Diane Roy
Director, Regulatory Services

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

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

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

September 21, 2016

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

Attention: Ms. Laurel Ross, Acting Commission Secretary and Director

Dear Ms. Ross:

Re: FortisBC Energy Inc. (FEI)

Project No. 3698886

Multi-Year Performance Based Ratemaking Plan for 2014 through 2019 approved by British Columbia Utilities Commission (BCUC or the Commission) Order G-138-14 – Annual Review for 2017 Rates (the Application)

Response to the Commission Information Request (IR) No. 1

On August 2, 2016, FEI filed the Application referenced above. In accordance with Commission Order G-122-16 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

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A. EVALUATION OF THE PERFORMANCE BASED RATEMAKING (PBR) PLAN

1.0 Reference: EVALUATION OF THE PBR PLAN

Exhibit B-2, Application, Section 1.4.1, p. 4

Overview of operating and maintenance (O&M) savings

FortisBC Energy Inc. (FEI) states on page 4 of the Application: "In 2016, FEI is projecting O&M expenses excluding items forecast outside of the PBR formula to be approximately $11.1 million lower than the formula amount, an increase of $0.9 million from that achieved in 2015."

1.1 Please provide the actual pre-tax and after-tax O&M savings amounts for the years 2014 and 2015 and the projected pre-tax and after-tax O&M savings for 2016.

Response:

The amounts requested for 2014 through 2016 are provided in the table below. Note that the results shown for 2014 are the pre-amalgamation FEI O&M savings.

$millions	Actual 2014	Actual 2015	Projected 2016
Pre-tax O&M savings	$ 7.5	$ 10.2	$ 11.1
After-tax O&M savings	$ 5.6	$ 7.6	$ 8.2

1.1.1 For each years' O&M savings provided in the above response, please separately provide the amount attributable to labour savings and the amount attributable to non-labour savings.

Response:

Subject to the limitations described below, the following table provides an estimated split between labour and non-labour savings for each year.

Estimated O&M Savings (in millions)

	2014 Actual	2015 Actual	2016 Projected
Labour	2	7	5
Non-labour	6	3	6
Total	8	10	11

The split between labour and non-labour savings set out above is only an estimate. It is difficult to calculate the split between labour and non-labour as it is dependent on having an O&M Base in dollars split between labour and non-labour and a supporting FTE base for a starting point.

While an O&M Base amount was developed based on the 2013 Projected O&M, correlating the O&M Base amount to the O&M FTEs is not a straightforward calculation. This calculation depends on an estimated allocation of employees' time to non-O&M activities, including capital work and deferral activities, which may change from year to year. For these and other reasons, the correlation of the O&M Base amount to the O&M FTEs may not represent a normalized level of labour dollars. Depending on the assumptions used, the split between labour and non-labour O&M savings will be impacted.

Further, as indicated in the response to BCUC IR 1.1.6 in the Annual Review for 2016 Rates, a 2013 Base FTE is not available since FEI did not have an approved number of FTEs for 2013. Without a Base FTE starting point that corresponds to an approved O&M Base budget, the process of splitting O&M savings into labour and non-labour is difficult.

Finally, in FEI's view, it is not necessarily significant whether the O&M savings are attributable to labour or non-labour. There are a number of reasons why the amount of labour vs. non-labour can fluctuate from year to year which do not relate to the success of PBR. For example, the choice of contractor utilization versus in-house labour will vary from year to year depending on conditions and business requirements of the Company.

2.0 Reference: EVALUATION OF THE PBR PLAN

Exhibit B-2, Section 1.4.2, Table 1-2, p. 5;

FEI Annual Review of 2016 Rates proceeding: Exhibit B 2, p. 5; Exhibit B-5, BCUC IR 1.1

Staffing levels

FEI provided the following table in response to BCUC information request (IR) 1.1 in the FEI Annual Review of 2016 Rates proceeding:

	Headcount	Average FTEs	End of Year FTEs
2013 Actual	1,764	1,679	1,682
2014 Actual	1,704	1,650	1,624
2015 Projected	1,686	1,598	1,656

Table 1-2 on page 5 of the Application provides the following information on staffing levels:

- 2015 Actual Headcount – 1,656
- 2015 Actual Full Time Equivalents (FTEs) – 1,573
- 2016 Projected Headcount – 1,721
- 2016 Projected FTEs – 1,613

2.1 Please explain the basis for FEI's projection of 2016 headcount and FTEs, including, if applicable, the number of months of actual data used in the 2016 projections.

Response:

FEI's 2016 projected headcount and FTEs were based on the available actual data at the time the projection was prepared, which was five months of actual data (up to May 31, 2016), and on input from departments regarding projected headcount and FTE changes at that time.

2.2 Please explain the factors which contributed to the actual 2015 headcount and actual 2015 FTEs being lower than the amounts projected for 2015.

Response:

Similar to how the 2016 projected headcount and FTEs were prepared, FEI's 2015 projected headcount and FTEs were based on input from departments and available actual data in 2015 at the time the projection was prepared. Contributing factors to the differences from the projection were unanticipated turnover of staff and the Company's ability to fill vacancies during the remainder of 2015.

As shown in the table below, for 2015, the difference between the projected and actual headcount and FTEs was relatively small, totaling to less than two percent when compared to the projection.

	Headcount	Average FTEs
2015 Actual	1,656	1,573
2015 Projected	1,686	1,598
Increase (decrease)	(30)	(25)
% Inc (dec)	-1.8%	-1.5%

2.3 Please expand Table 1-2 of the Application to include the "End of Year FTEs," as was provided by FEI in response to BCUC IR 1.1 in the FEI Annual Review of 2016 Rates proceeding.

Response:

Table 1-2 of the Application has been expanded to include the End of Year FTEs in the table below.

	Headcount	Average FTEs	End of Year FTEs
2013 Actual	1,764	1,679	1,682
2014 Actual	1,704	1,650	1,624
2015 Actual	1,656	1,573	1,579
2016 Projected	1,721	1,613	1,667

3.0 Reference: EVALUATION OF THE PBR PLAN

Exhibit B-2: Section 1.4.2, p. 5; Section 6.3.5, Table 6-6, pp. 53-54;

FortisBC Inc. (FBC) Annual Review of 2017 Rates proceeding, Exhibit B 2, pp. 4-5

Staffing levels

FEI states the following on page 5 of the Application:

> The projected increase in headcount of 65 from the end of 2015 to the end of 2016 is comprised of new positions and the filling of existing vacancies, primarily from the following areas: 7 headcount for the start-up of the Tilbury LNG Expansion Facility5; 6 headcount in Engineering for capital work; 6 headcount in EH&S in support of the Target Zero safety program; 16 headcount in the Contact Centre staffing to fill vacancies and to handle higher call volumes expected in the winter season; and the remainder consisting mostly of vacancies filled across other departments.

Footnote 5 on page 5 of the Application further states: "The O&M and capital costs for the Tilbury Expansion are flowed through outside of the PBR formula."

Table 6-6 on page 53 of the Application shows a Projected 2016 labour amount for the Tilbury Plant of $0.673 million and a Forecast 2017 amount of $2.160 million.

3.1 Please clarify how the addition of seven headcount for the start-up of the Tilbury LNG Expansion Facility are being accounted for and where the costs associated with the additional seven headcount are found.

Response:

FEI clarifies that the seven headcount referred to in the preamble are incremental headcount for the Tilbury LNG Facility as a whole. These positions do not work solely on the Tilbury LNG Expansion Facility, but the work they do is in support of the Rate Schedule 46 Revenues. The costs of the incremental seven headcount are included in the 2016 Projected and 2017 Forecast O&M Labour that supports the Rate Schedule 46 Revenues, shown in Table 6-6.

3.1.1 If the seven additional headcount are recorded as part of the forecast labour O&M shown in Table 6-6, please explain how much of the Projected 2016 and Forecast 2017 labour O&M provided in Table 6-6 relate to the seven additional headcount.

Response:

The additional seven headcount represents $0.393 million of the Projected 2016 O&M labour and $0.945 million of the Forecast 2017 O&M labour provided in Table 6-6 for the Tilbury Plant. The larger amount in the 2017 Forecast reflects a full year of labour costs.

3.2 Please explain whether the seven additional headcount positions are performing functions solely related to the Tilbury LNG Expansion Facility. If not, please explain what other functions these employees perform and whether the labour associated with these other functions are considered to be part of FEI's approved Base O&M.

Response:

The seven additional headcount positions are not performing functions solely related to the Tilbury LNG Expansion Facility. They are part of the total Tilbury plant staffing and, therefore, perform functions related to both the Expansion Facility and the Existing Facility. All of the associated incremental costs are in support of the Rate Schedule 46 O&M, which is excluded from the Base O&M and flowed through outside of the formula O&M.

Please refer to the responses to BCUC IR 1.23.1 and 1.23.2.

3.2.1 If a portion of the seven headcount positions' labour costs are being included in the formula-driven O&M, please provide the amounts for 2016 and 2017 and explain how FEI is tracking the O&M related to the Tilbury LNG Expansion Facility versus the O&M being included in the PBR formula.

Response:

Please refer to the response to BCUC IR 1.3.2.

3.3 Please separately provide the increase in headcount in 2016 related to new positions versus the increase in headcount related to the filling of vacancies comprising the increase in headcount in 2016 of 65.

Response:

This response also addresses BCUC IR 1.3.4, which requests the same information for the 2016 projected increase of 40 FTEs.

Of the 2016 projected increase of 65 headcount and 40 FTEs, 19 headcount / 12 FTEs are related to positions added. These include positions added for: the support of the Tilbury Expansion Facility - Rate Schedule 46 (7 headcount / 4 FTEs); the Target Zero program (6 headcount / 6 FTEs); and Engineering positions for capital projects (6 headcount / 2 FTEs).

The remaining projected net increase of 46 headcount and 28 FTEs in 2016 is related to filling of vacancies, primarily in the Contact Centre.

3.4 Please provide the same description as was provided for the projected 2016 increase in headcount of 65 on page 5 of the Application for the projected 2016 increase in FTEs of 40. Please also separately provide the increase in FTEs in 2016 related to new positions versus the increase in FTEs related to the filling of vacancies.

Response:

Please refer to the response to BCUC IR 1.3.3.

On pages 4 to 5 of the FBC Annual Review for 2017 Rates application, FBC describes the “Sharing of Gas and Electric Contact Centre Staff” initiative. FBC states: “As of June 30, to date in 2016, staff in the Prince George contact centre answered approximately 3,200 electric calls, reflecting about 3 percent of the total electric calls received.”

3.5 Please explain whether the increase in headcount of 16 in FEI's Contact Centre in 2016 was in part attributable to the sharing of gas and electric contact centre staff.

Response:

The increase in headcount is not attributable to the sharing of gas and electric contact centre staff.

For 2016, the projected 16 new hires in the Contact Centre, representing the difference between the headcount at the end of 2015 and the projection at the end of 2016, are required as the result of vacancies due to attrition in 2015 and seasonal staffing requirements. Attrition occurs throughout the year for many reasons. However, generally, when an employee leaves the Contact Centre, the employee is not replaced immediately and instead new employees are hired in groups to optimize the recruitment and training process.

FBC further states on page 5: "In 2015, six billing analyst roles that were vacant in FEI's Burnaby office were filled by FBC in its Trail office, providing a new opportunity for the six CSR [customer service representatives] no longer required as a result of the changes described above."

3.6 Please explain the impact, if any, on FEI's headcount in 2015 and 2016 and associated labour costs of the six billing analyst roles being filled by FBC in its Trail office. Please clarify if FEI or FBC are recording the labour costs associated with these six positions.

Response:

In 2015, FEI's headcount went down by 6 as a result of the six billing analyst roles being filled in FBC's Trail office. However, these positions were vacant within FEI at the time, so no employees were impacted as a result. The six positions are included in FBC's headcount and the corresponding labour costs are being charged to FEI.

FEI states on page 5 of the Application: "…from 2013 Actual to 2016 Projected, total FTEs for the Company decreased by 66, with the decreases estimated to contribute to O&M savings of approximately $5 million7."

Footnote 7 states: "2013 Actual FTEs is used as the reference point for the start of the PBR Plan as a 2014 Base average FTEs is not available." [emphasis added]

3.7 Please confirm, or explain otherwise, that the underlined statement in the above preamble should instead state a "2013 Base average" is not available.

Response:

Confirmed. FEI had intended to correct this after the error was discovered in responding to BCUC IR 1.6.1 in the Annual Review for 2016 Rates. FEI will correct this in its Annual Review for 2018 Rates.

On page 5 of the application in the FEI Annual Review of 2016 Rates proceeding, FEI stated: "…from 2013 Actual to 2015 Projected, total FTEs for the Company decreased by approximately 81, with the decreases estimated to contribute O&M savings of approximately $7 million."

3.8 Please explain why, based on the decreases in FTEs and the resultant savings in O&M described in the current Application and the previous years' application, the per-FTE O&M savings projected for 2016 equal $75,758 [$5,000,000/66 FTEs] while the per-FTE O&M savings projected for 2015 equaled $84,420 [$7,000,000/81 FTEs].

Response:

A primary factor that is contributing to the calculated decrease in projected O&M savings per FTE as indicated in this question is the change to the forecast employee affiliation composition (i.e. IBEW, MoveUP and M&E). Provided below is a comparison of the forecast employee affiliation composition of the decrease in positions at the end of 2015 and 2016.

		Headcount	Average FTEs
2015 Projected	MoveUp	(96)	(82)
	IBEW	(24)	(18)
	M&E	42	19
	Total	**(78)**	**(81)**
2016 Projected	MoveUp	(96)	(96)
	IBEW	7	(4)
	M&E	46	34
	Total	**(43)**	**(66)**

Different employee affiliations (i.e. IBEW, MoveUp, M&E) have different average annual salaries. A change in the composition will affect the calculation of the per-FTE O&M savings outlined in this question.

Another factor that may affect the per-FTE O&M savings calculation is the percentage of an employee's time charged to other work besides O&M. Depending on their job, employees may charge their time to non-O&M, including capital and deferral accounts and to Core Market Administration. This will affect the per-FTE O&M savings calculation.

Please also refer to the response to BCUC IR 1.1.1.1 for further discussion on the determination of the split of O&M savings between labour and non-labour.

3.8.1 What factors have contributed to the apparent decrease in savings achieved per FTE in the current Application?

Response:

Please refer to the response to BCUC IR 1.3.8.

4.0 Reference: MAJOR INITIATIVES UNDERTAKEN

Exhibit B-2: Section 1.4.3, p. 6; Appendix C2, pp. 1–2

Regionalization Initiative

4.1 Please provide the following information for Phase 1 of the Regionalization Initiative:

- Actual 2014 labour and non-labour savings;
- Actual 2015 labour and non-labour savings;
- Projected 2016 labour and non-labour savings; and
- Cumulative O&M savings to-date.

Response:

Provided below is a summary of the O&M savings related to Phase 1 of the Regionalization Initiative. Each year's indicated savings are in comparison to the allowed overall O&M and are not incremental year-over-year. The information provided is consistent with that provided in Table 4 of FEI's Compliance Filing in its Annual Review for 2015 Rates dated June 30, 2015, and was also confirmed in FEI's response to BCUC IR 1.2.1 in its Annual Review for 2016 Rates.

Regionalization - Phase 1 O&M Savings
$ millions

Year	Labour	Non Labour	Total
2014	$ 0.85	$ 0.15	$ 1.00
2015	$ 0.85	$ 0.15	$ 1.00
2016	$ 0.85	$ 0.15	$ 1.00
		Cumulative to-date savings	$ 3.00

As indicated in Exhibit B-2, Table C-1 in Appendix C2, the estimated savings due to the Regionalization Initiative are part of the overall savings achieved due to the broader initiatives of improving customer service, enhancing the productivity focus and strengthening the accountability culture.

FEI notes a typographical correction to Exhibit B-2 page 6 in the section describing the Regionalization Initiative. The reference to "…. Annual O&M savings in 2015 were approximately $0.9 million compared to 2013 actuals" should instead state "approximately $1.0 million compared to 2013 actuals".

FEI states on page 6 of the Application: "The second phase of the Regionalization Initiative is expected to result in incremental annual O&M savings of approximately $1.1 million."

4.2 Please explain when FEI determined that the Regionalization Initiative would be separated into multiple phases and why.

Response:

FEI determined in the third quarter of 2015 that the Regionalization Initiative would have a second phase when further opportunities were identified to improve work order cycle time and increase workflow productivity by regionalizing the pre-requisite, closing and hazards functions.

4.3 Does FEI anticipate that there will be any further phases to the Regionalization Initiative? Please explain.

Response:

FEI has no plans for any further phases of the Regionalization Initiative at this time. FEI continually seeks opportunities to improve productivity and efficiency.

4.4 Please describe more fully all of the positions and functions which have now been regionalized.

Response:

The positions and functions that have been regionalized in the first and second phases are as follows:

1. Operations Support Representative positions that support the dispatch function
2. Operations Support Representative positions that support the pre-requisite function

3. Operations Support Representative positions that support the closing function
4. Operations Support Representative positions that support the hazard function
5. Planning and Design Technicians / Technologists that support the planning function

4.5 Please describe FEI's overall plan for regionalization of its functions and when it expects the Regionalization Initiative to be complete.

Response:

The Regionalization Initiative was a component part of a broader strategy to improve customer service. The desire to improve customer service and achieve a more efficient process in the field prompted FEI to make the decision to transition from a centralized operation to a more regionalized operation. Regionalization places ownership, responsibility and accountability for customer service and field processes in the hands of those who are closest to the customers.

FEI's overall plan for the Regionalization Initiative is reflected in phase 1 and 2 of the initiative as described in Tables C-1 and C-2 of Appendix C2 of the Application. The Regionalization Initiative is expected to be complete by the end of Q4 2016. There are no plans to regionalize other work functions at this time.

FEI states the following on page 6 of the Application:

> By the end of the second quarter of 2016, the Pre-requisition, Closing and Hazards functions were successfully transitioned into the regions. This phase represents the second phase of the Regionalization Initiative that began in 2014 with the transitioning of the Field Dispatch and Planning and Design groups to regional locations.

4.6 Please explain the rationale for transitioning the Pre-requisition, Closing and Hazards functions into the regional locations and describe the activities/responsibilities attributable to these functions.

Response:

The rationale for transitioning the Pre-requisite, Closing and Hazards functions into the regional locations is based on reducing the number of process handoffs, encouraging local accountability for end-to-end work processing, increasing productivity and enhancing the customer experience.

The pre-requisite function is responsible for:

- Creating job packages for construction work.

The closing function is responsible for:

- Ensuring all job information for construction work is entered into the various systems (asset management, billing, etc.).

The hazards function is responsible for:

- Creating notifications for work-related hazards that are identified.

5.0 Reference: MAJOR INITIATIVES UNDERTAKEN

Exhibit B-2: Section 1.4.3, pp. 6–7; Appendix C2, p. 4

Review of technical and infrastructure support provider

FEI states on page 7 of the Application: "The 2015 O&M savings for the Information Services department compared to 2013 actuals are approximately $1.8 million."

5.1 Please confirm, or explain otherwise, that the $1.8 million of savings in 2015 and the projected $2 million savings in 2016 are attributable to the switch from the TELUS contract to the Compugen contract and not to any efficiency initiatives.

<u>Response:</u>

Confirmed that the identified savings in 2015 and 2016 are attributable to the switch from the TELUS contract to the Compugen contract and not due to other efficiencies. The higher O&M savings amount in 2016 is due to a full year under the new contract.

6.0 Reference: MAJOR INITIATIVES UNDERTAKEN

Exhibit B-2, Section 1.4.3, p. 7

Training and Development Initiative

FEI states on page 7 of the Application that the Training and Development Initiative was "implemented in 2015 and introduced a company-wide process that improves the ability of the Company to plan and track required training activities, ensuring skills requirements for employee training are addressed efficiently and effectively."

6.1 Please provide a more detailed description of the company-wide process which was implemented in 2015 and how this process enables FEI's departments to more effectively evaluate training requirements specific to each group.

Response:

The company-wide process implemented in 2015 provided a visual way for managers to identify annual mandatory and technical training requirements of their employees by position. Data is extracted from the employee's training records, validated by the manager and populated in a skills matrix, showing the training due in the coming year. The process includes a planning tool to assist managers with budgeting associated training costs, which are then submitted for directors' approval. Once the budget is approved, the training department oversees the scheduling of all technical and mandatory training activities across the Company. The skills matrix is updated quarterly showing each manager the status of training activities for each of their employees. The process also includes a budget summary which provides an overview of training costs and volumes by manager, course, month, employee, etc.

This process offers a simpler, more visual and updated summary of training requirements and expenses than was used previously.

6.2 Please provide both the O&M and capital expenditures incurred to implement this initiative and describe the nature of these costs.

Response:

The Company has incurred $0.188 million in O&M to date to implement the Training and Development Initiative. These costs are for consulting fees for analysis of the current state, design of the future process, and rollout of the process to all managers (including change management and training). No capital expenditures were incurred.

The Training and Development Initiative began in early 2015 and was initially rolled out in late 2015. Enhancements to the process were identified in early 2016 and will be implemented in late 2016.

7.0 Reference: MAJOR INITIATIVES UNDERTAKEN

Exhibit B-2, Section 1.4.3, p. 7

Online service application

FEI states on page 7 of the Application that it is "currently working on the development of an online service application for installation new service lines."

7.1 Please describe and quantify the information technology (IT) changes required to implement the online service application.

Response:

The IT changes required to implement the Online Service Application are a single internet application with multiple interfaces to existing applications.

The Online Service Application will be implemented as an internet application using .net technology and it will be accessible through the www.fortisbc.com website. The application will include interfaces with existing enterprise applications such as SAP, GIS, ClickSchedule, Café using Web Services and BizTalk. The application is designed to provide customers with a single, simple process to request installation of a new service line. To achieve this, the application will interface with FEI's existing applications to conduct multiple processes, such as assessing permitting requirements, identifying the location of the service via mapping (GIS) and scheduling a service installation.

7.2 Please separately provide the O&M costs and the capital expenditures required to develop and implement this initiative.

Response:

The current estimated capital cost for the Online Service Application is $1.7 million with an additional $0.166 million in one-time O&M costs for analysis, training and change management.

8.0 Reference: OVERVIEW OF CAPITAL EXPENDITURES

Exhibit B-2, Section 1.4.4, Table 1-3, pp. 7-13

Capital spending results

FEI states on page 8 of the Application: "As shown in Table 1-3, Projected 2016 capital expenditures excluding items forecast outside of the PBR formula are $13.767 million higher than the formula amount."

FEI further describes a number of contributing factors related to reductions to the capital formula amount, including: "The sustainment capital for the Vancouver Island region was reduced, resulting in an impact of $6.4 million in 2016 and $12.8 million cumulative."

8.1 With specific reference to the amounts provided in Table 1-3, please clarify FEI's statements regarding the impact of the reduction in sustainment capital for the Vancouver Island region on the capital expenditure results.

Response:

The discussion in lines 6 through 16 on page 8 of the Application was describing the factors that caused the approved formula capital spending to be lower than the requested formula capital spending. Had the reduction in sustainment capital for the Vancouver Island region not occurred, the "Formula" columns in Table 1-3 would have been greater, and the "Variance" columns would have been correspondingly smaller. The "Formula" columns would have been higher by $6.351 million[1] in 2015 and $6.417 million in 2016[2], for a cumulative total of $12.769 million. These amounts are calculated by escalating the $6.3 million reduction in the 2014 base capital that resulted from Order G-106-15[3] at the approved formula factors for 2015 and 2016, respectively.

Table 1-3 on page 8 of the Application shows a cumulative variance in Growth Capital of $27.982 million.

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1 $6.3 million x (1 + 0.201%) x (1 + 0.614%)

2 $6.351 million x (1 + 0.469%) x (1 + 0.567%)

3 In Order G-106-15, the Commission approved a 2014 Sustainment Capital Base for FEVI of $9.385 million on page 23 of the Decision, which was $6.258 million less than the requested Sustainment Capital Base of $15.643 million

FEI states on page 8 of the Application: "The growth factor service line additions (for the growth capital) and net customer additions (for the other capital) was reduced by one-half, resulting in an impact of $3.8 million in 2016 and $3.0 million cumulative."

8.2 For each of the Growth Capital variances provided in Table 1-3 (i.e. 2014, 2015, 2016 and Cumulative), please indicate how much of the variance is related to the growth factor service line additions being reduced by one-half.

Response:

The table below sets out the amount of the variances described in lines 12 through 14 on page 8 that is due to the 50% reduction in service line growth (Growth Capital), the amount that is due to the 50% reduction in net customer additions (Sustainment and Other Capital) and the total. The annual amounts are calculated as the difference between:

1. The approved capex; and
2. The same calculation, but using the approved growth factors with a 100% multiplier applied rather than a 50% multiplier.

