this response has been corrected accordingly. Also note that due to the one-time customer count adjustment in 2012, the per-customer figures are not directly comparable in all years. FEI will update this page in its next Evidentiary Update.

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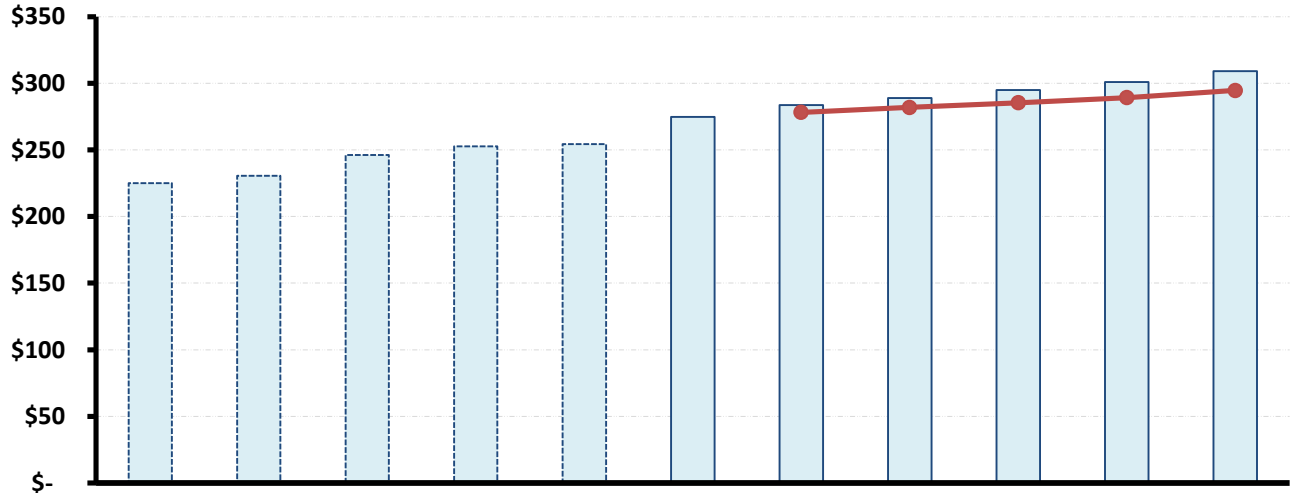
Comparison of PBR O&M per Customer vs. Forecast O&M per Customer



	2008 Actuals	2009 Actuals	2010 Actuals	2011 Actuals	2012 Actuals	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
O&M per Customer	$225	$230	$246	$253	$254	$275	$284	$289	$295	$301	$309
Allowed O&M per Customer Under PBR							$278	$282	$285	$289	$295

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17.0 Reference: Exhibit B-1, Application, Section B-6.2.4.2, 2014-2018 O&M

Exhibit B-1-1, Application, Volume 2, Appendix F6, Gas 5 year History of O&M and 5 Year Forecasts

Preamble: In Section B-6.2.4.2 of its Application, FEI discusses its O&M forecasts. In the formula at the top of page 57, it appears that the derivation of O&M is really an O&M per customer factor. The BCPSO requires information to understand the history of O&M per customer.

17.1 Please provide Appendix F6 in Excel format.

Response:

Regarding the preamble to this IR, the formula in Section B-6.2.4.2 is intended to forecast the total annual O&M allowed under the PBR formula. However, as in any formula where total costs and total customer numbers are known, a per unit cost can be determined by dividing the total cost by the total number of customers.

Please refer to Attachment 17.1 for Appendix F-6 in an Excel format.

17.2 In the response to 17.1 above please include a reconciliation between total O&M and controllable O&M for each year.

Response:

Please refer to the response to BCUC IR 1.17.1 for a reconciliation between total O&M and controllable O&M (as defined by the PBR formula) for each year.

17.3 Please provide the customers, similar to the customers that would be included in the formula at the top of page 57 of the FEI Application, for each year in Appendix F6.

Response:

Provided below is a summary of average customers for the years identified in Appendix F6.

	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Average Customers	825,696	832,751	839,017	845,282	834,888	840,721	859,708	N/A	845,495	850,620	856,001	861,402	866,681

18.0 Reference: Exhibit B-1, Application, Section B-6.2.4.2, 2014-2018 O&M

Exhibit B-1-1, FEI Application, Volume 2, Appendix F6, Gas 5 year History of O&M and 5 Year Forecasts

Preamble: In Section B-6.2.4.2 of its Application, FEI discusses its O&M forecasts. In the formula at the top of page 57, it appears that the derivation of O&M is really an O&M per customer factor. In Appendix F6, FEI provides O&M by activity or function. Functions include:

- Distribution,
- Transmission,
- LNG Plant,
- Customer Service,
- Energy Solutions & External Relations,
- Energy Supply & Resource Development,
- Information Technology,
- Engineering Services & Project Management,
- Operations Support,
- Facilities,
- Environmental Health & Safety,
- Financial & Regulatory Services,
- Human Resources,
- Governance, and
- Corporate

The BCPSO requires information to understand the cost drivers of each function, and how changes in each function are impacted by changes in customers.

18.1 Please fully explain the cost drivers for each function listed in Appendix F6.

Response:

The functions listed in Appendix F6 are the same as the departments discussed in Section C3 of the Application.

Section B 6.2.4.2 of the Application discusses the formulaic O&M. As discussed on page 57, the drivers of formulaic O&M are: average customers, inflation factor, and productivity factor.

Section C3 of the Application discusses both Actual and Forecast O&M. Within this Section the term 'business driver' should be used inter-changeably with the term 'cost driver'. Section C3,Pages 124-133 provides an overview and description of broad based business drivers that

are common across the organization. Section C3, Pages 134-201 discusses forecast O&M on a department basis. Here, a review of business drivers that are specific to each department can be found.

In addition to the explanation above the Functionalization and Classification of costs that are part of embedded cost of service allocation (COSA) studies for Rate Design are also helpful. The nature of the operating and maintenance costs stem from the primary driver for the costs of the gas plant in service. The following functions have been copied from the preamble to this IR and FEI has added beside each one the primary drivers which are used in the classification of costs in the COSA for FEI.

- Distribution – Distribution system capacity requirement of customers served from the distribution system and the number of customers
- Transmission – System peak capacity requirements for all customers
- LNG Storage – Peak capacity requirements of firm service customers, excludes Interruptible Service customers and firm Large Industrial Customers.
- Customer Service – Number of customers
- Energy Solutions & External Relations – Primary driver is the number of customers, however some costs within this function are related to system capacity
- Energy Supply & Resource Development – O&M costs are related to gas control activities and major resource development projects and these type of fixed costs are classified as capacity
- Engineering Services & Project Management, and Operations Support – Costs are allocated based on capacity and number of customers that follow the functionalization and classification of gas plant costs as the work performed is related to gas plant
- Information Technology, Facilities, Environmental Health & Safety, Financial & Regulatory Services, Human Resources, Governance and Corporate – These costs are general and exist because of the presence of the utility, they are broadly allocated based on the functionalization and classification of the gas plant costs which are related to the number of customers and the capacity requirement to serve customers. The costs in these areas are general and do not directly track to the number of customers, peak system capacity or energy throughput. The allocation method allows for the costs to be broadly allocated for customer responsibility from all customers.

As can be seen in the above list, in almost every case, the classifier is demand/capacity or customers or a combination of both. This reflects what B&V has indicated in its reports and in various responses to IRs, i.e. that outputs for a LDC are measured by demand and customers, and not throughput. The only cost that is driven by throughput is odorant which is an immaterial portion of the overall revenue requirement.

19.0 Reference: Exhibit B-1, FEI Application, Section B-6.2.5

Preamble: In Section B-6.2.5 of its Application, FEI discusses Capital Expenditures under PBR. In Appendix F6, FEI provides history of O&M. The BCPSO requires a similar schedule for capital.

19.1 Please provide a schedule similar to Appendix 6 that provides historic and forecast capital expenditures. Please provide capital by asset account, clearly identifying (i) growth capital, (ii) sustainment and other capital, and (iii) CPCN capital.

Response:

Please refer to the table presented below.

	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Sustainment Capital													
Meter Recalls/Exchanges	11,563	14,479	19,126	22,922	24,197	25,062	21,272	22,471	25,967	26,852	25,869	24,225	25,085
Transmission System Reinforcements	13,299	11,848	9,771	10,808	14,964	18,005	24,386	25,180	16,555	20,479	15,537	14,221	14,298
Distribution System Reinforcements	8,050	8,524	5,198	7,670	8,574	8,691	7,610	7,858	10,112	7,282	7,546	8,073	8,653
Distribution Mains & Service Renewals & Alt.	9,398	12,757	11,342	17,736	16,556	20,500	21,845	22,556	25,815	24,433	28,245	34,059	34,304
Total Sustainment Capital	42,309	47,608	45,437	59,137	64,291	72,258	75,114	78,065	78,449	79,045	77,198	80,578	82,340
Growth Capital													
New Customer Mains	10,983	6,133	4,538	4,510	5,374	5,033	6,500	6,783	5,374	5,462	5,561	5,664	5,798
New Customer Services	17,954	12,073	13,874	14,423	17,423	16,791	12,910	13,471	18,360	19,502	20,214	20,337	20,363
New Customer Meters	3,300	1,498	1,905	1,699	1,403	1,438	2,105	2,197	1,664	1,805	1,876	1,877	1,862
Total Growth Capital	32,237	19,704	20,317	20,632	24,200	23,262	21,515	22,451	25,398	26,769	27,651	27,878	28,022
Other													
Biomethane - Interconnect	-	-	504	-	-	1,100	1,015	1,032	3,908	1,100	1,864	1,864	1,864
Equipment	2,996	6,607	3,434	3,499	3,951	3,875	2,930	5,840	6,818	7,328	7,127	7,358	6,702
Facilities	1,988	2,805	4,177	5,840	1,996	7,549	4,124	4,194	3,904	4,026	4,122	4,269	4,626
IT	10,468	14,245	12,418	14,503	13,983	21,600	18,000	20,107	20,105	20,105	20,106	20,102	20,098
Total Other	15,452	23,657	20,533	23,841	19,930	34,124	26,069	31,173	34,735	32,560	33,218	33,593	33,289
Total Gross Capex	89,998	90,968	86,287	103,610	108,421	129,644	122,698	131,689	138,582	138,374	138,067	142,050	143,652
CIAC	(11,291)	(4,615)	(3,922)	(7,948)	(5,830)	(5,864)	(5,400)	(5,492)	(5,821)	(5,821)	(5,821)	(5,820)	(5,819)
Total Net Capex	78,707	86,353	82,365	95,662	102,591	123,781	117,298	126,197	132,762	132,554	132,247	136,230	137,833
CPCN[(1)]	7,848	12,879	203	31,268	88,470								

(1) Includes AFUDC on CPCN's

19.2 Please provide the response in Excel format with formulae and links intact.

Response:

Please refer to Attachment 19.2 for the fully functional electronic spreadsheet.

20.0 Reference: Exhibit B-1, FEI Application, Page 62, line 25

Preamble: In line 25 of page 62, FEI provides its formula for Growth Capital. The Growth Capital for year "t" is based on the cost per service line addition in the previous year. The BCPSO requires information to understand why FEI does not use the 2013 Base as provided in Table 6-6 as the cost per service line additions.

20.1 Please confirm that, in the formula on page 62, FEI will use actual growth capital in year "t-1" and actual service line additions in year "t-1". If not confirmed, please fully explain.

Response:

The characterization of line 25 provided in the preamble to this question is not correct. Growth Capital for year "t" is not based on the cost per service line addition in the previous year.

Growth Capital is driven by service line additions (which are calculated as a percentage of gross customer additions) that arise from providing service for new customers. For that reason, the PBR formula FEI proposes to apply to Growth Capital is tied to the forecasted service line additions for the upcoming year. In essence, the formula escalates the unit price of all growth capital per service line addition – termed the Average Growth Capital Cost per Service Line Addition – by the I-X Mechanism and forecasted Service Line Additions to determine the Total Allowed Growth Capital under PBR for year "t". The following formula illustrates the formula applied to Growth Capital:

$$GC_t = \frac{GC_{t-1}}{SLA_{t-1}} \times [1 + (I - X)] \times SLA_t$$

Where:

$GC = Growth\ Capital\ Allowed\ Under\ PBR$
$SLA = Service\ Line\ Additions$
$t = Upcoming\ year$
$I = Inflation\ Factor$
$X = Productivity\ Factor$

Actuals for Growth Capital and Service Line Additions for year "t-1" are not used. Rather, it is the formula-driven Growth Capital per Service Line Addition for year "t-1" that is used. The formula-derived Growth Capital Allowed per Service Line Addition under PBR for the current year is escalated by the PBR formula and multiplied by the upcoming year's forecasted Service Line Additions. The product of this calculation equals the Total Allowed Growth Capital under PBR for the upcoming year "t". For example, to determine the Total Growth Capital Allowed under PBR for 2014, the 2013 Base unit cost per service line addition is escalated by the PBR formula and multiplied by the 2014 forecasted Service Line Additions.

20.2 If the response above is confirmed, please fully explain why the growth capital factor is not based on the 2013 base growth capital from Table 6-6, divided by the service line additions included in the 2013 base.

Response:

The growth capital formula calculation can be found in Table B6-7. The Growth Capital for 2014 is calculated using the 2013 Growth Capital per Service Line Addition as the starting point. The 2013 Growth Capital per Service Line Addition is the 2013 base growth capital from Table B6-6 ($22,451 thousand) less the Insurance and OPEB expenses tracked outside the PBR formula ($569 thousand) divided by the service line additions included in the 2013 base (7,989). See Table B6-7 for the PBR Growth Capital calculation and results.

21.0 Reference: Exhibit B-1, FEI Application, page 64

Preamble: On page 64 of its Application, FEI provides its formula for sustainment capital. The formula includes growth in customers. The BCPSO requires information to understand how growth in customers impacts sustainment capital.

21.1 Please confirm that sustainment capital is to maintain the existing system. If not confirmed, please fully explain.

Response:

This is generally true. Please also refer to the response to BCPSO IR 1.21.2.

21.2 Please fully explain why growth in average customers should be a factor in sustainment capital.

Response:

Sustainment capital includes the installation of system capacity improvements. System capacity improvements are required when a significant number of additional customers connect to the system and the forecasted pressures within the piping system will be too low to provide adequate gas supply to all customers and generally take the form of the installation of additional mains in parallel with the existing mains. Thus, customer growth within a piping system drives the need for system capacity improvements and sustainment capital expenditures. For a discussion of the difference between sustainment and growth capital please refer to the response to BCPSO IR 1.21.3.

21.3 Please fully explain why the growth capital component does not cover growth in customers.

Response:

The growth capital component represents the capital costs required to connect new customers to the system and, as such, does cover the growth in customers. The customer growth is

reflected through the "Service Line Additions" driver of the Growth Capital Formula and the formula is directly connected to customer additions.

In contrast, sustainment capital pertains to capital work required to sustain the system for all customers (existing and new). The customer driver for the sustainment capital spending recognizes that as more customers are added to the system, the overall size of the system will increase, meaning that more capital of a sustaining nature is needed to serve the larger system. This is why the sustainment capital portion is driven by the **average** number of customers rather than the driver used for growth capital which is service line additions (which is in turn based on customer additions).

