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September 18, 2018

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

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: FortisBC Energy Inc. (FEI)

Project No. 1598966

Annual Review for 2019 Delivery Rates (the Application)

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

On August 3, 2018, FEI filed the Application referenced above. In accordance with the British Columbia Utilities Commission Order G-143-18 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to CEC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

1. Reference: Exhibit B-2, page 14

To calculate the 2018 dead band adjustment, FEI notes that its actual 2017 capital exceeded the formula by approximately 9.88 percent, after the 2017 dead band adjustment. FEI is further projecting to exceed the 2018 formula by 40.01 percent as shown in Table 1-4 and discussed further in Appendix C-4. Therefore, the cumulative amount over the capital formula for calculating the two-year dead band adjustment is 49.89[12] percent. FEI must exclude from the Earnings Sharing calculation the greater of:

- The one-year capital dead band difference between the projected capital spending overage of 40.01 percent and the one year dead band limit of 10 percent, for a net adjustment of 30.01 percent; or
- The two-year capital dead band difference between the cumulative projected capital spending overage of 49.89 percent and the two year cumulative dead band limit of 15 percent, for a net adjustment of 34.89 percent.

Accordingly, FEI added 34.89 percent of its 2018 capital, or $54.145 million[13] 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.

[12] 9.88 percent plus 40.01 percent
[13] $217.301 million actual spending less $54.145 million = $163.156 million revised spending. When compared to $155.209 million approved formula this results in a revised capital spending variance of 5.12% over one year and 15% over two years.
[14] Section 10, Table 10-2, Line 33

1.1 Please confirm that the 2017 and 2018 formula capital amounts are different from each other and provide the formula capital amounts for 2017 and 2018.

<u>Response:</u>

FEI confirms that the 2017 and 2018 formula capital amounts are different from each other. 2018's formula capital grew at the 2018 net inflation factor for Growth and Other capital. The 2017 formula and actual capital amounts and the 2018 formula and <u>projected</u> capital amounts are included in Table 1-4 of the Application. 2018 actual capital amounts are not yet available. An excerpt of Table 1-4 is also provided below for reference.

	2017			2018		
	Actual	Formula	Variance	Projected	Formula	Variance
Growth	59.542	33.477	26.066	67.912	37.485	30.428
Other	139.416	113.104	26.311	146.260	114.596	31.664
Pension/OPEB	2.663	2.663	-	3.127	3.127	0.000
Total	201.621	149.244	52.377	217.299	155.207	62.092
			35.09%			*40.01%*

1.2 Please provide the actual spending for 2017 and 2018.

Response:

Please refer to the response to CEC IR 1.1.1.

1.3 Please confirm that it is mathematically incorrect to add two percentages (such as 9.88% and 40.01%) from different base figures (to arrive at a cumulative 49.89% for a two-year period).

For example Assume Yr 1 = 100; and Year 2 = 125:

9.88% * 100 = 9.88
40.01% * 125 = 50.0125
Total = **59.8925**
59.8925 = 48% of 125
59.8925 = 53% of 112.50

FEI Methodology:

9.88% + 40.01% = 49.89%
49.89% * 125 = **62.3625**

Response:

Not confirmed in the context of this calculation, which results from the PBR Decision. This issue was explored in response to BCOAPO IR 1.5.2 in FEI's Annual Review for 2018 Rates, and also BCOAPO IR 1.1.1 in FEI's Annual Review for 2017 Rates. As discussed in FEI's previous IR responses, FEI has calculated a cumulative two-year variance as directed by the PBR Decision. Alternative calculations using the same base figure would result in an average variance, which would be contrary to the direction in the PBR Decision. FEI has copied the response to BCOAPO 1.5.2 below.

5.2 FEI refers to a 17.74% adjustment based on a two year average. Please fully explain why the cumulative variance of 13.57% as reported in Table 1-4 is not used.

Response:

The 17.74 percent[1] adjustment is not based on a two-year average, but is the cumulative two-year variance above the two-year dead band, as described on page 14 of the Application. The "cumulative" variance of 13.57 percent reported in Table 1-4 of the Application is the average of all variances for all years of the PBR term.

By using the cumulative two-year variance, FEI is following the approved capital dead band mechanism, which was discussed in FEI's Annual Review for 2017 Rates at pages 10 through 13. The PBR Decision stated at page 175:

> …the Commission Panel directs, in addition to the one year 10 percent dead-band previously approved, a two year cumulative 15 percent dead-band for all Fortis' formulaic capital spending.

The Commission Panel did not approve a dead band that takes the average of all variances for all years of the PBR term, which is what the 13.57% represents.

FEI responded to a similar question regarding whether the calculation should be on a cumulative or average variance in the Annual Review for 2017 Rates. This response is provided below:

> BCOAPO 1.1 Please provide the calculation of the 19.1% increase in capital identified in line. In the response, please fully explain why the proper calculation is not derived by summing the actual/projected capital and formula capital for 2015 and 2016 and then calculating the percentage on the cumulative amounts.
>
> Response:
>
> The cumulative 19.1% variance was calculated as the sum of the 2015 and 2016 variance percentages from Table 1-3 (9.88% + 9.22% = 19.1%). This calculation is in accord with the Commission's direction, as referenced on page 11 of the

[1] 32.74 percent two-year cumulative variance less 15 percent two-year cumulative dead band.

> Application, for a "two year **cumulative** 15 percent dead-band". [Emphasis added.]
>
> The alternative presented in the question would result in the calculation of an **average** variance for the two years of 9.54%,[2] and not a **cumulative** variance for the two years.

Specifically with respect to the calculation CEC has shown in the preamble to this question, it appears the two alternatives being proposed by CEC are either to use the "average" method (shown as a 53 percent amount resulting from an average base over the two years of 112.50) or to use the second of the two years (shown as a 48 percent amount resulting from using the second year base of 125). The first method proposed is the same as the average method that has already been addressed in the responses above. The second method is not one that has been suggested in the preceding annual reviews; however, FEI does not see any reason to adopt that method (arbitrarily choosing only one of the two years as the base for a two-year cumulative calculation) over the one that has been approved.

1.4 Please provide the actual total amounts over the capital deadband for 2017 and 2018 and recalculate the cumulative amount over the capital deadband over the two years.

Response:

As shown on Line 33 in Table 10-2 in the Application, the actual amount over the capital dead band for 2017 was $37.632 million and the projected amount over the capital dead band for 2018 is $54.145 million. The cumulative amount over the capital dead band for the two years is the sum of the two amounts, $91.777 million.

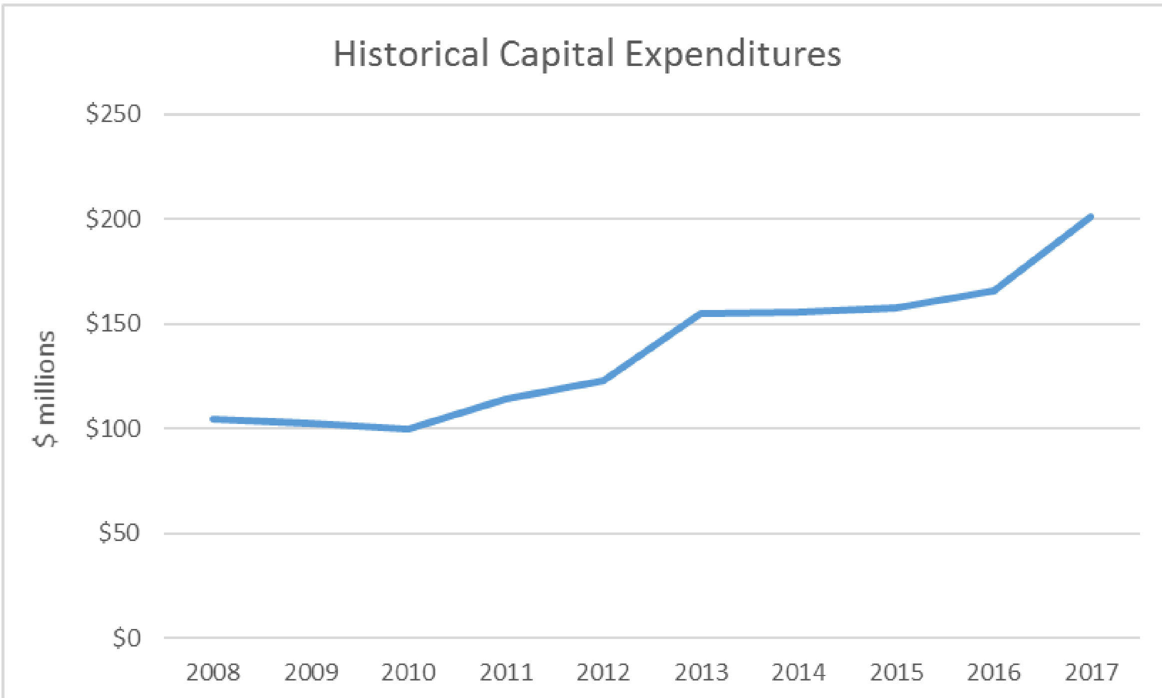
Please also refer to the response to CEC IR 1.1.3.

1.5 Please provide a graph of FEI's capital expenditures for the last 10 years.

[2] From Table 1-3, ((157,903 + 163,157) – (143,705 + 149,390)) / (143,705 + 149,390).

