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October 9, 2015

Via Email
Original via Mail

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
P.O. Box 49130
Three Bentall Centre
2900 – 595 Burrard Street
Vancouver, BC V7X 1J5

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: FortisBC Energy Inc. (FEI)

Multi-Year Performance Based Ratemaking Plan for 2014 through 2019 approved by British Columbia Utilities Commission (Commission) Order G-138-14 (the PBR Plan) – Annual Review for 2016 Rates (the Application)

Response to the Commercial Energy Consumers Association of British Columbia (CEC) Information Request (IR) No. 1

On September 3, 2015, FEI filed the Application referenced above. In accordance with Commission Order G-138-15 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to CEC IR No. 1.

Due to a number of corrections and updates to the forecasts in the Application, FEI will be filing an Evidentiary Update prior to the Annual Review Workshop. The Evidentiary Update will include the items listed below, as discussed in the referenced IR responses:

- Correction to include AFUDC return on the earnings sharing amount (see response to CEC IR 1.33.3);
- Corrections to various Biomethane line items (see response to BCUC IR 1.19.1);
- Update to the forecast for the BC One Call project (see response to BCUC IR 1.25.2)
- Update for new information regarding the VIGJV 2016 Contract Demand and termination of service to Burrard Thermal (see response to BCUC IR 1.10.2); and

- Update for new information regarding Rate Schedule 46 LNG volumes (see responses to BCUC IR 1.18.3 and 1.18.4).

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 Reference: Exhibit B-2, Page 4

> **1.4 EVALUATION OF THE PBR PLAN**
>
> FEI has continued its productivity focus in 2015 and initiated additional projects to enhance the customer experience and improve productivity. As a result of this focus and these initiatives, FEI was able to realize savings in O&M expenditures, while FEI's capital expenditures continue to be above the capital formula amount. Overall, the savings achieved result in $5.068 million of earnings sharing that will be returned to customers in 2015, serving to reduce overall delivery rates for FEI's customers. FEI's performance with respect to SQIs, as reported in Section 13 of the Application, demonstrates that FEI achieved these savings while maintaining a high level of service quality.

1.1 Did FEI identify any efficiency initiatives with payback periods that would extend beyond the PBR period?

<u>Response:</u>

In Item 3 of Table 1-1 of the Application, FEI states that "FEI has not identified any efficiency investments with a payback beyond the end of the PBR period." The major initiatives listed in Appendix C-3 all have paybacks within the PBR period.

1.1.1 If yes, please identify these efficiency initiatives and provide an estimate of the costs and payback periods of each.

<u>Response:</u>

Please refer to the response to CEC IR 1.1.1.

2 Reference: Exhibit B-2, Page 5

Table 1-2: Employees at Year-End[5]

	Headcount	FTEs
2013 Actual	1,764	1,679
2014 Actual	1,704	1,650
2015 Projected	1,686	1,598

As shown in Table 1-2 above, from 2013 Actual to 2015 Projected, total FTEs for the Company decreased by approximately 81, with the decreases estimated to contribute to O&M savings of approximately $7 million[6]. The largest FTE declines are expected in the Customer Service and Operations areas as discussed below.

2.1 Please identify each of the areas with the staff reductions which resulted in FEI reducing total headcount by 20 and 52 FTEs in 2015.

Response:

FEI assumes that CEC is requesting information on the decreases from 2014 Actual to 2015 Projected, which are 18 headcount (not 20 headcount) and 52 FTEs.

Similar to the explanations provided for the FTE/Headcount changes from 2013 Actual to 2015 Projected (81 FTEs, 78 headcount), the estimated staffing changes from 2014 Actual to 2015 Projected are also primarily from Customer Service (-43 FTEs, -32 headcount) and Operations (-6 FTEs, +11 headcount).

3 Reference: Exhibit B-2, Page 5

> Customer Service reductions from 2013 to 2015 are estimated at approximately 65 FTEs contributing to O&M savings of approximately $4.7 million. Reductions include M&E reductions due to management reorganization and COPE reductions related to experienced lower call volumes and lower high-bill complaints in 2015 as the result of warmer weather. Included in the estimated total of $4.7 million in Customer Service savings are reductions in COPE FTEs related to Project Blue Pencil in 2015, contributing an estimated O&M savings of $1 million.
>
> Operations reductions from 2013 to 2015 are estimated at approximately 14 FTEs contributing to estimated O&M savings of $1.7 million. Reductions include those due to ongoing productivity initiatives. Included in the estimated total of $1.7 million in Operations savings are reductions related to the Regionalization initiative started in 2014, contributing an estimated annual O&M labour savings of $0.850 million.

3.1 Please provide further details of the ‘management reorganization’ and why it resulted in M&E reductions.

Response:

The management reorganization was an initiative that looked at the current scope of accountability for all M&E roles within Customer Service in an effort to streamline and find efficiencies. Changes included increasing the number of direct reports for front line and middle level management as well as reducing the number of support roles in process development and budget oversight and instead, placing these responsibilities on the leaders of the department. An additional change included increasing the scope of the COPE Customer Service Leader role so that these employees could play a more active role in the coaching and development of employees. All of these changes resulted in a reduced need for M&E staff, leading to the reductions discussed above.

3.2 Please breakout the number of FTEs and the savings that were a result of M&E reductions.

Response:

There were 10 M&E FTEs included in the O&M savings estimate for Customer Service, of which approximately 8 FTE reductions related to the management reorganization in Customer Service that resulted in estimated savings of approximately $765 thousand in 2015.

3.3 Please breakout the number of FTEs and the savings that were a result of COPE reductions.

Response:

Of the estimated savings of 65 FTEs for Customer Service, approximately 55 FTEs are COPE resulting in approximate savings of $3.3 million, some of which were temporary as a result of the warmer than normal weather in the winter of 2014 / 2015 as described in the preamble to this question.

3.4 Were any of the savings and/or reductions in FTEs a result of implementation or increases in e-billing?

Response:

No. There were no FTE reductions or labour savings as a result of the increased adoption rate of paperless billing as FEI's bill print and postage and mailing needs are provided by third party vendors.

3.4.1 If yes, please provide the M&E savings that were a result of changes in e-billing in both FTEs and $.

Response:

Please refer to the response to CEC IR 1.3.4.

3.4.2 If yes, please provide the COPE savings that were a result of changes in e-billing in both FTEs and $.

Response:

Please refer to the response to CEC IR 1.3.4.

4 Reference: Exhibit B-2, Pages 5 and 6, Appendix C-3

initiatives. Included in the estimated total of $1.7 million in Operations savings are reductions related to the Regionalization initiative started in 2014, contributing an estimated annual O&M labour savings of $0.850 million.

1. ***The Regionalization Initiative*** is aimed at both enhancing the customer experience and achieving a more efficient process in the field. Throughout 2014, Operations moved certain aspects of its centralized operational activities into regional locations. In particular, the Field Dispatch and Planning and Design groups are now located within their regional locations. The transition to a regional operations model has also resulted in eight emergency centres around the province instead of one large central emergency centre. These changes have enabled optimal decision making, and have been found to be more cost-effective and to serve customers better. 2015 marked the first full year operating under a regional business model. 2015 O&M savings projected for the Operations department compared to 2013 actuals are approximately $1 million.

Table D-1: Regionalization Initiative

	2014	2015+
Activities undertaken	• Operations Supervisor recruitment and training • Dispatcher relocation, recruitment and training • Planner relocations • Process review and modification • IT infrastructure modifications • Facilities modifications	None
Organizational changes	• Dispatch staff decreases • Operations staff increases due to hiring of Operations Supervisors • Operations staff decreases due to retirements and terminations not replaced • Planners staff re-allocated to Operations	None
O&M expenditures incurred or expected to be incurred	**$0.9 million** This included costs for a number of activities including employee development/ training, IT and facilities.	None
Capital expenditures incurred or expected to be incurred	**$1.3 million** This includes costs for IT, facilities and communications.	None
Anticipated savings	**$1.0 million** approximately. As discussed in the response to BCUC IR 1.2.1 in the annual review for 2015 delivery rates, it is difficult to separate Regionalization savings from the savings achieved due to the broader initiatives of improving customer service, enhancing the productivity focus and strengthening the accountability culture.	Ongoing

4.1 What were the $150 thousand in savings ($1 million less $0.85 million) that were not a result of labour savings? Please explain.

Response:

The $1 million anticipated savings directly related to regionalization were from improved utilization of internal resources and minimizing unproductive day-time standby costs (labour and vehicles). The $150 thousand non-labour O&M savings were in reduced vehicle costs (lease or depreciation, insurance, etc.) allocated to day-time standby costs.

5 Reference: Exhibit B-2, Page 6

> 3. ***Review of Technical and Infrastructure Support Provider*** is an initiative to review the existing agreement with the Company's technical and infrastructure service provider responsible for providing Information Systems (IS) Customer and Infrastructure Services to FEI. This includes the employee help desk and operation of the end-user environment, data centre infrastructure, communication and security networks. In 2015, FEI replaced its existing technical and infrastructure support provider through an RFP process with a new service provider, Compugen. The new contract with Compugen is designed to better support the Company's requirements and to drive efficiency. For each new efficiency identified, on a one-time basis (i.e. first full year savings), the vendor shares in the savings that are achieved, providing an incentive for Compugen to work with FEI to continue to look for efficiencies. Additionally, the new contract provides dedicated support resources rather than a distributed support service resulting in quicker response times and better understanding of the Company's requirements. The 2015 O&M savings projected for the Information Systems department compared to 2013 actuals are approximately $1.8 million.

5.1 How many efficiency initiatives did Compugen conduct in 2015?

Response:

Compugen has not yet conducted any efficiency initiatives in 2015, and there are none anticipated before the end of the year as Compugen will continue to be focused on stabilization of services.

5.2 Please provide a discussion of each of the major efficiency initiatives with the estimated cost savings from each.

Response:

There have not been any initiatives in 2015.

5.3 Please provide an assessment of whether or not the savings are ongoing or one-time and the amount for each category.

Response:

Please refer to the responses to CEC IRs 1.5.1 and 1.5.2.

5.4 Please confirm that Compugen is able to provide long term planning assistance through its Assessments and Roadmap Services or other area.

Response:

FEI confirms that Compugen is able to provide long term planning assistance through its Assessments and Roadmap Services.

5.5 Please provide the proportion of sharing that Compugen receives and how it is calculated.

Response:

Please refer to the response to BCUC IR 1.4.4.

6 Reference: Exhibit B-2, Page 7

1.4.4 Capital Expenditures Overview

FEI is not projecting any savings in capital relative to the formula in 2015.

Projected 2015 capital expenditures excluding items forecast outside of the PBR formula are $6.816 million higher than the formula amount. Growth capital is projected to be above the formula by $9.733 million as the formula for growth capital, which utilizes one-half of prior year service line additions, does not adequately fund the increase in capital required to support customer additions. In addition to growth capital, FEI was challenged in 2015 in sustainment capital in the Vancouver Island region, where FEI was unable to reduce sustainment capital spending to match the significant $6.3 million reduction to the Base Capital amount for Vancouver Island determined by the Commission in June 2015.[7]

FEI has sought to mitigate the impact of spending in growth and sustainment capital above the formula amount by making significant reductions to its IT capital plans in 2015, and through shifting projects otherwise planned for 2015 into 2016. However, the challenges FEI is facing in meeting its growth and sustainment capital formula spending amounts are expected to continue through the remainder of the term of the PBR Plan.

6.1 Please confirm that total sustainment capital spending is projected to be $2.917 million lower than formula or otherwise rationalize the $6.816 million in total capital expenditures being above formula, with the $9.733 million for the growth capital expenditures being above formula.

Response:

Not confirmed.

FEI does not have a capital formula specific to sustainment capital. FEI has a growth capital formula and a sustainment/other capital formula. The sustainment/other capital spending formula for 2015 is $110.901 million (Schedule 18 of Section 11 of the compliance filing in FEI's Annual Review for 2015 Rates) and the 2015 projection is $107.984 million. This includes spending in the categories of Sustainment, IT, Equipment and Other.

6.2 Please provide the Vancouver Island region growth capital formula and the Vancouver Island region growth capital spending, and explain why FEI expects to be above formula.

Response:

The 2015 Vancouver Island region growth capital formula amount is $7.923 million, which FEI calculated by applying the 2015 growth capital formula to the amount approved to be included in the 2014 Growth Capital for Vancouver Island. FEI is projecting to spend $11.580 million in 2015 for the Vancouver Island region.

As stated on page 7 of the Application, the formula for growth capital, which utilizes one-half of prior year service line additions, does not adequately fund the increase in capital required to support customer additions.

6.3 Please provide the Vancouver Island region sustainment capital formula and the Vancouver Island regions sustainment capital spending and explain why FEI expects to be above formula.

Response:

FEI does not have a capital formula specific to sustainment capital for Vancouver Island. FEI's statement on page 7 of the Application, that "FEI was challenged in 2015 in sustainment capital in the Vancouver Island region" was based on comparing to the amount of sustainment capital that FEI had proposed be included in the 2014 capital base for Vancouver Island of $15.643 million (which was the 2014 Approved amount), and deducting the $6.258 million reduction determined by the Commission, for an allowed base sustainment capital amount in 2014 of $9.384 million. Since FEI has projected $16.397 million of sustainment capital spending for Vancouver Island in 2015, it is clear that the main reason for the variance from formula is, as stated on page 7, due to the "significant $6.3 million reduction to the Base Capital amount for Vancouver Island determined by the Commission in June 2015.".

6.4 Is FEI deferring projects to outside the PBR term if it continues to have problems meeting its capital spending requirements throughout the PBR term? Please explain why or why not.

Response:

As noted in the preamble, FEI has deferred some projects from 2015 to 2016 in order to allow additional time to prioritize the required spending in consideration of both 2015 and 2016 together. At this time FEI has not identified any projects that it is planning to defer to outside of the PBR term.

Although FEI is investing significant effort in managing capital spending, FEI expects that its capital expenditures are likely to exceed either the one-year 10% or the two-year cumulative 15% capital spending deadband at some time in the remainder of the PBR Term.

6.5 Please confirm or otherwise explain that project deferral is not necessarily in the ratepayers best interests.

Response:

Depending on the specifics of the project, the timing of the deferral, and the rate treatment of the capital variances, there will be situations where project deferral may not be in the best interests of ratepayers. This can be due to long term cost or rate implications, impacts on system safety or reliability, or impacts on the ability of customers to attach to the system.

6.6 Please discuss the reductions that were made to the IT program for 2015 including:

- Total IT capital plans for 2015;
- Total amount of the reduction to IT capital plans for 2015;
- Identification of major projects that were either eliminated or deferred and whether or not they were eliminated or deferred; and
- Identification with quantification of long term costs that may occur for each project as a result of with the project deferral and/or elimination.

Response:

FEI's total 2015 IT capital plan was $18.8 million. The IT capital plan was reduced mid-year by $3.5 million by deferring a number of lower priority projects in the latter half of 2015, using priority assessment scores to determine which projects would be deferred. In accordance with

FEI's annual Project Portfolio Management (PPM) practice for IT capital, all of these projects have been resubmitted for 2016 prioritization and potential execution.[1]

Provided below is list of the major projects that were deferred. Deferring these projects should not result in any long-term costs or increased capital costs to execute the projects, but will result in the deferral of the benefits attributed to the projects as indicated in the following table.

[1] FEI's PPM practice for IT capital was described in the FEI 2014-2018 Multi-Year PBR Plan in section C4 on page 244, and in the FortisBC Energy Utilities 2012-2013 Revenue Requirements and Rates Application on page 377 and 378.