	($ millions)			
	2014	2015	2016	Cumulative
50% Reduction in Service Line Growth	(0.151)	(1.829)	2.215	0.235
50% Reduction in Net Customer Addition Growth	0.259	0.939	1.586	2.785
Total	0.108	(0.889)	3.801	3.020

Note that in years when service line growth was negative (2014 and 2015), the 50% reduction in service line growth serves to increase the formula capital rather than reduce the formula capital.

9.0 Reference: OVERVIEW OF CAPITAL EXPENDITURES

Exhibit B-2: Section 1.4.4.1, pp. 8–9; Section 1.4.4.3, pp. 12–13

Capital spending results

On pages 8 and 9 of the Application, FEI describes seven contributing factors to the capital cost pressures:

1. The addition of certain larger industrial mains where the cost significantly exceeded the average customer addition cost that was contemplated under the formula, but that had incremental revenues attached to them and therefore passed the main extension test;
2. Capital costs required to carry out the Regionalization Initiative discussed above;
3. The installation of Jomar valves on meter sets to allow for meters to be exchanged without turning off gas to the residence;
4. Increased in-line inspection activity required to maintain alignment with evolving industry practice;
5. Unanticipated system improvements and new stations to supply gas to large new customers;
6. Integrity related capital for Burns Bog pipeline stress relief; and
7. Pressures from the increased cost of equipment and supplies purchased from the United States due to the unfavourable exchange rate.

9.1 For each of the seven identified factors, please indicate in which year(s) the impact was experienced and whether the factor was related to Growth capital or Other capital.

Response:

The table below shows which years the seven identified factors contributed to capital cost pressures over the first three years of the PBR term, as well as the category of capital to which it is related.

Capital Pressure	2014	2015	2016	Category
Large industrial mains	YES	YES	YES	Growth Capital
Regionalization	YES	NO	YES	Other Capital
Jomar Valves	NO	YES	YES	Other Capital
Increased ILI	YES	YES	YES	Other Capital
System Improvements & new stations	YES	YES	YES	Other Capital
Burns Bog Stress Relief	YES	YES	YES	OtherCapital
Exchange Rate Impacts	NO	YES	YES	Growth and Other Capital

FEI notes that Item 5, unanticipated system improvements and new stations to supply gas to large new customers, is funded through sustainment capital but the capital cost pressures are driven by customer growth and the addition of large new customers.

FEI states on pages 12 to 13 of the Application: "Within the many projects that contribute to capital spending in any given year, FEI is unable to isolate any that in particular are ongoing and should be added to the formula."

9.2 For each of the seven identified factors contributing to the capital cost pressures, please explain why FEI does not anticipate these factors to continue occurring in the remaining years of the PBR term.

Response:

FEI clarifies that the statement on pages 12 to 13 of the Application was not meant to indicate that the capital cost pressure factors would no longer occur during the remaining years of the PBR term. The statement was specific to the discussion on whether or not the annual capital formula amount should be increased. FEI intended to convey that it is difficult to identify which particular project or cost pressure it was that caused the dead band to be exceeded and that establishing how much the formula should be increased on an ongoing basis due to a particular cost pressure is difficult to determine. It is also not necessary to carry out such an exercise given the existing capital dead band mechanism.

FEI expects that the following factors will continue to contribute capital cost pressure over the remainder of the PBR term:

3. The installation of Jomar valves on meter sets to allow for meters to be exchanged without turning off gas to the residence;

4. Increased in-line inspection activity required to maintain alignment with evolving industry practice;

7. Pressures from the increased cost of equipment and supplies purchased from the United States due to the unfavourable exchange rate.

Item 6, Integrity related capital for Burns Bog pipeline stress relief, will contribute to capital cost pressure through 2017.

FEI is unable to predict with a high degree of certainty the capital cost expenditures for item 5 and item 1 and whether they will continue to contribute capital cost pressures over the remainder of the PBR term. The decision for large industrial customers to connect to FEI's system, their load profile and the location they wish to connect to is largely driven by factors outside the control of FEI. As such, it is difficult for FEI to accurately forecast mains expenditures and the corresponding system improvements to support the addition of new, large industrial customers.

FEI does not expect Item 2 to contribute capital cost pressure in the remaining years of PBR term because the regionalization effort is substantially complete.

The following questions pertain to the addition of certain larger industrial mains (i.e. project #1 in the above preamble):

9.3 How much was the variance between the average customer additions cost that was contemplated under the PBR formula and the actual cost of adding the larger industrial mains? Please state the formula cost and the actual cost and explain why the actual costs significantly exceeded the average customer additions costs determined by the formula.

Response:

The average cost per metre of main in FEI's 2013 Base was $62/metre. The actual cost per metre of main was $87 in 2014, $121 in 2015 and $118 year to date in 2016. The 2014 through 2016 costs have been influenced upward by a number of larger cost mains. The 15 mains with the highest cost per metre that FEI has installed since 2014 had an average cost per metre of $285, which has contributed approximately $3 million to date to the capital cost pressure when compared to the average cost that was embedded in the PBR formula.

FEI used historical mains expenditures as the basis for the 2013 Approved growth capital, which was then used to set the Base Capital under PBR. FEI mains expenditures are driven by customer growth and the type of customer impacts the timing, size and cost of the mains. It is difficult to predict with a high degree of certainty the capital cost expenditures related to mains expenditures and whether they will continue to contribute capital cost pressures over the remainder of the PBR term. The decision for large industrial customers to connect to FEI's system, their load profile and the location they wish to connect to is largely driven by factors outside the control of FEI.

9.4 Please explain why the higher cost of larger industrial mains additions was not budgeted for by FEI at the time of establishing its original Base Capital.

Response:

FEI's Base Capital in the PBR plan was not established based on a budget for the PBR term. The Base Capital was approved by the Commission to be equal to FEI's Approved 2013 capital expenditures, with adjustments to add in the Vancouver Island and Whistler service areas in 2015. FEI's Base Capital is then subject to the formula over the term of PBR as discussed in section 7 of the Application.

FEI's 2013 Base Capital included expenditures for main additions based on the forecasting method used at that time, which was to use the most recent three year historical ratio of new mains to forecast additions. FEI's forecasting method for mains was discussed in section 4.5.2 of the PBR Application.

FEI also notes that main activity levels vary considerably from year to year. In its PBR Application, FEI noted that new mains had varied from a high of 200,000 metres in 2008 to a low of 65,000 metres in 2012. The decision for large industrial customers to connect to FEI's system, their load profile and the location they wish to connect is largely driven by factors outside the control of FEI. As such, it is difficult for FEI to accurately forecast mains expenditures to support the addition of new, large industrial customers.

The following questions pertain to the installation of Jomar valves on meter sets (i.e. project #3 in the above preamble):

9.5 Please explain if FEI's approved Base Capital spending envelope includes costs related to the installation of Jomar valves or other similar valves.

Response:

The Jomar valve was only approved for use on meter sets in Q4 2015. As such, costs related to the installation of Jomar valves were not included in FEI's Base Capital spending envelope which was set based on FEI's 2013 Approved capital expenditures.

The capital costs for the Jomar valves are required to reduce the future O&M cost of the meter exchange program and to improve the customer experience associated with meter exchange service. As discussed in response to CEC IR 1.5.3, savings from the installation of Jomar valves are anticipated in association with any visits subsequent to the Jomar valve installation that require turning off gas at the meter set.

9.5.1 If yes, please provide the amount included in FEI's Base Capital related to the installation of these valves and explain why this amount is not sufficient to cover the costs of project #3.

Response:

Please refer to the response to BCUC IR 1.9.5.

9.5.2 If no, please explain why the cost of installing the Jomar valves on meter sets was not included in FEI's approved 2013 Base capital and explain the change in circumstances which has resulted in these costs now being required.

Response:

Please refer to the response to BCUC IR 1.9.5.

9.6 Please provide the total capital cost incurred for project #3 and provide the year(s) in which the expenditures were incurred.

Response:

The total capital cost incurred for the installation of Jomar valves on meter sets to the end of 2016 are provided below:

Year	Capital Cost ($ millions)
2015	1.1
2016 Projection	2.6
TOTAL	3.7

9.7 Please indicate if FEI expects to incur further costs related to project #3 and if so, please provide the forecast amounts for each of the remaining years in the PBR term.

Response:

Yes, FEI expects to incur further costs related to the installation of Jomar valves in the remaining years of the PBR term, as follows:

Year	Capital Cost ($ millions)
2017 Forecast	2.7
2018 Forecast	2.9
2019 Forecast	3.0
TOTAL	8.6

9.8 Could the costs of project #3 have been foreseen by FEI? Please explain.

Response:

No. The Jomar valve was only approved for use on meter sets in Q4 2014 so could not have been foreseen at the time the PBR capital base was established.

Whether or not the costs could have been foreseen is not a relevant consideration. The Base Capital was not set based on FEI's forecast of its capital requirements over the PBR term, but was set equal to FEI's Approved 2013 capital expenditures, with adjustments to add in the Vancouver Island and Whistler service areas in 2015 (based on Vancouver Island and Whistler Approved 2014 capital expenditures less the $6.258 million reduction from Order G-106-15). Over the course of the PBR term, the Base Capital is increased by formula, and not by any forecast of expenditures. Therefore, whether or not FEI's capital cost pressures could have been foreseen does not help explain why there are capital cost pressures in excess of the dead band.

The following questions pertain to the increased in-line inspection activity (i.e. project #4):

9.9 Please confirm, or explain otherwise, that FEI's approved Base Capital spending envelope includes costs related to in-line inspection activity.

Response:

Confirmed. FEI's Base Capital includes costs related to its in-line inspection activity, at levels consistent with its 2013 Commission-approved capital.

9.9.1 If confirmed, please provide the amount included in FEI's Base Capital for this activity and explain why this amount is not sufficient to cover the costs of project #4.

Response:

The following table shows the amount included in FEI's Base Capital for in-line inspection activity escalated by the PBR capital formula over the current PBR term. As the inflation factor for 2018 and 2019 is unknown, the 2017 capital formula amount for this activity has been carried forward uninflated through 2019. The table also shows the in-line inspection activity actual amounts for 2014 and 2015 and the forecast amounts for 2016 to 2019. Finally, the table shows the difference between the capital formula amounts and the actual/forecast amounts.

In-Line Inspection Activity

($000)	2014	2015	2016	2017	2018	2019	Total
Capital Formula	1,350	1,361	1,375	1,389	1,389	1,389	8,253
Actual/Forecast	3,294	2,656	7,051	5,225	4,469	9,393	32,088
Difference	1,944	1,295	5,676	3,836	3,080	8,004	23,835

Some degree of flexibility is built into FEI's multi-year capital plan with the understanding that conditions change and the plan must be capable of adapting to moderate changes in scope and cost. However, the approximately $24 million difference between the capital formula amounts and Actual/Forecast for in-line inspection activity, required by FEI for the safe and reliable operation of its transmission pipeline assets, exceeds FEI's ability to reprioritize work within the plan without increasing the risk exposure in the gas delivery system.

9.9.2 Could the costs associated with the evolving industry practice have been foreseen when the PBR plan was originally put in place? Please explain why or why not.

Response:

As explained in the response to BCUC IR 1.9.8, whether or not the costs could have been foreseen is not a relevant consideration.

However, the increased in-line inspection activity could not have been foreseen at the time the PBR plan was put in place because FEI had not yet evaluated the technology for use. Late in 2013, FEI applied the circumferential magnetic flux leakage in-line inspection technology in a selected pipeline to evaluate the ability to detect longitudinally-oriented features. Early results obtained by this incremental technology provided material improvements to FEI's integrity management capabilities, leading to its subsequent adoption for all in-line inspected pipelines.

9.10 What is the increased in-line inspection activity cost?

Response:

Please refer to the response to BCUC IR 1.9.9.1.

9.11 How has the in-line inspection activity changed since the commencement of the PBR term and what is driving up the costs of this activity?

Response:

The industry practice of in-line inspection activity has changed in recent years in the following areas:

- Adoption of new or improved in-line inspection technologies, typically to enhance capabilities with respect to imperfection detection and sizing;
- Increased inspection frequency, typically to provide increased statistical confidence in data analyses; and
- Increased numbers of pipelines subject to in-line inspection, in part influenced by commercialization of in-line inspection tools over an expanding range of pipeline diameters, pipeline configurations and operating pressures, to leverage economies/efficiencies possible with the use of in-line inspection tools (i.e. in-line inspection typically provides cost effective integrity verification versus other methods, including pipe replacement).

The drivers of industry change in this area, such as the heightened resolve by companies and regulators toward achieving zero transmission pipeline incidents, are provided in FEI's response to BCSEA IR 1.3.3.1.

When making decisions on the adoption of industry practice and necessary in-line inspection activity, FEI continually assesses information received from sources such as newly received asset data, recently performed analyses, industry experience and practice, and technology availability.

The changes to FEI's in-line inspection activity that are resulting in the higher costs of this activity are aligned with industry practice and are required for the safe and reliable operation of FEI's transmission pipeline assets. These changes are as follows:

- As discussed in the response to BCUC IR 1.9.9.2, FEI adopted circumferential magnetic flux leakage technology for all in-line inspected pipelines;

- FEI's re-runs of geometry and standard magnetic flux leakage tools are now planned on a maximum 7-year interval; and
- FEI increased the number of transmission pipelines subject to in-line inspection. As an example, FEI performed initial baseline in-line inspections for a number of pipeline segments in the Lower Mainland. In addition to the in-line inspection costs, capital expenditures were incurred for retrofits to enable the loading/unloading and passage of the tools.

FEI expects ongoing evolution of its in-line inspection program. Significant current initiatives under evaluation include:

- The need for and feasibility of adopting in-line inspection technology to inspect all transmission pipelines operating at hoop stresses of 30% or more of the specified minimum yield strength (SMYS) of the pipe; and
- The need for and feasibility of adopting crack-detection capabilities within its in-line inspection program.

9.12 Given the in-line inspection activity was increased to maintain alignment with evolving industry practice, does FEI expect the costs will continue to remain high for the foreseeable future and therefore continue to cause capital cost pressures?

Response:

Due to the rapid evolution of in-line inspection technology and practices in industry, FEI expects the costs for the in-line inspection activity will continue to remain high for the foreseeable future and continue to cause capital cost pressure. Please refer to the response to BCUC IR 1.9.9.1, which provides the estimated capital costs associated with the in-line inspection activity over the PBR term.

9.12.1 If yes, please provide a rationale for why FEI is not recommending an increase to the annual capital formula amount for the remaining years of the PBR term. If no, please discuss why not.

Response:

Please refer to the discussion that starts on line 34 of page 12 of the Application, with the clarification provided in response to BCUC IR 1.9.2.

The following questions pertain to the unanticipated system improvements and new stations (i.e. project #5):

9.13 Please provide the total cost related to the system improvements and new stations required to supply gas to the large new customers.

Response:

The total capital costs incurred to date, and projected for 2016, for system improvements and new stations for large new customers are as follows:

Year	Capital Cost ($ millions)
2014	0.6
2015	2.7
2016 Projection	1.8
Total	5.1

9.14 Please clarify whether the large new customers were unanticipated or the system improvements and new stations required to supply gas to these large new customers were unanticipated, or both. Please also explain why FEI did not anticipate these costs.

Response:

As explained in the response to BCUC IR 1.9.8, whether or not the costs could have been foreseen or anticipated is not a relevant consideration.

FEI clarifies that the specific system improvements and new stations that were incurred for these large new customers as shown in the response to BCUC IR 1.9.13 were unanticipated at the time of developing the base for the PBR application. FEI forecasts new customer additions and the costs to supply gas to those customers based on historical figures. FEI does not forecast specific new industrial customers as FEI cannot be sure that the customer is attaching until they have made a final commitment. Prior to that, a customer may have an intention of connecting, but the forecast attachments of this type of customer cannot be reliably predicted because the customer must weigh several factors prior to committing.

9.15 Does FEI anticipate any ongoing sustaining capital costs associated with project #5?

<u>Response:</u>

Any addition of large new customers could result in the need for system improvements or new stations to support the added load. However, given that this work is driven by third parties and that the upgrades required to supply gas to new customers are dependent on the load characteristics of the customer and the location on the system that they choose to connect, FEI is unable to predict with a high degree of certainty what additional cost pressures will be generated by Item #5 for the remainder of the PBR term.

9.15.1 If yes, please provide a rationale for why FEI is not recommending an increase to the annual capital formula amount for the remaining years of the PBR term. If no, please explain why not.

<u>Response:</u>

Please refer to the discussion that starts at line 34 of page 12 of the Application, with the clarification provided in the response to BCUC IR 1.9.2.

The following questions pertain to project #6 on the integrity related capital for Burns Bog pipeline stress relief:

9.16 Please explain if FEI's approved Base Capital spending envelope includes integrity related costs or similar costs for pipeline stress relief.

Response:

FEI's approved Base Capital, which was based on the 2013 Approved capital expenditures, did not include any integrity-related costs for pipeline stress relief. Carrying out pipeline stress relief is not a routine activity and is done only in response to a need identified through FEI's monitoring and inspection activities. FEI conducts planned inspections and monitoring activities to ensure the ongoing safety and integrity of the pipeline system. In July 2013, engineering analysis of soil monitors indicated unexpected amounts of ground movement and a possible integrity threat to the transmission pipelines in Burns Bog. Further pipeline evaluations, including in-line inspection (i.e. pipeline profile determination and pipe strain estimation, obtained through use of a geometry in line inspection tool) and physical pipeline probing, were performed later in 2013 to verify the hazard and further characterize the integrity threat.

In 2014, it was determined that the transmission pipelines in Burns Bog had likely been over-stressed due to soil loading to an extent that warranted mitigation on a planned, non-emergent basis. FEI scheduled and carried out mitigative action on the NPS 24 line in 2015 and 2016. FEI has scheduled additional stress relief work on the NPS 36 line through 2017. No further stress relief work is planned after 2017.

9.16.1 If yes, please provide the amount included in FEI's Base Capital for integrity related costs for pipeline stress relief and explain why this amount is not sufficient to cover the costs of project #6.

Response:

Please refer to the response to BCUC IR 1.9.16.

9.16.2 If no, please explain why integrity related costs for pipeline stress relief were not included in FEI's approved Base capital and explain the change in circumstances which has resulted in these costs now being required.

Response:

Please refer to the response to BCUC IR 1.9.16.

9.17 Please provide the total capital expenditures incurred for project #6 and indicate which year(s) the costs were incurred.

Response:

The total cumulative capital expenditures incurred by year for Burns Bog pipeline stress relief are shown in the following table.

Year	Capital Cost ($ millions)
2014	0.3
2015	1.8
2016 Projection	1.3
TOTAL	3.4

9.18 Could the cost of project #6 have been foreseen by FEI? Please explain why or why not.

Response:

As explained in the response to BCUC IR 1.9.8, whether or not the costs could have been foreseen is not a relevant consideration.

However, the integrity related capital for Burns Bog pipeline stress relief could not have been foreseen by FEI until late 2013 or 2014. Please refer to the response to BCUC IR 1.9.16, which outlines when FEI determined the need for Burns Bog pipeline stress relief.

10.0 Reference: OVERVIEW OF CAPITAL EXPENDITURES

Exhibit B-2, Section 1.4.4.3, pp. 12–13

Treatment of capital spending outside of the dead band

FEI states the following on page 12 of the Application:

> At this time, for 2016, FEI is projecting to be within the 10 percent one-year capital dead band, but to exceed the 15 percent two-year cumulative dead band…Accordingly, FEI has added 4.1 percent of its 2016 capital spending, or $6.118 million to its opening plant in service in 2017. FEI has also reduced the cumulative capital expenditures utilized in the earning sharing mechanism by the same amount…In this way, there is no earnings sharing on the amount by which FEI exceeded the dead band.

10.1 Please fully explain and compare the impact on the following items of adding the $6.118 million to the opening plant in service in 2017 (i.e. FEI's proposed approach) versus leaving the $6.118 million as part of the 2016 capital expenditures (and thus exceeding the dead band):

i. 2016 and 2017 depreciation expense;

ii. 2016 and 2017 financing costs;

iii. 2016 and 2017 rate base; and

iv. 2016 projected earnings sharing.

Response:

The regulatory treatment contemplated in this question is not the approved treatment under FEI's PBR Plan.

Nevertheless, FEI provides below the calculations as requested. FEI has assumed the following changes from the approved treatment:

1. There is no capital dead band;
2. The result of no capital dead band is that all variances between actual capital spending and formula capital are subject to the earnings sharing calculation; and
3. Only the formula capital is added to rate base.

In the table below, a positive number represents an increase to that item and a negative number represents a decrease. For the earnings sharing, the negative number indicates a decrease in the amount of income FEI shares with customers (a reduction in earnings sharing benefits for customers). The earnings sharing amount, although affecting rates in 2017, is calculated based on the 2016 variance and, similar to the other 2017 impacts shown in the table below, would continue through the remaining term of the PBR.

Item	Description	2016 ($million)	2017 ($million)
i	Depreciation Expense	$0.000	-$0.182
ii	Financing Costs	$0.000	-$0.394
iii	Rate Base	$0.000	-$6.027 (mid-year)
iv	Projected Earnings Sharing	N/A	-$0.139

Items (i) and (ii) for 2016 are zero because the capital expenditures were not included in the 2016 forecast for capital additions and therefore did not attract depreciation or financing costs in setting the 2016 cost of service. The 2017 amounts shown for items (i) and (ii) are the impacts to the forecast of the 2017 cost of service only. Through the process of preparing the 2017 BCUC Annual Report, depreciation expense and financing costs will be trued-up to their actual costs with the difference captured in the flow through account. What this means is that whether the costs are added to rate base or not in the following year for rate setting purposes, customers will ultimately pay the actual depreciation and financing costs in each year of the PBR term. In summary, the only difference between the approved method and the method posed in the question is the impact to earnings as shown in the earnings sharing line above.

10.2 Please discuss the potential impact of FEI's proposal to add $6.118 million of capital expenditures to the opening plant in service in 2017 on the 2017 earnings sharing calculation.

Response:

FEI notes that the addition of $6.118 million of capital expenditures to the opening plant in service in 2017 is a result of the operation of the dead band as approved under the PBR Plan and not FEI's proposal. As explained below, once the $6.118 million is added to rate base, it is no longer a consideration for the earnings sharing for 2016, 2017 or any future years.

As explained on page 12 of the Application, if the capital dead band is exceeded, the opening plant in service for ratemaking purposes in the following year will be adjusted up or down by the amount that actual capital expenditures vary outside of the dead band from the formula-based amount, and the capital expenditure level utilized in calculating the earnings sharing is adjusted up or down by the same amount.

Since the earnings sharing is calculated based on cumulative capital expenditure variances, once the capital expenditure variance is removed from the earnings sharing calculation, it remains out of the calculation in future years. Therefore, once the $6.118 million is added to rate base, it is no longer a consideration for the earnings sharing for 2016, 2017 or any future years.

Please also refer to the response to BCSEA IR 1.4.1.

B. DEMAND FORECAST

11.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Appendix A1, Table A1-3, p. 3

Conference Board of Canada (CBOC) BC Housing Starts

Table A1-3 presents the forecast percent change for 2010 through to 2017 based on the CBOC Provincial Medium Term housing starts as at November 3, 2015.

11.1 Please provide an updated version of Table A1-3 using the most recent CBOC housing starts data.

Response:

The CBOC data used in Table A1-3 is current. The next CBOC Provincial Medium Term housing starts forecast is not expected until late 2016.

11.1.1 Please explain the impact to the residential demand forecast and the revenue requirement that would occur if the updated table provided in response to the previous question was used to prepare FEI's residential demand forecast. Please include the relevant calculations and updated versions of Schedules 16, 17, 18 and 19 with your response.

Response:

Please refer to the response to BCUC IR 1.11.1.

12.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Section 3.4, pp. 29–30; Appendix A-2, Section 3.3, p. 6;

FEI Annual Review of 2015 Rates proceeding, Exhibit B-1, Section 3.4, pp. 19–20; Appendix A3, p. 2;

FEI Annual Review of 2016 Rates proceeding, Exhibit B-2, Appendix A1, p. 3

Residential Net Customer Additions

On page 19 of the FEI Annual Review of 2015 Rates application (Exhibit B-1), FEI explained that "[t]he Conference Board of Canada (CBOC) housing starts forecast found in Appendix A3 provides a proxy for residential net customer additions…"

The CBOC Housing Starts table in Appendix A3 of the FEI Annual Review of 2015 Rates application showed forecasts for 2015 percentage changes in single-detached housing starts and multi-family housing starts of -9.5 percent and 4.6 percent, respectively.

Figure 3-6 on page 20 of the FEI Annual Review of 2015 Rates application showed a Residential Net Customer Additions forecast of 9,710 in 2015, down from a 2014 historical actual of 10,472.