Response:

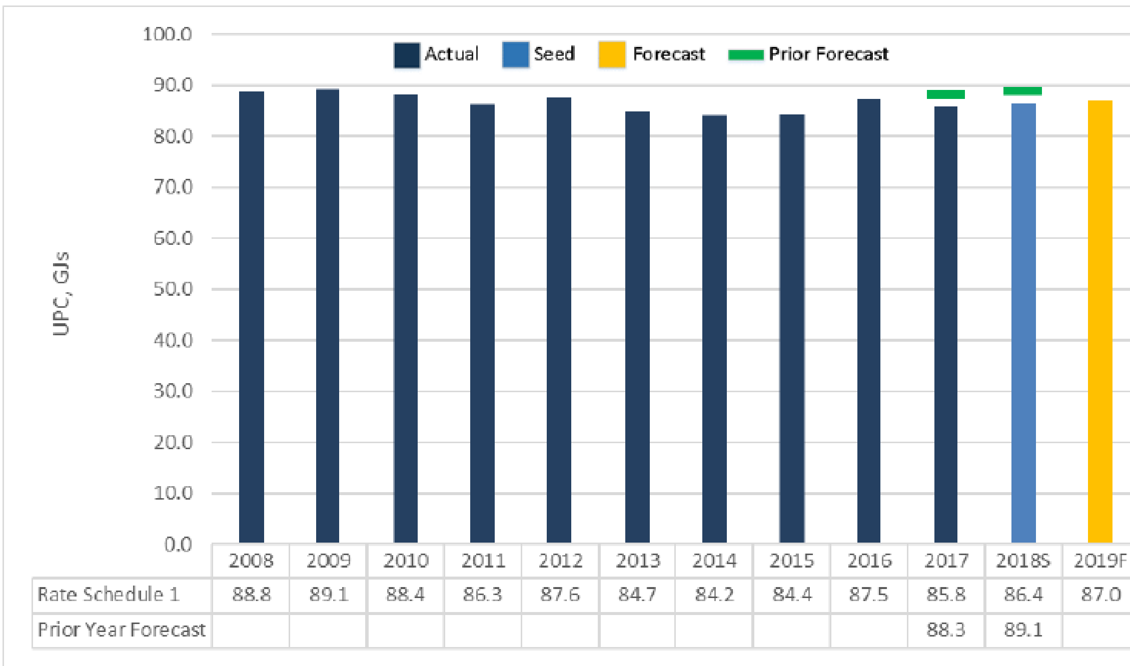
The following graph shows FEI's base capital expenditures for the last 10 years. 2008 to 2014 actual capital expenditures have been adjusted to include FEVI and FEW for comparison purposes.



2. Reference: Exhibit B-2, page 26 and 27

> 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.

Figure 3-1: Rate Schedule 1 UPC



2.1 Please provide FEI's views as to what may have caused the UPC declines in RS 1 UPC in 2013 and 2014 relative to other years.

<u>Response:</u>

Please refer to the response to BCUC IR 1.12.2.

2.2 To what does FEI attribute the anticipated increase in RS 1 UPC? Please explain.

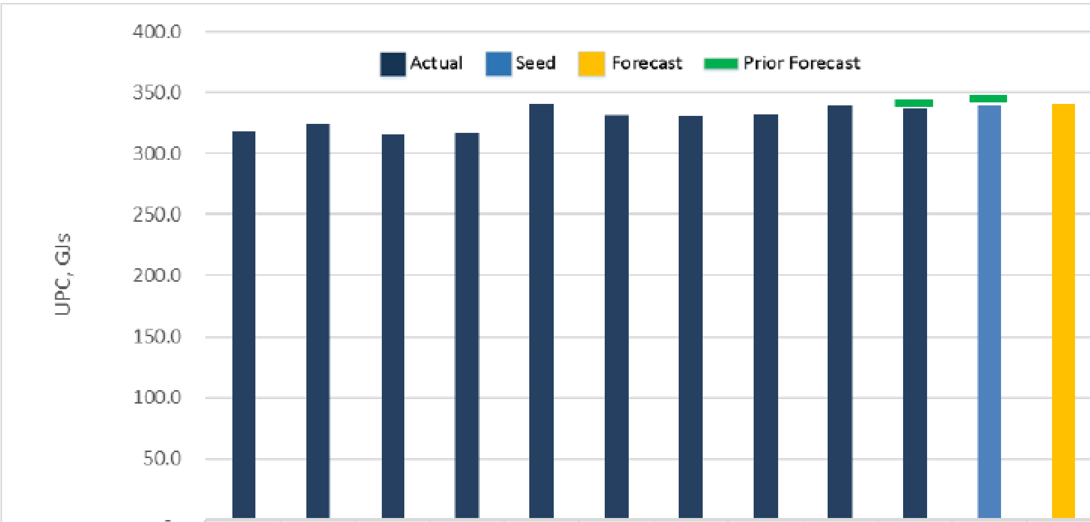
Response:

The forecast increase in UPC is a result of the forecasting methodology which is based on the past three years of consumption. The increase in UPC to date, which may continue going forward, could be the result of one or many factors including but not limited to an increase in the number of gas appliances used in a home, the size of a home, a change in how gas appliances are used and/or an increase in the number of residents living in a home.

3. Reference: Exhibit B-2, page 27

As shown in Figure 3-2, the Small Commercial (Rate Schedule 2) UPC is forecast to increase by 2.3 GJs (0.7 percent) in 2019.

Figure 3-2: Rate Schedule 2 UPC



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Rate Schedule 2	318.2	325.1	316.2	317.7	341.2	331.6	330.6	332.6	339.1	336.8	339.0	341.3
Prior Year Forecast										342.1	345.2	

3.1 Please provide FEI's views as to what may have caused the increase in RS 2 UPC in 2012 relative to other years.

Response:

Please refer to the response to BCUC IR 1.12.2.

3.2 To what does FEI attribute the continued increases in RS 2 UPC over the last 4-5 years? Please explain.

Response:

Please refer to the response to BCUC IR 1.12.2.

3.3 How does FEI believe that the UPC for Rate Schedule 2 might be impacted by another recession such as that in 2008? Please explain.

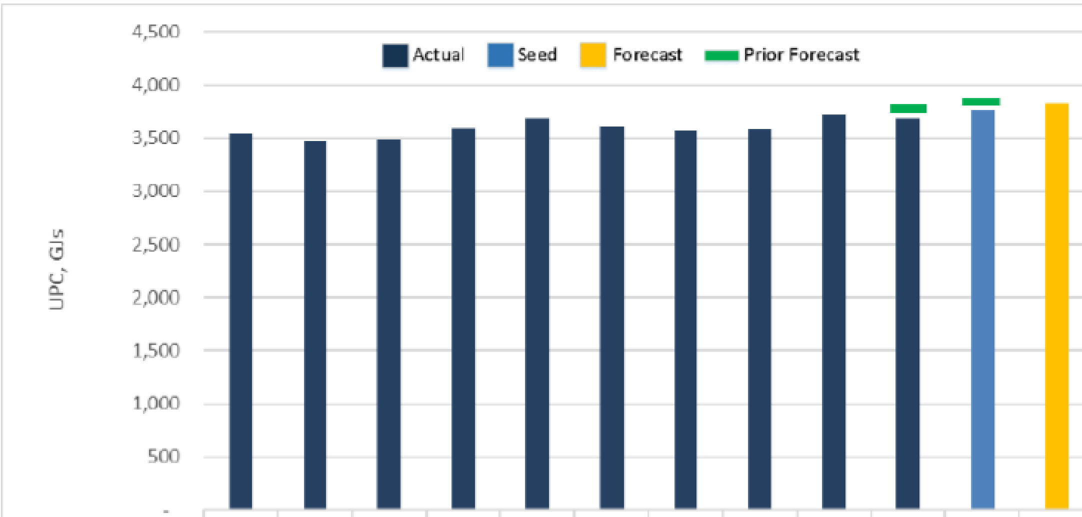
Response:

Please refer to the response to BCUC IR 1.12.2.

4. Reference: Exhibit B-2, page 28

As shown in Figure 3-3, the Large Commercial (Rate Schedule 3) UPC is forecast to increase by 68 GJs (1.8 percent) in 2019.

Figure 3-3: Rate Schedule 3 UPC



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Rate Schedule 3	3,539	3,480	3,485	3,588	3,684	3,610	3,573	3,587	3,721	3,692	3,763	3,831
Prior Year Forecast										3,781	3,842	

4.1 Please provide FEI's views as to the main factors that contribute to variability in the Rate Schedule 3 UPC.

Response:

Please refer to the response to BCUC IR 1.12.2.

4.2 What factors does FEI believe are contributing to the expected increase in UPC for Rate Schedule 3? Please explain.

Response:

Please refer to the response to BCUC IR 1.12.2.

4.3 Please discuss how the UPC for Rate Schedule 3 might be impacted in the event of another recession like 2008.

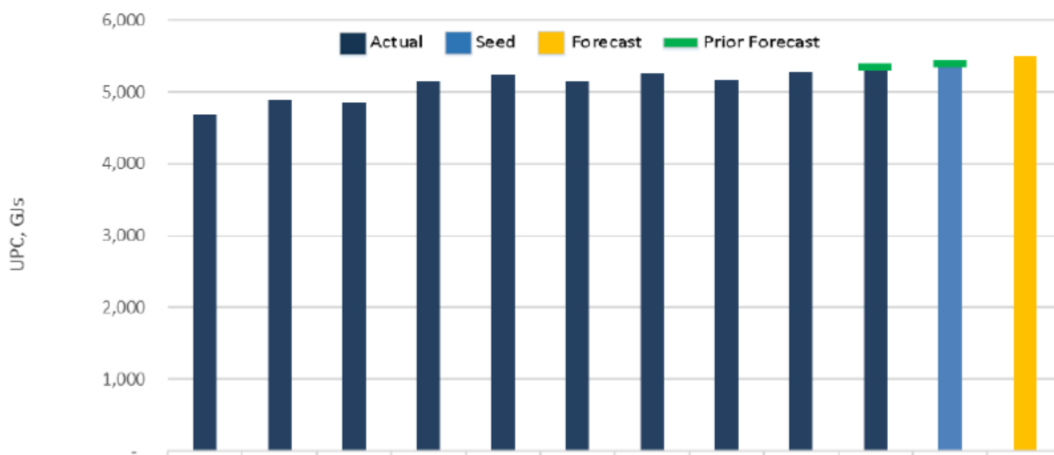
Response:

Please refer to the response to BCUC IR 1.12.2.

5. Reference: Exhibit B-2, page 29

As shown in Figure 3-4, the Large Commercial Transportation (Rate Schedule 23) UPC is forecast to increase by 56.4 GJs (1.0 percent) in 2019.

Figure 3-4: Rate Schedule 23 UPC



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Rate Schedule 23	4,698	4,886	4,850	5,138	5,238	5,149	5,260	5,174	5,279	5,361	5,435	5,492
Prior Year Forecast										5,353	5,399	

5.1 Please confirm that the UPC for Rate Schedule 23 also relies on weather-normalized data.

Response:

Confirmed.

5.2 To what does FEI attribute the general increase in UPC since 2008?

Response:

Please refer to the response to BCUC IR 1.12.2.