Project Name & Type	Description	Portfolio Action	Total Capital Costs ($000)	2015 Planned Capital Costs ($000)	Impact of Deferral
Identity Management Enhancement	Enablement of Single Sign-on (SSO) and increasing the security of customer or employee identity across internal and external domains.	Deferral	$650.0	$650.0	Existing and compliant security protocols remain in place. SSO will be delayed which will impact customer and employee user experience
e-Procurement Transformational	The provision of a flexible solution that would enable standardization, improve visibility and increase relationships between internal and external partners with introduction of a user friendly web self-service Supply Chain Portal.	Deferral	$500.0	$500.0	Delays in the realization of planned efficiencies, specifically: improved collaborations, partnerships, customer service and standardization
Leak Survey Transformational	Deliver a scalable solution that will facilitate the exchange of field work between FortisBC and their chosen contractors	Deferral	$450.0	$450.0	Delays in the realization of planned workforce management and field data collection efficiencies
3D Plant Modelling Transformational	To maintain and update the Mount Hayes 3D Plant model, a software package needs to be purchased and drafters need to be trained and utilized it	Deferral	$300.0	$300.0	Delays in realizing the project closure requirements by Asset and Records management and the reduction of rework on future capital projects to complete detailed field checking prior to project design. This would be extendable to other large-scale facilities.
Connector Phase 2 Enhancement	Improve the Connector experience by leveraging the enhanced search, mobile, social and content editing capabilities afforded by SharePoint 2013	Deferral	$412.0	$250.0	Delays in the realization of planned efficiencies driven by improved search and collaboration experience for all employees
FortisBC Redesign Enhancement	Website redesign will make it easier for customers and other stakeholders (e.g., media) to get what they need done on fortisbc.com, and increase customer satisfaction.	Deferral	$633.0	$250.0	Delays in the realization of planned benefits, specifically: improving customer experience, increasing searchability and navigation, and addressing regional territory needs

Project Name & Type	Description	Portfolio Action	Total Capital Costs ($000)	2015 Planned Capital Costs ($000)	Impact of Deferral
LAPS Replacement Sustainment	Technical replacement for the Load and Pressure Survey (LAPS) system	Deferral	$310.0	$150.0	Delays in the mitigation of an identified technology risk as the existing application is outdated and poses a support risk
Regulatory Compliance Transformational	Provide a more comprehensive method of recording, tracking, assigning, reporting and auditing compliance with BCUC directives and decisions.	Deferral	$226.0	$150.0	Delays in the introduction of technology which will improve FortisBC's ability to deliver against Regulatory commitments
SAP Upgrade Sustainment	The upgrade of the SAP Enterprise including CRM, ISU, Portals, BI/BW.	Deferral	$633.0	$300.0	Delays in the mitigation of identified technology risk as the existing application is outdated and poses a support risk
			$5,353.5	**$3,000.0**	

The remaining $500 thousand of deferred IT capital spending is made up of a variety of small sustainment projects that could be deferred until 2016.

7 Reference: Exhibit B-2, Pages 13 and 14

- For growth capital, the growth factor is 50% of the ratio of the service line additions (SLA) one year previous to the SLA two years previous, expressed as [1 + ((SLAt-1/SLAt-2)/SLAt-2) x 50%)].
- For all other cases, the growth factor is 50% of the ratio of the average number of customers (AC) one year previous to the average number of customers two years previous expressed as [1 + ((ACt-1/ACt-2)/ ACt-2) x 50%)].

May-14	851,169	104,847	2,705	958,721			
Jun-14	850,515	104,882	2,718	958,115	952,655		
Jul-14	850,036	104,889	2,721	957,646			
Aug-14	849,603	105,047	2,726	957,376			
Sep-14	849,829	105,323	2,738	957,890			
Oct-14	851,467	105,719	2,755	959,941			
Nov-14	854,127	106,227	2,762	963,116			
Dec-14	855,614	106,629	2,768	965,011			
Jan-15	966,744			966,744			
Feb-15	967,096			967,096			
Mar-15	967,144			967,144			
Apr-15	967,038			967,038			
May-15	966,516			966,516			
Jun-15	965,884			965,884	963,450	0.567%	2016

Jun-14	502	130		632	9,090		
Jul-14	668	184	10	862			
Aug-14	706	203	3	912			
Sep-14	972	321	6	1,299			
Oct-14	855	261	7	1,123			
Nov-14	1,363	296	6	1,665			
Dec-14	597	250	3	850			
Jan-15	717	316	2	1,035			
Feb-15	604	256	-	860			
Mar-15	572	214	3	789			
Apr-15	684	222	1	907			
May-15	604	204	9	817			
Jun-15	682	237	6	925	12,044	16.249%	2016

7.1 Please confirm or otherwise explain that the calculation for the capital growth factor is calculated as follows, which includes subtracting SLAt-2 from SLAt-1 rather than dividing as indicated in the formula above.

Growth factor = [(SLAt-1 – SLAt-2)/SLAt-2 *.50] as 1 + [(12,044-9,090)/9,090*.5] so that the growth factor is 1.16249

Response:

Confirmed. FEI will correct the presentation of the growth capital formula in its next Annual Review.

7.2 Please confirm or otherwise explain that the calculation for the growth factor in all other cases is calculated as follows, which includes subtracting ACt-2 from ACt-1 rather than dividing as indicated in the formula above.

Growth factor = 1+ [(ACt-1 – ACt-2)/ACt-2 *.50] as 1 + [(963,450-952,655)/952,655 *.5] so that the growth factor is 1.00567.

Response:

Confirmed. FEI will correct the presentation of this formula in its next Annual Review.

8. Reference: Exhibit B-2, Page 19

- Seed Year: The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available, and will be different than the original forecast for that year in the previous filing. For example, for this Application the Seed Year is 2015 and the Seed Year forecast is based on the latest actual years, including 2014. As such, the 2015 Seed Year forecast in this Application will differ from the 2015 Forecast presented in the Annual Review for 2015 Delivery Rates, for which 2014 actual data was not available.

8.1 Please clarify whether the use or calculation of the 'seed year' is a new methodology, or if it has been used in the past by FEI.

<u>Response:</u>

The calculation of the seed year is not a new methodology. The concept of a seed year is consistent with past practice. In the Annual Review for 2015 Rates, the seed year was referred to as a forecast (or sometimes as a projection), which caused confusion between the approved forecast for the year immediately preceding the Test Year (2014) and the update for that same year provided in the Annual Review. To avoid this confusion and any implication that there is a consideration of actuals included as there would be in a projection, FEI has initiated the use of the term "Seed" Year in its filings.

Below is a graphical presentation and discussion of what the seed year is and how it is used.

In January 2015 FEI was in the following position with respect to the availability of actual data:

Actual																																																Approved											
2011												2012												2013												2014												2015											
J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	?	?	?	?	?	?	?	?	?	?	?	?	F	F	F	F	F	F	F	F	F	F	F	F

As indicated in the figure above, in January 2015 actual historical data ("A") was available for 2011 through 2013. The approved values for 2015 are from the prior Annual Review Update forecast, which are shown as "F". The approved values were derived from the 2011-2013 actuals. The 2014 actuals were not known until the end of Q1-2015 and are shown as "?" in the above figure.

When the forecast process started in May for this Application (marked with an X below), actual data for 2012 through to March of 2015 was known, as indicated in the following:

Actual																																				Actual												Forecast											
2012												2013												2014												2015												2016											
J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A		X								F	F	F	F	F	F	F	F	F	F	F	F

The goal of the forecasting process was to develop forecast values for 2016 (shown in light blue).

One method to develop the 2016 forecast values is to use a projection technique:

Projection												Forecast											
2015												2016											
J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
A	A	A	P	P	P	P	P	P	P	P	P	F	F	F	F	F	F	F	F	F	F	F	F

Although actual values for January through March 2015 were known, the seasonality in the FEI data prevents using a projection technique as discussed in the response to BCUC IR 1.11.1.

FEI therefore re-forecasts 2015 using the newly available 2014 year end actual data. The new forecast for 2015 does not match the 2015 approved forecast because the 2015 approved forecast used data from 2011, 2012 and 2013.

In this case, 2015 is referred to as the seed year for the 2016 forecast. The situation is shown below.

Actual																																				Seed												Forecast											
2012												2013												2014												2015												2016											
J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F

The 2015 seed year and 2016 forecast are shown in the same color because they use the same growth rates and other metrics from the 2012-2014 historical data.

The 2015 seed year forecast will not match the 2015 Approved forecast because different historical years were used in the development of the two forecasts.

8.1.1 If it is a new methodology, please explain why FEI undertook this methodology versus any other methodology.

Response:

Please refer to the response to CEC IR 1.8.1.

8.1.2 If not, please confirm it is the same methodology that was described in the PBR application, and if it was used in the most recent annual review.

Response:

Confirmed, it is the same methodology that was described in the PBR application and used in the most recent annual review. Please also refer to the response to CEC IR 1.8.1.

9 Reference: Exhibit B-2, Appendix A3, Pages 23 and 24

Table A3-26: LML 12-Month Rate 1 Rolling UPCs

Date	Monthly UPC	12 month Rolling UPC	Period	Date	Monthly UPC	12 month Rolling UPC	Period
Jan-11	14.8	100.2		Jan-13	14.7	98.7	13
Feb-11	12.5	99.8		Feb-13	12.3	98.6	14
Mar-11	12.1	100.0		Mar-13	11.3	98.9	15
Apr-11	8.0	99.6		Apr-13	7.9	98.5	16
May-11	4.9	99.3		May-13	5.0	98.2	17
Jun-11	3.0	98.9		Jun-13	3.5	98.2	18
Jul-11	2.3	98.3		Jul-13	2.6	98.1	19
Aug-11	2.8	98.2		Aug-13	2.7	97.8	20
Sep-11	3.9	98.6		Sep-13	3.6	98.2	21
Oct-11	7.3	98.6		Oct-13	6.9	97.8	22
Nov-11	11.5	98.6		Nov-13	11.0	96.8	23
Dec-11	15.2	98.4		Dec-13	14.5	96.0	24
Jan-12	14.6	98.2	1	Jan-14	14.1	95.4	25
Feb-12	12.4	98.1	2	Feb-14	11.5	94.7	26
Mar-12	11.0	97.0	3	Mar-14	11.0	94.4	27
Apr-12	8.3	97.3	4	Apr-14	8.1	94.6	28
May-12	5.3	97.7	5	May-14	4.9	94.5	29
Jun-12	3.5	98.2	6	Jun-14	3.1	94.2	30
Jul-12	2.7	98.6	7	Jul-14	2.8	94.4	31
Aug-12	3.1	98.8	8	Aug-14	2.9	94.5	32
Sep-12	3.2	98.1	9	Sep-14	3.1	94.0	33
Oct-12	7.2	98.0	10	Oct-14	7.3	94.5	34
Nov-12	12.0	98.5	11	Nov-14	10.7	94.2	35
Dec-12	15.3	98.6	12	Dec-14	15.0	94.7	36

For the Lower Mainland, the residential UPC exhibits a regression statistic at 67% as shown in the preceding diagram. From the diagram the slope of the regression line is -0.1392 so the month over month UPC growth rate is -0.1392 GJs.

In this example, the 2014 Actual use rate is 47.3GJ. The 2015 seed use rate is then:

$$2015\ seed\ UPC = 94.7 + \left(12 \times (-0.1392)\right) = 93.03\ GJ \quad \text{(rounded to 93.0 GJ)}$$

For the 2016 Forecast, the growth rate is applied to the 2015 seed.

$$2016F\ UPC = 93.0 + \left(12 \times (-0.1392)\right) = 91.36\ GJ \text{ (rounded to 91.4 GJ).}$$

9.1 Please confirm or otherwise explain that the 2014 Actual use rate is 94.7 and not 47.3 GJ.

Response:

Confirmed.

The value of 47.3 was a typographical error.

9.2 If not confirmed, please explain how the 47.3 GJ factors into the calculation of the 2015 seed year UPC.

Response:

Please refer to the response to CEC IR 1.9.1.

10. Reference: Exhibit B-2, Appendix A-3, Page 24 and Page 28

5.3 THREE YEAR AVERAGE OPTION AS APPLIED TO INLAND

If a statistically significant trend does not exist for a particular rate schedule in a particular region, then FEI uses a three-year average of the annual growth rates.

Table A3-28: Rate Schedule 1 UPC (GJs)

Rate Schedule 1 UPC, GJs	Columbia	Inland	Lower Mainland	Revelstoke	Vancouver Island	Whistler
January	12.71671	12.70699	13.72200	8.28703	7.10498	15.33616
February	10.44112	10.24001	11.43894	7.01449	5.64096	11.60775
March	9.02912	7.88519	10.54059	5.92789	5.33138	10.52287
April	6.38838	5.25913	7.68715	3.69610	3.82794	6.93678
May	3.94200	2.98976	4.77008	1.80224	2.36601	3.94912
June	2.42941	1.95627	3.19478	0.92148	1.63793	2.67849
July	1.85058	1.71407	2.58215	0.80670	1.29045	2.10538
August	1.74197	1.72520	2.74594	0.77152	1.28962	2.10218
September	2.75121	2.45434	3.13862	1.31535	1.64930	2.89051
October	6.19125	5.75539	6.75142	3.60683	3.32179	5.48545
November	9.45872	9.30639	10.65296	5.91702	5.15340	7.98713
December	13.02672	12.70221	14.13221	8.12740	6.46375	13.45072

10.1 Which areas use the three year average to calculate the annual UPC growth rates and which use the regression method?

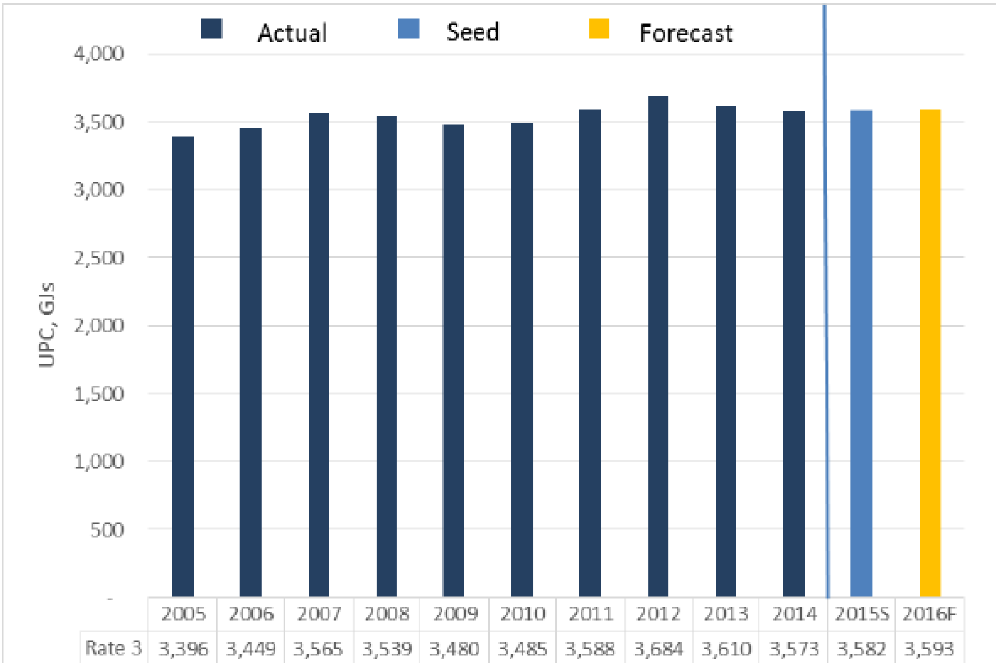
Response:

Please refer to the response to BCUC IR 1.12.2.

11. Reference: Exhibit B-2, Page 20 and Appendix A-3, Page 31

As shown in Figure 3-3, the upward trend in Large Commercial (Rate Schedule 3) UPC has been consistent and this trend is forecast to continue. The Rate Schedule 3 UPC is forecast to increase by 11 GJ (0.3 percent) in 2016.

Figure 3-3: Rate Schedule 3 UPC Trend Consistent with Prior Years



6.2 REGRESSION METHOD

None of the commercial rate classes in any of the sub-regions demonstrated a statistically significant trend in the current forecast. In the case that a region and rate class did result in a statistically significant trend the methodology as illustrated for Rate Schedule 1 in section 5.3 above would be used.

6.3 THREE YEAR AVERAGE METHOD FOR COMMERCIAL UPC CALCULATION

If a statistically significant trend does not exist then FEI uses a three-year average of the annual growth rates. For Lower Mainland, the regression statistic is 30%, so a three-year average method is used.

11.1 Please rationalize the statement that there is no statistically significant trend in any of the Commercial sub-regions with the statement that the UPC has been consistent and is likely to continue.

Response:

For the purpose of selecting a forecast method, FEI develops a statistical regression as discussed Section 6 of Appendix A-3 in the Application. In this context, the term "statistically significant trend" is used to describe the magnitude of the regression statistic, R^2. The regression is statistically significant if the value of R^2 is greater than or equal to 50%.