Figure 3-6 on page 30 of the Application shows Actual 2015 residential net customer additions of 12,508 and that actual residential net customer additions increased each year from 2012 through to 2015.

Figure 3-6 on page 30 of the Application also shows a forecasted decrease in residential net customer additions from the 2015 actual of 12,508 to the 2016 seed year and a further decrease from the 2016 seed year to the 2017 forecast year. The 2017 forecasts were made based on the CBOC Housing Starts table in Appendix A1 (Table A1-3), which shows percentage changes in single-detached housing starts and multi-family housing starts of -6.3 percent and -0.2 percent, respectively.

The following tables summarize the information presented in the above preambles.

Table 1: CBOC Housing starts in FEI Annual Review Applications

	Column 1	Column 3	Column 4	Column 5
Row 1		2015[1]	2016[2]	2017[3]
Row 2	CBOC BC Housing Starts Data as at:	Nov 24, 2014	No Data	Nov 3, 2015
Row 3	Forecast Percentage Change: Single-Detached Housing Starts	-9.5%	-0.5%	-6.3%
Row 4	Forecast Percentage Change: Multi-Family Housing Starts	4.6%	0.2%	-0.2%

Notes:
1) FEI Annual Review for 2015 Rates Application, Exhibit B-1, Appendix A3, CBOC Housing Starts Table, p. 2
2) FEI Annual Review for 2016 Rates Application, Exhibit B-2, Appendix A1, Table A1-3, p. 3
3) FEI Annual Review for 2017 Rates Application, Exhibit B-2, Appendix A1, Table A1-3, p. 3

Table 2: FEI Amalgamated Residential Net Customer Additions

	Column 1	Column 2	Column 3	Column 4	Column 5
Row 1	**Residential Net Customer Additions**	**2014[1]**	**2015[1]**	**2016[2,4]**	**2017[3]**
Row 2	Amalgamated RS1 Forecast	6,647	9,710	9,461	11,488
Row 3	Amalgamated RS1 Actual	10,472	12,508	N/A	N/A

Notes:
1) FEI Annual Review for 2017 Rates Application, Exhibit B-2, Appendix A2, Section 3.3, p. 6
2) FEI Annual Review for 2016 Rates Application, Exhibit B-2, Figure 3-6, p. 23
3) FEI Annual Review for 2017 Rates Application, Exhibit B-2, Section 3.4, p. 30
4) 9,461 forecast updated to 12,045 seed in FEI Annual Review for 2017 Rates Application, p. 30.

12.1 Please confirm, or otherwise explain, that based on the CBOC Housing Starts forecast, FEI forecasted a 7 percent reduction in the amalgamated residential net customer additions from an Actual 2014 amount of 10,472 to a Forecast 2015 amount of 9,710.

Response:

Confirmed.

12.2 Please state the actual percentage increase in residential net customer additions that occurred from 2014 to 2015.

Response:

The actual percentage increase in residential net customer additions from 2014 to 2015 is 19.4% based on the 2015 actuals of 12,508 as compared to the 2014 actuals of 10,472 shown in the table above.

12.2.1 Please explain the factors that FEI believes resulted in the increase in residential net customer additions, as opposed to the decrease that FEI had forecasted.

Response:

One of the factors FEI believes contributed to the increase in net customer additions in 2015 is the strong housing construction in 2015. The province experienced higher construction activity levels and subsequently higher gross customer additions than were anticipated at the time of filing the 2015 Annual Review.

12.2.2 Please discuss the likelihood that these factors (or similar factors) could re-occur during the 2017 test period.

Response:

While the new housing market was strong in 2015, and continues to be strong for 2016, it is difficult to assess if this trend will have a carryover effect in 2017. For example, the recent implementation of the foreign buyer's tax has introduced a new level of uncertainty into the housing market in the province.

FEI will continue to rely on the CBOC forecast as a proxy for residential net customer additions, as it has in the 2017 residential customer additions forecast described in section 3 of Appendix A3 and response to BCUC IR 1.14.1, as this continues to be the best indicator of housing starts.

12.2.2.1 If FEI considers that these factors could reoccur for the 2017 test period, please explain how FEI has accounted for them in the 2017 customer additions forecast.

Response:

Please refer to the response to BCUC IR 1.12.2.

13.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Appendix A-2

Historical and forecast data tables

13.1 Please confirm, or otherwise explain, that the historical energy demand data on page 2 of Appendix A2 is weather-normalized.

Response:

Confirmed.

13.1.1 If not confirmed, please provide the weather-normalized historical energy demand data on page 2 of Appendix A2.

Response:

Please refer to the response to BCUC IR 1.13.1.

14.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Appendix A3, p. 6;

FEI Annual Review of 2015 Rates proceeding, Exhibit B-2, BCUC IR 1.7.4

Demand forecast methodology – residential customer additions

14.1 Please provide calculations, with accompanying explanations, which show how the 2017 residential net customer addition forecasts were developed using the CBOC housing starts provided in Table A1-3 of Appendix A1 of the Application. Please provide the response in a manner similar to FEI's response to BCUC IR 1.7.4 in the FEI Annual Review for 2015 Rates proceeding.

Response:

The residential net customer additions forecast was developed based on housing starts data from CBOC forecast of November 3, 2015, Provincial Medium Term, Forecast: 20153 Run: 16, Table LTPF156 and LTPF157. The housing starts data was as follows:

BC Housing Starts

	2014	2015	2016	2017
SFD	9,569	10,499	9,808	9,188
MFD	18,787	22,565	23,102	23,064
	28,356	33,064	32,910	32,252

From the above housing starts forecast, the 2016 SFD growth rate is calculated as follows:

$$2016\ SFD\ Growth\ Rate = 1 - \left(\frac{9{,}808}{10{,}499}\right) = 6.6\%$$

The remainder of the growth rates are calculated, as shown in the following table:

BC Housing Starts Growth Rates

	2016	2017
SFD	-6.6%	-6.3%
MFD	2.4%	-0.2%

The following table shows the FEI proportions of the actual account additions by single family dwelling (SFD) and multi-family (MFD) based on historical percentages from internal data in columns A and B. The 2015 actual total additions are shown in column C, followed by the SFD and MFD proportions in columns D and E. Finally the CBOC growth rates for 2016 are applied to the SFD and MFD proportions for 2016 in column F and G and for 2017 in column I and J.

	Internal Split		2015 A			2016 S			2017		
Sub-Regions	**% SFD**	**% MFD**	**Total**	**SFD**	**MFD**	**SFD**	**MFD**	**Total**	**SFD**	**MFD**	**Total**
	A	B	C	D	E	F	G	H	I	J	K
Mainland			**8,831**	**5,277**	**3,553**	**4,930**	**3,637**	**8,567**	**4,618**	**3,631**	**8,249**
Lower Mainland	44%	56%	5,275	2,333	2,941	2,180	3,011	5,191	2,042	3,006	5,048
Inland	83%	17%	3,328	2,758	570	2,576	583	3,160	2,413	582	2,996
Columbia	77%	23%	185	143	42	134	43	176	125	43	168
Revelstoke*	100%	0%	43	43	-	40	-	40	38	-	38
Whistler	69%	31%	92	63	29	59	29	88	55	29	85
Vancouver Island	90%	10%	3,585	3,238	347	3,025	355	3,380	2,834	354	3,188
Total FEU			**12,508**	**8,579**	**3,928**	**8,014**	**4,022**	**12,036**	**7,507**	**4,015**	**11,522**

*Revelstoke: Calculation error corrected

In the course of responding to this question, FEI discovered a calculation error in the demand forecast for the Revelstoke sub-region. FEI has now recalculated the figures, and the resulting demand. In total, the demand forecast for Revelstoke has changed as follows:

Revlestoke	**2017 Filing**		**Revised Calculation**		**Percentage Change**	
Demand GJs	2016S	2017F	2016S	2017F	2016S	2017F
RATE1	75,085	78,378	70,542	71,909	-6%	-8%
RATE2	72,969	74,162	77,317	78,333	6%	6%
RATE3	72,516	72,865	114,785	132,709	58%	82%
Total	**220,569**	**225,404**	**262,645**	**282,951**	**19%**	**26%**

FEI will update the demand forecast for this correction in its Evidentiary Update.

15.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Appendix A3, pp. 8, 10;

FEI Annual Review of 2015 Rates proceeding, Exhibit B-2, BCUC IR 1.6.2;

FEI Annual Review of 2016 Rates proceeding, Exhibit B-5, BCUC IR 1.12.2

Demand forecast methodology – residential and commercial use rate

Figure A3-2 on page 8 of Appendix A3 of the Application depicts the flow chart for the use rate forecast calculation. The residential and commercial use rate forecast is developed using a regression method in some instances and a three-year average method in other instances.

15.1 Please produce a summary table showing whether a three-year average or a regression equation is used to produce the use per customer (UPC) forecast for each rate schedule in each region. Please provide this response in a manner similar to FEI's response to BCUC IR 1.12.2 in the FEI Annual Review of 2016 Rates proceeding.

Response:

The requested table is provided below for each sub-region.

Region	Rate Schedule	Method Applied for 2017F
LowerMainland	RS 1	Regression Model
	RS 2	3 Year Average Model
	RS 3	3 Year Average Model
	RS23	3 Year Average Model
Inland	RS 1	3 Year Average Model
	RS 2	Regression Model
	RS 3	Regression Model
	RS23	Regression Model
Columbia	RS 1	3 Year Average Model
	RS 2	3 Year Average Model
	RS 3	3 Year Average Model
	RS23	3 Year Average Model
Revelstoke	RS 1	Regression Model
	RS 2	3 Year Average Model
	RS 3	3 Year Average Model
Vancouver Island	RS 1	3 Year Average Model
	RS 2	Regression Model
	RS 3	Regression Model
	RS23*	Naïve Forecast
Whistler	RS 1	Regression Model
	RS 2	Regression Model
	RS 3	Regression Model
	RS 23*	Naïve Forecast

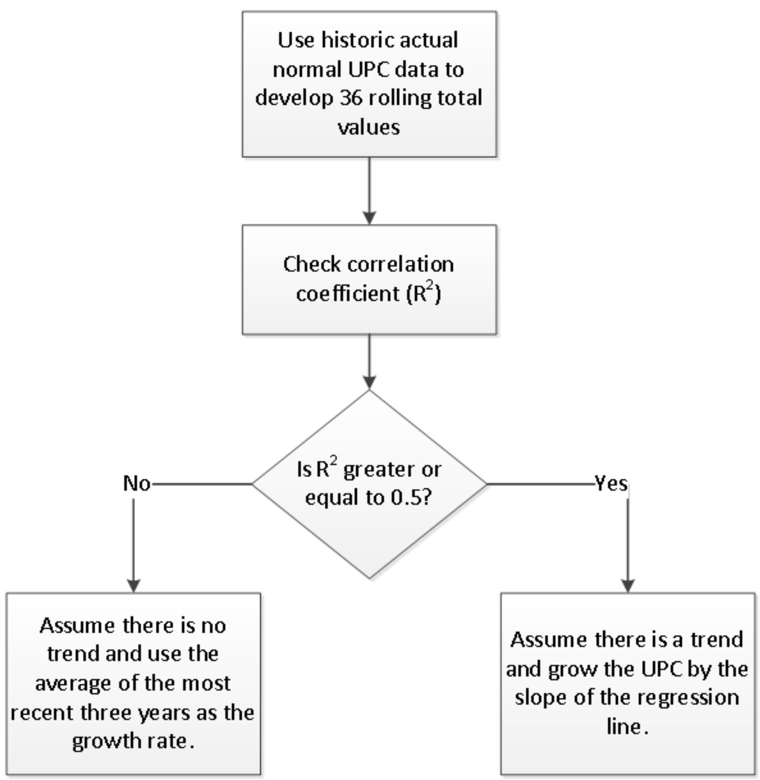
RS 23* Vancouver Island and Whistler, Naïve forecast was applied due to the absence of historic data

15.2 Please provide calculations, with accompanying explanations, showing how the 2017 UPC forecast was developed for: (i) the Mainland residential rate class; and (ii) one of the commercial rate classes in FEI's regions. Include in the response how the recent three years of data was incorporated into the development of the forecasts and factors that were considered. Please provide this response in a manner similar to FEI's response to BCUC IR 1.6.2 in the FEI Annual Review of 2015 Rates proceeding.

<u>Response:</u>

The UPC method for Lower Mainland Rate Schedule 1 (residential) and Lower Mainland Rate Schedule 3 (commercial) are demonstrated below. The Mainland UPC forecasts are developed from individual forecasts for the Lower Mainland, Inland and Columbia regions. Calculations for the Inland and Columbia regions are identical to the Lower Mainland so will not be shown here.

The UPC method is to use either a three-year average or the result of a regression. The regression is tested first and used if a trend is present (i.e. if an R^2 value greater than or equal to 50 percent). The following flow chart demonstrates the process.



(i) ***<u>Lower Mainland Rate Schedule 1</u>***

The rolling 12-month UPCs for Lower Mainland Rate Schedule 1 were calculated as follows:

LML RS 1	Monthly UPC	12 month Rolling UPC	Period
Jan-12	14.60		
Feb-12	12.40		
Mar-12	11.00		
Apr-12	8.30		
May-12	5.30		
Jun-12	3.50		
Jul-12	2.70		
Aug-12	3.10		
Sep-12	3.20		
Oct-12	7.20		
Nov-12	12.00		
Dec-12	15.30	98.60	
Jan-13	14.71	98.71	1
Feb-13	12.30	98.61	2
Mar-13	11.32	98.93	3
Apr-13	7.90	98.53	4
May-13	4.96	98.19	5
Jun-13	3.48	98.17	6
Jul-13	2.65	98.12	7
Aug-13	2.74	97.76	8
Sep-13	3.60	98.15	9
Oct-13	6.86	97.81	10
Nov-13	11.03	96.84	11
Dec-13	14.46	96.01	12
Jan-14	14.14	95.44	13
Feb-14	11.53	94.67	14
Mar-14	11.05	94.39	15
Apr-14	8.14	94.63	16
May-14	4.85	94.52	17
Jun-14	3.14	94.19	18
Jul-14	2.82	94.36	19
Aug-14	2.86	94.49	20
Sep-14	3.14	94.03	21
Oct-14	7.31	94.48	22
Nov-14	10.72	94.18	23
Dec-14	14.98	94.70	24
Jan-15	14.86	95.41	25
Feb-15	11.74	95.63	26
Mar-15	10.45	95.03	27
Apr-15	7.56	94.45	28
May-15	4.93	94.53	29
Jun-15	3.82	95.20	30
Jul-15	2.84	95.22	31
Aug-15	2.39	94.75	32
Sep-15	3.14	94.76	33
Oct-15	6.32	93.76	34
Nov-15	10.77	93.81	35
Dec-15	15.33	94.15	36

The following summary is developed.

LML RS 1	2012	2013	2014	2015	**2016S**	**2017F**
UPC	98.60	96.01	94.70	94.15	92.53	90.91
Growth		-2.6%	-1.4%	-0.6%		
3 Yr avg	-1.5%					
Correlation	68%					
Monthly Slope	(0.135)					
Result	Use Regression					

The R^2 (correlation) is 68 percent, so a trend is used, as per the flow chart above.

The slope of the regression equation is -0.135.

The 2016 seed year forecast is developed by adding 12 times the monthly slope (-0.135) to the 2015 actual UPC (94.14) as follows:

$$2016S\ UPC = 94.15 + (12 \times (-0.135)) = 92.53\ GJs$$

The 2017F forecast is developed by adding 12 times the monthly slope (-0.135) to the 2016 seed forecast as follows:

$$2017F\ UPC = 92.53 + (12 \times (-0.135)) = 90.91\ GJs$$

(ii) ***<u>Lower Mainland Rate Schedule 3</u>***

The rolling 12-month UPCs for Lower Mainland Rate Schedule 3 were calculated as follows:

1

LML RS 3	Monthly UPC	12 month Rolling UPC	Period
Jan-12	472.2		
Feb-12	418.1		
Mar-12	396.5		
Apr-12	316.3		
May-12	223.6		
Jun-12	160.8		
Jul-12	128.9		
Aug-12	143.6		
Sep-12	152.7		
Oct-12	274.3		
Nov-12	376.6		
Dec-12	458.4	3,522	
Jan-13	470.2	3,520	1
Feb-13	393.8	3,496	2
Mar-13	393.5	3,493	3
Apr-13	299.5	3,476	4
May-13	217.4	3,470	5
Jun-13	169.0	3,478	6
Jul-13	129.4	3,478	7
Aug-13	131.5	3,466	8
Sep-13	163.4	3,477	9
Oct-13	269.5	3,472	10
Nov-13	368.0	3,464	11
Dec-13	480.2	3,485	12
Jan-14	473.4	3,489	13
Feb-14	395.6	3,490	14
Mar-14	395.3	3,492	15
Apr-14	315.2	3,508	16
May-14	218.6	3,509	17
Jun-14	151.9	3,492	18
Jul-14	135.6	3,498	19
Aug-14	134.7	3,501	20
Sep-14	151.0	3,489	21
Oct-14	277.8	3,497	22
Nov-14	351.7	3,481	23
Dec-14	480.5	3,481	24
Jan-15	478.8	3,487	25
Feb-15	389.4	3,480	26
Mar-15	377.5	3,463	27
Apr-15	292.3	3,440	28
May-15	222.7	3,444	29
Jun-15	169.1	3,461	30
Jul-15	132.9	3,458	31
Aug-15	121.1	3,445	32
Sep-15	150.1	3,444	33
Oct-15	253.3	3,419	34
Nov-15	359.0	3,427	35
Dec-15	484.8	3,431	36

The following summary is developed.

LML RS 3	2012	2013	2014	2015	**2016S**	**2017F**
UPC	3,522	3,485	3,481	3,431	3,401	3,372
Growth		-1.04%	-0.12%	-1.45%		
3 Yr avg	-0.87%					
Correlation	41%					
Slope	-1.477					
Result	Use 3 Yr Avg					

The R^2 (correlation) is 41 percent, so the three-year average is used, as per the flow chart above.

The 2016 seed year forecast is developed by multiplying one minus the three year average decline (1-0.87%) times the 2015 actual UPC (3,431) as follows:

$$2016S\ UPC = 3{,}431 \times (1 - 0.0087) = 3{,}401\ GJs$$

The 2017F forecast is developed by multiplying one minus the three year average decline (1-0.87%) times the 2016 seed UPC (3,401) as follows:

$$2017F\ UPC = 3{,}401 \times (1 - 0.0087) = 3{,}372\ GJs$$

16.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Appendix A3, Section 8, pp. 12-19

Industrial survey

Figure A3-3 on page 12 of Appendix A3 of the Application shows that FEI sends out industrial surveys to customers in rate schedules 5, 7, 22, 25 and 27.

16.1 Please provide industrial survey response data broken down into the relevant rate classes using the template below. The column titled "Number of Customers" represents the number of customers in the database at the time the survey was issued.

	Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8
Row 1		2016 Industrial Survey Response (Actual)						
Row 2			Completed		Delivered but not completed		Undeliverable	
Row 3		Number of Customers	% Customers	% 2015 Demand	% Customers	% 2015 Demand	% Customers	% 2015 Demand
Row 4	Rate Schedule 5							
Row 5	Rate Schedule 7							
Row 6	Rate Schedule 22							
Row 7	Rate Schedule 25							
Row 8	Rate Schedule 27							
Row 9	Total							

<u>Response:</u>

The following table shows the response rate to the industrial survey in terms of customers and 2015 demand, as requested.

		Completed		Delivered but not complete		Undeliverable	
	Number of Customers	% Customers	% 2015 Demand	% Customers	% 2015 Demand	% Customers	% 2015 Demand
Rate Schedule 5	240	22%	1.0%	38%	1.4%	40%	1.4%
Rate Schedule 7	6	50%	0.2%	0%	0.0%	50%	0.1%
Rate Schedule 22	48	100%	61.3%	0%	0.0%	0%	0.0%
Rate Schedule 25	544	56%	16.0%	41%	6.3%	4%	0.5%
Rate Schedule 27	107	79%	10.4%	19%	1.4%	2%	0.1%
Total	945	52%	88.9%	35%	9.1%	13%	2.0%

Note that the percentage of customers in the above table differ slightly from the values reported in Table 3-1 in section 3.5.3 of the Application due to the inclusion of the results from 16 Rate Schedule 46 customers in Table 3-1.

The table shows the following:

1. Surveys were completed for 89% of the demand.

2. While 35% of customers received a survey and did not reply, this group accounts for only 9.1% of the demand. As with past surveys, FEI ensured that 100% of the largest customers (Rate Schedule 22) completed the survey.

3. 13% of the surveys were undeliverable. FEI ensured that all large customer surveys were delivered so this group accounted for only 2% of the demand.

17.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Appendix A2, Section 3.2, p. 5

Amalgamated net customers – Industrial

Section 3.2 in Appendix A2 of the Application contains historical data for FEI's amalgamated net customers. Data is shown for rate schedules 1, 2, 3 and 23.

17.1 Please complete the worksheet titled "(1) Number of Customers" in the attached Microsoft Excel file to provide forecasts, actuals and variances of the historical year-end number of customers for each industrial rate schedule.

<u>Response:</u>

Please refer to the table below and the fully functional spreadsheet provided in Attachment 17.1 for the annual industrial customer count and variances.

Please note that Vancouver Island and Whistler data prior to 2015 was compiled by mapping customers from FEVI and FEW historic rate schedules into FEI's rate schedules. All customer counts starting in 2015 are based on amalgamated data.

	Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8
Row 1		**FEI Amalgamated**						
Row 2		**Year-End Number of Customers**						
Row 3		**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Row 4	**Rate Schedule 5**							
Row 5	Forecast	328	283	284	265	282	233	233
Row 6	Actual	271	264	264	265	243		
Row 7	Variance	-57	-19	-20	0	-39		
Row 8	Variance %	-21%	-7%	-8%	0%	-16%		
Row 9								
Row 10	**Rate Schedule 7**							
Row 11	Forecast	2	4	4	3	3	5	5
Row 12	Actual	2	3	3	3	6		
Row 13	Variance	0	-1	-1	0	3		
Row 14	Variance %	0%	-33%	-33%	0%	50%		
Row 15								
Row 16	**Rate Schedule 22**							
Row 17	Forecast	45	43	43	45	46	50	50
Row 18	Actual	43	46	45	44	47		
Row 19	Variance	-2	3	2	-1	1		
Row 20	Variance %	-5%	7%	4%	-2%	2%		
Row 21								
Row 22	**Rate Schedule 25**							
Row 23	Forecast	580	557	557	499	601	560	560
Row 24	Actual	510	514	550	548	555		
Row 25	Variance	-70	-43	-7	49	-46		
Row 26	Variance %	-14%	-8%	-1%	9%	-8%		
Row 27								
Row 28	**Rate Schedule 27**							
Row 29	Forecast	98	101	101	95	104	107	107
Row 30	Actual	98	98	103	101	108		
Row 31	Variance	0	-3	2	6	4		
Row 32	Variance %	0%	-3%	2%	6%	4%		
Row 33								
Row 34	**TOTAL FORECAST**	1053	988	989	907	1036	955	955
Row 35	**TOTAL ACTUAL**	924	925	965	961	959		
Row 36	**TOTAL VARIANCE**	-129	-63	-24	54	-77		
1	**TOTAL VARIANCE %**	-14%	-7%	-2%	6%	-8%		

18.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Section 11, Schedules 16–18

Combined data for amalgamated demand forecast, revenue and margin

18.1 Please complete the worksheet titled "(2) Demand, Revenue and Margin" in the attached Microsoft Excel file to provide a table that combines FEI's customer and energy demand forecasts as well as the corresponding total revenues and margins by rate class.

<u>Response:</u>

Please refer to Attachment 18.1 for the completed worksheet.

19.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Section 3.5.4, pp. 36–37

Natural gas for transportation (NGT) and liquefied natural gas (LNG) demand

On page 36 of the Application, FEI states: "The following table shows the 2011 to 2015 Actual, 2016 Projected and 2017 Forecast annual demand for CNG and LNG for Rates Schedules 16/46 (LNG) and Rate Schedule 25 (CNG)."

19.1 Please state if the 2016 projected figures contain actual historical data from several months in 2016.

Response:

Yes. The projected figures for 2016 are based on actual consumption values up to June 30, 2016.

19.1.1 If so, please state the months in 2016 for which actual historical data was included in the 2016 projections.

Response:

Please refer to the response to BCUC IR 1.19.1.

20.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Appendix A4, pp. 1, 11

Demand forecasting performance review

On page 1 of Appendix A4 of the Application, FEI states: "The average residential demand forecast error from natural gas utilities captured in three separate surveys is 4.1 percent. Using its existing method, FEI's average absolute residential forecast error over the previous ten years was 2.1 percent and the absolute error in 2015 was 1.3 percent."