5.2.1 If 2008 represents a low point as a result of the recession, does FEI expect UPC to 'top off' in the near future? Please explain why or why not.

Response:

For forecasting purposes FEI does not speculate on low points or top-offs of the UPC as they are not required inputs for the forecast method. The forecast method (see Appendix A3) for RS 23 uses three years of historical weather-normalized actual data to prepare a two year forecast. The FEI method results in a linear forecast such that the year-over-year growth rate during the forecast period is the same. The FEI method does not forecast inflection points (such as would be seen in a "top off" event where the slope of the UPC changed sign).

5.2.1.1 If yes, when does FEI expect to see a 'top off' in Rate Schedule 23 UPC? Please explain.

Response:

Please refer to the response to CEC IR 1.5.2.1.

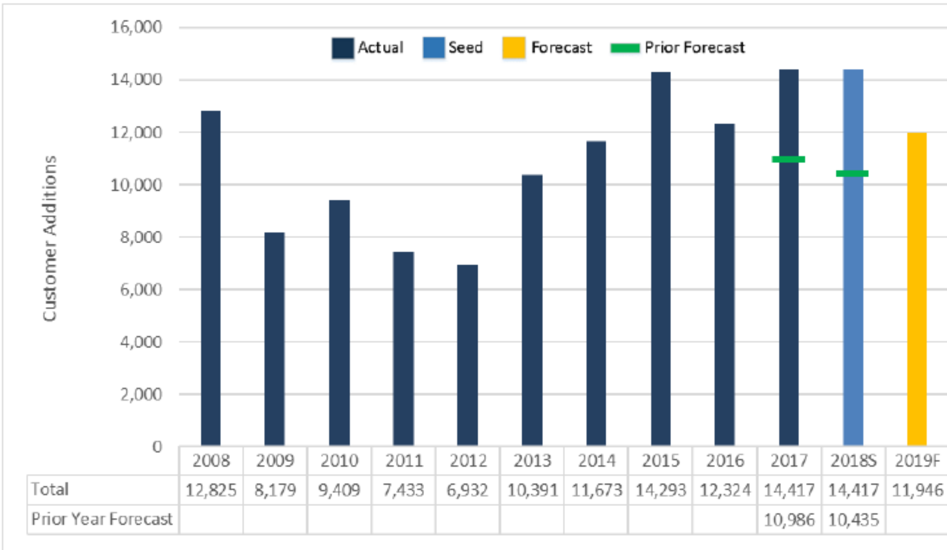
5.3 Please discuss how the UPC for Rate Schedule 23 might be impacted in the event of another recession like 2008.

Response:

Please refer to the response to BCUC IR 1.12.2.

6. Reference: Exhibit B-2, page 30 and page 31

Figure 3-5: Total Net Customer Additions

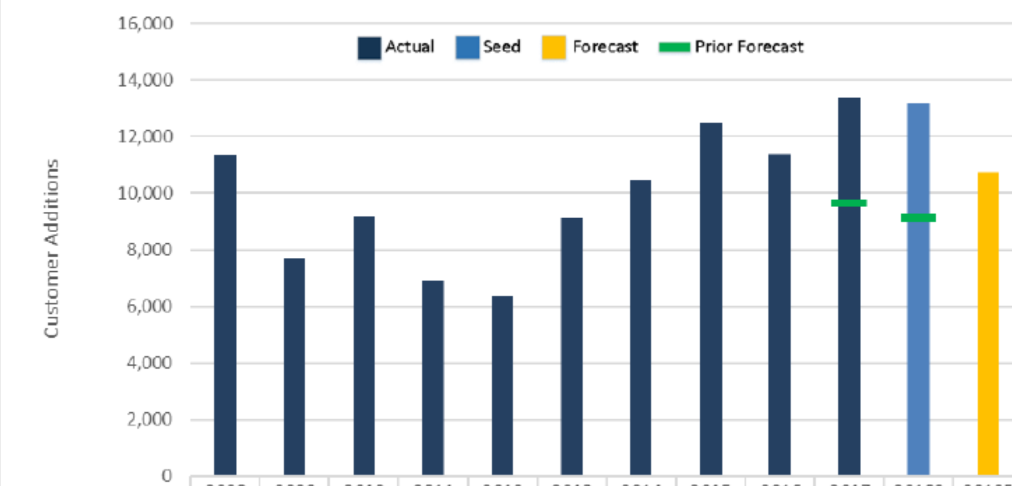


	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Total	12,825	8,179	9,409	7,433	6,932	10,391	11,673	14,293	12,324	14,417	14,417	11,946
Prior Year Forecast										10,986	10,435	

The Conference Board of Canada (CBOC) housing starts forecast found in Appendix A1 provides a proxy for residential net customer additions. The commercial net customer additions forecast is based on the average of the actual net customer additions over the last three years for which a full year of actual data is available (i.e., 2015 to 2017).

Figure 3-6 provides the residential net customer additions for 2008 through 2019.

Figure 3-6: Residential Net Customer Additions



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Rate Schedule 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
Prior Year Forecast										9,696	9,141	

As shown in the preceding figure, residential net customer additions started to recover in 2013. The 2019 Forecast of 10,724 additions reflects a lower CBOC housing starts forecast for BC than experienced in 2017 or projected for 2018.

6.1 Please provide FEI's interpretation of what caused the significant decline in residential and total net customer additions from 2008 to 2012.

Response:

Please refer to the response to BCUC IR 1.13.1.

6.2 Please provide FEI's interpretation of what caused the significant increase in residential and total net customer additions in 2017 that were not anticipated by FEI's forecasting methodology.

Response:

Please refer to the response to BCUC IR 1.13.1.

6.3 Does FEI believe that the CBOC housing starts forecast could be replaced by a better alternative? Please explain why or why not.

Response:

FEI believes that the separate single and multi-family forecasts provided by the current CBOC forecast are important features of the current method and cannot be replaced. As the housing market continues to transition towards more multi-family dwellings it is important to capture this transition in the forecast of customer additions. FEI is not aware of an alternative that provides this required information.

6.3.1 If yes, please provide recommendations for alternative sources of information that could be employed in forecasting following the conclusion of this PBR period.

Response:

Please refer to the response to CEC IR 1.6.3.

7. Reference: Exhibit B-2, page 35 - 36

As shown in Table 3-1 below, the response rate achieved in 2018 was 49 percent of industrial customers, representing approximately 89 percent of industrial volumes. Of the remaining

industrial customers, 44 percent received the survey and three reminder notifications but did not reply. This group represents 9 percent of the industrial demand. Surveys could not be delivered to 7 percent of the industrial customers due to issues such as incorrect email addresses. This group represents 1 percent of the total industrial load.

Table 3-1: Industrial Survey Response Rates

2018 Industrial Survey	Description	Customers	Demand
Survey Completed	The survey was delivered and completed.	49.35%	89.39%
Survey delivered but not completed	The survey was delivered , but after three follow-up emails was not completed.	43.86%	9.44%
Survey undeliverable	The survey was not deliverable. This can be a result of invalid email addresses, faulty email servers etc.	6.79%	1.17%
Total		100.00%	100.00%

The forecast of demand for customers that either chose not to reply to the survey or could not be contacted (representing 10 percent of the total industrial demand) was set to 2017 actual consumption.

7.1 Please provide the participation rates as provided in Table 3-1 for the last 3 years.

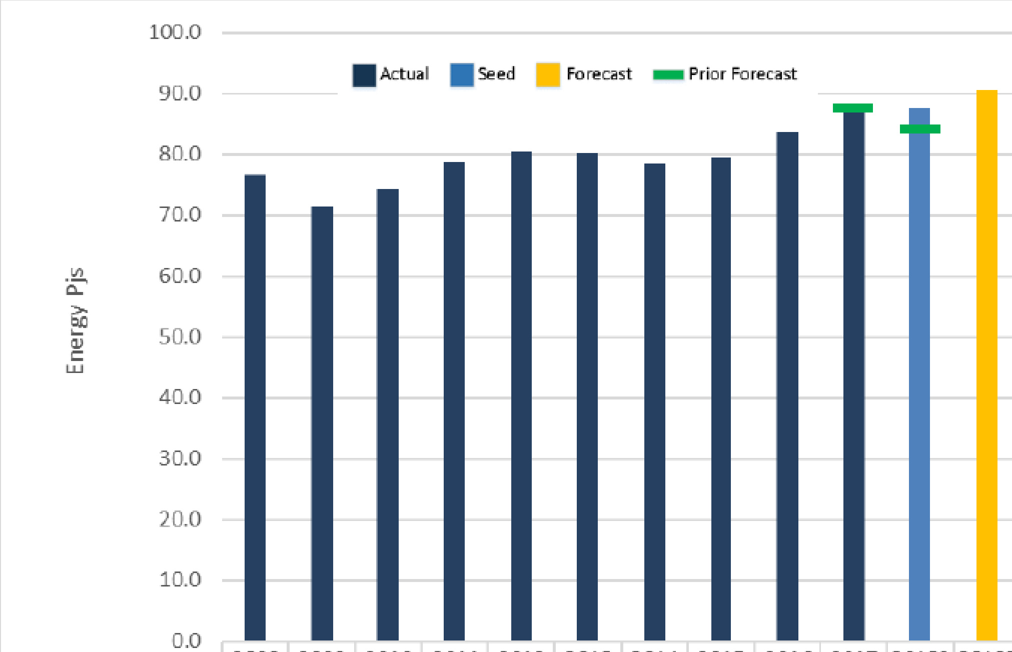
<u>Response:</u>

The industrial survey response rates from 2016 to 2019 are presented in the table below.

Industrial Survey Response Rates		Customers				Demand			
Status	Description	2016	2017	2018	2019	2016	2017	2018	2019
Survey Completed	The survey was delivered and completed.	44.00%	51.00%	49.44%	49.35%	86.00%	89.00%	88.59%	89.39%
Survey delivered but not completed	The survey was delivered , but after three follow-up emails was not completed.	41.00%	34.00%	44.43%	43.86%	12.00%	9.00%	10.56%	9.44%
Survey undeliverable	The survey was not deliverable. This can be a result of invalid email addresses, faulty email servers etc.	15.00%	15.00%	6.13%	6.79%	2.00%	2.00%	0.85%	1.17%
Total		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

8. Reference: Exhibit B-2, page 37

Figure 3-11: Industrial Demand[20]



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Industrial	76.6	71.4	74.4	78.8	80.6	80.1	78.6	79.6	83.7	87.4	87.7	90.6
Prior Year Forecast										87.7	84.3	

The Industrial demand in the figure above includes demand under Rate Schedule 22. The 2019 forecast Rate Schedule 22 demand is 43.2 PJs, up approximately 4.9 PJs from the 2018 Approved demand.