In Figure 3-3, the use of the words "upward trend" was to indicate that, overall, since 2005 the UPC has increased. In 2005, the Rate Schedule 3 UPC was 3,396 GJs. In 2016, the forecast Rate Schedule 3 UPC is 3,593 GJ. From inspection, a trend can be present without that trend being statistically significant.

11.2 Please explain why the 3 year average method would likely be more accurate and therefore appropriate to employ where there is no statistically significant trend.

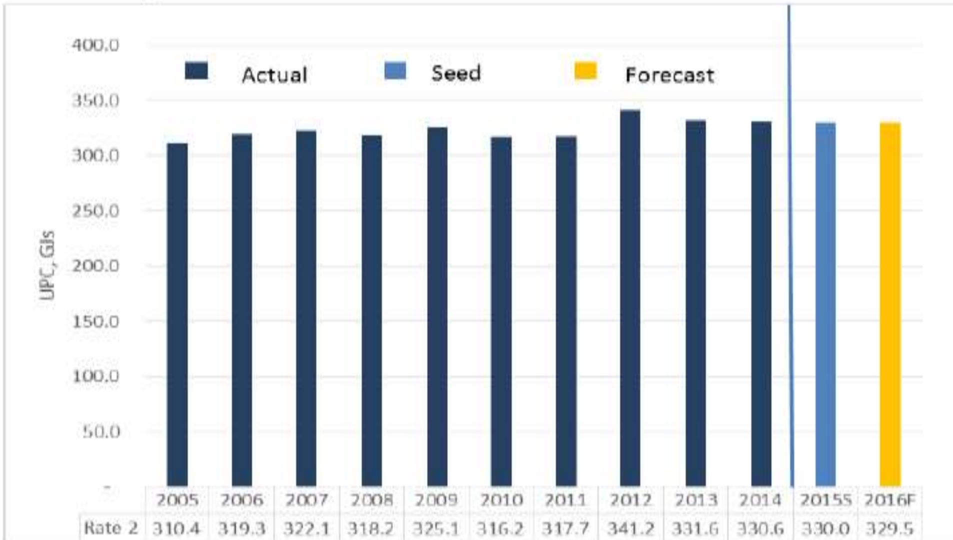
Response:

The lack of a statistically significant trend implies that there is no upward or downward trend relative to the typical variations in the historical data. In that case flat growth (as determined by the three year average) is appropriate and forecast by default.

FEI believes the established practice of using a three-year average provides the best combination of smoothing and relevance. Averaging over a longer period would smooth out the peaks further, but at the cost of using outdated data in the forecast. Using a shorter period than three years would use the most relevant data, but make the customer additions forecast highly subject to highs or lows experienced in a single year that do not reflect the overall trend.

12 Reference: Exhibit B-2, Page 21

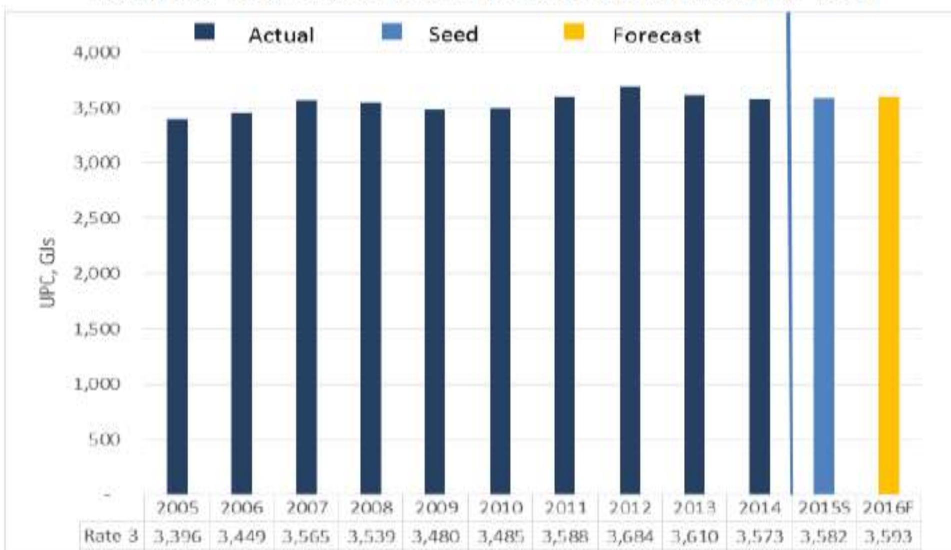
Figure 3-2: Rate Schedule 2 UPC Consistent with Prior Years



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015S	2016F
Rate 2	310.4	319.3	322.1	318.2	325.1	316.2	317.7	341.2	331.6	330.6	330.0	329.5

As shown in Figure 3-3, the upward trend in Large Commercial (Rate Schedule 3) UPC has been consistent and this trend is forecast to continue. The Rate Schedule 3 UPC is forecast to increase by 11 GJ (0.3 percent) in 2016.

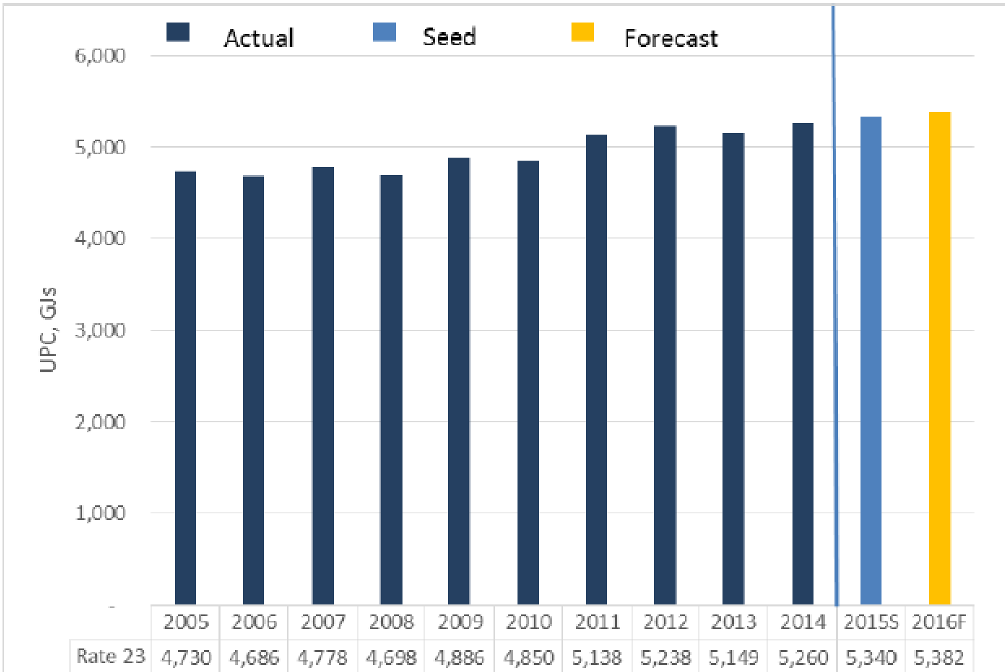
Figure 3-3: Rate Schedule 3 UPC Trend Consistent with Prior Years



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015S	2016F
Rate 3	3,396	3,449	3,565	3,539	3,480	3,485	3,588	3,684	3,610	3,573	3,582	3,593

As shown in Figure 3-4, the Large Commercial Transportation (Rate Schedule 23) UPC is forecast to continue the recent upward trend and grow by 42 GJs (0.8 percent) in 2016.

Figure 3-4: Rate Schedule 23 UPC Recent Upward Trend



12.1 Please provide FEI's views as to why the small commercial UPC is expected to decrease slightly, while the large commercial UPC is expected to increase.

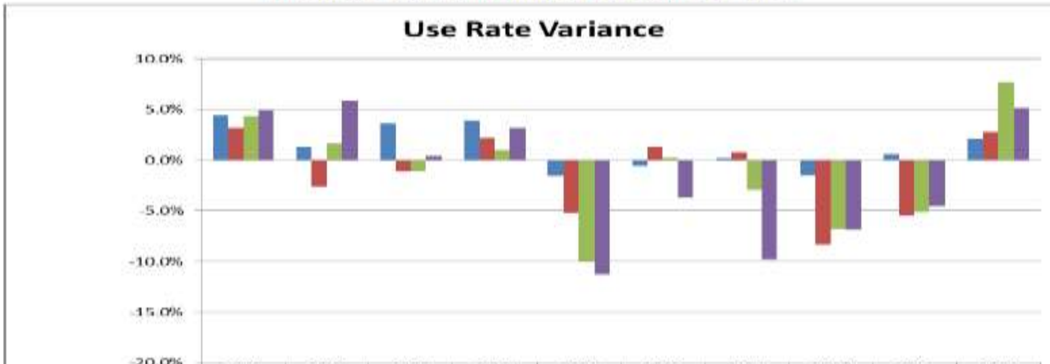
<u>Response:</u>

The forecast increase or decrease in UPC is based upon the trend of the last three years forecast into the future. The forecast for the small commercial and large commercial sectors is not based upon specific knowledge of usage patterns or industry changes. As noted in response to CEC IR 1.13.2, the commercial sector is comprised of over 180 sectors. As such it is not possible to know what is causing the specific shift in consumption.

13 Reference: Appendix A2, Pages 9 and 10

4.2 AMALGAMATED USE RATE VARIANCE

Figure A2-9: Amalgamated Use Rate Variance



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 1	4.4%	1.3%	3.7%	3.9%	-1.6%	-0.6%	0.2%	-1.5%	0.6%	2.1%
Rate Schedule 2	3.2%	-2.6%	-1.1%	2.2%	-5.2%	1.3%	0.8%	-8.3%	-5.4%	2.8%
Rate Schedule 3	4.3%	1.7%	-1.1%	1.0%	-10.0%	0.3%	-2.9%	-6.8%	-5.1%	7.7%
Rate Schedule 23	4.9%	5.9%	0.4%	3.1%	-11.3%	-3.6%	-9.8%	-6.9%	-4.5%	5.2%

The Rate Schedule 2 use per customer forecast variance improved in 2014 to 2.8% following higher variances in 2012 and 2013. The 2014 result is more typical of years prior to 2012. The three-year average forecast variance is -3.7%.

The Rate Schedule 3 use per customer forecast variance increased to 7.7% in 2014 following lower variances since 2010. The average variance from the prior three years (2012-2014) declined to just -1.4% from -4.9% in 2011-2013 and -3.1% in 2010-2012.

The Rate Schedule 23 use per customer variance increased to 5.2% in 2014 from -4.5% in 2013. The average variance for the three-year period from 2012-2014 was -2.1%.

13.1 Please extend the table to include the projected to 2015 figures versus the forecast.

<u>Response:</u>

Please refer to the responses to CEC IR 1.8.1 and BCUC IR 1.11.1.1.

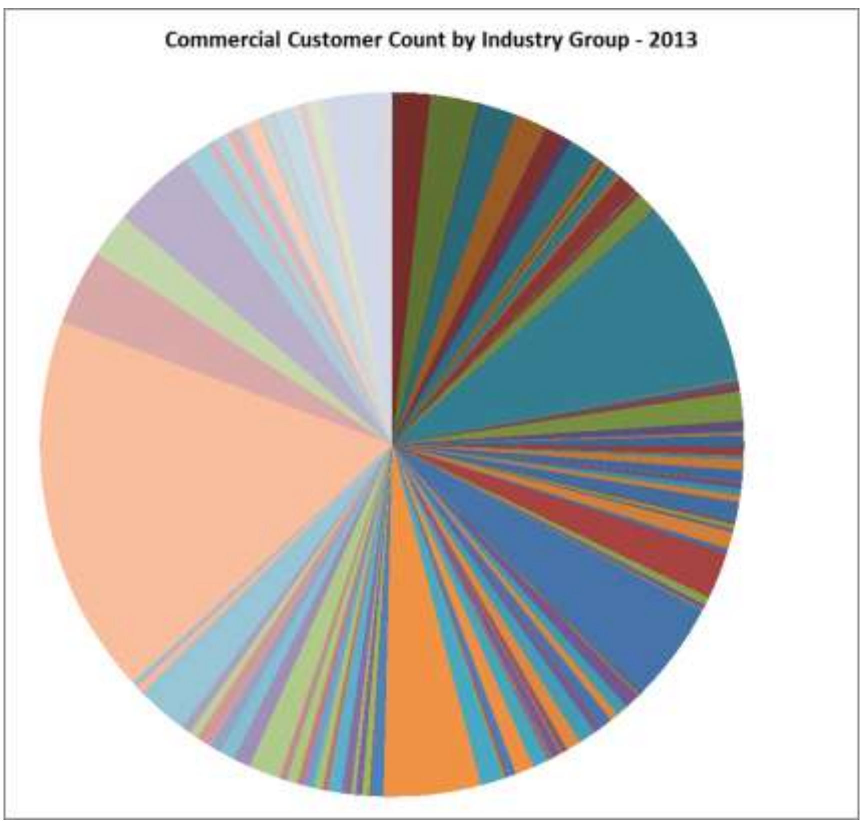
FEI does not develop projections for the current year so cannot provide expected use rate variances between projected and approved.

13.2 To what does FEI attribute the significant under forecasts in Commercial demand in 2009, 2012 and 2013?

Response:

FEI does not believe that its commercial demand forecasts are "significantly" under. FEI believes that its forecasts are reasonable and better than comparable utility averages. Table A2-1 in Section 3 of Appendix A2 in the Application shows the performance of the commercial demand forecast since 2010 compared to the Itron survey of 11 gas utilities. For 2012 the commercial demand variance of -2.8% was better than the Itron survey of 4%. The commercial demand variance in 2013 was even better at -0.2%.

Broadly speaking, demand variances (both under- and over-forecasts) occur for many reasons. When trying to pinpoint the source of the variance it is important to consider the composition of the commercial customers. The following pie chart shows the composition of customers in the commercial Rate Schedules (Rate Schedules 2, 3 and 23) for 2013. 2009 and 2012 are similar.



The pie chart above represents 180 different industrial sectors. Some sectors are present in all three commercial rate schedules while others are unique to one or two rate schedules.

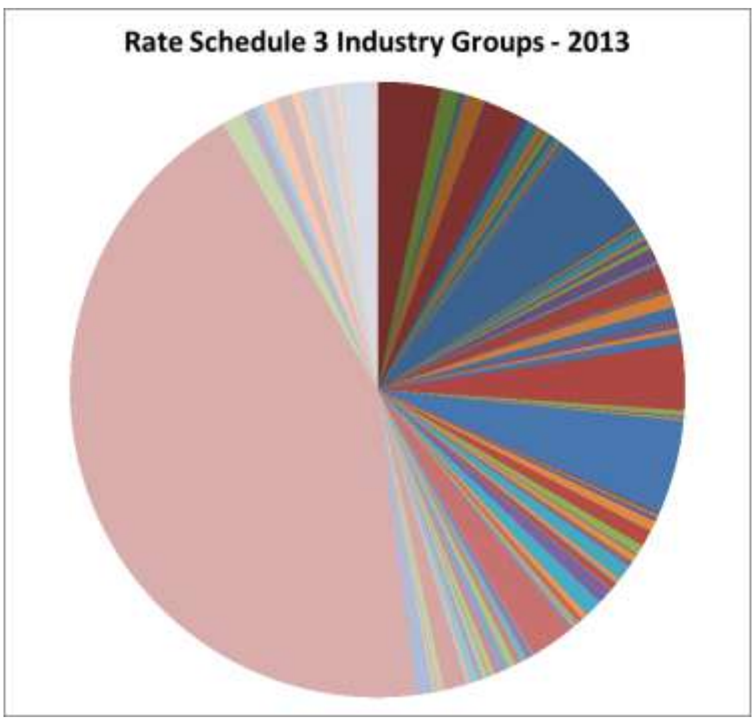
Customer demand in each of the 180 sectors is driven by different combinations of factors. Some sectors may be seeing growth (for a number of reasons), while others may be stable and others declining. Some of these changes may offset each other while others may result in changes in demand for the rate class. Understanding the sources of any variance in forecasting would require specific understanding of the drivers for each sector, and each rate class, for the three years identified and is not feasible.

13.3 To what does FEI attribute the significant under forecasts in Rate Schedule 3 in 2009, 2012 and 2013?

Response:

FEI does not believe that its Rate Schedule 3 forecasts are “significantly” under. The variance in forecast to actual is reasonable.