Tables A4-4, A4-5 and A4-6 on page 11 of Appendix A4 present survey results from the Boreas survey and two ITRON surveys regarding residential and commercial demand forecasting accuracy for sample groups.

20.1 Please complete the following table to the best of FEI's ability to indicate the size of the utilities (A-O) surveyed by Boreas. Please use the most recently available actual totals in instances where 2014 actual totals are unavailable.

Utility	2014 Totals (Actual)	
	Customer Count	Annual Energy Demand
	#	(PJ)
A		
B		
C		
...		
M		
N		
O		
FEI	964,971	206.5

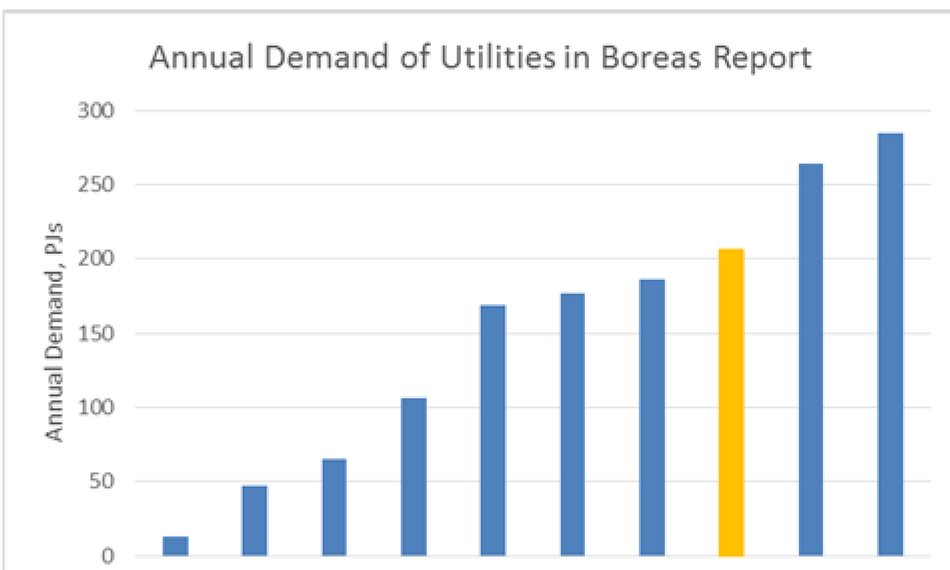
Response:

The following table indicates the size of the utilities (A-O) surveyed by Boreas.

Utility	2014 Totals (Actual)	
	Customer Count	Annual Energy Demand
	#	(PJ)
	739,645	unavailable
	unavailable	13[1]
	270,812	106[1]
	unavailable	unavailable
	unavailable	177[2]
	1,224,856	169
	unavailable	264
	unavailable	47[2]
	375,683	65
	unavailable	285
	1,412,940	186
FEI	964,971	206.5
1	2012 data shown; 2014 not available	
2	2013 data shown; 2014 not available	

The utility identifier has been removed to protect confidentiality.

The following chart shows the annual demand of FEI and each of the utilities from the Boreas report where the demand was available:



As seen from the above chart, the Boreas Report surveyed utilities of a range of sizes, some of which are smaller and some of which are larger than FEI. The average demand for the nine utilities where the demand is known is 146 PJ, whereas FEI's annual demand is 206.5 PJ. The range of the utilities surveyed and the comparability to FEI supports the validity of the Boreas Survey results.

Tables A4-7 and A4-8 on page 12 of Appendix A4 show the residential and commercial demand forecasting accuracy, respectively, for FEI.

20.2 For the rows titled "Error (PJ)" and "Percent Error," please explain the difference in results between:

i. Table A4-7 on page 12 of Appendix A4 and Table A2-3 on page 4 of Appendix A2; and

ii. Table A4-8 on page 12 of Appendix A4 and Table A2-4 on page 5 Appendix A2.

Response:

Table A4-7 shows the same data as Table A2-3, and Table A4-8 shows the same data as Table A2-4. In both cases the only difference is that the error (PJ) row was calculated as (Forecast – Actual) in Tables A2-3 and A2-4 and as (Actual – Forecast) in Tables A4-7 and A4-8. The error and percent errors values are therefore the same in both tables, except that one shows as a negative and one shows as a positive.

For example, in 2009 the residential demand error and percent error show as 1.0 and 1.3%, respectively, in Table A2-3, but show as -1.0 and -1.3% in Table A4-7.

Also note that the Tables A2-3 and A2-4 show data from 2006 through 2015 while Tables A4-7 and A4-8 show data from 2009 through 2015 (consistent with the results received in the Boreas Report).

20.2.1 Please provide the necessary updates to the relevant tables in response to the previous question.

Response:

No updates are required. Please refer to the response to BCUC IR 1.20.2.

21.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Appendix A4: Section 5, pp. 13–18; Section 6, pp. 19–29; Section 7, p. 30

Alternative forecasting techniques

On page 13 of Appendix A4 of the Application, FEI states: "FEI developed a list of alternate forecasting methods that included both time series methods and econometric regressions."

21.1 Please complete the following table to indicate the number of utilities in the Boreas' survey that used each of the forecasting methods in Column 2 to forecast the components of demand listed in columns 3 through to 6.

Column 1	Column 2	Column 3	Column 4	Column 5	Column 6
Item No.	**Forecasting Methods**	**No. of Utilities that use the corresponding forecast method to forecast[1]:**			
		Residential Use Rate	**Commercial Use Rate**	**Commercial Customer Additions**	**Commercial Customer Count**
1	FEI's Existing Method				
2	Holt's Exponential Smoothing (ETS)				
3	Time Series Linear Regression				
4	Naïve Forecast				
5	Three Year Moving Average with Trend				
6	Econometric Regression				
7	Three Year Average				

Note:
1) The number of utilities should be taken from the list of utilities (A-O) surveyed in the Boreas Consulting Inc. Report. (Appendix A4-B)

Response:

The following table shows the number of utilities in the Boreas' survey that used each of the forecasting methods as indicated in the columns.

Item No.	Forecasting Methods	No. of Utilities that use the corresponding forecast method to forecast:			
		Residential Use Rate	Commerical Use Rate	Commercial Customer Additions	Commercial Customer Count
1	FEI's Existing Method				
2	Holts Exponential Smoothing (ETS)				
3	Time Series Linear Regression	1	2		1
4	Naïve Forecast				
5	Three Year Moving Average with Trend				
6	Econometric Regression	4	3	2	1
7	Three Year Average	1	1	2	

Note:

- Some of the utilities in the Boreas' survey used forecasting methods that are not listed in the table.
- FEI's existing method uses a three year average for a number of components, so there is some overlap between rows 1 and 7.
- Every utility will implement methods slightly differently depending on the quality and quantity of data they have available.
- In Appendix A4, FEI demonstrates that Holt's Exponential Smoothing outperforms all of the methods listed in the table, except for FEI's existing method.
- The fact that no other utilities are using Holt's Exponential Smoothing underscores FEI's recommendation to continue testing Holt's Exponential Smoothing prior to implementation. No other utilities have experience with this method.

In Table A4-10 on page 14 of Appendix A4, FEI states that the Holt's Exponential Smoothing forecasting method "uses the entire data set (all available data) but weights recent data more heavily than older data. Several different versions exist: Holt's method accounts for trend (if it exists) and was tested as part of this investigation."

FEI also states: "Exponential Smoothing was recently introduced as a new forecasting feature in Microsoft Excel 2016, making it easily accessible to FEI, the Commission and interveners for testing and verification."

21.2 Please outline the annual incremental costs that FEI would incur to test the Holt's Exponential Smoothing model alongside FEI's existing model. Please provide explanations where necessary.

Response:

FEI has recommended testing Holts Exponential Smoothing on additional data as it becomes available prior to making a decision on the forecast method for residential use rates, commercial use rates and commercial customer additions. This testing will continue each year for the remainder of the PBR term.

Assuming FEI's proposal is accepted, FEI has not forecast any incremental costs to test the Holt's Exponential Smoothing model as the work will be undertaken by FEI's existing staff.

21.3 Please discuss and compare the effectiveness of Holt's method when a trend exists and when a trend does not exist.

Response:

Holt's Linear model is appropriate and effective to use both when a trend is present and when a trend is not present. When a trend is not present the equations for Holt's Linear method will simplify such that the future forecast is the same as the current level, as demonstrated below.

The three equations for Holt's Linear method are:

$$1{:}\ Level\ at\ time\ \mathrm{t} = L_t = \alpha Y_t + (1-\alpha)(L_{t-1} + b_{t-1})$$

$$2{:}\ Trend\ at\ time\ t = b_t = \beta(L_t - L_{t-1}) + (1-\beta)b_{t-1}$$

$$3{:}\ Forecast\ at\ time\ (t+m) = F_{t+m} = L_t + b_t m$$

In equation three, "m" is the number of periods forward to forecast, so m >= 1.

If we use the above equations to forecast a value one period into the future (m=1), and assume there is no trend in the data (i.e. the trend at time t, b_t, is zero), then equations two and three become:

$$2{:}\ Trend\ at\ time\ t = b_t = 0$$

$$3{:}\ Forecast\ at\ time\ (t+1) = F_{t+1} = L_t + (0 \times 1)$$

Equation three then simplifies to:

$$3{:}\ Forecast\ at\ time\ (t+1) = F_{t+1} = L_t$$

This means the forecast one time period ahead will be equal to the current level, which is true only in the case where there is no trend. This confirms that in the case where a trend does not exist in the data it is still appropriate to use Holt's Linear method.

All of the historical data FEI uses for forecasting has some trend, even if it is very small. As shown above, Holt's Linear method will remain effective even with a data set that exhibited no year over year trend.

21.4 Using historical actuals to forecast 2015 demand, please provide calculations and explanations that illustrate how Holt's Exponential Smoothing (ETS) forecasting method would be used to develop: (i) residential use rate; (ii) commercial use rate; and (iii) commercial customer additions.

Response:

The Holts Linear Exponential Smoothing method (ETS) is implemented as a "wizard" in Excel 2016 and, as a result, intermediate calculations and steps are not exposed or reproducible. Microsoft has not published, and is unlikely to publish, the specific algorithms and procedures used in their software. Therefore, to demonstrate the key elements of the method, a manual model is required. The model shown below uses accepted practices, but may differ from the optimization methods and strategies used by Microsoft in Excel 2016.

ETS is applied the same to all data sets, including use rates and customers. Given that the illustration of ETS is quite technical (as shown below) and the same for all data sets, FEI has provided one illustration.

Below FEI illustrates how ETS can be used to develop the 2015 forecast UPC for the Lower Mainland. To do this, FEI first introduces the three equations used in ETS and sample Lower Mainland UPC data for purposes of the illustration. FEI then explains how the equations are used with the data to develop the 2015 forecast UPC for the Lower Mainland.

ETS Equations and Sample Data

The three equations used in ETS to develop level, trend and forecast data are shown below:

Reference Number	Description	Equation
1	Level forecast at time t	$L_t = \alpha Y_t + (1-\alpha)(L_{t-1} + b_{t-1})$
2	Trend forecast at time t	$b_t = \beta(L_t - L_{t-1}) + (1-\beta)b_{t-1}$
3	Aggregate forecast at time t	$F_{t+m} = L_t + b_t m$

Sample Lower Mainland UPC data (GJ) is provided below, including actual and forecast data from 2004 to 2013 and forecast data for 2014 and 2015. In the discussion below, the 2015 forecast value of 94.04 GJ in row 12, column 6 of the table below will be developed using the three ETS equations above.

	Alpha	**0.500**					
	Beta	**0.000**					
	1	2	3	4	5	6	7
	Date	**Actual, Y**	**Level, L**	**Trend, b**	**Period, m**	**Forecast, F**	**Error**
1	2004	107.81	107.81	(1.10)			
2	2005	103.92	105.32	(1.10)	1	106.71	(2.8)
3	2006	103.16	103.69	(1.10)	1	104.22	(1.1)
4	2007	102.62	102.60	(1.10)	1	102.59	0.0
5	2008	99.51	100.51	(1.10)	1	101.50	(2.0)
6	2009	100.18	99.79	(1.10)	1	99.41	0.8
7	2010	99.81	99.25	(1.10)	1	98.69	1.1
8	2011	97.10	97.63	(1.10)	1	98.15	(1.1)
9	2012	98.60	97.56	(1.10)	1	96.53	2.1
10	2013	96.01	96.24	(1.10)	1	96.46	(0.5)
11	2014				1	95.14	
12	2015				2	94.04	
						SSE	**20.33**

Establish Starting Values for the Level and Trend

From the ETS equations 1 and 2 above, the level and trend at time “t” rely on level and trend values from the previous time period (t-1).

In this model FEI has set the starting level to be the same as the 2004 actual (107.81). There are a number of ways of setting the initial trend. Excel uses the SLOPE function over the entire set of actual data and therefore sets the initial trend at -1.1 as shown in the table above.

Once the initial values are set, equations can be entered into each remaining cell in columns 3, 4 and 6, as shown below.

Cell Formulas

The three equations shown above are next entered into columns 3, 4 and 6 of rows 2 through 12. The following view of the above model confirms the correct equations have been entered into the columns. Column 3 uses equation 1, Column 4 uses equation 2 and Column 6 uses equation 3.

	Alpha	**0.5**					
	Beta	**0**					
	1	2	3	4	5	6	7
	Date	**Actual, Y**	**Level, L**	**Trend, b**	**Period, m**	**Forecast, F**	**Error**
1	2004	107.81	=C9	=SLOPE(C9:C18,B9:B18			
2	2005	103.92	=Alpha*C10+(1-Alpha)*(D9+E9)	=Beta*(D10-D9)+(1-Be	1	=D9+E9*F10	=C10-G10
3	2006	103.16	=Alpha*C11+(1-Alpha)*(D10+E10)	=Beta*(D11-D10)+(1-B	1	=D10+E10*F11	=C11-G11
4	2007	102.62	=Alpha*C12+(1-Alpha)*(D11+E11)	=Beta*(D12-D11)+(1-B	1	=D11+E11*F12	=C12-G12
5	2008	99.51	=Alpha*C13+(1-Alpha)*(D12+E12)	=Beta*(D13-D12)+(1-B	1	=D12+E12*F13	=C13-G13
6	2009	100.18	=Alpha*C14+(1-Alpha)*(D13+E13)	=Beta*(D14-D13)+(1-B	1	=D13+E13*F14	=C14-G14
7	2010	99.81	=Alpha*C15+(1-Alpha)*(D14+E14)	=Beta*(D15-D14)+(1-B	1	=D14+E14*F15	=C15-G15
8	2011	97.1	=Alpha*C16+(1-Alpha)*(D15+E15)	=Beta*(D16-D15)+(1-B	1	=D15+E15*F16	=C16-G16
9	2012	98.6	=Alpha*C17+(1-Alpha)*(D16+E16)	=Beta*(D17-D16)+(1-B	1	=D16+E16*F17	=C17-G17
10	2013	96.01	=Alpha*C18+(1-Alpha)*(D17+E17)	=Beta*(D18-D17)+(1-B	1	=D17+E17*F18	=C18-G18
11	2014				1	=$D$18+$E$18*F19	
12	2015				2	=$D$18+$E$18*F20	
						SSE	**=SUM(H10:H18^2)**

Application of Equations 1-3

The values for the level, trend and forecast in row 2 are determined as demonstrated below:

$$Equation\ 1: L_t = 0.50 \times 103.92 + (1 - 0.50)(107.81 - 1.10) = 105.32$$

$$Equation\ 2: b_t = 0.0(104.78 - 107.81) + (1 - 0.0)(-1.10) = -1.10$$

Equation 3 is then used to get the forecast value for 2006 in row 3:

$$Equation\ 3: F_{t+1} = 105.32 - (1.10 \times 1) = 104.22$$

Calculations for columns 3, 4 and 6 are repeated for all rows, through row 10.

Establish the Alpha and Beta Parameters

Once the equations have been entered into the model, values for the alpha and beta parameters can be established. Alpha and beta values must be selected before the forecasts in rows 11 and 12 can be computed. The purpose of the data in rows 1 through 10 is to establish the optimum values of alpha and beta. The data in rows 1 through 10 is referred to as the initialization set.

The process to establish the optimum values of alpha and beta is as follows:

1. Enter values for alpha and beta in the Alpha and Beta cells in the model. In the screen shot above the values are 0.0 and 0.5, respectively.

2. Values in rows 1 through 10 will be updated using the new parameters.

3. The error calculation in column 7 is the difference between the forecasted value in column 6 and the actual value in column 2. The forecast value in column 6 is from equation 3.

4. Square each error to remove the positive/negative cancellation effect, and then sum the squared errors (SSE).

5. The optimum values for alpha and beta are the pair that result in the minimum SSE over the initialization set.

6. Alpha and beta can be established using values established by Excel, or by step wise trials. Both methods result in the same values, as shown below:

   a) In Excel 2016 the formula "=FORECAST.ETS.STAT" can be used to determine the values of alpha and beta selected by Excel. For the Lower Mainland Rate Schedule 1 data used in this example, the values chosen by Excel are Alpha = 0.05 and Beta = 0.

   b) Alternatively step wise trials can be used. The following chart or "heat map" shows the SSE results of step wise trials for every combination of alpha and beta at 0.05 intervals. Both alpha and beta must be between 0 and 1. The "heat map" shows the sensitivity of the model to the choices of alpha and beta. The chart is colored such that green cells represent lower SSE (better) values than yellow and orange or red cells. Each cell represents a complete model run. The optimum value (20.3) for Alpha=0.50 and Beta=0.0 is black.

	ALPHA																				
		0.0	0.05	0.10	0.15	0.20	0.25	0.30	0.35	0.40	0.45	0.50	0.55	0.60	0.65	0.70	0.75	0.80	0.85	0.90	0.95	1.00
BETA	0.0	51.9	38.9	31.4	27.1	24.5	22.8	21.8	21.0	20.6	20.4	20.3	20.4	20.7	21.1	21.6	22.3	23.1	24.0	25.0	26.2	27.5
	0.05	51.9	37.4	30.0	26.2	24.1	22.8	22.0	21.5	21.1	20.9	20.9	21.0	21.3	21.8	22.3	23.1	23.9	24.9	26.1	27.4	28.8
	0.10	51.9	36.2	29.0	25.8	24.2	23.3	22.6	22.2	21.8	21.6	21.6	21.7	22.0	22.4	23.1	23.8	24.8	25.9	27.2	28.6	30.1
	0.15	51.9	35.0	28.4	25.8	24.7	24.0	23.5	23.0	22.6	22.3	22.2	22.3	22.6	23.1	23.8	24.6	25.6	26.9	28.3	29.8	31.6
	0.20	51.9	34.1	28.0	26.1	25.4	24.9	24.3	23.7	23.2	22.9	22.8	22.8	23.1	23.7	24.4	25.3	26.5	27.8	29.4	31.2	33.1
	0.25	51.9	33.3	27.9	26.7	26.3	25.8	25.1	24.4	23.8	23.3	23.2	23.3	23.6	24.2	25.0	26.1	27.3	28.9	30.6	32.6	34.7
	0.30	51.9	32.6	28.0	27.4	27.2	26.7	25.8	24.9	24.2	23.7	23.5	23.6	24.0	24.7	25.6	26.8	28.2	29.9	31.8	34.0	36.5
	0.35	51.9	32.0	28.3	28.3	28.2	27.4	26.3	25.3	24.5	23.9	23.8	23.9	24.4	25.2	26.2	27.5	29.1	31.0	33.2	35.6	38.3
	0.40	51.9	31.5	28.7	29.1	29.0	28.1	26.8	25.5	24.6	24.1	24.0	24.2	24.8	25.6	26.8	28.3	30.1	32.2	34.6	37.3	40.3
	0.45	51.9	31.2	29.2	30.0	29.8	28.6	27.0	25.7	24.8	24.3	24.2	24.5	25.2	26.1	27.5	29.1	31.1	33.4	36.1	39.1	42.4
	0.50	51.9	30.9	29.9	30.9	30.5	29.0	27.2	25.8	24.8	24.4	24.4	24.8	25.6	26.7	28.1	30.0	32.2	34.7	37.7	41.0	44.7
	0.55	51.9	30.7	30.6	31.8	31.1	29.2	27.3	25.8	24.9	24.5	24.6	25.1	26.0	27.2	28.9	30.9	33.3	36.2	39.4	43.1	47.2
	0.60	51.9	30.6	31.3	32.6	31.6	29.4	27.3	25.8	24.9	24.6	24.8	25.4	26.4	27.8	29.6	31.9	34.5	37.7	41.3	45.4	49.9
	0.65	51.9	30.6	32.1	33.3	31.9	29.5	27.3	25.8	25.0	24.8	25.0	25.7	26.9	28.4	30.4	32.9	35.9	39.3	43.3	47.8	52.7
	0.70	51.9	30.6	32.9	34.0	32.2	29.5	27.2	25.7	25.0	24.9	25.3	26.1	27.4	29.1	31.3	34.0	37.3	41.1	45.5	50.4	55.8
	0.75	51.9	30.7	33.6	34.6	32.3	29.4	27.1	25.7	25.1	25.1	25.5	26.5	27.9	29.8	32.2	35.2	38.8	43.0	47.8	53.2	59.2
	0.80	51.9	30.9	34.4	35.0	32.4	29.3	27.0	25.7	25.2	25.3	25.8	26.9	28.4	30.5	33.2	36.5	40.4	45.1	50.4	56.3	62.7
	0.85	51.9	31.1	35.2	35.4	32.4	29.1	26.9	25.7	25.3	25.5	26.1	27.3	29.0	31.3	34.2	37.9	42.2	47.3	53.1	59.6	66.6
	0.90	51.9	31.4	35.9	35.8	32.3	29.0	26.8	25.8	25.4	25.6	26.4	27.7	29.6	32.1	35.4	39.3	44.1	49.6	56.0	63.1	70.6
	0.95	51.9	31.7	36.6	36.0	32.2	28.8	26.8	25.8	25.6	25.9	26.7	28.1	30.2	33.0	36.6	40.9	46.1	52.2	59.2	66.9	75.0
	1.00	51.9	32.0	37.2	36.2	32.1	28.7	26.8	25.9	25.7	**26.1**	27.0	28.6	30.9	34.0	37.9	42.6	48.3	55.0	62.6	70.9	79.5

Calculation of the Forecast on Row 11 and 12

Once the optimum values of alpha and beta are established, they can be used to forecast the level and trend. Row 10 is the final year of actual values. The trend component established in row 10 will be used in the forecast years for 2014 seed and 2015 forecast (rows 11 and 12).

Using the data in row 10, the seed year forecast in row 11 for 2014 is developed using the ETS equations as follows:

$$Equation\ 1: L_t = 0.50 \times 96.01 + (1 - 0.50)(97.56 - 1.10) = 96.24$$

$$Equation\ 2: b_t = 0.0(96.24 - 97.56) + (1 - 0.0)(-1.10) = -1.10$$

$$Equation\ 3: F_{t+1} = 96.24 - 1.10 \times 1 = 95.14$$

The resulting value of 95.14 GJs is the 2014 seed year forecast value, shown on row 11, column 6 of the table above.

In row 12, “m” becomes 2 because we need to forecast two periods forward. L_t and b_t remain unchanged. For all subsequent forecast periods, the level is assumed to remain constant while the trend component changes linearly.

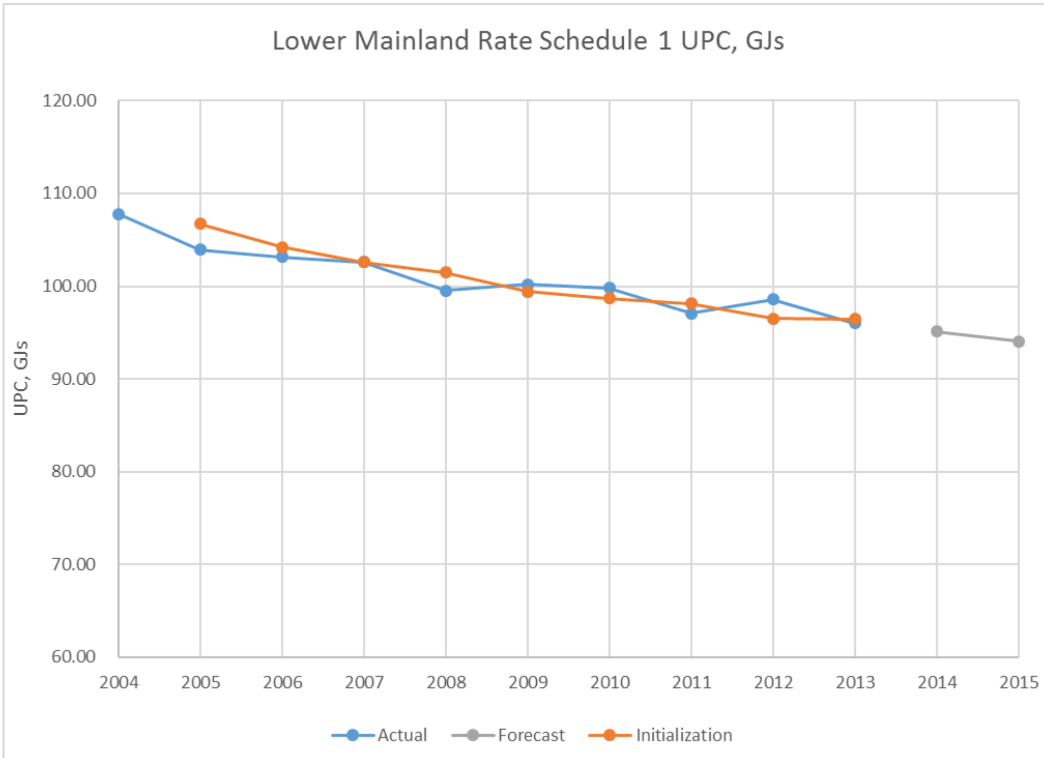
The forecast at any time (t+m) is calculated using equation 3 above. Thus, the forecast in row 12 for 2015 is calculated as follows:

$$Equation\ 3: F_{t+1} = 96.24 - 1.10 \times 2 = 94.04$$

The resulting 94.04 GJs is the forecast value shown for 2015 on row 12, column 6.

