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May 3, 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. 1598946

2017 Long Term Gas Resource Plan (LTGRP) (the Application)

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

On December 14, 2017, FEI filed the Application referenced above. In accordance with British Columbia Utilities Commission Order G-33-18 establishing 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 Ken Ross at (604) 576-7343.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

1. Reference: Exhibit B-1, page 60

> The 2017 LTGRP uses a 2015 base year, starts its forecast in 2016 and ends the forecast horizon in 2036. The 2017 LTGRP selected the 2015 base year because FEI had not finalized its 2016 actuals in time for the 2017 LTGRP analysis to import this data while also being able to conclude in the 2017 submission year.

1.1 Has FortisBC Energy Inc. ("FEI") completed the 2016 base year at this time?

Response:

Confirmed.

FEI interprets the term "2016 base year" in this request to mean 2016 actual data.

1.1.1 If so, please identify any key differences between 2015 and 2016.

Response:

Customers

The following table shows the 2015 and 2016 year end customer totals by rate group[1]:

Table 1: FEI Customer Counts

FEI Customer Counts			
	2015	2016	2016 vs 2015
Residential	888,135	899,473	1.3%
Commercial	92,549	93,551	1.1%
Industrial	1,017	1,012	-0.5%
Total	981,701	994,036	1.3%

Residential customer additions were strong in 2016. The year-end residential customer count increased 1.3 percent (11,338) compared to 2015.

Similarly, commercial customer growth was also strong. The 2016 year-end total increased 1.1 percent from 2015 (an increase of 1,002 customers).

[1] The Industrial rate group includes LNG customers in this IR response.

Industrial customers declined in 2016 compared to 2015. The year-end industrial customer count decreased by 5 customers. As shown below even though the customer count was off in 2016, the industrial demand did increase.

Use Rate

FEI calculates use rates for residential and commercial customers. The following table compares residential and average commercial use rates in 2016 to 2015.

Table 2: FEI Normalized Use Per Customer

FEI Normalized Use Per Customer (Gjs)			
	2015	2016	2016 vs 2015
Residential	83.7	86.9	3.8%
Commercial	605.3	619.4	2.3%

The residential use rate increased 3.8 percent compared to 2015. Please refer to the response to CEC IR 1.1.2 for a discussion of this increase compared to historic changes.

The average commercial use rate was also higher by 2.3 percent in 2016 compared to 2015.

Demand

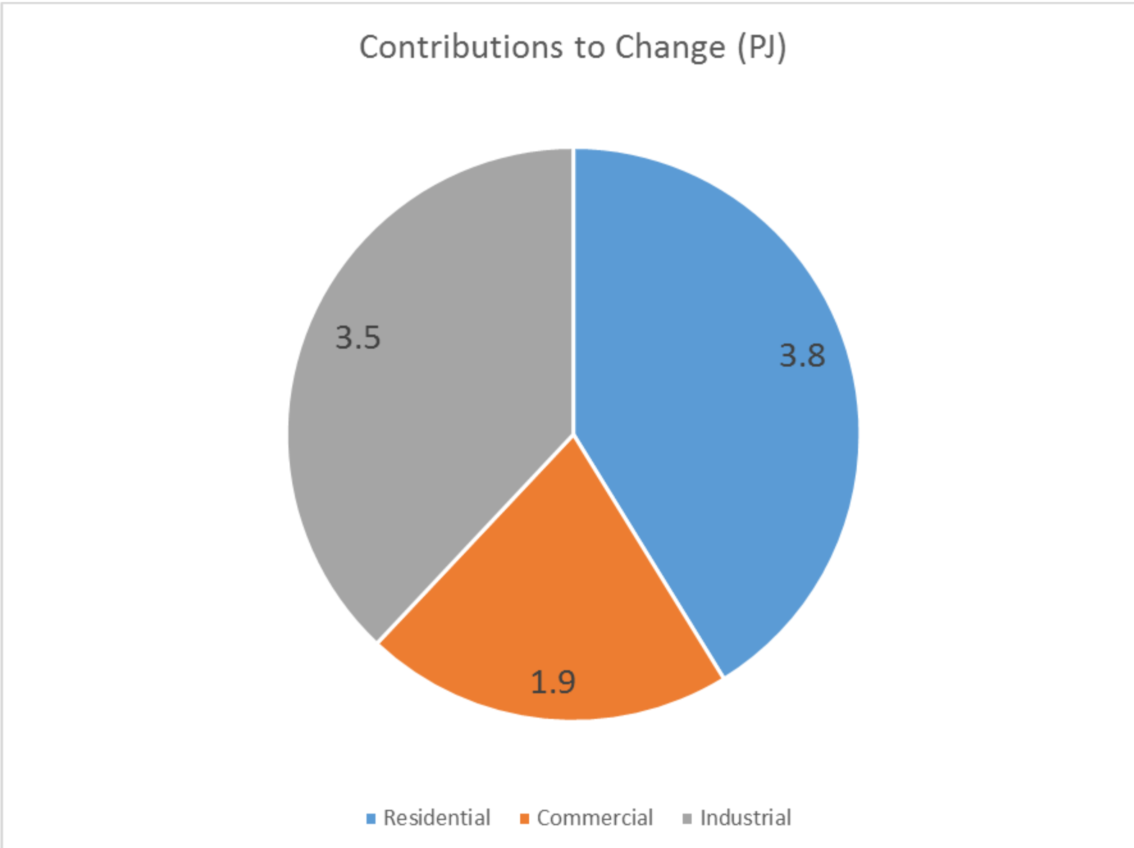
Demand is a product of use rates and customers. For the residential and commercial rate groups both the customer totals and use rates increased in 2016 so it follows that the demand for these two rate groups also increased in 2016. In the industrial rate group the year end customer count was lower but the annual demand was higher. This implies that some existing customers increased their demand in response to their specific market conditions. The results are shown below:

Table 3: FEI Energy

FEI Energy (Pjs)			
	2015	2016	2016 vs 2015
Residential	74.4	78.2	5.1%
Commercial	56.0	58.0	3.4%
Industrial	61.3	64.9	5.7%
Total	191.7	201.0	4.8%

The following figure shows the contribution by rate group to the increase in 2016 demand compared to 2015:

Figure 1: Contributions to Change (PJ)



2016 demand increased due to increases from all sectors. The largest increases in demand were recorded in the residential and industrial rate groups, with an increase in residential customer count while the industrial customer count declined in 2016.

1.1.2 Please provide a discussion as to how the variances between 2015 and 2016 would affect the planning.

Response:

FEI consulted with Posterity Group Consulting Inc. (Posterity) to provide the following response.

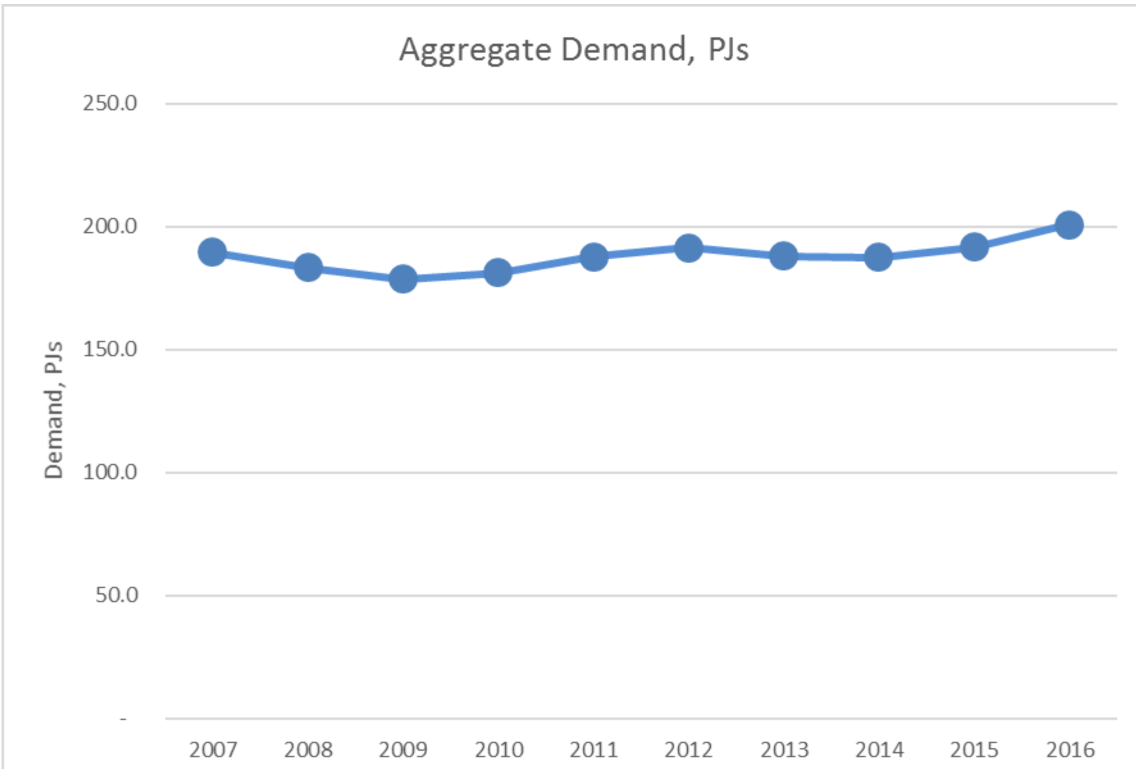
The End Use forecast method used for planning starts with the last known weather normalized actual data available at the time the forecast is prepared. The trends that shape future scenarios and future demand are independent of the starting point (base year).

Increased demand in 2016 compared to 2015 is expected to shift all End Use scenarios higher.

However, as the following chart shows, differences always exist between pairs of years. The previous LTGRP used data from 2010 and then in 2011 and 2012 the demand also increased.

The volatility in the source data is one reason that the End Use forecast models a number of different future scenarios.

Figure 1



1.2 Does the base year information typically change significantly from year to year? Please comment and provide approximate quantifications of any volatility that FEI normally experiences.

Response:

Data volatility can be measured using the standard deviation.

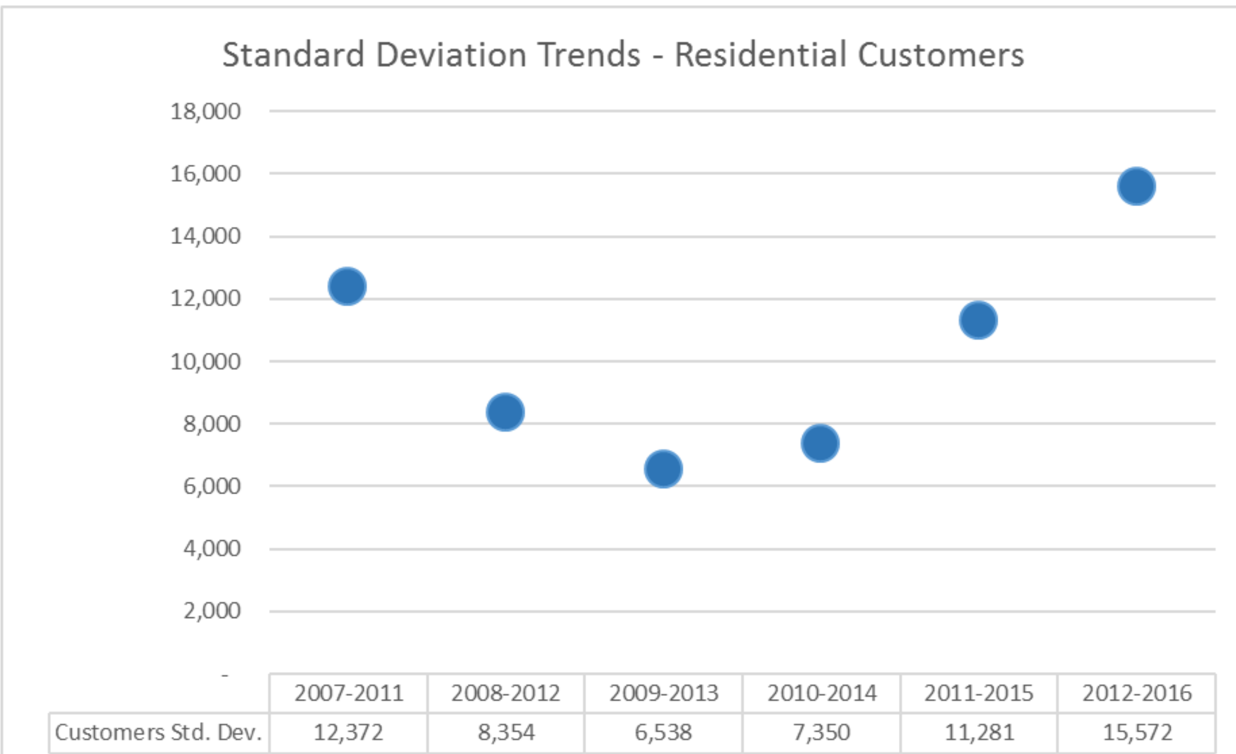
The standard deviation is a measure of the distance the points in a dataset lie from the mean of the dataset. If the standard deviation calculated from one set of data points is larger than the standard deviation calculated from a different set then we can say that in general the data points in the first set are more volatile and lie further from the mean than do the points in the second dataset.

In the following charts, FEI has used five-year rolling periods to examine changes in the standard deviation over time. This aids in assessing whether particular aspects that make up the aggregate demand forecast are becoming more or less volatile, or are remaining about the same.

Residential

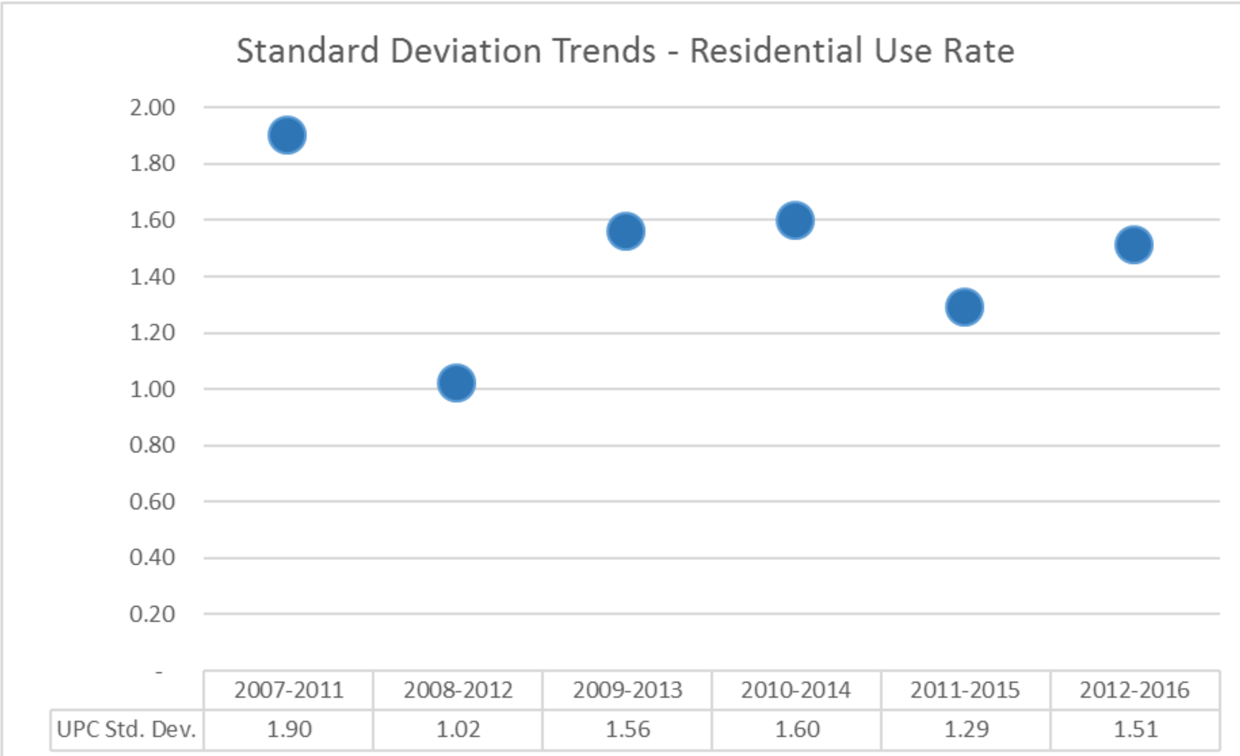
Residential customer totals have become more volatile in recent years. The increased volatility may be due to increased customer additions following the post-recession slowdown.

Figure 1



The volatility in the residential use rate does not show the same trend that is apparent in residential customer counts. Since 2009 the volatility in use rates has been more consistent.

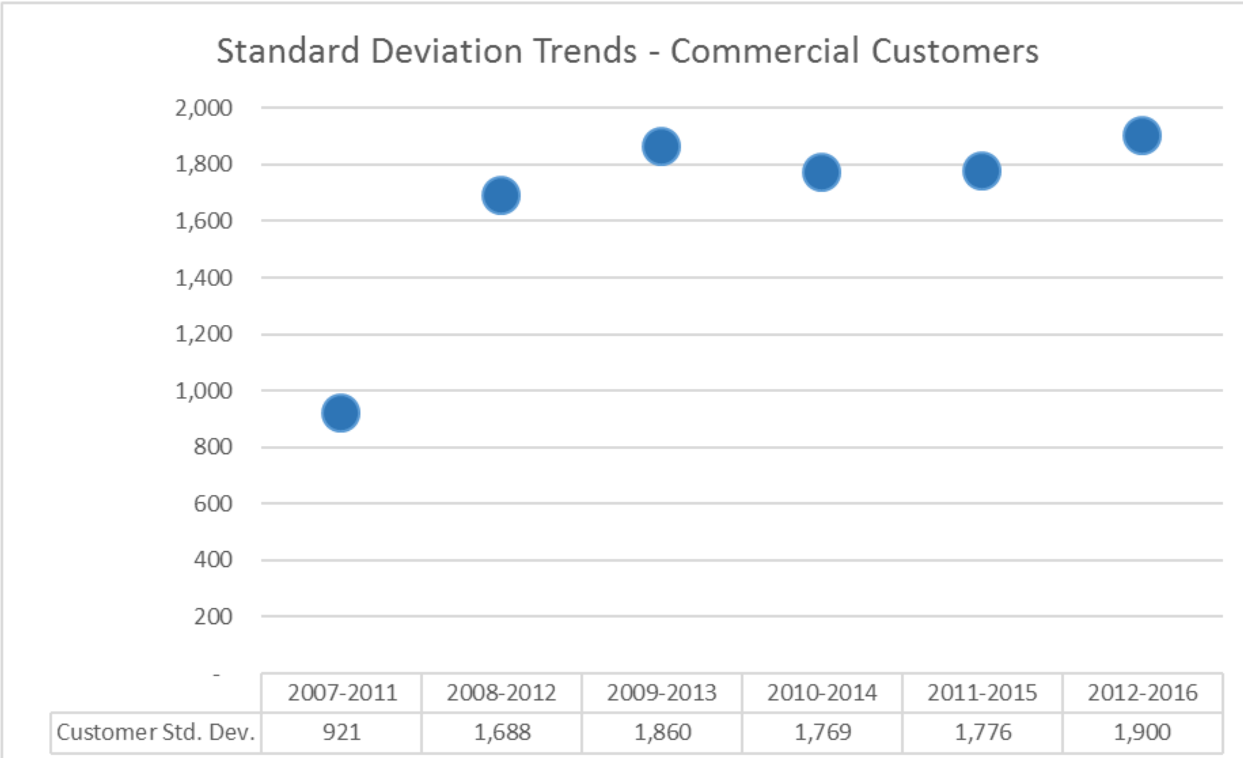
Figure 2



Commercial

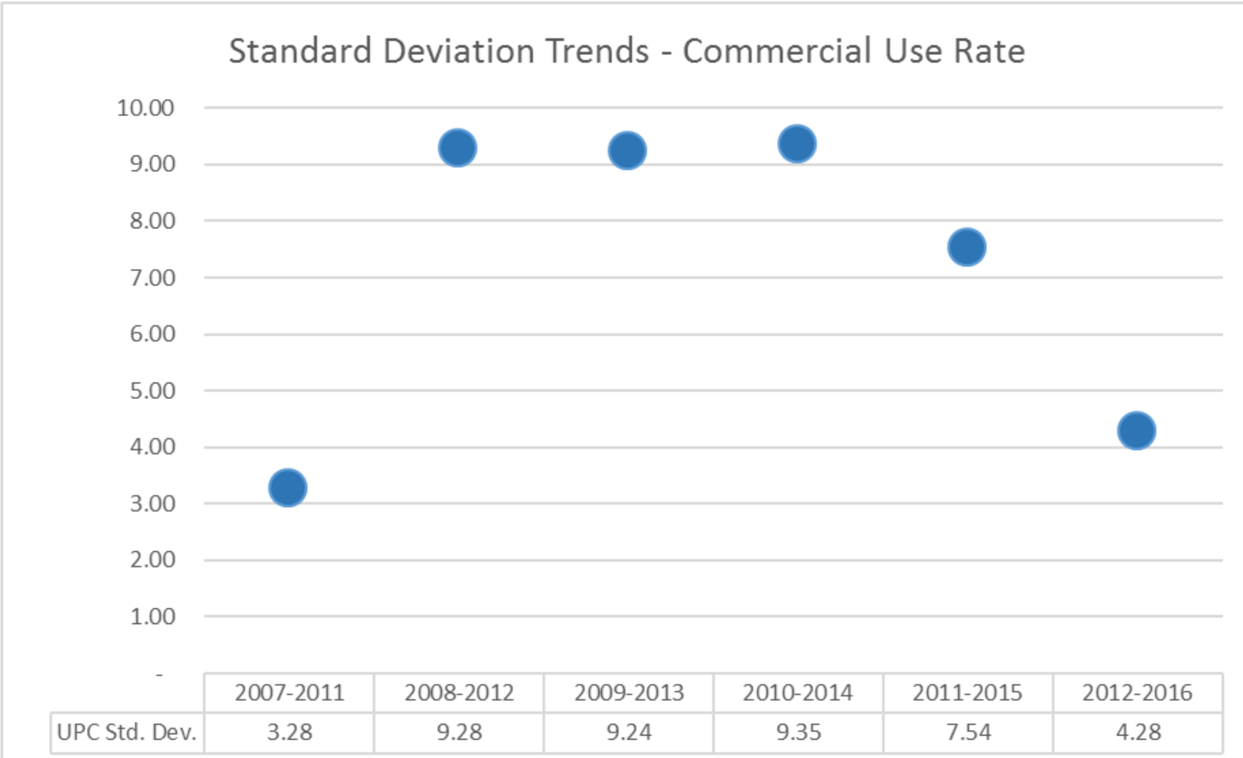
Unlike residential customers, annual commercial customer totals have shown more consistency recently.

Figure 3



Volatility in commercial use rates is stable to declining. Rate Schedule 2 is shown below as an example. Volatility in the weather normalized use rates has been not deviated significantly from the mean in recent years.

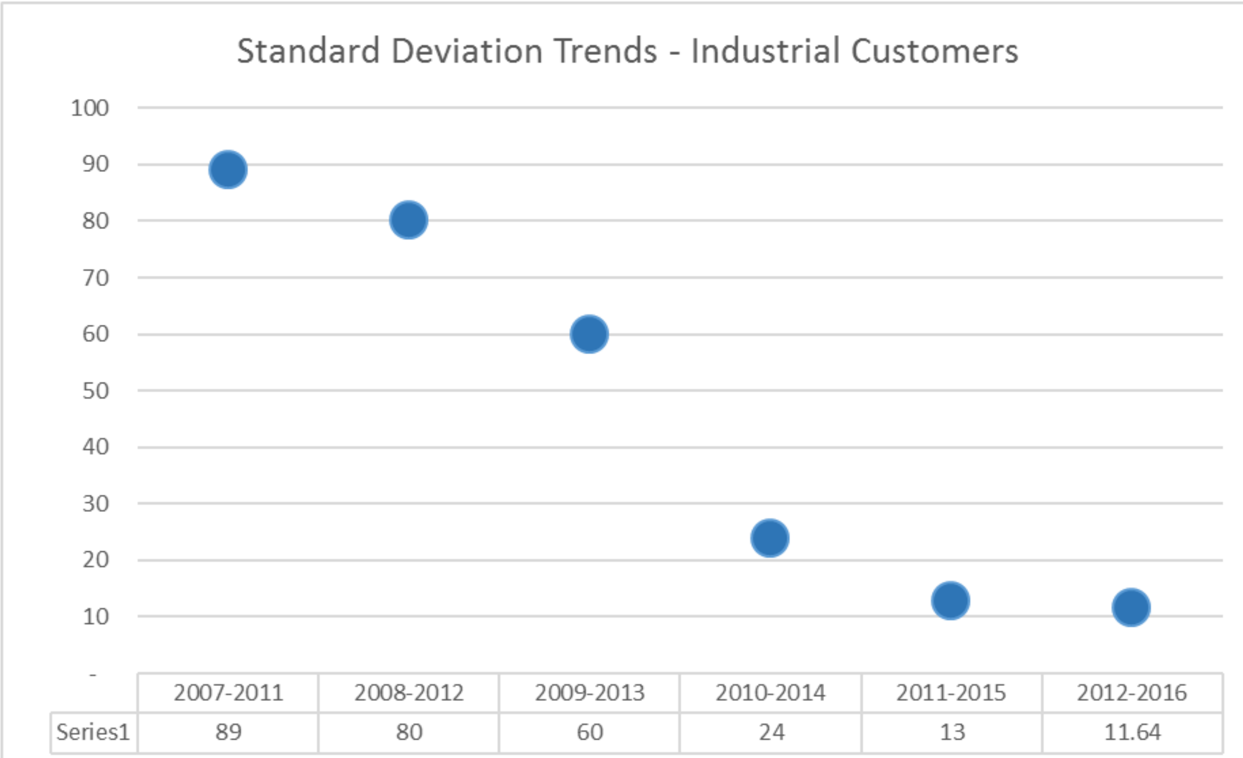
Figure 4



Industrial

Volatility in year-end industrial customer totals has decreased significantly in recent years. FEI now expects the year-end industrial count to be within 12 customers of the five-year average. Use rates are not recorded or forecast for industrial customers and as such a plot cannot be provided for industrial UPC.

Figure 5

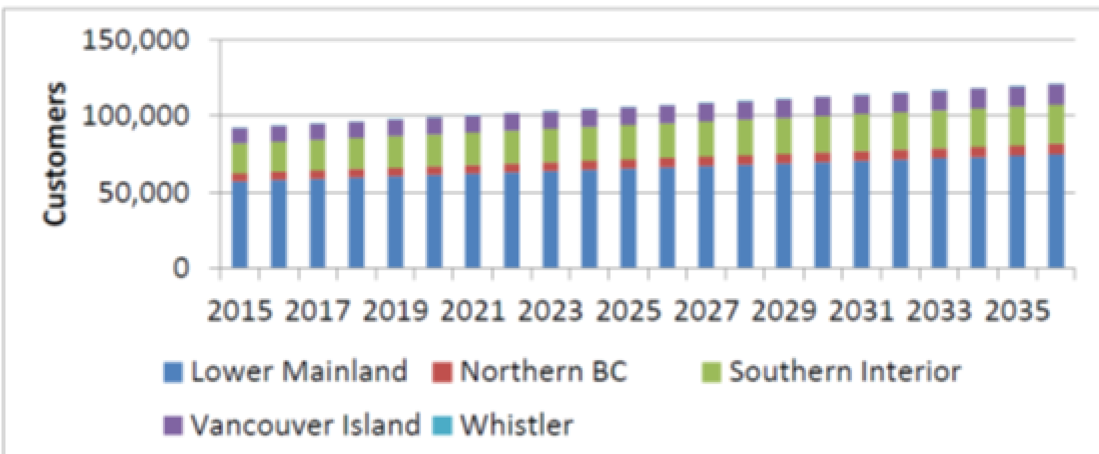


Standard Deviation Trends - Industrial Customers
100
90
80
70
60
50
40
30
20
10
-
2007-2011
2008-2012
2009-2013
2010-2014
2011-2015
2012-2016
Series1
89
80
60
24
13
11.64

2. Reference: Exhibit B-1, page 61 and 62

> ***3.3.1.2 Commercial***
>
> Recent trends in commercial customer additions are used to forecast future additions. The net customer additions are estimated based on actual additions in the latest three years. Recent additions are stronger than in the period between 2010 and 2014 with annual new attachments averaging in the range of 1,400.
>
> ______________________
>
> Figure 3-3 shows the Reference Case long term account forecast for commercial rate schedule customers for each of FEI's service regions. The Reference Case predicts continued growth of 31 percent across the planning horizon with regional distribution remaining relatively unchanged.

Figure 3-3: Long Term Customer Forecast by Region – Commercial (Excluding NGT)



2.1 By relying on actuals from the previous three years is FEI only able to predict one year of customer additions or does FEI ultimately rely on forecasted information? Please explain.

<u>Response:</u>

FEI forecasts short term commercial additions using three years of historic actual data. The BC STATS Household formation forecast is then used to guide the longer term customer additions forecast.

As described in the response to BCUC IR 1.11.1, FEI is then able to forecast customer additions for the full 20 year planning horizon.

2.2 Please provide the calculation for forecasting commercial customer additions over the 20 year period.

Response:

Please refer to the response to BCUC IR 1.11.1.

2.3 How does FEI account for recessionary periods in its long-term planning? Please explain.

Response:

FEI does not try to predict precise cycles in economic strength but examines scenarios which generally are of greater or lesser economic strength throughout the planning horizon, thus addressing the potential for economic recessions or economic growth according to the scenario.

2.4 Do recessions typically influence the number of commercial customers, Use per Customer or both? Please explain.

Response:

Due in part to a very small sample set of recessions FEI is unable to quantify or comment on their effect on customer additions and use rates. FEI believes that customer counts and use rates are driven by many factors that are all properly combined in the intrinsic data used for time series forecasting. For the purpose of demand forecasting, FEI does not believe it is necessary or useful to try and quantify the effect of each of the many drivers embedded in the historic demand.

Additionally FEI believes that each of the 178 industries that FEI's commercial customers operate in are each affected by events like recessions differently. For example the "Construction" and "Automobile Dealers" sectors could be expected to be affected differently than sectors such as "Hospitals" or "Federal Government".

FEI does not believe a more accurate forecast would result if FEI were to try to forecast the future effects of specific events like recessions on all the different industrial sectors in which our customers operate.

2.5 Please provide customer additions data for the last 20 years.

Response:

Please see historical commercial customer additions data below.

Table 1: Historical Commercial Customer Additions.

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
FEI Commercial Additions (Incl. FTN)	1,910	944	1,231	1,508	454	232	551	557	1,255	1,201	1,789	1,002

FEI is unable to provide additions data before 2005 due to the lack of historical electronic data.

3. Reference: Exhibit B-1, page 65

> Beginning with the calibrated base year, the Reference Case forecast was built using the Company's 20-year account forecast (discussed in Section 3.3), with new residential dwellings, commercial floor area and industrial facilities added based on the account growth rates. Anticipated efficiency improvements, such as the natural replacement of furnaces, were incorporated in both existing buildings and new construction. Anticipated changes in the saturation and gas shares for specific end-uses were also included. The end-use forecast model provides the forecast consumption values for each forecast year at the same level of granularity as the base year.

3.1 How are new residential dwellings, commercial floor area and industrial facilities added based on the account growth rates? Please explain.

Response:

FEI consulted with Posterity to provide the following response.

New residential dwellings are added to the end-use model in each forecast year, based on the forecast customer growth rate for the applicable scenario (Section 1.2.1.1 of Appendix B-1 of the Application describes how FEI developed scenario-specific customer forecasts for all sectors). Dwellings are added as whole (not fractional) dwelling units. UPC is based on the evolving fuel shares, appliance saturations, and unit energy consumption, by end use, of the newest vintage of each region's dwellings of each dwelling type.

New commercial customers are added to the model in each forecast year, based on the forecast customer growth rate for each rate class for the applicable scenario. Commercial customers are added as whole (not fractional) buildings. Floor area for the new customers is based on the average floor area for each region's buildings of each commercial building type in each rate class. UPC is based on the evolving fuel shares and consumption per floor area, by end use, for each region's commercial buildings of each building type.

New industrial customers are added to the model in each forecast year, based on the forecast customer growth rate for each rate class for the applicable scenario. Industrial customers are added as whole (not fractional) customers. Consumption for the new customers is based on the evolving fuel shares and existing customer consumption, by end use, for each region's industrial customers of each industrial sub-sector and rate class.

