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September 18, 2018

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, B.C.
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Attention: Mr. Patrick Wruck, Commission Secretary and Manager, Regulatory Support

Dear Mr. Wruck:

Re: FortisBC Energy Inc. (FEI)

Project No. 1598966

Annual Review for 2019 Delivery Rates (the Application)

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

On August 3, 2018, FEI filed the Application referenced above. In accordance with Commission Order G-143-18 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, Sections 1.4.1 & 1.4.2, pp. 5–6, Table 1–3; FEI Annual Review for 2018 Delivery Rates, Exhibit B-2, pp. 5–6; Exhibit B-3, BCUC IR 1.5, 1.7, & 1.9

Overview of operating and maintenance (O&M) savings

Page 5 of the FortisBC Energy Inc. (FEI) Annual Review for 2019 Delivery Rates application (Application) states:

> In 2018, as we near the end of the term of the current PBR Plan, FEI continues to be faced with the increasingly difficult challenge of finding new productivity opportunities to meet the annual savings embedded in the formula, and to sustain the level of incremental O&M savings achieved in recent years. As a result, the 2018 projected O&M savings of $5.0 million is lower than recent years, recognizing the impact of the PIF factor in the allowed annual O&M funding available. Contributing also to the productivity challenge are new cost pressures the Company is experiencing.

1.1 Please describe the new cost pressures FEI is experiencing in 2018 and expects to experience in 2019 with respect to O&M inside the formula.

Response:

This response also addresses BCUC IRs 1.1.1.1, 1.1.1.2 and 1.1.1.3.

FEI provides the following discussion of the formula and Productivity Improvement Factor (PIF) related O&M savings to enhance clarity and interpretation of the information. Formula savings are calculated by taking the difference between the actual O&M spending and the allowed O&M as provided using the formula approach (i.e., inflation, growth and productivity). Any savings calculated may be considered as one-time or permanent (sustainable), depending on the nature of the variance (i.e., temporary vacancy savings are considered one-time savings whereas a permanent headcount reduction would be considered permanent savings). On the other hand, the PIF related savings are determined based on the approved PIF factor (1.1 percent) applied to the O&M Base. The PIF related savings are imbedded as part of the formula and reduce the O&M Base funding by approximately $2.7 million each year. However, the savings cannot clearly be identified as permanent, as permanent savings are typically determined by comparing actual O&M spending to the allowed O&M funding available, instead of by reducing broadly the allowed funding available as the PIF does.

Formula savings can decrease as a result of cost pressures that increase actual spending compared to the allowed funding. Additionally, the impact of the PIF reduces the O&M Base

funding that would otherwise be available. Without sufficient productivity related savings to offset the decreased allowed funding resulting from the annual PIF challenge, all else equal, the resulting formula savings will be lower.

For 2018, factors contributing to the forecast decrease in formula O&M savings from the recent year's result (i.e., $7.9 million savings in 2017 compared to forecast $5.0 million savings in 2018) include the ongoing impact of the PIF factor, the increasingly difficult challenge of finding new productivity opportunities with significant incremental savings, and cost pressures the Company is experiencing. Considering the increasingly difficult challenge of finding new productivity opportunities with significant incremental savings, the ongoing impact of the PIF factor itself reduces the allowed O&M funding each year by approximately $2.7 million. The PIF influence coupled with the cost pressures discussed below are expected to contribute to the forecasted decline in annual formula savings.

In order to respond to the evolving risks of changing cyber security landscape, O&M costs for cyber security are expected to increase by up to approximately $0.5 million in 2018. This pressure was discussed in the 2018 Annual Review Application, section 1.4.1, page 5. In 2019, this incremental funding will be required again to sustain the activities and may increase in the future.

Additional cost pressures the Company is managing are related to the growth and aging of the Company's pipeline and distribution system, estimated to total to approximately $1 million incremental in 2018. The Company continues to grow its asset base as new customers are attached to the distribution system, with new mains and service installations at high levels in recent years. In addition to the initial capital investment to install the necessary infrastructure required, the new assets also require supporting O&M resources to process and to operate and maintain them. These associated O&M costs are not directly charged to the capital activities and as a result are adding to the O&M costs pressures. The associated O&M costs are for support staff to process the higher number of capital jobs (i.e. employees to process new service orders) and for employee administration and training costs for staff (i.e. Planners, Engineers, Quality Assurance personnel, Construction crews, Trades Trainers) required to support the higher capital work. These cost pressures are expected to be sustained and may increase in future years depending on activity and personnel levels. Similarly, as the existing infrastructure continues to age, more resources are required to support activities to maintain the system. These growth and aging infrastructure related cost pressures are expected to continue and may increase in the future.

Other cost pressures the Company is managing are related to vehicle fuel and insurance costs and municipal fees. Vehicle fuel and insurance expenses have been rising with the average increase for 2018 and 2019 expected to be approximately $200 thousand incremental per year to O&M expenses. Additionally, fees paid to municipalities and other expenses to meet municipal regulations and allow the Company to obtain the necessary permits are expected to increase on average $100 to $200 thousand per year in 2018 and 2019.

Remediation activities related to erosion, landslides and fires in the spring and summer of 2018 in the Interior regions are also expected to reduce 2018 formula O&M savings by approximately $750 thousand. It is reasonable to expect these type of related cost pressures will continue into the future.

For 2018, the incremental cost pressures discussed above total to approximately $2.6 million and are expected to contribute to the forecast decline in formula O&M savings.

To offset some of these cost pressures, FEI has been continuing its ongoing productivity focus, including a broad-based Company-wide effort to seek alternate solutions to the filling and pursuing initiatives that result in savings that are shared with customers while maintaining service levels.

The cost pressures discussed above have related FTE/Headcount impact and have been considered in the 2018 Projected FTE/Headcount by FEI. However, FEI has not specifically identified FTE/Headcount with each cost pressure and instead has forecast staffing requirements at a general department level only.

1.1.1 Please discuss why these cost pressures are new for 2018 and 2019 and whether FEI expects these cost pressures to continue beyond 2019.

Response:

Please refer to the response to BCUC IR 1.1.1.

1.1.2 To the best of FEI's ability, please quantify these cost pressures by year.

Response:

Please refer to the response to BCUC IR 1.1.1.

1.1.3 Please discuss if these new cost pressures will result in additional headcount and Full Time Equivalents (FTEs) and quantify where possible. Please also indicate whether the additions have already been included in Table 1–3.

Response:

Please refer to the response to BCUC IR 1.1.1.

On pages 5–6 of the FEI Annual Review for 2018 Delivery Rates proceeding (2018 Annual Review) application, FEI explained that it is experiencing incremental cost pressures related to integrity digs.

In response to British Columbia Utilities Commission (BCUC) Information Request (IR) 1.5 in the 2018 Annual Review, FEI stated:

> One particular revision in the published CSA Z662-15 standard that remains under assessment by FEI and may result in future cost pressures is a requirement to consider sharp dents with a length to depth ratio less than 20 as defects unless their measured curvature strain is less than 6 percent, or unless determined by an engineering assessment to be acceptable.

1.2 Please provide any updates regarding FEI's assessment of the revision to the CSA Z662-15 standard referenced in the above preamble and whether, as a result of FEI's assessments, there has been an increase in cost pressures.

Response:

To date, there has been no increase in cost pressures as a result of the above revision to the CSA Z662-15 standard. FEI is continuing its assessments, including working with in-line inspection vendors to provide additional data from prior years' inspections. It is anticipated that the additional data will enable better characterization of these dents, which may result in fewer being considered sharp (and consequently requiring excavation and repair).

In response to BCUC IR 1.7 in the 2018 Annual Review, FEI provided three tables related to integrity digs and structural repairs.

1.3 Please update the first table (i.e. the number of digs per year) to provide the actual 2017 results, the 2018 Year End Forecast (YEF) and the 2019 Forecast number of digs. Please explain any significant variances in 2017 actual results compared to historical results.

Response:

Reason for Digs	Number of Digs per Year								
	2011	2012	2013	2014	2015	2016	2017	2018 YEF	2019 Forecast
Dent digs (includes dig selections that were influenced by the strain-based criteria)	0	6	27	12	10	32	21	15	Under development (u/d)
Circumferential magnetic flux leakage in-line inspection digs	0	0	0	27	20	11	44	39	u/d
Other ILI digs	45	24	21	19	32	33	25	36	u/d
Non-ILI digs	9	8	4	4	2	0	8	5	u/d
Total Integrity Digs	**54**	**36**	**52**	**62**	**64**	**76**	**98**	**95**	**≈ 105 +/- 10%**

As discussed in the responses to BCUC IRs 1.1.7 and 1.1.8 from FEI's Annual Review for 2018 Rates, strain-based criteria for dents have resulted in dent dig increases in 2016 and 2017 compared to historical results. Please refer to the response to BCUC IR 1.1.2 for information pertaining to FEI's dent dig forecasts.

With respect to circumferential magnetic flux leakage (CMFL) in-line inspection digs, there were more digs in 2017 compared to historical results. Based on findings from integrity digs of CMFL-detected features during 2014 to 2016, FEI determined that additional integrity digs were required to assess pipe condition. This analysis process applies to all in-line inspections, and will periodically result in identifiable incremental volumes of work. Upon completion of an in-line inspection run, it can take up to 6 months or longer prior to defining required integrity digs.

1.4 Please update the second and third tables (i.e. number of structural repairs per year and percent of repairs associated with dents) to include 2017 results. Please explain any significant variances in 2017 actual results compared to historical results.

Response:

The requested table is provided below.

Reason for Structural Repairs	Number of Structural Repairs per Year						
	2011	2012	2013	2014	2015	2016	2017
Dent repairs due to CSA Z662 criteria	1	1	0	1	1	1	1
Dent repairs due to FEI determination	0	3	2	3	1	12	8
Metal loss repairs due to CSA Z662 criteria	4	0	1	2	2	1	2
Metal loss repairs due to FEI determination	0	2	0	2	3	2	2
Other repairs (e.g. weld-related issues, material testing cutouts)	5	1	2	2	2	0	2
Total Structural Repairs	**10**	**7**	**5**	**10**	**9**	**16**	**15**
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
% of Repairs Associated with Dents (includes repairs resulting from the strain based criteria)	10%	57%	40%	40%	22%	81%	60%

Although there has been an increase in the category Dent repairs due to FEI determination in 2016 and 2017, this is not unexpected given the increased number of integrity digs for dents in those years (32 in 2016 and 21 in 2017). Other factors that contribute to year-to-year fluctuations in dent repairs include variations in terrain condition (e.g. pipelines installed in rocky terrain tend to have more dents), the number of third-party damages found, and the number of features identified to be interacting with existing dents.

In response to BCUC IR 1.9 in the 2018 Annual Review, FEI provided the following update on "notable initiatives" related to in-line inspection and integrity management:

- Provision of in-line inspection capability to NPS 6 outside diameter and larger transmission pipelines operating at hoop stresses of 30% or more of the specified minimum yield strength of the pipe;
- Assessment of the need for and feasibility of adopting crack-detection capabilities within FEI's in-line inspection program; and
- Development of enhanced risk assessment capabilities to enable FEI's vision of managing the integrity of its transmission pipeline assets through a quantitative risk-based approach by 2020.

1.5 Please provide a further update on the above initiatives and describe any new initiatives (if any).

Response:

FEI's progress on the above initiatives, including a discussion of impacts on cost pressures, is as follows:

- With respect to provision of in-line inspection capability to NPS 6 outside diameter and larger transmission pipelines operating at hoop stresses of 30 percent or more of the minimum yield strength of the pipe, FEI is planning to submit a CPCN application for the Inland Gas Upgrades Project later in 2018 to address this issue. The pipelines within the scope of the Inland Gas Upgrades Project will require varying levels of O&M and Sustainment Capital expenditures over their lifecycle depending on the proposed integrity management solution for each of the pipelines. The proposed solutions include an ongoing ILI program (e.g. recurring ILI tool runs, data analysis, integrity digs, etc.), the installation and/or upgrade of pressure-regulation facilities to reduce the operating stress of the line, and pipeline replacement. Forecasts of expenditures are under development. FEI is currently forecasting a near-term incremental $500 thousand per year for integrity digs on its non-piggable pipelines for managing time-dependent threats such as corrosion.

- With respect to its assessment of the need for and feasibility of adopting crack-detection capabilities within FEI's in-line inspection program, FEI's assessments to-date indicate that this is needed and feasible with process changes, including changes to operational practices, and infrastructure modifications. As such, FEI is seeking approval of a new non-rate base deferral account to capture development costs associated with this project, referred to as the Transmission Integrity Management Capabilities (TIMC) project. Similar to the Inland Gas Upgrades Project, this project will also require varying levels of O&M and Sustainment Capital expenditures over the lifecycle of impacted pipelines depending on the integrity management solution. Forecasts will be developed as part of FEI's preparation of its CPCN application for the project. Please also refer to the response to BCUC IR 1.8.9.

- With respect to its development of enhanced risk assessment capabilities to enable integrity management of transmission pipeline assets through a quantitative risk-based approach by 2020, FEI has identified that a quantitative risk assessment is required to support its CPCN development for the TIMC project and to meet its commitments to the BC Oil and Gas Commission. The CPCN is expected to be filed in mid-2020. The quantitative risk assessment will identify pipelines requiring modifications, as well as their urgency and priority. This assessment will also provide a quantified determination of the need for adopting crack-detection tools, with the result either supporting FEI's continued path toward crack-detection ILI or supporting alternative lifecycle integrity management solutions. In addition to system modifications required to adopt crack-detection in-line inspection tools within its transmission pipeline system, the CPCN application for the TIMC project will describe resources required to establish sustainable

processes for repeatable quantitative risk assessments necessary for the ongoing management and reassessment of FEI's aging transmission pipelines. Incremental O&M and Sustainment Capital forecasts will be developed as part of FEI's CPCN preparation.

FEI has no other "notable initiatives" related to in-line inspection or integrity management to report on at present.

1.5.1 Please discuss each of the above, including any new, initiative's current and future impacts on cost pressures.

Response:

Please refer to the response to BCUC IR 1.1.5.

2.0 Reference: EVALUATION OF THE PBR PLAN

Exhibit B-2, Section 1.4.2, p. 6; Appendix C3, pp. 1-2, Tables C3-1 & C3-2; 2018 Annual Review, Exhibit B-3, BCUC IR 2.8, 2.9, & 2.10

Staffing levels

Table C3-2 in Appendix C3 of the Application provides information on the changes in annual FTEs, including the following information:

- Actual 2017: increase of 25 FTEs outside of Base O&M
- Actual 2017: increase of 42 FTEs inside of Base O&M
- Projected 2018: increase of 58 FTEs outside of Base O&M
- Projected 2018: increase of 21 FTEs inside of Base O&M

On page 6 of the Application, FEI states:

> Of the 67 FTEs increase observed from 2016 (1,581 FTEs) to 2017 (1,648 FTEs), approximately 28 were in the Operations and Engineering area, including Tilbury LNG, in response to increased operational and capital work requirements; approximately 14 in the Contact Centre and Billing Operations resulting from the timing of new hire classes, with the remainder of the overall increase in various departments throughout the Company.

In response to BCUC IR 2.8 in the 2018 Annual Review, FEI stated the following:

> On a FTE basis, for the total projected increase in FTEs of 69, approximately 25 FTEs are related to new positions and 44 FTEs are related to filling of vacancies, and seasonal and temporary staffing. For the approximate 25 FTEs related to new positions, 3 FTEs are for the Tilbury LNG Plant Expansion, 4 FTEs are in the Project Management Office department, 2 FTEs are in the Conservation Energy Management department, 6 FTEs are in Operations, 3 FTEs in Market Development and External Relations, and the remaining 7 FTEs are in various other departments.

In response to BCUC IR 2.9 in the 2018 Annual Review, FEI explained the projected increase in headcount for 2017 in terms of positions inside and outside of Base O&M.

2.1 With reference to the explanations provided by FEI in the 2018 Annual Review, please provide an updated explanation for the 2017 actual FTE and headcount additions in 2017.

Response:

In comparing 2017 against 2016 Actual, FTEs increased by 67 while headcount increased by 68. This was consistent with the 2017 projected increase of 69 FTEs and 57 headcount. More information is provided in the response to BCUC IR 1.2.3.

From a total resources required perspective, management of new and vacant positions and consideration for use of other resources like contractors and consultants where appropriate all contribute to meeting the resource needs of the Company. Factors contributing to variances between actual and projected FTE/headcount include the timing of employee hires, unanticipated turnover and use of contractors and consultants.

The timing of the hiring/termination of employees will impact the reported change in FTEs/headcount year over year. For example, employees added closer to the end of 2016 will have less of an impact on the reported FTEs in 2016 (i.e. less than full FTEs) due to their late hiring in the year. However, the added employees are reported as part of the headcount (i.e. full headcount) at the end of 2016. When the same employees carryover into 2017 (i.e. the same employees that were added in late 2016), they are reported as full FTEs for 2017 and included in the headcount (i.e. full headcount) for 2017. In this example, FTEs will increase in 2017 compared 2016, reflecting their full year impact with headcount remaining the same.

2017 vs 2016 Actual – New and Vacant positions

For the total 67 FTEs increase, approximately 30 FTEs are related to new positions and 37 FTEs are related to filling of vacancies, and seasonal and temporary staffing. For the 30 FTEs related to new positions, 5 FTEs are for the Tilbury LNG Plant Expansion, 4 FTEs are in the Project Management Office department, 1 FTE in the Conservation Energy Management department, 13 FTEs are in Operations and Engineering, 3 FTEs are in Market Development and External Relations, and the remaining 4 FTEs are in various other departments.