Summary Plot

A plot of the actuals and forecast values demonstrates the reasonableness of the forecast:



The above plot also shows the initialization data (orange) developed with the optimized values of alpha and beta. If less optimal values are chosen, the orange line will deviate further from the actual line and result in a less accurate forecast.

Calculations for commercial use rates and customer additions are identical not reproduced here.

On page 30 of Appendix A4, FEI states:

> Of the six alternative forecasting methods tested and compared, ETS is the best performing alternate method and the only alternate method that consistently produced test results in the same range of accuracy as FEI's Existing Method… At this time, FEI is recommending that it continue to use the Existing Method and that further testing be completed on the ETS method over the remaining term of the PBR.

21.5 Please list and explain the high-level evaluation criteria that FEI intends to use to choose its recommended forecasting method for residential and commercial UPC and commercial customer additions.

Response:

FEI intends to evaluate forecast performance using the mean absolute percent error (MAPE), as used in Appendix A4, Tables A4-20, A4-22, A4-24 and A4-26.

Given that the current method already performs well (approximately twice as well as the results from the survey sample group (page 11, Appendix A4)), any improvement using the ETS method will need to be demonstrated over the remaining term of the PBR.

Test data for Vancouver Island and Whistler will be very limited, so results from these two regions will need to be examined carefully prior to incorporation with the remainder of the FEI data.

Consistent with past practice and for efficiency, FEI will use the same methods in all regions and sub-regions and within rate groups. For example the UPC method chosen for Lower Mainland Rate Schedule 1 will also be used to forecast the UPC for Columbia Rate Schedule 1 and Vancouver Island Rate Schedule 1.

21.6 Please explain if FEI has any concerns with changing the residential and commercial UPC forecasting method or the commercial customer additions forecasting methodology during the PBR period.

Response:

FEI does not recommend implementing an alternate method until additional data is available. For a discussion of the concerns and reasons, please see section 7 of Appendix A4.

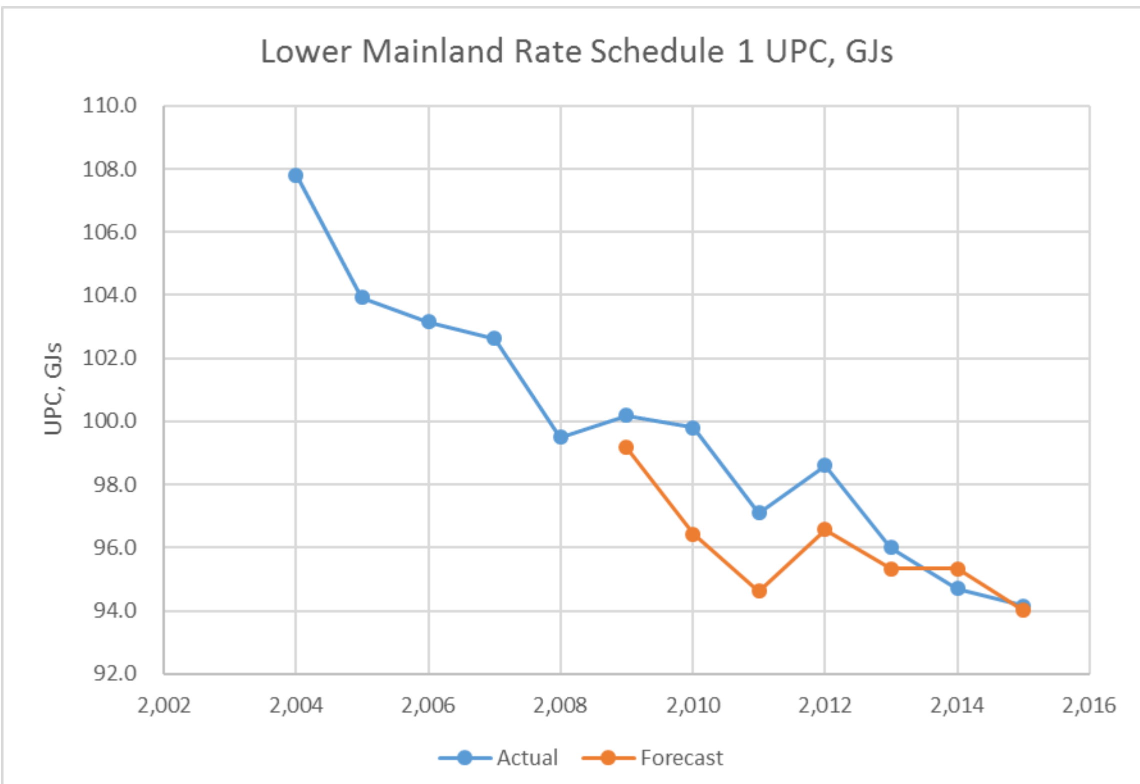
21.7 Please discuss the feasibility of applying Holt's Exponential Smoothing method to historical data to prepare ex-post forecasts for residential and commercial UPC and commercial customer additions for 2009, 2010 and 2011.

Response:

Preparing ex post forecasts for 2009, 2010 and 2011 is not feasible due to insufficient historical electronic data.

For example, the forecast for 2009 is based on a seed year forecast for 2008 and therefore actual data up to and including 2007. The detailed electronic data record necessary for this modeling starts in 2004, which means only four years of data would be available for the initialization set. The initialization set of data is important because it is used to establish the alpha and beta parameters used in the model. If the initialization set is not long enough, then the resulting alpha and beta parameters can lead to erroneous forecasts.

An example of this effect can be seen from examining the Lower Mainland Rate Schedule 1 UPC forecast. A plot of the actual and forecast demand is as follows:



The convergence of the forecast and actual plots in the above chart demonstrates the improvement in the model as more historical data is used. As more years of actual data are used, the Holt's Linear model is able to develop better estimates for the alpha and beta model parameters and therefore produce a better forecast.

Preparing ex post forecasts for 2009, 2010 and 2011 and combining the results with those in Appendix A4 may lead to inaccurate conclusions about the performance of the Holt's Linear model. In the future, at least 12 years of historic data will be available for Mainland to initialize the model, so this will not be an issue for future forecast tests.

Models for different data sets (i.e. regions and rate classes) can be expected to stabilize at different points. Some will require more data points (years) and some will require less. Using a smaller data set for model initialization in regions such as Vancouver Island and Whistler, while not desirable, will be unavoidable in proposed future testing. Vancouver Island and Whistler account for less than 10% of the overall demand, so results from these two regions will have a smaller impact on the overall model decision.

21.7.1 If feasible, please produce ex-post forecasts for residential and commercial UPC and commercial customer additions for 2009, 2010 and 2011.

Response:

Please refer to the response to BCUC IR 1.21.7.

21.7.1.1 Please compare the ex-post forecasts provided in response to the previous question with FEI's historical actual data using: (i) percent error; (ii) absolute percent error; and (iii) mean absolute percent error. Please discuss the results.

Response:

Please refer to the response to BCUC IR 1.21.7.

On page 19 of Appendix A4, FEI states the following:

> The demand forecast for all residential and commercial rate schedules is the product of a customer forecast and a use rate forecast. FIS forecasts were created to test each component (residential use rates, commercial use rates, commercial customer additions) independently. Only one component was changed for each run so that the impact of a single change could be measured.

21.8 For residential use rate tests, please discuss whether errors in the customer forecast could cancel or intensify errors in the use rate forecast to produce a more favourable or less favourable demand forecast, respectively. Please include examples with calculations to support this discussion.

Response:

As discussed in Appendix A3, the calculation of the residential demand forecast is the simple product of the use rate and forecast number of customers. Regardless of the method used to forecast the use rate or customers, an error in one is independent of the other and can result in either larger or smaller demand errors.

The mathematics are simple as shown in the table below (note sample numbers shown for discussion only):

	Use Rate (GJs)	Customers	Demand (GJs)	APE
Actual	100	100	10,000	
UPC over forecast	110	100	11,000	10%
Customer under forecast	100	90	9,000	10%
UPC over forecast and Customer over forecast	110	110	12,100	21%
UPC under forecast and Customer under forecast	90	90	8,100	19%
UPC over forecast and Customer under forecast	110	90	9,900	1%
UPC under forecast and Customer over forecast	90	110	9,900	1%

In the case where one component is over or under forecast, the error is less than when both components are over or under forecast. When one component is over forecast and one component is under forecast, the results can be offsetting.

In both the existing and alternate methods the component forecasts are independent of one another. While it can be advantageous in terms of the calculation of the APE to have an over forecast situation offset by an under forecast, this is something that is beyond the control of FEI or any forecast method to influence.

In Appendix A4, Tables A4-20, A4-22, A4-24 and A4-26 present the results of alternate forecasting methods by observing Forecast Demand (column 5) and Actual Demand (column 6).

21.9 Please provide an updated version of each of the four tables referenced in the above preamble to replace Forecast Demand (column 5) and Actual Demand (column 6) with:

1. Forecast Residential UPC (column 5) and Actual Residential UPC (column 6) for Table A4 20;
2. Forecast Commercial UPC (column 5) and Actual Commercial UPC (column 6) for Table A4-22;
3. Forecast Commercial Customer Additions (column 5) and Actual Commercial Customer Additions (column 6) for Table A4-24; and
4. Forecast Commercial Customers (column 5) and Actual Commercial Customers (column 6) for Table A4-26.

Response:

This response is divided into four sections to match the four parts of the question.

1. Residential UPC

The analysis in appendix A4 was developed using data and forecasts for three regions (Lower Mainland, Inland and Columbia). However, unlike demand and customers, use rates cannot be summed across regions. For this reason, the UPC forecasts for Rate Schedule 1 must be presented in three tables (one each for Lower Mainland, Inland and Columbia). The three tables are shown below, followed by an analysis of the results.

Lower Mainland Rate Schedule 1 UPC

1	2	3	4	5	6	7	8
Year	**UPC Method**	**Customers Method**	**Demand Forecast Method UPC X Customers**	**Forecast UPC, GJ**	**Actual UPC (GJs)**	**APE**	**4 Yr. MAPE**
2012	Traditional	Traditional	Traditional X Traditional	98.1	98.6	0.5%	
2013	Traditional	Traditional	Traditional X Traditional	97.2	96.0	1.3%	
2014	Traditional	Traditional	Traditional X Traditional	97.0	94.7	2.5%	
2015	Traditional	Traditional	Traditional X Traditional	94.6	94.2	0.5%	1.2%
2012	ETS	Traditional	ETS X Traditional	96.6	98.6	2.0%	
2013	ETS	Traditional	ETS X Traditional	95.3	96.0	0.7%	
2014	ETS	Traditional	ETS X Traditional	95.3	94.7	0.6%	
2015	ETS	Traditional	ETS X Traditional	94.0	94.2	0.2%	0.9%
2012	TSLR	Traditional	TSLR X Traditional	96.2	98.6	2.4%	
2013	TSLR	Traditional	TSLR X Traditional	94.9	96.0	1.2%	
2014	TSLR	Traditional	TSLR X Traditional	94.8	94.7	0.1%	
2015	TSLR	Traditional	TSLR X Traditional	93.7	94.2	0.5%	1.0%
2012	Naïve	Traditional	Naïve X Traditional	99.8	98.6	1.2%	
2013	Naïve	Traditional	Naïve X Traditional	99.8	96.0	4.0%	
2014	Naïve	Traditional	Naïve X Traditional	98.6	94.7	4.1%	
2015	Naïve	Traditional	Naïve X Traditional	96.0	94.2	2.0%	2.8%
2012	Smooth/Trend	Traditional	Smooth/Trend X Traditional	96.3	98.6	2.3%	
2013	Smooth/Trend	Traditional	Smooth/Trend X Traditional	95.2	96.0	0.8%	
2014	Smooth/Trend	Traditional	Smooth/Trend X Traditional	95.0	94.7	0.3%	
2015	Smooth/Trend	Traditional	Smooth/Trend X Traditional	94.2	94.2	0.1%	0.9%
2012	Retail Sales	Traditional	Retail Sales X Traditional	97.9	98.6	0.7%	
2013	Retail Sales	Traditional	Retail Sales X Traditional	97.0	96.0	1.0%	
2014	Retail Sales	Traditional	Retail Sales X Traditional	94.5	94.7	0.2%	
2015	Retail Sales	Traditional	Retail Sales X Traditional	91.3	94.2	3.0%	1.2%

1

Inland Rate Schedule 1 UPC							
1	2	3	4	5	6	7	8
Year	UPC Method	Customers Method	Demand Forecast Method UPC X Customers	Forecast UPC, GJ	Actual UPC (GJs)	APE	4 Yr. MAPE
2012	Traditional	Traditional	Traditional X Traditional	73.8	77.0	4.2%	
2013	Traditional	Traditional	Traditional X Traditional	72.9	73.6	1.0%	
2014	Traditional	Traditional	Traditional X Traditional	76.2	75.1	1.4%	
2015	Traditional	Traditional	Traditional X Traditional	72.9	76.1	4.2%	2.7%
2012	ETS	Traditional	ETS X Traditional	70.5	77.0	8.4%	
2013	ETS	Traditional	ETS X Traditional	68.0	73.6	7.6%	
2014	ETS	Traditional	ETS X Traditional	77.8	75.1	3.6%	
2015	ETS	Traditional	ETS X Traditional	70.4	76.1	7.4%	6.8%
2012	TSLR	Traditional	TSLR X Traditional	68.5	77.0	11.0%	
2013	TSLR	Traditional	TSLR X Traditional	66.0	73.6	10.3%	
2014	TSLR	Traditional	TSLR X Traditional	69.4	75.1	7.6%	
2015	TSLR	Traditional	TSLR X Traditional	68.7	76.1	9.7%	9.7%
2012	Naïve	Traditional	Naïve X Traditional	75.7	77.0	1.7%	
2013	Naïve	Traditional	Naïve X Traditional	75.7	73.6	2.9%	
2014	Naïve	Traditional	Naïve X Traditional	77.0	75.1	2.5%	
2015	Naïve	Traditional	Naïve X Traditional	73.6	76.1	3.2%	2.6%
2012	Smooth/Trend	Traditional	Smooth/Trend X Traditional	70.3	77.0	8.7%	
2013	Smooth/Trend	Traditional	Smooth/Trend X Traditional	68.2	73.6	7.3%	
2014	Smooth/Trend	Traditional	Smooth/Trend X Traditional	70.5	75.1	6.2%	
2015	Smooth/Trend	Traditional	Smooth/Trend X Traditional	70.7	76.1	7.1%	7.3%
2012	Retail Sales	Traditional	Retail Sales X Traditional	71.8	77.0	6.8%	
2013	Retail Sales	Traditional	Retail Sales X Traditional	70.0	73.6	4.8%	
2014	Retail Sales	Traditional	Retail Sales X Traditional	68.3	75.1	9.1%	
2015	Retail Sales	Traditional	Retail Sales X Traditional	64.4	76.1	15.3%	9.0%

1

Columbia Rate Schedule 1 UPC							
1	2	3	4	5	6	7	8
Year	UPC Method	Customers Method	Demand Forecast Method UPC X Customers	Forecast UPC, GJ	Actual UPC (GJs)	APE	4 Yr. MAPE
2012	Traditional	Traditional	Traditional X Traditional	79.9	83.0	3.7%	
2013	Traditional	Traditional	Traditional X Traditional	78.9	79.9	1.2%	
2014	Traditional	Traditional	Traditional X Traditional	81.1	80.5	0.7%	
2015	Traditional	Traditional	Traditional X Traditional	79.3	80.9	2.0%	1.9%
2012	ETS	Traditional	ETS X Traditional	76.1	83.0	8.3%	
2013	ETS	Traditional	ETS X Traditional	73.3	79.9	8.2%	
2014	ETS	Traditional	ETS X Traditional	78.4	80.5	2.6%	
2015	ETS	Traditional	ETS X Traditional	76.3	80.9	5.7%	6.2%
2012	TSLR	Traditional	TSLR X Traditional	73.9	83.0	11.0%	
2013	TSLR	Traditional	TSLR X Traditional	71.0	79.9	11.1%	
2014	TSLR	Traditional	TSLR X Traditional	74.3	80.5	7.7%	
2015	TSLR	Traditional	TSLR X Traditional	73.9	80.9	8.7%	9.6%
2012	Naïve	Traditional	Naïve X Traditional	81.9	83.0	1.3%	
2013	Naïve	Traditional	Naïve X Traditional	81.9	79.9	2.5%	
2014	Naïve	Traditional	Naïve X Traditional	83.0	80.5	3.1%	
2015	Naïve	Traditional	Naïve X Traditional	79.9	80.9	1.2%	2.1%
2012	Smooth/Trend	Traditional	Smooth/Trend X Traditional	76.3	83.0	8.1%	
2013	Smooth/Trend	Traditional	Smooth/Trend X Traditional	74.1	79.9	7.2%	
2014	Smooth/Trend	Traditional	Smooth/Trend X Traditional	76.1	80.5	5.5%	
2015	Smooth/Trend	Traditional	Smooth/Trend X Traditional	76.2	80.9	5.8%	6.6%
2012	Retail Sales	Traditional	Retail Sales X Traditional	77.4	83.0	6.7%	
2013	Retail Sales	Traditional	Retail Sales X Traditional	75.2	79.9	5.8%	
2014	Retail Sales	Traditional	Retail Sales X Traditional	73.0	80.5	9.3%	
2015	Retail Sales	Traditional	Retail Sales X Traditional	68.8	80.9	15.0%	9.2%

Use Rate Method	Comments
Traditional	The traditional method performed well in all three regions. While all methods other than Naïve performed similarly in the Lower Mainland, the traditional method did significantly better in Inland and Columbia (where the Naïve method did better).
ETS	The ETS method was the best performer in the Lower Mainland, tied with the Smooth/Trend method. The ETS method is expected to perform better as more historic data becomes available. There is some evidence of this in Lower Mainland where the 2015 error was only 0.2%. Further testing will be required to see if this trend continues. In the Inland and Columbia regions the ETS method outperformed all methods other than the traditional method and the naïve method.
TSLR	The time series linear regression method performed well in the Lower Mainland and was only 0.1% off the scores from the ETS and Smooth/Trend method. However performance slipped in the Inland and Columbia regions where the four year MAPE scores both exceeded 9%.

Use Rate Method	Comments
Naïve	The Naïve method performed consistently in all regions. In the Lower Mainland, the 2.8% MAPE score was the worst of the alternate methods. However, similar error levels in the Inland and Columbia regions made this method competitive with the Traditional method. The poor performance in the Lower Mainland is significant and confirmed in the demand testing in Appendix A4.
Smooth/Trend	The Smooth/Trend method performed very well in the Lower Mainland, tying for the best performance with the ETS method. However the results were not sustained in Inland and Columbia where percent error scores exceeded 6% in Columbia and 7% in Inland.
Retail Sales	While the regression with Retail Sales performed well in the Lower Mainland region, it struggled in Inland and Columbia where the four year average percent error exceeded 9%. The retail sales data and forecast is developed provincially and as a result may be more applicable to the Lower Mainland than either the Interior or Columbia regions.
Summary	Each method performed well in certain situations, but overall the Traditional and ETS methods appear to be the most consistent performers. This result is confirmed by the demand-based test completed in Appendix A4.

2. Commercial UPC

The use rates vary widely between the three commercial rate schedules (Rate Schedules 2, 3 and 23) and as a result they cannot be combined into a single number. FEI does not forecast or publish a single commercial UPC. In addition the testing of alternate methods for the commercial rate schedules was completed separately for the Lower Mainland, Inland and Columbia regions. As a result presenting the individual commercial UPC forecasts developed for Appendix A4 requires nine separate tables. An analysis of the results follows the tables.

1

Lower Mainland Rate Schedule 2 UPC							
1	2	3	4	5	6	7	8
Year	UPC Method	Customers Method	Demand Forecast Method UPC X Customers	Forecast UPC, GJ	Actual UPC (GJs)	APE	4 Yr. MAPE
2012	Traditional	Traditional	Traditional X Traditional	323.1	355.8	9.2%	
2013	Traditional	Traditional	Traditional X Traditional	322.2	348.8	7.6%	
2014	Traditional	Traditional	Traditional X Traditional	351.6	347.1	1.3%	
2015	Traditional	Traditional	Traditional X Traditional	349.0	345.1	1.1%	4.8%
2012	ETS	Traditional	ETS X Traditional	339.5	355.8	4.6%	
2013	ETS	Traditional	ETS X Traditional	343.1	348.8	1.6%	
2014	ETS	Traditional	ETS X Traditional	350.2	347.1	0.9%	
2015	ETS	Traditional	ETS X Traditional	354.9	345.1	2.8%	2.5%
2012	TSLR	Traditional	TSLR X Traditional	340.4	355.8	4.3%	
2013	TSLR	Traditional	TSLR X Traditional	344.0	348.8	1.4%	
2014	TSLR	Traditional	TSLR X Traditional	352.3	347.1	1.5%	
2015	TSLR	Traditional	TSLR X Traditional	356.9	345.1	3.4%	2.7%
2012	Naïve	Traditional	Naïve X Traditional	324.7	355.8	8.7%	
2013	Naïve	Traditional	Naïve X Traditional	324.7	348.8	6.9%	
2014	Naïve	Traditional	Naïve X Traditional	355.8	347.1	2.5%	
2015	Naïve	Traditional	Naïve X Traditional	348.8	345.1	1.1%	4.8%
2012	Smooth/Trend	Traditional	Smooth/Trend X Traditional	338.2	355.8	4.9%	
2013	Smooth/Trend	Traditional	Smooth/Trend X Traditional	341.2	348.8	2.2%	
2014	Smooth/Trend	Traditional	Smooth/Trend X Traditional	348.4	347.1	0.4%	
2015	Smooth/Trend	Traditional	Smooth/Trend X Traditional	354.8	345.1	2.8%	2.6%

2

Lower Mainland Rate Schedule 3 UPC							
1	2	3	4	5	6	7	8
Year	UPC Method	Customers Method	Demand Forecast Method UPC X Customers	Forecast UPC, GJ	Actual UPC (GJs)	APE	4 Yr. MAPE
2012	Traditional	Traditional	Traditional X Traditional	3,295	3,522	6.4%	
2013	Traditional	Traditional	Traditional X Traditional	3,274	3,485	6.1%	
2014	Traditional	Traditional	Traditional X Traditional	3,715	3,481	6.7%	
2015	Traditional	Traditional	Traditional X Traditional	3,569	3,431	4.0%	5.8%
2012	ETS	Traditional	ETS X Traditional	3,363	3,522	4.5%	
2013	ETS	Traditional	ETS X Traditional	3,366	3,485	3.4%	
2014	ETS	Traditional	ETS X Traditional	3,530	3,481	1.4%	
2015	ETS	Traditional	ETS X Traditional	3,538	3,431	3.1%	3.1%
2012	TSLR	Traditional	TSLR X Traditional	3,366	3,522	4.4%	
2013	TSLR	Traditional	TSLR X Traditional	3,369	3,485	3.3%	
2014	TSLR	Traditional	TSLR X Traditional	3,504	3,481	0.6%	
2015	TSLR	Traditional	TSLR X Traditional	3,525	3,431	2.7%	2.8%
2012	Naïve	Traditional	Naïve X Traditional	3,338	3,522	5.2%	
2013	Naïve	Traditional	Naïve X Traditional	3,338	3,485	4.2%	
2014	Naïve	Traditional	Naïve X Traditional	3,522	3,481	1.2%	
2015	Naïve	Traditional	Naïve X Traditional	3,485	3,431	1.6%	3.0%
2012	Smooth/Trend	Traditional	Smooth/Trend X Traditional	3,436	3,522	2.5%	
2013	Smooth/Trend	Traditional	Smooth/Trend X Traditional	3,454	3,485	0.9%	
2014	Smooth/Trend	Traditional	Smooth/Trend X Traditional	3,523	3,481	1.2%	
2015	Smooth/Trend	Traditional	Smooth/Trend X Traditional	3,548	3,431	3.4%	2.0%