Use rate variances (both under- and over-forecasts) occur for many reasons. When trying to pinpoint the source of a variance it is important to consider the composition of the customers in the Rate Schedule. The following pie chart shows the industrial sector composition of Rate Schedule 3 for 2013. 2009 and 2012 are similar.


Rate Schedule 3 Industry Groups - 2013

The pie chart above shows that Rate Schedule 3 customers belong to 149 different industrial sectors. The use rates for customers in each sector are driven by different factors.

Understanding the drivers for each sector that resulted in an overall variance of 5% to 10% for the three years identified is not feasible.

Please also refer to the response to CEC IR 1.13.2.

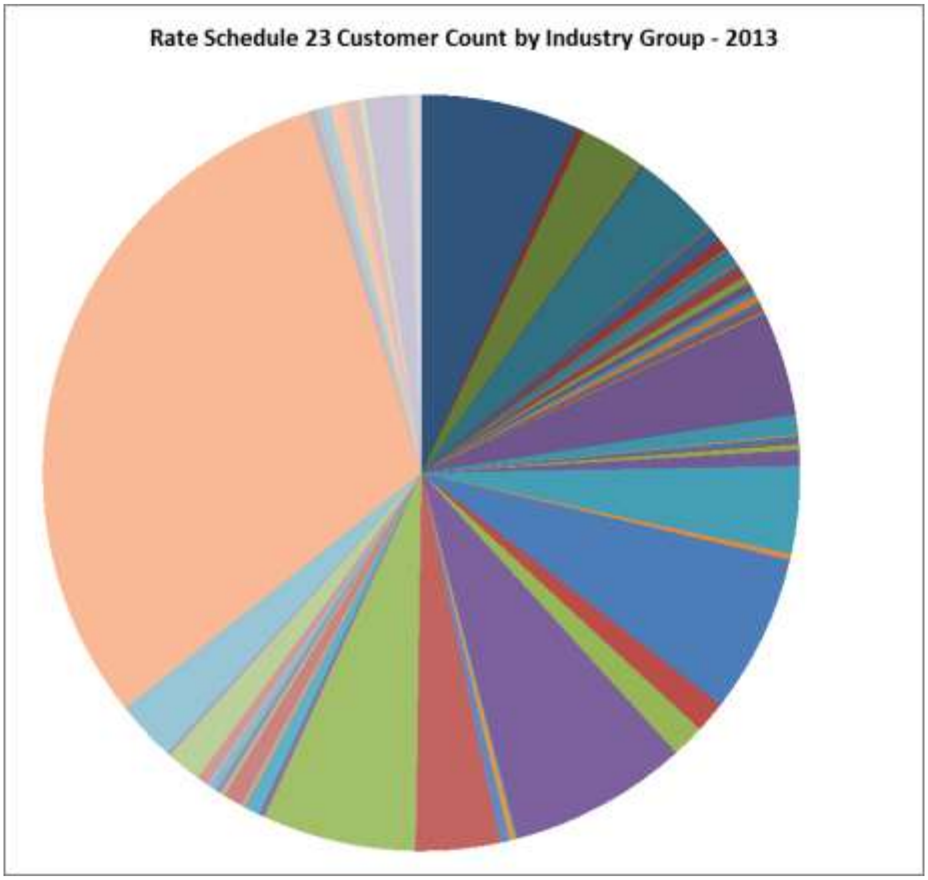
13.4 To what does FEI attribute the significant under forecasts in Rate Schedule 23 in 2009, 2011, 2012 and 2013?

Response:

FEI does not believe that its forecasts are "significantly" under. FEI believes that its forecasts are reasonable.

As discussed in the responses to CEC IRs 1.13.2 and 1.13.3, use rate variances (both under- and over-forecasts) occur for many reasons. As illustrated below, Rate Schedule 23 customers belong to 71 different industrial sectors. The use rates for customers in each sector are driven by different factors. Understanding the drivers for each sector that resulted in an overall variance of 4.3% to 11.3% for the four years identified is not feasible.

The following pie chart shows the industrial sector composition of Rate Schedule 23 for 2013. 2009, 2011 and 2012 are similar.



The pie chart above shows that Rate Schedule 23 customers belong to 71 different industrial sectors (listed below).

Accommodation and Casino Services
Alumina and Aluminum Production and Proc
Amusement, Recreation Industries
Animal Food Manufacturing
Animal Production
Automotive Parts, Accessories, and Tire
Bakeries and Tortilla Manufacturing
Beverage and Tobacco Product Manufacturing
Beverage Wholesaler-Distributors
Breweries
Cement and Concrete Product Manufacturing
Cement Manufacturing
Chemical Manufacturing
Coal Mining

Commercial Customer
Computer, Electronic & Electrical Product Manufact
Converted Paper Product Manufacturing
Crop Production - Mushrooms and Sprouts
Dairy Product Manufacturing
Educational Services
Electrical Equipment, Appliance and Comp
Elementary and Secondary Schools
Fabricated Metal Product & Machinery Manufacturing
Farm Product Wholesaler-Distributors
Food Manufacturing
Food Services and Drinking Places
Food Wholesaler-Distributors
Forestry and Logging
Full-Service Restaurants
Funeral Services
Greenhouse/Nursery and Floriculture Production
Grocery Stores
Hospitals
Local, Municipal and Regional
Management of Companies and Enterprises
Meat Product Manufacturing
Miscellaneous Manufacturing
Miscellaneous Store Retailers
Nursing and Residential Care Facilities
Other Chemical Product Manufacturing
Other Food Manufacturing
Other Machinery, Equip and Supplies W-D
Other Schools and Instruction
Other Wood Product, Furniture Manufacturing
Paper Mills
Personal and Laundry Services
Plastics and Rubber Products Manufacturing
Prime Contracting
Printing and Related Support Activities
Professional, Scientific, and Technical
Provincial and Territorial

Rail Transportation
Real Estate (office)
Real Estate (residential)
Refineries and Petroleum Manufacturing
Religious, Grant-Making, Civic, and Prof
Rental and Leasing Services
Residential Customer
Sawmills and Wood Preservation
Social Assistance
Sugar and Confectionery Product Manufacture
Transportation
Transportation Equipment Manufacturing
Universities
Veneer, Plywood and Engineered Wood Prod
Warehousing and Storage
Waste Management and Remediation Service

13.5 Please confirm that a balance of over and under forecasting would not necessarily be achieved in any given 5 year period.

Response:

Confirmed. Many factors could lead to an imbalance over a five year period or any other period.

However, in the case of FEI, the cumulative variance for the past five years is reasonable.

Table A2-1 from Section 3 of Appendix A2 in the Application is reproduced here for convenience, which shows a summary comparison between FEI's demand forecast variances to the 2014 average variance reported from the Itron survey by rate group for the five years from 2010 through 2014:

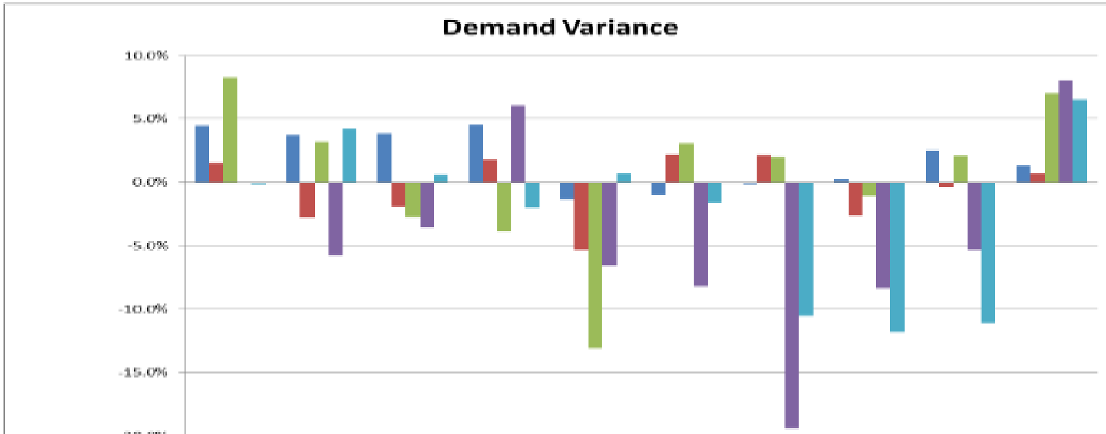
Table A2-1: Demand Under-and-Over Forecasting

Class	Itron Survey	FEI				
	2014	2010	2011	2012	2013	2014
Residential	2.9%	-0.9%	-0.1%	0.3%	2.5%	1.3%
Commercial	4.0%	1.3%	-0.4%	-2.8%	-0.2%	4.1%
Industrial	6.4%	-1.6%	-10.5%	-11.8%	-11.1%	6.5%

The 5 year average demand variance for all commercial customers is 0.4%, indicating a balance between over and under forecasting. In two of the preceding five years FEI had an over-forecast while in the other three years the commercial demand was under-forecast.

14 Reference: Exhibit B-2, Appendix A2, Pages 10 and 11

Figure A2-10: Amalgamated Demand Variance



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 1	4.5%	3.7%	3.8%	4.5%	-1.4%	-0.9%	-0.1%	0.3%	2.5%	1.3%
Rate Schedule 2	1.6%	-2.8%	-1.9%	1.8%	-5.4%	2.2%	2.2%	-2.6%	-0.4%	0.7%
Rate Schedule 3	8.3%	3.2%	-2.7%	-3.8%	-13.1%	3.1%	2.0%	-1.0%	2.1%	7.0%
Rate Schedule 23	0.0%	-5.8%	-3.5%	6.1%	-6.6%	-8.2%	-19.4%	-8.3%	-5.3%	8.0%
Industrial	-0.1%	4.2%	0.6%	-2.0%	0.7%	-1.6%	-10.5%	-11.8%	-11.1%	6.5%

The Rate Schedule 3 demand variance increased to 7.0% in 2014 following lower variances since 2010. The higher variance was due to higher use rate variances. The average variance from the prior three years (2012-2014) was 2.7%.

The Rate Schedule 23 demand variance was 8% in 2014, up from -5.3% in 2013. However, the average variance for the three-year period from 2012-2014 was -1.9%. The higher variances are due to high use rate variances from 2011 and 2012 when customers in this rate schedule consumed more gas then expected based on recent historic actuals.

Demand variance for all customers in the industrial rate schedules declined to 6.5% in 2014. Prior variances were higher due to large customer fuel switching, both to and from natural gas.

14.1 Please extend the table to include the projected to 2015 figures versus the forecast.

<u>Response:</u>

Please refer to the response to CEC IR 1.13.1.

14.2 Please provide an explanation for the 19% underforecast for Rate Schedule 23 that occurred in 2011.

Response:

Rate Schedule 23 has the smallest number of customers of the four rate schedules (1/2/3/23) that are forecast using use rates and accounts. Rate Schedule 23 also has the highest annual use rate.

The combination of small customer count and high use rates makes Rate Schedule 23 sensitive to changes in customer totals. The addition or subtraction of a small number of customers can have a large impact on total demand for the rate schedule.

In 2010 and 2011, nine customer additions were forecast for each year. The actual cumulative additions were 85. As a result, the actual demand was higher than forecast and a negative variance was reported. In 2014, after adding 97 cumulative customers over the previous two years, 57 customer additions were forecast while the actual net additions were -7. Instead of adding 57 customers, which would have been consistent with prior year trends, FEI lost 7 customers and, as a result, the actual demand was lower than forecast and a positive variance was reported. When customer additions do not materialize an over-forecast situation results because demand was forecast assuming new customers would join the system at the same rate as in prior years.

The average five year demand variance from 2010-2014 for rate schedule 23 is -6.6% while the 10 year average is -4.3%.

14.3 Please provide FEI's views as to why Rate Schedule 23 was overforecast in 2014, when it had been consistently and significantly under forecast for many years.

Response:

Please refer to the response to CEC IR 1.14.2.

14.4 Please provide an explanation for the >10% under forecasting that occurred in Industrial from 2011 to 2013.

Response:

The industrial demand variance from 2011 through 2013 was a result of high variances in Rate Schedule 22 mainly arising from customers that switched fuels and started using gas after the annual surveys and forecasts were completed. Please see Appendix A4 and the response to BCUC IR 1.17.2.

15 Reference: Exhibit B-2, Pages 27 and 28

For the 2016 Forecast, customers completed the survey in May-June 2015. As shown in Table 3-1 below, the response rate achieved in 2015 was 44 percent of industrial customers, representing approximately 86 percent of industrial volumes. Of the remaining industrial customers, 41% received the survey and three reminder letters but did not reply. This group represents 12% of the industrial demand. Surveys could not be delivered to 15% of the industrial customers due to issues such as incorrect email addresses. This group represents just 2% of the total industrial load.

Table 3-1: Industrial Survey response

2015 Industrial Survey	Description	Customers	Demand
Survey completed	The survey was delivered and completed.	44%	86%
Survey delivered but not completed	The survey was delivered, but after three follow-up emails was not completed.	41%	12%
Survey undeliverable	The survey was not deliverable. This can be a result of invalid email addresses, faulty email servers etc.	15%	2%
Total		100%	100%

15.1 Please confirm that although the survey covers 86% of demand the result is significant underforecasting.

Response:

Not confirmed.

Table 3-1 presents the response rates for the survey conducted in 2015 for the 2016 test year.

Until 2016 actual demand is available in 2017, FEI will not be able to determine if the result was an under or over forecast.

FEI notes that as discussed in Section 5.4 in Appendix A2 of the Application, six of the past ten years were under-forecast while over-forecasts were recorded in the other four years. The average variance over the ten year period was -2.5 percent.

16 Reference: Exhibit B-2, Page 28

The forecast of demand for all customers that either chose not to reply to the survey or could not be contacted (representing 14% of the total industrial demand) was set to 2014 actual consumption.

16.1 Has FEI ever determined whether or not the forecasting variances are occurring largely with the forecast for those customers who do not return the survey (and are assumed to the prior year's actual consumption) or whether they are equally a result of the error on the part of those customers returning the survey, or some other factor? Please explain why or why not.

Response:

FEI has determined that the majority of the industrial variance comes from Rate Schedule 22 customers, 100 percent of which respond to the survey.

The aggregate variance between actual and approved demand for industrial customers for 2014 was 7.6 PJs. 100 percent of the Rate Schedule 22 customers responded to the survey and together accounted for 7.2 PJs of the variance from the Approved (please refer to the response to BCUC IR 1.17.1) or 95% of the total. The remaining 5% of the variance is attributable to Rate Schedules 5, 7, 25 and 27 where there is a mix of responders and non-responders.

FEI believes that the Rate Schedule 22 demand is the most difficult for customers to forecast because of the magnitude of the loads and the multitude of customer-specific drivers. Additionally these loads are often completely "on" or completely "off" of gas usage and can result in large variances for those customers that can switch fuels.

The reasons for the Rate Schedule 22 variance are discussed in detail in Appendix A4 in the Application.

16.1.1 If yes, please provide a brief discussion as to where and why the forecast error is occurring.

Response:

Please refer to the response to CEC IR 1.16.1.

17 Reference: Exhibit B-2, A3, Page 49

> Once the target response rate has been achieved the survey is closed and no further responses are solicited. The data in the survey web site is then transferred automatically to the current forecast in FIS. Industrial rate classes are forecast by individual customer so the data for each customer is copied. Checks are completed to make sure that that data was copied properly and that the survey web site and that the current FIS forecast are in synch.
>
> Customers that do not respond to the survey are assigned their prior years consumption.
>
> FIS then sums the individual customer demand forecasts by rate class and region to develop the industrial demand forecast.