On a headcount basis, for the total increase in headcount of 68, approximately 52 are related to new positions and 16 are related to filling of vacancies, seasonal and temporary staffing. For the 52 headcount related to new positions, 4 headcount are for the Tilbury LNG Plant Expansion, 8 headcount are in the Project Management Office department, 5 headcount are in the Conservation Energy Management department, 19 headcount are in Operations and Engineering, 5 headcount are in Market Development and External Relations, and the remaining 11 are in various other departments.

For the changes related to filling of vacancies, seasonal and temporary staffing, the increase of 37 FTEs or 16 headcount are related to the filling of vacancies and seasonal staffing primarily in Customer Service, Market Development and External Relations and Operations and Engineering.

2017 vs 2016 Actual – Inside and Outside Base O&M positions

Of the total 68 increase to headcount[1] in 2017, 29 positions have been added to Outside of Base O&M and 39 positions are Inside of Base O&M.

The 29 positions (i.e. headcount) added to Outside of Base O&M relate to the following:

- 4 positions for the Tilbury Plant Expansion;
- 5 positions for Conservation and Energy Management activities;
- 8 positions for the Construction Supervisors Charged to capital; and
- The remainder consists of various positions primarily in support of capital activities.

The 39 positions (i.e., headcount) added to Inside of Base O&M relate to new positions and filling of vacancies primarily in Operations and Engineering, Market Development and External Relations and Customer Service.

2.2 With regard to 2018, please separately provide the number of projected increases in FTEs and headcount for 2018 which are related to new positions (i.e. positions added to a department that were not previously there and are thus incremental to FEI) versus filling of vacancies (i.e. existing positions).

Response:

The response below addresses BCUC IRs 1.2.2 and 1.2.2.1.

2018 Projected vs 2017 Actual – New and Vacant positions

On an FTE basis, of the total projected increase in FTEs of 79, approximately 36 FTEs are related to new positions and 43 FTEs are related to filling of vacancies, and seasonal and temporary staffing. Of the 36 FTEs related to new positions, 6 FTEs are for the Tilbury LNG Plant Expansion, 1 FTE is in the Project Management Office department, 1 FTE is in the Conservation Energy Management department, 20 FTEs are in Operations and Engineering, 2 FTEs are in Market Development and External Relations, and the remaining in various other departments.

[1] Refer to Appendix C3 of the Application clarifying the reporting of headcount and FTE for Outside of Base O&M.

On a headcount basis, of the total increase in headcount of 81, approximately 59 headcount are related to new positions and 22 headcount are related to filling of vacancies, and seasonal and temporary staffing. Of the 59 headcount related to new positions, 9 headcount are for the Tilbury LNG Plant Expansion, 2 headcount are in the Project Management Office department, 2 headcount are in the Conservation Energy Management department, 38 headcount are in Operations and Engineering, 3 headcount are in Market Development and External Relations, and the remaining in various other departments.

The projected increase of approximately 43 FTEs or 22 headcount related to the filling of vacancies, and seasonal and temporary staffing are primarily in the Project Management Office, Market Development and External Relations and Operations and Engineering.

2018 Projected vs 2017 Actual – Inside and Outside Base O&M positions

FEI's responses addressing headcount/FTEs changes classified by Inside and Outside Base O&M are approximations only, due to the difficulty in reporting by headcount and FTEs. This was discussed on page 2 of Appendix C3 of the 2019 Annual Review Application:

> Reporting on the classifications requested by headcount and FTE is inherently difficult. The headcount information provided in Table C3-1 has been completed in a similar manner to that reported on an FTE basis in Table C3-2 (i.e. one FTE equals one headcount). Where there are differences between the headcount and FTE information (which are typically caused by vacancies within a given period and the use of part-time and temporary employees), for the purpose of the information requested, the differences are reported as part of the Inside Base O&M classification, recognizing that the Inside Base O&M classification accounts for the majority of headcount and FTE at FEI.

The FTE and headcount numbers and the changes reported are the same for the outside of Base O&M.

Of the total projected 81 increase to headcount in 2018, approximately 62 positions are Outside of Base O&M and 19 positions are Inside of Base O&M.

The 62 positions (i.e. headcount) added to Outside of Base O&M relate to new positions and filling of vacancies for the following:

- 10 positions for the Tilbury Plant Expansion;
- 7 positions for the Charges to Deferral accounts; and
- The remainder consists of various positions primarily in Operations and Engineering in support of capital activities.

The 19 positions (i.e. headcount) added to Inside of Base O&M relate to new positions and filling of vacancies in Operations and Engineering, Market Development and External Relations and other departments.

2.2.1 With regard to the addition of new positions, please explain the nature of the new positions and how many of the new positions are inside and outside of Base O&M. Please provide the response in a similar level of detail as was provided in response to BCUC IRs 2.8 and 2.9 in the 2018 Annual Review.

Response:

Please refer to the response to BCUC IR 1.2.2.

Tables C3-1 and C3-2 in Appendix C3 of the Application provide information on the total annual headcount and FTEs, respectively, including the following information:

- Actual 2017: 1,735 headcount; 1,648 FTEs
- Projected 2017: 1,724 headcount; 1,650 FTEs
- Projected 2018: 1,816 headcount; 1,727 FTEs

2.3 Please explain why there were 11 more positions (headcount) filled in 2017 than projected and how this corresponds to the change in actual FTEs for 2017 (i.e. 2 less FTEs than projected).

Response:

For clarity, headcount represents that total number of employees at a certain time (i.e. year end) whereas FTEs represents the average FTE count over a period of time (i.e. year).

The variance between the projected 2017 headcount/FTEs and the actual 2017 headcount/FTEs is small, at less than one percent of the total forecast headcount/FTEs. Contributing to the small variance observed for headcount were employee hires in Operations in late 2017 for Distribution Apprentices that were not included in the projection.

As highlighted, the timing of the hiring/termination of employees will impact the reported FTEs/headcount. For example, employees (full time and temporary/part-time) added closer to the end of 2017 will have less of an impact on the reported FTEs in 2017 (i.e. less than full FTEs) due to their late hiring in the year. However, the added employees are reported as part of the headcount (i.e. full headcount) at the end of 2017.

2.4 Please identify the number of vacant positions broken down by outside of Base O&M, inside of Base O&M and by department at the end of 2017 and whether these positions are projected to be filled at the end of 2018.

Response:

There were approximately 22 vacant positions at the end of 2017 that are projected to be filled by the end of 2018. 14 positions are from Operations and Engineering, 3 positions from Project Management Office, and the remaining are from the other departments. Approximately 13 of the 22 positions are projected to be inside of Base O&M and 9 positions are projected to be outside of Base O&M.

2.5 Please explain why FEI is projecting such a large increase in FTEs outside of Base O&M for 2018, particularly when compared to years 2013 through 2017.

Response:

FEI is projecting an increase of about 58 FTEs for outside of Base O&M in 2018 primarily due to an increase in staffing required for higher capital activities. As mentioned on page 6 of the Application, new main and service installations are at a high level. There are more permitting and other requirements needed to receive approval and install new assets. The projected 58 FTE increase is comprised of approximately 45 FTEs for Charges to Capital activities, primarily supported with staffing from the Operations and Engineering areas, 6 FTEs for the Tilbury LNG Plant Expansion and 7 FTEs for Charges to Deferral accounts.

FEI is currently updating its overheads capitalized study to determine if a change is required to the capitalized overhead rate due to the continued growth in capital activities. If a change is required, FEI will request approval starting in 2020.

On page 6 of the Application, FEI states:

> These decreases are now being offset by increased staffing primarily in the Operations and Engineering area to meet operational and capital work requirements. FEI is growing and adding new assets that require maintenance to keep them operating safely and reliably. In addition, assets are aging and requiring additional maintenance and corrective work. Emergency calls, BC One Call tickets and activities around our pipelines are all increasing. Municipal agreements, codes, regulations, public expectation, and industry practices continue to evolve and drive additional work. New main and service installations are at high levels.

2.6 Please provide a table showing the changes in headcount and FTEs from 2013 to Projected 2018 broken down by sustainment, growth and other activities (e.g. municipal agreements, codes, regulations, public expectation and industry practices).

Response:

FEI does not track headcount and FTE information by the requested categories. FEI's Human Resources systems track employees and the positions that they occupy, as well as which part of the organization they belong to. In addition, the systems track changes in the status of positions, positions added and removed. FEI, however, does not track headcount and FTE information by the categories of Growth, Sustainment and Other. FEI also notes that the "other activities" described in the question (e.g. municipal agreements, codes, regulations, public expectations and industry practices) are drivers of growth and sustainment work, and not necessarily considered a separate category of activity. As a result, FEI is not able to provide the requested information.

Please refer to FEI's responses to BCUC IRs 1.2.1 to 2.5 for explanations of the overall headcount and FTE changes observed, including changes for the Operations and Engineering groups that support sustainment and growth capital.

In response to BCUC IR 2.10 in the 2018 Annual Review, FEI provided the following table:

Year	Affilation	Headcount	Average FTEs	Headcount change year over year	Average FTEs change year over year
2013 Actual	MoveUp	764	702		
	IBEW	528	520		
	M&E	472	457		
	Total	**1,764**	**1,679**		
2014 Actual	MoveUp	711	656	(53)	(46)
	IBEW	499	502	(29)	(18)
	M&E	494	492	22	36
	Total	**1,704**	**1,650**	**(60)**	**(28)**
2015 Actual	MoveUp	674	616	(37)	(40)
	IBEW	497	488	(2)	(14)
	M&E	485	469	(9)	(24)
	Total	**1,656**	**1,573**	**(48)**	**(77)**
2016 Actual	MoveUp	626	588	(48)	(28)
	IBEW	529	511	32	23
	M&E	512	482	27	13
	Total	**1,667**	**1,581**	**11**	**8**
2017 Projected	MoveUp	633	591	7	3
	IBEW	541	533	12	22
	M&E	550	527	38	45
	Total	**1,724**	**1,650**	**57**	**69**

2.7 Please complete the table above with Actual 2017 and Projected 2018 results.

Response:

The following table includes the Actual 2017 and Projected 2018 results.

Year	Affilation	Headcount	Average FTEs	Headcount change year over year	Average FTEs change year over year
2013 Actual	MoveUp	764	702		
	IBEW	528	520		
	M&E	472	457		
	Total	**1,764**	**1,679**		
2014 Actual	MoveUp	711	656	(53)	(46)
	IBEW	499	502	(29)	(18)
	M&E	494	492	22	36
	Total	**1,704**	**1,650**	**(60)**	**(28)**
2015 Actual	MoveUp	674	616	(37)	(40)
	IBEW	497	488	(2)	(14)
	M&E	485	469	(9)	(24)
	Total	**1,656**	**1,573**	**(48)**	**(77)**
2016 Actual	MoveUp	626	588	(48)	(28)
	IBEW	529	511	32	23
	M&E	512	482	27	13
	Total	**1,667**	**1,581**	**11**	**7**
2017 Actual	MoveUp	631	591	5	3
	IBEW	550	533	21	21
	M&E	554	524	42	43
	Total	**1,735**	**1,648**	**68**	**67**
2018 Projected	MoveUp	634	590	3	(2)
	IBEW	595	578	45	46
	M&E	588	559	34	35
	Total	**1,816**	**1,727**	**81**	**79**

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3.0 Reference: MAJOR INITIATIVES UNDERTAKEN

Exhibit B-2, Section 1.4.3, p. 8; Appendix C2, p. 4, Table C2-5; Appendix C3, pp. 1-2, Tables C3-1 & C3-2

Online Service Application initiative

On page 8 of the Application, FEI states:

> The Online Service Application (OSA) initiative enables customers to make a self-serve online request for a new service line installation and was launched on the Company's external website in September 2016. In March 2017, the additional functionality of requesting a service line abandonment was added to the tool.… Annual savings were approximately $0.05 million in 2017 and future years.

Table C2-5 in Appendix C2 of the Application states that no organizational changes are expected from the OSA and $0.05 million annual O&M savings were incurred in 2017 and expected in future years.

Tables C3-1 and C3-2 in Appendix C3 of the Application do not show any reductions in headcount or FTEs for 2016 and onwards from "Other Major Initiatives".

3.1 Please explain what the $0.05 million annual O&M savings are related to.

Response:

The $0.05 million savings represent approximately 1 FTE savings in the Contact Centre.

3.2 Please explain why the OSA does not result in any reductions in headcount or FTEs.

Response:

While the OSA results in a reduction of workload equivalent to one FTE, the OSA has also enabled the reassignment and reallocation of work to meet other needs within the Contact Centre rather than reducing headcount.

4.0 Reference: MAJOR INITIATIVES UNDERTAKEN

Exhibit B-2, Section 1.4.3, p. 8

SAP Integration initiative

On page 8 of the Application, FEI states:

> The project is in progress and is tracking well to the schedule, with completion expected in the third quarter of 2018. The total cost of the project remains on budget, estimated at $4.5 million. Based on the number of employees between the two companies, which is currently projected at approximately 77% FEI and 23% for FBC, approximately $3.5 million of the implementation costs will be allocated to FEI with the remaining $1.0 million to FBC. Total O&M savings for the project are expected to be approximately $0.9 million annually, with $0.6 million expected in FEI and $0.3 million FBC. The savings will start being realized in 2019.

4.1 Please clarify if the estimated project costs of $4.5 million will be allocated between FEI and FortisBC Inc. (FBC) based on the number of employees between the two companies at the point in time when the project is brought into service.

Response:

The estimated project cost of $4.5 million consist of $4.2 million of capital expenditures and $0.3 million of one-time operating costs. The total project cost of $4.5 million will be allocated between FEI and FBC based on the number of employees in the third quarter of 2018 when the project is brought into service. This allocation is currently projected at approximately 77 percent FEI and 23 percent for FBC.

4.2 Please clarify if the estimated annual O&M savings of $0.9 million will be allocated between FEI and FBC based on the number of employees between the two companies at the end of each year.

Response:

The estimated annual O&M savings of $0.9 million allocated between FEI and FBC, of $0.6 million and $0.3 million, respectively, is not based on the number of employees, but rather is based on the identifiable savings within each of FEI and FBC.

For details of the allocation of the estimated annual O&M savings between FEI and FBC, please refer to FEI's response to Undertaking No. 5 in FEI's Annual Review for 2018 Rates proceeding:

http://www.bcuc.com/Documents/Proceedings/2017/DOC_50235_B-11_FEI%20-Workshop-Undertakings.pdf

5.0 Reference: MAJOR INITIATIVES UNDERTAKEN

Exhibit B-2, Section 1.4.3, p. 9; Appendix C2, p. 5, Table C2-7

Gas Workforce Management initiative

On page 9 of the Application, FEI states:

> The project will streamline and improve work processes, and replace Syclo, ClickSchedule, and Tensing Mobile GIS. The Syclo system has not been significantly upgraded since its implementation in 2008 and is at end of life. ClickSchedule and Tensing Mobile GIS are nearing end of life and due for replacement. Bundling these 3 systems will simplify the user experience while providing FEI with the flexibility for future growth and improvement.
>
> The project is underway with completion expected in late 2019. The total cost of the project is estimated at approximately $6.5 million and will produce O&M savings of approximately $0.5 million annually starting in 2020.

Table C2-7 in Appendix C2 of the Application includes the following information:

- Organizational changes: none
- O&M expenditures incurred or expected in 2017-2019: $0.7 million
- Capital expenditures incurred or expected in 2017-2019: $5.8 million
- Annual anticipated savings: $0.5 million beginning in 2020

5.1 When were ClickSchedule and Tensing Mobile GIS implemented and how close is each system to its end of life?

Response:

Syclo, ClickSchedule, and Tensing Mobile GIS are at or near end of life and need to be replaced. The three systems are critical for FEI's Operations and, if Gas Workforce Management were delayed, these systems would need to be upgraded to extend their life so that FEI could continue to use them for another year. The cost to maintain these systems and extend their life for an additional year is estimated at approximately $0.7 million and would not offer any operational improvements. Syclo is at end of life and ClickSchedule and Tensing Mobile GIS end of life is 2020. When software, or the version of software, reaches end of life the vendors stop producing, supporting, maintaining the software, and providing cybersecurity patches. It becomes increasingly difficult to continue to use the software and the risk of security issues increases. Any extension to the life of these systems would only last a year or two. All three systems are fully depreciated.

5.2 Please clarify whether, if the Gas Workforce Management project was delayed, the existing systems (i.e. Syclo, ClickSchedule and Tensing Mobile GIS) could continue to be used for another year.

Response:

Please refer to the response to BCUC IR 1.5.1.

5.3 Please provide a more detailed description and breakdown of the projected O&M and capital costs by year.

Response:

The breakdown of the O&M expenditures incurred or expected in 2017 – 2019 is as follows:

Year	Expenditure	Description
2017	$70,000	Development of Processes, Change Management Strategy, Communications Strategy and Training Strategy
2018	$200,000	Development of Change Management and Detailed Training Plan, Execution of Change Management, Communications and Training Plan
2019	$850,000	Development of Training and Support Materials, Execution of Change Management Plan, Delivery of Training
Total	$1,120,000	

The O&M expenditures have increased since the Application was filed. As FEI developed the detailed training plan, previously unaccounted for training expenses were identified.

The breakdown of the capital expenditures incurred or expected in 2017 - 2019 is as follows:

Year	Expenditure	Description
2017	$740,000	Clevest MWFM Software Licenses, Clevest Professional Services and Internal Labour to develop Requirements and Design
2018	$2,190,000	Clevest Professional Services and Internal Labour to complete Design, Configure Software, Build Interfaces and Test Software
2019	$2,870,000	Clevest WorkBook and WorkSpace Software Licenses, Clevest Professional Services to Configure Software, Build Interfaces, Test and Deploy Software to Production
Total	$5,800,000	

5.4 Please describe the nature of the expected $0.5 million annual O&M savings.

Response:

The O&M savings are the result of reduced IS maintenance costs and Operations labour savings. Labour savings are expected to materialize as overtime reductions and are primarily the result of integrating Syclo, ClickSchedule, and Tensing Mobile GIS into a single application, bar code scanning of meters, elimination of paper forms and documents, and shut-off/relight list automation.