1

Lower Mainland Rate Schedule 23 UPC

1	2	3	4	5	6	7	8
Year	UPC Method	Customers Method	Demand Forecast Method UPC X Customers	Forecast UPC, GJ	Actual UPC (GJs)	APE	4 Yr. MAPE
2012	Traditional	Traditional	Traditional X Traditional	4,828	5,110	5.5%	
2013	Traditional	Traditional	Traditional X Traditional	4,858	5,082	4.4%	
2014	Traditional	Traditional	Traditional X Traditional	5,358	5,104	5.0%	
2015	Traditional	Traditional	Traditional X Traditional	5,241	5,022	4.4%	4.8%
2012	ETS	Traditional	ETS X Traditional	4,790	5,110	6.3%	
2013	ETS	Traditional	ETS X Traditional	4,800	5,082	5.6%	
2014	ETS	Traditional	ETS X Traditional	5,197	5,104	1.8%	
2015	ETS	Traditional	ETS X Traditional	5,190	5,022	3.3%	4.2%
2012	TSLR	Traditional	TSLR X Traditional	4,755	5,110	7.0%	
2013	TSLR	Traditional	TSLR X Traditional	4,764	5,082	6.2%	
2014	TSLR	Traditional	TSLR X Traditional	5,067	5,104	0.7%	
2015	TSLR	Traditional	TSLR X Traditional	5,142	5,022	2.4%	4.1%
2012	Naïve	Traditional	Naïve X Traditional	4,769	5,110	6.7%	
2013	Naïve	Traditional	Naïve X Traditional	4,769	5,082	6.2%	
2014	Naïve	Traditional	Naïve X Traditional	5,110	5,104	0.1%	
2015	Naïve	Traditional	Naïve X Traditional	5,082	5,022	1.2%	3.5%
2012	Smooth/Trend	Traditional	Smooth/Trend X Traditional	4,871	5,110	4.7%	
2013	Smooth/Trend	Traditional	Smooth/Trend X Traditional	4,907	5,082	3.4%	
2014	Smooth/Trend	Traditional	Smooth/Trend X Traditional	5,115	5,104	0.2%	
2015	Smooth/Trend	Traditional	Smooth/Trend X Traditional	5,196	5,022	3.5%	3.0%

2

Inland Rate Schedule 2 UPC

1	2	3	4	5	6	7	8
Year	UPC Method	Customers Method	Demand Forecast Method UPC X Customers	Forecast UPC, GJ	Actual UPC (GJs)	APE	4 Yr. MAPE
2012	Traditional	Traditional	Traditional X Traditional	269.5	293.9	8.3%	
2013	Traditional	Traditional	Traditional X Traditional	266.4	283.7	6.1%	
2014	Traditional	Traditional	Traditional X Traditional	291.9	290.5	0.5%	
2015	Traditional	Traditional	Traditional X Traditional	281.8	293.0	3.8%	4.7%
2012	ETS	Traditional	ETS X Traditional	271.4	293.9	7.7%	
2013	ETS	Traditional	ETS X Traditional	269.0	283.7	5.2%	
2014	ETS	Traditional	ETS X Traditional	279.0	290.5	3.9%	
2015	ETS	Traditional	ETS X Traditional	280.4	293.0	4.3%	5.3%
2012	TSLR	Traditional	TSLR X Traditional	270.5	293.9	8.0%	
2013	TSLR	Traditional	TSLR X Traditional	268.1	283.7	5.5%	
2014	TSLR	Traditional	TSLR X Traditional	277.7	290.5	4.4%	
2015	TSLR	Traditional	TSLR X Traditional	279.2	293.0	4.7%	5.6%
2012	Naïve	Traditional	Naïve X Traditional	275.8	293.9	6.2%	
2013	Naïve	Traditional	Naïve X Traditional	275.8	283.7	2.8%	
2014	Naïve	Traditional	Naïve X Traditional	293.9	290.5	1.2%	
2015	Naïve	Traditional	Naïve X Traditional	283.7	293.0	3.2%	3.3%
2012	Smooth/Trend	Traditional	Smooth/Trend X Traditional	271.0	293.9	7.8%	
2013	Smooth/Trend	Traditional	Smooth/Trend X Traditional	268.7	283.7	5.3%	
2014	Smooth/Trend	Traditional	Smooth/Trend X Traditional	277.2	290.5	4.6%	
2015	Smooth/Trend	Traditional	Smooth/Trend X Traditional	282.2	293.0	3.7%	5.3%

Inland Rate Schedule 3 UPC

1	2	3	4	5	6	7	8
Year	**UPC Method**	**Customers Method**	**Demand Forecast Method UPC X Customers**	**Forecast UPC, GJ**	**Actual UPC (GJs)**	**APE**	**4 Yr. MAPE**
2012	Traditional	Traditional	Traditional X Traditional	3,492	3,774	7.5%	
2013	Traditional	Traditional	Traditional X Traditional	3,491	3,664	4.7%	
2014	Traditional	Traditional	Traditional X Traditional	4,068	3,780	7.6%	
2015	Traditional	Traditional	Traditional X Traditional	3,754	4,052	7.4%	6.8%
2012	ETS	Traditional	ETS X Traditional	3,409	3,774	9.7%	
2013	ETS	Traditional	ETS X Traditional	3,387	3,664	7.5%	
2014	ETS	Traditional	ETS X Traditional	3,633	3,780	3.9%	
2015	ETS	Traditional	ETS X Traditional	3,675	4,052	9.3%	7.6%
2012	TSLR	Traditional	TSLR X Traditional	3,390	3,774	10.2%	
2013	TSLR	Traditional	TSLR X Traditional	3,369	3,664	8.0%	
2014	TSLR	Traditional	TSLR X Traditional	3,557	3,780	5.9%	
2015	TSLR	Traditional	TSLR X Traditional	3,614	4,052	10.8%	8.7%
2012	Naïve	Traditional	Naïve X Traditional	3,495	3,774	7.4%	
2013	Naïve	Traditional	Naïve X Traditional	3,495	3,664	4.6%	
2014	Naïve	Traditional	Naïve X Traditional	3,774	3,780	0.1%	
2015	Naïve	Traditional	Naïve X Traditional	3,664	4,052	9.6%	5.4%
2012	Smooth/Trend	Traditional	Smooth/Trend X Traditional	3,400	3,774	9.9%	
2013	Smooth/Trend	Traditional	Smooth/Trend X Traditional	3,383	3,664	7.7%	
2014	Smooth/Trend	Traditional	Smooth/Trend X Traditional	3,566	3,780	5.7%	
2015	Smooth/Trend	Traditional	Smooth/Trend X Traditional	3,670	4,052	9.4%	8.2%

Inland Rate Schedule 23 UPC

1	2	3	4	5	6	7	8
Year	UPC Method	Customers Method	Demand Forecast Method UPC X Customers	Forecast UPC, GJ	Actual UPC (GJs)	APE	4 Yr. MAPE
2012	Traditional	Traditional	Traditional X Traditional	5,256	5,949	11.6%	
2013	Traditional	Traditional	Traditional X Traditional	5,257	5,529	4.9%	
2014	Traditional	Traditional	Traditional X Traditional	6,490	6,048	7.3%	
2015	Traditional	Traditional	Traditional X Traditional	5,746	5,867	2.1%	6.5%
2012	ETS	Traditional	ETS X Traditional	5,305	5,949	10.8%	
2013	ETS	Traditional	ETS X Traditional	5,527	5,529	0.0%	
2014	ETS	Traditional	ETS X Traditional	5,047	6,048	16.6%	
2015	ETS	Traditional	ETS X Traditional	4,861	5,867	17.1%	11.1%
2012	TSLR	Traditional	TSLR X Traditional	5,419	5,949	8.9%	
2013	TSLR	Traditional	TSLR X Traditional	5,641	5,529	2.0%	
2014	TSLR	Traditional	TSLR X Traditional	5,496	6,048	9.1%	
2015	TSLR	Traditional	TSLR X Traditional	5,327	5,867	9.2%	7.3%
2012	Naïve	Traditional	Naïve X Traditional	4,875	5,949	18.0%	
2013	Naïve	Traditional	Naïve X Traditional	4,875	5,529	11.8%	
2014	Naïve	Traditional	Naïve X Traditional	4,615	6,048	23.7%	
2015	Naïve	Traditional	Naïve X Traditional	4,569	5,867	22.1%	18.9%
2012	Smooth/Trend	Traditional	Smooth/Trend X Traditional	5,245	5,949	11.8%	
2013	Smooth/Trend	Traditional	Smooth/Trend X Traditional	5,235	5,529	5.3%	
2014	Smooth/Trend	Traditional	Smooth/Trend X Traditional	5,696	6,048	5.8%	
2015	Smooth/Trend	Traditional	Smooth/Trend X Traditional	5,855	5,867	0.2%	5.8%

Columbia Rate Schedule 2 UPC

1	2	3	4	5	6	7	8
Year	UPC Method	Customers Method	Demand Forecast Method UPC X Customers	Forecast UPC, GJ	Actual UPC (GJs)	APE	4 Yr. MAPE
2012	Traditional	Traditional	Traditional X Traditional	302.5	324.6	6.8%	
2013	Traditional	Traditional	Traditional X Traditional	295.7	317.5	6.8%	
2014	Traditional	Traditional	Traditional X Traditional	309.2	318.8	3.0%	
2015	Traditional	Traditional	Traditional X Traditional	304.4	314.8	3.3%	5.0%
2012	ETS	Traditional	ETS X Traditional	310.7	324.6	4.3%	
2013	ETS	Traditional	ETS X Traditional	306.0	317.5	3.6%	
2014	ETS	Traditional	ETS X Traditional	312.3	318.8	2.0%	
2015	ETS	Traditional	ETS X Traditional	310.4	314.8	1.4%	2.8%
2012	TSLR	Traditional	TSLR X Traditional	309.5	324.6	4.7%	
2013	TSLR	Traditional	TSLR X Traditional	304.9	317.5	4.0%	
2014	TSLR	Traditional	TSLR X Traditional	309.7	318.8	2.8%	
2015	TSLR	Traditional	TSLR X Traditional	308.2	314.8	2.1%	3.4%
2012	Naïve	Traditional	Naïve X Traditional	316.6	324.6	2.5%	
2013	Naïve	Traditional	Naïve X Traditional	316.6	317.5	0.3%	
2014	Naïve	Traditional	Naïve X Traditional	324.6	318.8	1.8%	
2015	Naïve	Traditional	Naïve X Traditional	317.5	314.8	0.9%	1.4%
2012	Smooth/Trend	Traditional	Smooth/Trend X Traditional	314.3	324.6	3.2%	
2013	Smooth/Trend	Traditional	Smooth/Trend X Traditional	310.7	317.5	2.1%	
2014	Smooth/Trend	Traditional	Smooth/Trend X Traditional	311.5	318.8	2.3%	
2015	Smooth/Trend	Traditional	Smooth/Trend X Traditional	311.5	314.8	1.0%	2.2%

Columbia Rate Schedule 3 UPC

1	2	3	4	5	6	7	8
Year	UPC Method	Customers Method	Demand Forecast Method UPC X Customers	Forecast UPC, GJ	Actual UPC (GJs)	APE	4 Yr. MAPE
2012	Traditional	Traditional	Traditional X Traditional	3,552	3,554	0.1%	
2013	Traditional	Traditional	Traditional X Traditional	3,542	3,405	4.0%	
2014	Traditional	Traditional	Traditional X Traditional	3,530	3,473	1.6%	
2015	Traditional	Traditional	Traditional X Traditional	3,218	3,250	1.0%	1.7%
2012	ETS	Traditional	ETS X Traditional	3,564	3,554	0.3%	
2013	ETS	Traditional	ETS X Traditional	3,555	3,405	4.4%	
2014	ETS	Traditional	ETS X Traditional	3,528	3,473	1.6%	
2015	ETS	Traditional	ETS X Traditional	3,371	3,250	3.7%	2.5%
2012	TSLR	Traditional	TSLR X Traditional	3,609	3,554	1.6%	
2013	TSLR	Traditional	TSLR X Traditional	3,600	3,405	5.7%	
2014	TSLR	Traditional	TSLR X Traditional	3,555	3,473	2.4%	
2015	TSLR	Traditional	TSLR X Traditional	3,466	3,250	6.6%	4.1%
2012	Naïve	Traditional	Naïve X Traditional	3,572	3,554	0.5%	
2013	Naïve	Traditional	Naïve X Traditional	3,572	3,405	4.9%	
2014	Naïve	Traditional	Naïve X Traditional	3,554	3,473	2.3%	
2015	Naïve	Traditional	Naïve X Traditional	3,405	3,250	4.7%	3.1%
2012	Smooth/Trend	Traditional	Smooth/Trend X Traditional	3,752	3,554	5.6%	
2013	Smooth/Trend	Traditional	Smooth/Trend X Traditional	3,779	3,405	11.0%	
2014	Smooth/Trend	Traditional	Smooth/Trend X Traditional	3,602	3,473	3.7%	
2015	Smooth/Trend	Traditional	Smooth/Trend X Traditional	3,536	3,250	8.8%	7.3%

Columbia Rate Schedule 23 UPC

1	2	3	4	5	6	7	8
Year	UPC Method	Customers Method	Demand Forecast Method UPC X Customers	Forecast UPC, GJ	Actual UPC (GJs)	APE	4 Yr. MAPE
2012	Traditional	Traditional	Traditional X Traditional	5,054	4,615	9.5%	
2013	Traditional	Traditional	Traditional X Traditional	5,146	4,569	12.6%	
2014	Traditional	Traditional	Traditional X Traditional	5,177	4,773	8.5%	
2015	Traditional	Traditional	Traditional X Traditional	3,946	4,436	11.0%	10.4%
2012	ETS	Traditional	ETS X Traditional	5,305	4,615	14.9%	
2013	ETS	Traditional	ETS X Traditional	5,527	4,569	21.0%	
2014	ETS	Traditional	ETS X Traditional	5,047	4,773	5.7%	
2015	ETS	Traditional	ETS X Traditional	4,861	4,436	9.6%	12.8%
2012	TSLR	Traditional	TSLR X Traditional	5,419	4,615	17.4%	
2013	TSLR	Traditional	TSLR X Traditional	5,641	4,569	23.5%	
2014	TSLR	Traditional	TSLR X Traditional	5,496	4,773	15.2%	
2015	TSLR	Traditional	TSLR X Traditional	5,327	4,436	20.1%	19.0%
2012	Naïve	Traditional	Naïve X Traditional	4,875	4,615	5.6%	
2013	Naïve	Traditional	Naïve X Traditional	4,875	4,569	6.7%	
2014	Naïve	Traditional	Naïve X Traditional	4,615	4,773	3.3%	
2015	Naïve	Traditional	Naïve X Traditional	4,569	4,436	3.0%	4.7%
2012	Smooth/Trend	Traditional	Smooth/Trend X Traditional	5,196	4,615	12.6%	
2013	Smooth/Trend	Traditional	Smooth/Trend X Traditional	5,353	4,569	17.2%	
2014	Smooth/Trend	Traditional	Smooth/Trend X Traditional	5,249	4,773	10.0%	
2015	Smooth/Trend	Traditional	Smooth/Trend X Traditional	5,127	4,436	15.6%	13.8%

Use Rate Method	Comments
Traditional	In terms of demand the Traditional method performed much better than survey the sample group (section 4, Appendix A4). However, as shown in Table A4-22 all the alternate methods tested outperformed the Traditional method in the four years that were tested. The results in Table A4-22 appear to be confirmed when examining the UPC results; however, there were some cases where the performance of the Traditional method was on par with the alternative methods. In the Lower Mainland the traditional method performed as well as the Naïve method for Rate Schedule 2, but recorded the highest error scores in Rate Schedules 3 and 23. In the Inland region the Traditional Method performed well for Rate Schedules 2 and 3 where it recorded the second best results. In Rate Schedule 23 the Traditional method did well where the four year MAPE was 6.5%, only slightly worse than the 5.8% achieved by the Smooth/Trend method. In the Columbia region, the Traditional method did not perform well for Rate Schedule 2. However, the Traditional method did record the best score in Rate Schedule 3 (1.7%) and the second best score in Rate Schedule 23 (10.4%).
ETS	The ETS method performed well in the Lower Mainland. In Rate Schedule 2 the ETS method achieved the best score at 2.5%. In Rate Schedule 3 the results were competitive with the TSLR and Naïve methods, but lagging behind the Smooth/Trend method. In Rate Schedule 23 the results were also behind the Smooth/Trend method and the Naïve method. In the Inland region the ETS method tied for the second best score in Rate Schedule 2. In Rate Schedule 3 the results were better than the Smooth/Trend method and TSLR method but worse than the Traditional method and the Naïve method. In Rate Schedule 23 the ETS method perfectly forecast the 2013 UPC but did not fare as well in other years. The four year MAPE score was just over 11% which was higher than the Traditional and Smooth/Trend methods but significantly better that the Naïve method. In the Columbia region the ETS method performed well in Rate Schedule 2 compared to the Traditional and TSLR methods. In Rate Schedule 3 the ETS method was the best of the alternate methods while in Rate Schedule 23 the performance slipped to third place behind the Naïve and Traditional methods. The results from the region and rate UPC forecasts appear to support the result in Table A4-22. The ETS method appears to be a good candidate for an alternate method. However, the ETS method relies on historical data for model initialization and may improve in the future as more actual data becomes available, supporting the recommendation to continue testing this method.
TSLR	In the Lower Mainland the TSLR method performed well in Rate Schedule 2, just behind the ETS method but significantly better than the Traditional and Naïve methods. In Rate Schedule 3 the TSLR method recorded the second best result. The 4.1% MAPE score recorded in Rate Schedule 23 was more than a percent higher than the Smooth/Trend method, but tied with the ETS method. In the Inland region the TSLR method was the worst performer in Rate Schedules 2 and 3 but achieved a better score of 7.3% in Rate Schedule 23. In the Columbia region the TSLR method MAPE was 3.4% for Rate Schedule 2, which was the highest score for the alternate methods. In Rate Schedule 3 the score was second worst while in Rate Schedule 23 the method achieved the worst scores in the testing with a four year MAPE of 19%. Other than Columbia Rate Schedule 23 the TSLR method seems to be consistently in the middle of the pack, but was rarely able to achieve the best score in any region or rate schedule. This is consistent with the results in the Demand analysis in Table A4-22 where the TSLR method ranked second, just ahead of the Smooth/Trend method.

Use Rate Method	Comments
Naïve	The Naïve method recorded the worst result in Lower Mainland Rate Schedule 2 at almost 5%. This score is almost twice as high as the other alternate methods, but tied with the Traditional method. In Rate Schedule 3 the performance was lower than either of the trending methods and on par with the ETS method. In Rate Schedule 23 the Naïve method performed well recording a score of 3.5% over four years. The historical Rate 23 UPC for the Lower Mainland region is very flat, which favors the Naïve method. In the Inland region, the Naïve method was the top performer in Rate Schedule 2 and 3. However, in Rate Schedule 23 the performance was very poor at almost 19%. Particularly troubling are the scores from 2014 and 2015 (both over 22%) which are both single year forecasts. In the Columbia region the Naïve method performed very well in Rate Schedule 2, recording a result of just 1.4%. In Rate Schedule 3 the Traditional and ETS method both performed better, while in Rate Schedule 23 the Naïve method won by a wide margin. The Naïve method recorded some of the highest and lowest scores in the testing. For example in Inland Rate Schedule 23 the highest scores in the testing (23.7% in 2014) were recorded, while for the same year in the Columbia region the error was only 3.3%. FEI is concerned that this level of inconsistency could result in significant errors in future forecasts. Overall the high error scores from some regions and rate schedules offset the stronger results and FEI believes these are consistent with the Demand tests in Table A4-22 where the Naïve method achieved the lowest performance of all the alternate methods.
Smooth/Trend	The Smooth/Trend method first smooths the data point using a three year average. A trend line is then fitted through the smoothed data points. In general this method should perform well in regions and rate schedules where the TSLR method performed well. In the Lower Mainland the method achieved a strong result in Rate Schedule 2, similar to but slightly better to the TSLR method but not quite as good as the ETS method. In Rate Schedules 3 and 23 the method achieved the top scores. In Rate Schedule 23 the 2014 percent error was very low at 0.2%. In the Inland region the method tied with the ETS method but lagged behind the Naïve method and the Traditional method. In Rate Schedule 3 the method recorded one of the highest scores at 8.2%, including a score of over 9% in 2015. The Naïve, ETS and Traditional methods all fared better. In Rate Schedule 23 the method worked much better, recording a score of just 5.8%. In the Columbia region the Smooth/Trend method worked well, recording a score of 2.2%, just off the low score of 1.4% from the Naïve method. In Rate Schedule 3 the error scores increased again to 7.3%, making it the worst choice by a wide margin. In Rate Schedule 23 the score was high at 13.8% but competitive with all the other alternate methods except the Naïve method. The performance of the Smooth/Trend method appears to be consistent with the Demand testing presented in Table A4-22. In many regions it the method achieved very good results but the overall score was hampered by the scores recorded in regions such at Inland and Columbia Rate Schedule 3.
Summary	It is difficult to draw precise conclusions from examining the use rate forecasts. In Appendix A4 FEI developed a demand forecast by using the historical customer forecast that was filed in each of the test years, along with the UPC forecast from each alternate method. FEI believes that demand is a more useful way to compare forecasts because demand can be summed and compared more effectively. In

Use Rate Method	Comments
	addition, demand forecasts can be compared to the demand forecasts from other utilities to gauge the effectiveness of the various methods compared to the forecasts from other utilities. However, the results from the UPC analysis, while impossible to precisely quantity, do appear to support the findings presented in Table A4-22.

3. Customers Additions

Unlike the use rate forecasts, the results derived from forecasting commercial customer additions for the three commercial rate schedules (Rate Schedules 2, 3 and 23) and the three regions (Lower Mainland, Inland and Columbia) can be summed. The results follow in the table below.

Mainland Commercial Customer Additions

1	2	3	4	5	6	7	8
Year	UPC Method	Customers Additions Method	Demand Forecast Method UPC X Customers	Forecast Customer Additions	Actual Customer Additions	APE	4 Yr. MAPE
2012	Traditional	Traditional	Traditional X Traditional	149	105	41.9%	
2013	Traditional	Traditional	Traditional X Traditional	149	830	82.0%	
2014	Traditional	Traditional	Traditional X Traditional	388	693	44.0%	
2015	Traditional	Traditional	Traditional X Traditional	816	795	2.7%	42.7%
2012	Traditional	ETS	Traditional X ETS	166	105	57.8%	
2013	Traditional	ETS	Traditional X ETS	158	830	81.0%	
2014	Traditional	ETS	Traditional X ETS	72	693	89.6%	
2015	Traditional	ETS	Traditional X ETS	643	795	19.1%	61.9%
2012	Traditional	TSLR	Traditional X TSLR	446	105	324.9%	
2013	Traditional	TSLR	Traditional X TSLR	438	830	47.3%	
2014	Traditional	TSLR	Traditional X TSLR	145	693	79.1%	
2015	Traditional	TSLR	Traditional X TSLR	391	795	50.8%	125.5%
2012	Traditional	Naïve	Traditional X Naïve	35	105	66.7%	
2013	Traditional	Naïve	Traditional X Naïve	35	830	95.8%	
2014	Traditional	Naïve	Traditional X Naïve	105	693	84.8%	
2015	Traditional	Naïve	Traditional X Naïve	830	795	4.4%	62.9%
2012	Traditional	Smooth/Trend	Traditional X Smooth/Trend	150	105	43.0%	
2013	Traditional	Smooth/Trend	Traditional X Smooth/Trend	59	830	93.0%	
2014	Traditional	Smooth/Trend	Traditional X Smooth/Trend	38	693	94.6%	
2015	Traditional	Smooth/Trend	Traditional X Smooth/Trend	174	795	78.2%	77.2%

Customer Additions Method	Comments
Traditional	The traditional method was the top performer, consistent with the results in Table A4-24. The score of 2.7% recorded in 2015 is the lowest in all the tests.
ETS	As with the demand analysis, the ETS method is also the top performing alternate method. The ETS method relies on historical data for model initialization. Further testing will confirm whether or not additional data improves the results.
TSLR	The TSLR method performed well in the demand test but slipped to fifth place here. The very high score recorded in 2012 contributed to the high score. The highest demand score for the TSLR method was also recorded in 2012.
Naïve	The Naïve method performed very well in 2015 and as a result achieved a low overall score. As with UPC the inconsistency of the method is of concern, ranging from annual error scores of 4.4% to over 95%. The Naïve method produced the worst demand forecast as shown in Table A4-24.
Smooth/Trend	The Smooth/Trend method performed well, on par with the results from Table A4-24. While all the methods struggled in 2014, none recorded an error as high as the Smooth/Trend method.
Summary	Errors in commercial customer additions are much higher than demand, customer or UPC errors due to the much smaller values being forecast and the volatility, particularly from smaller regions and rate schedules. Even though the MAPE errors for the customer additions forecasts are higher than the MAPE scores for the customer forecast (shown in section 4, below), Appendix A4 Tables 24 and 26 confirms that forecasting customer additions leads to lower demand errors than does forecasting customers.