8.1 Please provide a brief discussion of the factors that FEI believes are the primary influences in industrial demand.

Response:

Please refer to the response to BCUC IR 1.12.2.

9. Reference: Exhibit B-2, page 46 and 47

5.3.2 MCRA

The revenue of $3.6 million per year is related to the inclusion of SCP capacity in the MCRA portfolio. To realize the full benefits of a longer term for the PBR Plan, Order G-138-14 directed FEI to extend the term of the PBR to the end of 2019 from the original proposal of 2018. However, through Order G-138-14, the Commission approved the continuation of the debiting of the MCRA and crediting of the delivery margin revenue in the amount of $3.6 million per year for only the **2014 to 2018** PBR Period. To align with the extension of the PBR term to the end of 2019, in this Application, FEI seeks approval for the continuation of the debiting of the MCRA and crediting of the delivery margin revenue in the amount of $3.6 million for 2019, the last year of the current PBR term. Consistent with current practice, the MCRA will continue to pay for the cost of its portion of the Spectra Energy Kingsvale South capacity.

The Company believes that this treatment of costs and revenues is appropriate as the SCP capacity is an essential part of FEI's midstream portfolio, meeting the objectives of safe, reliable and cost-effective resources, and continues to provide optimal benefits to customers.

9.1 Please provide a brief discussion of the impacts on FEI and/or ratepayers if the Commission does not approve the continuation of the debiting of the MCRA and crediting of the delivery margin revenue.

Response:

The $3.6 million per year for which FEI seeks approval to debit the MCRA, with the offsetting credit to the delivery margin, relates to east to west transportation capacity on the Southern Crossing Pipeline (SCP) which FEI holds within its gas supply resource portfolio to enable the movement of Alberta sourced gas to serve communities in the Interior of BC. As well, gas transported east to west via SCP can be used to serve load in the Lower Mainland. The SCP capacity remains an important component of FEI's gas supply resource portfolio.

If the Commission does not approve the continuation of the debiting of the MCRA and crediting of the delivery margin revenue, this will shift $3.6 million of costs currently recovered from Rate Schedules 1 through 7 FEI gas sales customers via the midstream rates (storage and transport charge), to all FEI non-bypass customers (including transportation-only customers) via the delivery rate. This would not be appropriate because the gas supply resources are held to meet the supply requirements of the gas sales customers and therefore should be recovered from Rate Schedule 1 through 7 FEI gas sales customers via the midstream rates.

9.2 Why did the Commission not approve the continuation of the MCRA when it extended the term of the PBR?

Response:

FEI cannot answer this question as there were no specific reasons given in the accompanying Reasons for Decision to Order G-138-14.

10. Reference: Exhibit B-2, page 51

6.3.2 Insurance

The insurance expense relates to insurance premium expense allocated to FEI by Fortis Inc.

The 2019 insurance expense is forecast at $5.473 million, an increase of $0.113 million or 2.1 percent from what was approved for 2018. The 2019 Forecast is calculated by taking the known annual insurance premium of $5.339 million which is applicable to the first six months of 2019 and escalating that amount by five percent for the remaining six months[34]. In forecasting insurance premium increases, FEI uses a five percent escalation unless there are indications which suggest significant increases are forthcoming as a result of loss history for the Company or the industry as a whole.

[34] $5.339 million/2 = $2.670 million x 1.05 = $2.803 million. $2.670 million + $2.803 million = $5.473 million.

10.1 Please provide the basis on which FEI uses a 5% escalation unless there are other indications.

<u>Response:</u>

The 5 percent escalation is based on a combination of historical increases in premiums, increases in the value of assets year over year and the expectations of Fortis Inc.'s insurance broker on future premiums. FEI uses a 5 percent escalation unless there are indications which suggest significant increases are forthcoming as a result of loss history for the company or the industry as a whole.

11. Reference: Exhibit B-2, page 52

Table 6-5: Biomethane O&M by Project ($ millions)

Line No	Description	2018 Approved	2018 Projected	2019 Forecast
1	Program Overhead	0.545	0.912	0.986
2	City of Surrey biofuel	0.011	0.081	0.010
3	Kelowna upgrader	0.318	0.673	0.147
4	Salmon Arm upgrader	0.200	0.218	0.180
5	New 2018 Project	-	-	-
6	**Sub-total - Transferred to BVA**	**1.074**	**1.884**	**1.322**
7				
8	Fraser Valley Biogas	0.011	0.011	0.011
9	Salmon Arm Landfill	0.011	0.011	0.011
10	Kelowna Landfill	0.011	0.011	0.011
11	Seabreeze Farms	0.011	0.011	0.011
12	Lulu Island WWTP	0.003	-	0.001
13	Dicklands Farm	-	-	-
14	**Sub-total - Recovered in delivery rates**	**0.047**	**0.043**	**0.046**
15				
16	**Total Biomethane O&M**	**1.121**	**1.928**	**1.369**

The 2019 forecast of total Biomethane O&M is $1.369 million as shown in the table above. Of this total, $1.322 million (shown in Table 6-1 above) relates to upgrader O&M, interconnection O&M and program overhead[35] which is transferred to the BVA for recovery through the Biomethane Energy Recovery Charge (BERC). The remaining O&M of $0.046 million is the O&M associated with interconnection stations which pre-dated or were approved in Order G-210-13[36], and is recovered through delivery rates.

The 2019 forecast O&M of $1.369 million is $0.248 million higher than the 2018 Approved O&M primarily due to assignment of additional resources to support supply development to meet the growing demand. This increase is partially offset by an estimate for the recovery of costs for the Kelowna fire insurance claim. 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.

[35] The 2019 forecasted Program Overhead of $986 thousand is comprised of $318 thousand for Customer Education costs, $60 thousand in future development costs and $608 thousand for resourcing.

[36] These projects were Fraser Valley Biogas, Salmon Arm Landfill, Kelowna Landfill, Seabreeze Farms, Lulu Island WWTP, and Dicklands Farm.

11.1 Please identify the line item that refers to 'interconnection O&M'.

Response:

Line number 2 (City of Surrey biofuel) represents the "interconnection O&M" referred to in the Application.

11.2 The projected Program Overhead for 2018 and forecast for 2019 is nearly double the 2018 Approved. Please detail the increases in that occurred in this line item.

Response:

Please refer to the response to BCSEA IR 1.4.1

11.3 Please provide a justification for the overhead costs related to customer education, future development costs, and resourcing, and relate these to program profitability.

Response:

The table below details the increases in Program Overhead.

Biomethane Program Overhead ($000s)

Particulars	2018 Approved	2018 Projected	2019 Forecast
Customer Education	$ 312	$ 312	$ 318
Project Development	25	60	60
Program Team	208	540	608
Total	$ 545	$ 912	$ 986

With respect to customer education, FEI is continuing to spend at levels in line with the previous year.

For new project development and the related resources (Project Team in the table above), both business and technical resources are required to assess new projects and negotiate new biomethane supply contracts. The number of supply projects being considered has increased dramatically both in response to demand and in response to the Greenhouse Gas Reduction Regulation which allows FEI to acquire renewable natural gas at a cost of up to $30. Additional technical resources are also required to support the increase in the number of operating projects. RNG Program costs are also discussed in the response to BCSEA IR 1.4.4.

With respect to the impact on the profitability of the Program, the increase in demand for biomethane will also result in an increase in revenue from the Program. As both supply and demand increase, the relative impact of the overhead costs will therefore decrease on a per GJ basis.

12. Reference: Exhibit B-2, page 56

> ### 7.1 *INTRODUCTION AND OVERVIEW*
>
> The 2019 Rate Base for FEI is forecast to be $4.481 billion. Rate Base is composed of mid-year net gas plant in service, construction advances, work-in-progress not attracting AFUDC, unamortized deferred charges, working capital, deferred income tax, and LILO benefit.

12.1 Please provide the definition of 'LILO benefit' or identify where this is described in the Application and provide quantification.

Response:

The Lease in Lease Out (LILO) benefit pertains to arrangements made with the municipalities of Kelowna, Nelson, Vernon, Prince George and Creston (dating back to 2000 to 2005) whereby natural gas distribution assets were leased to the municipality and subsequently leased back by FEI. Refer to Attachment 12.1 for copies of Commission Orders approving the LILO arrangements. These transactions resulted in an overall net benefit to the utility that was to be shared equally between customers and shareholders. To accomplish this, in the first year after each of the respective LILO arrangements, FEI has included a reduction from the rate base equal to 50 percent of the net present value of the after-tax benefits, causing the rates of customers to be lower than they would otherwise have been and ensuring that over the long term the customers receive their share of the benefits. These amounts were then amortized over the life of the lease contracts. As such, there has been a LILO benefit included as a reduction to rate base since 2002. The 2019 amount deducted from rate base is $195 thousand, as compared to the 2018 Approved amount of $328 thousand.

13. Reference: Exhibit B-2, page 57

> Unlike the O&M formula, the capital expenditure formula has two growth components in addition to formula inflation, resulting in separate calculations of Growth Capital and Other Capital. For 2019, the annual capital expenditures under the formula are calculated as:
>
> 2019 Growth Capital = 2018 Growth capital x [(1 + (I Factor – X Factor)] x [1 + SLA customer growth][42]
>
> 2019 Other Capital = 2018 Other Capital x [(1 + (I Factor – X Factor)] x [1 + customer growth][43]

13.1 Please identify the types of expenditures that are included in 'Growth Capital' and those that are included in 'Other Capital'.

Response:

The types of expenditures that are included in growth and other capital as used in the referenced section above are as follows:

1. Growth Capital – Consists of expenditures for the installation of new mains, services and meters.
2. Other Capital – Consists of all expenditures not included in Growth capital. This includes such items as Sustainment capital expenditures (e.g. Customer measurement, Transmission System Reliability and Integrity, Distribution System Reliability and Distribution System Integrity capital), and Other capital expenditures (e.g. Equipment, Facilities and Information Systems capital; and Contributions in Aid of Construction).