5.5 Please discuss if any reductions in headcount or FTEs are anticipated once the Gas Workforce Management project is fully implemented. If yes, please quantify. If no, please explain why not.

Response:

There is no headcount or FTE reduction anticipated once Gas Workforce Management Project is implemented. The Gas Workforce Management Project is a system replacement project driven by Syclo, ClickSchedule and Tensing Mobile GIS end of life and the technical risk of outdated systems.

5.6 Please explain what system is replacing Syclo, ClickSchedule, and Tensing Mobile GIS and why this system was chosen.

Response:

Syclo, ClickSchedule and Tensing Mobile GIS are being replaced by Clevest Workbook and Workspace. Clevest was chosen because the system met the FEI evaluation criteria better than any other proponent. FEI went through an extensive review and evaluation process before Clevest was chosen. The process included initial vendor demonstrations, Request for Information (RFI) and Request for Proposals (RFP) with five different software solutions

reviewed and three proponents shortlisted. Reference checks and site visits were undertaken. Selection criteria used included functional compliance, technology compliance, service and support, vendor viability, vendor strategy and vision, O&M costs, and capital costs. Following this rigorous selection process, Clevest was selected as the successful proponent.

Additionally, unlike the other leading workforce management software proponents who support a broad range of industries, Clevest is strictly focused on developing innovative solutions for the utilities industry.

The remainder of this response is being redacted and filed confidentially pursuant to Section 18 of the Commission's Rules of Practice and Procedure regarding confidential documents established by Order G-1-16. The information is of a commercially sensitive nature, and significant harm or prejudice to FEI's vendors and to FEI's competitive or negotiating position are reasonably expected to result if the confidential information was made public.

[redacted]

[redacted]

5.7 Please explain what alternatives, if any, FEI explored to the chosen replacement system, and why each alternative was determined less desirable than the chosen option.

Response:

Please refer to the response to BCUC IR 1.5.6.

6.0 Reference: MAJOR INITIATIVES UNDERTAKEN

Exhibit B-2, Section 1.4.3, p. 9

Common Trenching initiative

On page 9 of the Application, FEI states:

> Common Trenching is an initiative to improve the customer experience by introducing four-party trenching for new subdivisions and townhouse developments…
>
> …To date, FEI has completed four party trenching projects in the Fraser Valley, Okanagan and Vancouver Island. The projects have generated many learnings and satisfied customers, as well as provided FEI with opportunities to determine best practices and improve the process.

6.1 Please explain the circumstances which precipitated the need/desire for this initiative.

Response:

The Common Trenching initiative was precipitated by FEI's desire to continue to look for opportunities to improve customer experience, safety, and efficiency. FEI recognized the need to improve the construction practices and the industry's desire to work more closely with FEI to streamline new subdivisions and townhouse developments.

6.2 When did FEI commence the Common Trenching initiative? When was the first project undertaken and completed?

Response:

FEI launched the Common Trench initiative in January 2018. The first project was undertaken and completed in March 2018.

FEI started exploring the viability of common trenching in October 2014 and undertook a variety of small subdivisions and townhouse development projects where the customer provided the trench and FEI crews installed the pipe. From 2014 through 2017, FEI worked closely with customers and civil contractors to evolve the initiative and in February 2018 engaged select civil contractors to install gas infrastructure concurrently with other shallow utilities.

6.3 How many four-party trenching projects have been completed to date and how many are currently in-progress?

Response:

FEI has completed approximately 40 projects since introducing the Common Trench Initiative in January 2018 and has an additional 20 projects in-progress.

6.4 With reference to specific completed projects, please provide the total capital and O&M costs incurred to complete the projects and how these costs would have compared to FEI's status quo approach. Please also explain whether the projects required more resources (labour and other) than the status quo approach.

Response:

Expenditures for new subdivisions and townhouse developments are primarily capital in nature with no direct O&M costs.

As stated in the Application on Page 9, FEI is not able at this time to estimate the level of savings that may be achieved. The overall initiative is still in its beginning stages since its introduction in early 2018, making it difficult to provide meaningful cost analysis that is representative of the level of savings expected. Additionally, as the costs for many of the completed projects have not been finalized at this time, FEI is not able to provide the total capital expenditures incurred to date for the completed projects.

FEI expects reduced installation costs over time because Common Trench projects generally require less FEI resources to complete due to improved coordination with civil contractors, more efficient crew usage, and less civil infrastructure restoration.

6.5 Please confirm, or explain otherwise, that the trenching costs are considered to be inside Base O&M and/or capital.

Response:

The trenching costs associated with the Common Trenching initiative for new subdivisions and townhouse developments are included in Growth Capital expenditures as part of overall Base Capital. There are no direct O&M costs.

6.6 Please discuss if FEI anticipates both O&M and capital savings from four-party trenching projects.

Response:

Please refer to the responses to BCUC IRs 1.6.4 and 1.6.5.

6.7 Please discuss the quantitative and qualitative measures that FEI is using to assess the success of the Common Trenching initiative.

Response:

FEI is using the following quantitative and qualitative measures to assess the success of the Common Trenching initiative:

Qualitative

- **Customer Experience** - this is a measure of customers' feedback on the Common Trenching initiative. Improving the customer experience is a focus for FEI's Common Trenching initiative. FEI expects the customer to experience reduced construction time and development costs. The customer can work with their civil contractor and install gas infrastructure on their schedule with less coordination with FEI resources. In some cases, common trenching can reduce the amount of land required for roads right of ways.

Quantitative

- **Number of projects** – the number of the projects completed (i.e. the higher the better) is an indication of the demand and success of the initiative. As more projects are

completed using Common Trenching, FEI resources can be redirected to other aspects of operations.

- **Average number of days to complete projects** – reducing the number of days required to complete projects will be important to ensuring gas pipe is being installed on a timely basis. Reducing number of days to complete projects is beneficial as it enables developers to complete their projects faster reducing financing and other costs, and getting their product to market faster.

- **Costs for Common Trench projects** – monitoring the costs of the projects will help to ensure the projects are completed in a cost effective manner, leading to possible savings compared to the status quo over the long term. This initiative is expected to make it more economical for FEI to provide service and add customers resulting in benefits for all FEI customers.

6.8 With reference to specific completed projects, please provide a detailed discussion of the "lessons learned" from the projects, the implications (cost or other) of the issues which have arisen on the completed projects, and how FEI plans to address the issues in the future.

Response:

The lessons learned and plans to address the issues from the completed Common Trench projects are as follows:

Lessons Learned	Plan to address the issue	Implication
Comprehensive process and documentation is needed to embed Common Trenching into Operations and have consistent application of the initiative.	Engage design and execution stakeholders within FEI (Operations and Planning Managers) to standardize the process and develop the necessary documentation.	Resources for training and implementation will need to be available to complete the work.
Internal systems (SAP and CAFÉ) need enhancements to support Common Trenching projects. The current systems lack the ability to flag, and track Common Trench Projects.	Implement changes to internal systems to facilitate common trench projects.	Funds will be needed to enhance the systems.
Changes to the material management and delivery process are required to get materials to the civil contractor in a timely manner.	Change the material management and delivery process.	Resource requirements for planning changes, training and implementation.

Lessons Learned	Plan to address the issue	Implication
Additional quality assurance inspection is required to ensure activities performed are in conformance with expected requirements.	Develop a QA process specifically for Common trench projects and train Quality Assurance Supervisors.	Resources requirements to develop the QA process and train Quality Assurance Supervisors.

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7.0 Reference: MAJOR INITIATIVES UNDERTAKEN

Exhibit B-2, Section 1.4.3, pp. 9–10

Information technology opportunities

On page 9 of the Application, FEI states:

> The Planner Tool Box project was implemented in January 2018. The project streamlined and sped up the work order creation process, eliminated repetitive tasks, delivered improvements to user experience/interaction with information systems, and improved customer service. Anticipated labour savings of $0.15 million per year are expected from reduced planner time required to process the different work orders that planners work on (i.e. alterations, install mains, meters, etc.).

7.1 Please discuss if the anticipated labour savings of $0.15 million per year are expected to begin in 2018.

Response:

The Planner Tool Box project was implemented in January 2018 and labour savings of $0.15 million are expected in 2018.

7.2 Please explain if the Planner Tool Box project is expected to result in a reduction to headcount/FTEs and if so, the amount of the reduction. If no, please explain why not.

Response:

The Planner Tool Box project will not result in reduced headcount or FTE for the Company as a whole. Any labour savings will be reassigned to support increased activities and requirements in other areas.

On pages 9 and 10 of the Application, FEI states:

> The “Automate Customer Moves” initiative was completed in February 2018. This removes the need for manual intervention in the back end for processing

requests and improves turnaround time for customers to complete follow-on activities such as registering for paperless billing, equal payment plan and other Company products and services. At present, the automated completion rate is 66 percent of all online gas moves based on a year-to-date volume of 8,820. The estimated annual savings is $0.2 million starting in 2018.

7.3 Please describe the nature of the estimated $0.2 million in annual savings (i.e. labour or non-labour savings) and how the savings are expected to be achieved.

Response:

The $0.2 million in anticipated annual savings represents labour savings expected to be achieved through automating the move process. The automated process is expected to reduce the amount of manual intervention required for moves completed online, thereby reducing the level of FTE effort required.

7.4 Please explain if the Automate Customer Moves initiative is expected to result in a reduction to headcount/FTEs and if so, the amount of the reduction. If no, please explain why not.

Response:

The initiative is expected to result in savings equating to approximately 3 FTEs. These FTE savings may be achieved through allocation of hours, so headcount may not be impacted.

Please refer also to the response to BCUC IR 1.7.3.

On page 10 of the Application, FEI states:

> FortisBC is redesigning its website (www.fortisbc.com) in order to meets its evolving business needs and the needs and expectations of its customers…. Estimated annual savings are forecast to be $0.15 million shared between FEI and FBC. The project is currently underway with completion expected in 2019.

7.5 Please explain the nature of the estimated $0.15 million annual savings and clarify when the savings will begin.

Response:

The estimated $0.15 million annual savings are comprised of labour savings for Communication staff involved in developing and managing web content. The new content management technology platform and workflow functionality will reduce and simplify workload. Content authoring and publishing will become much more streamlined. In addition to gaining operational efficiencies, the new technology and publishing process will help facilitate collaborative team work internally. This will reduce duplicated effort with content management and publishing processes between Communications and Web Services, help improve information flow between service teams, and optimize service levels across channels.

The annual savings is anticipated to start being fully realized in 2020 after some time to operationalize the new functionality available.

7.6 Please explain how the savings will be allocated between FEI and FBC.

Response:

Since this is a shared initiative benefiting both FEI and FBC customers, the expected savings are expected to be allocated between FEI and FBC based on the number of customers of each company, with FEI's share at 88 percent and FBC's share at 12 percent.

7.7 Please provide the following information on the forecast website redesign costs:

- The total forecast O&M and capital costs;
- The time period over which the expenditures are expected to be incurred; and
- How much of the cost will be allocated to FEI and to FBC, and the allocation method which will be used to allocate the costs.

Response:

The total costs for the project are forecast to be approximately $1.4 million, with $1.3 million for capital and $0.1 million for O&M. Similar to the allocation of the savings, the project costs are

expected to be allocated between FEI and FBC based on the number of customers of each company, with FEI's share at 88 percent and FBC's share at 12 percent.

The project started in late 2017 and is expected to be completed in the first quarter of 2019.

Please refer also to the response to BCUC IR 1.7.5.

On page 10 of the Application, FEI states:

> A mobile application to improve ease of access for customers to account information was launched in early 2018. The objective of this customer service focused initiative is to improve ease of access for customers to account information as well as to provide a single point of entry to access current and future products and services. To date, there are 12,000 participants using the tool with a year-end target of 30,000 active users. The application is expected to improve the participation rate in our current online account tool which currently has 388,000 gas customer enrolled, as well as customers' satisfaction in their online experience.

7.8 Please provide the total cost of the mobile application, including the portion of the expenditures that are O&M and capital.

Response:

The total cost of the mobile application was $618,560 for capital expenditures with the costs allocated between FEI (88 percent) and FBC (12 percent) based on the number of customers in each company.

7.9 Please discuss the anticipated savings from the mobile application, including the type of savings anticipated. If no savings are anticipated, please explain why not.

Response:

FEI and FBC did not anticipate savings as a result of the implementation of the mobile application. The initiative was undertaken to improve options for customers, rather than to achieve operational savings. Previous to the application being launched, customers had the ability to access account information on the customer portal and by using self-serve options

over the phone. The implementation of the mobile application provides customers with another channel in which to access their information as well as FortisBC's products and services.

7.10 Is the mobile application also applicable to FBC?

Response:

Confirmed. The mobile application is also applicable to FBC. The reference to the mobile application was inadvertently omitted from the list of customer service initiatives for FBC.

7.10.1 If yes, please explain if the costs and savings are anticipated to be shared between FEI and FBC, and explain the allocation method for the costs and savings.

Response:

Please refer to the responses to BCUC IRs 1.7.8 and 1.7.9.

8.0 Reference: OVERVIEW OF CAPITAL EXPENDITURES

Exhibit B-2, Section 1.4.4, p. 11, Table 1-4; Appendix C4, Table C4-4; 2018 Annual Review, Exhibit B-2, p. 11, Table 1-4; Exhibit B-3, BCUC IR 6.12, 6.15 6.17 & 10.2; FEI Annual Review for 2017 Delivery Rates, Exhibit B-3, BCUC IR 9.9.1

Capital spending results

In Table 1-4 of the 2018 Annual Review application, the projected 2017 variance between formula and actual growth capital was $14.547 million and between formula and actual sustainment/other capital was $26.671 million.

In response to BCUC IR 10.2 in the 2018 Annual Review, FEI stated the following:

> FEI expects that, excluding any variances resulting from growth capital, 2017 will be the year with the largest sustainment/other capital spending variance in the six year PBR term. Overall on a cumulative basis, the sustainment/other capital spending variance (in isolation from the growth capital variance) over the entire PBR term is expected to average to just over 10 percent of the formula, which is very close to being within the dead band. FEI does not consider that level of variance to be significant in the context of the PBR Plan.

Table 1-4 on page 11 of the Application shows the following variances between formula and actual/projected sustainment/other capital:

- Actual 2017 sustainment/other capital variance - $26.311 million
- Projected 2018 sustainment/other capital variance - $31.664 million
- Projected cumulative sustainment/other capital variance - $59.291 million

Table 1-4 also shows an Actual 2017 variance of $26.066 million for growth capital.

8.1 Please explain in detail the causes/factors which resulted in the Actual 2017 variance in growth capital being $11.519 million higher than projected.

Response:

The primary driver of the $11.519 million variance between 2017 Projected and Actual growth capital expenditures is due to higher than anticipated service line additions and gross customer attachments.

At the time of the 2018 Annual review filing, FEI had forecast 2017 service line additions (SLA) of 14,753 and gross customer attachments of 17,000. In the last quarter of 2017, FEI experienced a significant increase in total SLA and customer attachment growth when compared to the same period in prior years.

In 2017, FEI's actual SLAs and gross customer attachments were 15,856 and 21,550, respectively. This represents a 7 percent increase in SLAs and a 23 percent increase in gross customer attachments. As discussed in Appendix C4 Capital Directives of the 2018 and 2019 Annual Review filings, the primary factor contributing to the cost per service line variance is the increase in customer attachments per service line, which results in a higher cost per SLA.

8.2 Please explain the causes/factors which resulted in the Actual 2017 variance in sustainment/other capital being $0.360 million lower than projected.

Response:

The actual 2017 sustainment /other capital was $0.360 million lower than the projected amount primarily due to less than anticipated third-party-driven mains and service alteration activity in the latter half of the year. Third-party-driven main and service alteration activity is especially difficult to predict as a significant portion is done "as and when required" for parties that do not provide long-term plans of their work. FEI ensures that these requests are met in a timely manner in order to ensure the safety and reliability of the system. The $0.360 million variance represents approximately 0.3 percent of the total 2017 Sustainment/Other capital formula.

8.2.1 As part of the above response, please discuss if any sustainment activities scheduled for 2017 were deferred to a future year.

Response:

From a total sustainment/other capital expenditure perspective, no sustainment activities scheduled for 2017 were deferred to a future year, as evidenced by the 2017 actual variance of $26.311 million being similar to the 2017 forecast variance of $26.671 million. Please refer to the response to BCUC IR 1.8.2 for discussion of this variance.

However, within the different activities (e.g. transmission in-line inspection program, distribution stations upgrade program, distribution mains renewal program, etc.), it is common practice to defer or advance specific projects based on a number of factors. These factors include material and labour resource availability; design completion; site access, permitting and preparation; weather and natural hazards; third party involvement; and, based on an evaluation of risk, to manage the total sustainment capital expenditure.

8.3 Please explain the change in circumstances and spending between FEI's response to BCUC IR 10.2 in the 2018 Annual Review and the preparation of the current Application which led to the projected 2018 spending variance in sustainment/other capital to exceed the spending variance in 2017.

Response:

Since FEI filed its Annual Review for 2018 Rates, there has been an increase in the projected sustainment/other spending for 2018 of approximately $6 million. The main reason for this increase is for additional fleet and equipment requirements related to capital growth. FEI has identified new vehicle and equipment requirements associated with the addition of Operations headcount. The majority of these positions are related to construction crews required to assist with the increasing volume of growth capital projects.

8.3.1 In consideration of the above response, please discuss FEI's expectations regarding 2019 sustainment/other capital spending and the expected variance between formula and actual spending compared to previous years.