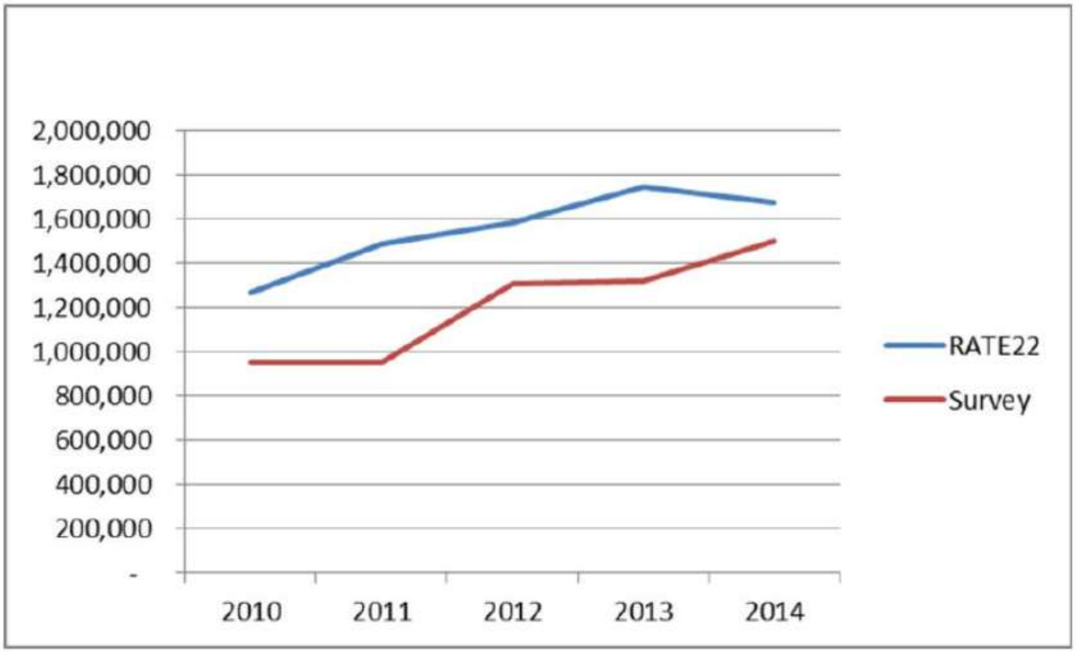
17.1 What is the target response rate in number of customers and volume?

Response:

Please refer to the response to BCUC IR 1.15.1 for the target response rate by volume. FEI does not have a target response rate based on number of customers.

18 Reference: Exhibit B-2, A4, Page 12

Figure A4-11: R22 Customer Actual and Forecast Demand



In the past five years there appears to be a pattern of chronic under-forecasting with five Rate Schedule 22 customers.

18.1 How does FEI propose to address the pattern of chronic under-forecasting with the five customers?

<u>Response:</u>

Please refer to Sections 5 and 6 of Appendix A4 of the Application (Exhibit B-2) for a discussion of how FEI will address customers that chronically under-forecast.

18.2 Could key account managers with the five rate chronic under-forecasters work cooperatively with the companies to develop the forecasts? Please explain why or why not.

Response:

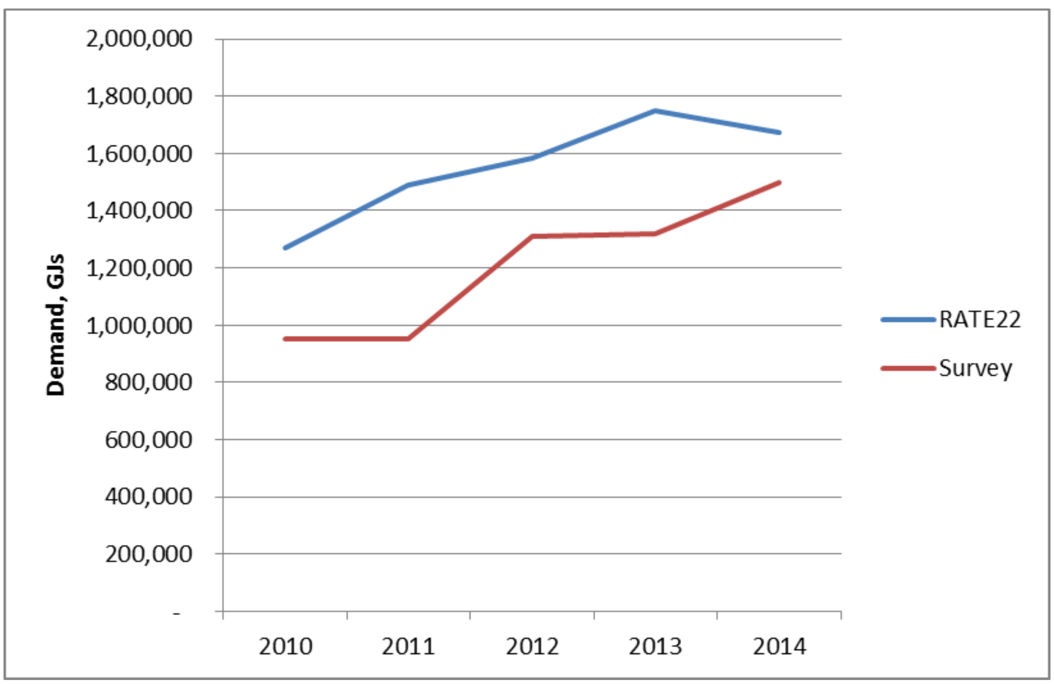
Please refer to the response to CEC IR 1.19.1 as well as Sections 5 and 6 of Appendix A4 in the Application (Exhibit B-2).

18.3 Please clarify that the demand represented by rate 22 customers is shown on the vertical axis and provide the units for the demand.

Response:

On lines 4 and 5 of page 12 in Appendix A4 of the Application, FEI states “An example of a customer that consistently consumed more than forecast is shown in the figure below”. This is therefore an example of a single customer.

The chart with the Y axis label is provided below.



19 Reference: Exhibit B-2, A4, Pages 14 and 15

> The industrial survey allows FEI to communicate directly with the customer. The survey relies on the customer completing its own forecast using methods that the customer deems appropriate for their business.

> A higher involvement between key account managers and customers at the time the survey is being completed can also lead to an improved forecast. This additional step was used for the first time in 2015 and resulted in an improved forecast from one customer. In this example, the survey was received and reviewed by an Industrial Marketing Manager. The manager was familiar with the customer but not aware of any changes to the business operation that would support the forecast submitted by the customer. A follow up was completed and the customer agreed that the survey was incorrect. The customer completed a new survey which was submitted and incorporated into the FIS model. The new survey was approximately 100,000 GJs higher than the original and comparable to prior forecasts and actual consumption.

19.1 Would it be worthwhile for those account managers with higher volume customers, or those subject to fuel switching to work cooperatively with the customer to develop the demand forecast rather than relying on the customer's own methods? Please explain why or why not.

Response:

FEI does not think it would be worthwhile for account managers to work cooperatively with their customers to develop the demand forecast based on both the subject matter expertise required and the resources required (cost & time). FEI believes that each large volume customer has expertise in their industry and is capable of preparing its forecasts accordingly. It would be inefficient for account managers to gain the significant industry expertise required to cooperatively develop a forecast with a customer. FEI believes that the additional step that it used for the first time in 2015, described below, achieves a similar result more efficiently.

For the first time in 2015, FEI used an internal review of all individual survey responses for higher volume customers and those subject to fuel switching. This allowed FEI to have follow-up discussions with select customers whose survey responses did not align with the account manager's understanding of the customer's account and business environment. As stated on page 18 of Appendix A4, for the 2017 Industrial Survey (to be completed in the spring of 2016), FEI proposes to more fully involve the key account managers in the process.

19.2 Please confirm that FEI will continue the additional step of having key account managers reviewing the forecasts on a consistent basis

Response:

Confirmed.

In the course of responding to this IR, FEI notice an error in Appendix A4 of the Application, where FEI stated: "The key account managers will review the forecast with each Rate Schedule 22 customer and discuss any risks such as fuel switching and chronic under-and over-forecasting." To clarify, all surveys will be reviewed by key account managers and FEI will contact those customers that are at risk of fuel switching or under-and over-forecasting, as well as those that submit surveys that do not appear correct. FEI does not intend to contact customers that are not at risk of fuel switching or under-and over-forecasting and that have submitted what appear to be reasonable surveys.

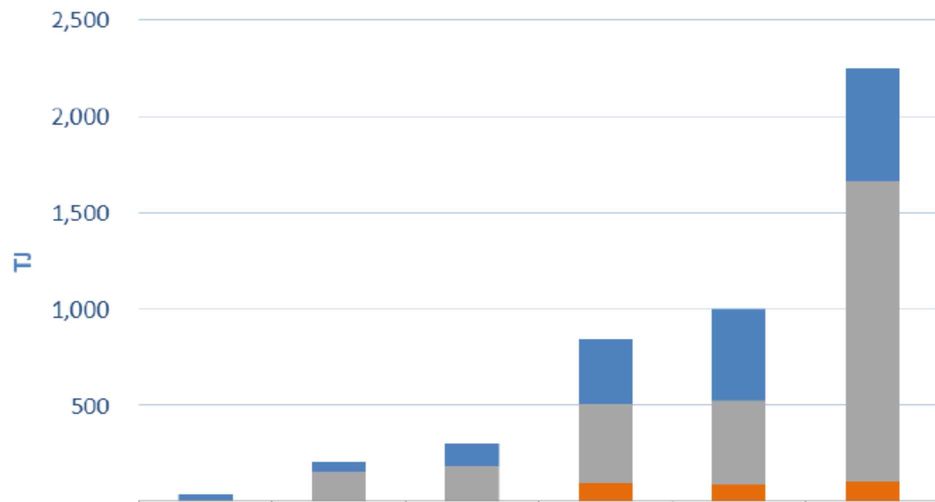
19.3 Would it be reasonable for those account managers with large accounts or those subject to fuel switching to check back with customers closer to the time when the demand will be filed? Please explain why or why not.

Response:

Since the survey is completed in June for an early September filing, FEI does not believe it would be reasonable to contact customers in June by survey and then again in July for an update. A July update would be the latest to still allow time for any changes to be worked into the FIS model. The survey is currently completed in June to allow FEI time to contact as many customers as possible prior to summer vacation absences.

20 Reference: Exhibit B-2, Page 30

Figure 3-12: Actual (A) Projected (P) and Forecast (F) Demand for CNG & LNG[14]



	2011A	2012A	2013A	2014A	2015P	2016F
Rate 25 - NGT	26	52	120	336	480	586
Rate16/46 - NGT	8	154	183	411	435	1,560
Rate 16/46 - Other	-	-	-	96	87	107

The Rate Schedules 16/46 - Other demand in 2014 to 2016 includes LNG used for non-NGT activities primarily related the use of LNG for power generation in northern Canada. These customers are currently taking LNG on a spot basis (i.e. with no contract demand). In 2015, FEI expects to deliver approximately 87 TJs to these customers and for 2016 the customers have indicated increases in LNG demand to approximately 107 TJ's.

[14] Forecast includes all NGT related and other LNG demand inclusive of contract and excess demand flowing through stations as well as 3rd party station CNG/LNG volume.

The following two tables identify, for the rate schedules listed above, the forecast of CNG and LNG volumes sold, associated delivery margin at 2015 rates[11], cost of gas at July 1, 2015 rates (applicable for Rate Schedule 46 only), and revenue (delivery margin plus cost of gas).

Table B-5: Rate Schedule 25 CNG Forecast

Volume, Revenue, Margin under RS 25		2015A		2015P		2016F
Demand (GJ)		401,493		480,297		586,224
Total Delivery Margin ($ millions)	$	0.326	$	0.617	$	0.728
Total Cost of Gas ($ millions)	$	-	$	-	$	-
Total Revenue ($ millions)	$	0.326	$	0.617	$	0.728

Table B-6: Rate Schedule 46 LNG Forecast[12]

Volume, Revenue, Margin under 46		2015A		2015P		2016F
Demand (GJ)		719,217		521,737		1,666,806
Total Delivery Margin ($ millions)	$	2.177	$	2.353	$	7.668
Total Cost of Gas ($ millions)	$	1.826	$	1.297	$	4.144
Total Revenue ($ millions)	$	4.003	$	3.650	$	11.811

20.1 Please confirm that the total forecast demand for CNG and LNG for FEI amalgamated is included in the above table and amounts to 2,253 TJ.

Response:

Confirmed. However, due to recent developments described in response to BCUC IR 1.18.3 and 1.18.4, FEI will be reducing its 2016 LNG Forecast in an Evidentiary Update prior to the Annual Review Workshop.

20.1.1 If not, please identify where any other demand related to CNG and LNG is included in the application.

Response:

Please refer to the response to CEC IR 1.20.1.

20.2 Please confirm that the Rate Schedule 46 LNG Forecast of 1,666,806 GJ represents 1,560 TJ of NGT and 107 TJ of 'Other' as indicated in Figure 3-12 above.

Response:

Confirmed. Please also refer to the response to CEC IR 1.20.1.

20.3 Please explain what practices FEI uses to predict the spot demand (i.e., with no contracts).

Response:

Forecasting demand for spot LNG supply agreements is challenging because demand is based on a variety of factors which may be unique to each customer. As such, the best source of information is direct communication with the customers.

To forecast demand for new spot LNG supply contracts, FEI directly engages with end use customers to be informed of business case plans and potential operational requirements. Demand estimates are generated based on these discussions with the customer.

For existing spot LNG supply customers, in addition to direct communication with the customer regarding their potential future consumption, FEI also considers past consumption history as a baseline for forecasting future demand.

21 Reference: Exhibit B-2, Page 40

> The T-South Enhanced Service agreement between Spectra Energy and FEI is in effect until October 31, 2016, and provides a maximum capacity of 91 MMcfd, as approved in Order G-104-13. The Company continues to investigate its options for contracting the capacity beyond 2016.

21.1 For how long may FEI want to extend the contracting capacity with Spectra Energy?

Response:

The Company continues to pursue a multi-year extension of the T-South Enhanced Service agreement between Spectra Energy and FEI (previous extensions of this service agreement have been, on average, 2 year terms). However, for such a renewal to be successful, Spectra Energy must first decide to continue its enhanced service offering, and then shippers must contract for that service.

Absent a renewal of the T-South Enhanced Service, FEI will explore other deal structures to maximize mitigation value from SCP.

22 Reference: Exhibit B-2, Page 41

> FEI has forecast the other revenue components for 2016 reflecting all applicable contracts and fixed revenues, and based on the Company's best knowledge of the factors that drive the variable components. Variances in other revenue are recorded in either the SCP Mitigation Revenues Variance Account (for variances in the items discussed in Section 5.3), the CNG/LNG Recoveries deferral (for variances in the CNG & LNG Service Recoveries forecast discussed in Section 5.2.4) or the Flow-through variance deferral, for all other variances.

22.1 Please confirm or otherwise explain that the Other Revenue includes all the spot market or non-contracted sales anticipated by FEI.

Response:

As shown in Table 5-1 of the Application, total Other Revenue consists of many different components, each of which is further explained in detail in Section 5.2 of the Application. Most of the items that make up other revenue are not related to, or affected by, spot market or non-contracted sales. Therefore, FEI assumes that the CEC is specifically asking whether the NGT Related Recoveries included in Other Revenue include all spot market or non-contracted sales anticipated by FEI.

For reference, Table 5-3 from the Application has been reproduced below followed by an explanation of each of the three line items.

NGT Related Recoveries, ($ millions)			
	Approved 2015	Projected 2015	Forecast 2016
NGT Overhead and Marketing Recovery	0.227	0.222	0.263
NGT Tanker Rental Revenue	0.215	0.168	0.486
CNG & LNG Service Revenues	1.914	1.816	2.426
Total NGT Related Recoveries	**2.356**	**2.205**	**3.174**

1. NGT Overhead and Marketing Recovery (OH&M): As described in Section 5.4.2 of Appendix B in the Application, the OH&M charge is limited to CNG and LNG contract volume delivered through an FEI-owned CNG or LNG fueling station. Therefore this only includes contracted station volumes; there is no OH&M charge on the spot or non-contracted sales.
2. NGT Tanker Rental Revenue: As explained in Section 6.1.3 of Appendix B in the Application, these are revenues FEI collects from customers when FEI uses an FEI-owned tanker to deliver LNG to the customer. To arrive at a forecast amount for anticipated tanker rental revenue, all LNG and CNG volumes are taken into

consideration including spot market sales (non-contracted sales) to arrive at the amount of projected delivery requirements for customers.

3. CNG & LNG Service Revenues: As explained in Section 5.4.1 of Appendix B in the Application, the service revenues are based on the contracted demand associated with the existing and forecast CNG and LNG fueling stations using contracted and forecast rates. Therefore the service revenues do not include non-contracted demand.