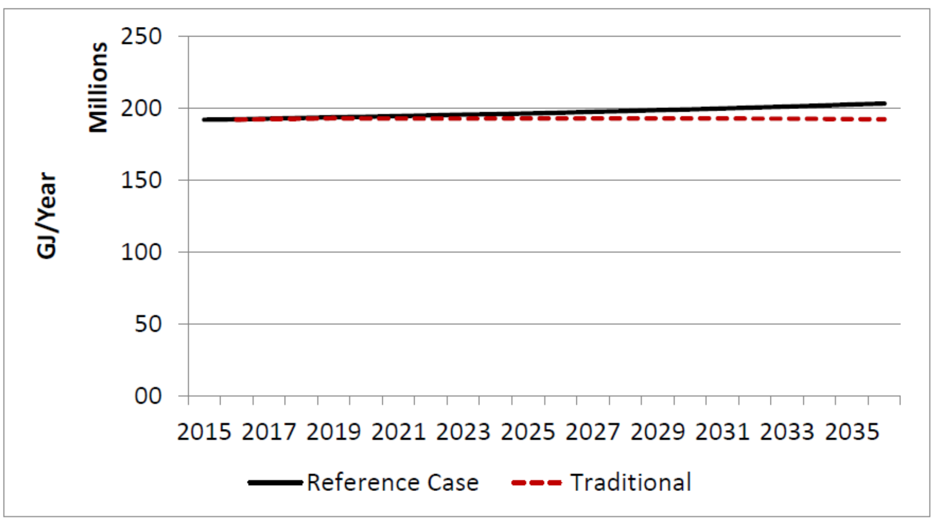
4. Reference: Exhibit B-1, page 67

3.4.3 Comparing the Traditional and End-Use Methods For Forecasting Annual Demand

As discussed above, FEI's end-use method differs in a number of ways from its time-series based Traditional Annual Method. Comparing the end-use method Reference Case results with the results of the Traditional Annual Method grounds the results of the end-use method before FEI proceeds to use this method for examining the impact on annual demand of alternate future scenarios. If the results of the Traditional Annual Method demand forecast and the end-use method Reference Case annual demand are reasonably aligned, then the end-use method provides a reasonable basis for developing alternate future scenarios.

Figure 3-6 below compares the annual demand results of the Traditional Annual Method with the results of the end-use method Reference Case. By the end of the planning period the two forecast methods differ by less than six percent. This variance is due to the various differences between the two methods. One of these differences is that the Traditional Annual Method includes intrinsic historical end-use trends, whereas the end-use method Reference Case limits itself to fully known, legally enshrined, and mandatory data. For example, the Traditional Annual Method includes historical change trends of energy performance codes and standards while the end-use method Reference Case only accounts for such changes that are already legally enshrined and are or will be mandatory during the forecast horizon. By the same token, the Traditional Annual Method includes historical C&EM program participation trends whereas the end-use method Reference Case relies on specific assumptions regarding future changes in equipment characteristics and adoption but not C&EM programs. Across the LTGRP planning horizon, FEI uses the end-use method Reference Case to plan for its forecast long term annual demand.

Figure 3-6: Comparison of Annual Demand Forecasts

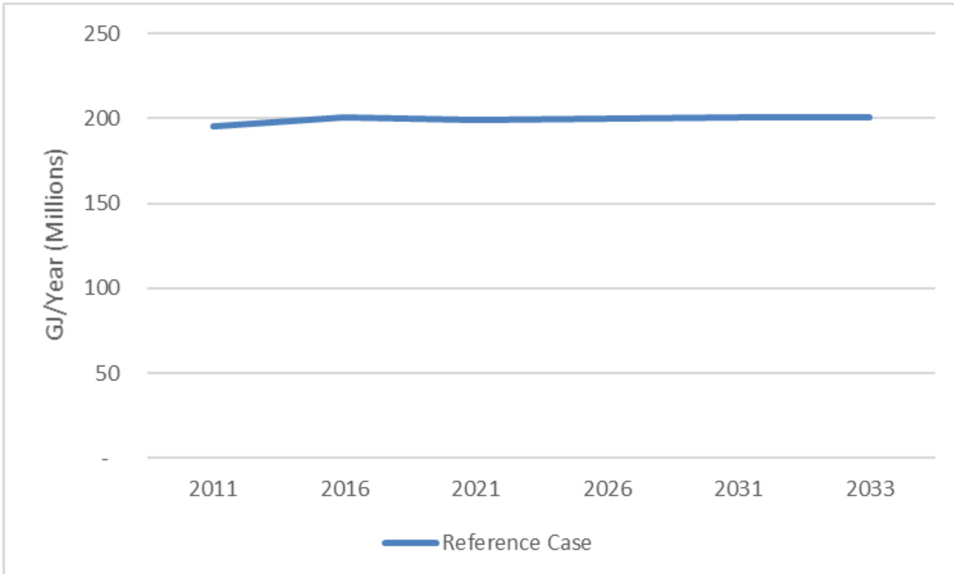


4.1 Please plot FEI's previous end-use reference case from the most recent LTRP.

Response:

As requested, a plot of FEI's previous end-use reference case from the most recent LTRP is provided below.

Figure 1: 2014 LTRP Reference Case Annual Demand Forecast

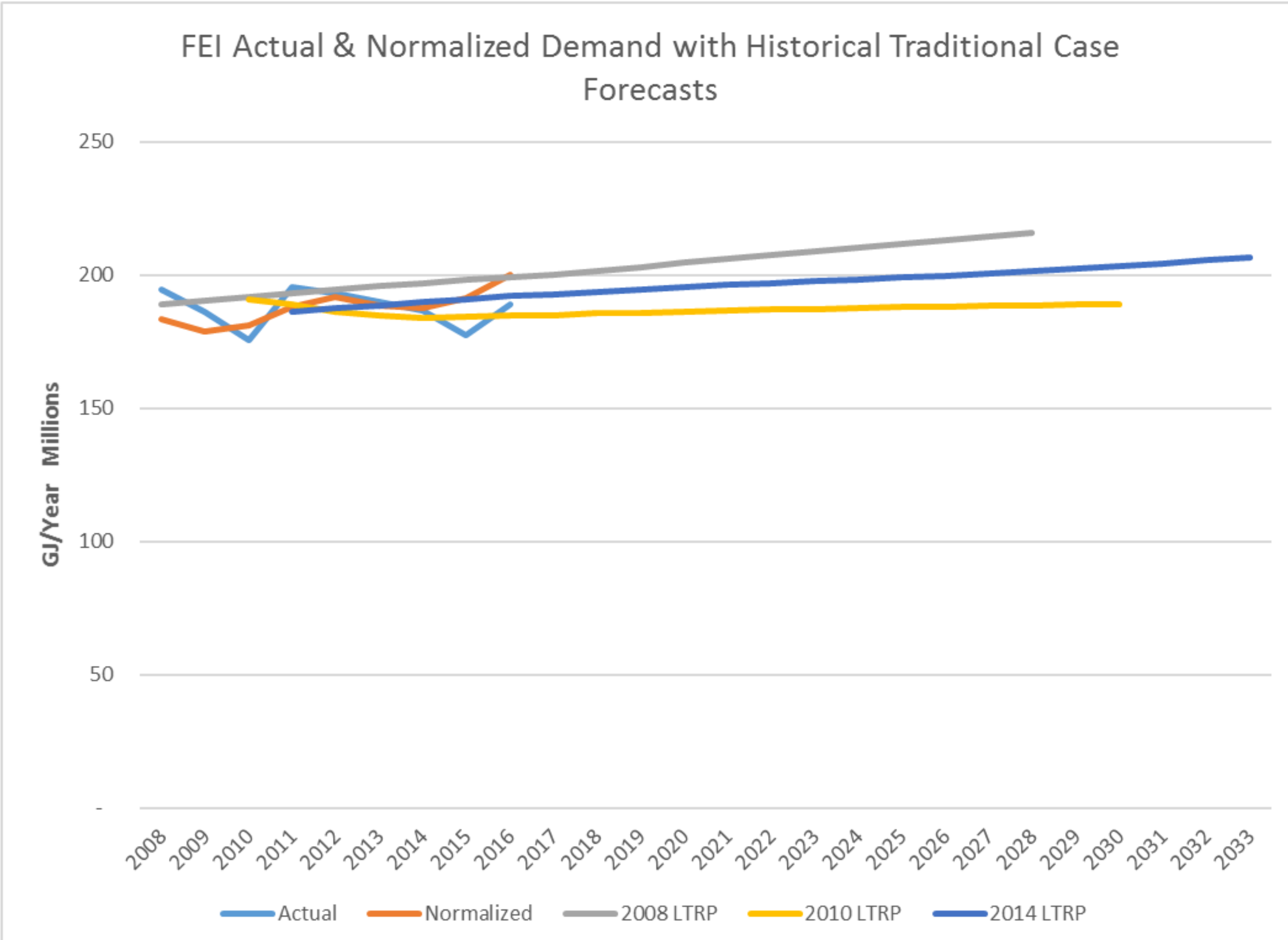


4.2 Please provide a graph of FEI actual demand and weather normalized demand against FEI's previous traditional case forecasts by vintage year of forecast for the prior 10 years of forecast to show the accuracy of the forecasting.

<u>Response:</u>

The graph below presents FEI actual demand and weather-normalized demand against FEI's previous traditional case forecasts by vintage year of forecast for the prior 10 years.

Figure 1: FEI Actual and Normalized Demand with Traditional Case LTRP Forecasts[2]



Note that residential and commercial demand is normalized prior to being used in either the Traditional or End Use method. As a result the forecast also assumes normal weather. Plotting actual data against the forecast is not recommended but shown here in an effort to be responsive to this question.

4.3 Please provide a graph of FEI actual demand against FEI's previous end use reference case forecasts.

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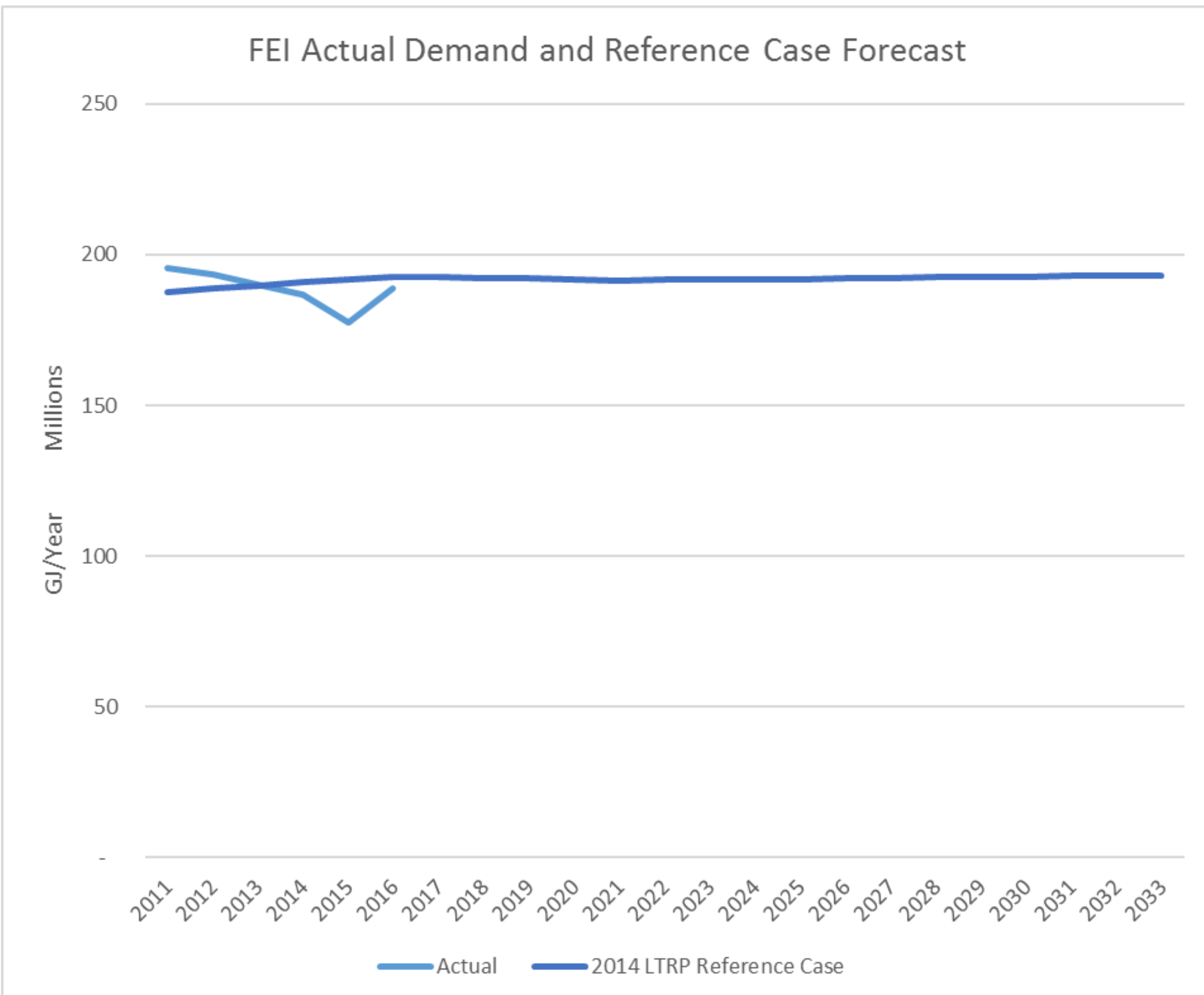
[2] Burrard Thermal Generation, Vancouver Island Joint Venture and Island Generation are not included.

Response:

The residential and commercial actual data used in both Traditional and End Use forecasts is weather normalized. As a result the forecasts assume normal weather. FEI does not believe that useful comparisons can be made by comparing actual results to weather normalized forecasts, so plots of both actual and weather normalized actual data are included.

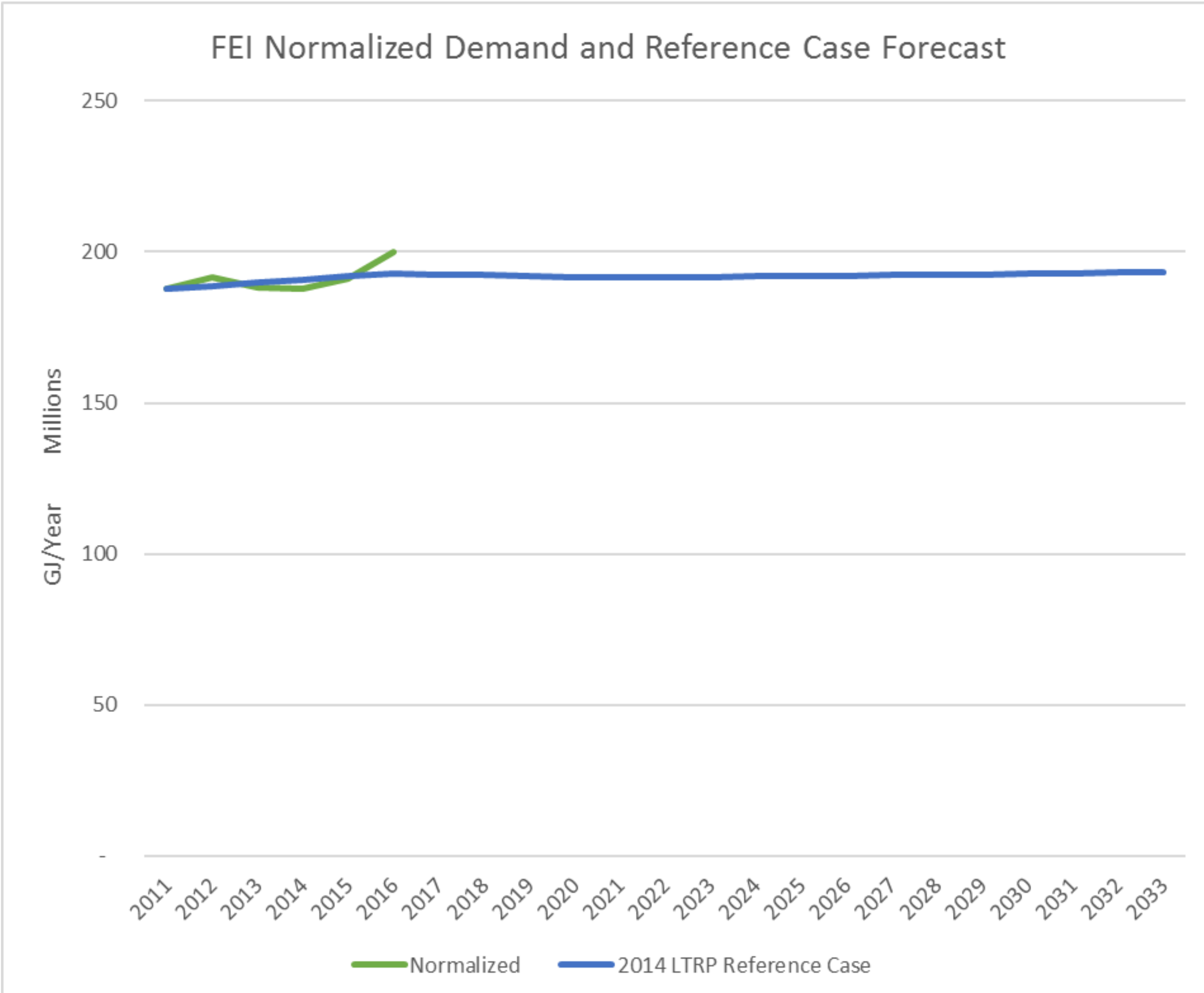
A graph of FEI actual demand against FEI's previous end use reference case forecast is provided below. (The 2014 LTRP was the only previous LTRP to use an "end use" reference case forecast).

Figure 1: FEI Actual Demand and the 2014 LTRP End Use Reference Case Forecast[3]



[3] Burrard Thermal Generation, Vancouver Island Joint Venture and Island Generation Cogen not included.

Figure 2: FEI Normalized Actual Demand and the 2014 LTRP End Use Reference Case Forecast



4.4 Please elaborate on how the 6% variance between the reference case and the traditional case could potentially impact FEI's long term planning.

Response:

FEI interprets this question to refer to long term planning for annual demand as this question refers to Figure 3-6 which displays the annual demand forecast. Long term planning is strictly based on the Reference Case forecast. Therefore, the variance between the Traditional forecast and the reference case end use forecast has no impact on FEI's long term planning. The Traditional forecast is only used as a test to make sure the reference case is reasonable.

The Traditional forecast uses the same data set but different methods and FEI believes this makes the Traditional forecast a useful tool for checking the reference case forecast before addition scenario modelling is completed. The Traditional forecast is not used for long term planning purposes.

4.5 Would it be fair to say that the traditional method could provide a better predictor under constant conditions and stable growth trends whereas the end-use method might be better under uncertain conditions and potentially changing growth trends? Please explain.

Response:

The existence or lack of stable conditions is not a determinant of whether to use a time series or an end-use forecast method for long range planning.

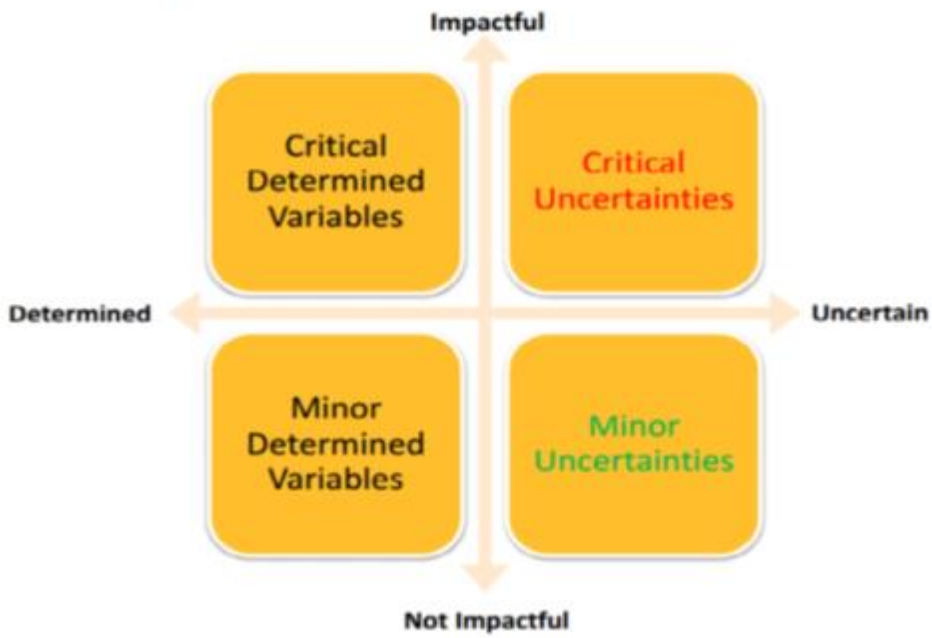
FEI has no evidence and is unable to predict whether one forecast is better under stable or unstable conditions. In addition it is not clear what constitutes stable and unstable conditions. As shown in the responses to CEC IRs 1.4.2 and 1.4.3 both the 2014 Traditional and end-use Reference Case forecasts are performing well compared to actual demand.

The Traditional forecast is only used as a check on the Reference Case forecast to make sure the latter forecast is reasonable. This test is completed before additional scenario modeling is completed in the end-use forecast method. Once the checks are complete, the Traditional forecast serves no further purpose.

The Traditional forecast is tied to the FEI short term forecast for consistency. FEI believes this connection provides further value when the Traditional forecast is used to validate the Reference Case.

5. Reference: Exhibit B-1, Appendix B-1, page 2

Figure B1-1: Classification of Planning Environment Variables



5.1 FEI's 'critical uncertainties' include the following as outlined on pages 3 and 4 of Appendix B-1.

Economic Variables:
Economic Growth, Natural Gas Price

Policy Variables:
Carbon Price
Non-Price Carbon Policy

Extraneous Variables:
RNG Demand
CNG and LNG Demand for Vehicles
Large Industrial Point Loads

5.1.1 What other critical variables did FEI consider and reject, if any?

Response:

The table below provides the requested explanation and also responds to CEC IRs 1.5.1.2, 1.5.1.3, 1.5.2, 1.5.3, and 1.5.4. FEI interprets these questions to relate to the 2017 LTGRP end-use annual demand forecast method scenario analysis specifically.

Table 1

Category	Variables	Discussion (Where Applicable)
Critical Uncertainties Considered but Rejected	Degree of energy system centralization	FEI did not include this uncertainty because it has not analyzed how this would specifically impact the 2017 LTGRP model levers.
	Cost of diesel	FEI did not include this uncertainty because it does not have definitive research on energy cross-price elasticities.
	Low carbon thermal energy prices	FEI did not include this uncertainty because it does not have definitive research on energy cross-price elasticities.
	Electricity rates	FEI did not include this uncertainty because it does not have definitive research on energy cross-price elasticities.
	Climate change	FEI considered analyzing the impact of climate change on outdoor air temperature but did not include this uncertainty because the FBC 2016 Long Term Electric Resource Plan analyzed this critical uncertainty and found its impact to be immaterial.
Critical Determined Variables Utilized	Electricity rates	
	Natural gas rates	The 2017 LTGRP treats this as an exogenous variable and provides projected delivery rate change as an analysis result in Section 8.6 of the Application
Minor Determined Variables Utilized	Inflation rate	
Minor Uncertainties Utilized	N/A	As explained on page 1 of Appendix B-1 of the Application, FEI based its scenario analysis on critical uncertainties since they represent those conditions that stakeholders felt could have the biggest impact on FEI's business. As such, FEI's scenario analysis does not rely on minor uncertainties.

5.1.2 Please explain why they were rejected.

Response:

Please refer to the response to CEC IR 1.5.1.1.

5.1.3 Did FEI consider climate change as a critical variable? Please explain why or why not.

Response:

Please refer to the response to CEC IR 1.5.1.1.

5.2 FEI provides an overview of its Critical Uncertainties in Appendix B-1. Please provide an overview of the Critical Determined Variables that FEI utilized in its planning.

Response:

Please refer to the response to CEC IR 1.5.1.1.

5.3 Please provide an overview of the Minor Determined Variables that FEI utilized in its planning.

Response:

Please refer to the response to CEC IR 1.5.1.1.

5.4 Please provide an overview of the Minor Uncertainties that FEI utilized in its planning.

Response:

Please refer to the response to CEC IR 1.5.1.1.

6. Reference: Exhibit B-1, Appendix B-2, page 8

> End-use models tend to be much more data intensive than econometric models. However, the companies that use them believe as energy efficiency policies and standards become more important, end-use modeling provides them the level of detail required to assess the impact of energy efficiency standards and regulations. Similar to econometric models, the parameters used in end-use forecasting models vary from company to company, but in most cases, include energy prices, saturation levels of different end-uses, saturation levels of different energy sources, vintage or age of dwellings, dwelling type, dwelling size, and vintage or age of different end-use equipment. This data is often collected from end-use surveys.

6.1 Does FEI's end use forecasting consider saturation of different end-uses, saturation of different levels of energy sources, vintage or age of dwellings, dwelling type, dwelling size and vintage or age of different end-use equipment?

Response:

FEI consulted with Posterity to provide the following response.

FEI's end use forecasting considers all of these factors. Dwelling types were segmented in the model by region, vintage, and detachment type. For each segment, data from FEI's 2012 Residential Energy Use Survey was used to estimate the saturation of each end use, the saturation of different levels of energy sources (fuel shares for each end use), average dwelling size, and age (and therefore assumed average efficiency) of different end-use equipment.

6.1.1 Please identify any parameters listed that are not in FEI's modelling and explain why FEI did not include those parameters.

Response:

Please refer to the response to CEC IR 1.6.1.

7. Reference: Exhibit B-1, Appendix B-1, page Exhibit B-1, Appendix B, page 14 and page 3

1.2.2 Critical Uncertainty Impacts on the Forecast Model

Table B1-2 below summarizes how each critical uncertainty impacts the mechanics of the 2017 LTGRP forecast model and discusses specific attributes of individual critical uncertainties.

Table B1-2: Summary of Critical Uncertainty Impacts on the Forecast Model

Critical Uncertainty	Model Levers	Comments
Economic Factors		
Economic Growth	- Residential building stock - Commercial floor area - Industrial facilities	See Table B1-1 above.
Natural Gas Price	Long run natural gas fuel share	Based on a literature review of existing research by FEI and Posterity, the 2017 LTGRP uses -0.2 and -0.5 as the long run price sensitivity values for residential and commercial/industrial customers, respectively. Since these are long run values, the 2017 LTGRP forecast model calculates the total fuel share change from these values by the end of the planning period and subsequently solves for the required annual change rates required to produce the total change. The model ensures that the calculated annual change rates are achievable in relation to the rate of end-use equipment replacements.

> **1.2.1 CRITICAL UNCERTAINTY INPUTS**
>
> ***1.2.1.1 Economic Growth***
>
> The 2017 LTGRP provides further analysis to simulate the impact of economic growth on customer counts. FEI relies on simulation because its research does not suggest sufficient correlation between Gross Domestic Product (GDP) and natural gas consumption or customer counts. Moreover, relying on third party GDP growth forecast ranges introduces an additional source of potential forecast errors.
>
> As an alternative to any strong direct correlation between GDP growth and customer numbers/natural gas consumption, the 2017 LTGRP relies on a statistical approach using Prediction Intervals (PI). This approach applies FEI's historical variance in customers by rate schedule to FEI's Reference Case customer forecast. The 2017 LTGRP uses these PI to perturb the Reference Case customer forecast into respective High and Low customer forecast outcomes.
>
> This statistical method serves as a proxy to model the potential impact of economic growth on customer numbers but may also account for other intrinsic factors, such as FEI marketing and promotional campaigns. Note that rate schedules with fewer customers experience a greater range between their High and Low outcomes than larger rate schedules.

7.1 Are there other potential model levers for economic growth that FEI considered?

Response:

FEI assumes references to "model levers for economic growth" refers to the BCUC suggestion in the 2014 Decision (Commission Order G-189-14) that "Furthermore, for all scenarios based on different economic growth assumptions, the forecasts for new customer additions should reflect those changed assumptions.".

When developing enhancements to the model based on this suggestion, FEI determined that an approach that modeled a range of future expectations based on past experience was both appropriate and consistent with other aspects of the forecast. Historic data intrinsically contains all the factors and drivers experienced by our customers, and FEI felt it was reasonable to assume that those multitude of factors and drivers would continue for the forecast period. FEI used the statistical Prediction Interval (PI) method because it met these objectives and was well documented in the literature.

Desirable characteristics of the method include:

1. Based on actual FEI data
2. Does not rely on a third party forecast, which would introduce its own variance
3. PI method results in both upper and lower scenarios

4. Scenarios are more divergent for smaller regions and rates where volatility is higher
5. The PI method is well supported in the literature
6. The PI method is cost effective to implement

FEI determined that the Prediction Interval method was both relevant and appropriate and presented the method to the Resource Planning Advisory Group (RPAG) for their input. FEI followed up the meeting with a short survey in which the majority of respondents (86%) said that FEI did not need to consider any other approaches.

As a result of the desirable characteristics of the approach and the broad acceptance from the RPAG FEI did not consider further methods.

7.1.1 If yes, please identify and explain why FEI rejected these potential model levers.

Response:

Please refer to the response to CEC IR 1.7.1.

7.1.2 If not, please explain why not.

Response:

Please refer to the response to CEC IR 1.7.1.

7.2 Please explain what FEI means by ‘Industrial Facilities’.

Response:

FEI consulted with Posterity to provide the following response.

Industrial facilities are customers whose NAICS (North American Industry Classification System) code in FEI's 2015 base year actuals identifies them as production facilities. In the end-use method, industrial customers are distinguished from commercial customers based on their patterns of energy use: commercial buildings use natural gas primarily for uses such as space heating, water heating, and cooking; industrial customers use natural gas more for industrial processes. Industrial facilities, by this definition, exist in all but the residential rate schedule.

7.3 What evidence does FEI have that the model levers used for economic growth are relevant and appropriate? Please provide.

Response:

Please refer to the response to CEC IR 1.7.1.

7.4 Please provide the source of information for the 'Residential Building Stock' metric.

Response:

FEI consulted with Posterity to provide the following response.

Residential building stock, for the base year, is based on FEI's data on the number of Rate Schedule 1 customers in 2015. Growth in residential building stock is based on the forecast number of account additions for Rate Schedule 1. Please refer to FEI's response to CEC IR 1.3.1 for an explanation of how residential customers are added throughout the planning horizon.

7.5 Please provide the source of information for the Commercial floor area metric.

Response:

FEI consulted with Posterity to provide the following response.

Commercial floor area for the base year is a calculated value. The inputs are the 2015 normalized actual consumption by region, rate schedule and segment, from the FEI consumption data for customers in 2015 (in GJ), and the whole building energy utilization index (EUI) values developed by the BC CPR (in GJ/m^2). Dividing consumption data by EUI provides an estimate of floor area. Growth in the number of commercial customers was based on the forecast number of account additions for each applicable rate schedule. Please refer to FEI's response to CEC IR 1.3.1 for an explanation of how commercial customers are added throughout the planning horizon.

7.6 Please provide the source of information for the 'Industrial Facilities' metric.

Response:

FEI consulted with Posterity to provide the following response.

Industrial facilities were based on the 2015 FEI data for number of customers and total consumption by region, rate schedule, and segment. Growth in number of industrial customers was based on the forecast number of account additions for each applicable rate schedule. Please refer to FEI's response to CEC IR 1.3.1 for an explanation of how industrial facilities are added throughout the planning horizon.

7.7 Is Economic Growth only used to simulate the impact of economic growth on customer counts, or does it impact customer use as well? Please explain.

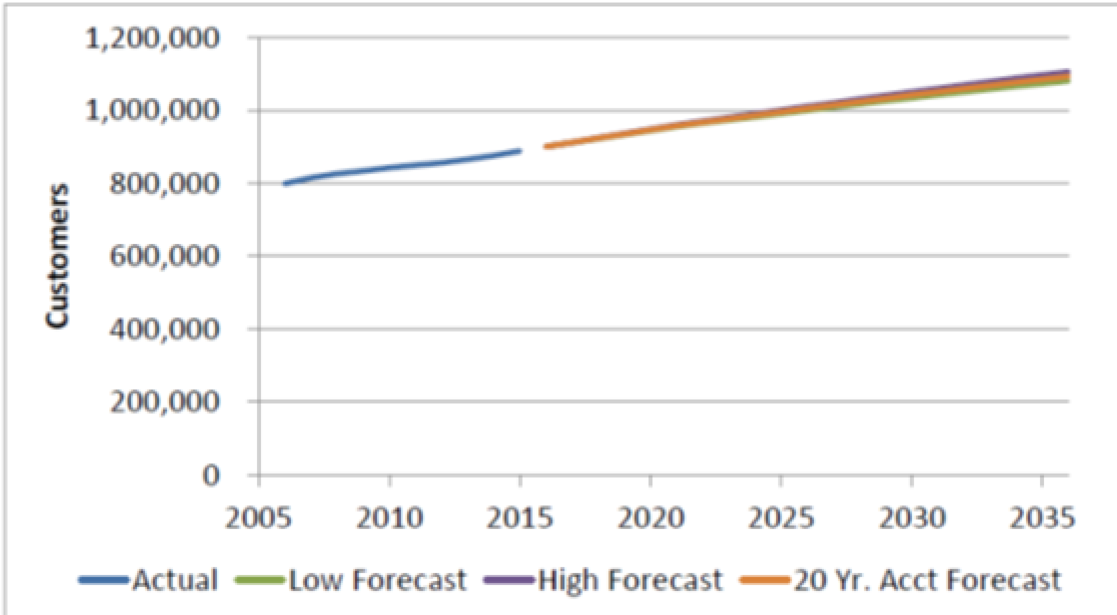
Response:

FEI consulted with Posterity to provide the following response.