22.0 Reference: Exhibit B-1, FEI Application. Section B-6.3.2

Preamble: In Section B-6.3.2 of its Application, FEI discusses Flow-Through Expenses. There are

- Interest Expense
- Return on Equity
- Taxes
- Pension and OPEB Expenses and Insurance Costs
- Revenues
- Depreciation and Amortization
- Rate Base other than Gas Plant in Service (from Capital Expenditures)

The BCPSO requires an understanding of the changes in flow through costs and the impact on the PBR plan

22.1 Please identify and fully discuss all changes in the proposed flow through items from the currently approved deferral accounts.

Response:

To clarify, FEI is not requesting any new deferral accounts in this Application specifically related to any of the flow-through items discussed in Section B6.3.2. Existing deferral accounts that capture variances between the actual and forecasted costs, such as the Insurance Variance and Pension and OPEB Variance deferrals, will continue through the PBR period.

The list in Section B6.3.2 is provided to identify which items will be subject to annual re-forecasting during the Annual Review process. The first six items are all currently included in the cost of service and revenue requirements for FEI in the existing 2013 approved RRA. The seventh item refers to amounts included in the rate base for FEI, such as gas-in-storage inventory and other working capital items that do not pertain to the PBR I-X capital formulas. These items are all included in the existing 2013 approved RRA and have been included in rate base on the same basis for some time.

22.2 On page 69, lines 5-9, FEI indicates that Pension and OPEB Expenses and Insurance Costs are afforded deferral treatment. In Table B6-4, FEI adds Pension costs of $10,605,000 to O&M in arriving at the 2013 base O&M. Please fully explain why, given that pension costs are afforded deferral treatment, there

should be an amount added to O&M for pension costs to arrive at the 2013 base O&M.

Response:

Refer to the response to BCUC IR 1.12.1 and 1.12.1.1 for a further explanation of the treatment of pension and OPEB and insurance expenses during the PBR term.

23.0 Reference: Exhibit B-1, FEI Application, Section B-6.3.3, Exogenous Adjustments

Preamble: In Section B-6.3.3 of its Application, FEI discusses its proposal for exogenous adjustments. The BCPSO requires information to better understand the FEI proposal.

23.1 Please confirm that FEI has not proposed a materiality limit for exogenous adjustments. If not confirmed, please provide the materiality limit and a reference to where it is proposed.

Response:

Confirmed.

23.2 Please provide the FEI recommendation for a materiality limit for exogenous adjustments.

Response:

FEI recommends no materiality provision on the exogenous factor adjustments. FEI and B&V believe that placing a materiality limit is most likely to deny prudent cost recovery and thus increase the underlying risk. The cost increases or decreases arising from exogenous factors are non-controllable costs that would be subject to recovery in rates under cost of service-based ratemaking without any materiality threshold. The appropriate mitigation of this risk is to not set a limit on recovery.

24.0 Reference: Exhibit B-1, FEI Application, Section B-6.4, Earnings Sharing Mechanism

Preamble: In Section B-6.4 of its Application, FEI discusses its earnings sharing mechanism. The BCPSO requires information to better understand the FEI proposal.

24.1 Please confirm that FEI has not proposed a dead band for earnings sharing. If not confirmed, please provide the dead band and a reference to where it is proposed.

Response:

Confirmed.

24.2 Please provide the FEI recommendation for a dead band for earnings sharing.

Response:

FEI is not proposing a dead-band for its earnings sharing mechanism. A deadband would mean that all savings within the band flow to the Company, not customers, during the PBR period (i.e. until rebasing occurs at the end of the period). Under FEI's proposal with no deadband, customers benefit immediately under the ESM, and then continue to benefit through rebasing. In other words, customers stand to benefit.

FEI believes that a dead-band would increase the regulatory burden required to review and approve the amount of the shared earnings. Based on FEI's positive experience with the earnings sharing mechanism in the 2004 PBR (which was also designed with no dead-band) and the PBR guiding principles (see page 43 of the Application, particularly principle number 5 regarding sharing benefits) an ESM with no dead-band can best achieve the PBR design objectives.

25.0 Reference: Exhibit B-1, FEI Application Section B-6.5, Efficiency Carry-Over Mechanism (ECM)

Preamble: In Section B-6.5 of its Application, FEI discusses is proposed Efficiency Carry-Over Mechanism for the end of the PBR term. As FEI has proposed that there be an ECM at the end of the PBR term, the BCPSO requires an understanding of how efficiencies achieved under Cost of Service (COS) will be accrued to customers.

25.1 Please confirm that it is FEI's view that, if customers pay the cost of projects that result in financial benefits, such as reduced costs, the benefits should be reflected in customer rates, and not shareholder returns. If not confirmed, please fully explain.

Response:

Customers do not pay the costs of projects, except in certain cases where a contribution-in-aid-of-construction is required for a specific project. However, FEI agrees that the regulatory compact would suggest that net benefits of capital projects that produce O&M savings would be reflected in customer rates upon rebasing, while the Company earns a fair return on its invested capital.

This fundamental relationship is still true whether under cost of service regulation or under PBR. O&M and capital are rebased at the conclusion of a PBR to ensure the long term benefits of the savings go to customers. Customers achieve greater benefits in the long term under PBR than under traditional cost of service regulation because the PBR effectively delays rebasing to incent the utility to invest more to achieve new cost savings, efficiencies and/or new revenues. In the meantime, customers get the benefit through earnings sharing.

25.2 The BCPSO notes that, in Table B6-4, FEI identifies Sustainable Savings as an adjustment to O&M costs. Please fully provide a summary of all savings generated in the previous COS regime, whether FEI considers the savings sustainable or not. In the response, please provide a complete description of the savings and an explanation of why FEI considers the savings sustainable or not.

Response:

The following table provides a summary of O&M savings generated in the most recent COS regime which covers 2010 through 2013 (with 2013 savings being provided on a forecast basis).

Please note that of the $14.7 million of savings in each of 2012 and 2013, $17.7 million in total for the two years was related to the Customer Service department and has been captured in the Customer Service deferral account for return to customers.

O&M ($thousands)	2010 Actual	2011 Actual	2012 Actual	2013 Projected
Allowed	206,464	214,680	226,992	236,003
Actual/Projected	206,518	213,606	212,269	221,333
Savings/(Overspend)	**(54)**	**1,074**	**14,723**	**14,670**

During 2010 and 2011 the savings/overspend was minimal.

For an analysis of the 2012 savings, please refer to the response to BCUC IR 1.82.1.

For an analysis of the 2013 projected savings please refer to the response to BCUC IR 1.83.1.

25.3 Please fully explain how the inclusion of O&M savings in the ECM is not a double counting of the Earnings Sharing Mechanism.

Response:

The inclusion of O&M savings in the ECM is not a double counting of the Earnings Sharing Mechanism because the O&M benefit in the ECM (as well as the capital benefit) only affects customer rates after the end of the PBR term. This is illustrated in Appendix D-6 of the Application on page 3. Line 28 of the table on page 3 indicates that rate adjustments for the ECM are permitted only after the end of the PBR five-year term.

The ECM is structured to provide the same incentive for FEI to pursue O&M and capital savings in each year of the PBR term. With the ECM, customers benefit through 50/50 sharing of the O&M and capital efficiency savings achieved for a five-year period regardless of when in the PBR term they are achieved, and then receive 100% of the savings in the longer term as the yearly ECM benefits lapse successively.

25.4 Please fully explain why, given that FEI includes incremental capital expenditures based on its formula in rates, that there is any need for an ECM.

Response:

Customers benefit during the term of the PBR from capital savings achieved through the X factor, and through the earnings sharing mechanism. After the end of the PBR term, customers benefit as these savings are rebased in opening rate base.

There is no mutual exclusivity between including savings associated with lower capital expenditures based on the PBR formula in rates and the implementation of an ECM. In other words, the ECM is a complementary mechanism to the PBR plan that does not contradict any other PBR plan elements.

The ECM is designed to provide the same level of motivation for FEI to pursue both capital and O&M savings throughout the five-year PBR term. Customers receive long term benefits when the efficiencies and savings achieved by FEI are fully rebased in rates.

Since O&M and capital will be rebased to actual levels after the end of the PBR term, without an ECM there will be a diminishing incentive with each passing year for FEI to pursue further savings. The proposed ECM resolves this dilemma by ensuring that incremental savings and efficiencies achieved in the fourth or fifth year will provide the same incentive to the utility as those in the first year. Better long term benefits accrue to customers as the savings and efficiencies achieved throughout the full PBR term are rebased in rates going forward.

26.0 Reference: Exhibit B-1, FEI Application, Section B-6.6, Service Quality Indicators

Exhibit B-1, FEI Application, Table B5-1,

Exhibit B-1-1, Appendix D7

Preamble: In Section B-6.6 of its Application, FEI discusses Service Quality Indicators. In Table 6-9, FEI includes a number of SQIs, but does not include benchmarks for all.

Further, in table B-5-1, FEI asserts that there are no penalty/reward mechanism attached to SQIs in the PBR plan

The BCPSO requires an understanding of the consequences of failure to meet SQIs.

26.1 Please provide a full discussion of whether FEI considers the current service levels adequate for its customers. In the response, please provide the basis of the FEI understanding.

Response:

In general, FEI believes that its current service levels as represented by SQIs and benchmarks are appropriate for its customers and reflective of the current approved funding. As FEI has indicated in its Application, the objective of SQIs is to ensure that the Company continues to provide an "acceptable level" of service at an "acceptable level" of cost to our customers. This is consistent with PBR Principle 4 as outlined in Section B6.1 PBR Principles in Exhibit B-1, "the PBR plan should maintain the utility's focus on maintaining, safe, reliable natural gas service and customer service quality while creating the efficiency incentives to continue with the productivity improvement culture."

Following is a discussion of why FEI believes the service levels for its proposed SQIs are appropriate.

- **Customer Satisfaction Index** - Overall, FEI believes its customers are satisfied as indicated in the Company's customer satisfaction index. Recent years' results have been stable (refer to Appendix D7 Figure D7-3 of Exhibit B-1-3), performing at over 80 percent, indicative of customers' general level of satisfaction with the Company.

- **Telephone Service Factor** - FEI believes that the appropriate balance of cost and service for non-emergency calls is 70 percent of calls answered in 30 seconds or less (70/30) and for emergency calls, 95 percent of calls answer in 30 seconds or less

(95/30). FEI believes that these service levels reflect an appropriate balance between cost and service levels, is a service level adequate for customers, and allows for a better comparison between its gas and electric operations. Recent years' results are consistent with the proposed benchmarks.

- **First Contact Resolution** - FEI believes that a target of 78 percent is an adequate service level given that the average call center in the industry is achieving a score of 70 percent (refer to Appendix D7 Figure D7-7 of Exhibit B-1-3). The proposed target reflects the 2012 results achieved by FEI.

- **Billing Index** – The proposed benchmark of 5.0 is consistent with the initial benchmark originally established for this measure back in 2004. Recent years' results are consistent with the proposed benchmark of 5.0.

- **Meter Reading Accuracy** - This is a new measure being tracked starting in 2012. The proposed 95 percent level for meter reading is consistent with actual results realized in 2012 and represents the target built into the new contract for meter reading.

- **Meter Exchange Appointment** - FEI's recent performance has been consistently above 95 percent, which is higher than the original benchmark of 92.2 percent established back in 2004. The proposed benchmark is set at 95 percent.

- **Emergency Response Time** - Under the CGA definition of emergency events (refer to page 5 of the Service Quality Indicators report included in Exhibit B-1-3 Appendix D-7), FEI's response time is consistently higher than the industry average (i.e. 97.7 percent average from 2010 – 2012 compared to industry average near 95 percent) and in the top quartile of CGA member companies. The proposed benchmark is set at 95 percent.

- **Safety, All Injury Frequency Rate and Public Contacts with Pipelines** - These SQIs are informational in nature, focused more on ensuring safety, from both an employee and a public safety perspective, than on actual service quality.

For the proposed PBR Plan, FEI believes the proposed SQIs and benchmarks are appropriate. In setting the benchmarks, representing the targeted service levels for the proposed SQIs, FEI relied primarily on the performance of the SQIs over the last three years. And given that the O&M costs proposed during the PBR period will be managed to a similar level, after adjusting for inflation, with the O&M spending levels observed from 2010 – 2012, FEI believes it is appropriate to base the proposed benchmarks on recent years' performance that are reflective of the costs required to provide the service levels.

26.2 Please confirm that, in Alberta, the Alberta Utilities Commission has engaged in a consultative process to develop a rule related to penalties related to service quality indicators. If not confirmed, please fully explain.

Response:

In Alberta, the Alberta Utilities Commission's (AUC) Rule 002 sets out the service quality reporting requirements for electric and gas distributors. In AUC's Decision 2012-237, the Commission indicated that it shall initiate a consultation process to review and revise the AUC Rule 002. AUC also stated that following the completion of the consultative process, the Commission will issue a bulletin indicating the process to be followed with respect to the adjudication of penalties.

AUC Rule 002 is a general rule and not specific to the PBR plans. In other words, even if the consultation process leads to development of a penalty mechanism, the defined mechanism would not be specific to a PBR plan and will apply to all the utilities even after the PBR term is finished.

The link below includes the latest bulletin update that is available on AUC's website regarding this consultation process:

http://www.auc.ab.ca/rule-development/service-quality-and-reliability/Documents/Rule002AnnualReviewMeetingsandPenaltiesConsultationApril9_2013meetingsummary.pdf

26.3 Please provide a full explanation of the consequences of failure to meet any of the SQIs.

Response:

Please refer to the response to COPE IR 1.7.8.

In addition, as mentioned in Exhibit B-1 Section B6.7.2.2 Non Financial Triggers, failure to meet one (or more) SQI benchmarks does not necessarily constitute unacceptable performance. Triggering of the off-ramp provision would be warranted only if there is a sustained serious degradation of the SQIs.

26.4 In Appendix D7, Table D5-5, FEI provides the recent history of meter exchange performance. Please provide the average of the three years history provided, and an explanation of why the recent three years history should not form the basis of the benchmark.

Response:

Please refer to the discussion on page 7 of the report titled "Service Quality Indicators" in Appendix D7.

As indicated in Table D5-5 (Table D7-5 in the Evidentiary Update), the results for each of 2010, 2011 and 2012 have been provided along with the average of the three years (2010 to 2012 – 95.7%). The proposed benchmark of 95% is based on this recent three year history.

Please note FEI incorrectly updated Table D7-5 of Appendix D7 in the July 16, 2013 Evidentiary Update when it should have updated Table D7-6 instead. Following is a revised Table D7-5 incorporating a correction to the current benchmark from 95.0% reported in the Evidentiary Update to the 92.2% that was originally reported. FEI will update this page in its next Evidentiary Update.

Table D7-5: Recent historical results for meter exchange appointments met and benchmarks

2010	2011	2012	2010 - 2012 Average	Current benchmark	Proposed benchmark
94.2%	96.5%	96.5%	95.7%	92.2%	95.0%

26.5 In Appendix D7, Table D5-6, FEI provides the recent history of Telephone Service Factor performance. Please provide the average of the three years history provided, and an explanation of why the recent three years history should not form the basis of the benchmark.