14. Reference: Exhibit B-2, page 61

> **LMIPSU PROJECT CPCN**
>
> The LMIPSU Project CPCN application was filed with the Commission in December 2014 and approved through Order C-11-15. The LMIPSU Project includes the Coquitlam Gate IP Project, which will address an increasing number of gas leaks on the Coquitlam Gate IP line and restores operational flexibility and resiliency to the Metro Vancouver IP system. The LMIPSU Project also includes the Fraser Gate IP Project, which will provide required seismic upgrades to the Fraser Gate IP line. Only the Vancouver section of the Coquitlam Gate IP Project and the East 2nd and Woodland station are forecast to be in service in 2018, and to be added to rate base January 1, 2019. The projected cost of the Vancouver section and of the East 2nd & Woodland Station equal $59.151 million and $11.791 million respectively totalling $70.942 million added to rate base January 1, 2019. The estimated capital cost for the LMIPSU Project, including AFUDC and abandonment/demolition costs, is $511.517 million. FEI forecasts expenditures of $168.832 million and $171.642 million[44] in 2018 and 2019, respectively. The 2019 capital expenditures are forecasted to be added to rate base in future years, and are therefore not included in 2019 delivery rates.

14.1 Does FEI expect the LMIPSU project to be completed within the approved budget?

Response:

FEI expects the LMIPSU project to be completed within the February 2018 Revised Control Budget of approximately $517 million. Following completion of the detailed design and further progression of construction execution planning, contract negotiations and municipal stakeholder engagement, FEI has updated its control budget and provided the revised figure to the Commission. The increases are associated with construction, project execution and delivery resource availability, permit and approval costs. The forecast total to complete as at June 30, 2018 was $512 million including AFUDC and abandonment/demolition costs. FEI is seeking further cost reduction opportunities and will continue to provide updated forecasted total costs to complete via quarterly project progress report submissions to the Commission.

14.1.1 If not, please explain why not.

Response:

Please refer to the response to BCUC IR 1.14.1.

14.1.2 If not, how will the Commission be advised of cost-overruns?

Response:

The Commission is provided with quarterly progress reports over the duration of the project that include updated cost forecasts.

15. Reference: Exhibit B-2, page 67 and 68

Table 7-8: 2017 LTRP Approved Deferral Costs

Activity		Total Approved Expenditure
Scenario Development	$	75,000
Comparison of End-Use Demand Forecasting Methodologies	$	45,000
Alternative Residential and Commercial Customer Additions Forecast	$	25,000
End-Use Demand Forecast	$	180,000
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
Incremental Consultation Activities	$	50,000
DSM Portfolio Scenario Analysis Including Alternative DSM Funding and Savings Scenarios	$	200,000
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**

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 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. The timing of these expenditures have been extended as a result of receiving approval from the Commission to extend the submission date for the LTGRP from June to December 2017 and continued work on these activities required to complete the regulatory proceeding.

With this Application, FEI is requesting approval to also capture the legal fees, intervener and participant funding costs, Commission costs, required public notification costs, and miscellaneous administrative costs related to the LTRP Application, which are currently forecasted at approximately $0.260 million, in this existing deferral account. FEI is seeking recovery of these costs, given they also were not included in the FEI base O&M under the PBR. This request is similar to other requests FEI has made previously to recover application and regulatory proceeding related costs through deferral accounts. FEI believes this is the appropriate account to use given the account was already created to capture costs related to the LTRP that were not embedded in FEI's formula O&M.

15.1 What was the original intention for where legal fees, Commission costs, public notification costs, etc. would be captured? Please explain and provide any rationale of which FEI is aware.

Response:

The original intention for where regulatory application or proceeding costs would be recorded was in a deferral account. These regulatory application costs include legal fees, Commission costs, public notification costs, and intervener Participant Assistance/Cost Awards.

Attachment 15.1 provides the responses to CEC IRs 1.28 series and 1.29 series in the Annual Review for 2016 Delivery Rates proceeding where FEI responded to a similar line of questioning.

Specifically, in the response to CEC IR 1.29.1 in the Annual Review for 2016 Delivery Rates proceeding, FEI stated:

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

Due to the periodic nature of regulatory proceeding costs, the lack of ability to accurately predict the timing or forecast amounts for such costs, regulatory proceeding costs are recorded in deferral accounts to be amortized into rates either during or at the conclusion of the proceeding. As such, no regulatory proceeding costs are included in O&M budgets and, therefore, do not form part of base O&M for the current PBR.

As is typical practice, FEI seeks approval for a specific deferral account for each application to record the related regulatory proceeding costs. FEI normally applies for a new deferral account to record regulatory application costs in the related application or in the next rate setting process (revenue requirements or annual review) depending on the anticipated timing of the application and proceeding.

In the case of this LTRP Application, FEI has applied to expand the scope of the existing 2017 LTRP Application deferral account[3], rather than applying for a new deferral account. Given that

[3] The 2017 LTRP Application deferral account was approved by Order G-193-15 to capture costs for new activities as directed by the Commission which were not previously undertaken as part of regular

the cost recovery period of the expenditures approved to be recorded in the 2017 LTRP Application deferral account is expected to be over the same period as the regulatory proceeding costs, FEI believes that expanding the scope of the existing deferral account is appropriate and more efficient than creating an additional deferral account, and will provide a more comprehensive view of the total incremental costs incurred in developing and filing its LTRP.

15.2 Please provide evidence that the legal fees, intervener and participant funding costs, Commission costs, etc. were not included in the FEI base O&M under the PBR.

Response:

Please refer to the response to CEC IR 1.15.1.

O&M activities.

16. Reference: Exhibit B-2, page 68

7.5.2.2 2017 Rate Design Application

As part of the Annual Review for 2015 Rates Application, FEI received approval through Commission Order G-86-15 to establish the 2017 Rate Design Application deferral account to capture the costs related to filing that application and the regulatory proceeding to review it. FEI noted in that it would request an amortization period for this account in an upcoming annual review filing once there was greater certainty over the process and forecast balance of this deferral account.

Given this proceeding has concluded in 2018, FEI is now seeking approval to amortize these costs over five years beginning in 2019. This amortization period is appropriate given it is consistent with other recovery periods for regulatory proceeding related costs and FEI expects to file a new COSA study within five years as directed by Commission Order G-4-18.

16.1 Other than consistency, is there any other rationale for why 5 years is the appropriate time frame for amortization?

Response:

As stated in the Application, 5 years is also the appropriate time frame for amortization because FEI expects to file a new COSA study within five years.

In general, FEI considers the following factors when proposing amortization periods:

- Benefits matching - Ensures that costs are aligned with the benefits or the term of a proposal;
- Rate Impact/Smoothing - If deferred costs are large enough to produce a material rate change for customers, then a longer amortization period may be proposed; and
- Consistency with past proposals.

16.2 Please elaborate on the importance of consistency with other recovery periods for regulatory related costs.

Response:

Please refer to the response to CEC IR 1.16.1. FEI considers all the factors noted in response to CEC IR 1.16.1 when proposing amortization periods.

16.3 Over what issues in the process did FEI require greater certainty before setting the amortization period?

Response:

FEI was not referring to issues in the process, but rather the type of process. FEI required greater certainty of the forecast balance in the deferral account, which is influenced by the type of process as referred to in the preamble (written or oral), and also of the period of time before the next rate design application or COSA study would be filed.

16.4 How does the forecast balance impact the appropriate time frame for amortization? Please explain.

Response:

Please refer to the response to CEC IR 1.16.1.

16.5 Please identify and describe any alternative amortization period options and the advantages and disadvantages of each.

Response:

Please refer to the response to CEC IR 1.16.1. Given Commission Order G-4-18 and the directive to file another COSA within five years of FEI's final 2016 Rate Design Decision date, FEI believes a five-year amortization period is the most appropriate choice given the benefits matching criteria. However, a shorter amortization period of three years is also an option given the rate impact would be similar to a five year amortization period.

17. Reference: Exhibit B-2, page 76

> On October 21, 2014, the provincial government introduced an LNG income tax on net income from LNG facilities in BC. The new LNG income tax was expected to apply to income from liquefaction activities at, or in respect of, LNG facilities in BC, for taxation years beginning on or after January 1, 2017 but has not yet come into force because the regulation by the Lieutenant Governor in Council required to proclaim this tax in force has not yet occurred. On March 22, 2018, the provincial government announced its intention to repeal this tax provided the LNG Canada project proponents conclusively decide to proceed with their projects on or before November 30, 2018. This would ensure this tax legislation and its application to FEI would be permanently deleted and would have to be re-enacted by the BC legislature in the future should a successor government wish to re-introduce this tax.
>
> If it proceeds, the proposed LNG income tax would be a two-tier tax that applies a minimum 1.5 percent tax on LNG facilities' profits before recovery of capital investment costs and a 3.5 percent tax on LNG facilities' profits once payback is achieved (which increases to 5.0 per cent in 2037 and thereafter). This LNG income tax would apply to income earned at the existing Tilbury Facility, the Tilbury Expansion and the Mt. Hayes LNG Facility on Vancouver Island.
>
> In conjunction with the LNG income tax legislation, the provincial government also proposed a Natural Gas Tax Credit (NGTC) against the current 11 percent BC corporate income tax. The NGTC is effectively equal to the lesser of (i) 3.0 percent of the cost of gas owned and liquefied by the taxpayer at the LNG facility and (ii) the BC corporate income tax payable by the taxpayer from all sources (not just LNG income), but cannot be greater than the amount that would reduce the effective BC corporate income tax rate to less than 8 percent.
>
> Because the LNG income tax legislation is not in force and the provincial government announced that it intends to repeal this legislation should the LNG Canada project proponents make a conclusive decision to proceed by November 30, 2018, estimates of the LNG income tax and NGTC have not been included in forecast 2019 rates.

17.1 Please provide estimates of the LNG income tax and NGTC if the LNG income tax legislation comes into force.

<u>Response:</u>

FEI estimates that it would have no LNG income tax payable, and that a credit of less than $1 million would be available to FEI. If the legislation does come into force in 2018 or 2019, the actual amount of any tax payable or tax credits will be captured in the Flow-through deferral account and recovered from/returned to customers in 2020.

17.2 If the tax and tax credits come into effect, when would this likely occur, and when would the impacts be transmitted to ratepayers?