Response:

The variance between forecast sustainment/other capital spending and the formula amount for 2019 that was forecast at the time of the 2018 Annual Review was approximately $24 million. FEI is currently finalizing its 2019 capital budget; if the variance for 2019 changes significantly from the $24 million amount, FEI will provide an update as part of its upcoming Evidentiary Update.

8.4 Please discuss whether, in consideration of the projected 2018 sustainment/other capital spending variance (and the expected 2019 variance), FEI would now consider the level of variance to be significant in the context of the PBR Plan.

Response:

FEI calculates the cumulative variance including the 2018 Projected to be 10.8 per cent. Given the 10 percent dead band established as part of the PBR Plan, FEI does not consider this level of variance in sustainment/other capital spending to be significant. Once FEI has an updated 2019 capital budget as discussed in the response to BCUC IR 1.8.3.1, FEI will calculate the variance to the end of the PBR term and provide an updated response to this IR.

On page 7 of Appendix C4 of the Application, FEI states:

> The average cost per metre of main in FEI's 2013 Base was $62 per metre. The actual cost per metre of main was $87 in 2014, $121 in 2015, $121 in 2016, $110 in 2017, with 2018 expected to be an average of 2016 and 2017 unit costs.

8.5 Please explain the causes/factors which resulted in a lower average cost per metre of main in 2017 compared to 2015 and 2016.

Response:

The factors which resulted in a lower average cost per metre of main in 2017 compared to 2015 and 2016 are outlined below:

1. Unit cost on large mains over $100 thousand – While the number of large new customer mains has not decreased significantly in 2017 as compared to 2015 and 2016, the average unit cost per metre of main for those orders is lower than that of prior years. This is primarily due to decreased complexity on these larger mains jobs over $100 thousand in 2017, which results in lower costs.

2. Pipe diameter of new customer mains – FEI installed a lower percentage of medium (88 to 114mm) to large diameter pipe (168 to 273mm) in 2017 compared to that of 2016 and 2015. In 2017, 23 percent of all new customer mains installed were medium to large diameter pipe compared to 40 percent and 26 percent in 2015 and 2016 respectively. Smaller diameter pipes tend to have a lower unit cost than that of larger sized pipes and is one of the primary factors leading to a lower average unit cost per metre of main in 2017 compared to 2015 and 2016.

8.6 Please provide a table which shows the following for years 2014 to 2017 (actuals) and 2018 (projected): (i) number of new mains; (ii) metres of new mains; (iii) number of new mains costing more than $100,000; and (iv) number of new mains costing more than $50,000.

Response:

The 2014-2017 actuals and 2018 projections for New Customer Mains are provided in the table below:

	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 YTD Actual	2018 Projection
Number of New Mains*	828	1,052	1,148	1,328	1,309	1,964
Meters of New Mains	98,582	116,682	108,451	151,874	131,482	179,000
Number of new mains costing more than $100K	4	15	11	12	11	17
Number of new mains costing $50k-$100k	8	22	16	25	22	33
Total No of new mains costing over $50k	12	37	27	37	33	50

*Count of New Customer Mains Orders

FEI does not typically project the number of New Customer Mains orders completed on an annual basis as the number of orders in any given year can be variable. For the purposes of providing a 2018 projection for this response, FEI has used the 2018 year to date actual results as at August 31st and assumed the same monthly level of order activity for the balance of the year.

In response to BCUC IR 6.12 in the 2018 Annual Review, FEI provided the following table:

Vancouver Island Sustainment/Other Capital Spending (000's)

	Actual/ Projection	PBR Formula	Variance
2015	16,400	11,612	4,788
2016	19,130	11,733	7,397
2017	21,019	11,850	9,169
Total	56,550	35,195	21,355

8.7 Please update the above table to include the Actual 2017 and Projected 2018 amounts.

Response:

Please note the response to BCUC IR 6.12 noted above was revised by way of an errata (Exhibit B-3-2 of the proceeding) to remove the pension and OPEB amounts from the 2015/2016 actual and 2017 projection. The updated figures from the errata filing for 2015 and 2016 have been utilized in the table below.

As stated on page 11 of the Application, the reduction in sustainment capital on Vancouver Island resulted in an impact of $6.6 million in 2018 and $25.8 million cumulatively based on the method described in response to BCUC IR 1.6.11 in FEI's Annual Review for 2018 Rates (escalating the reduction in the 2014 base capital that resulted from Order G-106-15 at the formula factors for 2015 and subsequent years).

Below, FEI provides the alternate method requested by the Commission in response to BCUC IR 1.6.12 in the Annual Review for 2018 Rates, which is a comparison of the actual sustainment/other capital for Vancouver Island compared to the 2014 base inflated by the PBR formula. The table includes the 2018 year-end projection. The August 31, 2018 year-to-date actual results are approximately $11.6 million. When including the 2018 projected results, the capital spending in excess of the formula for Vancouver Island is $5.2 million for 2018 and $32.4 million cumulative. These figures continue to support FEI's conclusion that the PBR Decision reduction to base sustainment capital for Vancouver Island is causing a significant capital pressure.

Vancouver Island Sustainment/Other capital spending (000's)

	Actual/ Projection	PBR Formula	Variance
2015	16,062	11,612	4,450
2016	18,812	11,733	7,079
2017	18,611	11,850	6,761
2018	17,202	12,006	5,196
Total	91,500	59,051	32,449

In response to BCUC IR 6.15 in the 2018 Annual Review, FEI stated that the following table is still reasonable for 2018 and 2019 forecasts regarding the capital cost of Jomar Valves:

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

8.8 Please provide the actual costs for 2017 and an updated forecast for 2018 and 2019 capital costs, if different from the table above.

Response:

The updated actuals and forecast capital cost for by-pass (Jomar) valves is provided in the following table.

Year	Capital Cost ($ millions)
2017 Actual	2.6
2018 Forecast	2.5
2019 Forecast	2.3
TOTAL	7.4

The 2018 and 2019 forecasts are reduced due to a reduction in the number of planned meter exchanges.

In response to BCUC IR 9.9.1 in the FEI Annual Review for 2017 Delivery Rates proceeding, FEI provided the following table:

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

In response to BCUC IR 6.17 in the 2018 Annual Review, FEI stated:

The primary driver for the higher 2019 forecast than in the other years is FEI's projection of running crack-detection in-line inspection technology in selected pipelines beginning that year. As described in the response to BCUC IR 1.1.9, FEI is currently assessing the need for and feasibility of adopting crack-detection capabilities within its in-line inspection program. Because FEI continues to develop its strategy on this issue, the capital spending forecast for FEI's ILI activity could change.

8.9 Please discuss FEI's current assessment of the need for and feasibility of adopting crack-detection capabilities within its in-line inspection program.

Response:

In alignment with FEI's request for a new deferral account for the Transmission Integrity Management Capabilities (TIMC) project in Section 12.4.1.1 of FEI's 2019 Annual Review of Rates, FEI's assessments to-date indicate that the adoption of crack-detection capabilities within its in-line inspection (ILI) program is needed and feasible with process changes and infrastructure modifications.

Given the age of its transmission pipelines, their operating characteristics, and industry experience with pipelines of similar vintage and operation, FEI has determined that it is necessary and appropriate to initiate CPCN planning at this time to enhance its in-line inspection capabilities for adoption of crack-detection tools. Stress corrosion cracking (SCC) has been responsible for failures on Canadian pipeline systems constructed before 2000, and is recognized by pipeline operators, pipeline regulators, and pipeline technical associations as a time-dependent integrity risk that must be managed. While FEI has not had any pipeline failures caused by SCC, this type of corrosion has been previously detected in the Company's pipeline system. The risk associated with SCC increases with time, and significant portions of FEI's transmission system have been in-service since 1957. FEI's transmission pipelines also have characteristics, such as coating type and operating stress level, that are consistent with an identified potential for SCC. FEI also has transmission pipelines located in highly populated areas where potential consequences of failure are higher. Through FEI's involvement in industry associations such as the Canadian Energy Pipeline Association, FEI is aware of other operators' experiences with SCC and increasing reliance on crack-detection ILI tools. FEI has leveraged this knowledge in its assessment to-date of SCC as a relevant integrity risk and in its planning toward adopting crack detection ILI tools.

Due to the projected extent of process changes, including changes to operational practices, and infrastructure modifications required to adopt crack-detection tools in the FEI system, FEI is undertaking a quantitative risk assessment of its transmission pipeline assets that will identify pipelines requiring modifications, as well as their urgency and priority. This assessment will use relevant pipeline characteristics and potential consequences of failure to provide a quantified determination of the need for adopting crack-detection tools. The result either will support FEI's

continued path toward crack-detection ILI, or may support alternative lifecycle integrity management solutions.

FEI's preliminary evaluation indicates that adopting crack-detection ILI tools is technically feasible. The cost of infrastructure modifications that will be required to manage tool travel speed within the pipeline, tool length impacts on ILI operations, and the capability to reduce the operating pressure of transmission pipelines for extended time periods without impacting customers are projected to exceed the FEI CPCN threshold. For this reason, FEI has sought approval of a new non-rate base deferral account to capture development costs associated with this project.

8.10 Please update the table above and explain the causes/factors for significant changes in forecasts, if applicable.

Response:

The updated table showing in-line inspection activity from 2014 to 2019 is provided below.

($000)	2014	2015	2016	2017	2018	2019	Total
Capital Formula	1,350	1,361	1,375	1,389	1,407	1,438	8,320
Actual/Forecast	3,294	2,656	5,917	3,919	4,734	6,329	26,849
Difference	1,944	1,295	4,542	2,530	3,327	4,891	18,529

Changes have occurred for 2016, 2017, and 2019 as compared to the previous table. 2016 and 2017 actuals were less than forecast primarily due to release of contingency funds when anticipated costs for tool re-runs and other potential operational challenges (e.g. additional pipeline cleaning costs) did not materialize.

The reduction to the 2019 forecast is related to removal from the plan of two pipeline segments for crack-detection in-line inspection. This reduction is predicated upon FEI's assessment that the system modifications to manage tool speed within these pipelines, to accommodate tool length impacts on ILI operations, and to provide the capability to reduce the operating pressure of these pipelines for extended time periods without impacting customers will likely not be feasible to implement in time for 2019 inspection.

Table C4-4 in Appendix C4 of the Application shows the following information with respect to capital variances in "Unanticipated system improvements and new stations to supply gas to new customers".

- Actual 2014 variance: $0.60 million
- Actual 2015 variance: $2.7 million
- Actual 2016 variance: $1.764 million
- Actual 2017 variance: $1.901 million
- Forecast 2018 variance: $7.403 million

8.11 Please explain why the Forecast 2018 variance is significantly larger than the actual variances experienced in previous years.

Response:

The expenditures in system improvements and new stations have exceeded planned expenditure levels in every year of the PBR. This can be attributed to two main reasons:

- The addition of large industrial customers that often apply for gas service with short notice and can drive significant system improvements to meet forecast demand.
- The advancement of known system improvements due to higher than anticipated growth of core loads.

Due to the fact that new system improvements are being identified on a regular basis and known system improvements are being rescheduled from year to year based on updated forecasts and hydraulic modeling, it's not possible to identify specific projects that make up the variance. However, the primary reason that the 2018 forecast expenditure in this category is significantly higher than previous years is a system upgrade that is driven by a significant capacity shortfall in Whistler that cannot be resolved by typical infill system improvements. The continued high growth in Whistler has exceeded the ability of the gas system to continue to provide gas for the expected peak load. In order to meet the customer demand, a second supply of gas is required to reinforce the system. This includes installation of a new station as well as larger than typical system improvements to connect the station to high pressure supply at the upstream end, and to the distribution system at the downstream end. The project includes the installation of a new station at an estimated cost of $0.754 million, and system improvements to extend the existing intermediate pressure pipeline further into Whistler to the location of the new station and the installation of additional distribution pressure pipe to connect the station and reinforce the system at an estimated cost of $3.1 million.

Since the filing of the FEI Annual Review for 2019 Rates, the 2018 estimated cost for the Whistler IP extension has increased from $3.1 million to $10.3 million. This project was initially planned to be phased over the course of 3 years from 2015 to 2020. The need for later phases

of the project was advanced due to higher than anticipated growth of core load and Whistler's conversion of its bus fleet to CNG. Additionally, the project has met with significant delays in identifying a route that is acceptable to all stakeholders. As a result of the project delays and the increased customer load, the three phases of the project have been compressed into one to be executed this year. As a result, FEI will provide an update to its 2018 projected capital expenditures in its upcoming Evidentiary Update.

The Whistler IP Extension explains the increase in the 2018 variance as compared to previous years. In addition to the Whistler IP Extension project, the Campbell River Capacity Upgrade also contributes to the overall $7.2 million variance for 2018. This project includes installation of a new station at an estimated cost of $2.145 million and system improvements of $1.312 million. System improvements include the installation of 5.5 km of 114 mm polyethylene DP to connect the new Deerfield Road station to the existing Campbell River DP system to supply the growing customer demand in the area. The new station and system improvements provide support to the Courtney, Campbell River and Comox distribution systems.

8.12 Please explain how much of the forecast $7.403 million variance, if any, is related to unanticipated system improvements, and provide a detailed explanation for the unanticipated system improvements.

Response:

Please refer to the response to BCUC IR 1.8.11.

8.13 Please explain how much of the forecast $7.403 million variance, if any, is related to new stations to supply gas to new customers, and provide a detailed explanation for the new station costs.

Response:

Please refer to the response to BCUC IR 1.8.11.

On pages 10 and 11 of Appendix C4 of the Application, FEI states:

> In the spring of 2017, flooding in the Ashcroft area caused Cache Creek to leave its previous channel and create a new channel that eroded the ground cover over the Ashcroft Lateral NPS 88 pipeline. Approximately 150 metres of pipeline needed to be replaced and lowered below the new creek profile. Further flooding in the spring of 2018 exposed additional sections of the pipeline. Planning is underway to restore ground cover this year and protect the pipeline from further damage.

8.14 Please discuss if any capital costs are forecast for 2019 with respect to the Ashcroft Lateral Pipeline replacement. If so, please quantify the forecast capital cost.

Response:

The Ashcroft Lateral was exposed in multiple locations when Cache Creek flooded in 2017 and 2018. Ongoing stream erosion still poses a threat to the pipeline in other areas that were not exposed. A portion of the pipeline was replaced in 2017 to move it below the newly created river channel. Further work has been required in 2018 to replace exposed or damaged segments of pipe and to reinforce the channel and banks to prevent further pipeline exposures and damage.

The capital forecast for natural hazard mitigation on the Ashcroft Lateral due to the flooding of Cache Creek and its tributaries is $1.022 million in 2018 and $0.620 million in 2019.

On page 11 of Appendix C4 of the Application, FEI states:

> In 2017, FEI is implementing cyber security measures to protect networks, computers and data from attack, theft, damage or unauthorized access.

8.15 Please discuss if any capital costs are forecast for 2019 with respect to cyber security. If so, please quantify and describe the forecast capital costs.

Response:

The cyber security program continues to evolve. Each year is considered to be a new program as threats are constantly changing and projects are re-evaluated based on a risk-based approach to cybersecurity to address current threats. The forecast capital costs for Cyber Security for 2019 is $2.9 million. This is made up of additional enhancements to end-point devices, wireless threat detection and notification and increasing our visibility through additional

1 monitoring and reporting tools and systems, including more frequent testing, customer
2 configuration and code changes to deploy updates to code and operating systems from
3 hardware and software companies.

4

9.0 Reference: OVERVIEW OF CAPITAL EXPENDITURES

Exhibit B-2, Appendix C4, p. 13; FEI 2018 Annual Review, Exhibit B-3, BCUC IR 7.2

Capital prioritization process

On page 13 of Appendix C4 of the Application, FEI states that in 2017 it implemented the first phase of an "asset Investment Planning (AIP) tool" and that the second phase of implementation is currently underway, and includes electric sustainment, information systems, fleet and facilities.

In response to BCUC IR 7.2 in the 2018 Annual Review, FEI provided the forecast capital and operating costs associated with Phase 1 of the AIP tool as $2 million and $105,000, respectively.

9.1 Please provide the total actual capital and operating costs associated with Phase 1 of the AIP tool.

Response:

The table below details the total actual capital costs for Phase 1 AIP implementation, the forecast capital cost for Phase 2 AIP implementation, and the forecast annual operating cost for each phase. The costs are separated to show the allocation of costs between FEI and FBC. The costs for AIP implementation for Gas system assets and Electric network assets were allocated 100 percent to their respective utilities. The allocation of costs for AIP implementation for shared services (Information Systems, Fleet, Facilities) is based on the employee count of each of the utilities. Applying this methodology, the resulting allocation is 77 percent FEI and 23 percent FBC.

PHASE 1 AIP Implementation					
Business Unit	**Actual Capital FEI ($million)**	**Actual Capital FBC ($million)**	**Total Actual Capital ($million)**	**Annual Operating Cost FEI ($000)**	**Annual Operating Cost FBC ($000)**
Gas System Assets	1.89	0	1.89	159	0
PHASE 2 AIP Implementation					
Business Unit	**Forecast Capital (FEI) ($million)**	**Forecast Capital (FBC) ($million)**	**Total Forecast Capital ($million)**	**Annual Operating Cost FEI ($000)**	**Annual Operating Cost FBC ($000)**
Electric Network Assets	0	0.78	0.78	31	76
Information Systems	0.44	0.14	0.58		
Facilities, Fleet	0.11	0.04	0.15		
Phase 2 Total	**0.55**	**0.96**	**1.51**	**31**	**76**
Project Total	**2.44**	**0.96**	**3.40**	**190**	**76**

9.2 Please provide the forecast total capital and operating costs associated with Phase 2 of the AIP tool.

Response:

Please refer to the response to BCUC IR 1.9.1.