Response:

Telephone service factor (TSF) is a measure that balances service quality and cost. A higher TSF means more resources are available to answer calls. A lower TSF translates into lower

resource levels and therefore, lower costs. The goal of a TSF target is to get as close to the target as possible. If the TSF results are lower than target, then service levels are lower than expected. If TSF results are higher than target, it suggests that it is possible to reduce the amount of resource costs spent going forward while still achieving an acceptable level of service. FEI did not set the target at the three year average of 76% because, as discussed in section C3.5.4 of the Application, FEI is proposing amending the target from 75% to 70% in order to align the targets for the gas and electric operations and to more effectively balance cost and service levels. A higher benchmark (such as the three year average results) can be attained, but at a higher cost.

Please note following is a revised Table D7-6 of Appendix D7 incorporating a correction to the current benchmark for Emergency TSF from 92.2% previously reported to 95.0% currently.

Table D7-6: Recent historical results for Telephone Service Factor

Type of Call	2010	2011	2012	Current benchmark	Proposed benchmark
Emergency	99.2	96.5%	96.5%	95.0%	95.0%
Non Emergency	77.2	74.7	76.2	75.0%	70.0%

26.6 Appendix D7, page 17, removes number of complaints to BCUC as a performance metric. Please provide the history of complaints for 2010-2012 and an explanation of why FEI would exclude this metric.

Response:

The number of complaints to BCUC totaled 37 in 2010, 4 in 2011 and 3 in 2012. As at the end of July, 2013 we have 2. FEI believes the following two measures are more indicative of service levels.

As indicated in Appendix D7, both First Contact Resolution (FCR) and Customer Satisfaction Index (CSat) Performance Metrics, reflect a more timely and accurate state of service and quality levels. The CSat takes into account four different customer satisfacation surveys. This customer satisfaction model was designed to provide feedback regarding customer satisfaction and to ensure that service quality is maintained at acceptable levels during the various stages of application. FCR is a reflection of the customers' opinion on whether or not their issue has been resolved on the first contact. Both metrics are measured direct from our customers' perspective thereby providing a true reflection of service levels.

26.7 In Appendix D7, Table D5-10, FEI provides the recent history of AIFR performance. Please provide an explanation of why the recent three years history should not form the basis of a benchmark.

Response:

The three proposed SQIs of Annual Injury Frequency Rate, Public Contacts with Pipelines and Customer Satisfaction Index are considered information only indicators with their performance assessed by comparing to previous years' performance.

These three SQIs can be influenced by events beyond the control of and external to company operations. As such, setting a benchmark / target for these SQIs is inappropriate.

26.8 In Appendix D7, Table D5-11, FEI provides the recent history of Public Contact with Pipelines. Please provide an explanation of why the recent three years history should not form the basis of a benchmark.

Response:

Please refer to the response to BCPSO IR 1.26.7.

26.9 In Appendix D7, Figure D5-3, FEI provides the recent history of CSI performance. Please provide an explanation of why the recent three years history should not form the basis of a benchmark.

Response:

Please refer to the response to BCPSO IR 1.26.7.

26.10 Please provide the percentage of non-emergency appointments met on time for each of 2010-2012.

Response:

With the exception of meter exchange work, appointments are not routinely made for non-emergency work. The percentage of appointments met on time for meter exchange work is a current SQI and historical results are summarized as follows:

2010: 94.2%

2011: 96.5%

2012: 96.5%

26.11 Please provide the average time a customer was required to wait for a non-emergency appointment for each of 2010-2012.

Response:

Non-emergency appointments are limited to meter exchange activities. Customers can choose an AM or PM four hour appointment window. On average, for the 2010-2012 time periods, customer service technicians met the appointment window 95.7% of the time.

The Company does not track the average time a customer was required to wait for a non-emergency appointment. If the assigned technician is unable to meet the appointment window, usually due to having to respond to an emergency call (i.e. gas odour , hit line, fire, etc.), either the technician or the dispatcher will call the customer to reschedule the meter exchange or re-assign the work to another resource who can complete the work.

27.0 Reference: Exhibit B-1, FEI Application, Section B-6.7.2, Off Ramps

Preamble: In Section B-6.7.2 of its Application, FEI indicates an off ramp if ROE exceeds or drops below the authorized ROE by 200 basis points. The BCPSO requires information to understand the proposed off ramps.

27.1 Please fully explain whether the ROE used for determination of off ramps is before or after earnings sharing.

Response:

The ROE used for the determination of the off-ramp is after earnings sharing. This is explained in Section B6.7.2.1 of the Application:

*"FEI is proposing that the PBR Plan be reviewed if the **post-sharing achieved ROE** of the Company exceeds or drops below the allowed ROE by 200 basis points in any single year of the PBR term."*

This approach is the same as the one that was in place during the 2004 PBR Plan, although the off-ramp after-sharing ROE in that case was 150 basis points above or below the allowed ROE.

27.2 Please provide the actual and authorized ROE for FEI for each of 2008-2012.

Response:

Please refer to the table below which provides the actual and allowed ROEs for FEI from 2008 through 2012.

	FEI ROE		
	Allowed (a)	Actual Pre-ESM (b)	Actual Post-ESM[1] (c)
2008	8.62%	10.64%	9.63%
2009	8.99%	11.89%	10.44%
2010	9.50%	9.42%	N/A
2011	9.50%	10.15%	N/A
2012	9.50%	10.12%	N/A

Notes:

[1] Post-ESM only applicable for the years when FEI was under PBR (2004 - 2009)

28.0 Reference: Exhibit B-1-1, FEI Application, Appendix D-1

Preamble: In Appendix D-1 of its Application, FEI provides a Black and Veach (B&V) regarding PBR in other jurisdictions.

28.1 On page 2 of Appendix D-1, B&V provide the five principles of the Alberta Utilities Commission regarding PBR. Please fully explain whether B&V agrees with each of these principles. To the extent B&V agrees with the AUC principles, please explain how the FEI PBR plan meets or satisfies these principles.

Response:

B&V provides the following response.

Please refer to the response to BCUC IR 1.2.2. There is also a discussion of these issues in Appendix D-1 pages 45-47. B&V believes that all of the general principles and objectives that have been articulated in testimony, reports and academic literature are relevant to and inform the discussion of any PBR Plan. We also believe that the principles articulated by FEI represent the most complete set of standards for assessing the FEI plan because they address the specifics of the fourth AUC principle related to unique characteristics and circumstances of FEI. Having said all of this the goal of the FEI plan in our view was to satisfy the principles articulated in the testimony supporting the Plan as filed. With respect to the AUC Principles, B&V offers the following comments:

- **Principle 1**: A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality.

  Comment: The AUC correctly recognizes that even a comprehensive PBR Plan cannot match the efficiency of a competitive market. Having recognized that goal, B&V believes that the principle offers a reasonable basis for assessment of the plan elements but care must be taken to strike a balance with other plan objectives such as Principle 2.

- **Principle 2**: A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.

  Comment: This is a fundamental principle of regulation and any form of regulatory policy - PBR or Cost of Service - must meet this principle.

- **Principle 3**: A PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.

Comment: This principle is a useful concept and reasonable principle. It is possibly a fundamental benefit of PBR over cost of service regulation when coupled with the potential for productivity improvements and a lower rate trajectory.

- **Principle 4**: A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design.

  Comment: This principle requires that plans be customized on a variety of dimensions. The AUC did not follow this principle in adopting a single plan for gas and electric utilities and only provided a single accommodation through the use of a different cap - revenue or price - for the two industries subject to the plan.

- **Principle 5**: Customers and the regulated companies should share the benefits of a PBR plan.

  Comment: This is only a partial description of the fundamental principle related to stakeholders. The AUC did not follow this principle except in a limited sense because the AUC did not adopt earnings sharing so the only benefit to customers during the period of the plan was the stretch factor.

B&V notes that in terms of the AUC principles the FEI PBR Plan more closely satisfies these principles from the AUC than does the plans the AUC adopted. FEI's successful prior PBR experience is a factor that facilitates modifications that improve the overall scope of the Plan.

28.2 Please fully explain whether FEI agrees with the five principles of the AUC.

Response:

FEI agrees with the essence of the AUC's five principles as discussed in the responses to BCPSO IRs 1.11.3 and 1.28.1. FEI believes that its proposed principles are the most complete set of standards for assessing FEI's PBR plan and are applicable in practice.

29.0 Reference: Exhibit B-1, FEI Application, Section D1, Financing and Return on Equity

29.1 Please provide a table similar to Table D1-1 that contains actual 2010-2012 average 30 year Government of Canada for each year, the indicative spread for each year, and the actual FEI issues of long term debt for each year.

Response:

The information for 2010 through 2012 has been provided below. FEI only issued one long term debt series during those years. Series 25 was issued on December 9, 2011.

	2010	2011	2012	FEI Series 25 Issue[1]
Indicative Spread	1.44%	1.46%	1.39%	1.62%
30 Yr GOC	3.77%	3.30%	2.44%	2.68%
New Issue Rate	5.22%	4.76%	3.83%	4.30%

Source: CIBC Capital Markets

Notes: [1] - Per Pricing Supplement dated December 6, 2011

As indicated in the Application on page 255, FEI anticipates issuing long term debt in each of 2015, 2016 and 2017. The interest rates for those issues will be reforecast in the annual reviews in the preceding year. Any variance between the actual interest rate at which the debt is issued and the forecast interest rate will be captured in the Interest Variance deferral account and returned to or recovered from customers in future years.

29.2 On page 255, line 15, FEI indicates that forecasts are based on available projections from Canadian Chartered Banks. Please provide the source for the forecast 30 year Government of Canada Bonds.

Response:

Forecasts for the 30 year Government of Canada Bonds were provided by the following banks:

- Toronto Dominion
- Bank of Montreal
- Scotiabank

- CIBC
- National Bank
- Royal Bank of Canada

30.0 Reference: Exhibit B-1, FEI Application, Section D2, Taxes

30.1 Please fully discuss FEI's awareness of previous income tax rulings around the treatment of indirect costs, commonly known as Rainbow or Candarel adjustments.

Response:

FEI interprets the references to "Rainbow or Candarel" as references to the following income tax cases:

1. *Canderel Ltd. v. Canada*, 1998 CarswellNat 81 (Supreme Court of Canada); and
2. *Rainbow Pipe Line Co. v. R.*, 2002 CarswellNat 1378 (Federal Court of Appeal).

FEI is aware of the framework set out in Canderel for computing income for tax purposes and in particular the analysis used for determining if and when expenditures are deductible. In addition, FEI is aware of the decision in Rainbow and the considerations to be taken into account in determining whether a particular expenditure should be capitalized or expensed for income tax purposes. These considerations are taken into account in the calculation of FEI's income for tax purposes.

By way of an example, during 2010 FEI undertook a review of its tax treatment of removal costs to determine whether all or a component of these costs could be deducted for tax purposes in the year incurred. Prior to 2010, FEI's removal costs were capitalized to Undepreciated Capital Cost (UCC) for income tax purposes. As a result of the company's review, it was determined that costs classified as "removal costs" for accounting purposes could reasonably be deducted for income tax purposes, as opposed to adding the costs to UCC. Beginning with the 2010 tax return, FEI has deducted removal costs for tax purposes. Because this review was not completed in time to include the related tax benefits in rates for 2010 and 2011, the company deferred 2010 and 2011 tax benefits totalling roughly $5.3 million to the Tax Variance account and returned these to customers in 2012. It is also worth noting that because of the judgment involved in making these determinations, it is always possible that the Canada Revenue Agency would take a different view than the company in respect of the deductibility of certain expenditures.

30.2 Please fully explain any reviews, challenges, or appeals that FEI is aware of or contemplating, that would see FEI income taxes related to previously filed returns change materially.

Response:

FEI is not aware of or contemplating any reviews, challenges or appeals that would see FEI income taxes related to previously filed returns change materially. As noted on page 261 of the Application:

> *"At any time, FEI can face changes in tax laws or accepted assessing practices in respect of Federal income tax, Provincial income tax, Federal or Provincial sales taxes or any other tax that may be imposed. As discussed in Section D4, FEI will continue the approved deferral account treatment to capture the impact of changes in tax laws or accepted assessing practices, audit reassessments in respect of any tax year, and impacts on taxes of changes in accounting policies, at Federal, Provincial, Municipal or any other level of jurisdiction."*

Consistent with past practice, FEI records significant assessments in the Tax Variance Deferral Account, for future refund to or recovery from customers.

30.3 In Section D2.3, FEI indicates that its O&M and Capital include costs of the Carbon Tax on fuel used for its own use. Further, FEI indicates that there are no announced changes to the Carbon Tax rates. Please fully explain why costs related to the carbon tax for FEI own use should be inflated by the PBR formula.

Response:

FEI has proposed an O&M and capital formula that is intended to set the levels of these costs to be included in delivery rates. It is not intended that each specific item within the base O&M and capital numbers will in actual fact increase at the formula amount, but rather that the costs are managed as a whole at or below the formula level.

The carbon tax is levied on the fuel that is used to operate compressors, line heaters, motor vehicles and space heating. It is likely that the amount of fuel used to operate these items will increase during the PBR Period, and that carbon tax costs will increase as a result. However, as with any other O&M or capital item, the rate of increase is not intended to be exactly the same as the PBR formula.

For context, FEI notes that the total amount of carbon tax paid on fuel used for its own use on an annual basis and included in its O&M and capital base is approximately $500 thousand.

30.4 On page 261, FEI includes Table D2-2. There is a line related to "internal labour/salaries". Please fully explain how PST is applicable to internal labour and salaries.

Response:

The line titled "internal labour/salaries" is the internal labour and salary costs that FEI has incurred and charged to the PST project to implement the transition back to BC PST and is not PST on "internal labour/salaries". PST is not applicable to internal labour and salaries and no PST on internal labour & salaries has been included in the amount shown on this line.

31.0 Reference: Exhibit B-1, FEI Application, Section D3, Accounting Policies

31.1 Please explain FEI's views on whether the BCUC is bound by accounting pronouncements, such as US GAAP or IFRS, in setting regulatory accounting and reporting requirements, and in setting revenue requirement.

Response:

FEI has interpreted "accounting pronouncements", as used in this question, to mean a set of accounting principles, such as US GAAP or IFRS.

While the BCUC is not bound by US GAAP or IFRS, the BCUC Uniform System of Accounts alludes to rate-regulated utilities applying generally accepted accounting practices and principles. Consistent with the Uniform System of Accounts, FEI believes that the BCUC should follow the only established system of generally accepted accounting principles relevant to rate-regulated utilities, which is US GAAP. The use of US GAAP for setting regulatory accounting and reporting requirements and setting revenue requirements was approved pursuant to Commission Order G-117-11 for the Fortis BC Utilities Application to Adopt US GAAP effective January 1, 2012 and further reiterated in Section D3.1 of the Application.

The adoption of US GAAP for regulatory purposes beginning in 2012 has allowed for the continuation of both transparency and comparability between regulatory and external financial reporting since US GAAP allows for regulated entities to recognize regulatory assets and liabilities under ASC 980, *Regulated Operations*, while IFRS does not currently have existing standards that permit similar treatment.