The Economic Growth critical uncertainty is only used to simulate the impact of economic growth on customer counts, not customer energy use. As noted in Section 1.2.1.1 of Appendix B-1 of the Application (reproduced in the preamble), FEI relies on this approach because its research does not suggest sufficient correlation between GDP and natural gas consumption.

8. Reference: Exhibit B-1, Appendix B-1 page 6

Figure B1-2: Customer Forecast Parameters – Rate Schedule 1



8.1 Please explain what 'Acct' Forecast means.

<u>Response:</u>

'Acct' Forecast is a shortened form of 'Account' also known in the Reference Case as the 'Customer Forecast'. This represents the Reference Case outcome for the Economic Growth critical uncertainty in the 2017 LTGRP scenario analysis.

8.2 What factors other than economic growth is used to forecast customers for the residential rate schedule, if any? Please explain.

<u>Response:</u>

Please refer to the response to BCUC IR 1.10.2.

8.3 Please provide the actual and percentage changes applied to the model drivers that resulted in the Low, High and Acct Forecast for the residential rate schedule.

Response:

FEI interprets the term "Actual" in this context to mean "forecast values" since they are forecasts and have not actually occurred yet. The forecast values and percentage changes in the Low, High and Account Forecast for the residential rate schedule are provided in the table below. These are not drivers of the forecast, but rather are forecast results.

Table 1: Residential Rate Schedule 1 - Customer Forecast Parameters

Year	Account Forecast	Account Forecast Change	Account Forecast % Change	Low Forecast	Low Forecast Change	Low Forecast %	High Forecast	High Forecast Change	High Forecast % Change
2015	888,135			888,135			888,135		
2016	900,173	12,038	1.4%	900,173	12,038	1.4%	900,173	12,038	1.4%
2017	911,695	11,522	1.3%	911,287	11,114	1.2%	912,103	11,930	1.3%
2018	923,246	11,551	1.3%	922,384	11,097	1.2%	924,108	12,005	1.3%
2019	934,801	11,555	1.3%	933,447	11,063	1.2%	936,155	12,047	1.3%
2020	946,344	11,543	1.2%	944,463	11,016	1.2%	948,223	12,068	1.3%
2021	957,278	10,934	1.2%	954,844	10,381	1.1%	959,712	11,489	1.2%
2022	967,265	9,987	1.0%	964,252	9,408	1.0%	970,278	10,566	1.1%
2023	976,711	9,446	1.0%	973,097	8,845	0.9%	980,325	10,047	1.0%
2024	985,789	9,078	0.9%	981,558	8,461	0.9%	990,020	9,695	1.0%
2025	995,170	9,381	1.0%	990,305	8,747	0.9%	1,000,035	10,015	1.0%
2026	1,004,674	9,504	1.0%	999,163	8,858	0.9%	1,010,186	10,151	1.0%
2027	1,014,004	9,330	0.9%	1,007,835	8,672	0.9%	1,020,175	9,989	1.0%
2028	1,023,382	9,378	0.9%	1,016,544	8,709	0.9%	1,030,220	10,045	1.0%
2029	1,032,635	9,253	0.9%	1,025,120	8,576	0.8%	1,040,150	9,930	1.0%
2030	1,041,739	9,104	0.9%	1,033,538	8,418	0.8%	1,049,938	9,788	0.9%
2031	1,050,681	8,942	0.9%	1,041,789	8,251	0.8%	1,059,572	9,634	0.9%
2032	1,059,431	8,750	0.8%	1,049,841	8,052	0.8%	1,069,020	9,448	0.9%
2033	1,068,060	8,629	0.8%	1,057,768	7,927	0.8%	1,078,353	9,333	0.9%
2034	1,076,512	8,452	0.8%	1,065,512	7,744	0.7%	1,087,512	9,159	0.8%
2035	1,084,705	8,193	0.8%	1,072,992	7,480	0.7%	1,096,417	8,905	0.8%
2036	1,092,647	7,942	0.7%	1,080,219	7,227	0.7%	1,105,076	8,659	0.8%

9. Reference: Exhibit B-1, Appendix B-1, page 6

Figure B1-3: Customer Forecast Parameters – Rate Schedule 2

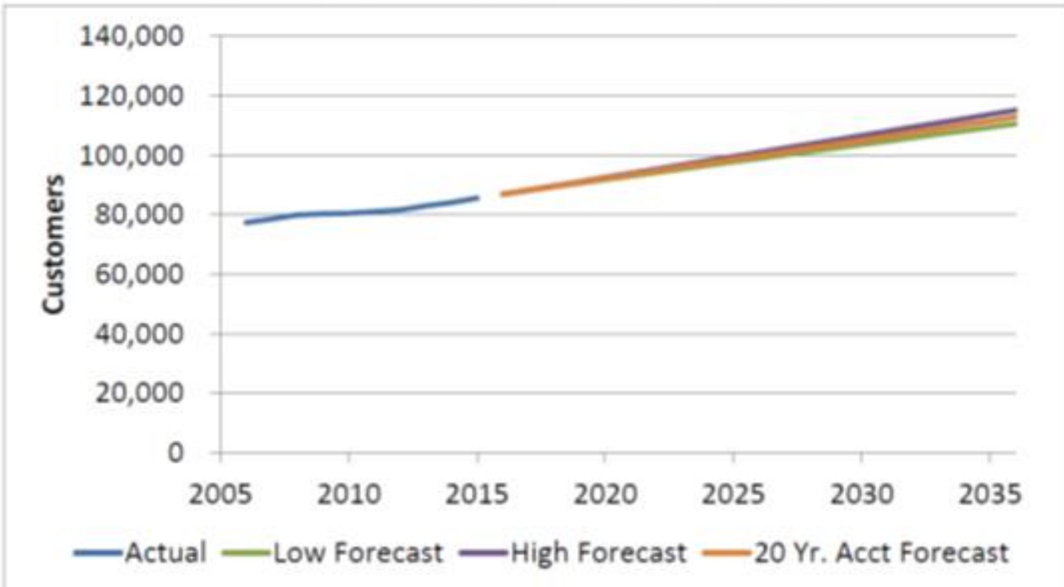
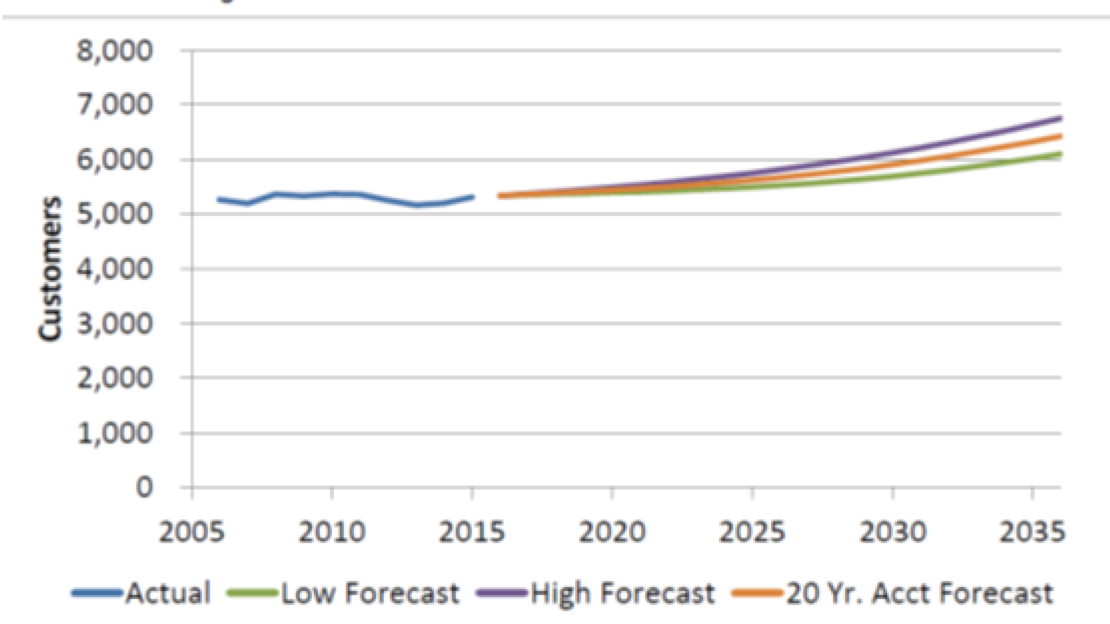


Figure B1-4: Customer Forecast Parameters – Rate Schedule 3



9.1 What factors other than economic growth is used to forecast customers for rate schedules 2 and 3 if any? Please explain.

Response:

Please refer to the response to BCUC IR 1.11.1.

9.2 Please provide the actual and percentage changes applied to the model drivers that resulted in the Low, High and Acct Forecast for Rate Schedule 2 and 3.

Response:

FEI interprets the term "Actual" in this context to mean "forecast values" since they are forecasts and have not actually occurred yet. The forecast values and percentage changes in the Low, High and Acct Forecast for the commercial rate schedule 2 and 3 are provided in the table below. These are not drivers of the forecast, but rather are forecast results.

Table 1: Commercial Rate Schedule 2 - Customer Forecast Parameters

Year	Account Forecast	Account Forecast Change	Account Forecast % Change	Low Forecast	Low Forecast Change	Low Forecast % Change	High Forecast	High Forecast Change	High Forecast % Change
2015	85,075			85,075			85,075		
2016	86,388	1,313	1.5%	86,388	1,313	1.5%	86,388	1,313	1.5%
2017	87,699	1,311	1.5%	87,625	1,237	1.4%	87,774	1,386	1.6%
2018	89,013	1,314	1.5%	88,855	1,230	1.4%	89,171	1,397	1.6%
2019	90,323	1,310	1.5%	90,075	1,220	1.4%	90,572	1,401	1.6%
2020	91,636	1,313	1.5%	91,294	1,219	1.4%	91,981	1,409	1.6%
2021	92,950	1,314	1.4%	92,501	1,207	1.3%	93,396	1,415	1.5%
2022	94,229	1,279	1.4%	93,678	1,177	1.3%	94,781	1,385	1.5%
2023	95,541	1,312	1.4%	94,875	1,197	1.3%	96,202	1,421	1.5%
2024	96,805	1,264	1.3%	96,030	1,155	1.2%	97,579	1,377	1.4%
2025	98,073	1,268	1.3%	97,184	1,154	1.2%	98,965	1,386	1.4%
2026	99,355	1,282	1.3%	98,346	1,162	1.2%	100,365	1,400	1.4%
2027	100,645	1,290	1.3%	99,516	1,170	1.2%	101,775	1,410	1.4%
2028	101,920	1,275	1.3%	100,666	1,150	1.2%	103,171	1,396	1.4%
2029	103,204	1,284	1.3%	101,827	1,161	1.2%	104,580	1,409	1.4%
2030	104,488	1,284	1.2%	102,987	1,160	1.1%	105,990	1,410	1.3%
2031	105,756	1,268	1.2%	104,127	1,140	1.1%	107,384	1,394	1.3%
2032	107,059	1,303	1.2%	105,303	1,176	1.1%	108,816	1,432	1.3%
2033	108,339	1,280	1.2%	106,454	1,151	1.1%	110,223	1,407	1.3%
2034	109,615	1,276	1.2%	107,600	1,146	1.1%	111,629	1,406	1.3%
2035	110,891	1,276	1.2%	108,746	1,146	1.1%	113,035	1,406	1.3%
2036	112,170	1,279	1.2%	109,884	1,138	1.0%	114,444	1,409	1.2%

Table 2: Commercial Rate Schedule 3 - Customer Forecast Parameters

Year	Account Forecast	Account Forecast Change	Account Forecast % Change	Low Forecast	Low Forecast Change	Low Forecast % Change	High Forecast	High Forecast Change	High Forecast % Change
2015	85,075			85,075			85,075		
2016	86,388	1,313	1.5%	86,388	1,313	1.5%	86,388	1,313	1.5%
2017	87,699	1,311	1.5%	87,625	1,237	1.4%	87,774	1,386	1.6%
2018	89,013	1,314	1.5%	88,855	1,230	1.4%	89,171	1,397	1.6%
2019	90,323	1,310	1.5%	90,075	1,220	1.4%	90,572	1,401	1.6%
2020	91,636	1,313	1.5%	91,294	1,219	1.4%	91,981	1,409	1.6%
2021	92,950	1,314	1.4%	92,501	1,207	1.3%	93,396	1,415	1.5%
2022	94,229	1,279	1.4%	93,678	1,177	1.3%	94,781	1,385	1.5%
2023	95,541	1,312	1.4%	94,875	1,197	1.3%	96,202	1,421	1.5%
2024	96,805	1,264	1.3%	96,030	1,155	1.2%	97,579	1,377	1.4%
2025	98,073	1,268	1.3%	97,184	1,154	1.2%	98,965	1,386	1.4%
2026	99,355	1,282	1.3%	98,346	1,162	1.2%	100,365	1,400	1.4%
2027	100,645	1,290	1.3%	99,516	1,170	1.2%	101,775	1,410	1.4%
2028	101,920	1,275	1.3%	100,666	1,150	1.2%	103,171	1,396	1.4%
2029	103,204	1,284	1.3%	101,827	1,161	1.2%	104,580	1,409	1.4%
2030	104,488	1,284	1.2%	102,987	1,160	1.1%	105,990	1,410	1.3%
2031	105,756	1,268	1.2%	104,127	1,140	1.1%	107,384	1,394	1.3%
2032	107,059	1,303	1.2%	105,303	1,176	1.1%	108,816	1,432	1.3%
2033	108,339	1,280	1.2%	106,454	1,151	1.1%	110,223	1,407	1.3%
2034	109,615	1,276	1.2%	107,600	1,146	1.1%	111,629	1,406	1.3%
2035	110,891	1,276	1.2%	108,746	1,146	1.1%	113,035	1,406	1.3%
2036	112,170	1,279	1.2%	109,884	1,138	1.0%	114,444	1,409	1.2%

10. Reference: Exhibit B-1, Appendix B-1, page 9 and 10

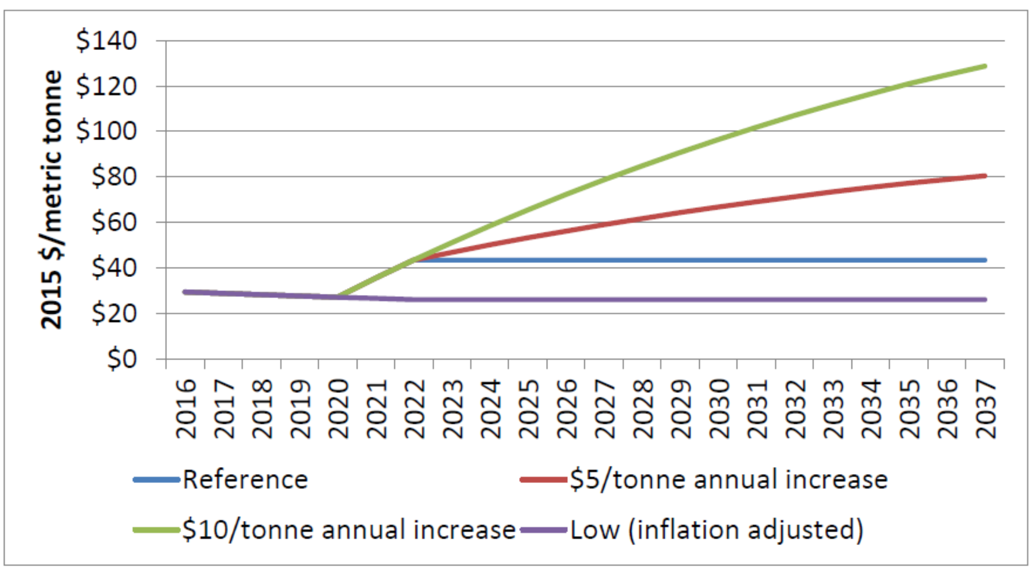
1.2.1.3 Carbon Price

FEI and FBC collaborated to develop their long term carbon pricing trajectories by consulting internal and external subject matter experts. The resulting carbon pricing trajectories take into account the Canadian federal carbon pricing backstop mechanism. The trajectories have been validated via the LTERP RPAG and have also received support from the LTGRP stakeholders (in the RPAG and FEI's community engagement workshops).

Figure B1-8 below displays the 2017 LTGRP's carbon pricing outcomes. These include one addition in relation to the 2016 LTERP. FEI added a Low trajectory at BC's 2016 carbon tax level since the possibility exists that BC's carbon price may remain constant at this level if BC's government does not increase it and if the Canadian federal carbon pricing backstop mechanism does not proceed or flounders during its interim review. The Low and Reference carbon price outcomes assume that prices will increase by inflation after 2022. This prevents the carbon prices in these outcomes from dropping back to or even below current levels in real terms by the end of the planning period. This carbon pricing range intends to account for

considerable policy uncertainty in relation to BC provincial, Canadian federal, and wider North American developments (as discussed in Section 2 of the Application).[1]

Figure B1-8: Carbon Price Forecast – Per Metric Tonne



[1] The September 11, 2017, BC budget update proposes to increase the carbon tax by $5 per tonne per year for the next four years, beginning April 1, 2018, until the carbon tax rate is equal to $50 per tonne in 2021. If this increase is maintained each year, as proposed in the updated budget, the carbon tax will increase to $50 per tonne one year earlier than FEI's Reference Case carbon price assumption. The current BC budget does not provide any indication that increases to the carbon tax will continue to occur once the tax rate reaches $50 per tonne. Between 2018 and 2021, the BC budget update causes the proposed BC carbon price to be higher than FEI's Reference Case carbon price assumption. In the long run, however, the variance between FEI's Reference Case carbon price assumption and the information provided in the BC budget update is immaterial.

10.1 Why do the reference case and $5/tonne annual increase appear to commence in 2022 rather than in 2018, when they are expected to commence?

Response:

The carbon pricing critical uncertainty outcomes in the 2017 LTGRP considers proposed carbon legislation not yet enacted at the time these outcomes were required for analysis in the 2017 LTGRP. Therefore, at that time, there was some uncertainty regarding the level of carbon price increases beyond 2018. While the September 2017 BC budget update had proposed to increase the carbon tax by $5 per tonne per year starting in 2018 until the carbon tax is equal to $50 per tonne in 2021, this recommendation was not enacted into legislation by the time the 2017 LTGRP assumptions were finalized. FEI's assumptions include a starting point of $50 per tonne (in nominal terms) for all carbon pricing critical uncertainty outcomes, except the Low outcome, in 2022, with increases of $10 per tonne per year occurring between 2020 and 2022. While this does not exactly reflect now-enacted BC carbon policy, the differences between it and FEI's Reference Case are immaterial over the long run.

Further increases of $5 per tonne and $10 per tonne occur in the Medium and High increase outcomes after 2022. FEI has no indication that the province is planning increases but included these assumptions based on feedback from its stakeholders and public discourse about potential future carbon pricing trajectories.

10.2 The Low scenario seems to assume that BC would not proceed with the $5/tonne increase commencing in 2018 which is already established in the BC Budget update. Please discuss the likelihood of this occurring.

Response:

Now that the $5 per tonne carbon price increases have been enacted into legislation (rather than proposed at the time the carbon price critical uncertainty outcomes were developed for the 2017 LTGRP) and the effective date of the first increase on April 1, 2018 has passed, the Low carbon price outcome is not possible for 2018 and, at this time, appears unlikely for 2019 to 2021. However, changes in provincial and federal governments and their carbon policies could occur in the future and so there is still uncertainty regarding carbon pricing beyond the next few years. Therefore, FEI believes that a Low carbon pricing outcome is still appropriate to provide a potential range of carbon pricing outcomes over the long term planning horizon of the 2017 LTGRP.

10.3 What if any indication does FEI have that the province might increase carbon pricing by $10/tonne commencing in 2020? Please provide.

Response:

Please refer to the response to CEC IR 1.10.1.

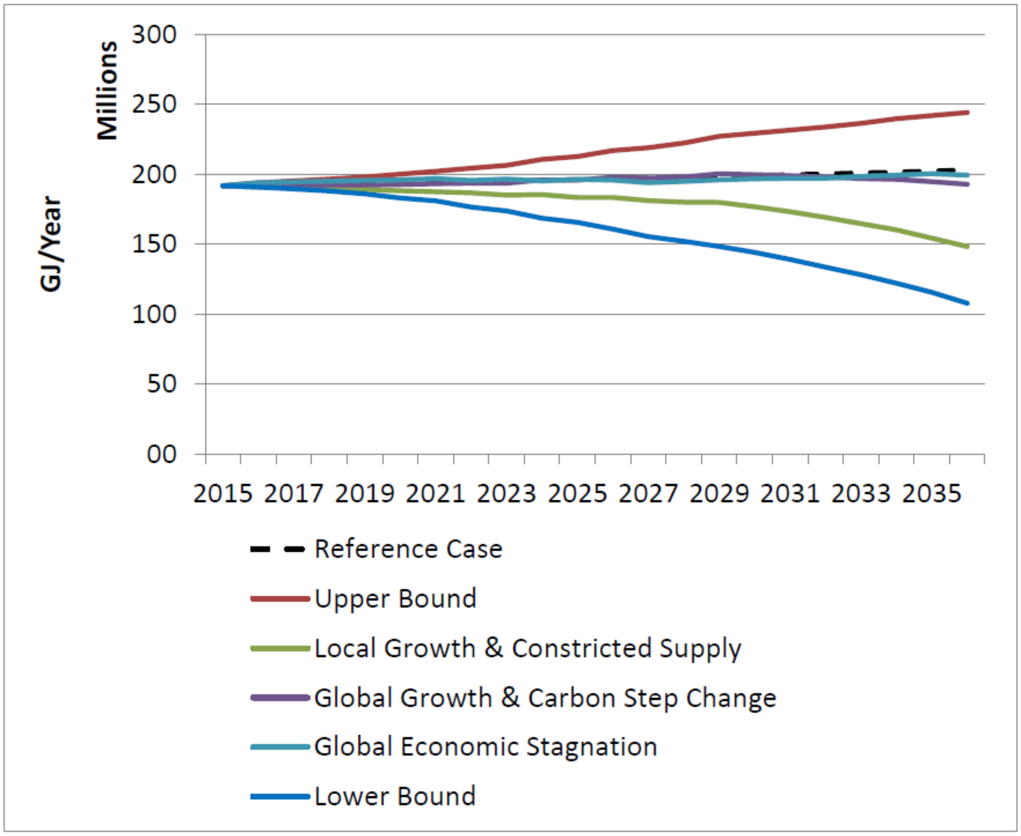
10.4 Please discuss FEI's views as to how the $/tonne increases would likely factor into and/or impact on the province's ability to meet its legislated greenhouse gas reduction targets established for 2020 and 2050.

Response:

The 2017 LTGRP does not examine BC's province-wide GHG emissions but simply estimates the potential GHG impacts of FEI's forecast activities across its 20-year planning horizon. The Province itself is best suited to answer the question of the likely impact on the Province's ability to meet legislated targets via carbon pricing.

11. Reference: Exhibit B-1, page 74

Figure 3-8: Annual Demand Scenarios – All Sectors (Excluding NGT)



> As can be seen in Figure 3-8, the Upper and Lower Bound scenarios denote the range of the forecast. By the end of the planning period, this range accounts for a variation of 67 percent around the Reference Case. This range has widened since the 2014 LTRP due to increased policy uncertainty and FEI's updates to the scenario analysis inputs. Nevertheless, the majority of scenarios (and the Reference Case) cluster within a narrower annual demand range since outcomes across critical uncertainties offset each other's impact on annual demand.

11.1 Please confirm that the End Use method does not attach any likelihood of occurrence to the scenarios, but instead simply provides a range of possible outcomes.

<u>Response:</u>

Confirmed; across the LTGRP planning horizon, FEI uses the end-use method Reference Case to plan for its forecast long-term annual demand and its Traditional Peak Method to plan for its forecast long-term peak demand. The 2017 LTGRP includes a scenario analysis in order to examine a range of possible outcomes. This enhances FEI's ability to identify new opportunities and better serve customer needs in the long term.

11.2 Does FEI monitor policy or economic changes in order to examine which scenario appears to be unfolding? Please explain.

Response:

Yes, FEI monitors policy and economic changes to the degree that these can be observed between LTGRP filings to assess how the planning environment is unfolding and the possible outcomes over the 20-year planning horizon. Updates to the planning environment are then captured and addressed in the next LTGRP filing in three to five years. Because not all conditions in any one scenario are likely to unfold in their entirety, and due to the frequency of LTGRP submissions, FEI does not compare previous LTGRP scenarios to updated scenarios. Instead, scenarios are revised with new information and the updated outcomes over the 20 year planning horizon are evaluated.

11.3 If yes, how does FEI conduct the monitoring and how does it use the information.

Response:

Please refer to the response to CEC IR 1.11.2.

11.4 Could the various scenarios also be applied to the 'traditional' forecast?

Response:

The Traditional Annual forecast is prepared and used as a validation of the end-use annual demand Reference Case forecast. Once the validation step has been completed the increased granularity of the end use method makes it the appropriate tool for examining future scenarios.

As a result the various scenarios developed as part of the end-use annual demand forecast method are separate from the Traditional Annual forecast. The various scenarios could not be applied to the Traditional Annual forecast because the parameters used to create the various scenarios, such as granular control over model levers that respond to scenario critical uncertainties at the end-use level, are not available within the Traditional Annual method.

11.5 If no, please say why not.

Response:

Please refer to the response to CEC IR 1.11.4.

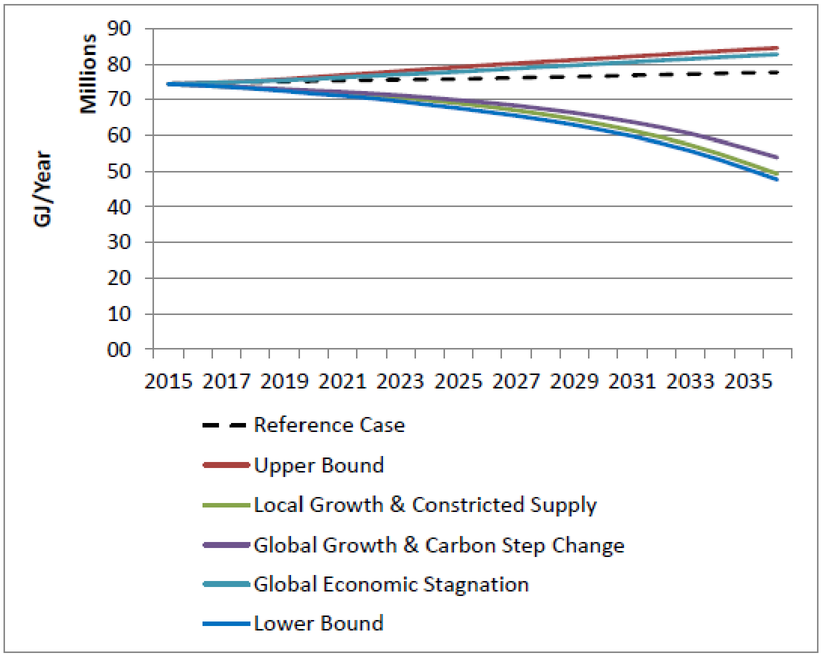
11.6 If yes, please provide the same scenarios but applied to the traditional forecast instead of the Reference case.

Response:

Please refer to the response to CEC IR 1.11.4.

12. Reference: Exhibit B-1, page 75 and page 76

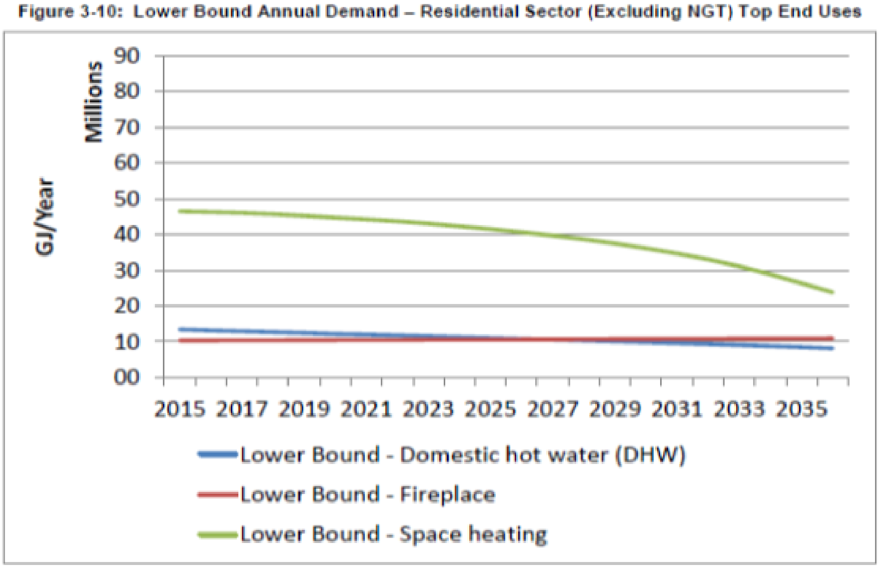
Figure 3-9: Annual Demand Scenarios – Residential Sector



As illustrated for the Lower Bound scenario in Figure 3-10 below, the declining demand scenarios also involve a significant decline in space heating annual demand. Measured by

annual demand, central space heating remains the top end-use until the end of the planning period. Domestic hot water end-use annual demand declines below fireplace annual demand near the middle of the planning period (this does not apply to the Reference Case and Upper Bound scenario). This observation represents one of the interesting results that can be extracted by utilizing the end-use method (in contrast to the Traditional Annual Method).

Figure 3-10: Lower Bound Annual Demand – Residential Sector (Excluding NGT) Top End Uses



12.1 Please confirm that all the residential scenarios account (either independently or by virtue of being included in the reference case) for the recent (2016 or later) but already existing changes in the City of Vancouver (COV) energy efficiency bylaws or policies severely restricting the use of natural gas in new buildings in the CoV.

Response:

This response also responds to CEC IRs 1.12.1.1 and 1.12.1.2. The Reference Case includes the effect of the City of Vancouver Building Bylaw (VBBL) regarding newly constructed buildings up to the VBBL version effective May 1, 2017. The energy assumptions in the 2017 LTRPG end-use model are based on estimated percentage reductions in energy consumption as required in the VBBL, relative to current construction standards in the BC Building Code. The Reference Case does not include the City of Vancouver's rezoning requirements. The Lower Bound scenario begins with the same assumptions as the Reference Case, but introduces additional reductions in energy consumption due to accelerated adoption of the BC Energy Step Code throughout the province, as well as improvements in efficiency due to improved equipment standards (as explained in Section 1.2.1.4 of Appendix B-1 of the Application). The Upper Bound scenario incorporates a reduction in code compliance (as explained in Section 1.2.1.4.1 of Appendix B-1 of the Application), such that energy consumption in new dwellings does not decrease as quickly in response to the VBBL.

The City of Vancouver bylaws and policies continue to be more restrictive relative to other municipalities as it pertains to natural gas use and as a result, are expected to cause downward pressure on natural gas demand and upward pressure on rates. The City of Vancouver policies may provide opportunities for FEI's C&EM, NGT, and RNG activities although it is unclear that these opportunities will, within the City of Vancouver, entirely offset the downward pressure on natural gas demand for the built environment.

12.1.1 If yes, please explain if they are accounted for in the scenarios or in the reference case.

Response:

Please refer to the response to CEC IR 1.12.1.

12.1.2 If no, please provide a discussion of the expected impact of the City of Vancouver bylaws and policies relating to energy efficiency and the use of natural gas.

Response:

Please refer to the response to CEC IR 1.12.1.

12.2 What proportion of FEI's natural gas demand comes from the City of Vancouver and the Lower Mainland?

Response:

In the base year, 2015, approximately 14 percent of FEI's natural gas demand came from the City of Vancouver, while 60 percent of FEI's natural gas demand was from the Lower Mainland.

12.3 Please provide a list of municipalities that have adopted or are in the process of considering policies moving in a similar direction to the COV policy.