9.3 Please discuss if any of the costs associated with Phase 1 and 2 of the AIP are shared with FBC. If yes, please indicate how much and provide the cost allocation and methodology.

Response:

Please refer to the response to BCUC IR 1.9.1.

10.0 Reference: OVERVIEW OF CAPITAL EXPENDITURES

Exhibit B-2, Section 1.4.4.1, p. 11; Appendix C4, pp. 15–16, Table C4-5; 2018 Annual Review, Exhibit B-3, BCUC IR 9.1

Projects planned to be undertaken outside of PBR term

On page 11 of the Application, FEI states:

> In addition to the formula-related pressures noted above, FEI has continued to experience other capital cost pressures in 2018 due to work that had been re-prioritized from previous years of the PBR term into 2018 and to manage unforeseen urgent and higher priority activities in 2018.

10.1 Please provide a list and description of: (i) the larger projects that have been re-prioritized from previous years of the PBR term into 2018; and (ii) unforeseen urgent and higher priority capital activities in 2018. Please also include the capital cost of each of these projects and activities.

Response:

(i) Larger projects that have been re-prioritized from previous years of the PBR term into 2018:

Project Name	Reason for Project	2018 YEF ($000)	Total Project Value ($000)	Original Planned Execution Year
OLIGRF273 5106m kP 120.8 Class 3&2	Pipeline upgrades due to population encroachment and resulting change in class location	1,860	1,860	2014
OLIGRF273 1.2km kP 119.7 Class 3		1,100	1,100	
Lougheed Hwy DP Main Renewal (Final phase)	Replace the existing steel main with a history of leaks with a new polyethylene main	1,560	5,609	2013/2014

(ii) Unforeseen urgent and higher priority capital activities in 2018:

Project Name	Reason for Project	2018 YEF ($000)	Total Project Value ($000)
Main Alteration - Cultus Lake Rd & Vedder Mountain Rd – Chilliwack	Third party requested main relocation	159	159
Main Alteration-Install McDonald Rd., Richmond YVR	Third party requested main relocation	225	225
Hwy 1 Keith Rd Interchange, NVAN 168DP Main Alteration	Third party requested main relocation	477	667
YVR North Airfield - Relocate DP	Third party requested main relocation	1,235	1,250

Project Name	Reason for Project	2018 YEF ($000)	Total Project Value ($000)
Mt Hayes - Perlite Top Up	Unplanned replacement of perlite insulation in annular space of Mt. Hayes LNG tank	900	900
Hwy 16 W @ Hiller Rd -Main Alteration – Prince George	Third party requested main relocation	198	198
LIVCOQ323 ILI ROSEN	Pipeline modifications to improve ILI data collection	940	940
WESLTL114 kP6.74 Slide Mitigation HID3205	Mitigation of debris flow on pipeline right of way	353	357
CASNEL168 kP5.5 Debris Flow Mitigation HID3206	Replacement of damaged pipe and ground improvement due to debris flow	407	409
Main Alteration: 168DPPE 4thAve Rocky Creek	Third party requested main relocation	150	150
PRIOLI323 kP52.9 Rattlesnake (Paul) Creek HID916	Ground improvements due to washout adjacent to pipeline right of way	263	266

On page 15 of Appendix C4 of the Application, FEI states:

> FEI continuously manages its capital investment plan to achieve the values stated in section 4.1. In order to achieve these goals, some projects that provide less value, or that are less time-sensitive, may be reprioritized to future years in favour of more urgent or valuable projects. Likewise, if additional capital is made available through project delays or cost savings, projects may be brought forward based on their assessed value and their ability to be successfully executed.

10.2 Please provide a table listing the larger projects that have been executed during the PBR term which were not originally planned for execution at the beginning of the PBR term. Please also include the amount of the capital expenditures and the years incurred.

Response:

The following table lists projects over $1 million in value that have been executed during the PBR term that were not planned at the time of the 2014-2019 PBR Application.

Project Name	Description	Actuals (2014-YTD 2018) ($000)	Expenditure Year(s)
PRI OLI 323 Similkameen River Crossing @ kP39.5	Stream channel reinforcement to protect pipeline from exposure and damage	1,218	2017
PRI OLI 323 - Replace K05-1 Valve Assembly	Replace valves that are bypassing gas	1,055	2017 - 2018
GRF TRA 273 - 115m pipe replacement	Replacement of a section of pipe due to metal loss detected by in line inspection program	1,336	2017
NIC FRA 610 - pipe stress relief	Replacement of a section of pipe subjected to excessive soil loading	3,031	2014 - 2016
HUN NIC 762 - 3rd party Parking Lot construction over pipeline	3rd party requested pipeline upgrade to allow construction of parking lot (costs recovered from 3rd party)	1,208	2016
ROE TIL 914 - pipe stress relief	Replacement of a section of pipe subjected to excessive soil loading	2,925	2016 - 2017
Whistler IP Extension	Capacity upgrade to meet customer demand	1,626	2015 - 2018
Deerfield Rd - New TPDP station	New station to increase supply to Campbell River to meet customer demand	1,873	2016 - 2018
SCADA - Gas Control System Replacement	Upgrade of Gas Control systems due to obsolescence of servers, monitors, and software	2,661	2017 - 2018
Kitchener B Compressor Unit 2 - Replace combustion liners	Replacement of combustion liners due to equipment failure	1,271	2015
SI-890m x 168 DPPE along Glover Rd	Capacity upgrade to meet customer demand	1,354	2015
SI - 1750m x 168 DPPE along old Clayburn Rd	Capacity upgrade to meet customer demand	1,048	2015 - 2017
SI - 720m x 323 IPST Salter St	Capacity upgrade to meet customer demand	1,129	2018

In response to BCUC IR 9.1 in the 2018 Annual Review, FEI provided a table that included the estimated cost of each of the projects delayed beyond the PBR Term.

10.3 Please provide a similar table with the current estimated cost of the projects listed in Table C4-5 of Appendix C4 of the Application.

Response:

Table C4-5 of Appendix C4 of the Application has been reproduced below and updated to include the estimated cost of the projects listed.

Description	Estimated Timing	Estimated Cost ($millions)	Current Status
Class Location Upgrade: 765m (9 segments) of 1975 vintage 323mm OD East Kootenay Link Mainline, Salmo and Creston	2016	2.1	Planned for 2022
Class Location Upgrade: 1319m (1 segment) of 2000 vintage 610mm OD Southern Crossing Pipeline, West of Moyie River at Yahk	2017	2.2	Planned for 2022
Class Location Upgrade: 2782m (1 segment) of 2000 vintage 610mm OD Southern Crossing Pipeline, Grand Forks	2018	3.9	Planned for 2022
Tilbury LNG Plant Buildings	2018	1.0	Delayed to assess business requirements.
Distribution Main, Service Renewals and Alterations: Penticton Second Supply – Penticton	2015	4.3	Planned for 2020. Reprioritized due to capital constraints and to allow routing and siting review with the City of Penticton.
The addition of pipe storage to the Burnaby Operations building	2014	2.0	Delayed due to further review of requirements for space strategy.

11.0 Reference: OVERVIEW OF CAPITAL EXPENDITURES

Exhibit B-2, Section 1.4.4.2, p. 14

Treatment of capital spending outside of the dead band

On page 14 of the Application, FEI states:

> Accordingly, FEI added 34.89 percent of its 2018 capital, or $54.145 million to its opening plant in service for 2019 so that the two-year cumulative capital variance is within the two-year dead band at 15 percent. FEI also reduced the cumulative capital expenditures utilized in the earning sharing mechanism by the same amount ($54.145 million), such that the earnings sharing with customers is increased (see Section 10 of the Application). In this way, there is no earnings sharing on the amount by which FEI exceeded the dead band.

11.1 Please confirm, or explain otherwise, that FEI is requesting approval to remove the amount of formula capital which has exceeded the cumulative dead band from the earnings sharing calculation for 2018, and to add the amount of capital in excess of the dead band to FEI's opening 2019 plant additions balance.

Response:

Similar to other components of the PBR Plan that are reflected in FEI's proposed 2019 delivery rates, FEI does not believe that further approval is necessary for the treatment of capital outside the dead band. FEI is treating the capital outside the dead band as approved by the PBR Decision (summarized on pages 10 to 13 of FEI's Annual Review for 2017 Rates), and as further confirmed by Commission Orders G-182-16 and G-196-17. Section 1.4.4.2 of the Application discusses this treatment and the determinations made in the aforementioned orders.

B. DEMAND FORECAST AND REVENUE AT EXISTING RATES

12.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES
Exhibit B-2, Sections 3.1 to 3.4, pp. 24–31, Figures 3-1 to 3-6
Use per customer (UPC) and demand forecast

On page 24 of the Application, FEI states:

> The total normalized demand is forecast to be approximately 235.4 PJs in 2019. The forecast for 2019 is up 7.2 PJs from 2018 Approved, with increases of 6.26 PJs for industrial demand, 0.78 PJs for Natural Gas for Transportation (NGT) and 0.61 PJs for commercial demand, partially offset by a decrease in residential demand of 0.45 PJs.

On page 26 of the Application, FEI states:

> Individual UPC projections for each residential and commercial rate schedule are developed by considering the recent (three-year) historical weather-normalized UPC. The analysis of historical normalized residential use rates indicates an inclining trend for the residential and commercial rate schedules. As shown in Figure 3-1, the Residential (Rate Schedule 1) UPC is forecast to increase by approximately 0.6 GJs (0.7 percent) in 2019.

12.1 Please explain why there is a decrease of 0.45 PJs forecast for 2019 residential demand when UPC is forecast to increase by 0.6 GJs (0.7 percent) and residential net customer additions are forecast to increase by 10,724 in 2019, as shown in Figure 3-6.

Response:

The 0.45 PJ decrease cited in the question is a comparison between 2018 Approved and 2019 Forecast values, as described on lines 8-9 of page 24 of the Application. In contrast, the UPC increase of 0.6 GJs and the customer increase of 10,724 are both comparisons between the 2018 Seed Year and the 2019 Forecast values.

Valid comparisons can only be made between approved and forecast values or seed and forecast values. For example, the 2018 approved residential UPC (Figure 3-1) was 89.1 GJs while the 2019 forecast is 2.1 GJs lower at 87 GJs. This decline in use rate contributed to the 0.45 PJ decline in demand, but was offset by the increase in customers.

12.2 Please discuss the reasons for the decrease in the UPC for Rate Schedule (RS) 1, RS 2 and RS 3 from 2016 to 2017, as shown in Figures 3-1 to 3-3.

Response:

This response also addresses BCUC IRs 1.12.2.1, 12.2.2, and CEC IRs 1.2.1, 1.3.1, 1.3.2, 1.3.3, 1.4.1, 1.4.2, 1.4.3, 1.5.2, 1.5.3 and 1.8.1

FEI cannot definitively explain any change in UPC in a given year as it is a result of many factors that may be both compounding and offsetting. For example, use rates for RS 1 customers may go down due to increased appliance efficiency and/or improvements in building envelopes, but this may be offset by an increase in the number of appliances used in a home, a change in how appliances are used and/or the number of people in a home.

Small Commercial Rate Schedule 2 customers operate in 178 industry sectors, while Large Commercial Rate Schedule 3 customers operate in 153 industry sectors and Rate Schedule 23 customers operate in 85 industry sectors. Customers in FEI's Industrial rate schedules operate in 67 different sectors. These industry sectors and the customers within them each have heterogeneous requirements because they are all affected differently by many different factors and energy uses. In addition, one-time or infrequent events (e.g. recessions) also impact customers and sectors in different ways. While FEI's account managers work with larger commercial customers to understand their needs, the large number of industry sectors and individual heterogeneous requirements included in these rate schedules would require extremely extensive market research to ascertain current and future customer requirements. This level of analysis would be cost prohibitive and FEI is not confident that there would be any additional value (or more accurate forecasts) from such an approach.

FEI believes the current methods remain appropriate. By applying a trend to, or averaging, the most recent data, annual fluctuations can be minimized and smoothed out. Smoothing techniques such as trending and averaging are common and well established practices to minimize year-over-year fluctuations.

FEI expects that its load will continue to be influenced by many factors that may have affected load variances in the past, including customer behavior, economic activity, DSM, government policies (such as environmental policy), new technology, housing formations, etc. The current methods fully account for all these intrinsic factors and together result in long term forecast performance that is significantly better than the industry average.

12.2.1 Please discuss whether the UPC results for RS 1, RS 2 and RS 3 have likely been affected by external factors such as increases in appliance efficiencies and environmental policy.

Response:

Please refer to the response to BCUC IR 1.12.2.

12.2.2 How does FEI anticipate these factors, including the external factors discussed in the above response, will continue to impact the UPC forecasts for future periods? Please explain.

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, Section 3.4, p. 29; Appendix A2, p. 2, Table A2-1

Customer additions

On page 29 of the Application, FEI states: "Net customer additions have been stronger since 2013 with the largest increase occurring in 2017. The Company is forecasting net customer additions at 14,417 in 2018 and 11,946 in 2019."

13.1 Please explain the factors FEI believes resulted in an increase in total net customer additions between 2016 and 2017.

Response:

This response also addresses BCUC IR 13.1.1, and CEC IRs 1.6.1 and 1.6.2

FEI cannot definitively explain the cause of the decline in total and net residential net customer additions from 2008 to 2012 or the cause of the increase in 2017, as it is the result of many factors that can be compounding and offsetting. Net customer additions comprise various activities such as new or gross customer attachments, move-ins, move-outs and vacancies (disconnects and non-disconnects). The types of factors that can affect these activities include an increase in new customers connecting to the natural gas system. As new housing stock is constructed, and a higher number of customers convert from other fuels such as oil or propane to natural gas, net customers will increase. This can be compounded by fewer disconnections. However, an increase can be offset by a higher number of customers disconnecting gas service, for example, if their home is torn down. On a customer base of more than a million customers, small variations in these factors can swing net customer additions.

The 2018 forecast of gross customer additions is expected to remain strong and comparable to 2017; however, for 2019 gross customer additions are expected to decline. This is due to indications that the new housing construction market is softening, largely due to policy and regulation changes that affect the purchase or ownership of a home such as tightening mortgage rules, the foreign buyer's tax and the speculation tax.

13.1.1 Please discuss whether the factors discussed above are expected to continue in 2018 and 2019.

Response:

Please refer to the response to BCUC IR 1.13.1.

13.2 Please explain why, in Table A2-1 of Appendix 2 of the Application, the sum of existing customers plus customer additions in one year does not equal the number of existing customers in the following year.

Response:

Industrial and NGT customer additions were omitted from the FEI Customer Additions section of Table A2-1 of Appendix A2. Industrial and NGT customer additions have now been added to the table below.

FEI Customer Counts

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
RS 1	836,583	844,306	853,492	860,403	854,050	863,189	873,661	886,169	897,528	910,885	924,080	934,804
RS 2	84,619	85,065	85,193	85,704	81,123	82,452	83,625	85,076	86,074	86,973	88,088	89,203
RS 3	5,460	5,429	5,466	5,451	5,220	5,134	5,169	5,301	5,189	5,441	5,532	5,623
RS 23	1,306	1,348	1,406	1,433	1,520	1,529	1,522	1,724	1,803	1,712	1,728	1,744
Industrial	1,145	1,113	1,017	951	954	981	977	976	955	976	978	978
NGT	0	0	0	2	5	10	18	31	42	56	66	68
Total	929,114	937,261	946,574	953,943	942,872	953,295	964,971	979,277	991,591	1,006,043	1,020,472	1,032,421

FEI Customer Additions

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
RS 1	11,321	7,723	9,186	6,911	6,371	9,139	10,472	12,508	11,359	13,357	13,195	10,724
RS 2	1,330	446	128	511	577	1,329	1,173	1,450	998	899	1,115	1,115
RS 3	171	-31	37	-16	-104	-86	35	132	-112	252	91	91
RS 23	3	42	58	27	88	9	-7	202	79	-91	16	16
Industrial	-52	-32	-96	-66	8	27	-4	-1	-21	21	2	0
NGT	0	0	0	2	3	5	8	13	11	14	10	2
Total	12,773	8,147	9,313	7,369	6,943	10,423	11,676	14,305	12,314	14,452	14,429	11,948

FEI also notes that the customer count for the following year is the sum of the customer count for the current year, plus the customer additions for the following year.

For example, in Table A2-1 the year-end residential customer count in 2008 is shown as 836,583. The 2009 residential customer additions were 7,723. Therefore, the 2009 residential customer total is:

$$2009\ Residential\ Customers\ = 836{,}583 + 7{,}723 = 844{,}306$$

The same example for total customers (including industrial and NGT) follows:

$$2009\ Total\ Customers\ = 929{,}114 + 8{,}147 = 937{,}261$$

14.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Section 3.6, Tables 3-2 & 3-3, pp. 39–40; Section 12.4.2.2, Table 12-5, p. 135; BCUC Order G-125-17A

Revenue and margin forecast and Flow-through deferral account

On August 17, 2017 the BCUC issued Order G-125-17A approving FEI's application to provide a credit to certain customers during the period the customer was under an Evacuation Order due to wildfires in 2017.

In Table 3-2 and Table 3-3 of the Application, FEI provides the forecast sales revenue at approved rates and the forecast gross margin at approved rates, respectively.

In Table 12-5 on page 135 of the Application, FEI provides the 2018 Flow-through deferral account additions.

14.1 Please provide the total number of residential and commercial customers which received the evacuation relief in 2017 approved by the BCUC pursuant to Order G-125-17A.

Response:

The table below shows the total number of residential and commercial customers who received evacuation relief in 2017.