Additionally, FEI believes that the same set of accounting principles should be used for regulatory purposes as what's used for external financial reporting purposes so that the underlying economic substance of the Company's operations is appropriately reflected. If the BCUC set accounting requirements that differed from what was used to account for the same transaction for external financial reporting purposes, this would result in the Company having to maintain two sets of accounting records which would result in a significant amount of work and cost to the Company and customers and decrease the relevance of the external financial statements. Furthermore, adopting the same set of accounting principles for financial reporting and regulatory reporting will enhance both transparency and comparability between regulatory and external financial reporting.

32.0 Reference: Exhibit B-1, FEI Application, Section D 3.3 Depreciation Rates and Methodology

32.1 Please confirm that FEI will not change depreciation or depreciation related rates during the term of the PBR, without explicit Commission approval. If not confirmed, please fully explain.

Response:

Confirmed that FEI will not change depreciation rates during the term of the PBR without Commission approval. Regarding changes in depreciation rates, please refer to page 267 Section D3.3 Depreciation Rates and Methodology of Exhibit B-1 where FEI indicated that it:

> *"… 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."*

Regarding changes to the depreciation expense amounts, depreciation expense varies from year to year based on the capital amounts that drive the expense. However, FEI would not propose any changes to the method used to calculate depreciation expense during the term of the PBR without prior Commission approval.

33.0 Reference: Exhibit B-1, FEI Application, Section D3.5 Asset Losses

33.1 In section D3.5.1, FEI indicates that no action is required for assets not in use. Please fully explain the process FEI would envision, should a material asset arise that is no longer in use during the term of the PBR.

Response:

During the term of the PBR, should an asset of material value be determined to be no longer "used and useful" and have no expectation of future use, the asset will be retired following the usual retirement process as discussed in section D3.5.1 of Exhibit B-1.

Please refer to the response to BCUC IR 1.186.2 for further discussion of "used and useful" considerations.

34.0 Reference: Exhibit B-1, FEI Application, Section D3.6, Shared and Corporate Services.

34.1 Please reconcile the Total Allocated to FEI on Schedule D3-4 to Schedule C3-2.

Response:

The amount "Total Allocated to FEI" shown in Table D3-4 represents the total amount of O&M that is included in the shared services pool that is not allocated to either FEVI or FEW and therefore remains in FEI. The O&M included in Table C3-2 represents the total O&M for FEI (including amounts that are not subject to sharing), broken down by department. The following table shows the total FEI O&M, the amount that is not subject to sharing, and the amount of shared O&M that remains in FEI after allocation to FEVI and FEW. The first column in the table is taken from the 2013 Projection column of Table C3-2 and the second column is a breakdown of the amount of shared O&M that remains in FEI, by department.

(In thousands of $)	2013 Projection	Shareable	Non-Shareable
Operations	63,509	10,016	53,493
Customer Service [1]	41,825	9,765	32,060
Energy Solutions & External Relations	19,215	9,786	9,429
Energy Supply & Resource Dev	4,000	1,903	2,097
Information Technology	24,217	17,425	6,792
Engineering Services & PM	15,456	9,114	6,342
Operations Support	11,867	6,765	5,103
Facilities	9,249	1,061	8,188
Environment Health & Safety	2,681	2,495	186
Finance & Regulatory Services	13,279	7,297	5,982
Human Resources	8,458	7,357	1,101
Governance	7,935		7,935
Corporate	(358)	730	(1,088)
	221,333	83,713	137,620

1 2013 Projection excludes Customer Service deferred O&M

34.2 Please confirm that there have been no changes to the allocations or methodologies for costs from Fortis Inc, Fortis Utilities Holdings Inc, or any other Fortis Entity to FEI from those previously approved by the BCUC. If not confirmed, please fully explain each change.

Response:

Except as described below, FEI confirms there have been no changes to the allocation methodologies for allocating costs from Fortis Inc., FortisBC Holdings Inc. or any other Fortis entity.

Starting in 2014 the Executive cross charges to and from FortisBC Inc. (FBC) are expected to use the Massachusetts Formula during the term of the PBR, instead of management estimates of time allocations as used in the recent past. The Massachusetts formula, as described in the Application, is a composition allocator and using this formula mimics the amount of time and effort that each of the executives spend, on average on each of the entities. Allocating the executive pooled costs based on the Massachusetts Formula will allow for a more streamlined and efficient approach of allocating the costs, while ensuring an appropriate and transparent allocation methodology.

In the course of responding to this response, FEI realized that the Company did not specifically request approval for the use of the Massachusetts formula with respect to Executive Management time. FEI will file a revision to the draft order to reflect this specific approval as part of its next Evidentiary Update.

34.3 Please confirm that there will be no change to the allocation methodologies during the term of the FBR. If not confirmed, please fully explain.

Response:

FEI confirms that it has no plans to change the allocation methodologies with respect to the existing shared and corporate services over the term of the PBR.

34.4 Please fully explain how the impact of acquisitions or divestitures by Fortis Inc, Fortis Utilities Holdings Inc, or any other Fortis entity will be dealt with during the term of the PBR.

Response:

Acquisition or divestitures by Fortis Inc. or FortisBC Holding Inc. have not been forecast to occur during the term of the PBR. These types of events are very difficult to forecast and so none of these type of events have been included during the term of the PBR. If these types of activities do occur during the term of the PBR, FEI does not propose to adjust the formula-driven O&M that is included in rates each year; these types of impacts are considered as part of the overall challenge FEI has in meeting its O&M targets under PBR.

34.5 On lines 4-5 of page 285, FEI indicates that costs are allocated from Fortis Inc. based on the "assets by subsidiary driver."

34.5.1 Please provide a working paper in support of the allocation of costs from Fortis Inc. to Fortis Holdings Inc for the years 2010, 2011, 2012, and 2013.

Response:

The allocation of costs from Fortis Inc to FortisBC Holdings Inc for 2010, 2011, 2012 and 2013 is as follows:

Fortis Inc.
Recoveries Billings
(000's)

2010

	Assets Actual	**Assets** Total	**Actual** Allocation %	**Actual** Recoveries $000's	**Actual** FP Mgmt Fee $000's	**Actual** Net Pole Revenue $000's	**Actual** Total (net) costs being recovered $000's
FortisBC Holdings Inc.	5,142,273	11,347,509	45.32%	5,871	(680)	(653)	4,539
Less: non-regulated costs included in allocation from Fortis Inc							(738)
							3,801

2011

	Assets Actual	**Assets** Total	**Actual** Allocation %	**Actual** Recoveries $000's	**Actual** FP Mgmt Fee $000's	**Actual** Net Pole Revenue $000's	**Actual** Total (net) costs being recovered $000's
FortisBC Holdings Inc.	5,190,097	11,607,511	44.71%	6,295	(671)	(152)	5,472
Less: non-regulated costs included in allocation from Fortis Inc							(444)
							5,028

2012

	Assets Actual	**Assets** Total	Actual Allocation %	Actual Recoveries $000's	Actual FP Mgmt Fee $000's	Actual Net Pole Revenue $000's	Actual Total (net) costs being recovered $000's
FortisBC Holdings Inc.	5,493,264	12,759,067	43.05%	6,241	(646)	(19)	5,576
Less: non-regulated costs included in allocation from Fortis Inc							(558)
							5,018

2013

	Assets Actual	**Assets** Total	Pro Forma Allocation %	Pro Forma Recoveries $000's	Pro forma FP Mgmt Fee $000's	Actual Net Pole Revenue $000's	Pro Forma Total (net) costs being recovered $000's
FortisBC Holdings Inc.	5,562,842	13,264,278	41.94%	5,903	(629)	-	5,274
Less: non-regulated costs included in allocation from Fortis Inc							(866)
							4,408

34.5.2 Please fully explain why the Massachusetts formula is not used for the allocation of Fortis Inc. Costs.

Response:

The Massachusetts formula uses three main drivers for allocating costs, operating revenue, payroll and average net book value of capital assets plus inventories.

Fortis Inc. does not use the Massachusetts method for allocating its costs for the following reasons:

- Revenue is not a representative cost driver as revenue in the Fortis utilities is different and not comparable. For example, certain utilities such as FortisAlberta, may only charge customers for distribution services, which would result in a disproportionately low allocation of costs to this utility, while other utilities would receive a disproportionately high allocation of the costs as revenues include both distribution services and the cost of energy supply. This is particularly exaggerated in periods when customer rates and related revenues reflect the pass-through to customers of rising purchased power, gas and fuel prices.

- Payroll is also not an appropriate cost driver as the nature of the services from Fortis Inc. (i.e. services limited to equity and access to capital market, Governance, and to a lesser extent Financial Reporting and Risk Management/Insurance) to its subsidiaries is not related to the payroll costs in its utilities.

Instead of the Massachusetts method, Fortis Inc. believes that the Asset allocation method, in conjunction with Fortis Properties' management fee (please refer to the response to COC IR 1.7.2 for discussion), is the more appropriate way to allocate its operating costs to its subsidiaries. The choice of the Asset allocation method is reflective of the autonomy with which Fortis Inc.'s regulated utilities operate, as the nature of the services being provided by Fortis Inc. (see above discussion) is more correlated with the net investment required of Fortis Inc. in its utilities.

34.5.3 Please provide a table that demonstrates how costs would be allocated from Fortis Inc. to Fortis Holdings Inc for the years 2010, 2011, 2012, and 2013, using the Massachusetts formula, with the costs of natural gas or electricity excluded.

Response:

The table below compares the allocation of the Fortis Inc. (FI) fee to FortisBC Holdings Inc. (FHI) using net assets compared to using the Massachusetts formula. In both cases, the fee is before management fee exclusions for items like defined benefit supplemental plan costs and stock compensation costs. The results of the two methods are comparable with only slight differences.

Please also refer to BCPSO 1.34.5.2 regarding the use of the Massachusetts formula.

(000's)	**Asset Allocation Model**			
	Actual			*Estimate*
	2010	**2011**	**2012**	**2013**
Net operating costs recoverable	**$ 10,015**	**$ 12,239**	**$ 12,953**	**$ 12,575**
FHI rate using Assets Allocation	45.32%	44.71%	43.05%	41.94%
Net operating costs allocated to FHI	$ 4,539	$ 5,472	$ 5,576	$ 5,274
	Massachusetts Formula Model			
	Actual			*Estimate*
	2010	**2011**	**2012**	**2013**
Net operating costs recoverable	**$ 10,015**	**$ 12,239**	**$ 12,953**	**$ 12,575**
FHI rate using Massachusetts Formula Allocation	44.30%	43.27%	42.54%	42.24%
Net operating costs allocated to FHI	$ 4,437	$ 5,296	$ 5,510	$ 5,312
Difference - FHI	$ 102	$ 176	$ 66	$ (38)

35.0 Reference: Exhibit B-1-1, FEI Application, Appendix F2a, KPMG Study

Preamble: In Section,

35.1 In Table 5.5 of the KPMG study, the total FI recoverable operating costs are $12.575 million. On Table 5.7 of the KPMG report, $5.273 million of the $12.575 million is allocated to FHI. In Table 6.5, KPMG reports FHI costs of $12.423 million. Please provide a reconciliation that clearly demonstrates the

Response:

Table 5.5 shows the total **Fortis Inc**. costs before any exclusion for specific items with a total of $12.575 million. Table 5.7 shows the same total of $12.575 million split between the allocation to **FHI** and to **other Fortis entities**. In this table, the allocation to **FHI** is estimated at $5.273 million. However, some costs are excluded from the allocation to the gas utilities. These exclusions are identified in Table 6-2, leading to a reduction of the initial $5.273 million allocation to $4.408 million. This allocation of $4.408 million from **Fortis Inc. to FHI** is reflected in Table 6-5 as the Fortis Inc. Management Fee.

Table 6-5 includes the **Fortis Inc**. allocation of $4.408 million plus the operating costs contained in **FHI that are allocated to the FEU**. The sum of these costs totalling to $12.423 million are what is allocated to the gas utilities. The details of the allocation to the gas utilities are shown in Table 6-7.

35.2 In Table 6.2 of the KPMG report, there is a management fee of $5.273 million. Please fully explain how management fees are included in the costs of FI, and how the recovery of management fees are included in forecast costs of FI.

Response:

To clarify, these costs are not included in FI's costs. They are instead allocated from FI to FHI via a management fee charge.

Table 6-2 shows the allocation of management fees from Fortis Inc. (FI) to the parent company of the gas utilities, FortisBC Holdings Inc. (FHI). The "management fee" includes the costs as outlined in Table 5.7 and further described in Table 5.2. As discussed in the response to BCPSO IR 1.35.1, due to exclusions outlined in Table 6-2, the $5.273 million is reduced to $4.408 million. It is this amount that is allocated from Fortis Inc. to FHI in Table 6.5.

1 FHI then allocates its costs, including the allocation from Fortis Inc., to the gas utilities as shown
2 in Table 6-7.

3

36.0 Reference: Exhibit B-1-1, FEI Application, Appendix F2b, FEI-FEH Corp Services Amending Agreement No 2, effective January 1, 2014.

Preamble: In 2 of the amending agreement, proposes:

FEI agrees to pay to FHI for the Services to be provided and for a proportionate share of the common expenses incurred by FHI such as shareholder expenses and director compensation at an amount, on a take-or-pay basis, to be agreed upon in writing between FEI and FHI from time to time,"

The BCPSO requires an understanding of the nature of take or pay.

36.1 Please fully explain what costs are included in this take or pay provision, including an estimate of the costs that are to be charged to FAI if no services are used.

Response:

All the costs listed in Table D3-6 of the Application are included in the take or pay provision, irrespective of the amount of the services that are used by FEI. A take or pay contract means that the amounts are charged irrespective of the amount of services used in that year.

37.0 Reference: Exhibit B-1, FEI Application, Section D4, Deferrals

Preamble: In Section,

37.1 In Section D4, FEI proposes a deferral for its 2014-2018 PBR Application costs with an amortization of 5 year. Please fully explain how costs related to annual reviews, and the midterm review will be treated. Will the costs be included in the deferral account? If not, why not, if so, how will the costs be amortized?

Response:

FEI intends to add costs related to annual reviews and the midterm review to the 2014-2018 PBR Application costs deferral account for recovery from customers, since they are all part of the costs of the regulatory process for the Application.

38.0 Reference: Exhibit B-1, page 86, Table C1-1, Forecast Total Energy Demand 2014-18

Preamble: The referenced page states:

> The following Table C1-1 shows FEI"s total energy demand forecast for the PBR Period, and illustrates that the Company is expected to experience a slight increase in consumption. It should be noted that the forecast demand in this table 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.

38.1 Please confirm that the data in this table assumes that the number of customers in each rate class have been held constant. If unable to so confirm please explain fully.

Response:

The number of customers in residential and commercial rate classes is not held constant. For industrial rate classes, no customer additions are assumed.

FEI has used the same forecast methodology for the past 10 years, which can be summarized as follows:

1. Forecast the UPC by considering historical normalized UPC values for residential and commercial rate classes.
2. Forecast customer additions by considering the Conference Board of Canada (CBOC) forecast for residential and historic customer additions for commercial customers.
3. Survey all industrial customers for their individual 5 year forecasts. Amalgamate the results.
4. The energy forecast is the product of 1) and 2), added to 3), from above.