Response:

The City of Victoria, District of Saanich, Village of Slocan and the City of Nelson have adopted a community-wide 100 percent renewable energy target by 2050. FEI cannot comment on other municipalities that are in the process of considering other similar policies unless formal documentation is available that shows support for such policies.

13. Reference: Exhibit B-1, page 77

Figure 3-11: Annual Demand Scenarios – Commercial Sector (Excluding NGT)

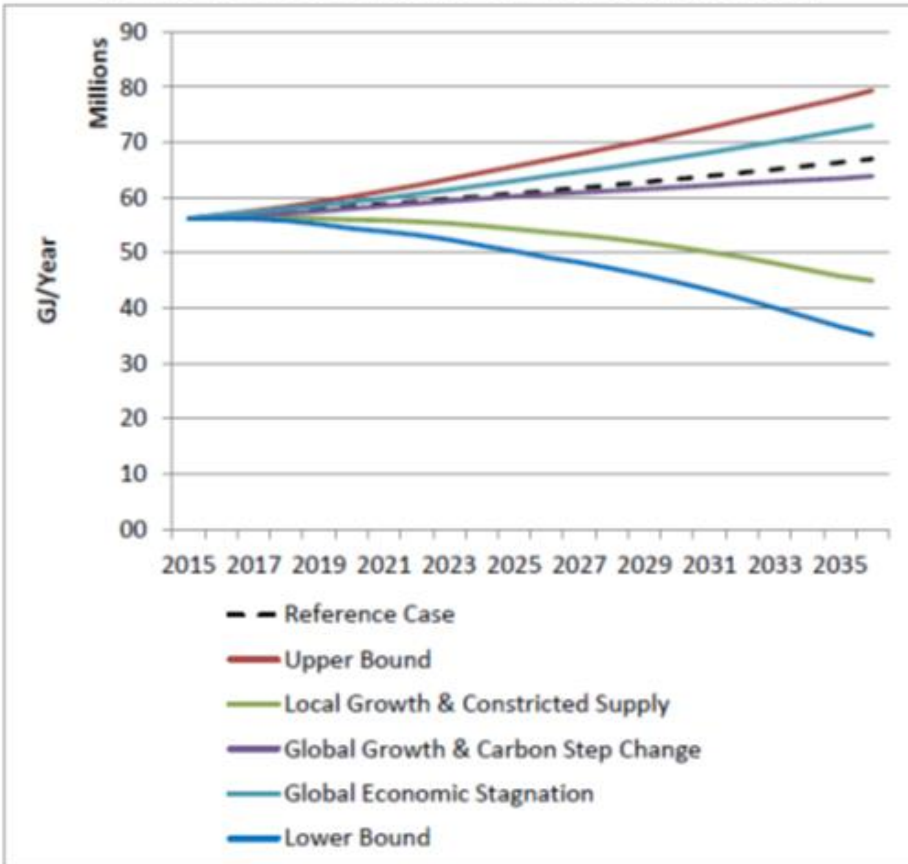


Figure 3-11 illustrates the following effects for the commercial sector:

- The annual demand difference between the Upper Bound and the Global Economic Stagnation scenarios illustrates the annual demand impact of the economic growth critical uncertainty on the commercial sector.
- The widened difference between the Local Growth & Constricted Supply and the Global Growth & Carbon Step Change scenarios highlights the increased annual demand impact of prices for the commercial in relation to the residential sector (price changes

13.1 Please confirm that all the commercial scenarios account (either independently or by virtue of being included in the reference case) for the recent (2017 or later) but already existing changes in the City of Vancouver (COV) energy efficiency bylaws or policies severely restricting the use of natural gas in new buildings in the CoV.

Response:

This response also addresses CEC IRs 1.13.1.1 and 1.13.1.2. The Reference Case includes the effect of the City of Vancouver Building Bylaw (VBBL) regarding newly construction buildings up to the VBBL version effective May 1, 2017. The energy assumptions in the 2017 LTRPG end-use model are based on estimated percentage reductions in energy consumption as required in the VBBL, relative to current construction standards in the BC Building Code. The Reference Case does not include the City of Vancouver's rezoning requirements. The Lower Bound scenario begins with the same assumptions as the Reference Case, but introduces additional reductions in energy consumption due to accelerated adoption of the BC Energy Step Code throughout the province, as well as improvements in efficiency due to improved equipment standards (as explained in Section 1.2.1.4 of Appendix B-1 of the Application). The Upper Bound scenario incorporates a reduction in code compliance (as explained in Section 1.2.1.4.1 of Appendix B-1 of the Application), such that energy consumption in new dwellings does not decrease as quickly in response to the VBBL. The other alternate future scenarios follow the same approach as the Upper and Lower Bound and set their VBBL outcomes according to the description in Table 3-1 of the Application.

The City of Vancouver bylaws and policies continue to be more restrictive relative to other municipalities as it pertains natural gas use in buildings and as a results are expected to cause downward pressure on natural gas demand and upward pressure on rates. The City of Vancouver policies may provide opportunities for FEI's C&EM, NGT, and RNG activities although it is unclear that these opportunities will, within the City of Vancouver, entirely offset the downward pressure on natural gas demand for the built environment.

13.1.1 If yes, please explain if they are accounted for in the scenarios or in the reference case.

Response:

Please refer to the response to CEC IR 1.13.1.

13.1.2 If no, please provide a discussion of the expected impact of the City of Vancouver bylaws and policies relating to energy efficiency and the use of natural gas.

Response:

Please refer to the response to CEC IR 1.13.1.

14. Reference: Exhibit B-1, page 77

Figure 3-12: Annual Demand Scenarios – Industrial Sector (Excluding NGT)

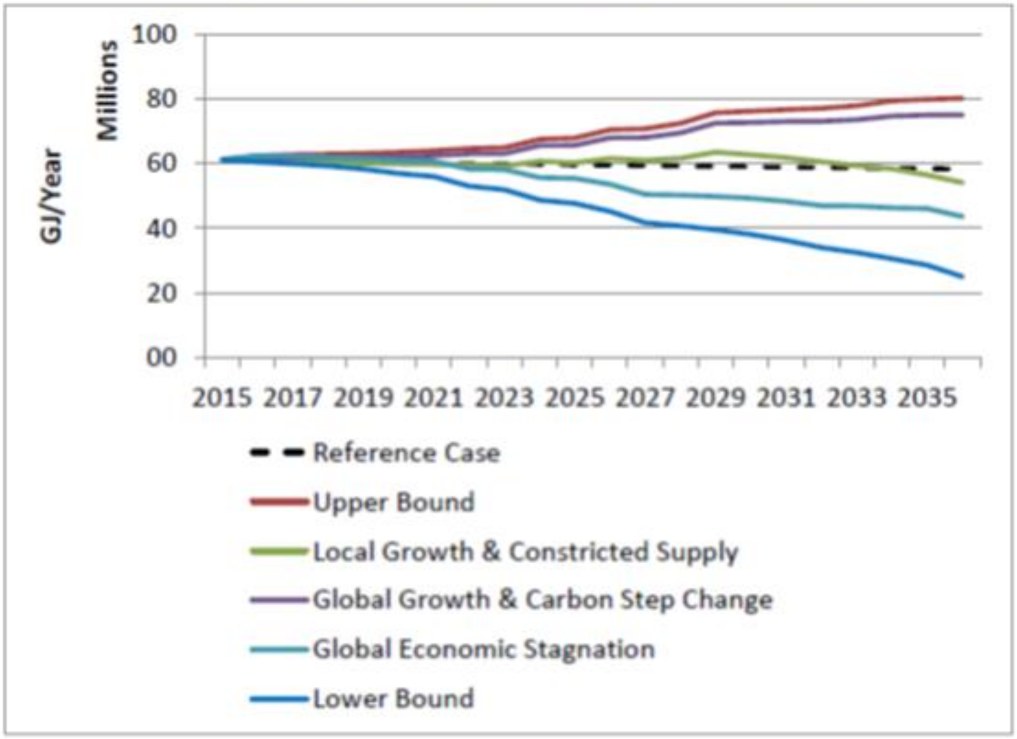


Figure 3-12 illustrates the following effects for the industrial sector:

- The annual demand trajectories are jagged because the economic growth critical uncertainty causes additions/removals of individual customers, and industrial customers typically have high annual demand.
- The annual demand difference between the Upper Bound and the Global Economic Stagnation scenarios illustrates the significant annual demand impact of the economic growth critical uncertainty on the industrial sector (in relation to the residential and commercial sectors).

14.1 Please identify the industry sectors utilizing natural gas, which have significant potential for being the contributors to lower or declining growth scenarios and identify those that have potential for being contributors to increased growth of demand.

Response:

FEI consulted with Posterity to provide the following response.

Increased or decreased annual demand in the industrial sector across the 2017 LTGRP scenarios is primarily due to industrial price response to natural gas commodity and carbon price as well as economic growth outcomes for each scenario. As explained in Section 1.2.1.1

of Appendix B-1 of the Application, the 2017 LTGRP relies on a statistical approach as a proxy for simulating the impact of economic growth on forecast customer counts. As such, industrial annual demand scenario results are a function of the 2017 LTGRP scenario analysis method and are not based on individual microeconomic examination of each applicable industry sector.

The four industrial sectors identified as having the largest potential to contribute to either increased or decreased growth in demand are Pulp & Paper, Wood Products, Miscellaneous Manufacturing, and Agriculture. These are also the four industrial sectors that have the largest demand in the Reference Case.

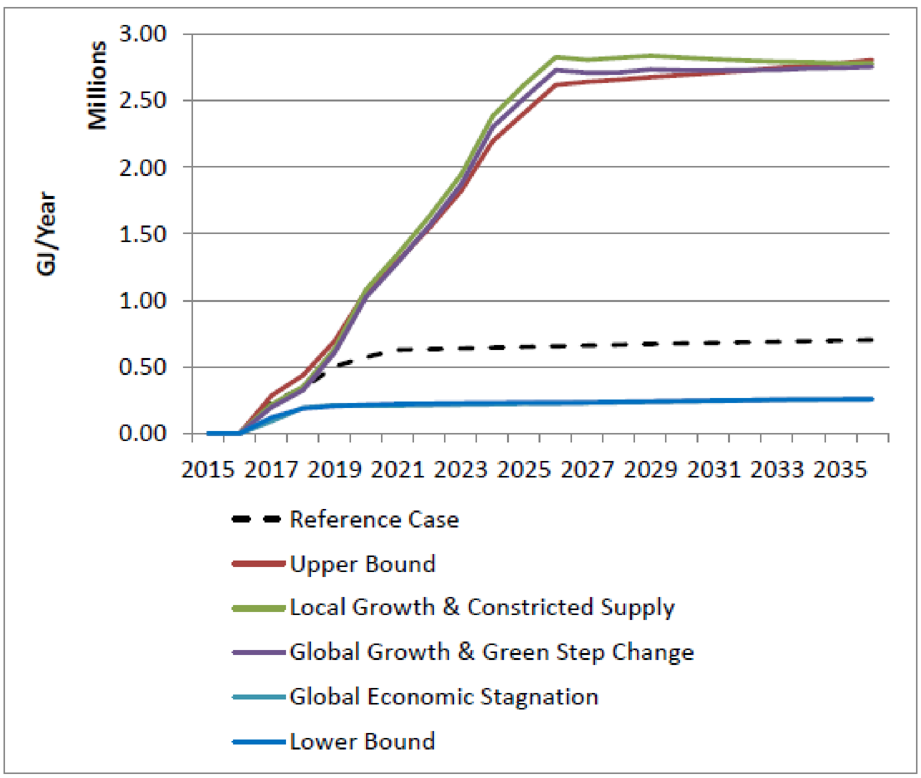
15. Reference: Exhibit B-1, page 79, page 80 and page 81 and page 70

3.4.6 RNG Demand

Based on the historical performance of the RNG program, FEI anticipated that the annual demand impact of this program across the planning period would be limited. FEI included a full quantitative RNG annual demand forecast in the 2017 LTGRP because of stakeholder interest in seeing this data. Stakeholders in both the RPAG and FEI's Community Engagement workshops voiced this opinion.

In the scenario analysis, shifts to RNG displace some fuel switching away from conventional natural gas to non-gas fuel types. For example, in the Global Growth & Carbon Step Change scenario, policy impels some customers to switch away from conventional natural gas. Across FEI's customer sectors, this switch away from natural gas is offset by the difference between the Reference Case RNG annual demand and the Global Growth & Carbon Step Change RNG demand.

Figure 3-14: RNG Annual Demand Scenarios – All Sectors



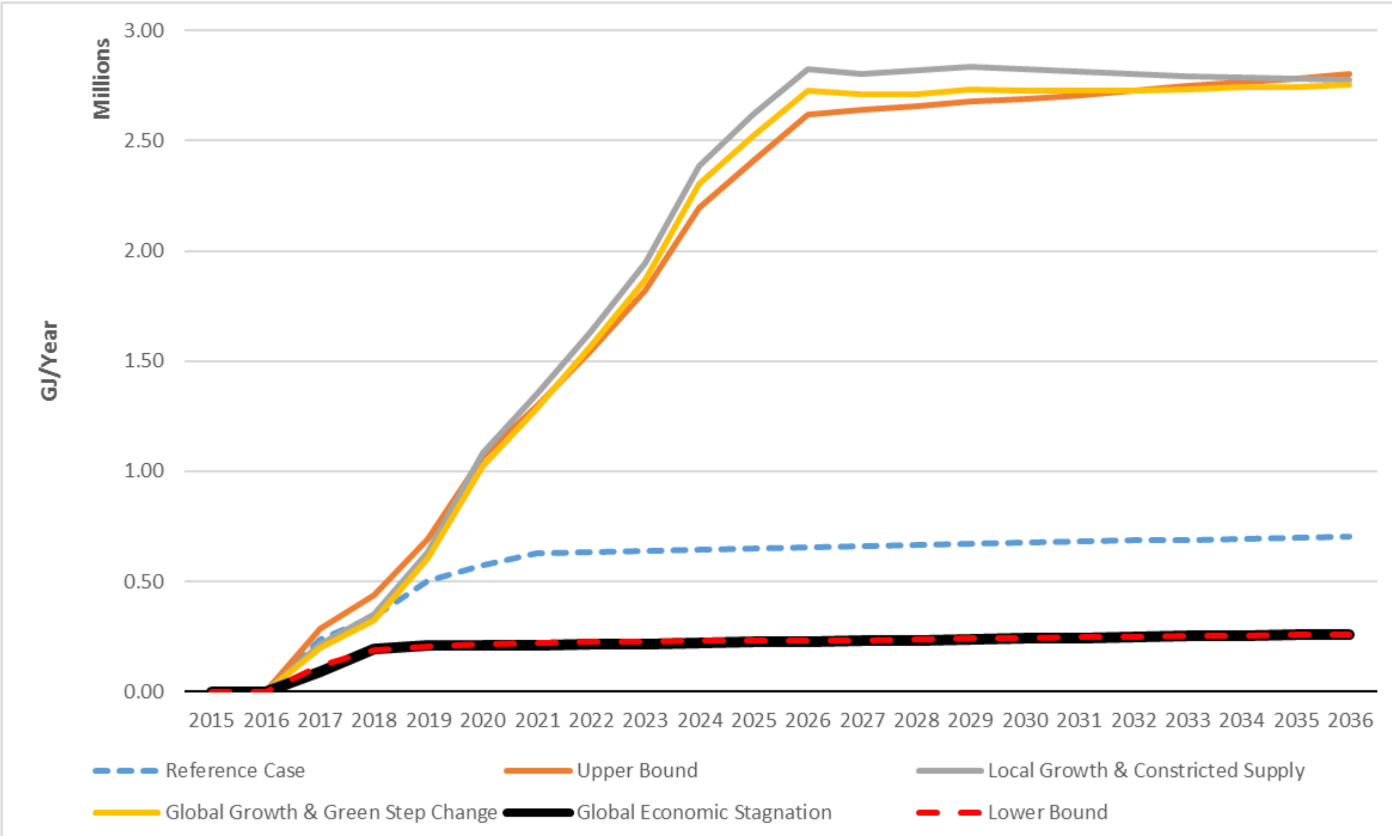
E (Lower Bound)	The BC economy experiences lower-than average growth as part of global economic stagnation. This reduces investment in regional gas supply so much that BC's demand balance becomes constricted. Global economic performance contributes to a political climate that is not favourable to carbon pricing and non-price carbon policy action in other jurisdictions but causes a counter-movement in BC. This causes the BC government to focus on carbon policy and electrification without support for NGT and RNG.	Economic Growth	Low	This represents the second of the two boundary scenarios. This combination of outcomes across the critical uncertainties is plausible but has not been prevalent in the past. Governments have typically been reluctant to impose taxes and other restrictions, including carbon pricing and carbon policy actions, during periods of economic stagnation.
		Natural Gas Price	High	
		Carbon Price	High Increase	
		Non-Price Carbon Policy Action	Accelerated	

15.1 The CEC is unable to see the Global Economic stagnation scenario. Please provide.

Response:

The Global Economic Stagnation scenario and the Lower Bound share a very similar forecast trend line. Please see the revised chart below for a better view of the Global Economic Stagnation Scenario (black line).

Figure 1: RNG Annual Demand Scenarios – All Sectors



15.2 Please confirm that it is reasonable to expect that FEI will be able to have significant influence on RNG sales.

Response:

Confirmed. FEI can play the role of educating customers and making it as easy as possible to purchase RNG.

15.3 Please elaborate on why the Lower Bound scenario results in a significant decrease to RNG demand.

Response:

FEI consulted with Posterity to provide the following response.

FEI assumes that this question is referring to the demand difference between the Lower Bound scenario and the Reference case.

The Lower Bound scenario approximately follows the expected minimum long term supply projections. It assumes that there is no further RNG supply development beyond the BCUC approved projects at the time of the submission of the LTRP. It can therefore be considered as somewhat pessimistic because it assumes the FEI will not develop any further supply regardless of any demand that materializes in the future.

Based on current government policy and existing customer demand growth, FEI believes that this scenario is not likely. Please also refer to the response to BCUC IR 1.19.4.

15.4 What actions, if any, could FEI take to maximize RNG sales under the Lower Bound circumstances.

Response:

FEI has taken a number steps to increase demand and is seeing increased interest from customers. With Commission approval, FEI lowered the price for customers to purchase RNG. This has already resulted in an increase in demand. FEI has also increased market awareness through an education campaign. Last, FEI engages directly with customers to offer products such as RNG.

15.5 What strategy options is FEI considering to enable increased demand for and supply of RNG after 2026.

Response:

FEI has seen customer demand for RNG grow faster than expected over the past year while carrying out its' education efforts. This suggests that there is appetite for RNG. At current customer interest, FEI believes that it has sufficient demand to absorb supply as it comes on to the system.

16. Reference: Exhibit B-1, page 83

> **3.4.7.1.1 CNG Base Scenario Demand Forecast**
>
> The CNG Base case forecast was derived in two parts: the number of vehicles that are expected to be in-service based on the GGRR incentive program,[107] and the estimated number of vehicles to come in-service after the GGRR program expires on March 31, 2022.
>
> For the period of 2017 to 2020, the forecast includes incremental load growth based on known and expected customer commitments that FEI has made under the GGRR incentive program (current and expected). From 2021 and beyond, the forecast contains assumptions regarding incremental load generated per year. FEI has assumed an annual growth in vehicles of about 85 additional CNG vehicles to the road per year. These additional CNG vehicles translate to an approximate net incremental growth of 100 thousand GJ per year.
>
> This method for the Base case assumes actual load from existing CNG customers in 2016 will continue throughout the term of the forecast period. This assumes that the existing customers are not retiring their CNG vehicles and will continue to renew or replace their CNG vehicles with a natural gas equivalent.
>
> For the Base case scenario, based on the growth of CNG demand, FEI assumes that it will capture about 4 percent of the eligible market by the end of the forecast period of 2036. This level of market capture constitutes a growth rate of approximately 6 percent per year.
>
> **3.4.7.1.2 CNG Low Scenario Demand Forecast**
>
> The CNG Low case scenario is based on no expansion or advancements on natural gas engines, the spread between diesel prices and natural gas prices decreasing in favour of diesel, policies becoming unfavourable to natural gas adoption and the availability and efficiency of alternative energy engines increasing (i.e. electric vehicles).
>
> This scenario assumes that minimal growth occurs and existing customers continue to renew their natural gas fleet vehicles with minimal additions to their natural gas fleet. As a result, the market share for the Low case scenario forecasts a market share of about 1 percent of the eligible market size by 2036, which results in an annual growth rate of about 1 percent per year or an average demand addition of approximately 8,000 GJ per year.

16.1 Please provide details of the trends in electric vehicles that FEI considered in its CNG Low Scenario Demand forecast.

Response:

As stated in the response to BCUC IR 1.20.3, FEI projects market capture rates of 1 percent, 4 percent and 15 percent of the overall heavy-duty diesel and CNG market for each of the Low, Base and High Scenario demand forecasts, respectively over the planning horizon to 2036. This would imply that there is still a sizable market share that could be captured by other fuel technologies such as hydrogen, battery-electric, or some other technology that is not presently feasible but could be over the planning horizon.

Furthermore, FEI acknowledges that there have been recent announcements regarding the provision of battery electric vehicles that could be commercially available for heavy-duty transportation trucking over the planning horizon.[4][5][6][7] However, due to the large degree of uncertainty regarding timelines, customer interest and general direction on the pace of adoption of these battery electric trucks, FEI did not explicitly model trends in battery electric vehicles in its CNG demand forecast. However, if battery electric vehicles were to emerge as commercially viable alternatives to diesel fuel, there would still be a sizable diesel market that could be captured by other fuel technologies.

16.2 What sources of information did FEI use in assessing electric vehicle uptake? Please provide the date of the information and a link to any sources if available.

Response:

Please refer to the response to CEC IR 1.16.1.

---

[4] https://www.theverge.com/2017/11/16/16667366/tesla-semi-truck-announced-price-release-date-electric-self-driving

[5] https://electrek.co/2018/01/24/volvo-electric-trucks/

[6] https://electrek.co/2017/11/15/byd-new-electric-truck-assembly-factory-canada/

[7] https://www.bloomberg.com/news/articles/2017-11-15/buffett-backed-byd-to-open-electric-truck-plant-in-canada

17. Reference: Exhibit B-1, page 84

> 3.4.7.1.3 <u>CNG High Scenario Demand Forecast</u>
>
> The High case scenario is predicated on expansion or advancements in natural gas engines (better efficiencies and availability), the spread between diesel prices and natural gas prices increasing in favour of natural gas, an increased spread in carbon pricing between diesel and natural gas, and policies favouring natural gas adoption.
>
> It assumes the popularity of NGT vehicles will increase dramatically due to operating advantages over diesel and that the natural gas refuelling infrastructure is constructed over time, providing better access to fuel for CNG customers.
>
> By 2036, for the High case scenario forecast, FEI expects to capture approximately 15 percent of the potential eligible market in BC, which equates to an average annual growth rate of about 16 percent per year or an average demand addition of approximately 532 thousand GJ per year from 2017 to 2036.

17.1 Does FEI's high demand scenario consider any increase in electric vehicle use?

<u>Response:</u>

As discussed in response to CEC IR 1.16.1, FEI did not model the emergence of battery electric vehicles in the demand scenarios. The High Scenario assumed a market capture rate of 15 percent of the diesel market for natural gas transportation over the planning horizon by 2036, which, as FEI stated in response to CEC IR 1.16.1, would imply that there is still a sizable market share that could be captured by other fuel technologies such as hydrogen, battery-electric, or some other technology that is not presently feasible but could be over the planning horizon.

17.1.1 If not, please explain why not.

<u>Response:</u>

Please refer to the responses to CEC IRs 1.16.1 and 1.17.1.

17.1.2 If yes, please elaborate on the EV assumptions and their impact on CNG.

Response:

Please refer to the response to CEC IR 1.17.1.

18. Reference: Exhibit B-1, page 85

> **3.4.7.2.1 LNG Low Scenario Demand Forecast**
>
> For the Low demand forecast scenario, FEI assumed that LNG demand would grow to about 13 million GJ per year by about 2025 through the capture of key LNG markets such as coastal freight vessels, domestic passenger ferries, locomotives, mine haul trucks and stationary power generation for industrial applications. Under this scenario, no growth is expected beyond this initial capture of 13 million GJ per year through to the end of the forecast period of 2036. This scenario also assumes that no trans-Pacific marine vessels adopt LNG as a marine fuel in response to the tighter emissions regulations that are expected to be imposed on the marine industry by the IMO beginning in 2020 (see Section 2).
>
> **3.4.7.2.2 LNG Base Scenario Demand Forecast**
>
> In the Base forecast scenario, FEI built upon the Low scenario but included some capture rate of trans-Pacific marine vessels as LNG fuel adopters. Through market intelligence and industry research, FEI has identified a certain segment of the trans-Pacific marine segment (international car and vehicle carriers) that would be ideal early adopters of LNG as a marine fuel. Over the forecast horizon to 2036, FEI assumed an annual growth rate of about 5 percent per year beyond 2028 as a Base case demand growth scenario.

18.1 What circumstances does FEI expect to occur that would enable it to capture an addition 13 million GJ per year by about 2025? Please explain.

<u>Response:</u>

FEI would like to clarify that the value of 13 million GJ per year in the Low Scenario stated in Section 3.4.7.2.1 was incorrectly provided in the LTGRP filing which will be corrected in an errata to be filed concurrently with this IR response. This value for the Low Scenario should be <u>*7 million GJ per year*</u> through to the end of the forecast period of 2036.

Nonetheless, the bulk of the demand that FEI forecasts to adopt natural gas over the long term will be from the marine transportation sector.

More specifically, the marine market is made up of the short sea, coastal freight and trans-Pacific segments. In the Low Scenario Demand forecast, FEI did not include demand from the trans-Pacific market segment due to the higher degree of uncertainty regarding natural gas adoption plans for this specific market segment. Although the International Maritime Organization will impose a sulphur emissions limit on *all* maritime traffic beginning in 2020, there is currently a sulphur emissions limit on all maritime traffic that specifically operate in designated Emissions Control Areas (ECAs). It is these coastal freight vessels, in addition to the short sea segment which is already adopting LNG that FEI is projecting to adopt LNG in the Low Scenario. A combination of stricter emissions limits and lower fueling costs versus current emission compliant fuels are expected to result in increased LNG adoption for these two (short sea and coastal freight) market segments before adoption is expected to occur for the trans-Pacific segment.

18.2 Please provide any evidence FEI has that it will make the initial capture of 13 million GJ per year by about 2025? Please provide.

Response:

As stated in response to CEC IR 1.18.1, the initial capture in the Low Scenario should be amended to 7 million GJ per year by about 2025.

Nonetheless, the forecast capture rate includes a combination of existing LNG supply agreements that FEI currently has contractually in place with various customers, plus agreements that FEI expects to execute with customers with a high degree of certainty, plus a forecast of markets that could adopt LNG as a fuel over the planning horizon. Discussions with these customers are in various stages of development and due to the commercial sensitivity of these discussions, FEI is unable to provide the specific details as requested.

At a high level, FEI has identified all potential adopters of LNG as a fuel based on discussions and engagement with these customers across all different market segments. Based on this information, FEI then applied probabilities of each customer adopting LNG over the planning horizon.

18.3 Why would the existing LNG demand, with no growth, not serve as an appropriate low scenario, or even base scenario, for the LNG demand? Please explain.

Response:

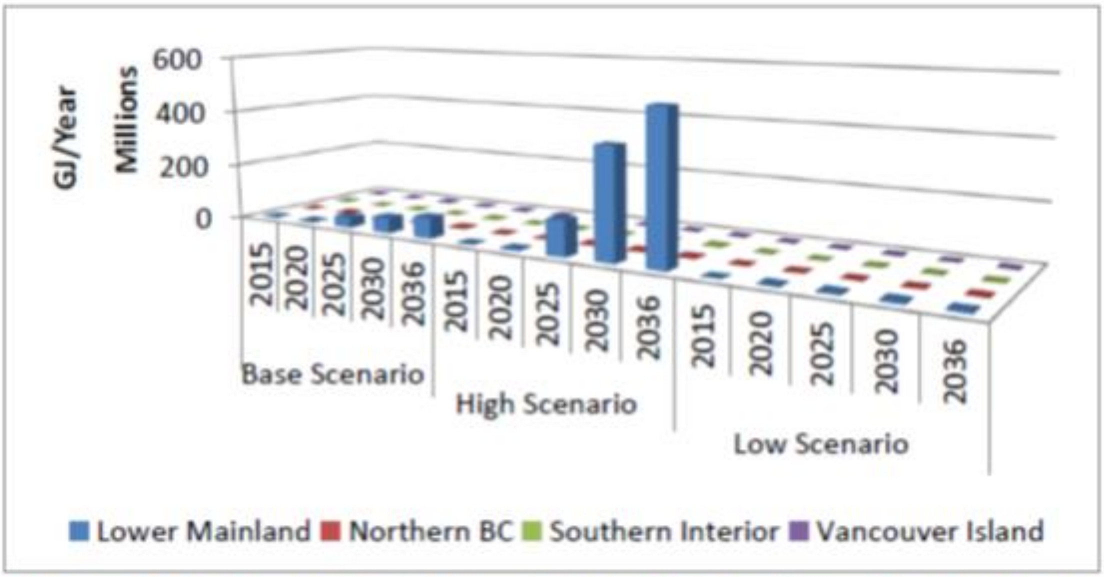
FEI believes that this would not provide an accurate representation of the overall development and growth of the LNG market over the planning horizon. For example, a number of prospective customers that FEI is engaged with have expressed strong interest in converting their marine vessels, locomotives, mine haul trucks and remote power generation applications to natural gas.

FEI continues to believe that natural gas adoption will continue to increase from current levels and as such the Low Scenario should reflect this increase in demand at a more conservative pace than for the Base and High Scenarios.

19. Reference: Exhibit B-1, page 88

Figure 3-18 below provides a regional look at the CNG and LNG annual demand for natural gas. This graph depicts the effect of adding NGT load to the distribution system and reveals that the majority of NGT load is expected to come onto the system in the Lower Mainland.

Figure 3-18: Forecast NGT Annual Demand (CNG & LNG) – by Scenario and Region



Note: Figure 3-18 displays milestones every five years only in order to fit the information to the report page; the forecast model contains information for all years of the planning period.

19.1 Why is the Lower Mainland likely to be the source of the vast majority of NGT load in the High and Base scenarios?

Response:

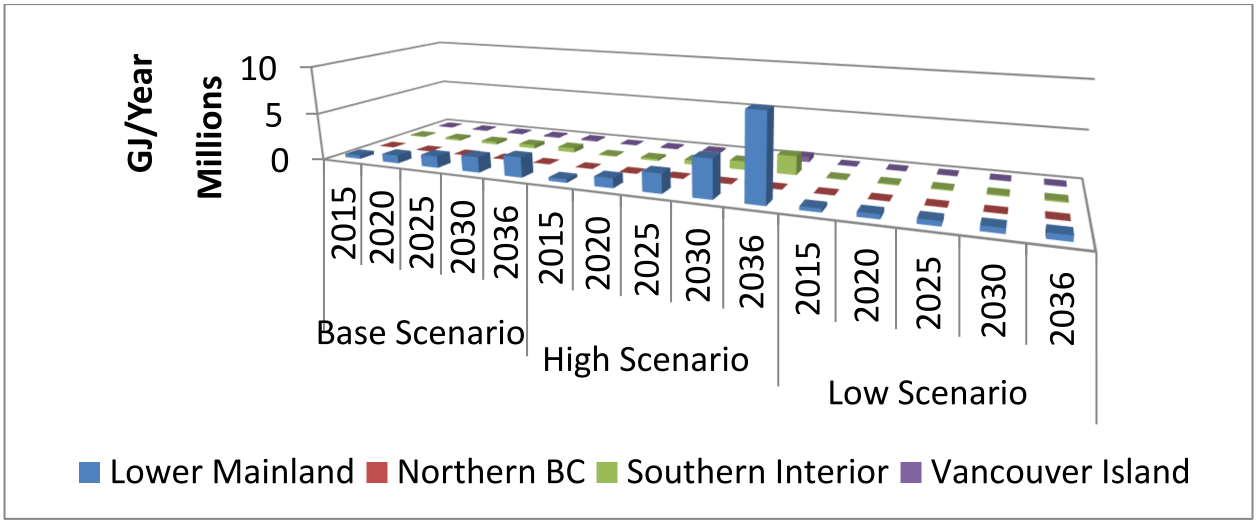
The Lower Mainland is expected to be the source of the vast majority of the NGT load because the LNG demand forecasts make up a large proportion of the overall NGT demand forecast. As a result of the location of the Tilbury LNG facility, the Lower Mainland gas transmission system that supplies the Tilbury LNG facility would be the initial source of natural gas demand to liquefy and provide to the market.