FEI has included a forecast of spot market sales in its CNG and LNG demand forecasts (which are not included in Other Revenue). A discussion of the forecast spot demand for CNG and LNG service can be found on page 9 of Appendix B Natural Gas for Transportation and LNG Service.

23 Reference: Exhibit B-2, Page 45

> Overall, Pension and OPEB expense for 2016 is forecast to be $1.830 million lower than what was approved for 2015, of which $1.481 million resides in O&M. This decrease is primarily due to favourable investment returns partially offset by a decrease in the assumed discount rate.

23.1 Please provide further details as to the decrease in the assumed discount rate, including what the old and new assumptions were, and why they were changed.

Response:

As prescribed by US GAAP, the assumed discount rate is an actuarially determined assumption that is based on the yield of a hypothetical portfolio of Corporate AA bond yields with cash flows that match the timing and amount of the expected benefit payments. The assumed discount rate for the forecast pension and OPEB expense for 2016 was 4.00% and the assumed discount rate for the approved pension and OPEB expense for 2015 was 4.25%. The approved 2015 pension and OPEB expense was estimated mid-2014 while the 2016 forecast for pension and OPEB expense was estimated during mid-2015. During this time, the assumed discount rate decreased due to lower yields on Corporate AA bonds. While the discount rates themselves are expected to change at various points in time, the methodology, as prescribed by US GAAP, to determine the assumed discount rates used for estimating pension and OPEB expense has not changed since the inception of the PBR Plan.

24 Reference: Exhibit B-2, Page 45

> The 2016 insurance expense is forecast at $6.275 million, a decrease of $0.374 million or 5.6 percent from what was approved for 2015. The 2016 Forecast is calculated by taking the known annual insurance premium of $6.116 million which is applicable to the first six months of 2016 and escalating that amount by five percent for the remaining six months[26]. The five percent escalation is based on a combination of historical increases in premiums, increases in the value of assets year over year and the expectations of Fortis Inc.'s insurance broker on future premiums.
>
> [26] $6.120 million/2 = $3.060 million x 1.05 = $3.215 million rounded up. $3.060 million + $3.215 million = $6.275 million.

24.1 In that the insurance expense, with a 5% premium, is still lower than that approved for 2015 by 5.6%, please explain why the 2015 insurance expense was so much lower than approved for 2015.

Response:

Actual 2015 insurance expense was lower than approved for 2015 as a result of market conditions allowing for reductions in premiums from the previous year's renewal. This type of premium relief is available for organizations such as FEI who exhibit good risk profiles and strong risk management. FEI was able to assist insurers in quantifying various catastrophic loss scenarios, alleviating some of the uncertainties associated with the underwriting and modeling process, resulting in favorable underwriting terms and conditions.

These reductions in premiums were realized despite a market forecast of increasing pressure on insurance rates within the energy, power and utility risk sector.

25 Reference: Exhibit B-2, Page 46, B-2 and B-4, Page 11

6.3.4 NGT O&M

NGT O&M is forecast to increase by $0.259 million from what was approved for 2015. The total NGT O&M of $1.185 million is composed of $0.987 million of NGT station O&M and $0.198 million of LNG tanker and related O&M (Appendix B Sections 5.1.3 and 6.1.2, and Table B-15). These O&M costs are offset by NGT revenue as discussed in Appendix B Section 4.1.2. Please refer to Appendix B NGT for a discussion of these amounts.

Table B-5: Rate Schedule 25 CNG Forecast

Volume, Revenue, Margin under RS 25		2015A		2015P		2016F
Demand (GJ)		401,493		480,297		586,224
Total Delivery Margin ($ millions)	$	0.326	$	0.617	$	0.728
Total Cost of Gas ($ millions)	$	-	$	-	$	-
Total Revenue ($ millions)	$	0.326	$	0.617	$	0.728

Table B-6: Rate Schedule 46 LNG Forecast[12]

Volume, Revenue, Margin under 46		2015A		2015P		2016F
Demand (GJ)		719,217		521,737		1,666,806
Total Delivery Margin ($ millions)	$	2.177	$	2.353	$	7.668
Total Cost of Gas ($ millions)	$	1.826	$	1.297	$	4.144
Total Revenue ($ millions)	$	4.003	$	3.650	$	11.811

25.1 Please confirm or otherwise clarify that FEI is referencing the $7.688 million in forecast delivery margin revenue for LNG as being the offset for the $1.185 million in O&M expenditures.

Response:

Not confirmed. Although the delivery margin of $7.668 million and $0.728 million in Table B-5 and Table B-6 in Section 4.2 of Appendix B in the Application helps to offset overall O&M expenses of the Company, they are not directly related to the NGT O&M of $1.185 million referenced above in the preamble.

For reference, Table 5-3 from Section 5: Other Revenue has been reproduced below and shows the associated revenues that help to offset the NGT specific O&M costs of $1.185 million referenced above.

Table 5-3: 2015 and 2016 NGT Related Recoveries

NGT Related Recoveries, ($ millions)	Approved 2015	Projected 2015	Forecast 2016
NGT Overhead and Marketing Recovery	0.227	0.222	0.263
NGT Tanker Rental Revenue	0.215	0.168	0.486
CNG & LNG Service Revenues	1.914	1.816	2.426
Total NGT Related Recoveries	**2.356**	**2.205**	**3.174**

The 2016 Forecast CNG and LNG Service Revenues of $2.426 million and NGT Overhead and Marketing Recoveries of $0.263 million offset the $0.987 million in NGT O&M station costs. These are discussed in detail in Sections 5.4.1 and 5.4.2 of Appendix B in the Application. The Tanker Rental Revenue Forecast of $0.486 million, discussed in Section 6.1.3 of Appendix B in the Application, offsets the $0.198 million of LNG tanker O&M.

26 Reference: Exhibit B-2, Page 54

> 2015. The LMIPSU is an integrity project to address an increasing number of gas leaks on the Coquitlam IP line and seismic upgrades required to the Fraser Gate IP line, with an expected in-service date at the end of 2018. The estimated capital cost for the LMIPSU CPCN in as-spent dollars, excluding AFUDC and including abandonment/demolition costs, is $241.413 million. In 2015 and 2016, FEI has forecast expenditures of $5.642 million and $28.879 million[34] respectively of this total. This is in addition to $1.647 million of expenditures in 2013 and 2014.

26.1 Please provide the estimated cost for the Fraser Gate IP line, independently of the Coquitlam IP line.

Response:

The above question has been addressed in FEI's responses provided during the evidentiary phase of the Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) CPCN Proceeding which is now closed and currently under review by the Commission. As noted in the responses to the LMIPSU CEC IRs 2.3.1 and 2.3.2 provided in Attachment 26.1, the estimated cost in as spent dollars for the Fraser Gate IP pipeline constructed separately from the LMIPSU Project is $12.289 million (excluding AFUDC) and would be more costly than if it was constructed as part of the LMIPSU Project. Please also refer to the responses to LMIPSU CEC IR 2.3.4, 2.4.2 and LMIPSU BCUC IRs 2.22.1 and 2.20.6, also provided in Attachment 26.1.

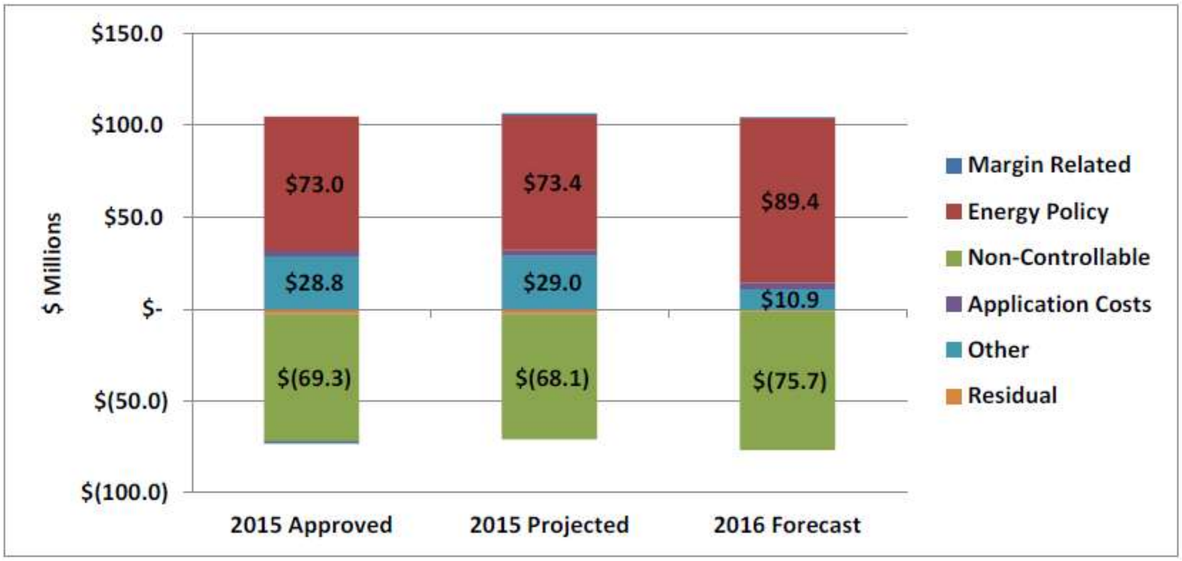
26.2 Please confirm that FEI could have applied for the Fraser Gate IP line as a separate CPCN.

Response:

Please refer to the response to CEC IR 1.26.1 and Attachment 26.1. FEI did not apply for a separate CPCN for the Fraser Gate IP pipeline because of the benefits associated with constructing both pipelines together. As noted in the response to LMIPSU CEC IR 2.3.1 (included in Attachment 26.1), if the Fraser Gate IP Project was undertaken independently of the Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) Project, several factors would impact the Fraser Gate IP project cost estimate and increased project costs would result. Please also refer to Part Two of FEI's Reply Submission in the LMIPSU proceeding, included as Attachment 26.2.

27 Reference: Exhibit B-2, Page 56

Figure 7-1: FEI Forecast Mid-Year Balances of Rate Base Deferral Accounts by Category



27.1 Please identify the individual accounts associated with the account categories 'margin related', 'energy policy', 'non-controllable', 'other' and 'residual'.

<u>Response:</u>

The individual accounts related to each of these categories are shown in Section 11, Schedules 11 and 11.1 of the Application.

28 Reference: Exhibit B-2, Page 56

7.5.1.1 2015 System Extension Application

On June 30, 2015, FEI filed with the Commission the 2015 System Extension Application which contained an evaluation of the Main Extension (MX) Test to ensure that the test remains appropriate for both existing and new customers. As part of the filing and review of this

Application, FEI expects to incur approximately $325 thousand in costs related to consulting costs, legal fees, intervener and participant funding costs, Commission costs and miscellaneous facilities, stationery and supplies. Therefore, FEI requests approval to capture the costs of the 2015 System Extension Application in this rate base deferral account and to amortize these costs over a two-year period beginning in 2016. Although FEI expects the system extension policies to be in place for longer than two years, there is a minimal rate impact difference between a two-year amortization period and an amortization period longer than two years. Any variances between the forecast account balances and the actual incurred costs will be amortized in rates the following year.

28.1 Did FEI seek a deferral account for the MX Test in the MX Test application currently before the Commission?

Response:

No. The 2015 System Extension Application costs are being requested in this Application only.

FEI believes the Annual Review process is the appropriate forum to request non-CPCN Application costs given that delivery rates are set during this process.

28.1.1 If no, please explain why not.

Response:

Please refer to the response to CEC IR 1.28.1.

28.2 Please explain whether or not a deferral account for the MX Test would serve to recover the costs outside of the PBR formulaic O&M

Response:

The deferral account for the MX Test will appropriately recover the costs outside the PBR formulaic O&M which is consistent with past Commission approvals including approval of the PBR plan. The costs of regulatory applications have always been recovered in deferral accounts and this practice has continued under PBR. For example, in the PBR Decision, the Commission approved the 2014-2018 PBR Application Costs Deferral Account, stating: "The Panel considers this treatment to be consistent with past deferral accounts approved for application-related costs." In addition, Commission Order G-178-14 established the 2015-2019 Annual Reviews deferral account and Commission Order G-86-15 approved the 2016 Cost of Capital Application and the 2017 Rate Design Application deferral accounts.

As discussed in Section 7.5.1.1 of the Application, the 2015 System Extension Application deferral account is requested to recover external costs related to the filing and regulatory review of the System Extension Application. As the costs for regulatory applications have been consistently granted deferral account treatment, these costs are clearly outside the PBR Base O&M. Given that these costs were not included in the PBR Formulaic O&M base, FEI will not be reducing the O&M formula for these costs.

28.2.1 If yes, does FEI propose to reduce the O&M formula for this spending?

Response:

Please refer to the response to CEC IR 1.28.2.

28.2.1.1 If not, please explain why not.

Response:

Please refer to the response to CEC IR 1.28.2.

29 Reference: Exhibit B-2, Page 57

7.5.1.2 BERC Rate Methodology Application

FEI filed an Application in August of 2015 relating to a proposed change to the rate methodology used from calculating the Biomethane Energy Recovery Charge (BERC) rate (the BERC Rate Methodology Application). As part of the filing and review of the BERC Rate Methodology Application, FEI expects to incur approximately $75 thousand in costs related to legal fees, intervener and participant funding costs, Commission costs and miscellaneous facilities, stationery and supplies, but notes the actual amount will be dependent on the process and number of participants. Therefore, FEI requests approval to capture the costs of the the BERC Rate Methodology Application in a rate base deferral account and to amortize the costs over a one-year period in 2016. Given the relatively small amount anticipated for this account, a longer amortization period has minimal impact on the rate impact to customers. Any variances between the forecast account balances and the actual incurred costs will be amortized in rates the following year.

29.1 Please verify that the Commission has already approved for costs such as the BERC rate methodology application to be captured outside of PBR formulaic O&M, and identify where the Commission did so.

<u>Response:</u>

It is clear that regulatory application costs are outside of formulaic O&M.

Regulatory application costs are not included in FEI's formulaic O&M as FEI does not record application costs in O&M expense; rather it is common practice for FEI to establish deferral accounts to record the costs of various regulatory applications and to recover these costs through the delivery rates of customers. This is because application costs are subject to considerations outside of the control of FEI such as the regulatory process that the Commission puts in place, whether or not the Commission levy will cover the costs of the Commission's participation, whether the Commission or interveners will engage consultants or experts and the overall level of PACA funding provided.

The practice of establishing a deferral account to record regulatory application costs has continued under PBR. See the response to CEC IR 1.28.2 for a discussion of regulatory costs recently approved for recovery through a deferral account under FEI's PBR. Specific to the BERC rate methodology deferral account, the establishment of a deferral account for BERC Methodology Application costs and the recovery of these costs from all non-bypass customers is consistent with the Commission's Order G-15-15 approving the recovery of the 2013 Biomethane Application Costs.

30 Reference: Exhibit B-2, Page 58 and C2, Page 10

The Commission also indicated at page 27 of its Decision that "it was of the view that costs eligible for deferral account treatment are largely restricted to the use of external resources (i.e. as opposed to those aspects of the filing developed by internal staff)". Consistent with this view, FEI is only proposing to capture in the deferral account the costs of external resources required to carry out the incremental activities for the 2017 LTRP.

Table 1 provides a summary of those tasks and activities that are incremental activities and for which FEI is requesting that costs be captured in the proposed deferral account.

Table 1: Summary of Anticipated Expenditures

	Activity	2016 Expenditure Estimate	Total Expenditure Estimate (based on upper estimate)
1.	Scenario Development	$ 75,000	$ 75,000
2.	Comparison of End-use Demand Forecasting Methodologies	$ 45,000	$ 45,000
3.	Alternative Residential and Commercial Customer Additions Forecast	$ 25,000	$ 25,000
4.	End-Use Demand Forecast	$ 95,000	$ 180,000
5.	Alternative Industrial customer Additions and Demand Analysis	$ 95,000	$ 145,000
6.	Impact of New End-use Trends on Time-of-Day Use and Linking the Annual and Peak Demand Forecasts	$ 70,000	$ 150,000
7.	Incremental Consultation Activities	$ 30,000	$ 50,000
8.	DSM Portfolio Scenario Analysis Including Alternative DSM Funding and Savings Scenarios	$ 60,000	$ 200,000
9.	Analyze and Report on Peak Demand Infrastructure Avoidance / Deferral Opportunities	$ 10,000	$ 80,000
10.	Infrastructure Contingency Plans	$ 0	$ 70,000
11.	Analysis of Impact on GHG Targets	$ 0	$ 30,000
	Total	**$ 505,000**	**$ 1,050,000**

30.1 Does FEI propose any limit on the extent of external resources that it can utilize in the preparation of the LTRP?

<u>Response:</u>

FEI considers the $1.050 million total forecast to be its upper estimate budget for the LTRP incremental activities and will be working within this budget to complete the necessary tasks. The Commission will have the opportunity to review any updated forecast in FEI's next Annual Review and the final actual costs when FEI seeks approval to recover the costs in the deferral account from customers.