Response:

FEI is not able to predict the likelihood regarding if and when the LNG Income Tax and Natural Gas Tax Credit will come into effect. Should the tax treatment for LNG and Natural Gas Tax Credit apply to FEI, these tax consequences would be included in the forecast tax year in which they apply. FEI would include the tax consequences in its revenue requirement.

Any variance between the amount included in the revenue requirement and the actual amounts would be captured in the Flow-through deferral account and would be returned to or recovered from ratepayers in the following year. In the event FEI did not have an approved Flow-through deferral account, FEI would likely request a deferral account to capture the impacts of the variance, and request a disposition period in a future application.

17.3 What are FEI's expectations with regard whether or not LNG Canada will conclusively decide to proceed with their projects by November 30, 2018? Please explain.

Response:

FEI is only privy to what is available to the public and at this time LNG Canada has not yet conclusively decided to proceed. Recent publicly available information suggests LNG Canada is continuing to advance the project and is awaiting a ruling from the Federal Court of Appeal on tariffs in September.

18. Reference: Exhibit B-1, page 85

Table 10-8: BERC Revenue and Volume

Line No	Volume and Revenue	2017 Actual	2017 Projected	2017 Variance	2018 Projected
1	**Volume (TJ)**				
2	**Short-term**				
3	Rate Schedule 1B	88.4	84.9	3.5	103.5
4	Rate Schedule 2B	13.2	10.9	2.3	15.8
5	Rate Schedule 3B	16.2	8.1	8.2	22.3
6	Rate Schedule 5B	-	-	-	-
7	Rate Schedule 11B	98.7	80.6	18.1	53.7
8	Rate Schedule 30	-	-	-	-
9	Sub-total	216.5	184.4	32.1	195.3
10					
11	**Long Term (a)**				
12	Rate Schedule 11B	16.6	35.5	(18.9)	146.9
13	Sub-total	16.6	35.5	-	146.9
14					
15	**Total Sales Volume (TJ)**	233.1	219.9	13.2	342.2
16					
17	**Recoveries ($000s)**				
18	**Short-term**				
19	Rate Schedule 1B	$ 931.5	$ 894.5	$ 37.0	$ 1,039.7
20	Rate Schedule 2B	138.8	114.7	24.1	158.6
21	Rate Schedule 3B	171.2	85.2	86.1	223.6
22	Rate Schedule 5B	-	-	-	-
23	Rate Schedule 11B	1,040.2	849.6	190.6	539.6
24	Rate Schedule 30	3.5	3.5	(0.0)	-
25	Sub-total	2,285.3	1,947.6	337.7	1,961.5
26					
27	**Long Term (a)**				
28	Rate Schedule 11B	166.0	374.1	(208.2)	1,475.2
29	Sub-total	166.0	374.1	(208.2)	1,475.2
30				-	
31	**Total Sales**	$ 2,451.2	$ 2,321.7	$ 129.6	$ 3,436.7

18.1 To what does FEI attribute the significant increase in sales volume and recoveries occurring in 2018? Please explain.

Response:

FEI attributes the 2018 increase in sales to the following:

- The lower BERC rate being closer to what customers are willing to pay for RNG;
- The impact of a full year of demand in 2018 from the UBC long term contract compared to six months in 2017;
- The resumption of marketing, customer education and awareness activities that led to increased customer awareness after the implementation of the BERC Methodology Decision and Order G-133-16; and

- Additional demand resulting from two new long term contracts which are expected to be filed in the coming months.

18.2 To what does FEI attribute the significant variance between 2017 Actual and 2017 Projected for Rate Schedule 11B?

Response:

With reference to Rate Schedule 11B under the Long Term heading, the 2017 results reflect only a part year, whereas the 2018 results reflect a full year of volumes.

On March 21, 2018, Order G-64-18 approved the Biomethane Long Term Large Volume Interruptible Sales Agreement between FEI and UBC effective October 1, 2017. As a result, the 2017 actual results contain three months of sales volume and revenues (October – December 2017) whereas the 2017 projected contains six months of sales volume and revenues (July to December 2017) based on when FEI had expected the application to be filed and approved. As stated above, 2018 reflects a full year of volumes.

19. Reference: Exhibit B-2, page 86

Table 10-9: RNG Customers by Rate Schedule

2018 RNG Projected Participation (Rate Schedule)	Customer Enrollment
Short-term	
Rate Schedule 1B	10,358
Rate Schedule 2B	197
Rate Schedule 3B	14
Rate Schedule 11B	6
Rate Schedule 5B	-
Rate Schedule 30 Off System	-
Long-term	
Rate Schedule 11B	3
Total	10,578

19.1 Please provide historical participation rates for the last 5 years.

<u>Response:</u>

The number of customers for the past five years are provided in the table below along with participation rates for the residential, small commercial and large commercial customer groups.

As at Dec 31	2013	2014	2015	2016	2017
RS 1B	6,290	6,686	6,633	7,542	8,965
Participation Rate	0.72%	0.76%	0.75%	0.84%	0.98%
RS 2B	126	137	123	163	183
Participation Rate	0.17%	0.16%	0.14%	0.19%	0.21%
RS 3B	13	14	12	14	15
Participation Rate	0.28%	0.26%	0.23%	0.27%	0.28%
RS 5B	-	-	-	-	-
RS 11B	2	4	4	6	5
RS 30 Off system	-	-	-	-	-
Long Term					
RS11B	-	-	-	-	1

19.2 Please provide a brief discussion of any major trends FEI sees in customer participation and why these are occurring.

Response:

FEI saw steady growth followed by a leveling off of residential customer enrollment (Rate Schedule 1B) as the BERC rate increased over time. Immediately following the reduction to the BERC rate, residential customer enrollment numbers increased. Please also refer to the responses to the BCSEA IR 1.4 series.

With respect to Rate Schedules 2B and 3B there has been a modest increase in the number of customers enrolled.

Rate Schedule 11B customers are typically higher volume and there are fewer. FEI has not added any new Rate Schedule 11B customers in two years, but one of those customers switched to the a long term agreement under Rate Schedule 11B tariff supplement.

20. Reference: Exhibit B-2, page 127 and 129

12.4.1 New Deferral Accounts

FEI is seeking approval of one new non-rate base deferral account to capture the two-phase development costs for FEI's Transmission Integrity Management Capabilities (TIMC) project[55]. The TIMC project will consist of system modifications required to enable the use of crack-detection inline inspection technology, also known as EMAT (Electro-Magnetic Acoustic Transducer). FEI expects to file a CPCN application for the TIMC project in mid-2020.

12.4.1.1 Transmission Integrity Management Capabilities (TIMC) Development Costs

FEI has initiated the development of the TIMC project, which will consist of modifications to FEI's transmission pipeline system to enable inline inspection with recently proven and commercialized crack-detection tools (commonly referred to as "EMAT tools", as the technology relies upon electro-magnetic acoustic transducers). EMAT tools[56] are primarily used for detecting and sizing anomalies associated with stress corrosion cracking and longitudinal seam welds (e.g. anomalies that may be associated with low-frequency electric resistance welding manufacturing processes) in FEI's transmission pipeline system.

The following table shows a forecast of expenditures related to Phases 1 and 2:

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**

FEI will propose an appropriate recovery treatment and period in its CPCN application for the TIMC project which will be submitted in conjunction with Phase 2.

20.1 Please discuss the process that would occur if the Commission approves the new non-rate base deferral account at this time, but does not approve the CPCN in mid-2020? Please include who would be responsible for the costs incurred up to the time of denial, and any remediation or other going forward costs that would be incurred.

<u>Response:</u>

Please refer to the response to BCUC IR 1.21.6.1.

FEI does not expect remediation costs (e.g., demobilization costs or contract penalties) related to the development costs will be required should the CPCN be denied.

20.2 Could FEI apply for a CPCN at this time? Please explain why or why not.

Response:

Please refer to the responses to BCUC IRs 1.21.1 and 1.21.2 for a detailed breakdown and accompanying explanation of the work determined necessary by FEI to enable a CPCN application in mid-2020.

FEI has proposed a two-phased approach to its TIMC project CPCN development. All of the work is required to meet the 2015 Certificate of Public Convenience and Necessity Application Guidelines (Appendix A to BCUC Order G-20-15); therefore FEI could not apply for a CPCN at this time.

21. Reference: Exhibit B-2, page 138 and page 143

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

Performance Measure	Description	Benchmark	Threshold	2017 Results	2018 June YTD Results
Billing Index	Measure of customer bills produced meeting performance criteria	5.0	≤5.0	0.75	2.58

The objective is to achieve a score of five or less.

The Billing Index is impacted by factors such as the performance of the Company's billing system, weather variability, which can cause a high volume of billing checks and estimation issues, and mail delivery by Canada Post.

The 2017 result was 0.75 which was better than the benchmark of 5.0. The June 2018 year-to-date performance is 2.58 which is also better than the benchmark. No significant billing issues have arisen in 2017 or so far in 2018.

21.1 Would FEI agree that it would be more appropriate to record the 'Threshold' as being >5? Please note the arrow direction.

<u>Response:</u>

Consistent with the CEC's interpretation of the Billing Index threshold, FEI interprets Billing Index results with the understanding that results higher than the threshold of 5.0 are considered outside of the acceptable performance range. As part of the SQI Consensus Recommendation on Thresholds for Service Quality Indicators under the FEI and FBC 2014-2019 PBR Plans, the threshold for the Billing Index measure was set at '<=5.0'. The threshold was set to be the same as the approved benchmark of 5.0, recognizing the historical volatility in performance.

To avoid possible confusion, FEI proposes that the label '<=' for the Billing Index threshold be eliminated, and that the threshold instead be stated simply as 5.0, which would be similar to the labelling convention used for other SQIs' thresholds. For the other SQIs, depending on the metric, performance outside of the acceptable performance range is measured by results higher or lower than the threshold.

21.1.1 If not, why not.

<u>Response:</u>

Please refer to the response to CEC IR 1.21.1.

22. Reference: Exhibit B-2, page 149, and page 150

Table 13-14: Transmission Incidents by Severity Level

OGC Severity Level	Reportable Incidents in 2015	Reportable Incidents in 2016	Reportable Incidents in 2017	Reportable Incidents June YTD 2018
Level 1 (moderate)	3	3	4	2
Level 2 (major)	0	0	0	0
Level 3 (serious)	0	0	0	0

22.1 Please confirm that the reportable incidents are a result of third party interaction with the pipelines, and that none of the reportable incidents in 2017 or 2018 are a result of FEI actions.