The purpose of the Tilbury T1A expansion is to support NGT load which is why the vast majority of the LNG demand is originating from the Tilbury LNG facility. Furthermore, since the marine market segments make up a large portion of the Base and High Scenarios, the Tilbury LNG facility's strategic location provides the necessary waterway access required to provide the fueling to this market.

19.2 Please provide figure 3-18 without LNG.

Response:

The figure below reproduces Figure 3-18 (Forecast NGT Annual Demand) from the Application with forecast CNG demand only (without forecast LNG demand).



20. Reference: Exhibit B-1, page 101

> ***4.2.2.1 Method***
>
> FEI applied the C&EM potential to its multi-scenario end-use forecast via the following steps:
>
> 1. In the 2017 LTGRP forecast model, construct a separate Reference Case which matches as closely as possible the BC CPR's Reference Case;
> 2. Import the CPR measure assumptions into this 2017 LTGRP CPR Reference Case;
> 3. Produce the technical energy savings potential in the 2017 LTGRP CPR Reference Case and calibrate the measure applicability rates in light of the BC CPR technical energy savings potential results;
> 4. Produce the economic energy savings potential results in the 2017 LTGRP CPR Reference Case;[116]
> 5. In the 2017 LTGRP CPR Reference Case, run the market potential energy savings analysis and calibrate individual measure participation rates in light of the BC CPR energy savings market potential results;
> 6. Import into the 2017 LTGRP CPR Reference Case, the expenditure parameters (i.e. ratio of incentive to non-incentive spending by program area and ratio of incentives to incremental costs by program area) from the BC CPR market potential analysis;
> 7. Apply the 2017 LTGRP Reference Case and produce the market potential energy savings, benefit-cost, and expenditure results;
> 8. Calibrate expenditure parameters at the measure level in light of the BC CPR results and existing program experience and re-run step 7; and
> 9. Run the step 7 analysis for the Upper Bound and Lower Bound scenarios.

20.1 Why did FEI only run the step 7 analysis for the upper and lower bound scenarios?

<u>Response:</u>

In the 2017 LTGRP, FEI applied the C&EM analysis results to the Reference Case, Upper Bound scenario and Lower Bound scenario in order to illustrate the potential range of estimated C&EM impacts across the Upper Bound and Lower Bound scenarios which resulted in the lowest and highest forecast of annual demand for natural gas across the 2017 LTGRP scenarios. This enables FEI to present the widest range of potential demand for natural gas after energy savings from cost effective demand-side measures. In contrast to the various intermediate scenario results, this total range is crucial to identifying resource needs across the 2017 LTGRP planning horizon.

21. Reference: Exhibit B-1, page 102

- An environment with increased development of renewable and district energy systems will tend to decrease the remaining natural gas share and therefore the potential for natural gas savings. An environment with little development of renewable and district energy systems will tend to have more potential for natural gas savings.
- A policy environment that encourages more existing adoption of energy efficiency (e.g. accelerated appliance standards) will tend to decrease the remaining potential for energy efficiency for utility programs to capture. Conversely, a policy environment that does not encourage existing adoption of energy efficiency will tend to increase the potential for utility programs.
- Following the BC CPR's approach, the 2017 LTGRP C&EM analysis applies the TRC test to commercial and industrial program areas but the MTRC test to the residential program area to simulate the current DSM landscape. Scenarios that are subject to accelerated non-price carbon policy action apply the MTRC test to all program areas in order to simulate the potential removal of the current MTRC cap as regulators potentially further recognize the economic and social non-energy benefits of C&EM activity.

21.1 Would FEI agree that government policy and an environment that promotes energy efficiency in general could potentially raise awareness of energy efficiency and stimulate participation by residential and commercial customers regardless of the focus? Please explain why or why not.

<u>Response:</u>

FEI is unaware what "focus" is being referred to in this question when it states "regardless of the focus". For the purposes of this response, FEI assumes an environment where government is investing more so than they have historically in communications to help promote energy efficiency in general and without fuel bias. Similar to FEI's response to BCUC IR 1.25.4, FEI has not conducted any research into the relationship between government promotion of energy efficiency and FEI C&EM program awareness or participation rates. However, the 2017 LTGRP C&EM analysis is informed by the results of the BC Conservation Potential Review (BC CPR). The BC CPR model included effects of communication and word-of-mouth dynamics.

Notionally speaking, and assuming all else being equal, FEI agrees that any substantial government efforts to promote energy efficiency in general and without fuel bias would likely lead to greater awareness of energy efficiency by FEI residential and commercial customers and subsequently result in more energy efficiency participation than would otherwise have occurred.

21.2 Is it FEI's position that DSM participation is currently being maximized such that reducing 'potential' participation results in reduced participation? Or is it possible that there remains sufficient unmet potential DSM available that reductions in the overall C&EM potential can still accommodate significant growth in C&EM? Please discuss.

Response:

FEI consulted with Posterity to provide the following response.

FEI interprets this question to ask whether the addressable potential identified by the 2017 LTGRP C&EM analysis is close to identified technical and economic potential, so that a reduction in technical and economic potential may automatically reduce addressable C&EM potential. The 2017 LTGRP C&EM analysis results, as informed by the BC CPR results and FEI's program experience, represent FEI's long term estimate of the potential for C&EM incentive activities to reduce natural gas demand. In general, FEI believes that planning environment changes (such as more stringent codes and standards) that reduce technical and economic potential, would cause addressable C&EM potential to equal a larger proportion of technical and economic potential. Section 4.2.3.5 of the Application suggests that, under the BC CPR Reference Case, addressable C&EM potential may be increased by higher incentive values but that resulting total energy savings may increase at a lesser rate than resulting C&EM portfolio expenditures. As such, it may be reasonable to assume that, under decreased technical and economic C&EM potential, meeting this same estimated level of C&EM potential, if possible, may require higher incentive levels.

21.3 Does, or will FEI engage in capacity related C&EM?

Response:

Please refer to the responses to the BCUC IR 1.29 series and also the responses to BCSEA IRs 1.23.3 and 1.23.3.1.

21.3.1 If yes, please identify the programs FEI uses or will use and provide a brief discussion of their historical effectiveness.

Response:

Please refer to the response to the BCUC IR 1.29 series.

21.3.2 If no, please explain why not.

Response:

Please refer to the response to the BCUC IR 1.29 series.

22. Reference: Exhibit B-1, page 102 and page 116

The C&EM analysis results indicate the outcome of pursuing all cost effective energy savings potential. Crucially, the BC CPR and the 2017 LTGRP C&EM analysis display a theoretical estimate of energy savings measure uptake in relation to the ratio between incentive levels and measure incremental costs. This estimate takes into account program experience and technology diffusion but does not take into account operational program delivery factors, such as staffing levels or specific program eligibility rules. This represents a critical difference to FEI's C&EM expenditure schedule which requests the Commission to approve expenditures for short or medium term C&EM activities. In contrast the BC CPR and the 2017 LTGRP C&EM analysis provide a long term forecast of estimated C&EM potential and activity.

Table 4-8 below summarizes the Reference Case cost effectiveness test results for all program areas while Figures 4-9 to 4-12 illustrate how cost effectiveness test results vary across scenarios. In general, Upper Bound cost effectiveness test ratios are lower than Lower Bound ratios because the low natural gas cost and carbon cost parameters in this scenario depress the avoided cost of gas which reduces the benefits from energy efficiency measures. The MTRC represents an exception to this as this test relies on the ZEEA for its avoided cost of gas. In the 2017 LTGRP, the ZEEA is not impacted by the natural gas and carbon cost critical uncertainties. In general, cost effectiveness test ratios fall over time as the more easily realized energy savings opportunities (i.e. the low-hanging fruit) are depleted. The 2017 LTGRP C&EM cost effectiveness test results also display the Cost of Conserved Energy (CCE) in dollars per GJ. The CCE is an industry standard method for expressing the TRC results in dollars per GJ. Electric utilities use the CCE to express the net cost of saving one unit of utility-supplied energy. The CCE can be used to express Utility Cost Test (UCT) results in dollars per GJ by applying the UCT benefit and cost inputs.[128] CCE results increase over time:

Table 4-8: Estimated Reference Case Cost Effectiveness Test Results – All Program Areas

Year	TRC	MTRC	UCT	CCE ($/GJ)
Aggregate	**2.2**	**11.3**	**2.2**	**4.7**
2017	4.8	25.4	4.4	2.8
2018	4.1	21.3	3.7	3.4
2019	3.5	18.2	3.2	3.7
2020	3.1	16.2	2.9	4.0
2021	2.8	14.5	2.7	4.3
2022	2.6	13.5	2.5	4.5
2023	2.4	12.6	2.4	4.6
2024	2.3	12.0	2.3	4.8

22.1 Please rationalize FEI's statement that the C&EM analysis results are the outcome of 'pursuing all cost-effective energy savings potential' with the FEI expected TRCs of well above 1.0.

Response:

Please refer to the response to BCSEA IR 1.21.4.

23. Reference: Exhibit B-1, page 123 and 155

> In its decision on the 2014 LTRP the BCUC requested FEI to make stronger linkages between the peak demand and the annual demand forecasts, to understand how "[…] new insights on evolving customer consumption patterns might affect time-of-day demand as well as annual demand […] and how changes in base load annual demand under different scenarios translate into changes in base load peak demand under the same scenario assumptions."[130]
>
> FEI commissioned Posterity to develop an exploratory process linking peak demand forecasts to the end-use scenarios used in the annual demand forecasts. Section 6.2.1.3 further discusses this process. Overall, Posterity's approach suggests that the 2017 LTGRP's C&EM forecast decreases peak demand. Section 6 discusses in detail how this may impact infrastructure expansion requirements across FEI's regional transmission systems. FEI emphasizes that Posterity's approach currently is theoretical in nature and unsupported by direct measurement. Thus FEI's infrastructure planning continues to rely on FEI's traditional peak demand forecast method (Traditional Peak Method).

> Since the exploratory end-use method is not based on metered FEI customer data, the Traditional Peak Method forecast which intrinsically reflects the current effects of DSM programs remains FEI's base forecast for determining infrastructure requirements and timing for addressing capacity constraints. By relying on the Traditional Peak Method, Section 6.3 thus addresses the requirements of section 44.1(2)(f) of the UCA. FEI will continue monitoring potential metering solutions that may allow FEI to field-validate the projections of the exploratory end-use peak demand forecast method and to better serve its customers.

23.1 Please elaborate on FEI's plans to monitor and provide direct measurements to allow FEI to field-validate the projections of the exploratory end-use peak demand forecast. Please briefly discuss the types of measurements that will be taken and when the monitoring will commence.

<u>Response:</u>

FEI is currently conducting an advanced metering pilot study on premises in portions of the Fraser Valley that will provide more granular consumption information, which will help validate the peak demand forecast. Please also refer to the response to BCSEA IR 1.23.3.1 for a complete discussion on current activities and future plans.

24. Reference: Exhibit B-1 Page 130, lines 3-6

This section and the Annual Contracting Plan (ACP) rely on FEI's traditional method for deriving system-wide demand for each day throughout the entire year as well as for the peak design day (i.e. the coldest day of the design year estimated via extreme value analysis within a return period of 20 years).

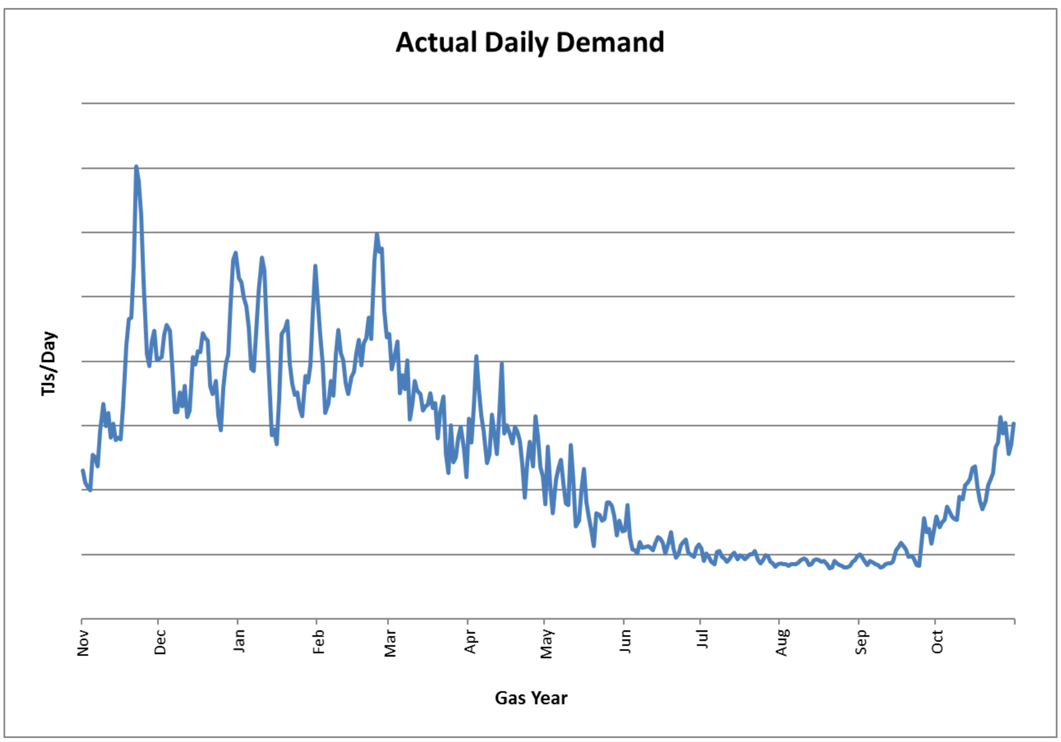
24.1 What is FEI's "traditional" method of forecasting system wide demand for each day and please provide detail of that forecasting.

Response:

FEI uses the traditional ACP method[8] to create system wide forecasts for both the Design weather and Normal weather scenarios. The method is illustrated below.

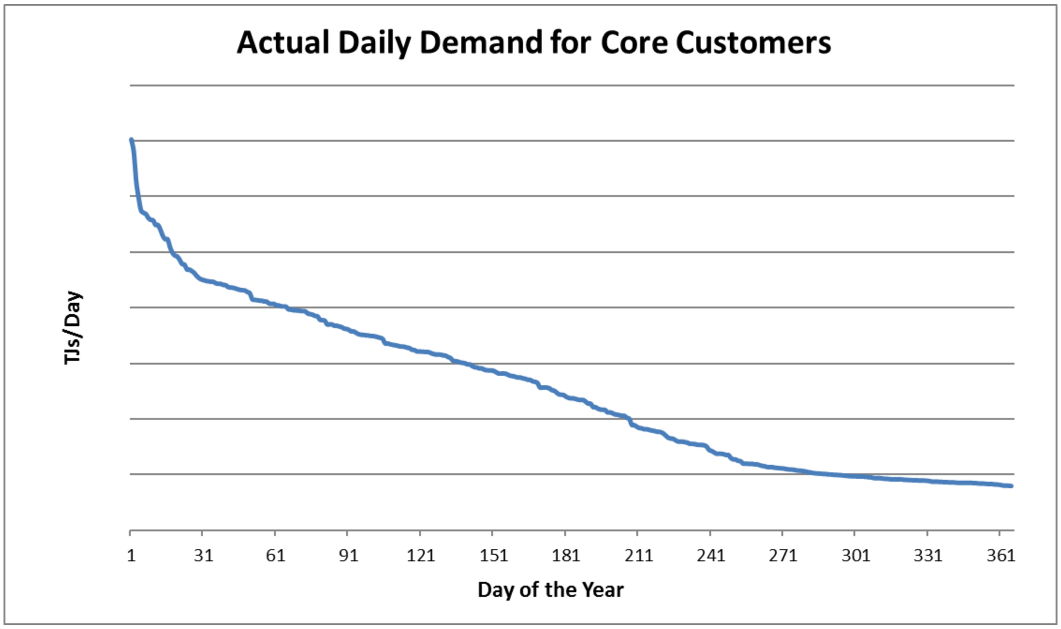
Daily Demand for Core Customers

Development of the two forecasts starts by gathering 365 days of daily demand data from all core customers (Rates 1-7 not including 6 and 46) for the prior gas year[9]. A sample plot is shown below:



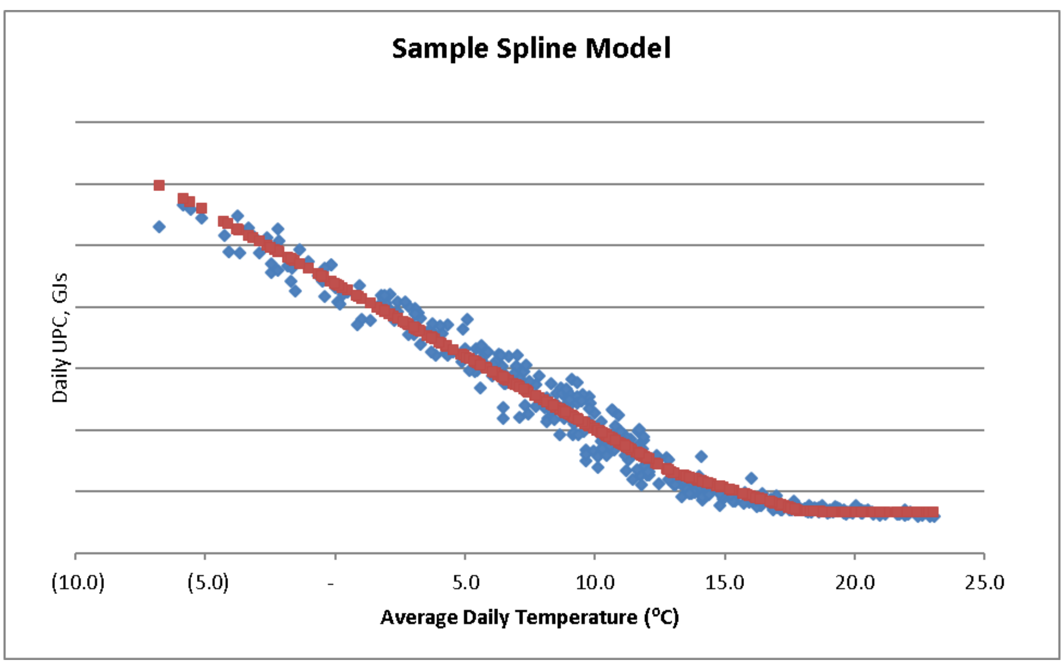
[8] Note that the Traditional ACP method is separate and distinct from the Traditional Demand method.
[9] The FEI gas year runs from Nov 1 to Oct 31.

Sorting the data by demand from largest to smallest results in a Load Duration Curve for the year:



Spline Plot

This daily demand data is divided by matching customer totals to calculate the daily average UPC. The average daily UPC is plotted against the average daily temperature (blue dots in the following figure). A spline regression model is then computed (red line below).



Once the spline plot is developed FEI uses it to determine the expected daily use rate for any average daily temperature. The next step is to develop both design and normal temperature profiles. These profiles are each 365 days in length and are derived using the methods described below.

Once the temperature profiles are established for the design year and normal year the spline plot is used to determine the corresponding daily UPCs.

Extreme Value Analysis for the Design Day

The peak day represents the coldest day of the design year and it has the highest daily demand in a year. The peak day demand forecast is derived through an Extreme Value Analysis, which estimates the coldest temperature expected to occur with a return period of once every twenty years.

Extreme Value Analysis is a statistical technique used to model observed data extremes in order to allow for generalizations about the likely recurrences of those events. This type of analysis is the accepted standard in Canada and is approved by the Atmospheric Environment Service of Environment Canada.

The data extremes are very cold temperatures (the coldest temperature experienced in each year), and the objective is to identify the coldest temperature that would be expected to reoccur once every twenty years.

To achieve the objective, historical weather data (the coldest day in each year) is collected and modeled using a non-linear regression approach known as Dr. Gumbel's extreme distribution Method of Moments. The functional form of this model is:

$$Return\ Period = \frac{1}{\left(1 - e^{\left(-e^{(\sigma(t-\mu))}\right)}\right)}$$

Where:

Return Period = the predicted return period based on the temperature;

σ, μ = constants determined from the regression analysis;

t = the temperature, in degrees Celsius

The regression determines values for σ and μ such that the sum of squares of error is minimized, using the above formula. Once the equation has been solved, the extreme value temperature can then be determined for a given return period using the following formula:

$$t = \mu + \frac{\ln\left(\ln\left(\frac{r}{(r-1)}\right)\right)}{\sigma}$$

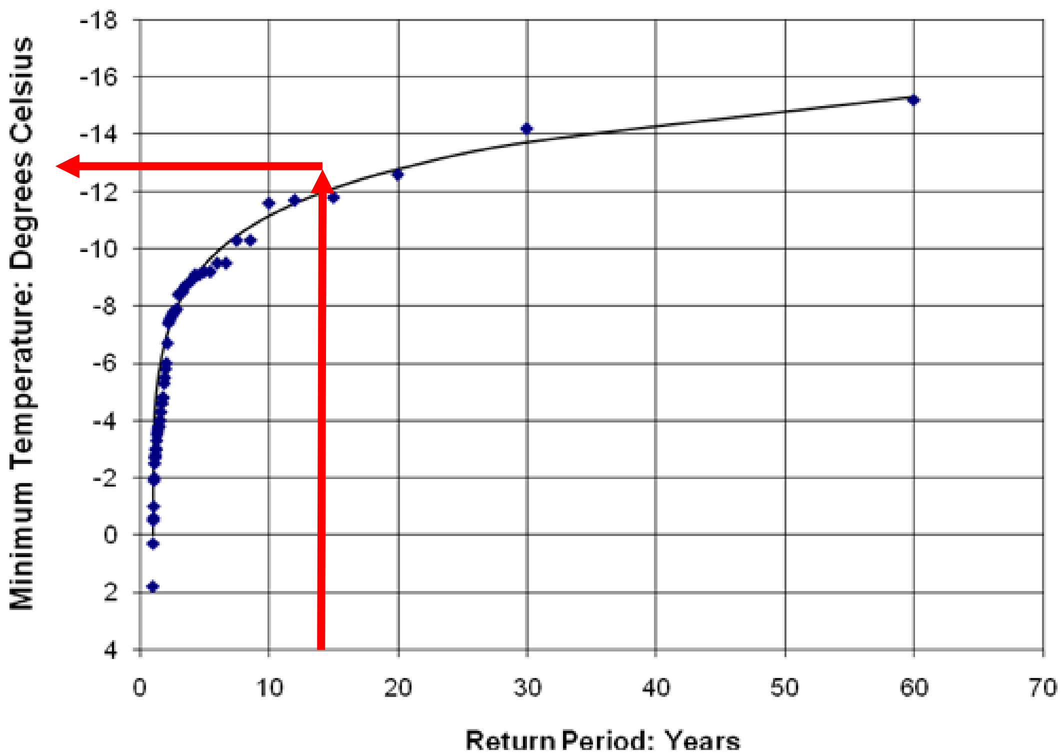
Where:

t = the extreme value temperature;

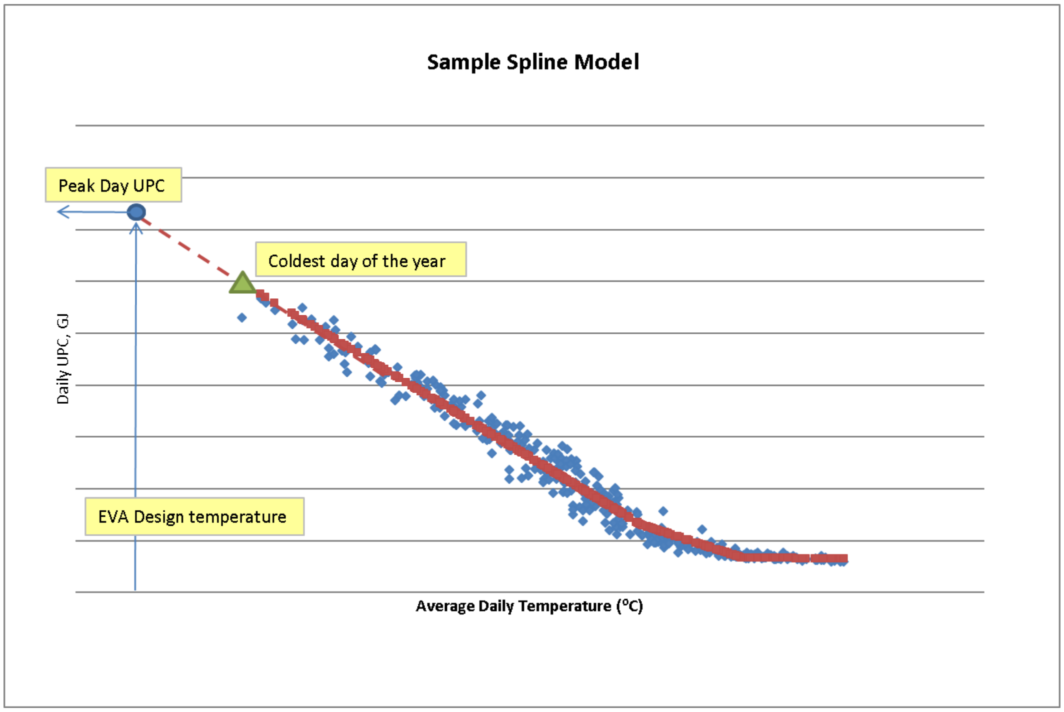
r = the return period; and,

σ, μ are the coefficients solved for in the above model.

The return periods are illustrated in the following graph:



The spline plot developed above can then be extended to incorporate the EVA Design Temperature as shown below. The coldest recorded temperature in the previous year is shown as the green triangle. The EVA temperature is normally much colder than the most recently experienced cold temperature. The "cold" end of the spline model is extended to intersect the EVA Design temperature. The resulting Peak Day UPC can then be read from the Y axis.



Design Year

The Design Year is defined as a "very cold" weather year derived from the five coldest weather years experienced in the past 60 years. FEI gathers the average daily temperature for each of the five years and then sorts the years according to temperature. The Design Year is then the row average. For example the 10th coldest day in the Design Year is the average of the 10th coldest days in each of the five coldest years. This method results in a very cold year.

Once the Design Year temperatures have been established the Design Day temperature from the EVA analysis is used to replace the temperature on the coldest day.

The following table shows the first ten rows of the Design weather table. The years are shown in the top row. The cell values are temperatures in degrees C. The Design Day temperature from the EVA analysis is shown in the yellow cell.

1964	1968	1971	1978	1985	Average
-12.6	-15.2	-8.9	-9.2	-11.7	-12.8
-8.8	-14.1	-7.0	-8.7	-10.0	-9.7
-7.4	-11.6	-6.3	-8.4	-10.0	-8.7
-5.7	-10.9	-6.0	-6.5	-8.3	-7.5
-3.7	-10.9	-5.1	-4.6	-7.8	-6.4
-3.1	-10.3	-4.5	-3.8	-7.5	-5.8
-2.2	-10.0	-4.1	-3.1	-7.2	-5.3
-2.0	-9.7	-3.7	-2.8	-7.0	-5.0
-2.0	-9.7	-3.5	-2.7	-5.3	-4.6
-1.2	-9.3	-3.1	-2.6	-4.8	-4.2

Once the 365 daily design temperatures are established the spline mode is used to predict the corresponding 365 design UPC values.

The design UPC values are then multiplied by the forecast number of customers to determine the forecast normal annual daily demand. The design daily demand is then summed for the year to determine the annual design load.

Normal Year

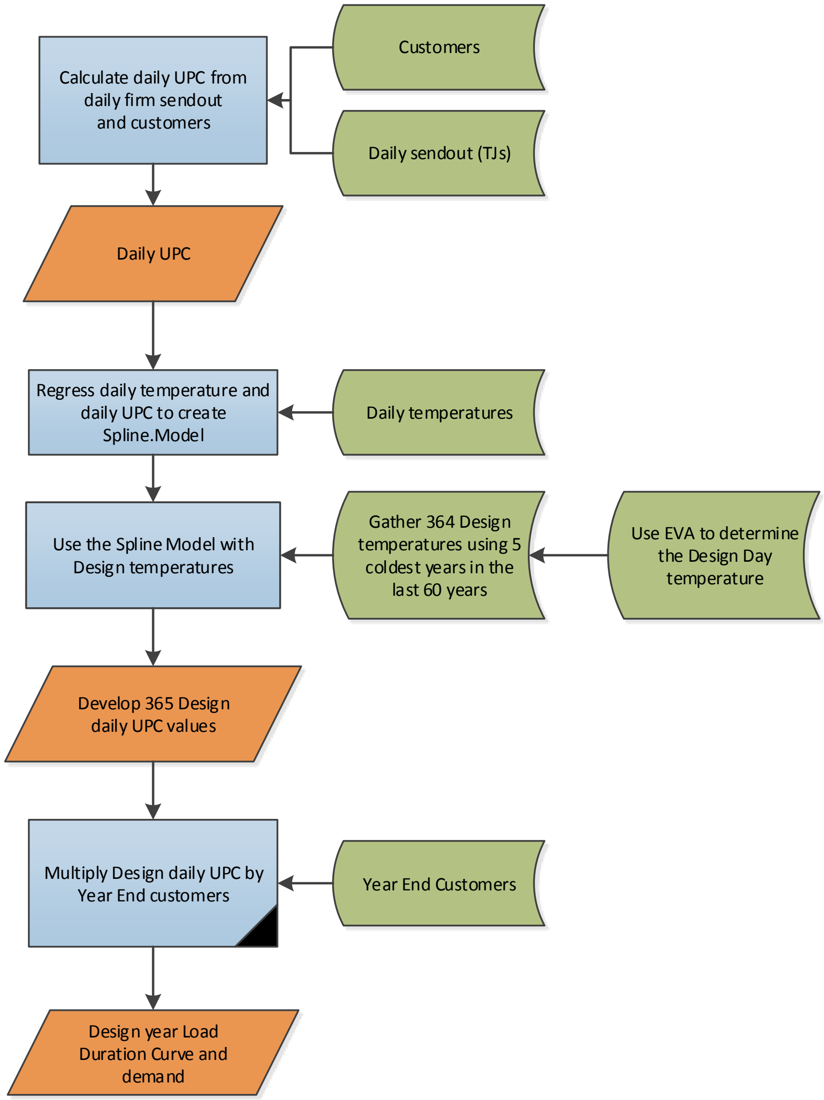
Normal daily temperatures are developed based on the average daily temperatures experienced over the past ten years. Once the 365 daily normal temperatures are established the spline mode is used to predict the corresponding normal 365 UPC values.

Rank	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	Average
1	(1.2)	(10.3)	(2.8)	(6.4)	(5.7)	(2.8)	(6.3)	(4.6)	(1.8)	(6.8)	(4.9)
2	(0.6)	(7.6)	(2.7)	(5.1)	(4.5)	(1.4)	(5.5)	(4.0)	(1.8)	(5.8)	(3.9)
3	(0.5)	(7.0)	(2.5)	(4.4)	(2.2)	(0.8)	(4.6)	(2.6)	(1.7)	(5.6)	(3.2)
4	(0.5)	(5.2)	(1.9)	(4.0)	(1.3)	(0.5)	(4.1)	(2.6)	(1.6)	(5.1)	(2.7)
5	(0.3)	(5.1)	(1.8)	(3.5)	(1.1)	(0.4)	(3.9)	(1.8)	(0.9)	(4.3)	(2.3)
6	(0.1)	(3.9)	(1.5)	(2.1)	(0.6)	0.4	(3.7)	(1.3)	(0.1)	(4.1)	(1.7)
7	-	(3.7)	(0.3)	(1.6)	(0.4)	1.0	(3.1)	(1.2)	0.1	(3.8)	(1.3)
8	-	(2.4)	(0.2)	(1.3)	(0.1)	1.0	(2.7)	0.7	0.2	(3.8)	(0.9)
9	0.1	(2.4)	(0.1)	(1.2)	0.2	1.1	(2.1)	1.0	0.3	(3.7)	(0.7)
10	0.2	(2.0)	0.2	(1.1)	0.2	1.2	(2.0)	1.0	0.5	(3.3)	(0.5)

The normal UPC values are then multiplied by the forecast number of customers to determine the forecast normal annual daily demand. The normal daily demand is then summed for the year to determine the annual normal load.

Summary Flow Chart

The following flow chart summarizes the steps detailed above for the development of the Design Year. In the flow chart green shapes represent inputs to the method; blue shapes are process and orange shapes are outputs.



Calculate daily UPC from daily firm sendout and customers
Customers
Daily sendout (TJs)
Daily UPC
Regress daily temperature and daily UPC to create Spline.Model
Daily temperatures
Use the Spline Model with Design temperatures
Gather 364 Design temperatures using 5 coldest years in the last 60 years
Use EVA to determine the Design Day temperature
Develop 365 Design daily UPC values
Multiply Design daily UPC by Year End customers
Year End Customers
Design year Load Duration Curve and demand

1

2

25. Reference: Exhibit B-1 Page 131, lines 3-4

Currently, FEI contracts for all of the gas supply resources required over the short to medium term.