30.1.1 If yes, what limits does FEI propose to establish for costs associated with the external resources?

Response:

Please refer to the response to CEC IR 1.30.1.

31 Reference: Exhibit B-2, C2, Page 11

- *Hours spent by external resources compared to internal resources:* An estimate of the number of hours to be spent by external consultants on these activities is presented along with the activity descriptions and cost estimates below. FEI has provided descriptions of associated work that will need to be completed by internal staff; however, since work completed by internal staff will be part of Base O&M, FEI has not developed estimates of hours spent by internal staff on incremental activities separate from other Base O&M activities.

31.1 Why does the completion of work within the Base O&M preclude FEI from developing estimates of the hours spent on the LTRP internally?

Response:

Please refer to the discussion in Section 3, pages 9 to 10, of Appendix C2, Exhibit B-2 for an explanation as to why developing estimates of the internal hours and costs spent on the LTRP overall is impractical. In addition, as FEI will be managing internal costs within the existing base O&M, an estimate of internal hours spent on only incremental activities would not be a meaningful exercise.

31.2 Over how many years does FEI normally prepare for an LTRP?

Response:

While some aspects of Long Term Resource planning are ongoing, preparing an LTRP can take FEI two to three years. A two-year time frame has been assumed for the costs provided in Appendix C2. In those years when internal staff do not devote as much time to the LTRP, other priority work is undertaken.

32 Reference: Exhibit B-2, C2, Pages 12 and 13

Consultant Activities:

- Review, identify and prioritize a full range of factors that could impact future planning for natural gas service;
- Review external sources of energy planning scenarios in BC and other jurisdictions in North America;
- Identify top priority uncertainties that could drive a reasonable range future scenarios conditions;
- Prepare draft scenarios for review with internal and external stakeholders;
- Ensure scenarios are developed sufficiently to allow future demand forecasting and contingency planning around each;
- Participate in internal and external stakeholder consultation on scenarios; and
- Prepare draft and final reports.

Consultant Activities:

- Identify a full list of forecasting entities in BC and other jurisdictions;
- Conduct in-depth interviews of forecasting staff and obtain forecasting methodology samples wherever possible;
- Conduct interviews with regulatory bodies in other jurisdiction to determine how forecasting methodologies are regulated;
- Determine if forecasting standards and/or best practices exist;
- Review FEI's forecasting methodologies to determine if they are in line with typical/best forecasting practice and standards;
- Make recommendations on forecasting methodologies; and
- Prepare draft and final reports.

32.1 Please confirm that much of the information that will be generated from external resources will be invaluable many other applications that FEI puts forward or other activities.

Response:

Not confirmed. By its nature, the LTRP is meant to inform other activities, planning processes and applications by the utility. As such, much of the information generated from external resources in completing the incremental activities for the LTRP may be useful and important in other applications; however, FEI cannot agree that "much of the information would be invaluable

[for] many other applications". FEI did not undertake these activities prior to the 2014 LTRP and the primary driver of these activities is the completion of the LTRP in the manner directed by the Commission.

32.2 If not confirmed, please explain why not.

Response:

Please refer to the response to CEC IR 1.32.1.

32.3 Please differentiate between the types of information that are usable only in preparation for the LTRP and that type of information which may also be of use for other purposes.

Response:

LTRPs by their very nature are meant to inform other activities and applications. As such all information developed for the LTRP may be usable for other purposes. Please also refer to the response to CEC IR 1.32.1.

32.4 Would FEI normally utilize internal resources to acquire or interpret any of the information that will be generated by the external resources and of use for other purposes? Please explain why or why not.

Response:

No. The deferral account is being sought to aid in the completion of incremental new planning analyses and activities that were first required for the 2014 LTRP. FEI therefore does not normally conduct these tasks.

33 Reference: Exhibit B-2, Pages 68 and 69

> Finally, FEI has calculated its final 2014 earnings sharing adjustment based on the results included in its 2014 Annual Report to the Commission. The final amount of earnings sharing for 2014 was $3.657 million, which was $0.316 million higher than the $3.341 million projected for 2014.

> FEI proposes to distribute $5.068 million to customers in 2016 as a reduction in 2016 revenue requirements through amortization of the projected 2016 opening after-tax balance of $3.750 million in the Earnings Sharing deferral account.

33.1 Please confirm that the final total amount of earnings available for sharing was $0.632 higher than the projected, and that the $0.316 million is the amount available for sharing to the ratepayer.

Response:

To clarify, for 2014, the total actual O&M, net of the higher equity return on base capital expenditures, was $0.632 million lower than the projected amount. This resulted in $0.316 million that will be returned to ratepayers in 2016 rates.

33.2 Please confirm or otherwise clarify that FEI shareholders receive the time value benefit of all the unspent O&M and capital for the duration of the year in which it was collected and not spent, the duration of the year in which earnings sharing is returned in rates incrementally over the year, and again for the duration of the year in which the true-up is returned incrementally over the next year.

Response:

While responding to this information request, FEI discovered an error in the amounts recorded in the Earnings Sharing deferral account.

BCUC Order G-162-14 stated: "FortisBC Energy Inc. is approved to establish the Earning Sharing deferral account to flow through to customers any result of the Earning Sharing Mechanism. FortisBC Energy Inc. shall apply a one year amortization period to the Earning Sharing deferral account <u>and shall accrue carrying charges on the deferral account based on FortisBC Energy Inc.'s currently approved weighted average cost of capital.</u>" [emphasis added]

Given FEI's treatment of this account as a non-rate base deferral, FEI should have been recording a weighted average cost of capital return (equivalent to AFUDC) on the deferral account actual balances. FEI will update the financial schedules in Section 11 of the Application, as part of the Evidentiary Update to be filed prior to the Annual Review Workshop, to include the AFUDC amounts that will be returned to customers through amortization of the deferral account in 2016. The total projected AFUDC for 2014 through 2016, related to the 2014 actual and 2015 projected earnings sharing amounts, is $458 thousand.

By including the weighted average cost of capital calculation in the deferral account, this serves to return the interest related to any timing differences to customers.

33.3 Please calculate the estimated interest value of the ratepayer portion of the Earnings Sharing that FEI achieved in 2014 and were returned to customers over a year or more.

Response:

Please refer to the response to CEC IR 1.33.2.

34 Reference: Exhibit B-2, Page 110

The materiality threshold (item 5) for FEI has been established at $1.140 million, as approved by Commission Order G-164-14.

For 2016, FEI has not identified any items that merit exogenous factor treatment.

34.1 Did FEI consider potential savings as well as costs in its determinations that there are no items that merit exogenous factor treatment?

<u>Response:</u>

Yes.

34.1.1 If no, were there any savings that might come close to meriting exogenous factor treatment? Please explain.

<u>Response:</u>

The Commission has already addressed CEC's submission that, "if there are exogenous savings that could approach the materiality threshold, it should be incumbent upon the utility to advise stakeholders of the possibility so that determinations can be made as to whether or not the materiality threshold is reached" in its Decision attached to Order G-86-15 in FEI's Annual Review for 2015 Rates. In that Decision on page 20 the Commission stated "The Panel agrees with FEI that given the materiality threshold that has previously been set, only savings or costs that exceed the threshold are relevant. Accordingly, the Panel declines to direct FEI to identify any savings or costs other than those that meet the threshold criteria."

35 Reference: Exhibit B-2, Pages 124, 125 and 126

Table 13-1: Approved SQI, Benchmarks and Actual Performance

Performance Measure	Description	Benchmark	Threshold	2015 June YTD Results
	Safety SQIs			
Emergency Response Time	Percent of calls responded to within one hour	97.7%	96.2%	97.5%
Telephone Service Factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	95%	92.8%	98.4%
All Injury frequency rate (AIFR)	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	2.08	2.95	2.42
Public Contacts with Pipelines	3 year average of number of line damages per 1,000 BC One calls received	16	16	10
	Responsiveness to the Customer Needs SQIs			
First Contact Resolution	Percent of customers who achieved call resolution in one call	78%	74%	81%

Performance Measure	Description	Benchmark	Threshold	2015 June YTD Results
Billing Index	Measure of customer bills produced meeting performance criteria	5.0	≤5.0	0.62
Meter Reading Accuracy	Number of scheduled meters that were read	95%	92%	98.2%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	70%	68%	71%
Meter Exchange Appointment	Percent of appointments met for meter exchanges	95%	93.8%	97.0%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.5
Telephone Abandon Rate	Informational indicator – percent of calls abandoned by the customer before speaking to a customer service representative	-	-	2.1%
	Reliability SQIs			
Transmission Reportable Incidents	Informational indicator – number of reportable incidents to outside agencies	-	-	2
Leaks per KM of Distribution System Mains	Informational indicator - measures the number of leaks on the distribution system per KM of distribution system mains	-	-	0.0026

Table 13-2: Historical Emergency Response Time

2009	2010	2011	2012	2013	2014
97.7%	97.7%	97.9%	97.4%	97.4%	96.7%

35.1 Does FEI intend to bring the Emergency Response time up to benchmark over the next year?

Response:

Yes. FEI is targeting to meet the benchmark over the next year and has improved the results in 2015 compared to 2014. FEI closely monitors emergency response time metrics and emergency response resources and is realizing improvements from regionalization of the dispatch groups and technician shift changes.

35.1.1 If yes, what plans does FEI have to do so?

Response:

Please refer to the response to CEC IR 1.35.1.

35.1.2 If no, please explain why not.

Response:

Please refer to the response to CEC IR 1.35.1.

35.1.3 If no, please discuss FEI's views as to the role of the benchmark and the role of the 'threshold'

Response:

Please refer to the response to CEC IR 1.35.1.

36 Reference: Exhibit B-2, Pages 124, 127 and 128

Table 13-1: Approved SQI, Benchmarks and Actual Performance

Performance Measure	Description	Benchmark	Threshold	2015 June YTD Results
Safety SQIs				
Emergency Response Time	Percent of calls responded to within one hour	97.7%	96.2%	97.5%
Telephone Service Factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	95%	92.8%	98.4%
All Injury frequency rate (AIFR)	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	2.08	2.95	2.42
Public Contacts with Pipelines	3 year average of number of line damages per 1,000 BC One calls received	16	16	10
Responsiveness to the Customer Needs SQIs				
First Contact Resolution	Percent of customers who achieved call resolution in one call	78%	74%	81%

Table 13-4: Historical All Injury Frequency Rate Results

All Injury Frequency Rate	2009	2010	2011	2012	2013	2014
Annual Results	2.49	2.66	1.66	1.91	3.02	1.73
Three year rolling average	2.55	2.26	2.27	2.08	2.20	2.22

review and to enhance the Company's existing Safety Management system and programs, FEI will be developing the "Target Zero" safety program with the official launch to take place in January 2016. This program will provide a structured format for employees at all levels to provide input into corporate safety enabling the Company to better understand the current state of the safety culture and prioritize and implement initiatives that are relevant to our employees. Increased O&M funding is being reallocated to support this program. Aspects of the program include:

36.1 Please provide the annual results for the AIFR for 2015.

Response:

The AIFR from January 1 to August 31, 2015 is 2.57. Annual results for 2015 will be available in January 2016.

36.2 Please explain why the AIFR was higher in 2015 than it was in 2014.

Response:

The AIFR for 2014 was the second lowest since 2009 and well below the benchmark of 2.08, magnifying the increase seen in 2015 year-to-date.

The exact nature and number of injuries in industrial, field-type working environments, where workers may often conduct similar tasks for many decades (such as those at FEI), is often unpredictable on a year by year basis. In addition to the work environment, this unpredictability may often be correlated to the general physical condition of a worker conducting these repetitive tasks, and that factor can vary significantly from person to person. Furthermore, the precise manner in which work is conducted can vary significantly as well.

Through August 31, 2015, 75 percent of the 2015 injuries are related to ergonomic causes, versus 64 percent of total injuries in 2014. The Company has continually emphasized its ergonomic programs, by an external, trained resource, and has supported its field crews through its supervisory instruction and work planning that specifically references ergonomic awareness. However, tasks related to lifting, pulling, turning, rotating, etc. continue to result in recordable injuries.

36.3 Do FEI's plans to improve safety contemplate the AIFR reaching the benchmark in 2016?

Response:

FEI's plans to improve safety are developed to eliminate all injuries in the workplace. However, due to the unpredictability of the number of injuries in any given year and the three year rolling average formula, FEI cannot state that it will achieve the approved benchmark in 2016.

36.3.1 If no, please explain why not.

Response:

Please refer to the response to CEC IR 1.36.3.

37 Reference: Exhibit B-2, Page 131

From 2009 to 2013 as indicated in the following table, the Company's TSF (Non-Emergency) results were consistent with a benchmark of 75 percent. The 2014 result was achieved with the Company targeting 75 percent as the benchmark until the Commission approved the revised target of 70 percent in mid-September 2014. In 2015 and future years, actual results are expected to be lower than that observed in the past, reflective of the revised target of 70 percent approved by the Commission.

37.1 Please provide the estimated cost savings that FEI will achieve as a result of meeting the lower 70% benchmark.

Response:

As stated in response to CEC IR 1.53.2 in FEI's Annual Review for 2015 Rates, "The new staffing levels are expected to achieve savings of $50,000 annually, starting in 2015. These savings relate to a reduction in the utilization of part time and temporary staff hours during peak call volume times which are typically Monday mornings and the mornings during the first week of each month. 2014 had lesser savings of approximately $20,000 due to the change being later in the year."

Attachment 26.1

3. Reference: Exhibit B-6, CEC 1.3.2 and Exhibit B-1-6, page 20 and page 24 Table 3-1

3.2 Are there any particular links between the Fraser Gate IP portion and the Coquitlam Gate IP pipeline portion such that the projects should be undertaken at the same time? Please explain.

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

The proposed Coquitlam Gate IP and Fraser Gate IP Projects both involve the construction and installation of NPS 30 pipe to replace existing pipe along sections of the two primary pipelines supplying gas to the Metro IP system. The Coquitlam IP Project as applied for is larger in scope; however, in general, both Projects share common attributes in terms of design, routing process, materials procurement and specialized construction and installation techniques due to their urban location. More specifically, with the replacement NPS 30 Coquitlam Gate IP pipeline in service, it will be possible to isolate the Fraser Gate IP pipeline and replace the seismically vulnerable segment of pipe with the proposed upgraded pipe without the use of a bypass. This particular link will require the commissioning window for both pipelines to be synchronized, and any delay in commissioning the Coquitlam IP pipeline would also likely delay the Fraser Gate IP pipeline commissioning.

It is therefore logical that both Projects should be undertaken at the same time in terms of planning, permitting, stakeholder consultation and ultimately construction and commissioning.

3.2 *REVISED PROJECT SCOPE*

As the boundary of lateral spread ground displacement was determined at a point greater than 80 metres east of the location of Test Hole AH95-2, it was deemed feasible to optimize the scope compared to what was originally applied for in the Application. The new proposed scope of the Fraser Gate IP Project involves the replacement of approximately 280 metres of NPS 30 pipeline operating at 1200 kPa and extending from Fraser Gate station at the 2700 block of East Kent Avenue to a point 30 metres east of where the existing NPS 30 pipeline turns north to cross beneath the CP Rail line. This pipeline will replace the section of the existing NPS 30 pipeline which does not meet FEI's seismic criteria for resistance to a 1:2475 year event.