Response:

The reportable incidents in 2017 or 2018 were not the result of FEI's actions. The reportable incidents were the result of either third party interactions with the pipelines or acts of nature.

22.2 Please provide a brief description of what constitutes Level 1, Level 2 and Level 3 severity levels and provide quantification in terms of $ impacts.

Response:

The following is a brief description of what constitutes the three OGC Severity Levels:

- Level 1 (moderate) – Moderate on site equipment damage and incident escalation highly unlikely (i.e., pulled IP service)
- Level 2 (major) – Major on site equipment damage and incident escalation possible (i.e., damaged Transmission main with possibility of a large customer outage)
- Level 3 (serious) – Major on site equipment or infrastructure loss and uncontrolled incident (i.e., station loss with blowing gas)

The OGC Severity Levels are determined using an OGC Incident Classification Matrix. All OGC related incidents are assessed for consequence and probability. The consequence and probability scores are added together to determine the overall risk score which is used to determine the level.

The cost impact to FEI can vary considerably based on the nature of the incident. A damaged service can range from a few hundred dollars to several thousand dollars and costs are typically recovered from the damager. An incident resulting from an act of nature can range from a few thousand dollars to hundreds of thousands of dollars.

Attachment 12.1

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BRITISH COLUMBIA UTILITIES COMMISSION

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-108-01

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by BC Gas Utility Ltd.
for Approval of Lease Arrangements with the City of Kelowna

BEFORE:	P. Ostergaard, Chair)	
	R.D. Deane, Commissioner)	October 17, 2001

O R D E R

WHEREAS:

A. On May 18, 2001, BC Gas Utility Ltd. ("BC Gas", "the Utility") applied to the British Columbia Utilities Commission ("the Commission") for approval to enter into Lease-In-Lease-Out ("LILO") arrangements with the City of Kelowna ("the City"), and to establish the mode of regulation under which the BC Gas rates will be set to take these arrangements into account; and

B. The LILO Application arises out of the existing BC Gas Franchise Agreement, which has been in place since 1957 and provides an option for the City to "buy-out" the existing natural gas distribution system within the municipality's boundary in the event that the parties cannot agree on the terms of franchise renewal; and

C. The City would enter into a 35-year capital lease with BC Gas for the natural gas distribution system within the municipality's boundary. Title to the assets remains with BC Gas but the value of the City's rights in the lease would be set at $50 million. The City would pre-pay 95% of this value to BC Gas as rent due under the lease; the remaining 5% would be paid to BC Gas over the life of the lease. After establishing the capital lease, the City would lease back the operation of the distribution system to BC Gas through a 17-year operating lease. The terms of the operating lease require BC Gas to make annual payments to the City over the 17-year term; and

D. BC Gas has franchise agreements with several other municipalities that contain purchase options and the Utility plans to offer this type of arrangement to them; and

. . . /2

E. The Commission held a Workshop and Pre-hearing Conference on the LILO Application on Thursday, July 5, 2001, and participants expressed their preference for a written hearing process; and

F. Commission Order No. G-78-01 established a Regulatory Agenda for a written public hearing and no submissions from the public were received; and

G. On August 13, 2001, BC Gas filed minor amendments to some of the agreements attached to, and forming part of, the LILO Application; and

H. The arrangements have been approved by the Inspector of Municipalities; and

I. The Commission has reviewed the LILO Application and finds that the arrangements should be approved.

NOW THEREFORE the Commission orders as follows:

1. The Commission approves for BC Gas the LILO Application (including the minor amendments to the agreements dated August 13, 2001) to enter into the proposed lease arrangements with the City of Kelowna, specifically:

   a. pursuant to Section 52 of the Utilities Commission Act ("the Act"), the encumbrance of property under the Capital Lease between BC Gas and the City (Appendix C of the Application), and the terms of that lease;

   b. pursuant to Section 52 of the Act, the encumbrance of property under the Additions Option Agreement between BC Gas and the City (Appendix E of the Application), and the terms of that agreement;

   c. the terms of the Operating Lease between BC Gas and the City (Appendix D of the Application);

   d. the determination of the rates of BC Gas on the basis that the revenue requirement of BC Gas be established with the property that is the subject of the Operating Lease with the City and the Additions Option Agreement with the City being in rate base at its depreciated value, being subject to normal depreciation, and earning a normal return on rate base;

. . . /3

e. the annual Operating Lease payments from BC Gas to the City and the payments from the City to BC Gas pursuant to the Capital Lease are to be accounted for as non-utility transactions;

f. the interest rate for the deemed debt required for regulatory reconciliation purposes in the City of Kelowna LILO arrangements be set for future Revenue Requirement Applications at a rate equal to the BC Gas cost of long term borrowing (including issue costs) at the time of closing of the City of Kelowna LILO transactions;

g. the principle implicit in the LILO arrangements that future material changes in accounting standards, taxes or financing terms that affect the LILO transactions, or the accounting for them, will not result in a change to the rates paid by customers, nor will such events adversely affect BC Gas and its shareholders; and

h. recovery of the costs incurred related to these transactions, including Development Costs and Closing Costs and the costs of this Application, in the manner described in Section 3.6 of the LILO Application, inclusive of crediting any reimbursed Development Costs to BC Gas' cost of service in the year in which they are received.

DATED at the City of Vancouver, in the Province of British Columbia, this *18th* day of October 2001.

BY ORDER

Original signed by:

Peter Ostergaard
Chair

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BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-66-02

TELEPHONE: (604) 660-4700
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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by BC Gas Utility Ltd.
for Approval of Lease Arrangements with the City of Vernon

BEFORE:	P. Ostergaard, Chair R.D. Deane, Commissioner K.L. Hall, Commissioner N.F. Nicholls, Commissioner	September 19, 2002

O R D E R

WHEREAS:

A. On June 28, 2002, BC Gas Utility Ltd. ("BC Gas", "the Utility") applied to the British Columbia Utilities Commission ("the Commission") for approval to enter into Lease-In-Lease-Out ("LILO") arrangements with the City of Vernon ("the City"), and to establish the mode of regulation under which the BC Gas rates will be set to take these arrangements into account; and

B. The LILO Application arises out of the existing BC Gas Franchise Agreement, which has been in place since 1957, renewed in 1978, and which provides an option for the City to "buy-out" the existing natural gas distribution system within the City's boundary in the event that the parties cannot agree on the terms of a franchise renewal; and

C. The City would enter into a 35-year capital lease with BC Gas for the natural gas distribution system within the City's boundary. Title to the assets remains with BC Gas but the value of the City's rights in the lease would be set at $25 million. The City would pre-pay 95 percent of this value to BC Gas as rent due under the lease; the remaining 5 percent would be paid to BC Gas over the life of the lease. After establishing the capital lease, the City would lease back the operation of the distribution system to BC Gas through a 17-year operating lease. The terms of the operating lease require BC Gas to make annual payments to the City over the 17-year term; and

D. Commission Order No. G-49-02 established a Regulatory Agenda for a written public hearing process and no submissions were received; and

E. The Commission has reviewed the LILO Application and finds that the arrangements should be approved.

NOW THEREFORE the Commission orders as follows:

1. The Commission approves for BC Gas the June 28, 2002 LILO Application to enter into the proposed lease arrangements with the City of Vernon, specifically:

   a. pursuant to Section 52 of the Utilities Commission Act ("the Act"), the encumbrance of property under the Capital Lease between BC Gas and the City and the terms of that lease;

   b. pursuant to Section 52 of the Act, the encumbrance of property under the Additions Option Agreement between BC Gas and the City and the terms of that agreement;

   c. the terms of the Operating Lease between BC Gas and the City;

   d. the determination of the rates of BC Gas on the basis that the revenue requirement of BC Gas be established with the property that is the subject of the Operating Lease with the City and the Additions Option Agreement with the City being in rate base at its depreciated value, being subject to normal depreciation, and earning a normal return on rate base;

   e. the annual Operating Lease payments from BC Gas to the City and the payments from the City to BC Gas pursuant to the Capital Lease are to be accounted for as non-utility transactions;

   f. the interest rate for the deemed debt required for regulatory reconciliation purposes in the City of Vernon LILO arrangements be set for future Revenue Requirement Applications at a rate equal to the BC Gas cost of long term borrowing (including issue costs) at the time of closing of the City of Vernon LILO transactions;

   g. the principle implicit in the LILO arrangements that future material changes in accounting standards, taxes or financing terms that affect the LILO transactions, or the accounting for them, will not result in a change to the rates paid by customers, nor will such events adversely affect BC Gas and its shareholders; and

   h. recovery of the costs incurred related to these transactions, including Development Costs and Closing Costs and the costs of this Application, in the manner described in Section 3.6 of the LILO Application, inclusive of crediting any reimbursed Development Costs to BC Gas' cost of service in the year in which they are received.

DATED at the City of Vancouver, in the Province of British Columbia, this 19th day of September 2002.