The movement in the overall energy forecast is a function of changes in UPC as well as changes in customer count.

38.2 If the number of customers in each rate class has been held constant, please confirm that the data displays UPC trends. If unable to so confirm please explain fully.

Response:

Please refer to the response to BCPSO IR 1.38.1.

38.3 Please confirm that the decline in residential demand is due to EEC and use of higher efficiency appliances. If unable to so confirm please explain fully.

Response:

FEI's short term UPC forecast methodology is consistent with past practice and has historically provided good results. While FEI's analysis of normalized short-term historic data is appropriate for short-term forecasting and provides an accurate overall picture of "what" happened, it is unable to tell us "why" it happened, except that the decline in residential demand is not a result of the weather.

However, FEI believes that the following factors have affected the decline in residential demand:

- Improved efficiency of the appliances installed and used within the home for heating, hot water, cooking and decorative (fireplaces);
- Behavioural changes by the people within the home, leading to more efficient use of appliances;
- A trend towards more multi-family homes, which typically have less demand than single family homes;
- BC Government Policy after January 2009 requiring furnaces to be 90 percent efficient or higher;
- Changes to building codes leading to more efficient building envelopes;

There may also be additional factors.

38.4 Is the increase in commercial demand due to expected economic growth of the existing customers?

Response:

The forecast increase in commercial demand is the result of both the addition of new commercial customers and increased consumption from existing customers. As shown in Figure C1-17, FEI is forecasting an additional 388 commercial customers in 2014. Figures C1-12 through 14 show the commercial UPC forecasts for rate schedules 2, 3 and 23, respectively. All three show an increasing UPC for 2014. The increases to both net customer additions and UPC results in the increase shown for the commercial demand forecast.

The forecast methodology does not try to determine "why" customers are consuming more or less. The increases in average consumption from existing customers could be the result of their economic growth or some other factor, such as fuel switching.

38.5 Please explain why industrial demand increases in 2015 and then falls back down thereafter.

Response:

Consistent with the forecasting methodology in place for over 10 years, the forecast of demand for industrial customers is based entirely on surveys gathered from the customers. The industrial customers themselves have the most precise understanding of their own future energy requirements and therefore are best able to provide an accurate forecast. This methodology has been reviewed and approved by the BCUC for over a decade.

The reason the demand increases to 2015 and then falls back down thereafter, is because customers themselves have forecasted an increase in demand to 2015 and a slight reduction thereafter.

However, it is important to note that for the purpose of this Application, only the forecast for 2014 is of relevance. FEI will forecast 2015 later in 2014 via a survey of industrial customers. This survey will then be used to determine expected volumes and revenues for these rate classes for 2015. This process will be repeated for each year of the PBR. Therefore, the volumes that are shown in this filing for the period beyond 2014 are only illustrative and do not form the basis of any future volume or revenue changes and subsequent revenue requirement.

39.0 Reference: Exhibit B1, page 88, Figure C1-2, Total Energy Demand

39.1 Please confirm that the number of customers in each rate class has been held constant for this figure. If unable to so confirm please explain fully.

Response:

Please refer to the response to BCPSO IR 1.38.1.

40.0 Reference: Exhibit B-1, page 88, Table C1-2, Net Customer Additions

40.1 Please confirm that the net additions shown in this table are as at year end. If unable to so confirm please explain fully.

Response:

Confirmed. The net additions shown in the table are as at year end (they reflect a full year of net additions). As such, a net addition for a particular year is the difference between total customer count at the end of the prior year and the count at the end of the current year.

40.2 Please provide a companion table that shows the total number of customers in each rate class as at year end.

Response:

The following table shows the total customers by rate class at year end.

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
RATE1	753,735	760,559	765,553	759,712	764,028	768,622	773,577	778,662	783,634	788,440
RATE2	75,986	76,028	76,437	72,235	72,591	72,922	73,227	73,524	73,835	74,139
RATE3	4,841	4,882	4,863	4,675	4,577	4,577	4,577	4,577	4,577	4,577
RATE23	1,348	1,406	1,433	1,520	1,577	1,634	1,702	1,763	1,824	1,887
RATE4	2	7	5	11	11	11	11	11	11	11
RATE5	282	234	224	216	216	216	216	216	216	216
RATE6	29	24	20	16	14	14	14	14	14	14
RATE7	4	3	2	3	3	3	3	3	3	3
RATE22B	4	4	4	4	4	4	4	4	4	4
RATE22B_SP	1	1	1	1	1	1	1	1	1	1
RATE22	22	21	21	23	23	23	23	23	23	23
RATE22_BY	10	8	7	6	6	6	6	6	6	6
RATE22_SP	1	1	1	3	3	2	2	2	2	2
RATE22A	8	9	9	9	9	9	9	9	9	9
RATE25	597	550	503	502	487	487	487	487	487	487
RATE25_BY	7	7	7	6	6	6	6	6	6	6
RATE27	99	101	98	98	95	95	95	95	95	95
Total	**836,976**	**843,845**	**849,188**	**839,040**	**843,651**	**848,632**	**853,960**	**859,403**	**864,747**	**869,920**

40.3 For forecasting purposes, does FEI assume that all customers are added mid-year for each year of additions? If not, please provide FEI's assumptions in this regard.

Response:

No, FEI forecasts total additions for the year and then distributes the total among the months using seasonality factors specific to each region and rate class. The seasonality factors are calculated based on historical net addition patterns. The Forecasting Information System (FIS) model performs all calculations at the monthly level and then rolls up the totals for reporting.

40.4 Please provide a table showing forecasted number of customers at mid-year for each year of the proposed PBR plan.

Response:

The following table shows the forecasted number of customers as of June for each year of the proposed PBR plan.

As of June	2013	2014	2015	2016	2017	2018
Residential	760,922	765,316	770,013	775,004	780,058	784,983
Commercial	78,307	78,638	79,029	79,405	79,760	80,135
Industrial	912	911	911	911	911	911
Grand Total	**840,141**	**844,865**	**849,953**	**855,320**	**860,729**	**866,029**

40.5 Please provide a table showing forecasted versus actual number of customers by rate class historically for all of the years for which data is available.

Response:

The following table shows the year end accounts by rate class from 2004 through 2012.

	2004		2005		2006		2007		2008	
Rate	**Actual**	**Forecast**	**Actual**	**Forecast**	**Actual**	**Forecast**	**Actual**	**Forecast**	**Actual**	**Forecast**
RATE 1	707,929	703,540	719,356	718,576	728,951	732,131	740,954	744,400	748,913	755,539
RATE 2	71,759	71,201	72,962	70,957	73,515	73,200	74,579	74,019	75,701	75,037
RATE 3	5,075	5,568	4,721	5,292	4,769	4,742	4,700	4,332	4,869	4,514
RATE 23	1,030	797	1,149	1,069	1,206	1,047	1,303	1,313	1,306	1,423
RATE 4	6	2	1	2	3	-	1	-	7	-
RATE 5	479	527	429	437	389	398	325	352	297	316
RATE 6	89	48	40	42	38	40	36	38	32	30
RATE 7	5	6	4	5	4	4	3	4	3	2
RATE 22	34	33	34	31	30	31	26	28	24	24
RATE 22 BYPASS	12	11	10	11	11	10	12	11	11	10
RATE 22 SPECIAL	1	1	1	1		1			2	
RATE 22A	9	9	10	9	10	9	10	10	11	10
RATE 22B	4	4	4	4	4	4	4	4	4	4
RATE 22B SPECIAL	1	1	1	1	1	1	1	1	1	1
RATE 25	578	410	597	529	678	567	624	619	596	596
RATE 25 BYPASS	7	8	7	7	7	7	7	7	7	7
RATE 27	104	94	100	97	101	98	101	97	102	95

	2009		2010		2011		2012	
Rate	**Actual**	**Forecast**	**Actual**	**Forecast**	**Actual**	**Forecast**	**Actual**	**Forecast**
RATE 1	753,735	766,209	760,559	758,903	765,553	763,886	759,712	773,231
RATE 2	75,986	75,638	76,028	77,204	76,437	77,954	72,235	76,126
RATE 3	4,841	4,522	4,882	5,083	4,863	5,191	4,675	4,962
RATE 23	1,348	1,490	1,406	1,319	1,433	1,328	1,520	1,526
RATE 4	2	-	7	7	5	7	11	7
RATE 5	282	316	234	283	224	283	216	236
RATE 6	29	30	24	32	20	32	16	21
RATE 7	4	2	3	2	2	2	3	4
RATE 22	22	24	21	22	21	21	23	20
RATE 22 BYPASS	10	10	8	10	7	10	6	8
RATE 22 SPECIAL	1		1	1	1	1	3	1
RATE 22A	8	10	9	8	9	8	9	9
RATE 22B	4	4	4	4	4	4	4	4
RATE 22B SPECIAL	1	1	1	1	1	1	1	1
RATE 25	597	596	550	579	503	579	502	550
RATE 25 BYPASS	7	7	7	7	7	7	6	7
RATE 27	99	95	101	99	98	99	98	101

41.0 Reference: Exhibit B1, page 91, SAP Adjustment and Appendix E-4

41.1 Please confirm that ratepayers will be held harmless over the PBR period as a result of the change in customer count methodology. If unable to so confirm please explain fully.

Response:

Confirmed. There will be no impact on the sales and transport volumes that are used to set customer rates as a result of the SAP adjustment because the overall energy demand remains the same.

For the forecast years in the PBR, the impact of the SAP adjustment has been carefully considered and isolated so as not to impact the UPC or the net additions forecasts. The higher UPC in 2012 as a result of SAP adjustment was not considered to be a true trend and was not included as part of the modeling analysis for the PBR years.

42.0 Reference: Exhibit B-1, page 92 and Fig. C1-6, and Appendix E1, Normalized UPC Lower ML

Preamble: The referenced page states:

> From the figure above we can see that there is a clear and consistent downward trend in use per customer irrespective of annual weather. The exception is in 2012 when the conversion to the new CIS had the impact of increasing the reported UPC. In rate schedules where a consistent trend is not identifiable a three year average is used.

42.1 Please provide a list of all the cases for which a three year trend is or has been used for forecasting UPC in any of FEI's service areas.

Response:

Regression analysis was carried out for each rate 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 t test statistics, the trend calculated from the regression model was used. Whenever the goodness of fit was not favorable, the average percentage change from 2009, 2010 and 2011 was used. The table below shows the list of all cases for which a three year trend is used (labeled as "Avg"). "Trend" indicates a statistically significant trend.

Region	RS1	RS2	RS3	RS23
LML	Avg	Avg	Avg	Trend
INL	Avg	Avg	Avg	Trend
COL	Avg	Avg	Avg	Trend
RSK	Avg	Avg	Trend	NA

42.2 Please confirm that the three-year average methodology involves taking the three most recent years for which UPC declines are available, applying an un-weighted average, and using this average for the forecast for the following year. If unable to so confirm please explain fully.

Response:

Confirmed. In the absence of any significant trend, the three year average of percentage changes is applied to the normalized actual UPC from the prior year. The average change from

the recent three years is applied on an un-weighted basis because each year in the analysis is assumed to have the equal weight.

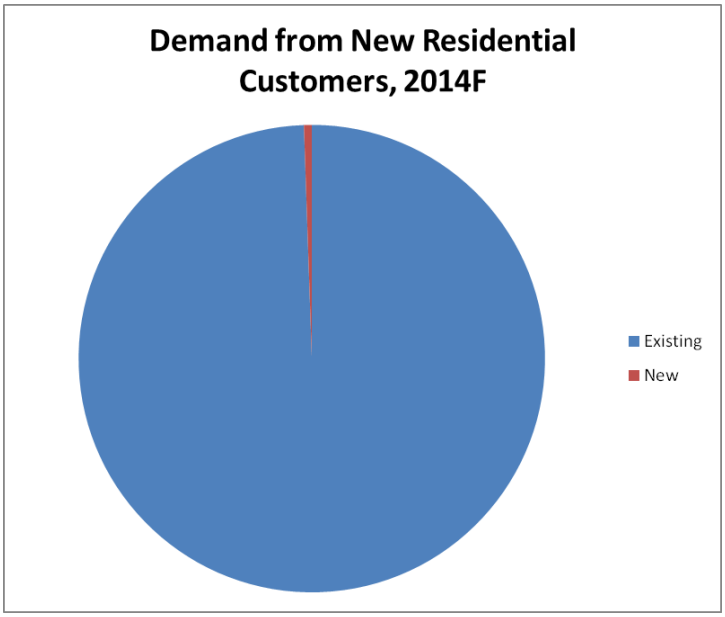
42.3 Does FEI assume that UPC for new additions is the same as UPC for existing customers?

Response:

Yes, we assume that UPC for new additions is the same as UPC for existing customers.

The current methodology does not apply a separate UPC to existing and new customers. The demand from the new customers, whether at the published rate class UPC or some other value, is very small relative to the demand from the rate class as a whole. Specifically, the residential volume from the new customers in 2014 is forecast to be only 0.54% of the total residential volume. Having a separate methodology for such a small customer segment would not lead to any significant change in the overall forecast.

The following pie chart shows the demand from the existing residential customers compared to the demand from new residential customers when calculated with a single rate class average UPC.



42.4 Please confirm that in identifying a trend in the data, FEI uses a linear regression methodology. If unable to so confirm please explain fully.

Response:

Confirmed. FEI uses a linear regression methodology to identify trends in residential and commercial UPC data.

42.5 Please provide summary details of all instances of FEI's identification of UPC trends in the past.

Response:

Please refer to the response to BCPSO 1.42.1. For the UPC rate schedules where analysis suggested a significant trend, more detail is provided below.

Region	Rate Class	Rsquare	Estimate.Index
COL	RATE23	0.89	26.11
INL	RATE23	0.68	21.35
LML	RATE23	0.58	10.03
RSK	RATE3	0.57	30.36

42.6 Please explain why the UPC increases in 2009.

Response:

The data shown in Figure C1-6 is actual normalized use rate per customer for the Lower Mainland. The 2009 data point in question is the actual UPC recorded for that year. Consistent with the trending methodology used to forecast UPC, the forecasts are generated based on a quantitative approach using historic data directly and without any speculation as to why.

To truly understand why the UPC increased relative to 2008, we would have needed to conduct a survey of residential customers to ask them why they used 0.7% more gas in 2009 than in 2008. Such a survey would have been expensive and, since the FIS forecast system does not have the ability to use the results from such a hypothetical survey as an input, the future forecasts would not be affected by this additional information.

42.7 Please provide evidence with respect to the accuracy of the past UPC forecasts for residential and commercial customers, that is, please provide a table showing forecasted versus actual UPC for each customer class for which historical data is available.

Response:

Please see Appendix E3 Forecasting Models Live Spreadsheets for the historical variances between the forecast and actual residential, commercial and industrial UPC.

43.0 Reference: Exhibit B1, page 94, Residential Customer Additions Forecast Methodology and page 96, Figure C1-8

43.1 Please indicate whether customer additions are forecast on a year-end basis or on some other basis.

Response:

Customer additions reflect a full year of additions and therefore the customer addition count is as of the end of the year.

Customer additions are forecast using the following method:

1. Develop growth rates from the CBOC long term housing starts forecast for both single and multi-family dwellings.
2. Apply the growth rates from 1) to the actual year end net additions from the previous year.
3. The annual net additions total is then distributed amongst the months of the year based on historical patterns.
4. The monthly account additions are loaded into the FIS model and the model is re-calculated.