Customer Type	# of Customers
Residential	10,690
Commercial	1,363

The total actual amount of the credits provided to these customers due to the wildfires in 2017 based on Order G-125-17A was $150,903. This amount was treated as a revenue shortfall, and was recorded in the Flow-through deferral account in 2017 and will be recovered from ratepayers in 2019 rates (as part of the calculation of the final 2017 Flow-through deferral account balance as set out in the response to BCUC IR 1.22.1).

Amortization of the $150,903 from wildfire relief in the Flow through deferral account results in a one-time delivery rate increase in 2019 of 0.019 percent for all non-bypass ratepayers or approximately $0.07 in 2019.

14.2 Please provide the total impact on FEI's 2017 revenue and margin resulting from the evacuation relief provided.

Response:

Please refer to the response BCUC IR 1.14.1.

14.2.1 As part of the above response, please identify the variance between the approved 2017 and the actual 2017 sales revenue and gross margin that are due to the customer credits approved by Order G-125-17A.

Response:

Please refer to the response BCUC IR 1.14.1.

14.3 Please explain how the revenue variance resulting from the evacuation relief bill credits was treated, including whether, and in what year, the variance was recorded in the Flow-through deferral account and in what year the variance will be recovered from ratepayers.

Response:

Please refer to the response BCUC IR 1.14.1.

14.3.1 Please provide the rate impact of the amortization of the revenue variance resulting from the customer credits.

Response:

Please refer to the response BCUC IR 1.14.1.

15.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Appendix A2, Section 3.18, pp. 19–22

Holt's Exponential Smoothing (ETS) method

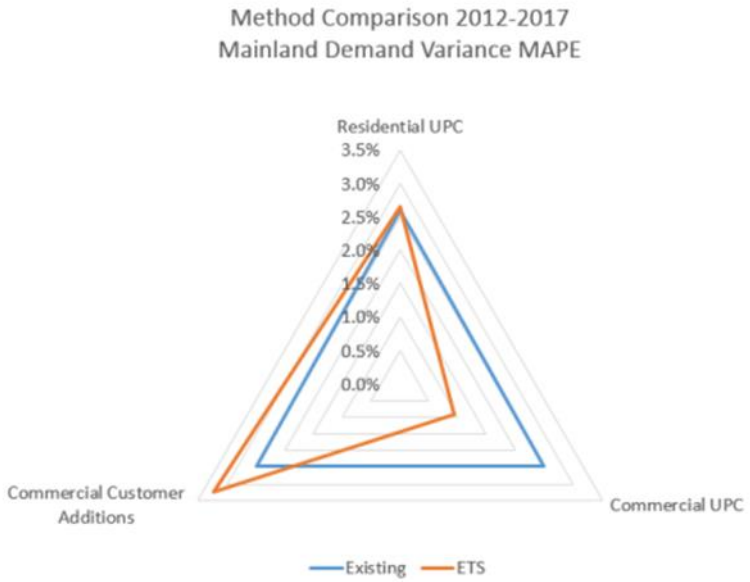
On pages 19–20 of Appendix A2 of the Application, in regards to residential UPC forecast results, FEI states that "the MAPE calculated from 2012 through 2017 remains almost identical for the two methods at 2.6 percent," and provides the following table:

	Year	Data Cutoff	Forecast Demand	Actual Demand (PJs)	APE	2012-2017 MAPE
Existing	2012	2010	69.9	69.8	0.1%	
	2013	2010	69.8	68.1	2.5%	
	2014	2012	69.5	68.5	1.5%	
	2015	2013	68.5	68.9	0.6%	
	2016	2014	67.7	72.3	6.4%	
	2017	2015	68.5	71.7	4.5%	2.6%
ETS	2012	2010	68.4	69.8	2.1%	
	2013	2010	67.6	68.1	0.7%	
	2014	2012	68.9	68.5	0.6%	
	2015	2013	67.6	68.9	1.9%	
	2016	2014	67.8	72.3	6.2%	
	2017	2015	68.6	71.7	4.4%	2.6%

On pages 20–21 of Appendix A2 of the Application, in regards to commercial UPC forecast results, FEI states that "the ETS MAPE calculated from 2012 through 2017 is 0.9 percent, while the MAPE for the existing method is 2.5 percent," and provides the following table:

	Year	Data Cutoff	Forecast Demand	Actual Demand (PJs)	APE	2012-2017 MAPE
Existing	2012	2010	47.1	48.8	3.4%	
	2013	2010	47.3	48.1	1.6%	
	2014	2012	50.2	48.8	3.0%	
	2015	2013	49.3	49.1	0.5%	
	2016	2014	49.3	50.8	2.9%	
	2017	2015	49.7	51.4	3.3%	2.5%
ETS	2012	2010	48.1	48.8	1.4%	
	2013	2010	48.5	48.1	0.8%	
	2014	2012	48.5	48.8	0.5%	
	2015	2013	49.1	49.1	0.0%	
	2016	2014	49.9	50.8	1.7%	
	2017	2015	50.9	51.4	1.0%	0.9%

On page 22 of Appendix A2 of the Application, FEI provides the following evaluation chart:



15.1 Please elaborate on FEI's findings over the PBR period regarding the appropriateness of the existing forecast method compared to the ETS method, including the pros and cons of each forecast method.

Response:

FEI has provided a summary of all of the available information over the PBR period in Appendix A1 Section 3.18. In Attachment 15.1, FEI has also provided its Annual Review for 2018 Rates responses to BCUC IRs 1.12.4 and 1.12.5, which is a summary of the reasons for continuing to use the existing forecast method as compared to the ETS method. The response to BCUC IR 1.12.4 indicates that the Commission has approved the continued use of the existing forecast method for the remainder of the PBR term.

A full report summarizing FEI's findings of the forecast method comparison completed during the PBR period, including the pros and cons of each method, a discussion of the pros and cons of using ETS for the UPC forecast only and a recommendation regarding which forecasting method to use going forward, will be filed as part of FEI's application for rates for 2020 and future years, to be filed in Q1 2019.

15.2 Please confirm, or explain otherwise, that FEI intends to make a recommendation regarding which forecasting method to use going forward (i.e. subsequent to the conclusion of the current PBR term) as part of its next rate application.

Response:

Confirmed.

Please refer to the response to BCUC IR 1.15.1.

15.3 Please discuss the suitability of using a forecast technique that utilizes both methods; for example, an approach which utilizes ETS for UPC forecasts and the existing method for customer additions.

Response:

Please refer to the response to BCUC IR 1.15.1.

15.3.1 What are the pros and cons of this approach? Please explain.

Response:

Please refer to the response to BCUC IR 1.15.1.

C. O&M EXPENSE

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

Exhibit B-2, Section 6.3.3, p. 52

Biomethane O&M

On page 52 of the Application, FEI states:

> In December 2017 there was a fire at the Kelowna upgrader and the remediation costs were recorded in 2018 with the expected net insurance claim recovery of approximately $0.213 million occurring in 2019.

16.1 Please explain the cause of the fire and any actions taken by FEI since then to prevent similar future incidents.

Response:

An FEI contractor was installing steel platforms in the Kelowna plant as part of a remediation project. This required some welding and grinding inside the plant (referred to as "hot work"). Work occurred during the month of December up until December 22nd. The following day, FEI received notification of the fire, which originated at materials stored on shelving against the wall inside the plant.

A review of plant process data confirmed the plant equipment was not a direct or contributing cause of the fire, and process parameters were within normal operating range at the time.

After the fire, an investigation by the Kelowna fire department inspector ruled the cause of the fire as "undetermined". Their report showed no definitive evidence that pointed to a single cause of the fire, but two possible scenarios were hypothesized:

i. The hot work activities (welding and grinding) created sparks that smoldered in the tarps stored in the plant near the work area. The tarps may have eventually ignited the following evening.

ii. A plastic bucket storing used batteries ignited from heat or spark generation from the batteries.

FEI's investigation did not reveal any further potential causes. As a result of the investigation by the fire department and FEI's internal investigation, there were several actions taken to eliminate the possible causes at this and other similar facilities.

i. Fire detection equipment was installed at the facility in order to enable a more rapid detection and response for any future incidents;

ii. Combustible materials are no longer being stored inside the building; and

iii. Battery storage and recycling practices have been modified to minimize the risk of heat/spark generation.

In addition, to increase awareness within FEI, the incident was discussed in workgroup safety meetings.

16.2 How much were the remediation costs recorded in 2018 O&M?

Response:

FEI recorded $0.463 million in remediation costs. This included both labour and parts to return the plant to its pre-fire condition. The entire plant was cleaned and damaged insulation and wall panels were removed and replaced. Certain heat-affected mechanical, electrical and instrumentation components were also replaced. The plant was re-commissioned and put into operation in June. Subsequent to the incident and remediation efforts, FEI filed an insurance claim and expects a net insurance recovery of approximately $0.213 million in 2019.

16.3 Please discuss the impact the fire at the Kelowna upgrader is expected to have on FEI's Service Quality Indicators (SQIs), if any.

Response:

The Kelowna upgrader fire will not impact FEI's Service Quality Indicators. The Kelowna upgrader is not regulated by the OGC and therefore the fire incident is not an OGC transmission reportable incident. No FEI pressure piping or vessels were materially affected by the fire. FEI responded within 12 minutes to the incident with no impact on FEI's Emergency Response Time.

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

2018 Annual Review, Exhibit B-3, BCUC IR 17.1

Incremental O&M to support rate schedule 46

In response to BCUC IR 17.1 in the 2018 Annual Review, FEI provided the following tables with respect to the Tilbury Plant:

	2017 Headcount	2018 Headcount
LNG Plant Operators	20	28
LNG Electrical and Instrumentation Technicians	2	2
LNG Administrative Assistant	1	1
	23	31

	2017 FTE	2018 FTE
Tilbury LNG FTEs	9	20

17.1 Please update the above tables for Actual 2017, Projected 2018 and Forecast 2019 results.

Response:

The following table shows the 2017 Actual, 2018 Projected and 2019 Forecast for the Tilbury Plant.

The FTE values provided in the table reflect the amount of labour expense associated with total employee headcount charged toward Rate Schedule 46 Activities.

	2017 Headcount Actuals	2018 Headcount Projected	2019 Headcount Forecast
LNG Plant Operators	19	25	25
LNG Millwrights	0	2	2
LNG Electrical and Instrument Technicians	2	4	4
LNG Administrative Assistant	1	1	1
	22	32	32

	2017 FTE Actuals	2018 FTE Projected	2019 FTE Forecast
Tilbury LNG FTEs	9	15	21

D. RATE BASE

18.0 Reference: DEFERRAL ACCOUNTS

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

Unamortized deferred charges and amortization (rate base and non-rate base)

18.1 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 on unamortized deferred charges by starting with the Actual 2017 ending deferral account balances and including the Projected 2018 deferral account additions and the Projected 2018 amortization.

Response:

Please refer to Attachment 18.1 which includes the requested information for Schedules 11, 11.1 and 12. The attached schedules reconcile with the opening balances in the equivalent 2019 schedules provided in the Application.

19.0 Reference: DEFERRAL ACCOUNTS

Exhibit B-2, Section 7.5.2, pp. 67–68, Table 7-8

2017 Long-term Resource Plan Application deferral account

FEI states the following on pages 67–68 of the Application:

> To date, total actual costs for this work have been $0.431 million with a further $0.100 million of expected costs by the time the regulatory proceeding for the LTGRP [Long-term Gas Resource Plan] is completed and a small amount of related stakeholder consultation in 2019. Costs have been lower than the original estimate as a result of FEI being able to complete more of the work using its own internal resources than originally estimated, as well as obtaining better commercial terms from external consultants than was estimated when preparing Table 7-8.

19.1 Please update Table 7-8 in the Application to reflect the actual costs of $0.431 million and expected costs of $0.100 million. If certain activities were not performed (thus contributing to the lower than forecast costs) please explain why.

Response:

There are no activities listed in Table 7-8 that were not performed for the 2017 LTGRP.

Please refer to the following updated Table 7-8 providing actual costs up to mid-year 2018. The approved expenditures amount in the updated Table 7-8 anticipated that all the listed activities would need to be done by external resources. Where there are no actual costs incurred for an activity, this indicates that, for this iteration of the LTGRP, FEI was able to complete that activity with internal resources. Since all of the activities listed in Table 7-8 were new activities that were not included within the base O&M funding, FEI will likely need to request similar amounts to be deferred in future iterations of the LTGRP.

1 **Updated Table 7-8: 2017 LTRP Approved Deferral Costs**

Activity	Total Approved Expenditure	Actual Costs	Expected Costs
Scenario Development	$ 75,000	$ 74,300	$ -
Comparison of End-Use Demand Forecasting Methodologies	$ 45,000	$ 45,000	$ -
Alternative Residential and Commercial Customer Additions Forecast	$ 25,000	$ -	$ -
End-Use Demand Forecast	$ 180,000	$ 138,400	$ 14,200
Alternative Industrial Customer Additions and Demand Analysis	$ 145,000	$ -	$ -
Impact of New End-Use Trends on Time-of-Day Use and Linking the Annual and Peak Demand Forecasts	$ 150,000	$ 56,300	$ 40,500
Incremental Consultation Activities	$ 50,000	$ 40,000	$ 4,900
DSM Portfolio Scenario Analysis Including Alternative DSM Funding and Savings Scenarios	$ 200,000	$ 77,400	$ 40,500
Analyze and Report on Peak Demand Infrastructure Avoidance / Deferral Opportunities	$ 80,000	$ -	$ -
Infrastructure Contingency Plans	$ 70,000	$ -	$ -
Analysis of Impact on GHG Targets	$ 30,000	$ -	$ -
Total	**$ 1,050,000**	**$ 431,400**	**$ 100,100**

2

3

E. ACCOUNTING MATTERS AND EXOGENOUS FACTORS

20.0 Reference: ACCOUNTING MATTERS

Exhibit B-2, Section 12.3.1.2, pp. 124–126

Cloud computing

On page 124 of the Application, FEI states: "An increasing number of IS solutions are being offered in the form of off-premise cloud computing services."

20.1 Please explain when (i.e. what year) FEI first began utilizing cloud computing services.

Response:

FEI first began utilizing cloud computing service in 2009 when it implemented the Fleet Complete Automated Vehicle Locate (AVL) system, which was a hosted solution. However, the implementation of this project occurred before Accounting Standards Update (ASU) 2015-05 Intangibles – Goodwill and Other – Internal – Use Software – Cloud Computing Arrangements became effective in 2015. Additionally, ASU 2015-05 was applied prospectively (i.e. was not applied retrospectively to existing systems), as permitted in the transition provisions of the standard, and therefore had no effect on the costs associated with the legacy AVL hosted project.

Since ASU 2015-05 became effective in 2015, there have been two cloud computing solutions, of which approximately $520 thousand of vendor implementation costs is estimated to not meet the capitalization criteria set out in ASU 2015-05. FEI is in the process of implementing these two solutions in 2018. FEI requested Commission approval for variance from GAAP for regulatory purposes to allow for treatment of the vendor implementation costs consistent with FEI's traditional on-premise software.

However, Accounting Standards Update (ASU) No. 2018-15 *(Subtopic 350-40) Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is A Service Contract,* which was expected in Q3 of 2018, was recently issued on August 29, 2018. The transitional provisions of ASU No. 2018-15 permit FEI to adopt the new guidance to support capitalization of cloud computing vendor implementation costs beginning in 2018 in accordance with generally accepted accounting principles.

Due to these recent developments in accounting guidance, FEI capitalized the $520 thousand of vendor implementation costs within the PBR capital formula, rather than being expensed, during 2018. As such, it is no longer necessary for FEI to request a variance from GAAP, as originally outlined in 12.3.1.2 in Section 12 of the Annual Review for 2019 Rates. FEI will be filing an evidentiary update in October at which time the approvals sought will be revised based on any changes including the removal of this item.

FEI states the following on page 125 of the Application:

> Based on the criteria in ASU 2015-05, FEI cannot forecast which of its future cloud computing solutions will have agreements with external vendors that will have provisions that meet the above criteria until the projects are further along in the process. This creates uncertainty from the outset around whether future cloud computing expenditures will be O&M or capital pursuant to ASU 2015-05.

20.2 To date, how many of FEI's cloud computing solutions have not met the ASU 2015-05 criteria and have therefore been expensed as O&M? Please provide both the number of computing solutions and the total amount which has been expensed as O&M.

Response:

Please refer to the response to BCUC IR 1.20.1

FEI states on page 125 of the Application: "In June 2018, the Financial Accounting Standards Board (FASB) agreed to issue a final ASU in the third quarter of 2018…" and "[t]he new ASU is expected to have an effective date of January 1, 2020."

On page 126 of the Application, FEI states:

> While the new ASU 350-40 supports the capitalization of initial external vendor cloud computing implementation costs and can be applied retroactively, it is not expected to become effective until 2020. FEI therefore requests approval to adopt the new guidance for rate-setting purposes beginning in 2019.

20.3 Please discuss the likelihood that the new ASU 350-40 guidance will come into effect on January 1, 2020.

Response:

Please refer to the response to BCUC IR 1.20.1.

20.4 If the new ASU 350-40 did not come into effect on January 1, 2020 or there was some material change from the exposure draft, how would FEI propose to address this delay or change in the event it is approved to vary from US Generally Accepted Accounting Principles (US GAAP) for 2019?

Response:

Please refer to the response to BCUC IR 1.20.1.

20.5 Please clarify over what time period the new standard would be able to be applied retroactively (i.e. the beginning of 2019 or an earlier time period).

Response:

As discussed in the response to BCUC IR 1.20.1, the issuance of a final ASU 2018-15 no longer requires FEI to apply the standard retroactively.

20.5.1 As part of the above response, please explain how FEI would utilize the retroactive treatment of the new standard (if at all) under a scenario where (i) FEI is approved to vary from US GAAP for 2019 and under a scenario where (ii) FEI is not approved to vary from US GAAP for 2019. Please quantify the impact of applying the retroactive treatment in each scenario, both from a cost perspective and a rate impact perspective.