25.1 Please provide definitions of Short and Medium term for contracts in months or years.

Response:

Resource	Short Term	Medium Tern
Commodity	1 day to 6 months	1 to 10 years
Transportation	1 year	2 to 7 years
Storage	1 year	2 to 7 years

The above table is based on the contracting renewal strategy of FEI's existing portfolio of resources. If additional resources are needed to meet future load requirements, FEI would be required to make longer term commitments.

26. Reference: Exhibit B-1 Page 133, lines 7-11

While the focus of price risk management in the past has been primarily on short term planning, FEI believes the current market price environment creates opportunities for longer-term strategies. Going forward, these could include consideration of longer term instruments or tools that could improve long term cost certainty.

26.1 Please provide a list and detailed definition of these longer term commodity strategies and purchasing instruments used for gas supply purchase.

Response:

The following are potential alternatives to manage long term (i.e. beyond five years) price risk.

Long Term Hedging

The commodity gas purchases within the ACP are currently generally based on index pricing at the AECO/NIT market hub, which is subject to the price volatility of the natural gas market. An alternative for mitigating this market price volatility over the longer term is using long term fixed price purchases or financial swaps, where the purchase price is locked in at a point in time and does not change for the contract term.

As these types of physical supply arrangements are not commonplace in the market, there is uncertainty regarding how many suppliers may be willing to transact with FEI. Locking in long-term market prices could also be done financially with fixed price swaps. FEI expects that the maximum term for these types of arrangements would be up to ten years based on the liquidity of the AECO/NIT market.

This type of supply arrangement helps manage the risk of higher prices or persistent price volatility that could occur in the future. FEI's gas customers could benefit from the increased stability in commodity rates over the longer term, particularly if market prices rise over time. Therefore, this type of arrangement is effective in meeting the primary price risk management objectives over a longer period. However, long term fixed purchases can result in higher than market costs if market prices move lower after locking in the fixed price. The current environment of low gas market prices near producer break-even costs provides an opportunity to capture low forward market prices that may not last indefinitely.

Volumetric Production Payment

Another tool for managing longer term price risk is a Volumetric Production Payment (VPP). In this arrangement, the buyer pays an upfront lump sum payment to a gas producer in exchange for specific volumes delivered over the term of the agreement up to twenty years. The buyer also receives a limited royalty interest in the production volumes, which is returned to the seller once the volumes have been delivered. This helps to reduce the risk to the buyer of the producer going bankrupt. Gas producers will use these types of arrangements to help finance production.

VPP arrangements provide gas cost certainty for a portion of the commodity supply portfolio and provide long term security of supply. Customers would benefit if market prices increase above the VPP contract price or are volatile. The capital investment would be included in FEI's rate base and earn a rate of return for shareholders.

Investing in Natural Gas Reserves

Another alternative for managing even longer term market price increases or volatility is investment in natural gas reserves. In this type of arrangement, the buyer would invest in gas producing reserves by entering into a joint venture with a gas producer for a term up to thirty years. The buyer would share in the cost of developing and producing the gas and earn the right to a portion of the production. Therefore, this type of arrangement would enable the utility to access gas supply on a cost basis rather than a market-price basis, sharing in the costs of production with a producer.

Under this type of joint venture transaction, the potential benefits to FEI's customers would include obtaining gas supply on a cost basis, reduced exposure to market price volatility, physical supply diversity and long term security of supply. The benefits for the producer include access to third party capital, without diluting the company's equity or taking on more debt, which may be important during periods of low market gas prices to maintain production operations.

In terms of rate setting and the accounting treatment of reserves, FEI would expect that any capital investment would be included in rate base upon which the utility would earn a rate of return, benefitting FEI's shareholders. Capital, operating and drilling costs would be included in FEI's gas costs and recovered like the costs for other sources of commodity supply.

Other Long Term Supply Arrangements

In addition to the more common types of arrangements to mitigate long term price risk described above, there may be other long-term supply arrangements with gas producers to manage price volatility and capture low-cost supply for the longer term. These could include an arrangement where FEI provides an upfront lump sum prepayment to a gas producer in exchange for long term supply. The amount of the prepayment would depend on the amount of supply to be delivered, the term of the agreement and the cost to produce and deliver this supply by the producer. The term of such an arrangement could be between ten and twenty years. The gas producer would benefit from receiving upfront capital to fund gas production and operations without resorting to more debt and equity, while FEI's customers would benefit from long-term cost-based supply. FEI expects that any capital investment would be included in rate base upon which the utility would earn a rate of return, benefitting FEI's shareholders.

Current Discussions

FEI is currently in the process of discussing options with producers to see if they have any interest in a long-term cost-based supply arrangement with FEI. At this point, FEI does not know which type of arrangement producers might have more preference for, if any, and it is possible that there may be supply arrangements of interest not listed in this response. If there is interest, and provided the arrangement meets the objectives of FEI's ACP and PRMP in the interests of customers, FEI would bring this forward in an application to the Commission for approval.

27. Reference: Exhibit B-1 Section 5.2, Page 136, lines 27-29

TransCanada's proposed projects will compete for the same supply currently accessed by Westcoast Energy Inc. (Westcoast) and on which FEI is reliant on for its customers.

27.1 Please outline long term strategies FEI has for procuring and maintaining long term replacement supply if or as supplies are lost to competing markets on the TransCanada system.

Response:

FEI is actively involved in National Energy Board (NEB) proceedings, which potentially affect FEI's access to supply, and is also involved in developing solutions with regional stakeholders to help ensure issues related to third party pipeline infrastructure are resolved fairly. These activities are important because they help to ensure that customers in BC will continue to have access to gas supply at fair market prices.

FEI also attempts to establish relationships with all producers and other counterparties[10] actively engaged in developments in northeast BC. Establishing these relationships has provided FEI with several long term supply commitments at Station 2, which helps promote the long term viability of the Station 2 marketplace and ensure the continued availability of supply from there over time. Moreover, maintaining these relationships is key, as it is important to keep an open dialogue so FEI and the producers can better understand each other's long term plans.

[10] Other counterparties include marketers and aggregators including financial institutions that are active in energy trading. These relationships are also important because they form part of the wholesale marketplace where FEI participates.

28. Reference: Exhibit B-1 Section 5.3.2, Page 139, lines 4-26

FEI contracts for seasonal storage at Aitken Creek Storage in NEBC and currently with Rockpoint Gas Storage in Alberta. These seasonal storage assets are available to be utilized throughout the winter season (November-March).

FEI also contracts for shorter duration market area storage resources, which are needed when colder than normal winter loads are greater than the supply available from seasonal storage and termed gas supply. FEI contracts these shorter duration assets at Jackson Prairie Storage in Washington and Mist Storage in Oregon. FEI also contracts with third parties such as Westcoast, TransCanada, and Northwest Pipeline (NWP) for transportation capacity in order to move supply purchased at the different market hubs, and to manage withdrawals and injections from storage facilities for delivery to FEI's transmission system.

Contracting for transportation capacity on Westcoast's T-North and T-South system provides FEI with access to gas supply from NEBC. Westcoast's T-North system allows FEI to access gas supply north of the Station 2 market hub, and to inject or withdraw from the Aitken Creek storage facility. Westcoast's T-South system allows gas supply to be delivered from Station 2 to FEI's Lower Mainland and Interior delivery system.

Contracting for capacity on TransCanada's NGTL and FoothillsBC systems and utilizing FEI's own Southern Crossing Pipeline (SCP) allows FEI to access gas supply from the AECO/NIT and Kingsgate markets and Alberta located storage facilities.

28.1 Has FEI identified any other transmission, storage or contract assets which it may be able to use to the benefit of customers in various future scenarios, other than its existing assets, and if so what might these be under different future scenarios.

Response:

FEI is always evaluating resource options to ensure security of supply for various future scenarios. Over the past few years, FEI has participated in two open seasons offered by Westcoast Energy (i.e. Winter Firm Service and T-South pipeline expansion). Moreover, FEI has evaluated storage expansions at Tilbury and Mist, and expanding FEI's Southern Crossing Pipeline.

28.2 If FEI had purchases of long term supply and or ownership of gas field supply capability what changes might FEI need to make to its transmission, storage or contracting assets.

Response:

FEI does not expect that purchasing long term supply and/or ownership of gas field supply arrangements would alter transmission or storage resources as FEI would utilize existing infrastructure (e.g. Westcoast Pipeline) to move the supply to its customer load areas. These arrangements would merely reduce the amount of commodity supply FEI purchases in other deal structures.

29. Reference: Exhibit B-1 Section 5.4, Page 142, lines 1-4

In addition to these strategies, FEI has also started to contract for some resources in excess of what Core customers are forecast to require in the short term. This approach is reasonable because the costs and ability to manage contract renewals within the portfolio of resources help to reduce the risk to Core customers.

29.1 Which excess resources are being contracted for?

Response:

The excess resources that FEI is referring to is the 75 TJ/day of additional T-South Huntingdon Delivery capacity that FEI secured effective November 1, 2015. FEI secured this capacity for RS 46 demand and the potential return of Firm Transportation customers to Core service. Please refer to Attachment 29.1 for a copy of the non-confidential 2014/15 Amendment to the Annual Contracting Plan for additional details.

29.2 What is the contract term of these resources?

Response:

The contract terms for these resources (i.e. T-South Huntingdon Delivery capacity) are November 1, 2015 to October 31, 2020 and November 1, 2015 to October 31, 2022. FEI can renew these contracts but must provide Westcoast Energy Inc. 13 months' notice prior to its expiry. Also important to note, FEI's contracted Westcoast's transportation portfolio has been designed so that portions of capacity are up for renewal each year. This flexibility allows FEI to either reduce or roll off existing contracts once they are up for renewal, if it encounters a future where the capacity is no longer required.

29.3 How is the cost of these resources being optimized to minimize the cost and risk of these excess resources to customers?

Response:

Please refer to the response to BCUC IR 1.34.1

29.4 What are the risks to Core customers that FEI refers to and please quantify the risk problem being addressed by excess resource holdings.

Response:

The risk that FEI is referring to is in reference to the alternative of not holding excess resources and instead attempting to contract for additional resources once the new load has materialized. This alternative may be more costly for customers due to the market factors laid out in Section 5.1.3 in the LTGRP and the limited transportation and storage resources currently available in the Pacific Northwest region or the I5 corridor.

As discussed in the response to CEC IR 1.29.1, FEI addressed a portion of this risk in November 2015 by contracting for an additional 75 TJ/day of T-South Huntingdon Delivery Capacity. FEI evaluates these regional market factors and the risks to the Core Customers on an annual basis through the Annual Contracting Plan.

30. Reference 7: Exhibit B-1 Section 5.5.2, Page 146, lines 7-9

However, at this point, FEI plans to investigate investing in reserves as a longer term strategy for helping to ensure security of supply and to provide cost stability.

30.1 What does FEI consider a reasonable term (years) for the life of reserves for producing property that FEI would invest in?

Response:

Please refer to the response to CEC IR 1.26.1.

30.2 Does FEI believe that FEI owned reserves would increase its overall gas supply portfolio flexibility? If so, explain how.

Response:

As discussed in the response to BCUC IR 1.37.1, FEI is not actively exploring investing in reserves and so does not have an understanding of whether or not owning reserves would increase FEI's overall gas supply portfolio flexibility. The parameters regarding the reserves supply, such as supply profile or flexibility, would likely be determined in negotiations with the gas producer.

30.3 If FEI owned reserves would FEI optimize the value of those reserves through the use of storage and market commodity transactions? If so please explain how such instruments would be used and the anticipated benefits.

Response:

Please refer to the response to CEC IR 1.30.2.

30.4 Does FEI consider FEI owned reserves to be a physical hedge against short term price volatility to be produced only when the cost to purchase market gas is greater than the marginal cost of physical production and delivery of FEI owned reserves? Please explain.

Response:

Please refer to the response to CEC IR 1.30.2.

31. Reference: Exhibit B-1 Appendix A Section 1.2, Page 3, lines 10-18

Taking into consideration that annual natural gas demand in Canada is approximately 3.5 Tcf, the WCSB resource represents the equivalent of approximately 300 years of supply at the current consumption level. The Montney formation in BC alone represents 271 Tcf of potential marketable natural gas.

As a result of the size of this resource and its attractive production economics, production of natural gas from basins located in NEBC has the potential to grow significantly in the coming years. This supply will be able to support existing markets in BC, as well as support potentially new markets (LNG and methanol exports) and meet growing industrial demand in Alberta, specifically from continued oil sands growth.

31.1 Please define attractive production economics and for whom? Producers? Buyers? Investors?

Response:

This response addresses the following round 1 CEC IRs related to resource, production, and market information:

31.1, 35.1, 36.1, 39.1, 40.1, 40.2, 43.1, 43.2, 44.1 - 44.7, 45.1, 45.2, 46.1, 47.1 - 47.5, and 50.1.

In general, the above referenced questions are concerned with the future adequacy of supply to continue to serve markets in BC. FEI is satisfied that public information provided by various provincial and federal agencies indicates that the resource located in the Western Canadian Sedimentary Basin (WCSB), and in northeast BC specifically, is more than adequate to serve the long-term demand of markets in BC. The resource located in the BC portion of the Montney formation alone represents approximately 159 years of potential marketable supply at current BC production levels. Considerable additional resource is located in the Horn River, Liard, and Cordova areas of northeast BC that has yet to be developed. Whether this supply gets fully developed depends on several factors:

- For producers to continue to invest and procure gas they must earn a reasonable return. If commodity prices for their production are lower than their breakeven cost, they will likely reduce or slow additional capital investment. Overtime, producers work to reduce their production costs to a level sufficient to warrant re-investing capital again to grow or maintain production levels. This process ensures that the marketplace today is a better place for consumers prior to the shale gas era, which is further discussed in CEC IR response 1.33.3.
- The integrated North American energy market, to which the WCSB and sub-basins located in northeast BC are connected, plays an important role in ensuring the continued development of replacement supply that is needed to offset declining well rates and to develop additional supply for market growth. Market access, improvements in

production techniques, attractive resource characteristics (liquids), and favourable geology combine to make the Montney basin one of the most attractive plays in North America and the focus of most of the current development in the WCSB.

- As the WCSB becomes better connected to the integrated North American energy market through additional pipeline expansions by Enbridge and TransCanada, it and especially the sub-basins located in northeast BC, will be better able to reach their full development potential. This continued development will help to ensure that the future demand of markets, including those located in BC, will remain reliably served.

Appendix A in the 2017 LTGRP, which prompted many of the above referenced IRs, was included simply to provide supplemental background information about the regional natural gas market and was not intended to act as a planning document on its own. FEI does not conduct its own independent analysis of many of the areas touched on by these questions to be able to provide the requested information. However, much of the information requested in these questions is publicly available through Federal and Provincial reports from agencies including the National Energy Board and the BC Oil and Gas Commission. Please refer to the material linked below.

Public Sources:

- Energy Briefing Notes published by the NEB including the following:
    - November 2013 “The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia.” https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/ltmtptntlmntnyfrmtn2013/ltmtptntlmntnyfrmtn2013-eng.html
    - March 2016 “The Unconventional Gas Resources of Mississippian-Devonian Shales in the Liard Basin of British Columbia, the Northwest Territories, and Yukon - Energy Briefing Note.” https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/ltmtptntlbcnwtkn2016/index-eng.html
    - September 2017 “Duvernay Resource Assessment.” https://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmprdct/rprt/2017dvrn/index-eng.html?=undefined&wbdisable=true
- BC Oil & Gas Commission (Technical Reports): https://www.bcogc.ca/publications/reports.
- National Energy Board (Statistics and Analysis and Publications): https://www.neb-one.gc.ca/index-eng.html.

- BC Government (Summary of Shale Gas Activity in Northeast BC): https://www2.gov.bc.ca/gov/content/industry/natural-gas-oil/petroleum-geoscience/statistics-industry-activity.
- Natural Resources Canada (Reports and Publications):
- http://www.nrcan.gc.ca/energy/publications/6539.

For information requested that is not included in these public reports, requires subscriptions to global energy market providers who prepare their own proprietary analysis, or is information privileged to individual producers. FEI is unable to provide this propriety analysis or privileged information.

31.2 Would investment in FEI owned reserves of this nature in NEBC stabilize long term gas costs and reduce supply risk? Please explain why or why not.

Response:

Please refer to the responses to BCUC IR 1.37.1 and CEC IR 1.26.1.

32. Reference: Exhibit B-1 Appendix A Section 1.2.2, Page 5, lines 15-19

The WCSB faces a particular challenge in this environment because US shale production is taking place very close to the WCSB's traditional markets in eastern North America, which has caused a significant portion of these markets to contract with this new supply source. Unless additional demand develops to match the growth in supply, prices will likely remain low for the near future and the ability of producers to survive in this environment becomes more uncertain.

32.1 Does sustained low pricing due to oversupply in the US present an opportunity for FEI to invest in long term NEBC and WCSB reserves at reduced valuations? If so what is the projected in ground valuation of such reserves? To the extent that FEI's views and analysis are confidential please provide such information under Commission confidentiality rules and processes.

Response:

Please refer to the response to BCUC IR 1.37.1.

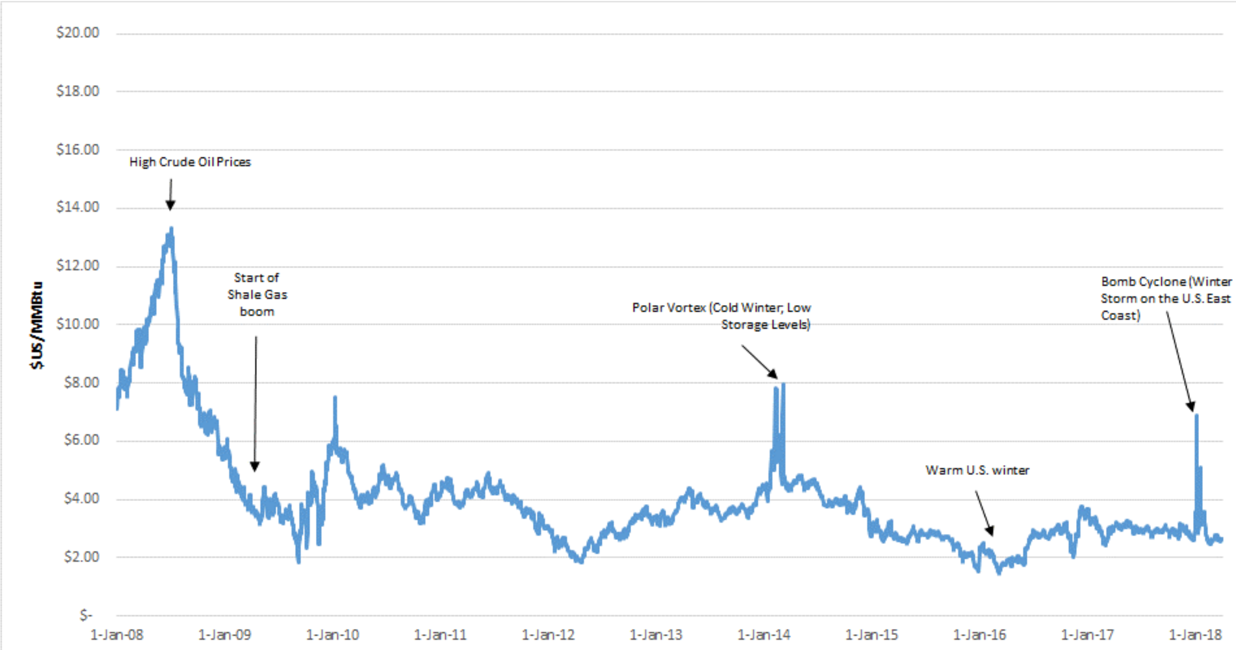
33. Reference: Exhibit B-1, page 133

> on rates. As previously mentioned in Section 2, while natural gas prices have continued to remain low in recent years because of the growth in shale gas supply, market price volatility remains because of frequent supply and demand imbalances. Furthermore, natural gas prices are not expected to remain at their current low levels over the long term. While the focus of price risk management in the past has been primarily on short term planning, FEI believes the current market price environment creates opportunities for longer-term strategies. Going forward, these could include consideration of longer term instruments or tools that could improve long term cost certainty. These strategies could then help to provide improved rate stability and ensure better security of supply for customers.

33.1 Please provide a history of the supply and demand imbalance history.

Response:

Natural gas market prices are frequently adjusting to supply and demand imbalances where during periods of excess demand prices will rise and during periods of excess supply prices will fall. The figure below shows Henry Hub settled spot prices in USD per MMBtu from January 2008 to March 2018. Since the shale gas era began in 2009 there have been many periods of supply and demand imbalance. During periods of excess demand, price spikes above $4 USD per MMBtu have occurred. Some examples of price spikes include February 2014, where prices to spiked near $8 USD per MMBtu as a result of the Polar Vortex weather pattern in the eastern United States and low storage levels. More recently, in January 2018, the storm known as “Bomb Cyclone” hit the eastern United States and caused prices to spike close to $7 USD per MMBtu. There have also been periods of excess supply where market prices dipped temporarily. For example, prices decreased below $2 USD per MMBtu during spring 2012 and 2016, when warm US winter weather resulted in supply outweighing demand and high season-ending storage levels.



The figure above illustrates the unpredictability of market prices where supply and demand imbalances can occur quickly and without notice, even during this era of abundant shale gas supply.

33.2 Please provide evidence why FEI believes natural gas prices are not expected to remain at their current low levels for the long term.

Response:

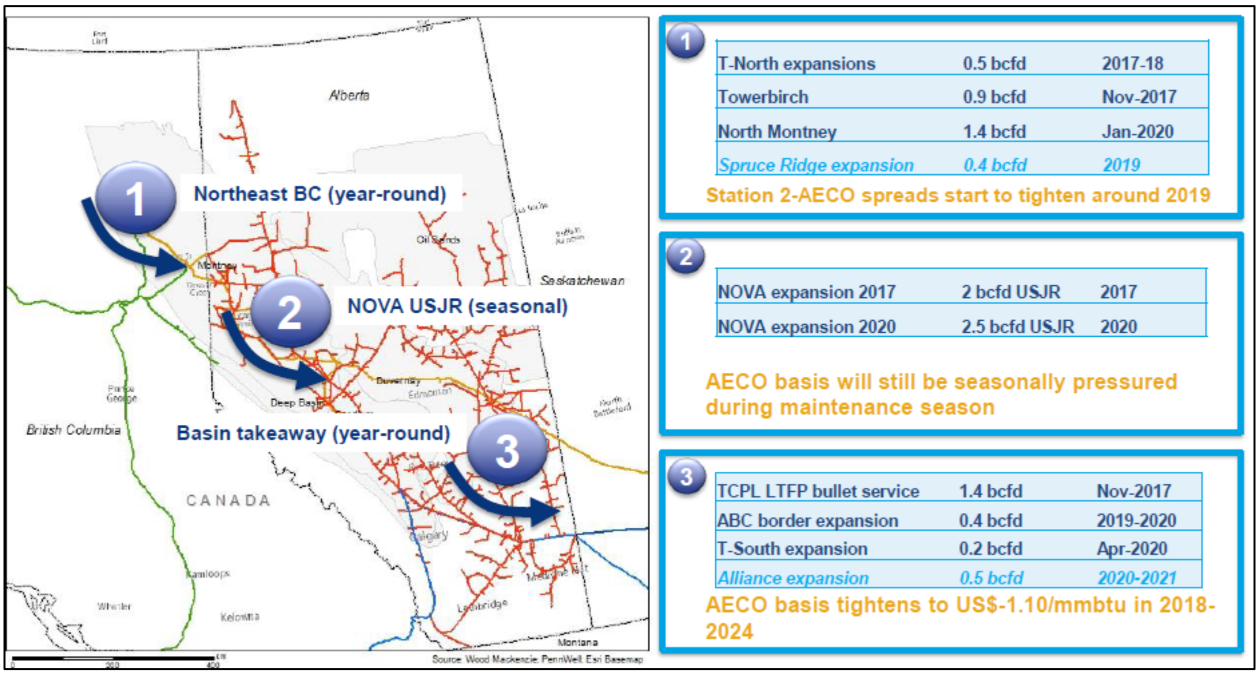
As discussed in Section 2.2.1 of the Application, the significant growth of shale gas supply in Canada and the US in recent years has resulted in a significant drop in natural gas prices. As shown in the price forecast in Figure 2-2 of the Application, Henry Hub gas prices are expected to remain low over the short to medium term and then increase over the long term. As discussed in Section 2.2.1 of the Application, the low prices have created significant opportunities for increased natural gas use, particularly in power generation, LNG exports, and the use of natural gas by the transportation and industrial sectors which is expected to offset the increasing supply, thereby increasing market prices over the long term.

In the short to medium term, regional prices may likely be even lower relative to Henry Hub prices as Alberta (AECO/NIT) and BC (Station 2) prices are forecasted to continue to trade at a significant discount to the Henry Hub price. One of the major reasons that prices are lower in

Western Canada relative to the Henry Hub is due to increasing supply coming from the US Northeast, which continues to displace traditional gas markets served by Western Canadian supply, and growing WCSB supply.

However, as discussed in Section 5.2 of the Application, pipeline developments which would provide more access for WCSB supply to markets over the next few years are expected to increase AECO/NIT and Station 2 prices relative to Henry Hub prices, as shown in the figure below.

WCSB Pipeline Developments[11]



Further evidence that regional market gas prices have limited downside, and therefore more upside potential going forward, is supported by market gas prices currently trading near many gas producer break-even costs, which average near $2 per GJ, as discussed in the response to CEC IR 1.33.3. It is expected that gas producers require market gas prices above their gas production costs, plus a rate of return, to continue to make commitments to producing supply over the long term.

[11] Source: Wood Mackenzie : North American Gas Outlook (November 2017)

33.3 Please provide evidence of the continued improvement in cost efficiency in both the North American oil and natural gas businesses, which has enabled them to compete at lower prices and resulted in surplus availability of low cost supply.

Response:

As the focus of FEI's gas supply contracting and price risk management is on gas markets in Western Canada, FEI has provided a response to this question by discussing gas production cost efficiency for the WCSB region rather than for North America. FEI does not have any information regarding North American or WCSB oil production cost efficiencies.

Before the shale gas era began in 2009, most of the gas production in the WCSB was coming from areas such as conventional gas and coalbed methane plays rather than from the Montney and Deep Basin plays. In 2007 the main coalbed methane plays in Western Canada included the Horseshoe Canyon and Mannville, which had average break-even costs of about $4.22 per GJ and $7.04 per GJ[12], respectively. The other main conventional gas plays at that time included the Horn River which had break-even costs of about $7.28 per GJ[13].

Since the shale gas era began gas producers' break-even costs have decreased over the last 10 years as gas producers have been able to lower their production costs and employ improved drilling techniques. This has enabled gas producers to produce more supply into the marketplace which, relative to demand over the past 10 years, has led to a decrease in market gas prices. So, overall, lower break-even costs have resulted in declining gas prices over time.

The following figure shows a recent update of the break-even costs for some major gas producers in the Western Canadian Sedimentary Basin (WCSB).[14]

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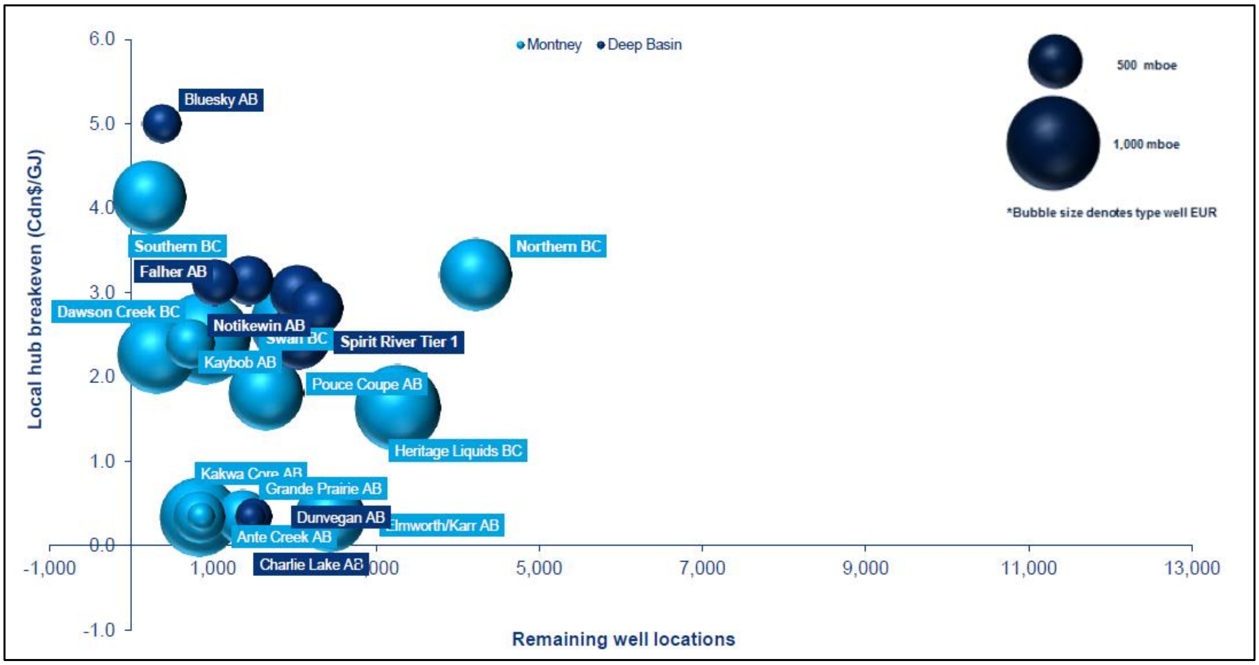
[12] Source: Wood Mackenzie April 2007, Upstream Insight, Western Canada

[13] Source: Wood Mackenzie May 2008, Upstream Insight, Western Canada

[14] Source: Wood Mackenzie November 2017. Montney refers to Northeast British Columbia, Deep Basin refers to Northwest Alberta gas production. EUR = Estimated Ultimate Recovery; mboe = Million Barrels of Oil Equivalents.

WCSB Gas Producer Break-Even Costs



The previous figure indicates that many major Canadian gas producers require market prices in the range of about $1 per GJ to $3 per GJ to break-even and earn a reasonable rate of return (assuming a 10 percent rate of return). Some producers require higher prices than this, up to about $5 per GJ while others can make a profit with market prices below $1 per GJ. In these lower-cost plays, producers benefit from the liquids and oil as well as the gas sales produced. Based on the figure, the average break-even market price for WCSB gas producers is currently estimated to be in the order of about $2 per GJ.

34. Reference: Exhibit B-1, Section 5.5.2, Page 145 Lines 37,38 and 39

Other potential instruments for managing longer-term market price volatility could include investment in natural gas reserves.

34.1 Does FEI believe that the longer-term cost of supply from its own reserves will be less volatile than the cost of supply from the market? If so, please explain.

<u>Response:</u>

FEI expects that the cost of supply from investing in gas reserves would be less volatile than the cost of gas supply from the market. Please also refer to the response to CEC IR 1.26.1.

35. Reference: Exhibit B-1, page 135

- The significant supply potential in NEBC, specifically in the Montney region, has prompted the development of competing infrastructure initiatives to provide greater access to existing and new markets. These developments could impact FEI's future access to secure reliable natural gas supply at a fair market price in BC.

35.1 Please define, in terms of reserves, well type curves, decline analysis, deliverability curves and reservoir pressures, a significant supply potential in NEBC. Please provide alternative sources of information for this statement.

<u>Response:</u>

Please refer to the response to CEC IR 1.31.1.

36. Reference: Exhibit B-1, page 136

> Another major development in the region is the significant supply potential in NEBC has prompted the development of infrastructure initiatives to provide greater access to existing and new markets. With increasing demand from industrial, power generation and oil sands demand within Alberta, and a push by producers to access this economic supply source, TransCanada has brought forward plans to expand into NEBC to access the significant resource that is located there. TransCanada's proposed projects will compete for the same supply currently accessed by Westcoast Energy Inc. (Westcoast) and on which FEI is reliant on for its customers. These regional pipeline initiatives are discussed in greater detail in Appendix A.

36.1 Please define economic supply source. Please provide different evidentiary sources and the parameters for evaluation of economic supply.

<u>Response:</u>

Please refer to the responses to CEC IRs 1.31.1 and 1.33.3.

37. Reference: Exhibit B-1, page 137

> 2. To develop a gas supply portfolio mix, which incorporates flexibility in the contracting of resources based on short term and long term planning and evolving market dynamics.

37.1 Please define evolving market dynamics.

Response:

Market dynamics in terms of pricing, infrastructure, supply and demand are continually changing in the region.