This process has remained unchanged (except for the addition of the single and multi-family dwelling granularity) for the past decade.

43.2 Please provide a table showing forecasted versus actual net residential additions, if possible split between single and multi-family dwellings, for each year for which historical data is available.

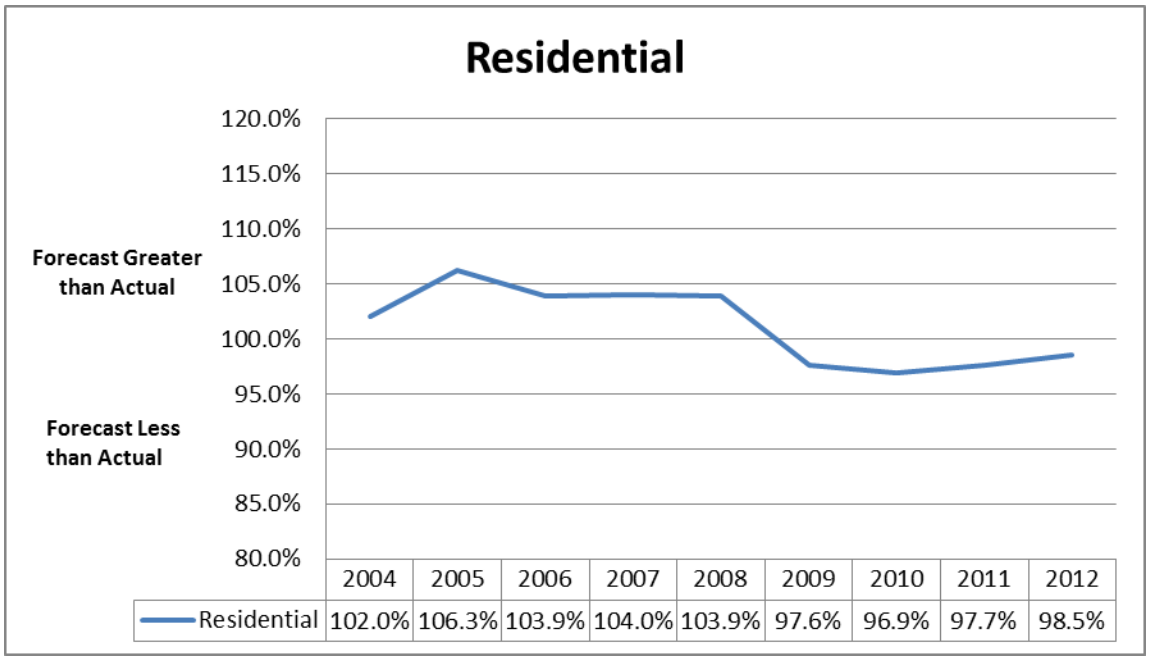
Response:

Please see Appendix E3 Forecasting Models Live Spreadsheets for historical variances between forecast and actual net residential additions. It is not possible to show the historical split between single and multi-family dwellings as we did not collect this data in the past.

43.3 Please provide a figure for residential customers similar to Figure C1-8 which is provided for commercial customers.

Response:

The following figure shows the residential net additions forecast variance.



44.0 Reference: Exhibit B1, page 98, RSAM

44.1 Please confirm that in calculating RSAM amounts, the forecast customer additions are used. If unable to so confirm, please explain.

Response:

The RSAM for Rate Schedules 1, 2, 3 and 23 is calculated for each separate Rate Schedule by taking the variance between actual and forecast use per customer (GJ), multiplied by the **actual** number of customers, multiplied by the delivery charge, and then adjusting the balance for income tax. In this manner, only the impact of variances in use rates is captured in the mechanism, and not the impact of variances in customer additions.

45.0 Reference: Exhibit A-3, BCUC IR 1.62.1

45.1 Please provide FEI's understandings with respect to standard statistical practice regarding the number of data points required to identify a trend at a 95% level of confidence.

Response:

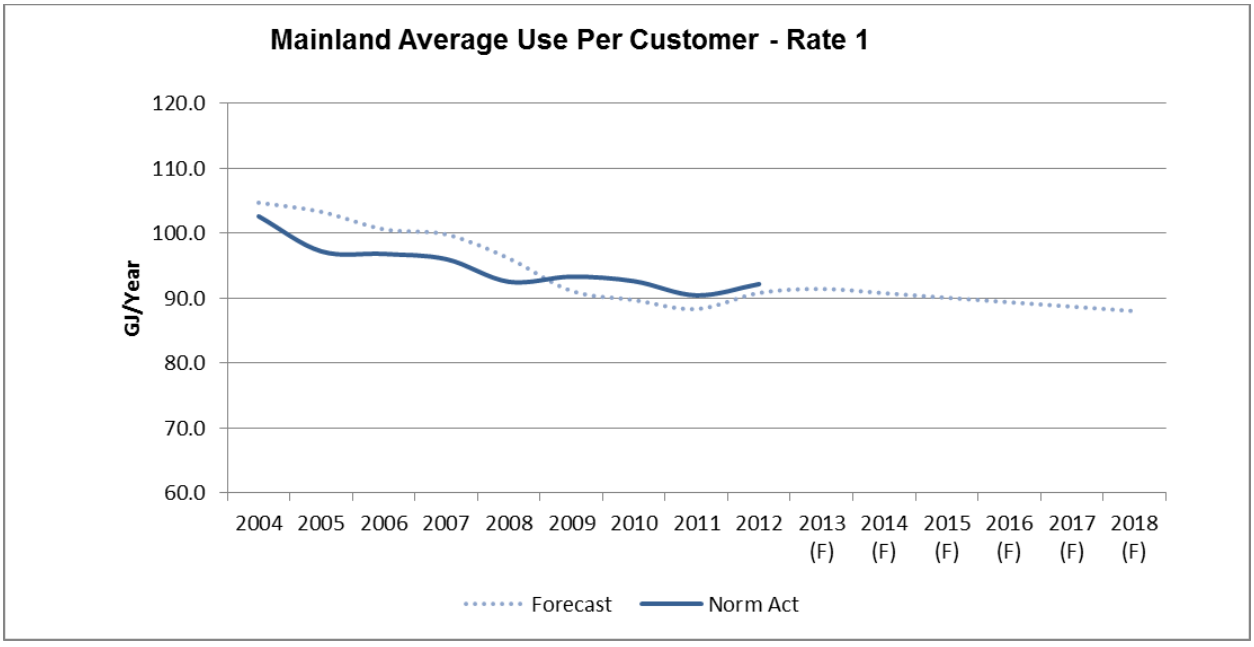
Consistent with standard statistical practice, FEI uses a minimum of 30 data points for the t-test to be valid in order to establish a confidence level of 95%. This is consistent with the Central limit theorem which states that a sample size greater than 30 would result in a normal distribution to a first approximation. Our trending analysis typically uses 36 data points which meets this minimum requirement.

46.0 Reference: Exhibit B1, page 100, Figure C1-11, Rate Schedule 1 UPC

46.1 Please augment Figure C1-11 by adding a line showing the UPC forecasted for each year 2004-12 inclusive.

Response:

The following figure is an extension of Figure C1-11 showing the forecasted UPC from 2004 through 2012.



47.0 Reference: Exhibit B-1, page 107, Figure C1-19, Normalized Residential Demand

47.1 Please explain why the normalized demand oscillates in the period 2004-2012. Does this indicate an issue or problem with the normalization methodology?

Response:

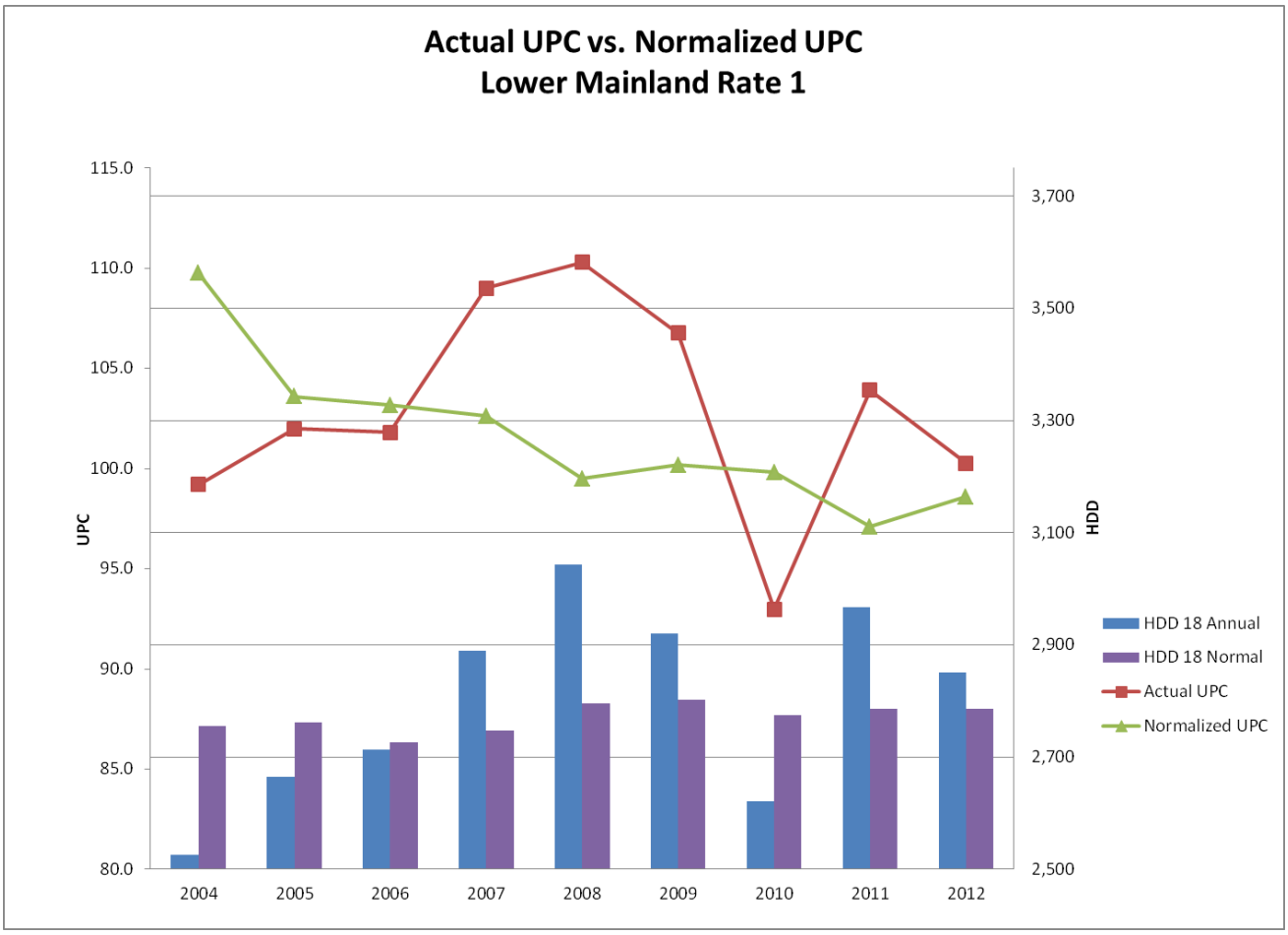
No, this does not indicate an issue or problem with the normalization methodology. From the chart, the normalized actual demand fluctuates randomly without any defined cycle or a pattern.

The normalization methodology is applied to UPC only. The normalized volume is the product of the normalized UPC and year end customer counts. To understand the effect the normalization method is having we need to consider only the UPC. Like all approximation models, the normalization method is not expected to produce a perfectly straight and smooth line.

The example below demonstrates how the actual UPC is adjusted through the normalization methodology based on the actual temperature and the 10 year normal temperature for Lower Mainland. In this example aggregate HDDs for the year are used to identify warm and cold years. Larger bars indicate colder years. During warmer than normal years the blue bar will be below the purple bar and normalization adjusts the UPC upwards. Similarly when the actual temperature is colder than normal (and the blue bar is larger than the purple bar) the UPC is decreased after normalization. As the figure demonstrates the normalization method in use at FEI consistently adjusts the actual UPC in the correct direction.

The normalized residential demand is then the product of the normalized UPC and total residential accounts.

FEI believes that this method, which remains unchanged from previous years, continues to provide good results.


Actual UPC vs. Normalized UPC
Lower Mainland Rate 1
UPC
HDD
115.0
110.0
105.0
100.0
95.0
90.0
85.0
80.0
3,700
3,500
3,300
3,100
2,900
2,700
2,500
2004
2005
2006
2007
2008
2009
2010
2011
2012
HDD 18 Annual
HDD 18 Normal
Actual UPC
Normalized UPC

1

2

48.0 Reference: Exhibit B-1, page 109, Table C1-4, Forecasted Demand

48.1 Please provide a revised table showing forecasted demand for 2014-18 that takes into account the forecasted number of customers and the forecasted UPC for each class.

Response:

The forecast demand shown in Table C1-4 already takes into account the forecasted number of customers and forecasted UPC for each rate class.

49.0 Reference: Exhibit B1, page 113, Forecast Gross Margin at Existing Rates

49.1 Does the referenced figure incorporate both forecasted customer additions and forecasted UPC? If not, please prepare a similar table that incorporates both of these forecasted items over the PBR period.

Response:

Confirmed. Table C1-8 incorporates both forecasted customer additions and forecasted UPC.

50.0 Reference: Exhibit B1, page 126, M&E Employees

Preamble: The referenced page states:

As a general policy, FEI establishes base salary and incentive compensation targets at the median level of a peer group of companies.

50.1 If FEI became aware that the actual M&E base salary and incentive compensation for one or more positions or categories was above the median level of the peer group, would FEI reduce the compensation level to the median?

Response:

FEI's approach to competitive compensation is to target both base and incentive pay at the market median of a peer group. The structure consists of five broad bands with base salaries administered within a range of 80% to 110% of the market median. Salary ranges are reviewed annually to remain market-competitive. There are a variety of positions included in each band. A market median incentive target is established for each band.

Within this context if FEI became aware that actual base salary and/or incentive target was above the median level of the peer group for one or more positions, the base salary would, in most cases, be administered such that for positions where actual is above 110% of market median, no further increases to base pay occur. Where unique market conditions exist, variations may be considered, but those circumstances are rare.

50.2 Has the scenario outlined in the previous part occurred in the past? If so, please provide details of FEI's response.

Response:

This scenario has occurred in the past. Please refer to the response to BCPSO IR 1.50.1.

51.0 Reference: Exhibit B1, page 124, Table C3-2, 2013 Departmental O&M Reconciliation

51.1 Please augment the referenced table by adding a column to show actual 2012 expenditures by department.

Response:

Table C3-2 has been extended to include 2012 actual expenditures.