4. Customers

The results derived from forecasting customers directly for the three commercial rate schedules (Rate Schedules 2, 3 and 23) and the three regions (Lower Mainland, Inland and Columbia) can be summed. Note that FEI does not currently forecast customers for the commercial rate schedules so there is no traditional method in the table below.

As discussed in Appendix A4, forecasting customers instead of customer additions resulted in higher error scores for the demand forecast. The table is included here for completeness, but FEI does not propose to pursue any of the methods that directly forecast customers.

1

Mainland Commercial Customers							
1	2	3	4	5	6	7	8
Year	UPC Method	Customers Method	Demand Forecast Method UPC X Customers	Forecast Customers	Actual Customers	APE	4 Yr. MAPE
2012	Traditional	ETS	Traditional X ETS	54,838	55,044	0.4%	
2013	Traditional	ETS	Traditional X ETS	54,813	55,874	1.9%	
2014	Traditional	ETS	Traditional X ETS	55,396	56,567	2.1%	
2015	Traditional	ETS	Traditional X ETS	56,909	57,362	0.8%	1.3%
2012	Traditional	TSLR	Traditional X TSLR	56,640	55,044	2.9%	
2013	Traditional	TSLR	Traditional X TSLR	57,304	55,874	2.6%	
2014	Traditional	TSLR	Traditional X TSLR	56,727	56,567	0.3%	
2015	Traditional	TSLR	Traditional X TSLR	57,075	57,362	0.5%	1.6%
2012	Traditional	Naïve	Traditional X Naïve	54,752	55,044	0.5%	
2013	Traditional	Naïve	Traditional X Naïve	54,752	55,874	2.0%	
2014	Traditional	Naïve	Traditional X Naïve	55,044	56,567	2.7%	
2015	Traditional	Naïve	Traditional X Naïve	55,874	57,362	2.6%	2.0%
2012	Traditional	Smooth/Trend	Traditional X Smooth/Trend	56,347	55,044	2.4%	
2013	Traditional	Smooth/Trend	Traditional X Smooth/Trend	56,943	55,874	1.9%	
2014	Traditional	Smooth/Trend	Traditional X Smooth/Trend	56,540	56,567	0.0%	
2015	Traditional	Smooth/Trend	Traditional X Smooth/Trend	56,868	57,362	0.9%	1.3%
2012	Traditional	3 yr avg customers	Traditional X 3 yr avg customers	54,654	55,044	0.7%	
2013	Traditional	3 yr avg customers	Traditional X 3 yr avg customers	54,654	55,874	2.2%	
2014	Traditional	3 yr avg customers	Traditional X 3 yr avg customers	54,912	56,567	2.9%	
2015	Traditional	3 yr avg customers	Traditional X 3 yr avg customers	55,285	57,362	3.6%	2.4%

Customer Additions Method	Comments
ETS	Forecasting customers using the ETS method would result in the lowest four year MAPE (tied with the Smooth/Trend method). The 2012 forecast error would have been 206 customers and was the best year of the four tested. However in 2015 the forecast error would have been 453 customers, compared to actual 2015 additions of 795 customers. As a result the ETS method of forecasting customers did not produce good results when evaluating the demand forecast.
TSLR	The TSLR method performed better in 2014 and 2015 than either of the first two years. This is likely due to having more data points available. However the four year MAPE score of 1.6% results in a third place ranking for this method.
Naïve	The Naïve method resulted in the second worst four year MAPE score of 2.0%. The 2015 error was 2.6% (1,488 customers), making it the second worst 2015 forecast of all the methods tested.
Smooth/Trend	The smooth/trend method resulted in the same performance as the ETS method, tied for the best alternative method in this group. As expected the Smooth/Trend method scored slightly better than the TSLR method due to smoothing the data points before fitting the regression line. The 2014 forecast error was only 27 customers and was the best forecast in this series.

Customer Additions Method	Comments
Three Year Average of Customers	Averaging the most recent three years total commercial customers resulted in the lowest forecast performance in this group with a four year MAPE of 2.4%. The 2015 result was also the worst score in this series at 3.6% (2,077 customers). These results demonstrate that the total commercial customer count, averaged over the prior three years, is not able to produce an accurate forecast.
Summary	In all cases the forecast percent errors from forecasting customers were lower than the percent errors calculated by forecasting customer additions. For example the lowest MAPE score from the forecast of customers was 1.3% (ETS and Trend/Smooth) while the lowest MAPE score from the customer additions forecast was much higher at 42.7% (Traditional method). However, the results strongly favor continuing the practice of forecasting customer additions. For example, after forecasting customers, the 2015 error for the ETS method would have been 453 customers (57,362 – 56,909), while the ETS method for customer additions would have resulted in an error of just 21 customers (795-816). As a result, and as concluded in Appendix A4, FEI will not be pursuing any of the methods that forecast commercial customers directly.

21.9.1 Please provide a discussion for each of the results in a manner similar to Table A4-21.

Response:

Please refer to the response to BCUC IR 1.21.9.

C. OPERATING AND MAINTENANCE EXPENSES

22.0 Reference: FORMULA O&M EXPENSE

Exhibit B-2, Section 6.2.1, pp. 49-50; FEI Application for 2017 and 2018 Revenue Requirements and Rates for the Fort Nelson Service Area, p. 27

Allocation of O&M to the Fort Nelson service area

On page 50 of the Application, FEI states that it has reduced the FEI 2017 Base O&M by $30 thousand related to communication and line heater fuel costs and that these O&M costs have been forecast as part of the Fort Nelson Service Area's revenue requirements starting in 2017.

On page 27 of FEI's Application for 2017 and 2018 Revenue Requirements and Rates for the Fort Nelson Service Area (FEFN 2017-2018 RRA), FEI states: "The increase in the 2017 and 2018 forecast costs reflect the inclusion of $25 thousand of communication costs and line heater fuel costs which are direct FEFN costs, but were previously centralized in FEI and not allocated to FEFN."

22.1 Please explain the variance between the $30 thousand reduction to FEI's Base O&M and the $25 thousand increase to FEFN's O&M in 2017.

<u>Response:</u>

As explained on Pages 49 and 50 of this Application, the $30 thousand reduction to FEI's Base O&M was determined using the 2013 communication and line heater costs of $29 thousand, which was the amount embedded in the PBR Base O&M, adjusted for the 2014 through 2016 escalation of the PBR formula. The $30 thousand reduction results in this item being removed from the calculation of 2017 formula O&M and future years' calculations of formula O&M.

The $25 thousand increase to FEFN's O&M is a current forecast of the direct costs expected for 2017.

In summary, the two amounts above cannot be directly related as the FEI amount was determined based on 2013 base O&M inflated by the PBR formula, while the FEFN amount is a 2017 forecasted amount.

23.0 Reference: O&M EXPENSE FORECAST OUTSIDE OF THE FORMULA

Exhibit B-2, Section 6.3.5, Table 6-6, pp. 53–54

Incremental O&M to support Rate Schedule 46 revenues

FEI states on page 54 of the Application: "Labour costs are forecast to increase due to additional staff required to support the operations at the new facility…"

Table 6-6 on page 53 of the Application shows a Forecast 2017 labour cost of $2.160 million for the Tilbury Plant.

23.1 Please provide a detailed explanation of the costs comprising the $2.160 million labour cost, including the number of FTEs/employees included in this cost and the roles/responsibilities of these employees.

Response:

Since the filing of the Application, FEI has been informed by TOTE that their LNG adoption plans have been delayed by at least one year. This customer was initially projected to begin taking LNG from FEI under Rate Schedule 46 beginning in May 2017. However, this customer is now not expected to begin taking LNG from FEI under Rate Schedule 46 until April 2018. FEI will file an updated LNG NGT demand and revenue and O&M forecast reflecting this volume change for 2017 as part of its Evidentiary Update. FEI will file an updated Table 6-6 with its Evidentiary Update.

The 2017 forecast labour cost of $2.160 million relates to three types of job functions at the Tilbury Plant: LNG Plant Operators, LNG Electrical and Instrumentation Technicians and an LNG Administrative Assistant. The forecast labour cost represents the portion of the total labour force at the Tilbury Plant that will perform work related to Rate Schedule 46. In 2017, with the start-up of operations for the Tilbury LNG Expansion Facility, the majority of the LNG production and LNG truck loading that supports Rate Schedule 46 Revenues will take place at the new facility and therefore labour costs are forecast to increase substantially in 2017. The $2.160 million represents about 70 percent of the total Tilbury Plant labour cost in 2017, which would correspond to 70 percent of the 23 employees, or approximately 16 FTEs. The remaining 30 percent is labour cost related to the peaking operation which is in the O&M formula.

The table below outlines the job function/title, associated role/responsibility (with descriptions from the collective agreements), and number of full-time employees (FTE) for each job function associated with the 2017 forecast labour cost in Table 6-6. Note there are a total of 23 employees listed but only a portion of each employee's time is included in the O&M cost that supports Rate Schedule 46 Revenues.

Job Function/Title	Role/Responsibility
20 LNG Plant Operators	• The general operation and performance of required maintenance at the Tilbury Plant. More specifically, but not limited to: ◦ The operation of equipment and processes such as: LNG storage tanks; cycle gas and boil off gas compressors; gas purification, liquefaction processes; send out equipment including LNG pumps, vaporizers, odorizer; nitrogen generator with associated equipment; cooling equipment; standby diesel generator; measurement, instrumentation, control and gas analysis equipment. ◦ Maintenance of a log of pressures, temperatures and volumes and make adjustments to control the operation. ◦ Loading of mobile LNG equipment. ◦ Liaise with the FEI gas control department for communication on send out and liquefaction. ◦ Major repairs, overhaul, general maintenance, painting and grounds maintenance.
2 LNG Electrical and Instrumentation Technicians	• The performance of duties associated with electrical, instrumentation and controls related to and/or located at the Tilbury Plant. More specifically, but not limited to: ◦ The installation, programming, activation, troubleshooting, and operation and maintenance of electrical, electronic, instrumentation, control, communication, and computer equipment. ◦ The development and maintenance of predictive analysis and preventative schedules. ◦ The preparation of comprehensive documentation of construction, inspection, commissioning, and operation and maintenance work. ◦ Maintain knowledge, skills and abilities in changing technology as it relates to equipment installed and/or available for the Tilbury Plant. ◦ Provide direction to other employees and /or other external contractors as it relates to work performed at or in support of the Tilbury Plant. ◦ Provide input into project planning as it relates to work performed at or in support of the Tilbury Plant and the responsibility for the execution of such plans.
1 Administrative Assistant	• The performance of general administrative matters at the Tilbury Plant. • More specifically, but not limited to: ◦ Review, code and process invoices, expenses and Visa statements. ◦ Maintain plant filing systems, maintain and update various manuals/documents, standards and related databases. ◦ Make travel and accommodation arrangements for staff, review and code employee expenses. ◦ Gather and maintain records for LNG truck loading and communicate with LNG logistics for truck scheduling. ◦ Arrange for meetings, book attendees, facilities, arrange for catering, attend meeting and prepare minutes.

23.2 Please explain how FEI distinguishes the labour costs which are incremental to the regular O&M costs for operating the Tilbury and Mt. Hayes LNG facilities as peaking storage facilities.

Response:

FEI distinguishes labour costs which are incremental to the regular O&M costs for operating the Tilbury and Mt. Hayes LNG facilities as peaking storage facilities through the distinct internal orders and cost centres associated with each facility.

The incremental costs to support Rate Schedule 46 revenues are associated with the production costs of LNG, labour for associated equipment maintenance due to usage, and the labour for truck loading.

The tracking of labour as between the formula O&M and the O&M in support of Rate Schedule 46 revenues is as follows:

1. All costs related to the Tilbury Expansion Facility are allocated to Rate Schedule 46. The labour for employees working at this facility is easily distinguishable since it is a separate physical facility.
2. Any labour associated with truck loading is 100% charged to Rate Schedule 46.
3. Any labour for when employees are working at the peak shaving Tilbury and Mount Hayes Facilities is captured in formula O&M. The exception to this is the labour associated with truck loading and miscellaneous other labour as required that is specifically attributed and allocated to Rate Schedule 46 through internal orders.

23.3 Do any/all of the employees at the Tilbury LNG facility perform work related to both the regular operation of the Tilbury facility and work related to the expanded operations? If yes, please explain how this time is tracked and recorded to ensure the costs are allocated appropriately.

Response:

All employees at the Tilbury LNG facility perform work related to both the regular operations of the Tilbury facility and work related to the expanded operations. FEI tracks labour which is incremental to the regular O&M costs for operating the Tilbury and Mt. Hayes LNG facilities as peaking storage facilities so that this labour is tracked outside of the PBR formula. Please refer to the response to BCUC IR 1.23.2 for a discussion of the cost allocation approach.

Table 6-6 shows an increase in Contractor costs for the Tilbury Plant of $0.260 million between Approved 2016 and Projected 2016, and a further increase of $0.100 million between Projected 2016 and Forecast 2017.

FEI states on page 54 of the Application that the increase in contractor expenses is due to “additional resources required for the preparation of operations at the expanded Tilbury LNG facility.”

23.4 Please describe the work performed by contractors for the expanded Tilbury LNG facility, including the number of contractors being utilized.

Response:

Contractors are used to aid in the preparation of the Safety Loss and Management Program which is a regulatory requirement under the LNG Facility Regulation. There are four contractors engaged in supporting various parts of the Safety Loss and Management Program which includes a corrosion program, a pressure vessel inspection program, an audit program and a management of change program.

In addition, two contractors are retained to support the operations and maintenance of the high voltage electrical sub-station and to provide a continuous supply of liquid nitrogen which are needed for the commissioning and regular operations at the expanded facility.

When the Tilbury Expansion Facility starts regular operations, contractors will also be needed to provide hazardous waste disposal, a continuous supply of materials, and support the maintenance of specialized equipment such as rotating equipment, pressure safety valves, pressure vessels, control systems, etc.

23.5 Please clarify whether the contractors are performing work on both the regular operations of the Tilbury facility as well as the expanded operations, and if so, how these costs are being tracked to ensure appropriate allocation of costs.

Response:

The contractors are performing work only on the expanded operations. There may be times in the future, due to the nature of the contractor's service, that they may be performing work on both the regular operations as well as the expanded operations. In these circumstances, separate service agreements will be in place and costs allocated separately for each operation.

D. RATE BASE

24.0 Reference: ALLOCATION OF CAPITAL EXPENDITURES TO THE FORT NELSON SERVICE AREA

Exhibit B-2, Section 7.2.1.1, p. 58

Intangible plant additions to the Fort Nelson service area

FEI states the following on page 58 of the Application:

> Given that Fort Nelson Service Area rates had already been set for 2015 and 2016, the earliest year that the allocation of the capital additions could be coordinated was in 2017. In the Annual Review of 2016 Rates, FEI therefore proposed that in its next Annual Review filing it would adjust its Base Capital starting in 2017 for the amounts to be allocated to the Fort Nelson Service Area. FEI proposed that this amount would consist of the actual 2013 Intangible Plant additions of $64 thousand, escalated by the PBR formula. <u>This final calculated amount is a $66 thousand reduction to the FEI 2017 Base Capital</u> (Section 11, Schedule 4, Line 17). These capital additions have been forecast as part of the Fort Nelson Service Area's revenue requirements starting in 2017. [emphasis added]

On page 33 of the FEFN 2017-2018 RRA application, FEI states:

> …FEI will begin allocating Intangible Plant costs to FEFN beginning in 2017 and the costs will be removed from FEI's 2017 Base Capital in the FEI Annual Review of 2017 Rates. <u>The amount of the allocation to FEFN's Intangible Plant in 2017 and 2018 is $46 thousand</u>, related to the purchase and sustainment of System Computer Software. [emphasis added]

24.1 Please explain the variance in the $66 thousand reduction to the FEI 2017 Base Capital described in the Application and the $46 thousand allocation to FEFN's Intangible Plant in 2017 and 2018 described in the FEFN 2017-2018 RRA application.

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

As explained on Page 58 of this Application, the $66 thousand reduction to FEI's capital formula was determined using the 2013 Intangible Plant additions of $64 thousand, which was the amount embedded in the PBR Base Capital, adjusted for the 2014 through 2016 escalation of the PBR formula. The $66 thousand reduction results in this item being removed from the calculation of 2017 formula capital expenditures and future years' calculations of formula cap expenditures.

The $46 thousand increase to FEFN's Intangible Plant additions is a current forecast of the Fort Nelson costs expected for 2017.

25.0 Reference: DEFERRAL ACCOUNTS

Exhibit B-2: Section 7.5.2.2, pp. 63-64; Section 11, Schedule 11, Line 12

Emissions Regulations deferral account

FEI states the following on pages 63-64 of the Application:

> In 2016, FEI collected pre-tax revenues of $2.4 million ($1.8 million after-tax) from the sale of credits earned under the Renewable Low Carbon Fuel Requirements Regulation (RLCFRR)…FEI issues a request for proposal to potential buyers to ensure it maximizes the value of these credits for the benefits of ratepayers…
>
> …These revenues, as well as any future credits received under the RLCFRR, are recorded directly in the deferral account. Any costs related to the administration of these sales, not already embedded in formula O&M, will be tracked by charging the costs to an internal order within the deferral account.

25.1 Please clarify the statement that any costs related to the administration of sales will be "tracked by charging the costs to an internal order within the deferral account." As part of this response, please explain what the "internal order" is and how this would be presented in FEI's deferral account schedules.

Response:

Internal orders are used in the finance SAP system for the internal tracking and management of costs. One or more internal orders can be used to track different subsets of costs or revenues within a specific deferral account. For the Emissions Regulation deferral account, FEI will utilize an internal order to record and track any incremental costs related to the administration of the RLCFRR sales in the deferral account.

The Emissions Regulation deferral account contains the total of all costs and revenues, such that any separate internal order balances are not shown in the deferral account financial schedules. However, the use of internal orders allows FEI to readily report on the various cost and revenue types that may constitute the total costs and revenues in the deferral account.

25.2 Please explain how FEI distinguishes between costs which are embedded in formula O&M and costs which are outside of the formula O&M. As part of this response, please explain and quantify the types of costs related to the sale of credits earned under the RLCFRR which are included within the O&M formula spending envelope.

Response:

The internal labour costs to administer the Emissions Regulations program are embedded in the formula O&M, given that these costs were included in the 2013 Base used to establish the formula O&M for the PBR Plan.

Costs outside the formula O&M would relate to external costs, such as consulting costs, that would be new costs and could not have existed in FEI's O&M at the time of establishing the FEI Base O&M for the PBR formula. FEI has yet to incur any costs in the deferral account related to the sale of credits earned under the RLCFRR during the PBR period.

25.3 Please describe the request for proposal process and how FEI ensures it maximizes the value of the credits sold for the benefit of ratepayers.

Response:

Following the Ministry of Energy and Mines' approval of FEI's earned credits as applied for under the Renewable and Low Carbon Fuel Requirements Regulation, FEI issued an RFP for the sale of these approved credits to fuel suppliers who provide transportation fuel in BC. The RFP invited these fuel suppliers to bid on FEI's earned credits. Once all bids were received, FEI reviewed the bids and awarded the RFP to the fuel supplier whose bid provided the highest economic benefit to FEI ratepayers.

25.4 Did FEI incur any administration costs related to the sales in 2016? If yes, please provide a breakdown and description of these costs and indicate whether the $1.8 million after-tax balance in the Emissions Regulations deferral account is net of these costs.

Response:

Please refer to the response to BCUC IR 1.25.2. FEI did not record any incremental administration costs in the Emissions Regulations deferral account.

25.5 Please explain how FEI has recorded the $2.4 million revenues earned in 2016 for financial reporting purposes.

Response:

FEI has recorded the $2.4 million in revenues earned in 2016 as an addition to the Emissions Regulation deferral account for both regulatory and financial reporting purposes.

26.0 Reference: DEFERRAL ACCOUNTS

Exhibit B-2, Section 11, Schedules 11, 11.1, 12

Unamortized deferred charges and amortization (Rate Base and Non-Rate Base)

26.1 In the same format as is provided in Schedules 11, 11.1 and 12 in Section 11 of the Application, please provide the previous years' information by starting with the Actual 2015 ending deferral account balances and including the Projected 2016 deferral account additions and the Projected 2016 amortization.

<u>Response:</u>

Please refer to Attachment 26.1 for the 2016 equivalent of Schedules 11, 11.1, and 12 in Section 11 of the Application.

27.0 Reference: DEFERRAL ACCOUNTS

Exhibit B-2, Section 11, Schedule 11.1; FEI Annual Review of 2015 Delivery Rates proceeding, Exhibit B-2, BCUC IR 24.1

2016 Cost of Capital Application

On line 4 of Schedule 11.1, FEI provides an opening 2017 balance of $1,258,000 in the 2016 Cost of Capital Application deferral account.

In response to BCUC IR 24.1 in the FEI Annual Review of 2015 Delivery Rates proceeding (Exhibit B-2), FEI provides the following estimate and breakdown of the 2016 Cost of Capital Application costs:

Description	Estimate Amount
Commission Costs	$150,000
Intervener PACA	$210,000
FEI Experts/Consultants	$70,000
Legal Costs	$60,000
Other / Miscellaneous	$10,000
	$500,000

27.1 Please provide the total final (or projected) costs incurred for the 2016 Cost of Capital Application utilizing the same breakdown as was provided in the above table, and explain the causes of the variances between forecast and actual expenditures.

<u>Response:</u>

The updated total projected costs for the 2016 Cost of Capital Application are provided in the table below. Costs are not yet final as FEI expects to incur additional Commission Costs and Intervener PACA costs that are not yet approved.

Description	Estimate Amount	Projected Amount	Variance
Commission Costs	$150,000	$150,000	$0
Intervener PACA	$210,000	$250,000	($40,000)
FEI Experts/Consultants	$70,000	$833,755	($763,755)
Legal Costs	$60,000	$453,945	($393,945)
Other / Miscellaneous	$10,000	$18,767	($8,767)
	$500,000	**$1,706,467**	**($1,206,467)**

The original estimate was prepared in January of 2015, which was before the Cost of Capital application was filed and before the regulatory process was determined. At the time FEI stated, "FEI has estimated $0.500 million in costs for 2015 but the cost could vary significant depending on the regulatory process.[4]" FEI also stated: "If an oral hearing is ordered, all cost categories will be significantly higher".[5]

The Cost of Capital proceeding was an extensive regulatory process, with expert evidence from both FEI and intervener groups and an oral hearing. The regulatory process increased the costs to the high end of a normal range for a regulatory process but comparable with other proceedings that involve expert witnesses and oral testimony. For example, Stage 1 of the 2012 Generic Cost of Capital proceeding resulted in $1.8 million of costs (before allocation to other utilities), FEI's 2012-2013 RRA resulted in $1.6 million of costs, and FEI's PBR proceeding resulted in $2.0 million of costs.

[4] FEI Annual Review for 2015 Rates, page 50.
[5] Response to BCUC IR 1.24.1

28.0 Reference: DEFERRAL ACCOUNTS

Exhibit B-2, Section 11, Schedule 11.1; FEI Annual Review of 2016 Rates proceeding, Exhibit B-5, BCUC IR 24.1, 24.2

Gas Asset Records Project deferral account

FEI provided the following table in response to BCUC IR 24.2 in the FEI Annual Review of 2016 Rates proceeding (Exhibit B-5):

	2012 Actual	2013 Actual	2014 Actual	2015 Projected	2016 Forecast	2017 Forecast	2018 Forecast	Total
Project 'A' - Consolidate & scan critical Gas System Asset Records into Filenet	280	570	772	852	1,100	1,100	546	5,220
Project 'B' - Implement improved drawing management & control systems	-	20	155	170	170	100	-	615
Project 'C' - Review & analyze historical drawings	30	245	140	250	500	500	300	1,965
Total	310	835	1,067	1,272	1,770	1,700	846	7,800

28.1 Please update the above table to include Actual 2015 and Projected 2016 expenditures as well as a revised forecast for 2017 and 2018 (if these forecasts have been revised).