Table 3-1: Updated Fraser Gate IP Project Financial Analysis

	Reduced Scope Alternative 2 – Route Option 1 – East Kent Ave South
Estimate Accuracy	Class 3
Total Direct Capital Cost excl. AFUDC (2014 $millions)	7.378
Total Direct Capital Cost excl. AFUDC (As-spent ($millions)	8.572
AFUDC (as spent ($millions)	0.419
Total As-spent ($millions)	8.990
Annual Gross O&M (2014 $millions)	0.001
Levelized Rate Impact $ / GJ – 60 Yr.	0.004
PV Incremental Cost of Service – 60 Yr. ($millions)	10.764

3.1 Please provide an estimate of the increased costs that would occur if the Fraser Gate project was undertaken independently of the Coquitlam Gate project, and include any opportunity to mitigate costs that may have occurred as a result of the change in project scope (ie. need for bypass or other factors influencing costs).

Response:

The basis of cost estimate included in Appendix A-23 of the Application assumes that the Coquitlam Gate IP Project and Fraser Gate IP Project would be constructed at the same time and by the same pipeline contractor. If the Fraser Gate IP Project was undertaken independently of the Coquitlam Gate IP Project, the following factors would impact the Fraser Gate IP Project cost estimate resulting in potentially increased Projects costs:

1. Contractor mobilization and demobilization, which would be shared between the two IP Projects, would increase to the full cost if the Fraser Gate IP Project was undertaken independently;
2. Independent pipe orders would not avail of the economy of scale associated with the larger pipe order for both IP Projects, and would therefore incur additional procurement costs due to the smaller order quantity for the Fraser Gate IP Project;
3. It is likely that the Coquitlam Gate IP pipeline contractor would not be available or interested in the much smaller scope of the Fraser Gate IP Project; therefore, knowledge and productivity gain from the Coquitlam Gate IP Project would be lost which could result in reduced pipeline productivity and an increased construction schedule;
4. A different pipeline contractor would require retesting and requalification to FEI procedures and standards, including revised pipeline test plans and hydrostatic test heads; and
5. If the Fraser Gate IP Project is constructed independently of, and prior to, the Coquitlam Gate IP Project, a temporary bypass would be required.

The above factors could result in additional Project costs in the range of approximately $2.7 – $3.2 million.

If the Fraser Gate IP Project could be constructed independently of, and after, the Coquitlam Gate IP Project, a temporary bypass would not be required. Please refer to the response to BCUC IR 1.3.6 for the portion of the total cost attributable to the bypass which would reduce the additional costs by approximately $1.4 million to an approximate range of $1.3 to $1.8 million.

3.2 Please provide an analysis of the net costs that would accrue to the ratepayer if the projects were undertaken separately and the capital costs reduced such that Fraser Gate IP project was not below the current capital exclusion criteria ($5 million) established for PBR.

Response:

If the Projects were undertaken separately, dependent on the timing of the Projects as described in FEI's response to CEC IR 2.3.1, the capital costs would not be reduced but rather increased. The increase in the capital costs of the Fraser Gate IP Project could be in the range of approximately $1.3 million to $3.2 million.

The following table presents the detail in Table 3-1 Updated Fraser Gate IP Project Financial Analysis after increasing the capital costs by $1.3 million and $3.2 million. The first row indicates the increase in the capital cost rather than the AACE Class level.

	Reduced Scope Alternative 2 – Route Option 1 – East Kent Ave South	
Capital Cost Addition (2014 $millions)	1.3	3.2
Total Direct Capital Cost excl. AFUDC (2014 $millions)	8.678	10.578
Total Direct Capital Cost excl. AFUDC As-spent ($millions)	10.082	12.289
AFUDC As spent ($millions)	0.492	0.600
Total As-spent ($millions)	10.574	12.890
Annual Gross O&M (2014 $millions)	0.001	0.001
Levelized Rate Impact $ / GJ – 60 Yr.	0.004	0.005
PV Incremental Cost of Service – 60 Yr. ($millions)	12.654	15.417

[redacted]

[redacted]

[redacted]

3.4 Please provide an analysis of the net costs that would accrue to the ratepayer if the projects were undertaken separately and the materiality threshold for capital exclusion criteria raised to $10 million or more such that the Fraser Gate project was below the capital exclusion criteria.

Response:

In its Decision accompanying Order G-138-14 regarding FEI's 2014-2018 Performance Based Ratemaking Application, the Commission approved FEI's $5 million CPCN exemption threshold as applied for until such time as any further determination by the Commission is made concerning capital exclusion[1]. The FEI/FBC Capital Exclusion Criteria proceeding that is currently underway will define what the appropriate capital exclusion criteria will be in the future and is not applicable to this Application, which was filed in 2014 under the then approved $5 million capital exemption threshold. FEI declines to provide the requested hypothetical information as it is not relevant to the CPCN under consideration.

[1] Order G-138-14, p. 181.

4. Reference: Exhibit B-6, CEC 1.3.2.1

3.2.1

Response:

Please refer to the resp

[redacted]

4.2 Please describe any regulatory or other issues that would arise if the Fraser Gate project was deferred until after the capital exclusion threshold for PBR were determined, and the capital exclusion materiality threshold was raised such that the project fell below the materiality threshold.

Response:

Any revisions to the capital exclusion criteria that may result from the FortisBC Capital Exclusion Criteria proceeding will not be applicable to this Application. The CPCN threshold of $5 million was approved and in place when this CPCN Application was filed and as such, it is the $5 million CPCN Capital Exclusion threshold that applies regardless of the outcome of the FortisBC Capital Exclusion Criteria proceeding. Similarly, FEI's Huntingdon Station Bypass CPCN was approved under the CPCN threshold that was in place at the time the application was filed, even though it was not known what threshold would be in place at the time it was constructed.

Further, the capital planning and the timing of capital projects is guided by system sustainment, growth-related and other operational considerations to ensure that natural gas services are provided safely, reliably and at the lowest reasonable costs to meet the energy demands of our customers. The Fraser Gate IP Project involves the replacement of a segment of the Fraser Gate IP pipeline identified to be unacceptably vulnerable to seismic activity.

Please also refer to the response to BCUC IR 2.22.1.

G. PROJECT ALTERNATIVES – FRASER GATE

20.0 Reference: ALTERNATIVES DESCRIPTION AND ALTERNATIVES EVALUATIONS

Exhibit B-1-6, p. 19; Exhibit B-4, BCUC 1.33.1.1.2, 1.33.1.2, 1.33.1.3

Alternatives to project as proposed

On page 19 of the Evidentiary Update FEI states that the revised scope of the Fraser Gate IP Project involves the replacement of approximately 280 metres of NPS 30 pipeline, and that this replacement length extends 80 metres into the competent soils zone.

In response to BCUC IR 1.33.1.1.2 FEI states that no significant movement is expected at the NPS 30 pipeline at the outlet of the Fraser Gate station if a 1:2475 seismic event occurs.

In response to BCUC IRs 1.33.2 and 1.33.3 FEI states reasons why it considers that an alternative involving ground improvement would offer no advantage over pipeline replacement.

[redacted]

20.6 The response to BCUC IR 1.33.1.1.1 FEI states that the cost of further modifications at Fraser Gate station will be managed within the sustainment capital budget; please discuss whether the cost of dealing with the seismic concern for the Fraser Gate pipeline by ground improvement could be managed within the sustainment capital budget.

Response:

The cost of dealing with the seismic concern for the NPS 30 Fraser Gate IP pipeline by either pipe replacement or by a potential ground improvement option is estimated at above the FEI CPCN threshold, and as such does not fall within sustainment capital.

22.0 Reference: PROJECT COSTS AND ACCOUNTING TREATMENT

FEI 2014-2019 PBR Decision, p. 181

PBR impact

On page 181 of the FEI 2014-2019 PBR Decision states: Until such time as any further determination is made concerning capital exclusion, the Panel approves the current CPCN exemption threshold as the threshold for exclusion for both utilities as applied for.

22.1 If the Fraser Gate IP project is made a standalone CPCN project and falls below the current CPCN exemption threshold of $5 million, please explain how the Fraser Gate IP project would be treated in the PBR.

<u>Response:</u>

As stated in the response to BCUC IR 2.20.6, the cost of dealing with the seismic concern for the NPS 30 Fraser Gate IP pipeline by either pipe replacement or by a potential ground improvement option is greater than the FEI CPCN threshold that was approved for 2014 and 2015 pursuant to Order G-138-14.

In the extremely unlikely event the Fraser Gate IP Project was reforecast to be below the $5 million threshold and the CPCN application was withdrawn, the capital and O&M expenditures for this project would be managed within the formula amounts as set out under the PBR plan.

[redacted]

Attachment 26.2

[redacted]

PART TWO: REPLY TO CEC SUBMISSION

3. CEC acknowledged that the proposed Projects were appropriately developed and costed. CEC recommended that the Commission approve the Coquitlam Gate IP Project and the Fraser Gate IP Project as proposed by FEI with the considerations as outlined in CEC's Submission. The primary point of contention raised by CEC is its recommendation that the Commission address the issue of the capital exclusion materiality threshold for PBR.[1] Specifically, CEC recommends that the Commission make a determination as to whether or not the capital exclusion criteria as very recently determined by the Commission in Order G-120-15 (the "Capital Exclusion Decision")[2] apply to the Projects.[3] FEI submits that such a determination is not necessary as:

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1 CEC Submission, p. 1.

2 *In the Matter of FortisBC Energy Inc. and FortisBC Inc. Multi-Year Performance Based Ratemaking Plans for 2014 through 2019 Approved by Decisions and Orders G-138-4 and G-139-14 Capital Exclusion Criteria under PBR – Compliance Filing*, Order No. G-120-15, July 22, 2015.

3 CEC Submission, p. 31.

(a) It is clear from the language of the Capital Exclusion Decision that it was not intended to apply to the Projects; and

(b) The Capital Exclusion Decision was issued after the Application for a CPCN for the Projects was filed and as such, it is not applicable to the Projects.

4. Though the above considerations are dispositive of the matter, in any event, the Projects are rationally grouped under one CPCN.

A. Capital Exclusion Decision, On Its Face, Does Not Apply

5. A review of the Capital Exclusion Decision makes clear that the Projects were intended to be excluded capital under PBR as there was no associated adjustment to Base Capital for projects between the then-current $5 million and the proposed $15 million thresholds. In reviewing the submission of FortisBC (FEI and FortisBC Inc. together), the Commission noted as follows at page 4 of Appendix A to the Capital Exclusion Decision:

> FortisBC submits that increasing FEI's materiality threshold from $5 million to the proposed $15 million <u>"would require an adjustment to its formula spending envelope (by way of a Base Capital adjustment), if the proposed higher CPCN threshold resulted in a need to incorporate additional capital work under the formula spending for capital projects between the current $5 million and the proposed $15 million thresholds."</u> However, it "does not anticipate any capital projects within this range of expenditure during the PBR Period and therefore submits that no adjustment to its Base Capital is required to accommodate the proposed CPCN threshold."
>
> (Emphasis added.)

6. FEI's position regarding the increase in the CPCN threshold took into consideration that the Fraser Gate IP Project would not result in an adjustment to Base Capital because FEI had requested a CPCN as part of the Lower Mainland Intermediate Pressure System Upgrade Project.

7. This consideration formed a part of the Commission's determination as it held as follows at page 12 of Appendix A:

> The Panel considers FEI's existing $5 million threshold to be low enough that it may be vulnerable to the possibility of combining projects. Raising it to $15 million will require no rebasing, will not be subject to the effects of distortion caused by large, lumpy projects and is supported by both CEC and BCOAPO. Further, the Panel is satisfied that because the Commission retains the authority to require a CPCN, the public interest is adequately protected if the CPCN financial threshold is raised to $15 million. Accordingly, for FEI, the Panel approves $15 million as the threshold for both capital exclusion for the PBR formula and CPCN exemption.
>
> (Emphasis added.)

8. It is clear that the Capital Exclusion Decision was premised in part on the fact that there were no anticipated FEI capital projects that would fall within the old and new thresholds, as otherwise rebasing would have been required, which it was not. Accordingly, the Projects should be treated as excluded capital under PBR. If the Fraser Gate IP Project is not excluded capital, rebasing is required.

B. Project Commenced Under Previous CPCN Threshold

9. While this above point is determinative of the matter, it is also evident that the Capital Exclusion Decision was meant to apply to future CPCN applications and not those that were already in progress. In its Decision accompanying Order G-138-14 regarding FEI's 2014-2018 Performance Based Ratemaking Application, the Commission approved FEI's $5 million CPCN exemption threshold as applied for until such time as any further determination by the Commission was made concerning capital exclusion. The Capital Exclusion Decision defined what the appropriate capital exclusion criteria would be in the future; however, the Capital Exclusion Decision is not applicable to this Application, which was filed in 2014 under the then approved $5 million capital exemption threshold.[4] The CPCN threshold of $5 million was approved and in place when this CPCN Application was filed and as such, it is the $5 million CPCN Capital Exclusion threshold that applies regardless of the Capital Exclusion Decision.[5] This

[4] Exhibit B-14, CEC IR 2.3.4.

[5] Exhibit B-14, CEC IR 2.4.2.

is further supported by the fact that the Capital Exclusion Decision made directions at the bottom of page 12 of Appendix A for the content of future CPCN applications.

10. FEI submits that it would not be just and reasonable to apply the Capital Exclusion Decision in the manner contemplated by CEC. The Commission should not accede to CEC's request, and should apply the Capital Exclusion Decision prospectively as intended. Should the Commission determine that the Fraser Gate IP Project is not excluded capital, a process to rebase capital for the PBR term would be required.

C. Projects Are Rationally Grouped

11. CEC also recommends that the Commission determine whether or not the Fraser Gate IP Project should be rationally grouped into the CPCN. FEI submits that there is no need for such a determination since the Capital Exclusion Decision, as described above, does not apply. However, in any event, the evidence shows that the Projects are rationally grouped together.

12. While each of the two Projects is justified on its own merits and can be constructed independently of the other Project, the proposed Coquitlam Gate IP and Fraser Gate IP Projects both involve the construction and installation of NPS 30 pipe to replace existing pipe along sections of the two primary pipelines supplying gas to the Metro IP system. The Coquitlam Gate IP Project as applied for is larger in scope; however, in general, both Projects share common attributes in terms of design, routing process, materials procurement and specialized construction and installation techniques due to their urban location. Both Projects are also premised on safety and will improve system reliability. With the replacement NPS 30 Coquitlam Gate IP pipeline in service, it will be possible to isolate the Fraser Gate IP pipeline and replace the seismically vulnerable segment of pipe with the proposed upgraded pipe without the use of a bypass.[6]

[6] Exhibit B-6, CEC IR 1.3.2.

13. By using the same contractor for both Projects and by executing the Projects in parallel, FEI believes there to be potential cost benefits resulting from overall project efficiencies and economies of scale and has prepared cost estimates on that basis.[7] FEI anticipates that execution costs will be minimized over the Projects' lifecycle compared to executing each Project on a standalone basis. In addition, there could also be reduced costs including mobilization costs, costs associated with personnel training and familiarization with FEI standards, procedures, and local regulations and requirements, and reduced costs associated with establishing relationships with local municipalities.[8]

14. With respect to leveraging economies of scale in materials procurement, for example, if the NPS 30 pipeline required for the Fraser Gate IP and Coquitlam Gate IP Projects necessitates the manufacture (a pipe mill run) of new pipe, then placing a unified order will realize manufacturing efficiencies and therefore potential overall procurement savings. The same potential benefit would also apply to the procurement of induction bends for each Project.[9] Joint approval of the Projects provides an opportunity for cost savings and improved constructability.[10]

15. It is therefore logical that the Projects should be undertaken at the same time in terms of planning, permitting, stakeholder consultation and ultimately construction and commissioning, and FEI has identified cost savings benefits that can be achieved by coordinating the construction of the Projects.[11]

16. CEC's assertion that FEI did not apply for a single CPCN[12] is not correct; FEI applied "for a…CPCN to construct and operate two IP pipeline segments".[13]

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[7] Exhibit B-6, CEC IR 1.64.1.

[8] Exhibit B-6, CEC IR 1.64.1.

[9] Exhibit B-6, CEC IR 1.65.1.

[10] Exhibit B-4, BCUC IR 1.3.6; Exhibit B-6, CEC IR 1.65.1.3.

[11] Exhibit B-6, CEC IR 1.6.2.

[12] CEC Submission, p. 32.

[13] Exhibit B-1, Application, p. 1, line 5; Exhibit B-1-1, Application Appendix G-2.

17. Accordingly, FEI submits that the Commission should issue a CPCN in the form requested and maintain the exclusion of CPCN capital under PBR.

[redacted]