Response:

Please refer to the responses to BCUC IRs 1.20.1 and 1.20.5.

FEI states on page 126 of the Application that one of the benefits to its proposed approach is it would “avoid a one-year change in capitalization policies and the associated potential volatility in O&M and capital.”

20.6 Please quantify the cloud computing implementation costs that FEI expects to recognize as capital expenditures for 2019 in the event it is approved to vary from US GAAP for 2019.

Response:

At this time, there is only one cloud computing project that is expected to occur in 2019 of which $250 thousand represents vendor implementation costs. There are likely other cloud computing solutions that could be considered during 2019; however, as described in 12.3.1.2 of the Application, "the form in which the solution is offered, either through traditional on-premise software or through cloud computing, is not known until discussions occur with the external vendor." Accordingly, the amount of vendor implementation costs for cloud computing solutions in 2019, other than the $250 thousand noted above, is not known at this time. As a result of ASU 2018-15 being issued on August 29, 2018, which permits FEI to early adopt the standard, the costs will be permitted to be capitalized under generally accepted accounting principles.

20.6.1 As part of the above response, please estimate the impact that the change in capitalization policies would have on O&M and capital in 2019 if FEI's request to vary from US GAAP in 2019 was not approved.

Response:

Please refer to the response to BCUC IR 1.20.6.

FEI further states on page 126 of the Application: "The proposed approach keeps FEI's O&M and capital funding envelopes consistent with the 2013 Base O&M and capital amounts for the final year of the PBR term, which were based on the assumption that IS implementation costs would be capitalized."

20.7 Please confirm, or explain otherwise, that at the time the PBR plan was established, cloud computing was not a prevalent Information System (IS) solution.

Response:

Confirmed. When the current PBR plan was established, cloud computing was not a prevalent Information System. It has become prevalent during the current PBR term.

20.8 Please explain when the issue of treatment of cloud computing implementation costs began to arise, and if the treatment of these costs has been an issue in previous years of the PBR term.

Response:

Please refer to the responses to BCUC IR 1.20.1.

20.8.1 If yes, please explain how FEI has addressed the treatment of these costs in the past, and why FEI is not able to deal with this issue in the same manner it has been dealt with in previous years.

Response:

Please refer to the response to BCUC IR 1.20.1.

20.9 Please confirm, or explain otherwise, that generally FEI's practice is not to request regulatory approval for changes related to proposed accounting or government-related changes (e.g. income tax rates) until the change has been made effective or enacted.

Response:

FEI agrees that it does not generally request approval for income tax rate changes until they have been enacted. Announced income tax rate changes have to go through a legislative process before they are implemented, and there can be changes to the announced changes before the final enactment. However, FEI may still discuss treatment options in its filings in advance of the government finalizing changes where there is value to be gained from exploring options with the Commission and interveners.

For proposed accounting changes, the timing of requesting approval will often depend on the timing of applications that FEI is filing, the term that is covered by the application(s), and the

implementation options for the accounting changes. Under the current PBR, FEI is required to bring forward accounting changes as part of the annual review process, which provides some opportunity to wait for accounting changes to be finalized before proposing adoption. Certain accounting standards may have transitional provisions that permit the guidance to be applied retroactively or early adopted. Other than the cloud computing accounting guidance, there have not been any recent accounting standards where FEI has intended to early adopt or retrospectively apply for rate setting purposes.

20.9.1 As part of the above response, please provide examples where FEI has requested approval from the BCUC to change its application of accounting standards or government policies in advance of the standard/policy being made effective/enacted.

Response:

Please refer to the response to BCUC IR 1.20.9.

21.0 Reference: NEW DEFERRAL ACCOUNTS

Exhibit B-2, Section 12.4.1, pp. 129–132, Tables 12-1 & 12-2; Appendix C4, Section 3.2, p. 10

Transmission integrity management capabilities (TIMC) development costs

On page 129 of the Application, FEI provides the following table showing the forecast development costs for the TIMC project:

Table 12-1: CPCN Development Costs ($000s)

Line No.	Phase	2018	2019	2020	Total
1	Phase 1	$ 5,680	$ 5,710	$ 230	$ 11,620
2	Phase 2	-	19,000	11,000	30,000
3					
4	Total	**$ 5,680**	**$ 24,710**	**$ 11,230**	**$ 41,620**

In Table 12-2 of the Application, FEI states that it is requesting the establishment of a new deferral account "to capture the development costs related to the TIMC project." FEI further states that "anticipated costs for this phase will be incurred from 2018 through 2021" and that in the absence of the proposed deferral account, these costs would have been forecast as a combination of O&M and capital expenses outside of the formula. FEI also states that "until the completion of Phase 1, the Phase 2 costs currently have a high degree of uncertainty."

21.1 Please provide a more detailed breakdown and accompanying explanation for the Phase 1 development costs, including the actual costs incurred to-date.

Response:

The following table provides a more detailed breakdown and accompanying explanation for Phase 1 development costs, including the actual costs incurred to-date:

Item	2018 Estimate ($)	2019 Estimate ($)	2020 Estimate ($) up to CPCN application (mid-2020)	Description
1. Integrity Data project: consulting	$2,030,000 (year-to-date actuals = $1,132,600)	$2,760,000		Provision of traceable, verifiable, and complete data (for data elements deemed suitable for consultant resources) required to quantify risk associated with FEI's transmission pipeline assets. Development of sustainable data processes and procedures. Excludes costs for internal implementation.

Item	2018 Estimate ($)	2019 Estimate ($)	2020 Estimate ($) up to CPCN application (mid-2020)	Description
2. Integrity Data project: FEI internal staff	$1,250,000 (year-to-date actuals = $275,000)	$1,250,000		FEI has leveraged internal resources from its Gas Asset Records Project team (which is funded by through a deferral account) to supplement consultant resources in providing traceable, verifiable, and complete data (for data elements deemed suitable for FEI internal resources) required to quantify risk associated with FEI's transmission pipeline assets.
3. Quantitative Risk Assessment (QRA) project: consulting	$1,930,000 (year-to-date actuals = $800,000)	$1,100,000		Quantitative risk assessment of FEI's transmission pipeline assets, to determine particular pipelines requiring modifications, as well as urgency and priority. This assessment will provide a quantified determination of need for adopting crack-detection tools, or alternately, may discount FEI's qualitative assessment temporarily or permanently. FEI anticipates that significant effort will be required to develop consequence models for safety and reliability.
4. FEI asset data collection required for QRA project: consulting	$350,000 (year-to-date actuals = $0)	$150,000		FEI will be required to fill critical data gaps in a timely manner in order to complete a meaningful QRA.
5. FEI incremental headcount required to advance the above work: FEI internal staff	$120,000 (year-to-date actuals = $0)	$450,000	$230,000	FEI has forecast the following incremental internal headcount to ensure timely completion of items 1 through 4 described above: • Capacity Planning Engineer • Senior Integrity Engineer • Senior Pipeline Engineer
Total	**$5,680,000** **(year-to-date actuals = $2,207,600)**	**$5,710,000**	**$230,000**	

21.1.1 As part of the above response, please identify which of the Phase 1 costs would be classified as O&M and which would be classified as

capital in accordance with US GAAP and why (in the absence of an approved deferral account).

Response:

As described in section 12.4.1.1 of the Annual Review for 2019 Rates filing, the expenditures for Phase 1 relate to "work to assess long-term system implications for adopting EMAT technology and to determine the scope of work". In the absence of an approved deferral account for a rate regulated entity such as FEI, the costs incurred during Phase 1 of the TIMC would generally be expected to be classified as O&M expenditures pursuant to US GAAP, including ASC 360 Property, Plant and Equipment and ASC 970-340 Real Estate Other Assets and Deferred Costs.

The classification of Phase 2 costs between O&M and capital requires a degree of professional judgement when applying the accounting guidance. Once Phase 1 has been completed, there is a high probability that this asset is required to be constructed. If this probability requirement is satisfied, the project is considered as part of the pre-acquisition phase under US GAAP, which in turn permits the capitalization of various project costs. Costs to develop the CPCN application may be classified as O&M in absence of a regulatory approved deferral account, while the front-end engineering design costs are likely to meet the capitalization criteria under US GAAP.

21.2 Please provide a more detailed breakdown and accompanying explanation for the Phase 2 development costs.

Response:

The following table provides a more detailed breakdown and accompanying explanation for the estimated Phase 2 development costs. These costs are all external costs, or internal resources incremental to those supporting historical ongoing activities. FEI reiterates that until the completion of Phase 1, the Phase 2 costs currently have a high degree of uncertainty and should be considered a placeholder until more detailed estimates are developed. If the deferral of these costs is approved, FEI will only recover the actual costs incurred.

Item	2018 Estimate ($)	2019 Estimate ($)	2020 Estimate ($) up to CPCN application (mid-2020)	Description
1. Front-end Engineering Design (FEED)	-	$9,000,000	$6,000,000	Costs associated with FEI developing a CPCN submission meeting the requirements of the 2015 Certificate of Public Convenience and Necessity Application Guidelines (Appendix A to Order Number G-20-15), including but not limited to: • Development of Class 4 cost estimates (per AACE International) for identified feasible alternatives • Development of Class 3 cost estimate (per AACE International) for the proposed project
2. Other CPCN development	-	$10,000,000	$5,000,000	Costs associated with FEI developing a CPCN submission meeting the requirements of the 2015 Certificate of Public Convenience and Necessity Application Guidelines (Appendix A to Order Number G-20-15), including but not limited to: • Indigenous Peoples and other Stakeholder consultation • ROW and property services costs • Environmental and archaeological assessment costs • CPCN development and legal costs
Total	-	**$19,000,000**	**$11,000,000**	

21.2.1 As part of the above response, please identify which of the Phase 2 costs would be classified as O&M and which would be classified as capital in accordance with US GAAP and why (in the absence of an approved deferral account).

Response:

Please refer to the response to BCUC IR 1.21.1.1.

21.3 Please provide past examples where FEI has requested deferral account approval for development costs in an amount comparable to the current request.

Response:

FEI incurred approximately $27 million in development costs for the Southern Crossing Pipeline project CPCN in the late 1990s. In today's dollars, inflated at 2 percent, it would equate to approximately $40 million, or the equivalent amount expected for the TIMC project development costs. Those amounts were recorded as plant work-in-progress when incurred and included in the rate base plant-in-service amount once the asset was in-service.

More recently, FEI has requested deferral accounts to capture development costs related to the LMIPSU project and the Eagle Mountain – Woodfibre Gas Pipeline project, each in the magnitude of several million dollars. While the magnitude of the development costs of these projects was not as large as for the TIMC project, FEI does not believe that dollar magnitude should be the determining factor whether development costs are approved for deferral.

Deferring development costs for large projects allows the cost of the complete project to be matched against when the benefits are realized. Matching costs and benefits is an accepted basis for deferral accounts, as reflected in the Commission's Regulatory Account Filing Checklist. Deferring development costs of large projects also has a rate smoothing effect, as the alternative would be to expense any O&M costs and amortize any capital beginning in 2019. FEI submits that it is preferable to amortize the development costs over a period that matches the cost and benefits of the project, as this will smooth the rate impact and avoid intergenerational inequity.

In addition, the deferral will ensure customers only pay for the actual development costs incurred, and will provide the utility with certainty over the treatment and disposition of costs in advance of actual construction activities occurring.

FEI could request this deferral within the CPCN Application itself; however, given the significant amount of costs that may be incurred related to consultation, feasibility, design, and determining the scope of the project, FEI considers it appropriate and reasonable to request deferral treatment in advance of the CPCN application. Applying for deferral in advance of the CPCN provides FEI with certainty over the treatment of the costs, and provides the Commission with the opportunity to review the deferral treatment and understand the nature of the costs being incurred in advance of filing the CPCN.

21.4 Please provide the estimated Certificate of Public Convenience and Necessity (CPCN) capital cost and provide a description of the project which FEI will be seeking approval for in the CPCN application.

Response:

FEI anticipates filing a long-term vision for adopting crack-detection capabilities within its in-line inspection program within the TIMC CPCN application. Given the complexities and timeline associated with developing Class 3 cost estimates in accordance with the BCUC 2015 CPCN Application Guidelines, it is possible that FEI, in its mid-2020 submission, may not apply for the full extent of anticipated system modifications that may eventually be warranted. Please also refer to the response to BCUC IR 1.8.9.

The pipelines requiring modification and details such as priority and detailed integrity management solutions are yet-to-be determined through the CPCN development process. Given this, any estimated capital cost is highly uncertain at this time. For business planning purposes, FEI is currently projecting expenditures associated with the TIMC project of $50 million in 2022, and $250 million in each of 2023, 2024, and 2025. Estimates for the years beyond this period are not yet defined. It is possible that the TIMC CPCN application may extend to later years.

21.5 Please clarify whether anticipated costs for Phases 1 and 2 are expected to be incurred from 2018 to 2020 as presented in Table 12-1 or from 2018 to 2021 as stated in Table 12-2.

Response:

Anticipated costs for Phases 1 and 2 are expected to be incurred from 2018 to 2020 as presented in Table 12-1.

21.6 Please discuss the likelihood that, based on the development work performed in Phases 1 and 2, FEI would decide not to proceed with the project.

Response:

FEI believes that it is extremely unlikely that the development work performed in Phases 1 and 2 will not support CPCN-level expenditures for adopting crack-detection capabilities within its in-line inspection program. Please refer to the response to BCUC IR 1.8.9 for further discussion of the need for project.

21.6.1 Please discuss the implications to ratepayers if this situation were to occur.

Response:

If the project did not proceed, FEI would propose an appropriate treatment for disposition of the costs collected in the deferral account, likely through amortization into non-bypass customers' rates.

21.7 Please discuss whether, given the uncertainty of the Phase 2 costs and the expected quantum of Phase 2 costs, FEI considered requesting deferral account treatment for only Phase 1 development costs in this application. Please discuss why such an approach would not be more appropriate.

Response:

In the case of Phase 1, FEI had not yet determined whether it would proceed with this work at the time of filing of the FEI Annual Review for 2018 Rates application. Shortly following the completion of the evidentiary update phase of that application, FEI received a direction from the BC Oil and Gas Commission to develop a quantitative risk assessment for its entire transmission pipeline system. As such, it was necessary to begin work on this initiative prior to filing of the Annual Review for 2019 Rates application. Consequently, FEI is now seeking deferral approval for the costs to date, and the remaining costs to complete Phase 1.

The Phase 2 costs overlap with the timing of the Phase 1 costs, with some of the costs expected to be incurred in 2019, prior to filing the CPCN and prior to the completion of the 2020 rates application process. These development costs are necessary in order to provide the required detail within the CPCN application in accordance with Commission guidelines. Consequently, FEI believes seeking deferral account treatment for these costs, prior to incurring the costs, is the most appropriate course of action.

FEI notes that deferring development costs is consistent with past FEI CPCN applications where FEI has sought to defer development costs within the CPCN application itself. However, given the magnitude and timing of the costs for both Phase 1 and Phase 2, FEI felt it was more

prudent to request the deferral account within this Application, and to include both phases within the request.

21.8 In consideration of the large quantum of development costs, particularly for Phase 2, please explain why it would not be more appropriate to request deferral account treatment for these expenditures in a separate application, such as at the time of filing the CPCN application.

Response:

Please refer to the responses to BCUC IRs 1.21.3 and 1.21.7.

21.8.1 As part of the above response, please clarify why FEI is requesting approval to defer the development costs related to the TIMC project in this Application instead of requesting approval during the anticipated CPCN application for the TIMC project.

Response:

Please refer to the responses to BCUC IRs 1.21.3 and 1.21.7.

21.9 Please explain if the TIMC project is related to the enhancements to FEI's in-line inspection activities described in section 3.2 of Appendix C4 of the Application.

Response:

The TIMC project is not related to the enhancements to FEI's in-line inspection activities described in section 3.2 of Appendix C4 of the Application.

The particular enhancements that are discussed, which pertain to the time period covered by Table C4-4 (i.e. 2014 – 2018), are unchanged from those that were discussed in response to BCUC IR 1.9.11 in the FEI Annual Review for 2017 Delivery Rates proceeding. At that time,

FEI stated that the changes to its in-line inspection activity that were resulting in higher costs were 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.

Sustainment capital variances related to issues addressed by the TIMC project are anticipated by FEI, but not until 2019. FEI is currently forecasting three pipeline segments for crack-detection in-line inspection in 2019, pending the results of front-end engineering design currently in progress to evaluate the timing and feasibility. It is not currently confirmed that the system modifications to manage tool speed within these pipelines, to accommodate tool length impacts on ILI operations, and to provide the capability to reduce the operating pressure of these pipelines for extended time periods without impacting customers will be feasible to implement in time to allow 2019 inspections to be carried out.

22.0 Reference: EXISTING DEFERRAL ACCOUNTS

Exhibit B-2, Section 12.4.2.2, Table 12-5, p. 135; 2018 Annual Review, Exhibit B-3, BCUC IR 21.1

Flow-through deferral account

In response to BCUC IR 21.1 in the 2018 Annual Review, FEI provided a table similar to Table 12-5 in the current Application which showed the approved and actual 2016 amounts recorded in the Flow-through deferral account.

22.1 Please provide the same table as was provided in response to BCUC IR 21.1 in the FEI 2018 Annual Review, but showing the breakdown of the approved and actual 2017 amounts recorded in the Flow-through deferral account.

Response:

FEI provides the requested table below.