Response:

The requested table is provided below. Note that amounts shown are in $ thousands.

	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Projected	2017 Forecast	2018 Forecast	Total
Project 'A' - Consolidate & scan critical Gas System Asset Records into Filenet	280	570	772	1,010	1,200	1,230	779	5,841
Project 'B' - Implement improved drawing management & control systems	-	20	155	147	100	150	-	572
Project 'C' - Review & analyze historical drawings	30	245	140	172	200	300	300	1,387
Total	310	835	1,067	1,329	1,500	1,680	1,079	7,800

28.2 Please explain any variances between Projected 2015 and Actual 2015 amounts and between Forecast 2016 and Projected 2016 amounts.

Response:

The Gas Assets Records project remains on track to meet the original forecast spend of $7.8 million. As a result of improvements to the gas asset project completion and close out process, Project ‘B’ and ‘C’ costs are reduced compared to last year’s projections, while there continues to be increased cost pressures for Project ‘A’ given the evolving scope of the critical records to be analyzed, sorted, and secured.

The 2015 actual expenditures were slightly higher than projected due to the project entering into areas/locations that required additional training, ramp up time, expertise and process/quality check enhancements due to a broader scope of work required in those locations than anticipated.

Staffing also continues to be a challenge due to staffing departures and the on boarding of additional staff that are now being cross trained to carry out multiple tasks across the project.

The 2016 costs are now projected to be less than provided in last year’s forecast due to some staffing departures which have led to work being delayed to 2018.

29.0 Reference: DEFERRAL ACCOUNTS

Exhibit B-2, Section 11, Schedule 11.1; FEI Annual Review of 2016 Rates proceeding, Exhibit B-5, BCUC IR 25.2

BC OneCall Project deferral account

FEI provided the following table in response to BCUC IR 25.2 in the FEI Annual Review of 2016 Rates proceeding (Exhibit B-5):

Stream	2012 Actual	2013 Actual	2014 Actual	2015 Projected	2016 Forecast	2017 Forecast	Total
Data Consistency Stream	20	285	847	450	350	100	2,052
Conflation Stream	126	590	100	-	-	-	816
Total	146	875	947	450	350	100	2,868

29.1 Please update the above table to include Actual 2015 and Projected 2016 expenditures as well as a revised forecast for 2017 (if this forecast has been revised).

<u>Response:</u>

The requested table is provided below. Note that amounts shown are in $ thousands.

Stream	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Projected	2017 Forecast	Total
Data Consistency Stream	20	285	847	372	400	128	2,052
Conflation Stream	126	590	100	-	-	-	816
Total	146	875	947	372	400	128	2,868

29.2 Please explain any variances between Projected 2015 and Actual 2015 amounts and between Forecast 2016 and Projected 2016 amounts.

Response:

The total forecast cost of the BC OneCall Project remains as forecast in the Annual Review for 2016 Rates.

The actual results for 2015 were $78 thousand lower than projected primarily due to employee absences. This unspent amount is now projected to be spent in 2016 and 2017.

30.0 Reference: DEFERRAL ACCOUNTS

Exhibit B-2, Section 11, Schedule 11.1; FEI Annual Review of 2016 Rates, Order G-193-15 Compliance Filing, Section 11, Schedule 11.1

TESDA Overhead Allocation Variance deferral account

Line 23 of Schedule 11.1 in FEI's Annual Review of 2016 Rates Compliance Filing pursuant to Order G-193-15 shows an ending 2015 balance in the TESDA Overhead Allocation Variance deferral account of $296 thousand and a 2016 amortization expense amount of $296 thousand.

Line 21 of Schedule 11.1 in Section 11 of the Application shows an ending 2016 balance in the TESDA Overhead Allocation Variance deferral account of $639 thousand and a 2017 amortization expense of $639 thousand.

30.1 Please explain the increase in the balance and resulting amortization expense for this deferral account between 2016 and 2017. As part of this response, please explain how the TESDA Overhead Allocation is determined and the reason for the increased variance in 2016 compared to 2015.

Response:

The increase in the balance and resulting amortization expense is due to the true-up of the 2015 actual variance compared to the projected amount embedded in the opening deferral balance in the FEI Annual Review for 2016 Rates. To reconcile the account balances and amortization amounts, FEI has provided the table below which shows the TESDA Overhead Allocation Variance deferral account continuity since its inception in 2014.

($000s)	2014	2015	2016	2017
Opening Balance	-	174	491	639
Projected Additions (after-tax)	-	296	444	-
True-up to actual Additions (after-tax)	174	195	-	-
Amortization	-	(174)	(296)	(639)
Ending Balance	174	491	639	-

As shown in the table above, the actual 2015 after- tax additions of $491 thousand ($296 thousand + $195 thousand) are similar to the 2016 projected after-tax additions of $444 thousand. The 2017 amortization is higher than 2016 because the 2016 amortization was based on projected additions of $296 thousand in 2015 and the 2017 amortization is based on projected additions in 2016 of $444 thousand, plus a further true-up from 2015 of $195 thousand.

The TESDA Overhead Allocation Variance deferral account was requested and approved as part of FEI's PBR Application. Additions to the account are calculated as the difference between the amount of the overhead allocation to FAES embedded in FEI's 2013 Base O&M escalated at the PBR formula, discussed in the paragraph below, and the actual recoveries from FAES for O&M activities in support of FAES. The positive balances in the account indicate that the actual recoveries from FAES are lower than the amount embedded in the O&M formula.

As discussed on Page 292 in the PBR Application:

> The amount of O&M currently forecasted to be recovered from thermal energy customers in the 2013 O&M Base is $854 thousand, as approved by Commission Order G-44-12. This amount will be inflated by the O&M formula for the PBR period.

This amount is the TESDA Overhead Allocation embedded in FEI customers annual delivery rates.

The actual (projected) recoveries from FAES are significantly lower than the amount included in the O&M formula discussed in the paragraph above. The difference is due to several factors which include a reduction in the service FAES requires from FEI due to the in-sourcing of these services in FAES, an overall reduction in the FAES tasks performed by FEI staff in general, and a reduction in the use of FEI facilities due to changes in the location of FAES staff. As noted above, the difference between the amount included in the O&M formula and the actual/projected costs are recorded in the TESDA Overhead Allocation Variance deferral account.

FEI notes that FEI recovers its overhead directly from FAES as directed by the Commission on page 232 of the PBR Decision rather than from the TESDA, but has not requested a change to the deferral account name to reflect this.

E. EARNINGS SHARING AND RATE RIDERS

31.0 Reference: EARNINGS SHARING

Exhibit B-2, Section 10.1.2, Table 10-3, p. 77; FEI Annual Review of 2016 Rates proceeding; Exhibit B-2, Table 10-1, p. 68; FEI Annual Review of 2015 Delivery Rates proceeding, Exhibit B-1, Section 11, Schedule 18

Calculation of earnings sharing adjustment for actual customer growth

Line 8 in Table 10-3 of the Application shows an amount of $111.862 million related to “2014 Reforecast Sustainment/Other Capital” with a reference to “Note 1”.

Note 1 states: “2016 Annual Review of Rates Table 10-1, Line 9 plus FEVI & FEW additions to base from 2015 Annual Review of Rates, Section 11, Schedule 18, Column 5, Lines 29 & 30”.

Table 10-1, Line 9 on page 68 of the FEI Annual Review of 2016 Rates application shows an amount of $100.202 million.

Lines 29 and 30 of Schedule 18 in Section 11 of the FEI Annual Review of 2015 Delivery Rates application shows an amount of $17.776 million and $0.142 million, respectively.

31.1 Please provide the detailed calculation for the $111.862 million shown on Line 8 of Table 10-3 in the Application. For each component of the calculation, please provide the applicable reference and provide explanations where possible.

Response:

The purpose of the customer additions adjustment is to allow FEI to recover the variance in earned return driven by the use of prior year customer additions for the growth term when compared to the actual customer additions. Consequently, the approved average customer growth term is recalculated using actual average customer growth.

As FEI advances through the PBR term, the base to be adjusted must include any previous years’ actual customer additions adjustments. Consequently, each year’s customer growth adjustment is based on the previous year’s reforecast base.

The following provides the detailed calculations for the $111.862 million from Table 10-3 of the Application. For ease of reading the references, FEI has added faint dotted lines between each of the items.

$ millions

Line No.	Particulars	Calculation		Reference
1	Average Customers Current Year		851,341	FEI Annual Review for 2016 Rates, Table 10-1: Calculation of Earnings Sharing Adjustment for Actual Customer Growth, Line 1
2	Average Customers Previous Year		841,175	FEI Annual Review for 2016 Rates, Table 10-1: Calculation of Earnings Sharing Adjustment for Actual Customer Growth, Line 2
3	Growth in Average Customers	Line 1 - Line 2	10,166	
4	Average Customer Growth	Line 3 / Line 2	1.209%	
5			50%	G-138-14
6	Average Customer Growth to be recast in Formula	Line 4 x Line 5	0.604%	
7	Net Inflation Factor		0.360%	G-86-15, G-106-15 Compliance Filing, Section 11, Schedule 18, Line 11, Column 3: FEI 2013 Base Formulaic Sustainment/Other Capital
8	Reforecast		$ 99.243	G-86-15, G-106-15 Compliance Filing, Section 11, Schedule 18, Line 28, Column 2: FEI 2013 Base Formulaic Sustainment/Other Capital
9	Current Year ReForecast Formulaic Sustainment/Other Capital	Line 8 x (1 + Line 7) x (1 + Line 6)	$ 100.202	
10	FEVI addition to amalgamated base Sustainment/Other Capital		$ 11.518	G-86-15, G-106-15 Compliance Filing, Section 11, Schedule 18, Line 29, Column 5: FEVI Base Formulaic Sustainment/Other Capital
11	FEW addition to amalgamated base Sustainment/Other Capital		$ 0.142	G-86-15, G-106-15 Compliance Filing, Section 11, Schedule 18, Line 30, Column 5: FEW Base Formulaic Sustainment/Other Capital
12		Sum of Lines 9 through 11	$ 111.862	

Line 3 represents the actual growth in average customers by subtracting 2013 Average Customers from 2014 Average Customers. Line 4 is the percentage growth and this is reduced by half based on the direction in G-138-14. On Line 9, one half of the actual growth and the approved inflation factors are used to adjust the 2013 Sustainment/Other Capital to a reforecast 2014 Formulaic Sustainment/Other Capital. In 2015, FEI, FEVI and FEW were amalgamated, therefore $11.518 million and $0.142 million for FEVI and FEW, respectively, are added to FEI's 2014 Reforecast Base to calculate an amalgamated 2014 Reforecast Base of Sustainment/Other Capital. This amount is then used as the base for the calculation of the 2015 adjustment.

Note that the source of the FEVI and FEW amounts that were referenced in the preamble to this question is incorrect. The statement in the preamble is "Lines 29 and 30 of Schedule 18 in Section 11 of the FEI Annual Review of 2015 Delivery Rates application shows an amount of $17.776 million and $0.142 million, respectively." The correct reference is to the approved amounts in the same schedule, but in FEI's compliance filing to Orders G-86-15 and G-106-15 filed on June 30, 2015. The amounts shown on that schedule (the approved amounts) are $11.518 million and $0.142 million, as shown in the table above.

F. ACCOUNTING MATTERS AND EXOGENOUS FACTORS

32.0 Reference: NON RATE BASE DEFERRAL ACCOUNTS

Exhibit B-2, Section 12.4.1, pp. 126–127

Kingsvale-Oliver Reinforcement Project (KORP) Feasibility Costs

FEI states on page 127 of the Application:

> As of December 31, 2015, approximately $109 thousand in costs had been accumulated in the deferral account. Given the current status of the KORP project and the age of the costs in the deferral account, FEI does not believe these costs can provide any benefit for future development work on this project or any derivation of it. Therefore, FEI is proposing to expense these costs and to discontinue use of the account.

32.1 Please clarify if FEI is proposing to recover the $109 thousand from ratepayers or if FEI is proposing to write off these expenses.

Response:

FEI is proposing that these costs be expensed to O&M and included in formula O&M. Since FEI is projecting its formula O&M to be below the formula amount, the effect of the earning sharing mechanism is that these costs will be shared with customers.

In the Decision attached to Order G-101-12 which approved the creation of the deferral account, with a spending limit of $850 thousand, the Commission stated:

> The Commission previously allowed Stage 1 costs to be recorded in a rate base deferral account (SCP Mitigation Variance deferral account). However, a more appropriate regulatory treatment of these costs would be to record feasibility expenses in an expense account either as part of a revenue requirement or upon separate application. FEI confirms it did not include either Stage 1 or Stage 2a forecast expenses in its 2012-2013 Revenue Requirement. (Exhibit B-3, BCUC 1.1.3.2)… The Commission is satisfied that the types of activities described for Stage 2a are properly categorized as feasibility costs and therefore should be treated as expenses.

The costs incurred in the KORP Feasibility Costs deferral account were preliminary investigation/feasibility costs mainly related to environmental assessments. FEI's approved treatment of these types of costs, not otherwise included within a specific deferral, is to recover these costs through O&M. The 2013 O&M Base for the PBR formula included a set level of preliminary investigation costs. As this is the normal treatment for this type of cost, it is appropriate to include the costs in formula O&M.

32.1.1 If FEI is proposing to recover these costs from ratepayers, please explain why this is appropriate.

Response:

Please refer to the response to BCUC IR 1.32.1.

32.2 Please clarify whether the $109 thousand costs are proposed to be expensed in 2016 or in 2017 and how/where these costs will be recorded.

Response:

FEI is proposing to expense the costs in 2016 to account 410-11 in the Activity View of the New Code of Accounts for O&M.

33.0 Reference: NON RATE BASE DEFERRAL ACCOUNTS

Exhibit B-2, Section 12.4.2, Table 12-2, pp. 127–130; FEI Annual Review of 2016 Rates proceeding; Exhibit B-2, Table 12-5, p. 122

Actual 2015 Flow-through deferral account additions

Table 12-2 on page 129 of the Application shows a 2015 Ending Deferral Account Balance True-up of $3.634 million.

Table 12-5 on page 122 of the FEI Annual Review of 2016 Rates application provided the 2015 Flow-through deferral account additions.

33.1 Please revise Table 12-5 from the FEI Annual Review of 2016 Rates application to include a 2015 Actual column which explains the true-up of $3.634 million between the 2015 Projected and 2015 Actual flow-through amounts.

Response:

FEI provides the requested table below. Similar to the 2016 financing true-up discussed on Page 129 of the Application, a true-up is also required for 2015 to account for the difference between financing costs embedded in the 2015 delivery rates and the actual 2015 financing costs.

Line No.	Particulars	FEI APPROVED G-106-15	FEI 2015 ACTUAL	Flow-Through Variance
	(1)	(2)	(3)	(4)
1	Delivery Margin			
2	Residential (Rate 1)	$ (435.303)	$ (435.517)	$ (0.214)
3	Commercial (Rate 2, 3, 23)	(212.508)	(217.887)	(5.379)
4	Industrial (All Others)	(104.925)	(106.017)	(1.092)
5	Total Delivery Margin	(752.736)	(759.421)	(6.685)
6				
7	O&M Tracked outside of Formula			
8	Insurance	6.649	6.237	(0.412)
9	Bio-Methane	0.646	1.085	0.439
10	Bio-Methane O&M transferred to BVA	(0.594)	(1.010)	(0.416)
11	NGT O&M	0.926	1.009	0.083
12	LNG Production O&M	0.935	0.624	(0.311)
13				
14	Property and Sundry Taxes	61.015	60.801	(0.214)
15				
16	Depreciation and Amortization	189.989	189.286	(0.703)
17				
18	Other Operating Revenue	(41.226)	(41.136)	0.090
19				
20	Interest Expense	133.189	133.222	0.033
21				
22	Income Taxes	49.002	52.834	3.832
23				
24	2015 Actual After-Tax Flow-Through Addition to Deferral Account (excluding financing)			(4.264)
25	2015 Projected After-Tax Flow-Through Addition to Deferral Account (excluding financing)			(0.713)
26				
27	2015 After-Tax Flow-Through Addition True-up to Deferral Account (excluding financing)			(3.551)
28	2015 Financing True-up			(0.083)
29				
30	2015 Ending Deferral Account Balance True-up			(3.634)

Attachment 17.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 18.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 26.1

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 11
(2016)

Line No.	Particulars	12/31/2015	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2016	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related Deferral Accounts										
2	Commodity Cost Reconciliation Account (CCRA)	$ (37,479)	$ -	$ 16,091	$ (4,184)	$ -	$ -	$ -	$ (25,572)	$ (31,526)	
3	Midstream Cost Reconciliation Account (MCRA)	(28,645)	-	(6,719)	1,747	-	22,095	(5,745)	(17,267)	(22,956)	
4	Revenue Stabilization Adjustment Mechanism (RSAM)	43,130	-	28,545	(7,421)	-	(23,039)	5,990	47,205	45,168	
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(4,213)	-	(195)	52	147	(153)	40	(4,322)	(4,268)	
6	Revelstoke Propane Cost Deferral Account	(324)	-	283	(74)	-	-	-	(115)	(220)	
7	SCP Mitigation Revenues Variance Account	(1,070)	-	144	(37)	543	-	-	(420)	(745)	
8		$ (28,601)	$ -	$ 38,149	$ (9,917)	$ 690	$ (1,097)	$ 285	$ (491)	$ (14,547)	
9	Energy Policy Deferral Accounts										
10	Energy Efficiency & Conservation (EEC)	$ 61,769	$ 9,650	$ 15,000	$ (3,900)	$ (8,365)	$ -	$ -	$ 74,154	$ 72,787	
11	NGV Conversion Grants	34	-	60	(16)	(16)	-	-	62	48	
12	Emissions Regulations	3	-	(2,439)	634	-	-	-	(1,802)	(900)	
13	On-Bill Financing Pilot Program	15	-	(2)	-	-	-	-	13	14	
14	NGT Incentives	16,041	-	7,163	(1,862)	(1,845)	-	-	19,497	17,769	
15	CNG and LNG Recoveries	(361)	-	(521)	136	331	-	-	(415)	(388)	
16		$ 77,501	$ 9,650	$ 19,261	$ (5,008)	$ (9,895)	$ -	$ -	$ 91,509	$ 89,330	
17	Non-Controllable Items Deferral Accounts										
18	Pension & OPEB Variance	$ 6,861	$ -	$ (7,029)	$ -	$ (6,771)	$ -	$ -	$ (6,939)	$ (39)	
19	BCUC Levies Variance	803	-	185	(48)	(423)	-	-	517	660	
20	Customer Service Variance Account	(10,371)	-	-	-	3,456	-	-	(6,915)	(8,643)	
21	Pension & OPEB Funding	(228,339)	42,135	-	-	-	-	-	(186,204)	(186,204)	
22	US GAAP Pension & OPEB Funded Status	148,811	(42,135)	-	-	-	-	-	106,676	106,676	
23		$ (82,235)	$ -	$ (6,844)	$ (48)	$ (3,738)	$ -	$ -	$ (92,865)	$ (87,550)	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 11.1
(2016)

Line No.	Particulars	12/31/2015	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2016	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Application Costs Deferral Accounts										
2	2014-2019 PBR Requirements	$ 982	$ -	$ -	$ -	$ (247)	$ -	$ -	$ 735	$ 859	
3	2014 Long Term Resource Plan Application	50	-	-	-	(50)	-	-	-	25	
4	AES Inquiry Cost	254	-	-	-	(132)	-	-	122	188	
5	Generic Cost of Capital Application	11	-	-	-	(11)	-	-	-	6	
6	2016 Cost of Capital Application	422	-	1,130	(294)	-	-	-	1,258	840	
7	Amalgamation and Rate Design Application Costs	522	-	-	-	(490)	-	-	32	277	
8	2015-2019 Annual Review Costs	266	-	180	(47)	(221)	-	-	178	222	
9	2017 Rate Design Application	-	-	940	(244)	-	-	-	696	348	
10	2017 Long Term Resource Plan Application	-	-	505	(131)	-	-	-	374	187	
11	LMIPSU Application Costs	-	586	4	(1)	(349)	-	-	240	413	
12	2015 System Extension Application	203	-	70	(18)	(120)	-	-	135	169	
13	BERC Rate Methodology Application	19	-	80	(21)	(55)	-	-	23	21	
14	All-Inclusive Code of Conduct/Transfer Pricing Policy Application	-	-	155	(40)	-	-	-	115	58	
15		$ 2,729	$ 586	$ 3,064	$ (796)	$ (1,675)	$ -	$ -	$ 3,908	$ 3,613	
16	Other Deferral Accounts										
17	Whistler Pipeline Conversion	$ 10,151	$ -	$ -	$ -	$ (745)	$ -	$ -	$ 9,406	$ 9,779	
18	2010-2011 Customer Service O&M and COS	14,560	-	-	-	(3,251)	-	-	11,309	12,935	
19	Gas Asset Records Project	1,279	-	1,680	(437)	(516)	-	-	2,006	1,643	
20	BC OneCall Project	782	-	400	(104)	(358)	-	-	720	751	
21	Gains and Losses on Asset Disposition	32,402	-	-	-	(3,986)	-	-	28,416	30,409	
22	Net Salvage Provision/Cost	(38,103)	-	13,661	-	(22,020)	-	-	(46,462)	(42,283)	
23	TESDA Overhead Allocation Variance	491	-	600	(156)	(296)	-	-	639	565	
24	PCEC Start Up Costs	920	-	-	-	(88)	-	-	832	876	
25	Huntingdon CPCN Pre-Feasibility Costs	-	364	-	-	(120)	-	-	244	304	
26	LMIPSU Development Costs	-	2,353	2	(1)	(793)	-	-	1,561	1,957	
27		$ 22,482	$ 2,717	$ 16,343	$ (698)	$ (32,173)	$ -	$ -	$ 8,671	$ 16,936	
28	Residual Deferred Accounts										
29	BFI Costs and Recoveries	$ (194)	$ -	$ (89)	$ 23	$ -	$ -	$ -	$ (260)	$ (227)	
30	Fuelling Stations Variance Account	53	-	-	-	(53)	-	-	-	27	
31	US GAAP Transitional Costs	(70)	-	-	-	70	-	-	-	(35)	
32	Residual Delivery Rate Riders	-	10	-	-	(8)	-	-	2	6	
33	Property Tax Deferral	(1,456)	-	-	-	1,448	-	-	(8)	(732)	
34	Interest Variance	(338)	-	-	-	338	-	-	-	(169)	
35	Interest Variance - Funding benefits via Customer Deposits	40	-	-	-	(40)	-	-	-	20	
36		$ (1,965)	$ 10	$ (89)	$ 23	$ 1,755	$ -	$ -	$ (266)	$ (1,110)	
37											
38	**Total**	$ (10,089)	$ 12,963	$ 69,884	$ (16,444)	$ (45,036)	$ (1,097)	$ 285	$ 10,466	$ 6,672	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 12
(2016)

Line No.	Particulars	12/31/2015	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2016	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**Non-Rate Base**										
2	Biomethane Variance Account	$ 1,320	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,320	$ 1,320	
3	KORP Feasibility Costs	-	-	-	-	-	-	-	-	-	
4	EEC-Incentives	22,036	(9,650)	741	-	-	-	-	13,127	12,757	
5	US GAAP Uncertain Tax Positions	277	-	-	-	-	-	-	277	277	
6	Mark to Market - Hedging Transactions	17,307	-	-	-	-	-	-	17,307	17,307	
7	Huntingdon CPCN Pre-Feasibility Costs	364	(364)	-	-	-	-	-	-	-	
8	Amalgamation Regulatory Account	1,109	-	10	-	-	(731)	190	578	844	
9	2014-2019 Earning Sharing Account	(4,194)	-	(4,905)	1,207	4,208	-	-	(3,684)	(3,939)	
10	Flow-Through Account	(4,347)	-	(1,409)	-	734	-	-	(5,022)	(4,685)	
11	Phase-In-Rider Balancing Account	(370)	-	-	-	-	(4,019)	1,045	(3,344)	(1,857)	
12	LMIPSU Application Costs	586	(586)	-	-	-	-	-	-	-	
13	LMIPSU Development Costs	2,353	(2,353)	-	-	-	-	-	-	-	
14	PEC Pipeline Development Costs and Commitment Fees	7,113	-	(1,119)	2,859	-	-	-	8,853	7,983	
15	Rate Stabilization Deferral Account (RSDA)	(47,598)	-	(507)	132	-	44,273	(11,511)	(15,211)	(31,405)	
16	FEW Rider B Refund Deferral	10	(10)	-	-	-	-	-	-	-	
17	**Total Non Rate Base Deferral Accounts**	$ (4,034)	$ (12,963)	$ (7,189)	$ 4,198	$ 4,942	$ 39,523	$ (10,276)	$ 14,201	$ (1,398)	