37.2 Please provide a quantitative analysis of flexibility in contracting of resources.

Response:

FEI always has a portion of its portfolio of resources (commodity, transportation capacity and/or storage contracts) expiring each year. For the majority of these resources, FEI has the flexibility of either expiring or re-contracting, if needed. The expiry dates of FEI's portfolio are confidential and are managed through the confidential filing of the Annual Contracting Plan.

38. Reference: Exhibit B-1, page 140

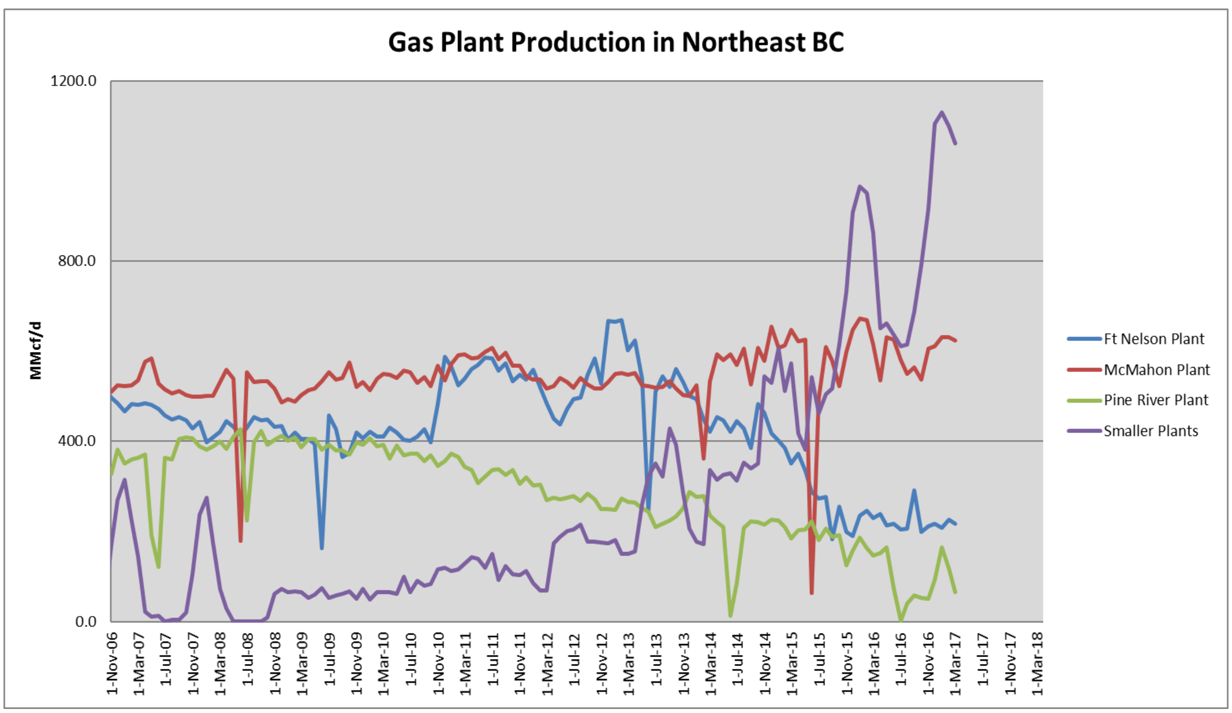
> several smaller facilities for delivery to Station 2. Historically, two-thirds of gas supply in BC flowed from Pine River located east of Station 2, McMahon located south of Fort St John, and Fort Nelson located south of the town of Fort Nelson. However, over the past few years, the supply from these plants has declined significantly. The drop in production levels from these three plants is due to the sustained low commodity prices making them uneconomic. New production is now focused primarily on the Montney basin, where the cost of supply is significantly lower. This has led to increasing production in a number of smaller plants that are

38.1 Please provide quantitative proof that the supply from these historically sourced plants has declined significantly and quantitative proof that the increase in production is coming from new smaller plants.

Response:

The figure below shows the monthly average production flows from Ft Nelson, McMahon and Pine River Plants ("historically sourced plants") and the smaller plants. As the graph below shows, Pine River and Fort Nelson Plant both decline at the same time as the smaller plants begin to increase.

The smaller plants are growing due to their location to the new resources plays such as the Montney.



Note: Data is taken from Enbridge Westcoast Energy Inc.'s website.

38.2 Is it just the low commodity prices making them uneconomic and/or operating costs and finding and development (F&D) costs? Please explain.

Response:

The operating costs and finding and development costs in certain areas (Pine River/Fort Nelson) are greater than other fields especially in the Montney. This is making higher costs areas uneconomic and is a major reason why see declining supply from Fort Nelson and Pine River, as shown in the graph in the response to CEC IR 1.38.1.

39. Reference: Exhibit B-1, page 140

> reliance on these smaller plants may come with additional risk over time. The risk exists that producers in the Montney basin may not be able to maintain their production levels given the significant drop in regional prices, as discussed briefly in Section 5.2. Moreover, with TransCanada's expansions in BC (discussed in Appendix A), the portion of NEBC gas production could change between Station 2, Alliance, and NGTL.

39.1 Please provide the risks associated with the producers and not being able to maintain their production level.

Response:

FEI believes that for producers to continue to invest and procure gas they must make a reasonable return over a period of time. If the prices for their product are lower than their breakeven costs they will likely reduce or slow their capital investment.

Please also refer to the response to CEC IR 1.31.1.

39.2 Please summarize the risks associated with the regulation and/or cessation of hydraulic fracturing?

Response:

The risks associated with the regulation and/or cessation of hydraulic fracturing are low. FEI purchases natural gas from BC and Alberta for distribution to customers across BC. Although FBC does not produce or extract natural gas, how the gas is produced is one of interest to FBC and its customers. This includes the process of hydraulic fracturing. This process has been occurring for decades, including in BC. Given the significant amount of supply produced by hydraulic fracturing, the BC government has regulations in-place to ensure the process remains safe. For instance, BC was the first province in Canada to make it mandatory for all producers in the province to disclose the fluids used in the hydraulic fracturing process. For more information on the regulations and legislation in place for BC and other provinces and territories regarding hydraulic fracturing visit http://fracfocus.ca/.[15]

FEI believes the scenario that hydraulic fracturing is suspended or discontinued is highly unlikely. If this scenario does occur, it can be assumed that a significant portion of unconventional reserves will decrease in the near term. However, because unconventional

[15] The BC Oil and Gas Commission created fracfocus.ca so that all provinces and territories can provide public access to regulations and locations of oil and gas activity.

plays include other new technologies such as horizontal and deep water drilling, the potential amount of supply that could be lost due to suspension of hydraulic fracturing cannot be accurately estimated at this time. According to a report from the NEB, "Duvernay Resource Assessment – Energy Briefing Note" an estimate of the ultimate potential for marketable natural gas in BC had conventional gas amounting to 9% of production while unconventional amounted to the remaining 91% (see figure below).[16]

[16] Duvernay Resource Assessment – Energy Briefing Note. (September 2017). https://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmprdct/rprt/2017dvrn/index-eng.html

Ultimate potential for marketable natural gas in the WCSB

NEB Estimate of Ultimate Potential for Marketable Natural Gas in the WCSB - Year-end 2015

Area	Gas Type	10^9 m^3			Tcf		
		Ultimate Potential	Cumulative Production	Remaining	Ultimate Potential	Cumulative Production	Remaining
Alberta	Conventional	6 276	4 712	8 610	221.6	166.4	313.4
	Unconventional	7 046			248.8		
	CBM portion	*101*			*3.6*		
	Montney portion	*5 042*			*178.1*		
	Duvernay portion	*2 168*			*76.6*		
	Alberta Total	**13 587**			**479.8**		
British Columbia	Conventional	1 462	811	15 505	51.6	28.6	547.6
	Unconventional	14 854			524.6		
	Horn River portion	*2 198*			*77.6*		
	Montney portion	*7 677*			*271.1*		
	Cordova portion	*248*			*8.8*		
	Liard portion	*4 731*			*167.1*		
	British Columbia Total	**16 316**			**576.2**		
Saskatchewan	Conventional	297	227	152	10.5	8.0	5.4
	Unconventional	82			2.9		
	Bakken portion	*82*			*2.9*		
	Saskatchewan Total	**379**			**13.4**		
Southern NWT	Conventional	132	14	1 368	4.7	0.5	48.3
	Unconventional	1 250			44.1		
	Liard portion	*1 250*			*44.1*		
	Southern NWT Total	**1 382**			**48.8**		
Southern Yukon	Conventional	61	6	271	2.2	0.2	9.6
	Unconventional	215			7.6		
	Liard portion	*215*			*7.6*		
	Southern Yukon Total	**276**			9.8		
WCSB Total		**31 941**	**5 770**	**26 172**	**1128**	**204**	**924**

Notes:

Determined from reliable, published assessments by federal and provincial agencies.

Cumulative production is determined from provincial and territorial gas reserves reports.

For this table, "unconventional" is defined as natural gas produced from coal (CBM) or by the application of multi-stage hydraulic fracturing to horizontal wells.

The ultimate potential for natural gas should be considered an estimate that will evolve over time. Additional unconventional potential may be found in unassessed formations.

Source: NEB Table 2 in "Duvernay Resource Assessment – Energy Briefing Note."

40. Reference: Exhibit B-1, page 141

- FEI continues to establish key relationships with major producers that plan to develop gas supply in NEBC, including the Montney and other producing regions, over the long term. Efforts include seeking long term supply arrangements with producers who are evaluating or actively involved in developing their production sources in order to commit them to supply the Station 2 marketplace; and

40.1 Please identify the major long-term area producers.

Response:

Please refer to the response to CEC IR 1.31.1.

40.2 Who are the largest land owners in the Montney?

Response:

Please refer to the response to CEC IR 1.31.1.

40.3 What is the strategy with these producers?

Response:

Please refer to the response to CEC IR 1.27.1.

40.4 Why would they be interested in long term supply arrangement?

Response:

Please refer to the response to BCUC IR 1.36.2.

40.5 What is FEI's history of long term arrangements with producers?

Response:

Over the past several years, FEI has negotiated long-term supply arrangements with producers for terms up to ten years in length. These arrangements provide supply at Station 2 and have been based on the AECO/NIT monthly index. These arrangements with producers have helped FEI secure a level of long-term supply commitment at Station 2, the main market hub FEI relies on for supply.

41. Reference: Exhibit B-1, page 145 -146

> Other potential instruments or tools for managing longer-term market price volatility could include investment in natural gas reserves or long term fixed price contracts. Investment in natural gas reserves would provide even longer-term price protection. This could involve entering into a joint venture arrangement with a natural gas producer, wherein the right to a
>
> portion of the gas production is earned by paying a share of the costs to develop the gas plays. Managing the risks associated with investing in reserves would be of paramount importance to FEI. These risks could include those relating to drilling, completing, and operating wells and would differ from typical regulated utility assets. This type of transaction would not provide the

41.1 Please identify the advantage parameters for upstream Vertical Integration.

Response:

Please refer to the response to CEC IR 1.41.2.

41.2 Please provide the case histories of utility companies vertically integrating?

Response:

FEI is aware of several major U.S. utilities that have vertically integrated or have explored vertically integrating by investing in gas production in recent years. These include Northwest Natural Gas Company (NWN), Northwestern Energy (Northwestern), Portland General Electric (PGE), and Florida Power and Light Company (FPL).

NWN has invested in reserves in the past as part of its overall price risk management strategy. In April 2011, NWN entered into an agreement with Encana under which NWN and Encana agreed to participate in a joint venture to develop gas reserves located in gas fields in Wyoming. Under the agreement, NWN paid a portion of the costs of drilling and in return received rights to the production of gas from certain sections of the field. The intent of this agreement was to provide customers with long-term supplies at stable pricing over the life of the gas reserves, approximately 30 years. During the first 10 years of the agreement, NWN projected the volume of gas under the agreement to be approximately 8-10 percent of its average annual requirements, with a peak of about 15 percent in the years during the height of the drilling program.[17]

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[17] Northwest Natural 2016 Integrated Resource Plan, page 3.53.

Northwestern has acquired gas production in major plays in Montana in order to mitigate supply cost and rate volatility for its customers. Since 2010, Northwestern has acquired gas production and gathering system assets in Montana, estimated to provide approximately 4.7 billion cubic feet annually or 23 percent of current annual natural gas load.[18]

PGE has also expressed its intent to further investigate longer term price risk management strategies such as investing in gas reserves as supply for its power generation needs for customers. In its 2016 IRP, PGE states that it has determined that a non-operating working interest, owned by PGE, is the best opportunity to hedge its long term needs.[19] A non-operating working interest is an ownership interest in a gas well that does not include participation in or any responsibility for the actual operation of the gas well. This type of arrangement would allow PGE the option for natural gas supply which provides insulation from structural changes in market prices. PGE has focused its attention on gas wells in the Rockies region given that it has experience in purchasing gas supply at market hubs in the Rockies, maintains long term transportation agreements in this region and it is a mature, well-understood gas producing region.[20] PGE plans to pursue cost-effective opportunities when they become available, if approved by their regulator.

FPL plans to invest in natural gas reserves in order to provide more stable fuel supply for its gas-fired power plants that serve electricity customers. FPL has partnered with PetroQuest Energy Inc., an independent oil and natural gas producer, in a joint venture to develop natural gas wells in the Woodford shale region in south eastern Oklahoma. With regard to the investment, the CEO of FPL stated: "We believe this to be the next logical step in providing clean electricity for our customers at affordable prices. This investment in natural gas production is an important component for delivering lower, more stable natural gas prices for our customers, and we anticipate identifying additional investment opportunities, thereby benefiting our customers even more over the long term."[21] A FPL spokesperson added: "FPL would be able to lock in gas prices at production costs rather than relying on market prices. The gas reserves would provide additional price stabilization to FPL's existing financial hedging program in two respects. The existing program focuses on short-term transactions because of the cost and credit risks associated with long-term financial hedges, whereas the gas reserves would provide a hedge against market-price volatility over multiple decades."[22]

FEI is aware that many electric utilities are vertically integrated in terms of owning or operating their own electricity-generating resources, such as hydro, wind, solar, natural gas or other

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18 https://www.northwesternenergy.com/docs/default-source/documents/ataglance/ataglancemt
19 Portland General Electric 2016 Integrated Resource Plan, page 86.
20 Portland General Electric 2016 Integrated Resource Plan, page 87.
21 http://www.naturalgasintel.com/articles/98823-florida-electric-utility-going-to-wellhead-for-better-gas-deal
22 http://www.naturalgasintel.com/articles/98823-florida-electric-utility-going-to-wellhead-for-better-gas-deal

sources. This ensures that they have generating assets to provide power to their customers when it is needed rather than relying on other sources, such as market purchases, for example. This is in contrast to natural gas utilities which have traditionally relied on market purchases rather than owning upstream gas resources. However, with the decrease in the costs of producing natural gas, gas utilities are looking into vertical integration, as in the examples discussed in the previous paragraphs.

41.3 Please provide your opinion of the gas production companies being interested in investing in utility-type assets?

Response:

FEI believes the interest of gas producers investing in utility-type assets would be limited. Gas producers are focused on developing their natural gas assets and selling to the market, not managing transmission and distribution systems as well as customer load requirements.

41.4 What are the corporate and industry economics that make upstream Vertical Integration positive and profitable?

Response:

FEI believes there are a number of factors that could make upstream Vertical Integration positive and profitable for FEI's customers. These include the characteristics and creditworthiness of the counterparty involved, market conditions, including supply and demand fundamentals and market pricing and the production costs of the gas producer as well as the producer's required rate of return. FEI does not have any specific information relating to the economics at this time.

41.5 What, if any, regulations impact the upstream vertical Integration?

Response:

There are some regulations that currently apply to gas producers that might become applicable to FEI if it engaged in vertical integration. These could include, for example, the Oil and Gas Activities Act and the Petroleum and Natural Gas Act. FEI has not made a thorough review of the possible regulations in effect currently, or their potential impacts on a public utility in BC pursuing gas supply ownership and so does not have any more specific information to respond to this question.

41.6 Please provide information on FEI's discussions with producers potentially interested in joint ventures and or long-term contracts. If this is confidential information please supply this under the Commission's confidentiality arrangements.

Response:

FEI is currently involved in initial discussions with gas producers to determine their interest in long term cost-based supply arrangements, such as those discussed in the response to CEC IR 1.26.1. FEI does not have any more information to provide at this time as these initial discussions have not yet concluded. Please refer to the response to BCUC IR 1.36.1.

42. Reference: Exhibit B-1, page 147

> Given the significant marketplace developments in terms of North American gas supply, demand and pricing as well as regional infrastructure changes, FEI must continue to monitor changes and be proactive in assessing challenges and identifying opportunities.

42.1 Please identify the methodology for assessing and identifying opportunities?

<u>Response:</u>

FEI relies on multiple factors when assessing and identifying marketplace developments and opportunities.

This includes being actively involved in National Energy Board (NEB) proceedings and establishing relationships with producers and other counterparties in Western Canada, as discussed in the response to CEC IR 1.27.1. Establishing these relationships with counterparties has provided FEI with important market reports, pricing, and commentary on the regional and North American natural gas marketplace. FEI is also involved in several Toll and Tariff meetings/conferences with regional pipelines and is a member of regional associations including the Northwest Gas Association.

From this market participation, FEI formulates and designs strategies as part of the ACP to deal with the different market condition that unfold over time.

42.2 Please describe FEI's criteria for acting on these assessments and information on how close FEI expects that it is to being able to take action beneficial to its customers.

<u>Response:</u>

FEI evaluates and pursues potential opportunities in the marketplace if they meet the objectives of the ACP, as indicated below:

1. To contract for resources that appropriately balances cost minimization, security, diversity and reliability of gas supply in order to meet the Core customer forecast design peak day and annual requirements; and

2. To develop a gas supply portfolio mix, which incorporates flexibility in the contracting of resources based on short term and long term planning and evolving market dynamics.

It is important to note that FEI can identify and act on these market opportunities, but FEI is only one shipper among several others in the region, including utilities, gas producers, and large gas intensive industrial customers. These parties may have differing strategies or responses to the regional market conditions. As a result, FEI may pursue a solution to a regional issue or act on an opportunity in the market but that does not always necessarily translate into success.

43. Reference: Exhibit B-1, Appendix A page 1

> Additionally, the significant supply potential in Northeast BC (NEBC) has prompted the development of infrastructure initiatives to provide greater access to existing and new markets. With increasing demand from industrial, power generation and oil sands demand, and the need to replace supply declines elsewhere within Alberta, TransCanada PipeLines Limited (TransCanada) continues to bring forward plans to expand into NEBC to access the significant resource that is located there.

43.1 Please provide evidence of supply declines in Alberta and BC.

<u>Response:</u>

Please refer to the response to CEC IR 1.31.1.

43.2 How much production needs to be brought on stream to keep current production profiles flat?

<u>Response:</u>

Please refer to the response to CEC IR 1.31.1.

44. Reference: Exhibit B-1, Appendix A page 3

> resources have transformed the North American natural gas supply picture. In BC, the natural gas potential is second only to the Marcellus shale gas play that is being developed in the northeast region of United States. A recent joint study conducted by the NEB, Yukon Geological Survey, the Northwest Territories Geological Survey and the British Columbia Ministry of Natural Gas Development reported the estimated total potential of marketable gas in the Western Canadian Sedimentary Basin (WCSB) (discovered and undiscovered) is now 1,051 Tcf.[1] The 1,051 Tcf estimation is 230 Tcf higher than the NEB's previous estimate in 2013 of 821 Tcf.[2] Taking into consideration that annual natural gas demand in Canada is approximately 3.5 Tcf, the WCSB resource represents the equivalent of approximately 300 years of supply at the current consumption level.[3] The Montney formation in BC alone represents 271 Tcf of potential marketable natural gas.[4]

44.1 Please provide alternate sources for these facts.

<u>Response:</u>

Please refer to the response to CEC IR 1.31.1.

44.2 What are the strategies of the top gas producers?

<u>Response:</u>

Please refer to the response to CEC IR 1.31.1.

44.3 How much new production are these companies forecasting – and please provide an indication of the basin for the production?

<u>Response:</u>

Please refer to the response to CEC IR 1.31.1.

44.4 How much processing capacity is expected to come online over the next few years?

Response:

Please refer to the response to CEC IR 1.31.1.

44.5 How has changing NGL and gas prices impacted revenue for producers and costs for natural gas supply?

Response:

Please refer to the response to CEC IR 1.31.1.

44.6 How will the liquids potential from the middle & lower Montney impact natural gas supply potential?

Response:

Please refer to the response to CEC IR 1.31.1.

44.7 Please provide quantitative evidence of each NGL product historical and future supply and pricing?

Response:

Please refer to the response to CEC IR 1.31.1.

45. Reference: Exhibit B-1, Appendix A page 3

> As a result of the size of this resource and its attractive production economics, production of natural gas from basins located in NEBC has the potential to grow significantly in the coming years. This supply will be able to support existing markets in BC, as well as support potentially new markets (LNG and methanol exports) and meet growing industrial demand in Alberta, specifically from continued oil sands growth. However, the impact of these developments for FEI customers remains difficult to foresee with any accuracy because the quantity and timing of additional market demand and new matching transportation capacity remains uncertain.

45.1 What evidence is there that supports the supply will be able to support existing markets in BC?

<u>Response:</u>

Please refer to the response to CEC IR 1.31.1.

45.2 Can the basin continue to sustain current production volumes and for how long does FEI estimate this will continue.

<u>Response:</u>

Please refer to the response to CEC IR 1.31.1.

46. Reference: Exhibit B-1, Appendix A page 3

> The prospect of new markets for production has not developed as quickly as many producers active in the WSCB had hoped. Environmental and regulatory review and approval requirements have slowed the development of new markets for this gas. Also, the crash in commodity prices in 2014 has eroded the economic attractiveness of much of the LNG export development considered for NEBC. Producers have been able to manage through this period by focusing on further production efficiencies. However, continued production efficiency improvement is increasingly difficult to realize.

46.1 Please give quantitative evidence of the production efficiency improvement.

Response:

Please refer to the response to CEC IR 1.31.1.

47. Reference: Exhibit B-1, Appendix A page 3

> 2 Developing new supply in the Montney basin has increasingly been the primary focus of
> 3 producers active in the WCSB since new production technology made shale gas development
> 4 economically attractive over the past decade. Within the WCSB, sub-plays in the Montney
> 5 formation in BC have among the most attractive production economics in North America. As a

47.1 Based on corporate level break-evens, how much production could be at risk?

Response:

Please refer to the responses to CEC IRs 1.31.1 and 1.33.3.

47.2 Can anyone generate a full cycle return in this price environment?

Response:

Please refer to the responses to CEC IRs 1.31.1 and 1.33.3.

47.3 At what price level do well level economics appear favorable?

Response:

Please refer to the responses to CEC IRs 1.31.1 and 1.33.3.

47.4 In FEI's view, which formations within Montney sub-plays are the most attractive?

Response:

Please refer to the response to CEC IR 1.31.1.

47.5 What impact does the NGL yield and mix have on economic production for each of the potential supply basins?

Response:

Please refer to the response to CEC IR 1.31.1.

48. Reference: Exhibit B-1, Section 5.5.2 Page 146 Lines 2,3,4

Managing the risks associated with investing in reserves would be of paramount importance to FEI. These risks could include those relating to drilling, completing, and operating wells and would differ from typical regulated utility assets. This type of transaction would not provide the same degree of price certainty as a hedging or fixed price purchase strategy but would provide cost-based supply for a longer period.

48.1 Does FEI currently assume the risks associated with investing in reserves?

Response:

Please refer to the response to CEC IR 1.26.1.

48.2 Please provide a brief description of the relevant experience FEI has in evaluating and managing the risks described above.

Response:

Please refer to the response to CEC IR 1.49.1.

48.2.1 Please describe how FEI intends to manage these risks.

Response:

FEI is currently involved in initial discussions with gas producers to determine their interest in long term cost-based supply arrangements. FEI has not completed these discussions and so does not know how the risks related to drilling and production, if applicable, might be managed. As discussed in the response to BCUC IR 1.37.1, FEI is not actively exploring investing in reserves but is instead focusing on other types of long term arrangements. One important feature of any arrangement would be the ability to transfer risks to producers that are appropriate for a producer to manage, such as those relating to drilling and operating gas wells. However, this transfer of risks may not be acceptable to the producer or increase the capital investment required by the producer.

48.3 How long a period does FEI believe they can cover with a hedging or fixed purchase price strategy?

Response:

Please refer to the response to CEC IR 1.26.1.

48.4 Please explain how FEI intends to forecast and manage the cost of supply in the long term (i.e. beyond the period which can be covered with a long term hedging or fixed price purchase strategy).

Response:

Please refer to the response to CEC IR 1.26.1.

48.5 Please provide any relevant precedents for a regulated utility investing in natural gas reserves and assuming the risks described above.

Response:

Please refer to the response to CEC IR 1.41.2.

48.6 Please describe how FEI would intend to be compensated for assuming these additional risks.

Response:

Given that FEI has not yet had discussions with gas producers regarding any long term cost-based supply arrangements (described in the response to CEC IR 1.26.1), FEI does not have any details regarding the risks involved or possible compensation for assuming any risks relating to drilling and operating wells under an investing in reserves arrangement. Please also refer to the response to BCUC IR 1.37.1.

48.7 Please describe the benefit to FEI Customers of FEI investing in natural gas reserves.

Response:

Please refer to the response to CEC IR 1.26.1.

49. Reference: Exhibit B-1, Section 5.5.2 Page 146 Lines 6 and 7

FEI suggests that long term fixed price hedges better suit FEI's risk profile and field of expertise.

49.1 Why does FEI suggest that long term fixed price hedges better suit FEI's risk profile and field of expertise?

Response:

Long term hedges suit FEI's risk profile and field of expertise more than investing in reserves because FEI has extensive experience with fixed price hedging in the natural gas marketplace and understands the potential risks associated with market price movements and the potential hedging gains and costs and their refunding or recovery from customers through the cost of gas used to determine commodity rates. FEI does not have direct experience with natural gas drilling and operating gas wells or any other associated costs that may be related to gas production.

49.2 Please provide any economic evidence FEI has that long-term hedging certainty is over the long term an economic benefit to customers.

Response:

FEI has interpreted this question as asking if long term hedging can provide commodity rates that are lower than market gas prices, thereby providing an economic benefit for customers. FEI does not have any evidence that long-term hedging certainty is, over the long term, an economic benefit to customers in this regard. As with any hedging program, there is no guarantee of hedging gains. FEI's price risk management objectives are to mitigate market price volatility to support rate stability and capture market opportunities to maintain commodity rates at historically low levels, rather than 'beat the market'. However, with longer term hedging, FEI's customers could benefit from greater commodity rate stability and historically low, although perhaps not the lowest, commodity rates.

49.3 Please confirm that the hedging market expects to earn a significant return on providing future certainty.

Response:

FEI has interpreted this question as asking if companies involved in the hedging market that provide the fixed price offers to FEI for its hedging program earn significant returns. FEI cannot confirm that this is true. FEI expects that hedging buyers and sellers will incur hedging gains and costs from time to time, depending on gas market price volatility and general market pricing trends as well as the counterparty's market price risk tolerance and ability to mitigate its price risk exposure.

50. Reference: Exhibit B-1, Section 5.5.2 Page 146 Lines 7,8,9

However, at this point, FEI plans to investigate investing in reserves as a longer term strategy for helping to ensure security of supply and to provide cost stability.

50.1 Does FEI believe that the future market supply of natural gas may not be secure for its needs in any of its scenarios for the future? If not, please explain.

<u>Response:</u>

Please refer to the response to CEC IR 1.31.1.

50.2 Why does FEI believe that an investment in natural gas reserves by FEI would be more secure than long term gas supply from the market?

<u>Response:</u>

Please refer to the response to BCUC IR 1.37.1.

50.3 Does FEI believe that supply from its own reserves will be more reliable than gas supply from the market? If so, please explain.

<u>Response:</u>

Please refer to the response to BCUC IR 1.37.1.

50.4 Does FEI believe that supply from its own reserves could provide price stability and lower costs of supply for its customers in the future and if so under what conditions.

<u>Response:</u>

Please refer to the response to BCUC IR 1.37.1.

50.5 In its effort to provide cost stability by investing in reserves, does FEI take away, or reduce, the possibility of its Customers enjoying lower cost supply from the market, or does FEI believe it can provide supply to its Customers at a lower cost than the market?

Response:

Please refer to the response to BCUC IR 1.37.1.

50.6 Would FEI be competing with any of its Customers for the purchase of natural gas reserves? If so, how would FEI handle this potential competition, or perceived competition, with its Customers.

Response:

Please refer to the response to BCUC IR 1.37.1.

50.7 Is FEI provided with confidential information by its Customers relating to their natural gas reserves, their future plans for these reserves, or to support service requests from FEI? If so, please describe how FEI would ensure that this confidential information is not used, or perceived to be used, to compete with these Customers either for the natural gas reserves, or for service on the FEI system.

Response:

Please refer to the response to BCUC IR 1.37.1.

50.8 Please describe how FEI would ensure fair and equitable treatment, and the perception of fair and equitable treatment between gas supply from the market and gas supply from FEI's own natural gas reserves.

Response:

Please refer to the response to BCUC IR 1.37.1.

51. Reference: Exhibit B-1, page 149

Growth in peak demand is among the most significant challenges for FEI's long term planning. System expansion needs are driven by annual increases in forecast peak demand. A low gas commodity price environment and the use of cleaner natural gas over traditional fossil fuels are stimulating increased interest from the industrial sector in using natural gas for new or expanded applications, although this interest can change quickly as energy prices change. Growth in natural gas demand as a transportation fuel is also increasing as a result of these market conditions. At the same time, FEI's system sustainment planning process identifies important near-term and longer term system renewal requirements; most recently projects of this nature are underway in the Lower Mainland area of FEI's system. FEI takes a broad outlook that considers long term system capacity and sustainment plans, potential new, large increases in industrial load, and growing CNG and LNG demand, enabling an integrated approach to determining the most effective system improvements.

51.1 Please confirm that significant expense and planning is required for an industrial customer to switch fuels.

Response:

Not confirmed. The expense and planning required for an industrial customer to switch fuels can vary significantly depending on the customer. The cost and complexity associated with switching fuels depends on the number of burner tips and the ability of the end-use equipment to accept different fuel sources. FEI currently has customers whose facilities can already accept multiple fuels, so the ability to switch fuel is not necessarily expensive nor would it take significant planning. Conversely, some customers would require more expense and planning to switch fuels.

51.2 If confirmed, please provide an order of magnitude for the increase in energy prices that would be required to diminish interest in the use of natural gas for new or expanded applications.

Response:

Please refer to the response to CEC IR 1.51.1.

52. Reference: Exhibit B-1, page 153

- Long lead times are needed for large infrastructure projects. This is due to regulatory reviews, public consultation, conceptual design, and detailed engineering, procurement, construction and commissioning schedules.

52.1 Please provide an order of magnitude dollar value for a small, medium and large infrastructure project.

<u>Response:</u>

The cost of capacity driven infrastructure projects can vary widely depending on the scope of work, site conditions, and whether it is in an urban or rural environment. FEI does not have a formal established definition of what constitutes a small, medium or large infrastructure project. However, based on recent experience they could be roughly broken down as follows:

- Small: Up to $15 million
- Medium: $15-$60 million
- Large: greater than $60 million.

52.2 Please provide a rough approximation of the lead times that are needed for small, medium and large infrastructure projects as defined in 25.1 above.

<u>Response:</u>

The lead times for capacity driven infrastructure projects can vary widely depending on the scope of work, site conditions, public consultation and whether it is in an urban or rural environment. The very high-level lead times listed below include the time required to complete front end engineering design, obtain regulatory approval, complete detailed engineering, permitting, and procurement of long lead materials and equipment and construction contractors, construction, and commissioning. All stages of the project are assumed to progress sequentially and continuously with no delays due to external factors.

- Small infrastructure project: 2-4 years
- Medium Infrastructure project: 4-6 years
- Large Infrastructure project: 5-11 years

53. Reference: Exhibit B-1, page 154

> UPC_{peak} values used in the Traditional Peak Method forecast are determined based on current measured consumption for customers. When applied to the 20-year account forecast to determine the peak demand forecast, these values are assumed to remain unchanged over the planning horizon. As such, there is no explicit allowance for evolving customer utilization in this approach. The estimates of UPC_{peak} are, however, refreshed annually so that assessments of future capacity constraints are always determined against current customer consumption patterns and end uses that reflect the presently measured impacts of energy economics, housing renewal, and DSM programs.[145]

> The Traditional Peak Method forecast currently remains FEI's base forecast for determining infrastructure requirements and timing for addressing capacity constraints. For system capacity contingency planning in the 2017 LTGRP, FEI creates High and Low Traditional Peak Method forecast scenarios by applying high and low variations of its LTGRP customer forecast to the Traditional Peak Method's UPC_{peak} values. The method for developing the High and Low customer forecast perturbations is comparable to the method used for the annual demand forecast in Section 3.