Table C3-2: 2013 Departmental O&M Reconciliation ($ thousands)

			Productivity		2013 Deferrals			Accounting Changes		
	2012 Actual	2013 Approved	(Sustainable Savings)	2013 Projection	PST (full year)	BCUC Fees & Insurance	Pension/OPEB (O&M portion)	Pension/OPEB (Retiree portion)	Software Fees	2013 Base
Operations	59,806	63,189	320	63,509	137		3,667	1,704		69,016
Customer Service [1]	40,737	52,452	(10,627)	41,825	18		1,744	810		44,398
Energy Solutions & External Relations	18,075	18,181	1,034	19,215	23		1,012	470		20,721
Energy Supply & Resource Dev	3,488	3,738	262	4,000	7		295	137		4,440
Information Technology	23,442	25,379	(1,162)	24,217	340		691	321	(1,800)	23,768
Engineering Services & PM	13,599	16,956	(1,500)	15,456	58		1,027	477		17,018
Operations Support	11,038	12,990	(1,123)	11,867	69		802	373		13,111
Facilities	9,563	9,259	(10)	9,249	40		146	68		9,504
Environment Health & Safety	2,481	2,999	(319)	2,681	12		123	57		2,872
Finance & Regulatory Services	12,149	14,184	(906)	13,279	3	923	597	277		15,079
Human Resources	8,610	8,511	(53)	8,458	22		487	226		9,192
Governance	7,366	7,935	-	7,935	-	93	-	-		8,028
Corporate	1,915	230	(587)	(358)	34		13	(5,851)		(6,161)
	212,269	236,003	(14,670)	221,333	762	1,016	10,605	(930)	(1,800)	230,985

1 2012 Actual and 2013 Projection excludes Customer Service deferred O&M

Please note that 2012 Actual is best compared against 2013 Projection as opposed to 2013 Base. The 2012 Actuals are also shown in Table C3-1.

51.2 Please provide the amount of Customer Service deferred O&M that is excluded from the 2013 projection.

Response:

As discussed on pages 123 and 151 of the Application and shown on Table C3-15: FEI Customer Service O&M Review, $10.285 million is the amount of deferred O&M that will be allocated to the Customer Service Variance Deferral Account for 2013.

51.3 Can FEI confirm that the PST adjustments made in this table assume a 12.7% capitalization and the application of a 1.7% factor?

Response:

The PST adjustments in Table C3-2 represent a full year impact to O&M of the return to PST/GST from HST. As with all gross O&M, this impact would be subject to a capitalization rate of 14%.

Please refer to the response to BCPSO IR 1.55.1 for confirmation that the return to PST results in a 1.7% increase in capital costs.

52.0 Reference: Exhibit B-1, page 133, Table C3-5, Departmental O&M Forecasts

52.1 The total O&M forecasted for each year is very closely approximated by applying an increase of 3.01% per year. Did an assumed overall increase of 3% in O&M play any part in forecasting FEI's O&M over 2014-18?

Response:

No, an assumed overall increase of 3% in O&M did not play any role in forecasting FEI's O&M over 2014-2018.

As explained in Section 3.1, page 121, the O&M forecast for 2014-2018 represents a high level forecast of future trends and upcoming challenges for FEI. In developing the 2014-2018 forecast, consideration was given to each of the following:

- General labour and benefit inflation
- Specific actuarial forecasts for Pension and OPEB
- Specific forecasts for Insurance and Rate 16 O&M
- Contract inflation for specific major contracts
- Individual pressures and opportunities identified by the various departments, recognizing an ongoing productivity focus.

Any resulting comparison to a 3% annual increase is strictly coincidental.

52.2 Does FEI consider compensation costs to be controllable, whether under cost-of-service regulation or under PBR?

Response:

For the most part, FEI considers compensation costs to be controllable, whether under cost-of-service regulation or under PBR. Two ways that FEI seeks to control costs are through:

1. The overall number of positions

2. Cost controls on compensation administration

Each vacancy created through voluntary/involuntary turnover and/or retirement is seen as an opportunity to look for efficiencies. Vacancies are not automatically filled.

FEI also manages compensation costs through a market tested compensation program for M&E employees anchored by a peer group selected to permit the Company to attract and retain talent. Base salary ranges are market tested annually. Incentive pay is linked directly to individual and corporate performance which reinforces results based rewards

FEI controls compensation costs for unionized employees by negotiating salaries and wages that are fair and reasonable, the costs of which are offset by other productivity gains achieved through collective bargaining.

It should be noted there are market-driven externalities that FEI is not always able to control, such as increased competition for "hot jobs" or the timing of employee retirements. However, FEI seeks to manage these costs as much as possible as discussed above.

53.0 Reference: Exhibit B1, page 149, Bad Debt Expense and

Exhibit B1, Section E, Schedules 25, 26, 53, and 54

Exhibit B-1-1Appendix F6, Appendix G2 Schedules 24, 52

53.1 Please provide details with respect to calculating the $4M in forecasted 2013 bad debt expense.

Response:

The estimated $4 million in forecasted 2013 bad debt includes the mass market bad debt for residential and commercial customers as well as industrial bad debt. The breakdown is as follows:

Mass Market Bad Debt	$3.587 million (based on experience rate of 0.322%)
Industrial Bad Debt	$0.200 million (based on historical averages)
Total Bad Debt	$3.787 million

53.2 Is there an amount embedded in rates with respect to bad debt expense? If so, please provide the amount.

Response:

Bad Debt expense of approximately $4 million is included in the Customer Service O&M that was approved for 2013 as part of FEI's 2012-2013 RRA.

53.3 Please explain how the bad debt amounts referred to in the referenced schedules are related to the $4M 2013 bad debt expense and to the forecasted bad debt expense forecasted for 2014-2018.

Response:

The bad debt expenses for 2013 and the forecast amounts for 2014 to 2018 were included in Appendix F6 and are as follows:

2013	2014	2015	2016	2017	2018
$3,789	$3,861	$3,942	$4,025	$4,110	$4,196

The Bad Debt Provision amount of $726 thousand for 2012, included in Section E (schedule 25) and Appendix G2 (schedule 24), is a onetime adjustment to reflect the portion of the Provision that is not deductible for income tax purposes.

The Reserve for Bad Debt amounts shown on the balance sheet, included in Section E (Schedule 53 and 54) and Appendix G2 (schedule 52), are accumulated reserves for bad debt from overdue balances (they represent the cumulative amounts expensed less amounts collected). These amounts are different from bad debt expenses included in O&M.

54.0 Reference: Exhibit B-1, page 178, Operations Support – Fleet Services

54.1 Please provide a summary table showing the 2012 FEI fleet, by vehicle type and model year.

Response:

Below is a summary table of the FEI vehicle fleet, summarized by vehicle type and model year

Vehicle Type	1982-1995	1996-2000	2001-2005	2006-2010	2011-Present	Total
CAR			1	11		12
LIGHT TRUCKS & VANS	1	24	71	212	80	388
MEDIUM TRUCKS	3	3	12	34	5	57
HEAVY TRUCKS	2		1	2	2	7
Total	6	27	85	259	87	464

54.2 Please provide the actual amount spent on fleet services operations support in 2012.

Response:

All Fleet services operating costs are charged out directly to the business units including the following: Customer & Corporate Services, Operations & Engineering, Facilities, Operations Support, Energy Solutions & External Relations, Finance & Regulatory and Energy Supply & Resource Development. These costs include items such as fuel, maintenance, insurance and expenses associated with managing the fleet. The total O&M costs associated with vehicles in 2012 was $3.848 million.

54.3 Please provide the projected amount spent on fleet services operations support in 2013.

Response:

All Fleet services operating costs are charged out directly to the business units including the following: Customer & Corporate Services, Operations & Engineering, Facilities, Operations Support, Energy Solutions & External Relations, Finance & Regulatory and Energy Supply & Resource Development. These costs include items such as fuel, maintenance, insurance and expenses associated with managing the fleet. The total projected O&M costs associated with vehicles in 2013 is $3.854 million.

54.4 Has there been any increase to the fleet size since 2012? If so, please specify any change to the fleet made in 2013.

Response:

Since 2012, FEI has not increased the size of the vehicle fleet. Furthermore, this flat trend is expected to continue over the period between 2014 – 2018.

55.0 Reference: Exhibit B1, page 206, Table C4-2, Base Capital Adjustments

55.1 Can FEI confirm that the overall effect of the return to PST is an increase of 1.7% in capital costs?

Response:

FEI confirms that the overall effect of the return to PST is an increase of 1.7% in capital costs.

Only that portion of capital expenditure that would attract PST was considered in calculating the PST impact on capital.

56.0 Reference: Exhibit B1, page 207, Table C4-3, Forecast FEI Capital Expenditures

56.1 Although growth capital and its components vary over the 2014-18 PBR period, the CIAC is almost constant over this same period. How was CIAC forecasted over the period?

Response:

The $5.8 million CIAC forecast for 2014-2018 is summarized in Exhibit B-1, Section C4.6.5, Table C4-24, page 249. Essentially there are three categories - CIACs from growth capital (new services, conversion services and new mains) and CIACs from third parties for billable capital work (sustainment capital - alterations, re-routing, lowering, etc.) and CIACs related to retirements of gas assets (pipe and stations).

The portion of CIACs related to growth capital was forecast at $1.777 million per year and was based on the average actual growth capital CIACs for 2011 and 2012 ($1.645 million and $1.860 million respectively). CIACs for growth capital have fluctuated fairly widely in the past and are difficult to predict with any certainty however the past two years were seen to be fairly consistent and therefore used as an average for the forecast. The CIAC forecast related to growth capital was not increased in step with slight increases in growth capital expenditures as much of the increase in regular growth capital expenditures reflected increased service additions activity in the Interior where service line unit costs are typically lower and below the levels requiring a customer contribution.

The portion of CIACs related to other capital (third party work) was forecast at $3.757 million per year and is based on a review of recent past expenditures, excluding very large amounts of work such as that caused by the Gateway Transportation Project in the Lower Mainland. In 2012 the work that was deemed to be billable to others was approximately $4.658 million excluding Gateway. In 2011 the amount was approximately $6.029 million. It is difficult to predict the actual work that will be requested to be done and considering the variability in the requests FEI believes that its forecast is reasonable.

The remaining CIAC forecast of approximately $0.287 million is related to retirements of gas assets (i.e. where municipal work has resulted in retirement of piping or stations).

56.2 Is the time profile of projected capital expenditures, i.e., an increase in 2014, flat for 2015 and 2016, then increased again in 2017 and 2018, in any way related to the PBR proposal?

Response:

No. The forecasted FEI capital expenditures presented in Table C4-3, page 207 of the Application are for reference purposes only. They represent a high level forecast of future trends and projected capital spending for FEI. The Company's proposed PBR Plan does not rely on the forecast capital expenditures. Rather, it relies on a formula-based approach, as discussed in Section B of the Application.

57.0 Reference: Exhibit B1, page 210 Asset Management Strategy

57.1 When was the PAS55 standard first published?

Response:

A Publicly Available Specification (PAS) is a sponsored fast-track standard, developed according to guidelines set out by the British Standards Institution (BSI). PAS55 was first published in 2004, sponsored by the United Kingdom Institute of Asset Management.

The 2008 update (PAS55:2008) garnered increasing participation: 50 organizations from 15 industry sectors in 10 countries.

The International Standards Organization (ISO) has built on PAS55 and other international guidelines for development of a new ISO 55000 series of international standards. The development of these standards is ongoing, with 31 countries participating, including Canada. The standards have an expected publication date of fall 2013/spring 2014.

57.2 Is adherence to PAS55 required for any Canadian gas distributors?

Response:

To FEI's knowledge, PAS55 is not currently a regulated requirement for any Canadian gas distributors. However, the standard was reviewed by a committee of the Canadian Gas Association and formed the basis of the "Guiding Document on Asset Management" from the CGA Asset Management Task Force.

57.3 Please indicate what standard FEI adhered to, prior to PAS55 and please briefly indicate the differences between it and PAS55, along with any implications for capital expenditures.

Response:

To clarify, in the Application, FEI stated the asset management strategy would incorporate established industry practices derived from the international PAS55 standard while also leveraging existing systems and processes already in place in both the gas and electric

divisions. As described in the response to BCPSO IR 1.57.2, the PAS55 standard is not currently a regulated requirement for any Canadian gas distributor; however, the standard is recognized as an important reference source for Canada's natural gas delivery industry and FEI recognizes the value of incorporating some of these practices where they result in customer benefits.

While there are no current asset management standards FEI is required to adhere to, asset management practice at the FEU and its predecessor companies has been continually evolving and improving since the initial installation of assets. Appendix C3 – Long Term Sustainment Plan provides the history of FEU's asset management practice and how it has progressed in time.

PAS55 formalizes a management system approach to asset management. A management system is a framework of processes and procedures used to ensure that objectives are met consistently and to required standards. It is commonly described as a "Plan, Do, Check, Act" approach.

Continuous improvement is an important element of all management systems. FEI considers the development of a common Asset Management Strategy as a continuous improvement initiative, driven in part by the opportunity to leverage systems and processes that are already in place in both the gas and electric divisions. While the historic asset management approach resulted in a generally reactive focus at the field activity level, FEI believes that management system enhancements can proactively improve focus on customer interests by equipping asset planners and decision-makers with processes and information to deliver consistent, optimized, and aligned asset plans.

A recent example of an asset management enhancement in FEI has been the development of the Long Term Sustainment Plan (LTSP) risk framework. The LTSP framework supports Asset Management staff in identifying long-term programs and projects, and in prioritizing those programs and projects relative to one another.

The level of capital expenditures projected throughout the 2014-2018 forecast period for FEI results from the current state of asset management planning in the organization, including enhancements provided by the LTSP. Overall, sustainment capital expenditures are forecast to increase throughout the PBR period. Notwithstanding this, FEI does not expect that the application of PAS55 principles will significantly increase or decrease total capital or maintenance expenditures during the PBR period; rather, it will help ensure that expenditures are allocated optimally to maximize the customer benefit.

58.0 Reference: Exhibit B1, page 219 and Exhibit A-3 BCUC IR 1.155.1,

Meter Exchanges

58.1 Regarding the new SS-06 sampling plan, has FEI knowledge, through communicating with other Canadian gas distribution utilities, that all Canadian gas distribution utilities will be implementing SS-06 effective January 2014?

Response:

All gas utilities have had the opportunity to be made aware of the requirements, including the mandated implementation date, of the new Measurement Canada sampling plan SS-06. In addition, FEI is not aware of any Canadian gas utility which manages its meter fleet using compliance sampling that will not be implementing this new standard on the mandated date.

This standard has been a topic of discussion at Canadian Gas Association (CGA) meetings with regard to the expected impacts and level of readiness for implementation of each member utility by the required date. In addition, Measurement Canada and the Canadian Gas Association have hosted detailed training seminars to educate staff of the member utility companies regarding the specific requirements of the new sampling plan. Finally, Measurement Canada has presented information at the annual Canadian Gas Association Measurement conference to further educate on the requirements of the new sampling plan to gas utility representatives. As such, it is reasonable to expect all Measurement Canada registered utilities that manage meter fleets through compliance sampling to fully understand and comply with the new compliance sampling standard including the requirement to meet the mandated implementation date.

59.0 Reference: Exhibit B1, page 220 and pages 239-240, Meter Unit Costs

Preamble: The first referenced page states:

> The meter unit cost is influenced by the type, the size, the design of the meter, the installation, fabrication and exchange conditions of the meter set and the timing of the bulk meter purchases and meter upgrade activity. A blended unit cost of all customer types is used for meter exchanges. Meter unit costs typically range from $75 to $10 thousand depending on the customer requirements.