BY ORDER

Original signed by:

Peter Ostergaard
Chair

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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-4-04

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by Terasen Gas Inc.
for Approval of Lease Arrangements with the City of Nelson

BEFORE:	L.A. Boychuk, Commissioner	)	
	L.F. Kelsey, Commissioner	)	January 8, 2004

O R D E R

WHEREAS:

A. On December 9, 2003, Terasen Gas Inc. (“Terasen Gas”) applied to the British Columbia Utilities Commission (“the Commission”) for approval to enter into Lease-In-Lease-Out (“LILO”) arrangements with the City of Nelson (“the City”), and to establish the mode of regulation under which the Terasen Gas rates will be set to take these arrangements into account; and

B. The LILO Application arises out of the existing Terasen Gas Franchise Agreement, which has been in place since 1980, and which provides an option for the City to “buy-out” the existing natural gas distribution system within the City’s boundary in the event that the parties cannot agree on the terms of a franchise renewal; and

C. The City would enter into a 35-year capital lease with Terasen Gas for the natural gas distribution system within the City’s boundary. Title to the assets remains with Terasen Gas but the value of the City’s rights in the lease would be set at $8 million. The City would pre-pay 95 percent of this value to Terasen Gas as rent due under the lease; the remaining 5 percent would be paid to Terasen Gas over the life of the lease. After establishing the capital lease, the City would lease back the operation of the distribution system to Terasen Gas through a 17-year operating lease. The terms of the operating lease require Terasen Gas to make annual payments to the City over the 17-year term; and

D. The municipal review process met the requirements of Commission Letter No. L-55-03; and

E. The Commission has reviewed the LILO Application and finds that the arrangements should be approved.

... /2

NOW THEREFORE the Commission orders as follows:

1. The Commission approves for Terasen Gas the December 9, 2003 LILO Application to enter into the proposed lease arrangements with the City of Nelson, specifically:

   a. pursuant to Section 52 of the Utilities Commission Act ("the Act"), the encumbrance of property under the Capital Lease between Terasen Gas and the City and the terms of that lease;

   b. pursuant to Section 52 of the Act, the encumbrance of property under the Additions Option Agreement between Terasen Gas and the City and the terms of that agreement;

   c. approval to enter into the Operating Lease between Terasen Gas and the City;

   d. the determination of the rates of Terasen Gas on the basis that the revenue requirement of Terasen Gas be established with the property that is the subject of the Operating Lease with the City and the Additions Option Agreement with the City being in rate base at its depreciated value, being subject to normal depreciation, and earning a normal return on rate base;

   e. the annual Operating Lease payments from Terasen Gas to the City and the payments from the City to Terasen Gas pursuant to the Capital Lease are to be accounted for as non-utility transactions;

   f. the interest rate for the deemed debt required for regulatory reconciliation purposes in the City of Nelson LILO arrangements be set for future Revenue Requirement Applications at a rate equal to the Terasen Gas cost of long term borrowing (including issue costs) at the time of closing of the City of Nelson LILO transactions;

   g. the principle implicit in the LILO arrangements that future material changes in accounting standards, taxes or financing terms that affect the LILO transactions, or the accounting for them, will not result in a change to the rates paid by customers nor will such events adversely affect Terasen Gas and its shareholders; and

   h. recovery of the costs incurred related to these transactions, including all Development Costs and Closing Costs and the costs of this Application, in the manner described in Section 3.6 of the LILO Application, inclusive of crediting any reimbursed Development Costs to Terasen Gas' cost of service in the year in which they are received.

DATED at the City of Vancouver, in the Province of British Columbia, this 21st day of January 2004.

BY ORDER

Original signed by:

Lori Ann Boychuk
Commissioner

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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-91-04

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by Terasen Gas Inc.
for Approval of Lease Arrangements with the City of Prince George

BEFORE: L.A. Boychuk, Commissioner
K.L. Hall, Commissioner October 7, 2004

O R D E R

WHEREAS:

A. On September 21, 2004 Terasen Gas Inc. ("Terasen Gas") applied to the British Columbia Utilities Commission ("the Commission") for approval to enter into Lease-In-Lease-Out ("LILO") arrangements with the City of Prince George ("the City") and to establish the mode of regulation under which the Terasen Gas rates will be set to take these arrangements into account; and

B. The LILO Application arises out of the existing Certificate of Public Convenience and Necessity, which has been in place since 1980, and which provides an option for the City to "buy-out" the existing natural gas distribution system within the City's boundary; and

C. The City would enter into a 35-year capital lease with Terasen Gas for the natural gas distribution system within the City's boundary. Title to the assets remains with Terasen Gas but the value of the City's rights in the lease would be set at $60 million. The City would pre-pay 95 percent of this value to Terasen Gas as rent due under the lease; the remaining 5 percent would be paid to Terasen Gas over the life of the lease. After establishing the capital lease, the City would lease back the operation of the distribution system to Terasen Gas through a 17-year operating lease. The terms of the operating lease require Terasen Gas to make annual payments to the City over the 17-year term; and

D. The municipal review process met the requirements of Commission Letter No. L-55-03; and

E. The Commission has reviewed the LILO Application and finds that the arrangements should be approved.

NOW THEREFORE the Commission orders as follows:

1. The Commission approves for Terasen Gas the September 21, 2004 LILO Application to enter into the proposed lease arrangements with the City of Prince George, specifically:

   a. pursuant to Section 52 of the Utilities Commission Act ("the Act"), the encumbrance of property under the Capital Lease between Terasen Gas and the City and the terms of that lease;

.../2

b. pursuant to Section 52 of the Act, the encumbrance of property under the Additions Option Agreement between Terasen Gas and the City and the terms of that agreement;

c. approval to enter into the Operating Lease between Terasen Gas and the City;

d. the determination of the rates of Terasen Gas on the basis that the revenue requirement of Terasen Gas be established with the property that is the subject of the Operating Lease with the City and the Additions Option Agreement with the City being in rate base at its depreciated value, being subject to normal depreciation, and earning a normal return on rate base;

e. the annual Operating Lease payments from Terasen Gas to the City and the payments from the City to Terasen Gas pursuant to the Capital Lease are to be accounted for as non-utility transactions;

f. the interest rate for the deemed debt required for regulatory reconciliation purposes in the City of Prince George LILO arrangements be set for future Revenue Requirement Applications at a rate equal to the Terasen Gas cost of long-term borrowing (including issue costs) at the time of closing of the LILO transactions;

g. the principle implicit in the LILO arrangements that future material changes in accounting standards, taxes or financing terms that affect the LILO transactions, or the accounting for them, will not result in a change to the rates paid by customers nor will such events adversely affect Terasen Gas and its shareholders;

h. recovery of the costs incurred related to these transactions, including all Development Costs and Closing Costs and the costs of this Application, in the manner described in Section 3.6 of the LILO Application, inclusive of crediting any reimbursed Development Costs to Terasen Gas' cost of service in the year in which they are received;

i. pursuant to Section 45 of the Act, the Schedules A and B from the 1958 CPCN will cease to be in effect; and

j. pursuant to Section 45 of the Act, a CPCN is granted which approves the Franchise Amendment Agreement between the City of Prince George and Terasen Gas.

DATED at the City of Vancouver, in the Province of British Columbia, this 7th day of October 2004.

BY ORDER

Original signed by:

L.A. Boychuk
Commissioner

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by Terasen Gas Inc.
for Approval of Lease Arrangements with the Town of Creston

BEFORE: L.A. Boychuk, Commissioner
L.F. Kelsey, Commissioner August 29, 2005

O R D E R

WHEREAS:

A. On August 10, 2005 Terasen Gas Inc. ("Terasen Gas") applied to the British Columbia Utilities Commission ("the Commission") for approval to enter into Lease-In-Lease-Out ("LILO") arrangements with the Town of Creston ("the Town") and to establish the mode of regulation under which the Terasen Gas rates will be set to take these arrangements into account; and

B. The LILO Application arises out of the existing Franchise Agreement, which has been in place since 1958, was renewed in 1988, and provides an option for the Town to "buy-out" the existing natural gas distribution system within the Town's boundary; and

C. The Town would enter into a 35-year capital lease with Terasen Gas for the natural gas distribution system within the Town's boundary. Title to the assets remains with Terasen Gas but the value of the Town's rights in the lease would be set at $5.5 million. The Town would pre-pay 95 percent of this value to Terasen Gas as rent due under the lease; the remaining 5 percent would be paid to Terasen Gas over the life of the lease. After establishing the capital lease, the Town would lease back the operation of the distribution system to Terasen Gas through a 17-year operating lease. The terms of the operating lease require Terasen Gas to make annual payments to the Town over the 17-year term; and

D. The municipal review process met the requirements of Commission Letter No. L-55-03; and

E. The Commission has reviewed the LILO Application and finds that the arrangements should be approved.

NOW THEREFORE the Commission orders as follows:

1. The Commission approves for Terasen Gas the August 10, 2005 LILO Application to enter into the proposed lease arrangements with the Town of Creston, specifically:

a. pursuant to Section 52 of the Utilities Commission Act ("the Act"), the encumbrance of property under the Capital Lease between Terasen Gas and the Town and the terms of that lease;

b. pursuant to Section 52 of the Act, the encumbrance of property under the Additions Option Agreement between Terasen Gas and the Town and the terms of that agreement;

c. approval to enter into the Operating Lease between Terasen Gas and the Town;

d. the determination of the rates of Terasen Gas on the basis that the revenue requirement of Terasen Gas be established with the property that is the subject of the Operating Lease with the Town and the Additions Option Agreement with the Town being in rate base at its depreciated value, being subject to normal depreciation, and earning a normal return on rate base;

e. the annual Operating Lease payments from Terasen Gas to the Town and the payments from the Town to Terasen Gas pursuant to the Capital Lease are to be accounted for as non-utility transactions;

f. the interest rate for the deemed debt required for regulatory reconciliation purposes in the Town of Creston LILO arrangements be set for future Revenue Requirement Applications at a rate equal to the Terasen Gas cost of long-term borrowing (including issue costs) at the time of closing of the LILO transactions;

g. the principle implicit in the LILO arrangements that future material changes in accounting standards, taxes or financing terms that affect the LILO transactions, or the accounting for them, will not result in a change to the rates paid by customers nor will such events adversely affect Terasen Gas and its shareholders;

h. recovery of the costs incurred related to these transactions, including all Development Costs and Closing Costs and the costs of this Application, in the manner described in Section 3.6 of the LILO Application, inclusive of crediting any reimbursed Development Costs to Terasen Gas' cost of service in the year in which they are received; and

i. pursuant to Section 45 of the Act, a CPCN is granted which approves the Franchise Amendment Agreement between the Town and Terasen Gas.

DATED at the City of Vancouver, in the Province of British Columbia, this 30th day of August 2005.

BY ORDER

Original signed by:

L.A. Boychuk
Commissioner

Attachment 15.1

28 Reference: Exhibit B-2, Page 56

__7.5.1.1 2015 System Extension Application__

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

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

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

__Response:__

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

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

28.1.1 If no, please explain why not.

__Response:__

Please refer to the response to CEC IR 1.28.1.

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

Response:

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

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

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

Response:

Please refer to the response to CEC IR 1.28.2.

28.2.1.1 If not, please explain why not.

Response:

Please refer to the response to CEC IR 1.28.2.

29 Reference: Exhibit B-2, Page 57

7.5.1.2 BERC Rate Methodology Application

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

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

Response:

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

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

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