Line No.	Particulars	FEI APPROVED G-182-16	FEI 2017 ACTUAL	Flow-Through Variance
	(1)	(2)	(3)	(4)
1	Delivery Margin			
2	Residential (Rate 1)	$ (452.786)	$ (452.513)	$ 0.273
3	Commercial (Rate 2, 3, 23)	(221.003)	(220.977)	0.026
4	Industrial (All Others)	(100.926)	(106.428)	(5.502)
5	Total Delivery Margin	(774.715)	(779.919)	(5.204)
6				
7	O&M Tracked outside of Formula			
8	Insurance	5.529	5.283	(0.246)
9	Bio-Methane	0.976	1.567	0.591
10	Bio-Methane O&M transferred to BVA	(0.912)	(1.532)	(0.620)
11	NGT O&M	1.557	1.508	(0.049)
12	LNG Production O&M	4.975	2.944	(2.031)
13				
14	Property and Sundry Taxes	67.450	63.281	(4.169)
15				
16	Depreciation and Amortization	199.526	197.700	(1.826)
17				
18	Other Operating Revenue	(42.958)	(42.922)	0.036
19				
20	Interest Expense	122.183	122.947	0.764
21				
22	Income Taxes	35.651	40.654	5.003
23				
24	2017 Actual After-Tax Flow-Through Addition to Deferral Account (excluding financing)			(7.750)
25	2017 Projected After-Tax Flow-Through Addition to Deferral Account (excluding financing)			(1.420)
26				
27	2017 After-Tax Flow-Through Addition True-up to Deferral Account (excluding financing)			(6.330)
28	2017 Financing True-up			(0.202)
29				
30	2017 Ending Deferral Account Balance True-up			(6.532)

F. SERVICE QUALITY INDICATORS

23.0 Reference: SERVICE QUALITY INDICATORS

Exhibit B-2, Section 13.2, pp. 139 & 151

Review of the performance of SQIs

On page 139 of the Application, FEI states, with respect to the emergency response time SQI, it experienced an 11 percent increase in emergency calls in 2017 compared to 2016.

23.1 Please explain the causes/factors contributing to the 11 percent increase in emergency calls in 2017 compared to 2016.

Response:

The 11 percent increase in emergency calls in 2017 compared to 2016 was primarily driven by an increase in gas odour calls downstream of the meter, non-gas related odour calls, and carbon monoxide investigations. FEI cannot say what caused this increase as it was not localized in a geographical area or in a particular time period during the year and the calls were not directly related to FEI assets.

23.2 Does FEI expect the increase in emergency calls to be a continuing trend? Please explain why or why not.

Response:

The increase in emergency calls in 2017 does not appear to be a trend as emergency calls, including gas odour calls, have returned in 2018 to levels similar to previous years.

On page 151 of the Application, FEI states:

> The June 2018 year-to-date result is 0.0030 which is based on 69 leaks detected year-to-date as compared to 54 in 2017 and 58 in 2016 for a similar time period.

23.3 Please explain why the number of leaks detected for the first six months of 2018 has increased by approximately 28 percent and 19 percent compared to the same period in 2017 and 2016, respectively.

Response:

As stated on page 150 of the Application, "Variability in the number of leaks detected is influenced by the timing of the leak survey program as well as the condition of the distribution system as some sections of the system are more prone to leaks depending on soil conditions, age of the pipelines, pipeline material and the location of the pipeline." Although the total number of leaks is higher for the first six months of the year in 2018 compared to 2016 and 2017, it is lower than the totals observed for the first six months of 2013 and 2014. Variability in the number of leaks detected is to be expected from year-to-year.

Number of leaks detected January to June (2013 to 2018)

	2013	2014	2015	2016	2017	2018
Jan-June Total	72	74	59	58	54	69

23.4 Please explain if FEI expects the increase in number of leaks to be a continuing trend. If yes, please discuss how FEI plans to reduce the number of leaks in the future.

Response:

As indicated in the response to BCUC IR 1.23.3, variability in the number of leaks detected is to be expected year-to-year due to the timing of the leak survey program as well as the condition and location of the sections of the distribution system being surveyed.

Attachment 15.1

[redacted]

FEI states on page 30 of Appendix A4 of the 2017 Application: "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."

FEI includes six reasons to support its recommendation, including that "the transition of the Vancouver Island and Whistler service areas to common rates will not be complete until 2018. Due to the changes to available rate schedules in those service areas, FEI will be unable to utilize the ETS method to provide forecasts for those areas until a number of years of comparable data is available."

12.4 Please explain whether it is possible for FEI to use the Holt's Linear Exponential Smoothing (ETS) method to produce its load forecast for the Annual Review for 2019 Rates application.

Response:

Using Holt's Linear Exponential Smoothing (ETS) method to produce FEI's load forecast for the Annual Review for 2019 Rates application is possible for the Mainland region only[8], and is not recommended for the following reasons:

1. As shown in Section 3.18.1 of Appendix A2, the ETS method is performing almost identically to the existing method for the residential UPC. FEI would not recommend changing methods unless there is a clear reason to do so.

2. As shown in Section 3.18.2 of Appendix A2, the commercial UPC forecast results from the ETS method are better over the span of five forecasts. While these results are promising, FEI intends to continue applying a consistent method to all rate schedules and regions and would therefore not recommend changing just the commercial UPC forecast at this time.

3. As shown in Section 3.18.3 of Appendix A2, the ETS method commercial customer additions forecast has not performed as well as the existing method.

4. Both the existing residential and commercial UPC forecasts continue to out-perform the industry averages for demand variance of 4 percent established in Appendix A4 of the Annual Review for 2017 Rates application.

5. In Section 7 of Appendix A4 of the Annual Review for 2017 Rates application FEI recommended further testing for the remaining term of the PBR and this was agreed to in Order G-182-16:

> The Panel agrees with FEI that the addition of more years of data points in the analysis of the ETS method will provide more solid evidence of the efficacy of this method as a possible alternative going into the future.
>
> Therefore, the Panel accepts FEI's proposal to continue using its existing forecasting method at this time while also continuing to test the ETS method and **directs FEI to report the Holt's Exponential Smoothing (ETS) test forecasts and the aggregate MAPE results as part of its Annual Review for 2018 Delivery Rates Application and in all remaining annual review applications.**

FEI continues to believe this is the best approach.

[8] Refer to BCUC IR 1.13 series where FEI explains why it cannot produce an ETS forecast for Vancouver Island and Whistler at this time.

12.5 Please elaborate on why FEI recommends continuing to use the existing forecast method, including a discussion of:

i. The appropriateness of the existing method and its forecasts;

ii. Any proposed refinement to the existing method to improve forecast accuracy;

iii. The pros and cons of changing the forecast method (such as changing to the ETS method) for the Annual Review for 2019 Rates application; and

iv. Whether, and if so how, the PBR period impacts the desirable timing to change the forecast methodology going forward.

Response:

The reasons FEI recommends continuing to use the existing method for the remainder of the PBR term were discussed in Appendix A4 in the Annual Review for 2017 Rates, reproduced below. These reasons are still valid.

> 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. FEI's recommendation is based on the following:
>
> - FEI's Existing Method has performed well over many years, consistently outperforming the average of the survey sample group in forecasting residential and commercial demand. Based on the data available at this time, FEI's Existing Method remains a reliable and reasonable demand forecasting method for FEI's revenue requirement purposes.
>
> - FEI's testing of ETS results in four data points. While four data points are sufficient to identify potential replacements, they are an insufficient basis on which to recommend the replacement of FEI's Existing Method, which has a proven performance record over more than 10 years.
>
> - The Boreas study did not find evidence of any other utility using ETS. This reinforces the need for further testing to confirm the suitability of the ETS method.
>
> - While the implementation of the method in Excel 2016 makes the method attractive, it is also new and time is required to ensure that the feature will provide a stable basis for FEI's demand forecast.

- FEI believes it is important to apply a consistent method of forecasting to all of its service areas. However, the transition of the Vancouver Island and Whistler service areas to common rates will not be complete until 2018. Due to the changes to available rate schedules in those service areas, FEI will be unable to utilize the ETS method to provide forecasts for those areas until a number of years of comparable data is available. Since the alternate tests cannot be performed for those service areas, the ETS method cannot be applied to all of FEI.

- The remaining term of the PBR provides a good opportunity to continue testing ETS as any variances in the demand forecast are captured in the Flow-through deferral account.

As established in Section 4 of Appendix A4 of the 2017 Application, a seven-year demand variance MAPE (mean absolute percent error) of 4 percent is a reasonable target for both residential and commercial rate schedules. Based on data from Section 3.4 of Appendix A2, the current seven-year (2010-2016) MAPE of FEI's Existing Method for residential demand is 1.9 percent, while the seven-year MAPE for commercial demand is 2 percent. FEI's Existing Method therefore remains a reliable and reasonable demand forecasting method for FEI's revenue requirement purposes.

Attachment 18.1

FORTISBC ENERGY INC. Section 11

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE Schedule 11
FOR THE YEAR ENDING DECEMBER 31, 2018 (2018)
($000s)

Line No.	Particulars	12/31/2017	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2018	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**1. Forecasting Variance Accounts**										
2	Midstream Cost Reconciliation Account (MCRA)	$ (69,895)	$ -	$ (19,682)	$ 5,313	$ -	$ 40,238	$ (10,864)	$ (54,890)	$ (62,393)	
3	Commodity Cost Reconciliation Account (CCRA)	(24,221)	-	6,411	(1,731)	-	-	-	(19,541)	(21,881)	
4	Revenue Stabilization Adjustment Mechanism (RSAM	(21,466)	-	11,552	(3,119)	-	5,659	(1,528)	(8,902)	(15,184)	
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(5,388)	-	(2,487)	672	147	33	(9)	(7,032)	(6,210)	
6	Revelstoke Propane Cost Deferral Account	18	-	(51)	14	-	-	-	(19)	(1)	
7	SCP Mitigation Revenues Variance Accoun	484	-	-	-	(132)	-	-	352	418	
8	Pension & OPEB Variance	(6,689)	-	1,163	-	1,433	-	-	(4,093)	(5,391)	
9	BCUC Levies Variance	47	-	2,385	(644)	739	-	-	2,527	1,287	
10	Customer Service Variance Account	(3,458)	-	-	-	3,458	-	-	-	(1,729)	
11	TESDA Overhead Allocation Variance	646	-	770	(208)	(612)	-	-	596	621	
12		$ (129,922)	$ -	$ 61	$ 297	$ 5,033	$ 45,930	$ (12,401)	$ (91,002)	$ (110,463)	
13	**2. Rate Smoothing Accounts**										
14											
15	**3. Benefits Matching Accounts**										
16	Energy Efficiency & Conservation (EEC)	$ 88,557	$ 12,881	$ 15,000	$ (4,050)	$ (11,599)	$ -	$ -	$ 100,789	$ 101,114	
17	NGV Conversion Grants	63	-	-	-	(14)	-	-	49	56	
18	Emissions Regulations	(3,063)	-	(2,148)	580	360	-	-	(4,271)	(3,667)	
19	On-Bill Financing Pilot Program	8	-	(1)	-	-	-	-	7	8	
20	Greenhouse Gas Reduction Regulation Incentives	27,064	-	9,175	(2,477)	(3,379)	-	-	30,383	28,724	
21	CNG and LNG Recoveries	(292)	-	(291)	79	105	-	-	(399)	(346)	
22	2014-2019 PBR	489	-	-	-	(244)	-	-	245	367	
23	AES Inquiry Cost	47	-	-	-	(47)	-	-	-	24	
24	2016 Cost of Capital Application	1,258	-	-	-	(419)	-	-	839	1,049	
25	2015-2019 Annual Review Costs	113	-	100	(27)	(89)	-	-	97	105	
26	2017 Rate Design Application	941	-	499	(135)	-	-	-	1,305	1,123	
27	2017 Long Term Resource Plan Application	322	-	257	(69)	-	-	-	510	416	
28	LMIPSU Application Costs	119	-	-	-	(119)	-	-	-	60	
29	2015 System Extension Application	(2)	-	-	-	2	-	-	-	(1)	
30	BERC Rate Methodology Application	19	-	-	-	(19)	-	-	-	10	
31	All-Inclusive Code of Conduct/Transfer Pricing Policy Application	(65)	-	-	-	65	-	-	-	(33)	
32	2019-2022 DSM Expenditures Application Costs	-	-	219	(59)	-	-	-	160	80	
33		$ 115,578	$ 12,881	$ 22,810	$ (6,158)	$ (15,397)	$ -	$ -	$ 129,714	$ 129,089	

FORTISBC ENERGY INC. Section 11

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE Schedule 11.1
FOR THE YEAR ENDING DECEMBER 31, 2018 (2018)
($000s)

Line No.	Particulars	12/31/2017	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2018	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**3. Benefits Matching Accounts (cont'd)**										
2	Whistler Pipeline Conversion	$ 8,667	$ -	$ -	$ -	$ (739)	$ -	$ -	$ 7,929	$ 8,298	
3	2010-2011 Customer Service O&M and COS	8,058	-	-	-	(3,251)	-	-	4,807	6,433	
4	Gas Asset Records Project	1,873	-	1,183	(319)	(301)	-	-	2,436	2,155	
5	BC OneCall Project	515	-	1	-	(74)	-	-	442	479	
6	Gains and Losses on Asset Disposition	24,429	-	-	-	(3,985)	-	-	20,444	22,437	
7	Net Salvage Provision/Cost	(64,773)	-	13,672	-	(36,167)	-	-	(87,268)	(76,021)	
8	PCEC Start Up Costs	788	-	-	-	(44)	-	-	744	766	
9	Huntingdon CPCN Pre-Feasibility Costs	122	-	-	-	(122)	-	-	-	61	
10	LMIPSU Development Costs	781	-	-	-	(781)	-	-	-	391	
11	2020 Revenue Requirement Proceeding	-	-	251	(68)	-	-	-	183	92	
12	City of Surrey Operating Terms Application Costs	-	146	200	(54)	(49)	-	-	243	195	
13		$ (19,540)	$ 146	$ 15,307	$ (441)	$ (45,513)	$ -	$ -	$ (50,040)	$ (34,714)	
14	**4. Retroactive Expense Accounts**										
15											
16	**5.Other Accounts**										
17	Pension & OPEB Funding	$ (187,894)	$ (5,504)	$ -	$ -	$ -	$ -	$ -	$ (193,398)	$ (193,398)	
18	US GAAP Pension & OPEB Funded Status	97,373	5,504	-	-	-	-	-	102,877	102,877	
19	BFI Costs and Recoveries	(354)	-	(107)	29	-	-	-	(432)	(393)	
20	Residual Delivery Rate Riders	-	1,783	14	(4)	(748)	-	-	1,045	1,414	
21	BVA Balance Transfer	4,069	2,251	-	-	-	(5,051)	1,364	2,633	4,477	
22		$ (86,806)	$ 4,034	$ (93)	$ 25	$ (748)	$ (5,051)	$ 1,364	$ (87,275)	$ (85,023)	
23											
24	**Total**	$ (120,690)	$ 17,061	$ 38,085	$ (6,277)	$ (56,624)	$ 40,879	$ (11,037)	$ (98,603)	$ (101,111)	
25	Less: Net Salvage Amortization Transferred to Biomethane BVA					24					
26	**Net Rate Base Deferred Amortization Expense**					$ (56,600)					

FORTISBC ENERGY INC. Section 11

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE Schedule 12
FOR THE YEAR ENDING DECEMBER 31, 2018 (2018)
($000s)

Line No.	Particulars	12/31/2017	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2018	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**1. Forecasting Variance Accounts**										
2	Biomethane Variance Account	$ (349)	$ (2,251)	$ 3,562	$ (962)	$ -	$ -	$ -	$ -	$ (1,300)	
3	Flow-Through Account	(19,034)	-	(19,407)	-	12,855	-	-	(25,586)	(22,310)	
4	Marketer Cost Variance	(26)	-	26	(7)	-	-	-	(7)	(17)	
5		$ (19,409)	$ (2,251)	$ (15,819)	$ (969)	$ 12,855	$ -	$ -	$ (25,593)	$ (23,627)	
6	**2. Rate Smoothing Accounts**										
7	Phase-In-Rider Balancing Account	$ 1,589	$ (1,589)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
8	Rate Stabilization Deferral Account (RSDA)	59	(59)	-	-	-	-	-	-	-	
9	2017 & 2018 Revenue Surplus	(24,421)	-	(6,985)	1,457	-	-	-	(29,949)	(27,185)	
10											
11	**3. Benefits Matching Accounts**										
12	EEC-Incentives	$ 27,582	$ (12,881)	$ 21,739	$ (5,647)	$ -	$ -	$ -	$ 30,793	$ 22,747	
13	Amalgamation Regulatory Account	135	(135)	-	-	-	-	-	-	-	
14	PEC Pipeline Development Costs and Commitment Fees	(2,398)	-	-	-	-	-	-	(2,398)	(2,398)	
15	Transmission Integrity Management Capabilities CPCN Development Costs	-	-	5,796	(1,534)	-	-	-	4,262	2,131	
16		$ 25,319	$ (13,016)	$ 27,535	$ (7,181)	$ -	$ -	$ -	$ 32,657	$ 22,480	
17	**4. Retroactive Expense Accounts**										
18											
19	**5.Other Accounts**										
20	US GAAP Uncertain Tax Positions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
21	Mark to Market - Hedging Transactions	48,458	-	-	-	-	-	-	48,458	48,458	
22	2014-2019 Earning Sharing Account	(2,683)	-	(1,748)	442	2,562	-	-	(1,427)	(2,055)	
23		$ 45,775	$ -	$ (1,748)	$ 442	$ 2,562	$ -	$ -	$ 47,031	$ 46,403	
24											
25											
26	**Total Non Rate Base Deferral Accounts**	$ 28,912	$ (16,915)	$ 2,983	$ (6,251)	$ 15,417	$ -	$ -	$ 24,146	$ 18,071	