59.1 Please provide the cost range and average cost for residential meters.

Response:

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.

In relation to residential meters, the unit 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 unit 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 unit 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.

59.2 Please provide the cost range and average cost for commercial meters.

Response:

Please refer to the response to BCPSO IR 1.59.1.

59.3 Please provide the cost range and average cost for industrial meters.

Response:

Please refer to the response to BCPSO IR 1.59.1.

59.4 Please provide a breakdown, for each year of the PBR plan, of the number of meters forecasted (new or replaced) among (i) residential, (ii) commercial, and (iii) industrial.

Response:

The table below provides a breakdown for the meter replacement forecast during the planned PBR period between 2014 and 2018 to ensure compliance with the new Measurement Canada mandated sampling plan SS-06. The totals are consistent with those provided in Table C4-9.

	2014	**2015**	**2016**	**2017**	**2018**
Residential	67345	70845	75345	75345	75345
Industrial	447	447	447	447	447
Commercial	4023	4023	4023	4023	4023
Total	71815	75315	79815	79815	79815

Furthermore, an additional table is presented below which provides the breakdown of forecasted new meter installs during the planned PBR period between 2014 and 2018.

	New Additions (reference Table C4-20 for totals)				
	2014	**2015**	**2016**	**2017**	**2018**
Residential	4,594	4,955	5,085	4,972	4,806
Industrial	0	0	0	0	0
Commercial	388	373	358	372	367
Total	4982	5328	5443	5344	5173

59.5 Can FEI confirm that meter costs are not allocated to any rate class according to the blended costs of meters for that rate class?

Response:

FEI confirms for this Application the meter costs are not allocated to any rate class according to the blended costs of meters for that rate class. For budgeting and planning an average cost for the various types of meters expected to be added is used (see Table C4-20, Page 240 of the Application).

60.0 Reference: Exhibit B-1, page 221, Pipeline Class Location Upgrades

Preamble: The referenced page states:

Clause 4.3.2 of CSA Standard Z662, Oil and gas pipeline systems, defines limitations on operating stress (safety factor) based on the number of dwellings within 200 m of the pipeline. An increase in the density of dwellings adjacent to a pipeline may result in the class location being changed leading to a requirement to reduce the operating stress of the pipeline and thus increase the factor of safety. CSA Z662 also requires annual assessments of the class location to recognise and accommodate development near the pipeline. In instances where the class location is changed as a result of development FEI must change the operating parameters of the pipeline. This may require reducing the operating pressure which leads to a loss of capacity and may limit the ability to meet customer demand. In instances where reducing operating pressure is unacceptable, the impacted section of pipeline must be replaced to meet the required safety factor while maintaining customer supply.

60.1 When was Standard Z662 issued?

Response:

The current edition was released in 2011.

60.2 When did clause 4.3.2 come into effect?

Response:

The requirements contained in Clause 4.3.2 of the current version of CSA Standard Z662 have been in place in essentially the same form since 1973. Similar requirements existed before then; however, they were stated differently.

60.3 With respect to the seven pipelines referred to, when did FEI first realize that to be compliant with the clause, upgrades would be required?

Response:

FEI first became aware of the potential sites in 2011 following an assessment of class location which resulted in further evaluation. Upgrade to these pipelines could impact either system operations or result in significant public disruption during construction; therefore, it was necessary to validate the pipe specifications and condition, the extent and type of development, and the long term operating conditions to confirm that the upgrades were necessary. The extent of the upgrades was determined during the first quarter of 2012.

60.4 Over what number of years are the segments to be replaced depreciated?

Response:

The segments to be replaced are going to be depreciated over 69.44 years based on the approved depreciation rate of 1.44% for transmission pipeline (465).

61.0 Reference: Exhibit B-1, page 34, FEI Pre-2004 PBR Experience

61.1 Beginning with 1994 and continuing for each successive year through 2003, please provide a table that shows the annual increase in delivery revenue along with the annual inflationary increase in the BC CPI.

Response:

The following table provides the % change in the Delivery Charge for Lower Mainland Residential customers and the % change in the BC CPI from 1994 through 2003.

	Lower Mainland Rate Schedule 1 - Residential Delivery Charge(s) Jan. 1			%	BC CPI %
	Non-Heating April 1 - Oct. 31	Heating Nov. 1 - March 31	Post Seasonal Rates	Increase	Increase
1994	$ 1.000	$ 2.000			1.9%
1995	$ 1.203	$ 2.406		20.3%	2.3%
1996	$ 1.268	$ 2.535		5.4%	0.9%
1997	$ 1.330	$ 2.669		5.3%	0.7%
1998			$ 2.247	1.1%	0.3%
1999			$ 2.253	0.3%	1.1%
2000			$ 2.327	3.3%	1.9%
2001			$ 2.632	13.1%	1.7%
2002			$ 2.502	-4.9%	2.3%
2003			$ 2.579	3.1%	2.1%

62.0 Reference: Exhibit B-1, page 35, Productivity Factor in Previous PBR

Preamble: The referenced page states:

> The parties involved in the NSP agreed that linking the productivity factor to BC-CPI would be beneficial for both ratepayers and FEI since the productivity opportunities would increase as inflation increased, and conversely FEI would have more limited opportunities for productivity improvements if the rate of inflation decreased. The productivity factor agreed to was 50 percent of CPI for 2004 and 2005, and 66 percent of CPI from 2006 to 2009.

62.1 Please discuss the advantages and disadvantages for ratepayers and for the utility of using such a % of inflation as a productivity factor as opposed to using a fixed productivity factor. Do the advantages and disadvantages depend on forecasts or expectations of inflation during the PBR period?

Response:

The advantages/disadvantages of a fixed productivity factor versus one that is expressed as a % of inflation are dependent on expectations for inflation in the PBR period and also on the expected volatility of inflation. In periods of stable inflation, it is possible that a fixed productivity factor and a percentage of inflation-based ("floating") X-factor could be structured to produce fairly similar results for the I-X formula.

If inflation rates are more volatile, and in particular moving upward, the floating X-factor may begin to produce X-factor results that are too large, making the productivity challenge in the I-X formula unreasonably difficult to achieve. A fixed X-factor may be more acceptable in these conditions.

On the other hand, if inflation rates are moving downward towards zero and perhaps even becoming negative a fixed X-factor may make the productivity challenge too onerous if the utility's own cost inputs are not facing the same very low or negative inflationary pressures. In this circumstance a floating X-factor may provide a reasonable hedge for both the utility and customers.

63.0 Reference: Exhibit B-1-1, Appendices F4 and F5, Deferral Accounts

63.1 Are the only criteria used by FEI, in determining whether a deferral account should be classed as a rate base or a non-rate base deferral account, as expressed in the Overview to Appendix F5?

Response:

Tthe Overview to Appendix F-5 provides a fairly comprehensive summary of the criteria FEI uses in determining whether a deferral account should be requested as a rate base or non-rate base account. In addition, there have been situations (such as the EEC Incentives non-rate base deferral account) where FEI has created a non-rate base deferral account due to the difficulty in forecasting the balances to be included in rate base, and where the balances are considered material.

63.2 Can FEI confirm that the interest applied to a rate base deferral account is equal to the utility's WACC and provide the current rate?

Response:

Yes. For rate base deferrals the return is implicit due to its inclusion in the utility's rate base.

The original approved return on rate base for 2013, from Order G-44-12 approving the 2012/2013 Revenue Requirement Application, was 7.82 percent. On an after-tax basis, it is equivalent to the utility's after-tax WACC, or AFUDC rate, of 6.82 percent.

The revised approved return on rate base for 2013, from changes to FEI's equity structure as a result of Order G-75-13 approving Phase 1 of the Generic Cost of Capital Proceeding, is 7.44 percent. On an after-tax basis, it is equivalent to the utility's after-tax WACC, or AFUDC rate, of 6.43 percent.

63.3 Please provide the current AFUDC rate that balances in non-rate base deferral accounts attract and explain how this rate is determined.

Response:

FEI has provided a numerical example below to show how the currently approved AFUDC (WACC) rate of 6.43 percent was determined.

Equity – 38.50% Equity Thickness x 8.75% ROE = 3.37%

Long-term Debt – 56.97% Long-term Debt Thickness x 6.87% Long-term Debt Rate x (1 – 25% tax rate) = 2.94%

Short-term Debt – 4.53% Short-term Debt Thickness x 3.50% Short-term Debt rate x (1 – 25% tax rate) = 0.12%

AFUDC = 3.37% Equity + 2.94% Long-term Debt + 0.12% Short-term Debt = ***6.43%***

63.4 Has FEI ever applied for a rate based deferral account to record expenses for a year in which rates have already been set? If so, please provide details.

Response:

Typically, FEI would not apply for a rate base deferral account to record expenses for a year in which rates have already been set. There are a number of situations, particularly for costs related to regulatory applications and proceedings, where costs are incurred part way through a year for which rates are already set and the rate base deferral is not added into rate base until the beginning of the following year. An example of this is the 2014-2018 PBR Application deferral, where FEI will incur the majority of the costs in 2013 but the account will not earn a return until it enters rate base in 2014.

63.5 Has FEI ever applied to the BCUC for a rate base deferral account and had the BCUC either (i) decline to approve any deferral account or (ii) decline to approve a rate base deferral account but approve a non-rate base deferral account? If so, please provide details.

Response:

FEI has reviewed the Commission's decisions with respect to its deferral account requests since the beginning of 2010 (excluding projects that were subsequently transferred to FAES) and

found the following orders that either declined to approve a deferral account or declined to approve the requested type of or return on a deferral account:

FEU Application for Approval of 2012 and 2013 Natural Gas Rates Order G-44-12 dated April 12, 2012:

> *"The discontinuance, modification, and creation of deferral accounts, and the amortization and disposition of balances of deferral accounts, for FEI, FEVI, FEW and Fort Nelson is approved subject to the following:*
>
> *a. The creation of an EEC non-rate base deferral account, attracting Allowance for Funds Used During Construction (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 is approved without any determination on the amortization rate and recovery of this account at this time.*
>
> *b. The request to expand the compressed natural gas (CNG) and liquefied natural gas (LNG) Service Recoveries Deferral Account for the 2012 and 2013 forecast period is denied.*
>
> *c. The creation of the natural gas vehicle (NGV) Incentives deferral account is approved on the basis that this account attracts no return."*

FEI Application for Approval of Kingsvale-Oliver Reinforcement Project Stage 2a Project Development Costs and Accounting Treatment Order G-101-12 dated July 23, 2012. FEI had requested that costs be added to the existing rate base SCP Mitigation Revenues Deferral Account. Instead, the Commission ordered:

> *"FEI is directed to establish a new non-rate base deferral account for recording of Stage 2a feasibility expenses with treatment of interest rate and deferral period to be determined at the next Revenue Requirement."*

FEI Application for Approval of a Temporary Service Agreement for Liquefied Natural Gas (LNG) Service, for Approval of a Service Agreement for LNG Delivery, for Approval of a Daily Charge for the Use of an LNG Tanker and for Approval of a Daily Charge for the Use of a Mobile LNG Refuelling Station Order G-156-12 dated October 22, 2012:

> *"The Panel approves a deferral account for the costs of the Amended Application; however, the use of a non rate base deferral account attracting AFUDC is denied. FEI may apply the weighted average cost of debt to the account. The Panel directs that FEI may not recover any of the costs of the Amended Application from its non-bypass customers. The Panel directs FEI to propose a method for recovery of this deferral*

account, calculate the effect of this treatment in the rate to Vedder, and file the amended rate within thirty days of the date of this Order."

FEI Application for Approval to Amend Rate Schedule 16 on a Permanent Basis Order G-88-13 dated June 4, 2013:

"The request to include the Application Costs in the NGV Application Deferral Account is denied. The Application Costs are to be placed in a new deferral account, attracting interest only, and amortized into rates over one year, beginning with the next revenue requirement period.

The request to use the CNG and LNG Recoveries Deferral Account for the purpose of capturing the incremental revenues received and the incremental costs for 2012 and 2013 for Rate Schedule 16 is denied. FEI is directed to establish a new deferral account for this purpose."

63.6 Is it FEI's understanding that the BCUC's criteria, in determining whether to approve a requested deferral account and, if so, whether the account should be a rate base or non-rate base account, are the same as FEI's criteria?

Response:

FEI uses consistent criteria to determine the appropriate treatment and recovery of deferral accounts. FEI has historically received decisions from the BCUC that would indicate that FEI and the BCUC were aligned in their understanding of the criteria to be used to evaluate deferral account requests. However, decisions received since the beginning of 2012 by FEI (listed in response to BCPSO IR 1.63.5), and also its affiliated companies FortisBC Inc. and FortisBC Alternative Energy Services Inc., would indicate that the BCUC does not always apply the same criteria as FEI to determine the appropriate treatment and recovery of deferral accounts.

Attachment 4.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 4.3

ERICA HAMILTON
COMMISSION SECRETARY
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VIA EMAIL

April 18, 2013

Ms. Diane Roy
Director, Regulatory Affairs – Gas
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8
(gas.regulatory.affairs@fortisbc.com)

Mr. Dennis Swanson
Director, Regulatory Affairs
FortisBC Inc.
Suite 100 – 1975 Springfield Road
Kelowna, BC V1Y 7V7
(electricity.regulatory.affairs@fortisbc.com)

Dear Ms. Roy and Mr. Swanson:

Re: FortisBC Energy Inc.
and FortisBC Inc.
2014 Revenue Requirements Application
Productivity Improvements in a Performance Based Rate Setting Environment

The British Columbia Utilities Commission (Commission) writes to provide FortisBC Energy Utilities and FortisBC Inc. (together the Companies), with further direction regarding the inclusion of an evaluation of Performance Based Regulation (PBR) methodologies, utilized in Canada and a proposal for a PBR methodology in the Companies' next Revenue Requirements Applications (RRA).

Commission Decisions on the FortisBC Energy Utilities 2012-2013 Revenue Requirements and Rates Application (FEU 2012-2013 RRA) and the FortisBC Inc. 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan (FortisBC 2012-2013 RRA and ISP) examined productivity improvements under a PBR setting.

The FEU 2012-2013 RRA Decision found there was sufficient evidence to suggest that introducing a PBR environment has the potential to act as an incentive to create productivity improvements but also recognized that there are limitations to the PBR methodology. The FortisBC 2012-2013 RRA and ISP Decision had the view that there is an ongoing need for utilities to manage their business in a manner that actively seeks out and creates efficiencies resulting in a productivity improvement culture.

The Commission requires FEU and FortisBC to describe its productivity improvement culture by an examination of PBR methodologies in its next Revenue Requirements Applications. This examination is to evaluate the most recent PBR methodologies employed by FEU and FortisBC and the various PBR methodologies approved by other jurisdictions in Canada. FEU and FortisBC are to propose a PBR methodology and explain how it addresses the limitations in the various PBR methodologies, and will achieve a productivity improvement culture.

Yours truly,

Erica Hamilton

PWN/yl

IP/April/FEI/04-18-2013_FEI-FBC_PBR 2014RRA

Attachment 17.1

REFER TO LIVE SPREADSHEET MODELS

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Attachment 19.2

REFER TO LIVE SPREADSHEET MODELS

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