53.1 Please provide FEI's historical average UPCpeak values for each rate class and for the system as a whole for the last 10 years.

Response:

Please refer to the responses to BCUC IRs 1.40.1 and 1.40.1.1 that provide the Traditional Peak Method UPC_{peak} values between 2007 and 2016.

53.2 Please provide a brief discussion of FEI's overall view of residential, commercial and industrial UPCpeak trends.

Response:

Please refer to the response to BCUC IR 1.40.1.1 for a discussion on the UPC_{peak} trends.

53.3 Why does FEI not consider and apply long term trends in UPCpeak to the 20 year account forecast for its long term infrastructure planning in addition to current customer consumption patterns?

Response:

As discussed in the response to BCUC IR 1.40.1.1, FEI's Traditional Peak Method results show that the UPC_{peak} values have remained relatively constant over the last decade. Therefore FEI believes that holding the UPC_{peak} values constant throughout a 20 year forecast period is the most reasonable approach supported by evidence for representing long term future trends at this time.

54. Reference: Exhibit B-1, page 156

> In forecasting peak demand associated with future CNG, for the VITS, CTS and ITS, FEI projected that incremental annual CNG demand of 200 TJ/year would trigger a new fuelling station somewhere in the system. A typical fuelling station designed to deliver up to 200 TJ/year is estimated to exert a peak hour demand of 2,200 standard m^3/hour. These peak demands are based on fast fill stations currently installed or being designed throughout the FEI system. The projected CNG facility demand is then distributed proportionally across the region and is included in each forecast. To illustrate the relative impact of CNG, forecasts with and without the CNG forecast included are shown in most demand forecast graphs in the following sections.

54.1 How many CNG fuelling stations does FEI currently support?

Response:

FEI supports a total of 26 CNG fueling stations located on FEI's distribution system. Most are located in the Lower Mainland. A breakdown of the CNG stations by region is below.

Region	Number of CNG Fueling Stations
Lower Mainland	16
Interior	5
Vancouver Island	4
Whistler	1

54.2 Are CNG stations currently evenly distributed throughout the FEI system or are they concentrated in certain regions?

Response:

CNG stations on the FEI distribution grid are primarily concentrated in the Lower Mainland, along key strategic transportation corridors and at return-to-base fleet sites. Please also refer to the response to CEC IR 1.54.1.

54.2.1 If concentrated in certain regions what regions are they concentrated in.

Response:

Please refer to the response to CEC IR 1.54.1.

54.2.2 If concentrated, does FEI expect the fuelling stations to continue to be concentrated in certain regions, or does FEI expect them to be more broadly based in the future? Please explain.

Response:

FEI's current CNG fueling stations are primarily concentrated along key strategic transportation corridors and at return-to-base customer sites mostly in the Lower Mainland. However, FEI expects that future growth in CNG demand and location of adopting customers will determine the precise locations of future CNG stations. For modelling purposes, FEI assumed that future CNG stations will be distributed based on potential station locations informed by discussions with customers, and proportionally allocated based on the average load distribution in each region. In 2016, the actual station regional CNG load allocation was:

Region	Percent Allocation 2016 CNG Load
Lower Mainland	77
Southern Interior	14
Vancouver Island	10
Northern BC	0
Whistler	0

FEI forecast a more broadly based future with an incremental load allocation per year of:

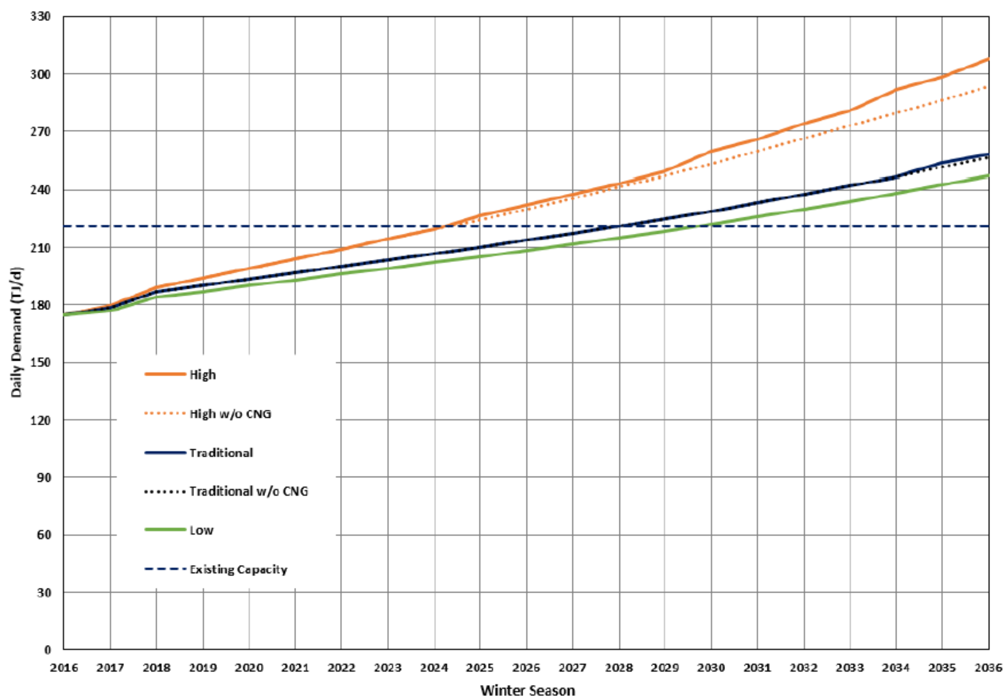
Region	Percent Allocation of Incremental Load
Lower Mainland	60
Southern Interior	20
Vancouver Island	10
Northern BC	5
Whistler	5

55. Reference: Exhibit B-1, page 159

VI Peak Demand Forecast (Traditional with Low and High Forecast Scenarios)

The VI regional peak demand forecast shown in Figure 6-3 below was analysed against Low and High demand scenarios. The Low and High demand scenarios were determined by applying high and low variations of the account forecast to the UPC_{peak} values derived in the Traditional Peak Method.[146] With respect to large industrial account additions, which traditionally have not been forecast because of the widely varied and unique demands of these customer classes, the high and low load forecasts represent an increase and reduction in industrial class customers, respectively. In order to approximate the UPC_{peak} for these customers, an average of existing customer UPCs in the region was used. In addition, the CNG forecast is included in the each forecast. Figure 6-3 shows that the Low and High scenarios move the VI capacity constraint back by two years to 2030, or advance it by three years to 2025. For comparison, the dotted lines show the peak demand forecast after removing the impact of CNG. In the case of the Low forecast the influence of CNG demand is negligible. Note that in Figure 6-3 there is a 5 TJ/d increase in demand in 2018. This represents BC Hydro Island Generation's contractual right to request a firm capacity of 50 TJ for 2018.

Figure 6-3: VI Demand-Capacity Balance Using Traditional, Low and High Peak Demand Scenarios



55.1 Please elaborate on how an average of existing customer UPCs in the region was used to develop the high and low load forecasts.

Response:

The same average UPC_{peak} that was determined by FEI's load gather process for the Traditional forecast, for customers with monthly consumption data, was used in both the Low and High forecasts. For customers with hourly billing (industrial rate schedules), no UPC_{peak} was calculated. The load growth in these rate schedules for the high and low forecast was proportional to the account growth in the rate schedules. The following paragraphs provide additional detail.

In its decision on FEI's 2014 LTRP, the BCUC requested FEI provide variable account forecasts, including industrial customers, based on different economic growth assumptions. See Appendix B-1 of the Application for an explanation of the method used to produce the high and low account forecasts. These account forecasts include core customers (Rates 1, 2 and 3) as well as increases or decreases in industrial account numbers. This variation in industrial accounts for the high and low forecasts is new for FEI's 2017 LTGRP and has not been done by FEI in previous resource plans. Industrial accounts continue to be held constant in the Traditional or Reference case forecasts. FEI determines UPC_{peak} for core customers (assumed residential/commercial but not industrial) whose metered consumption is read monthly and used in the annual load gather assessment. Please refer to BCUC IR1 39.1 for the details of the load gather process. The UPC_{peak} used for core customers for the high and low load forecast are the same values as were used in Traditional Peak Method. Only the growth in account numbers varies in the three forecasts, producing the load forecast variations.

For industrial customers, all of which have hourly metering available, the Traditional forecast is based on the observed hourly data or contractual limits for peak day quantities. As a result, an average UPC_{peak} for each rate class is not required or calculated. The peak values within these industrial rate schedules have a wide variation. Also in forecasting industrial load growth, assumptions about location and magnitude of load additions can influence the capacity the system has available to accommodate the load addition. In the Traditional load forecast, assumptions around how big or where the industrial load growth is eliminated by assuming that no changes occur to these rate classes over the forecast period. This allows the forecast to assess how capacity relative to core growth compares through the forecast.

To address the Commission's request to include varying account forecasts for the high and low cases, FEI also did not directly calculate an average UPC_{peak} for the each industrial rate classes or attempt to determine if more load should be added in some communities more than others as is done with the core rate classes. To determine industrial load for the forecast and for modeling the system capacity, the following three steps were implemented for each transmission system:

1. The industrial peak load in the base year for all industrial accounts in the transmission system was determined;

2. The annual industrial load contribution to the forecast each year was then calculated from the total industrial peak load in the base year multiplied by the incremental industrial account growth that had occurred to each year; and
3. For modeling, the annual industrial load addition was then further distributed among the regional gate stations throughout the transmission system proportionally to the load distribution that existed in the base year.

55.2 What period of lead time would be required for FEI to address a constraint such as the above?

<u>Response:</u>

Based on the current forecast, FEI would begin intensifying planning efforts around 2020 through 2024 for determining in more detail the most effective initial requirements to address the constraint.

55.3 Please discuss FEI's potential options for providing future capacity and FEI's best estimates of costs for these options at this time.

<u>Response:</u>

The Mt. Hayes LNG facility and the Peaking Agreement with BC Hydro Island Generation (IG) offer some flexibility in addressing the identified constraint on the VITS. The Peaking Agreement allows a curtailment of up to the Contract Demand (CD) for a couple of days up to a specified Curtailment Volume (CV). This CD can accommodate one peak day occurrence for the Traditional Peak Demand Forecast and the Low Peak Demand Scenario beyond the 20 year planning period. Further, when the CD is considered in combination with using the full send out capacity of Mt. Hayes, the peak day of the High Peak Demand Scenario can be met. However, over the course of a colder than normal winter where a peak day occurs, followed by additional peak or near peak days, the storage volume of LNG needs to be a consideration. For this reason, the addition of compression to move more gas from the Mainland through the VITS to avoid increasing the storage at Mt Hayes may be required (assuming the BC Hydro IG facility takes its full CD every day of this peak winter once their specified CV has been withheld). Adding compression near Squamish could be done when the constraint initially appears as indicated in Option 1 of Table 6-1 of the Application or more likely later in the forecast period as indicated in Option 2.

For the High Peak Demand Scenario additional projects could begin to be required starting in approximately 2030. Incremental compressor upgrades and additions may be required along with additional pipeline looping to maintain acceptable pressure at all points in the system.

Estimates for the options could range from $0 to $80 million to meet the Low Peak Demand Scenario or the Traditional Peak Demand Forecast and $220 to $650 million to meet the High Peak Demand Scenario. These costs are very high level at this time and do not consider routing or site specific conditions that could have significant impacts on the cost.

55.4 FEI's high load forecast scenario suggests the possibility of a constraint occurring approximately 3.5 years earlier than under the traditional method. How does FEI identify and ensure its ability to respond to constraints that appear earlier than anticipated under its traditional forecasting?

Response:

FEI prepares updated traditional account forecasts on an annual basis. Changes in account additions and UPC are incorporated into this annual iteration of the forecast. If results are actually tracking on a higher or lower trajectory than represented in a previous forecast, the new forecast adjusts the constraint timing and in subsequent years will generally begin to converge on the probable timing of the constraint. The constraint timing should be determined with a higher degree of confidence once it is within 4 to 8 years in the future. This process allows FEI to manage both an advancing or receding constraint. FEI will begin to escalate the level of assessment, refine alternatives and start engineering needed to address the constraint 4-5 years ahead of the constraint based on the scope of the proposed alternative solutions and perceived level of difficulty to execute. Refer also to the response to BCUC IR 1.40.3 for additional discussion.

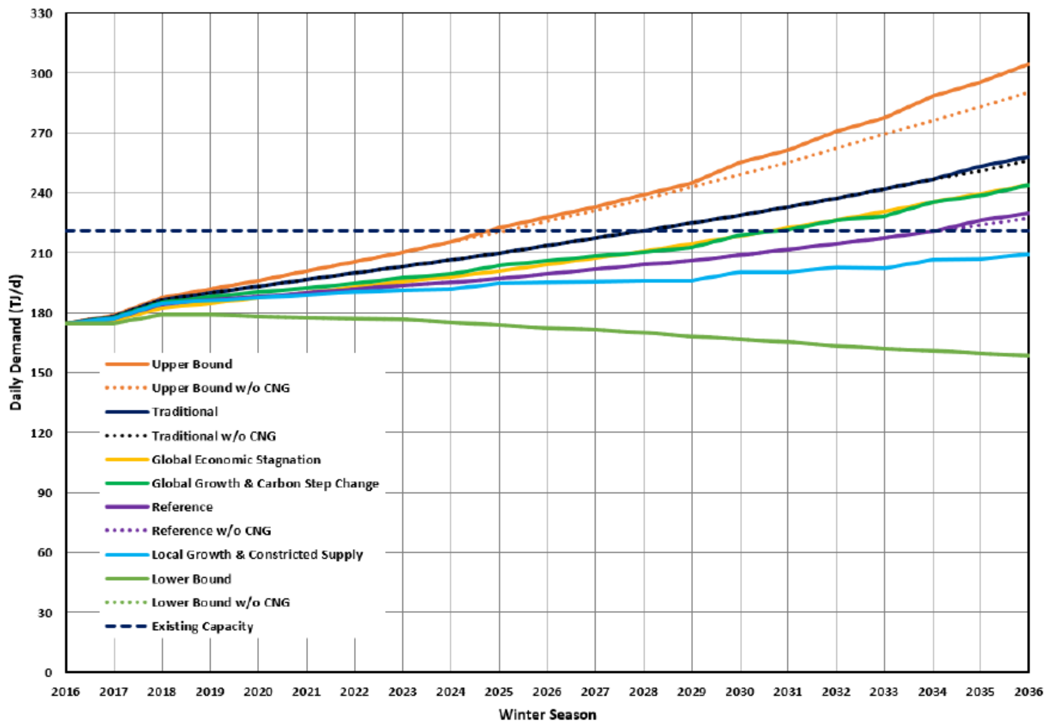
55.5 How does FEI ensure deferral of projects when the constraint occurs significantly later than anticipated?

Response:

Please refer to the response to CEC IR 1.55.4.

56. Reference: Exhibit B-1, page 162

Figure 6-5: VI Demand-Capacity Balance Using Traditional and End-Use Peak Demand Scenarios with DSM



VI System Expansion Alternatives

The identified capacity constraint in 2028 occurs six years after expiry of the FEI-BC Hydro Transportation Service Agreement (TSA) for service to BC Hydro's Island Generation facility. If FEI and BC Hydro extend the TSA beyond 2022, based on current Traditional forecast numbers, the VITS would have the following resource options to manage forecast demand for the Core and Firm Transportation customers (including the transportation requirements for the Vancouver Island Gas Joint Venture and BC Hydro Island Generation) and to thus address the capacity constraint that occurs in 2028:

56.1 Please briefly discuss how FEI's views of system capacity constraints have changed since the last LTRP.

Response:

FEI's estimate of the constraints in the VITS are similar to what was projected in the FEI 2014 LTRP. In fact, the timing of the projected constraint has remained consistent, and is projected in both plans at 2028. Load growth did not materialize in the intervening years 2012-2015 as was projected in the 2014 LTRP, but the current forecast while starting from a slightly lower base in 2015 is now projected to grow at a slightly higher rate through the forecast period. The higher growth rate projecting beyond 2028 in the 2017 LTGRP prompted some additional discussion of possible increased use of compression in the alternatives. This is identified as a means to limit the cumulative LNG send out from Mt. Hayes in winters in the latter part of the forecast.

56.2 Recognizing that FEI is relying on the traditional forecasting for peak system planning, the 'Local Growth & Constricted Supply' and 'Global Growth & Carbon Step change' end use scenarios both raise the prospect of significant reductions in the need for system capacity. Will FEI be taking any steps to determine if it is potentially on the path to such system capacity requirement reductions? Please explain.

Response:

Yes. The method developed for FEI by Posterity results in a set of UPC_{peak} values for each scenario that FEI can compare directly with the results of the annual load gather and Traditional peak forecasting. Please refer to the response to BCSEA IR 1.23.3.1 for additional discussion on steps to be taken.

56.3 Please provide an overview of what, if any system changes would be required to meet significantly reduced demand.

Response:

FEI's infrastructure does not have a minimum demand threshold that it requires to operate (i.e. the system can operate without adverse consequences with little or no demand); FEI's system is thus not expected to experience technical operation issues even under the 2017 LTGRP's Lower Bound demand forecast

56.4 Please provide an overview of what regulatory cost collection methodology changes FEI would consider in the event of significant and continuing capacity requirement reductions.

Response:

FEI does not anticipate changes to the cost collection methodology in the event of significant and continuing capacity requirement reductions and expects to continue to use FEI's revenue requirement and annual reviews to determine annual rate changes for all non-bypass customers. Significant and continuing capacity requirement reductions could change the peak demand requirements of some or all of FEI's rate schedules resulting in a different allocation of costs within FEI's cost of service allocation studies. Changes to the allocation of costs between rate schedules could influence rate rebalancing and rate design in FEI's future rate design applications.

57. Reference: Exhibit B-1, page 163

Table 6-1: Summary of VI Transmission System Expansion Portfolio and Timing

Demand Scenario	Option 1: Install Compressor near Squamish (V2)		Option 2: Increase Mt. Hayes Send-Out Allotment and Defer Squamish V2 installation	
High and Upper Bound	Install V2	2024	Increase Send Out	2024
			Install V2	2025
	Additional Compression and Install South Vancouver Island and Texada Island Pipeline Loops	2030	Additional Compression and Install South Vancouver Island and Texada Island Pipeline Loops	2030
Traditional	Install V2	2028	Increase Send Out	2028
			Install V2	2031
Reference	Install V2	2031	Increase Send Out	2031
			Install V2	2034
Low	Install V2	2030	Increase Send Out	2030
			Install V2	2034

In addition to capacity expansion on the VITS, there are two pressure control station additions served from new pipeline taps from the VITS that are identified for installation in the next few years to improve capacity in the growing distribution systems of Campbell River (Deerfield Road area) and Nanaimo (Extension Road area).

57.1 What criteria will FEI use to determine the appropriate course of action to address the prospective system constraint?

Response:

FEI will continue to monitor the projected timing of the capacity constraint. Closer to the time of the constraint, FEI will be able to assess in more detail the ability of the BC Hydro Island Generation (IG) Peaking Agreement, working in concert with Mt. Hayes send out capability, to defer the infrastructure installation further. This will include understanding with a better degree of certainty the Contract Demand that IG may require in the time following the constraint. The CD requested by IG can be a maximum of 50TJ/d but has varied and for example was 40 TJ/d in 2014 and is currently 45 TJ/d. Similarly, the number of days the facility will operate in the peak period would determine if the current LNG inventory can support the IG demand though the winter. If assessments at that time point to a need to supplement LNG volumes to continue to meet IG requirements, a determination for a course of action would be made at that time.

57.2 When will FEI make a determination as to the appropriate course of action?

Response:

Please refer to the response to CEC IR 1.57.1.

58. Reference: Exhibit B-1, page 164

> As a result of inquiries received, FEI is exploring developing the Utility's systems to accommodate transportation service for new, large industrial demand in various locations in its service territories. One such example in the VI service territory is a small scale LNG export and processing facility (Woodfibre LNG Project) located on the VITS at the former Woodfibre pulp mill site near Squamish. Woodfibre LNG Limited, a subsidiary of Pacific Oil & Gas, and FEI entered into a Development Agreement and, for a number of years, FEI has been carrying out development work, including a feasibility study, engineering, and exploring the regulatory and other approvals required to expand the VITS to provide a firm natural gas transportation service to the Woodfibre LNG Project. Woodfibre LNG Limited has presently indicated that it expects to require Firm Transportation service from FEI of up to 236 MMscfd on the VITS.[147] Should a final investment decision be made, the estimated in-service date of this facility is currently projected no earlier than 2021.

58.1 Please provide an approximation of the costs that FEI has incurred in conducting development work for the Woodfibre LNG project.

Response:

The development costs incurred by FEI on behalf of Woodfibre LNG are confidential at this time. However, it should be noted that Woodfibre is directly responsible for reimbursing FEI for all development costs should the project not proceed.

59. Reference: Exhibit B-1, page 169

Impact of Potential Future Demand for LNG Transportation Fuel

Natural gas demand for transportation consists of both the markets for CNG and LNG as vehicle fuel. Additional CNG load for transportation would be added in relatively small increments at various points on the system and has been included in the previous forecasts presented. In contrast, the greater potential demand and the point source nature of additional LNG production at Tilbury may create broader system impacts and could trigger the need for suitable system reinforcements of the CTS. The demand for natural gas from transportation sector fuel customers is forecast to continue growing over the next 20 years (see Section 3.4.7); the Lower Mainland area will likely drive LNG and CNG demand growth due to increasing road and coastal marine transport demand.

Based on FEI's natural gas demand forecasts for LNG, future phases of Tilbury LNG expansion beyond the current Phase 1A will need to be constructed. FEI's long term outlook must consider the system requirements for such an expansion.

Table 6-2: CTS Expansion Scenarios for LNG

Expansion Scenario	CTS Expansion Description	Max CTS Delivery to Tilbury Island, Delta
1	After CTS and LMIPSU projects	264 TJ/d
2	a) Add Replacement of 1.9 km NPS 6 feed to Tilbury Plant b) Add 15,000 HP to existing facility at Langley Compressor Stn.	436 TJ/d
3	a) Add 14.8 km NPS 42 Loop from Langley Compressor to Clayton Valve Stn. b) Add 15,000 HP to existing facility at Langley Compressor Stn.	577 TJ/d
4	a) Add 28.1 km NPS 42 Loop from Clayton Valve Stn. To Tilbury Area. b) Add 25 km NPS 42 Loop from Huntingdon to Langley Compressor Stn. c) Add 15,000 HP to existing facility at Langley Compressor Stn.	1,414 TJ/d

59.1 Please provide approximate costs for each Expansion scenario.

<u>Response:</u>

Expansion Scenario 1 was installed as the CTS Project in 2017 and is currently in service. These remaining infrastructure expansion scenarios are hypothetical. The actual scope and cost of future expansion of the CTS to address increased demand for LNG will be based on an assessment of need and circumstance that is present at that future time and will likely differ from the scenarios presented here. However, should incremental load requirements occur as outlined in the expansion scenarios, preliminary estimates indicate that:

- Expansion scenario 2 could cost approximately $90 to $130 million for pipe and compression,
- Expansion scenario 3 could cost approximately $250 to 375 million for pipe and compression, and
- Expansion scenario 4 could cost approximately $1.0 billion to $1.4 billion for pipe and compression.

These costs are very high level at this time and do not consider routing or site specific conditions that could have significant impacts on the cost.

59.2 Please provide FEI's LNG forecast or identify where it is in the application.

Response:

Figure 6-11 on page 172 of the Application represents the peak demand forecast and impact on the CTS of meeting the total annual demand including NGT (all sectors) shown in Figure 3-19 on page 89 of the Application. Figure 6-13 on page 175 of the Application represents the peak demand impact on the CTS of also meeting the "flow through" needs of a projected load like the Woodfibre LNG on the VITS. In the response to BCUC IR 1.43.3, FEI provided a revised Figure 6-3 showing the impact of the Woodfibre LNG facility on the VITS. Figure 6-13 and the revised Figure 6-3 represent the peak demand forecast and impact on the CTS and VITS for the annual demand shown in Figure 3-20 on page 90 of the Application. For the reason provided in Section 3.4.9 of the Application, this defines the extent to which an LNG forecast or other potential large new industrial demand can be represented within FEI's existing transmission systems. Please also refer to the responses to BCUC IR 1.8.2 and BCUC IR 1.21.5 for additional discussion.

59.3 Please provide a brief discussion of the underlying considerations for the LNG forecast or identify where it is in the application.

Response:

A detailed analysis and discussion is provided in FEI's LTGRP Section 3.4.7.2.1 regarding the long term LNG demand forecasts for the three different growth Scenarios.

59.4 Please outline the circumstances under which FEI's demand forecast for LNG would not materialize.

Response:

Generally speaking, the LNG demand forecasts would not materialize as modelled in the LTGRP if the key marine transportation markets, which make up the large bulk of the long term LNG demand, do not adopt LNG as a maritime fuel. Furthermore, if LNG does become a fuel of choice for the maritime sector but other bunkering (i.e. marine fueling) hubs develop LNG fueling capability for marine vessels before FEI, this could also impact the adoption of LNG sourced from BC.

In terms of LNG demand for all market segments, if the economic price spread between incumbent fuels (i.e. diesel/marine gas oil/marine fuel oil) and natural gas reduces to a level where the economic justification to adopt natural gas as a fuel no longer exists, this could also potentially jeopardize the adoption of natural gas as a fuel more generally across all various market segments.

59.5 If the LNG demand does not materialize, will FEI still construct future phases of Tilbury LNG expansion? Please explain.

Response:

Future phases of Tilbury LNG expansions will be assessed with greater scrutiny when the volume of customer demand surpasses the availability of LNG with the facilities currently being put into service at Tilbury.

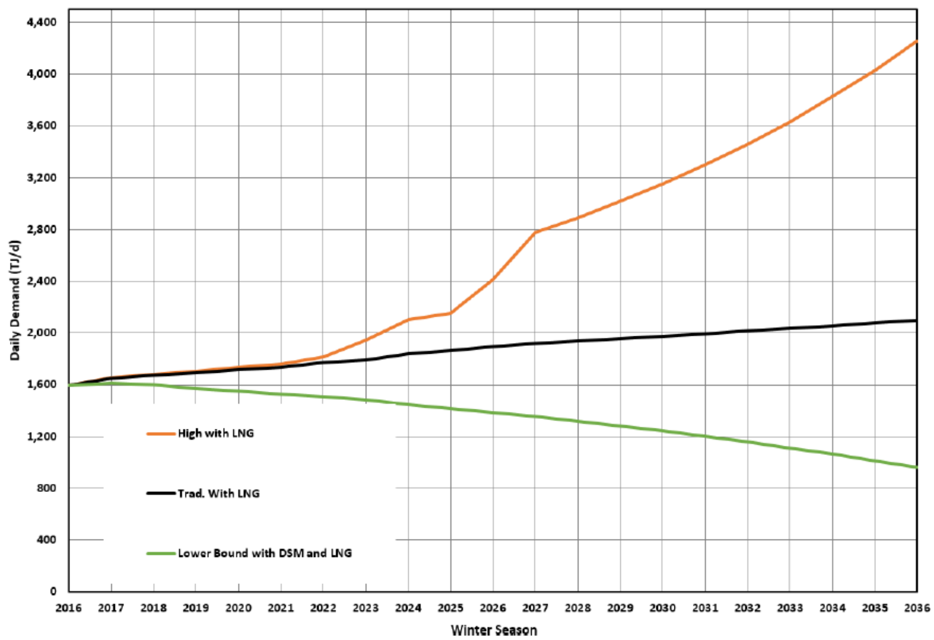
59.6 What criteria will FEI use to determine whether or not to proceed with the Tilbury expansion beyond the current Phase 1A? When will FEI make the determination?

Response:

Please refer to the response to CEC IR 1.59.5 for an explanation that includes customer demand volume and term of such new demand. The decision to proceed with subsequent expansions at Tilbury beyond Phase 1A will depend on the overall development of the long term customer demand for LNG from FEI. Please also refer to the response to BCUC IR 1.8.1.

60. Reference: Exhibit B-1, page 170

Figure 6-10: Impact of Traditional, High and Lower Bound (with DSM) on CTS Peak Demand Including LNG and CNG



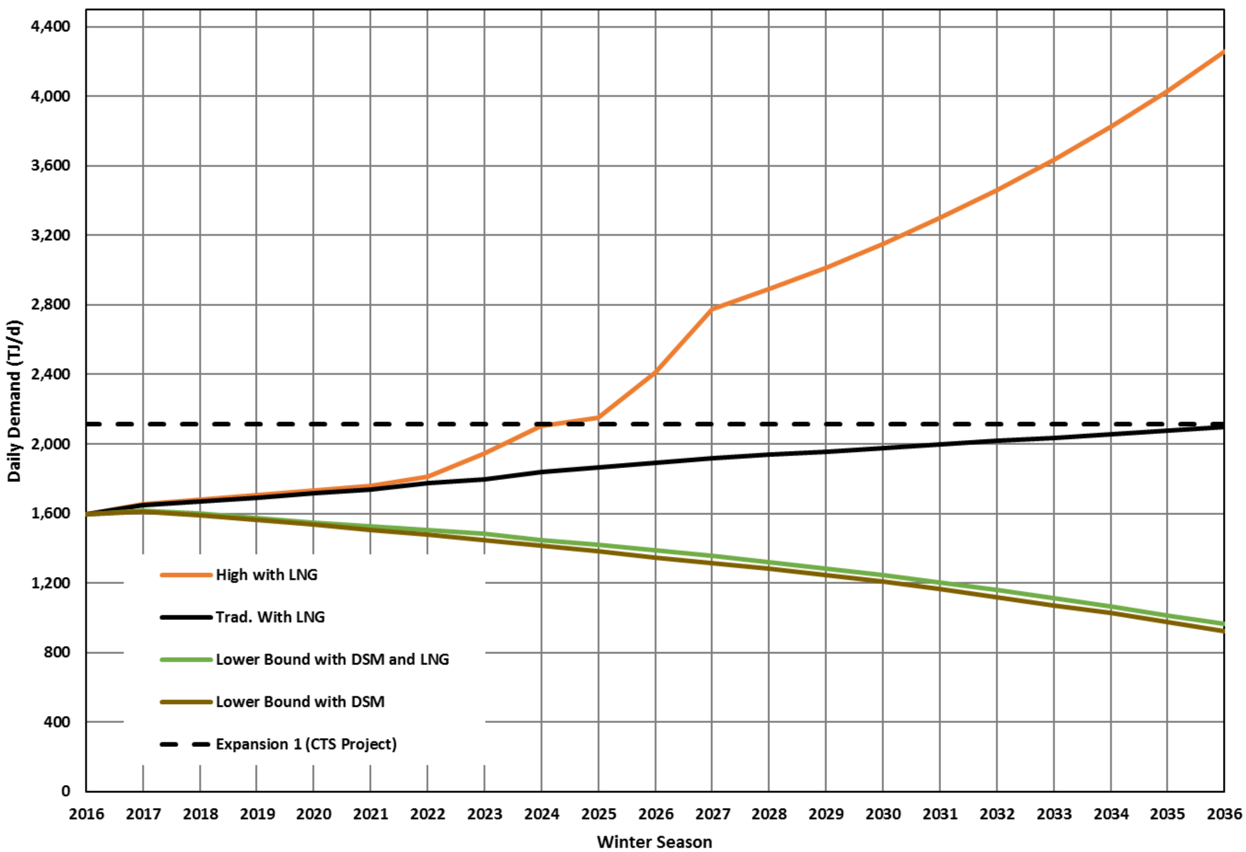
The peak demand forecasts shown have a very similar profile to the annual demand with LNG forecasts shown in Figure 3-18. The production of LNG is consistent throughout any day of the year and has no seasonal or daily peak. In practice, the actual peak demand that may occur on the CTS in any given period would be dependent on the liquefaction capacity installed at the LNG plant to meet the forecast. LNG liquefaction trains generally operate at a fixed production rate and, for reasons of efficiency, do not vary production rates substantially when in operation.

60.1 Please plot system capacity on the above graph.

<u>Response:</u>

A revised Figure 6-10 is presented below. To also address the response to CEC IR 1.60.2 the peak demand forecast for the Lower Bound with DSM (and no LNG) is also illustrated in the revised figure. FEI notes that the system capacity for the revised Figure 6-10 is the same as was identified on Figure 6-11 as “Expansion 1 (CTS Project)” in the Application and represents the current capacity of the CTS following the commissioning of the CTS Project in December 2017.

Figure 6-10 (Revised): Impact of Traditional, High and Lower Bound (with DSM) on CTS Peak Demand Including LNG and CNG



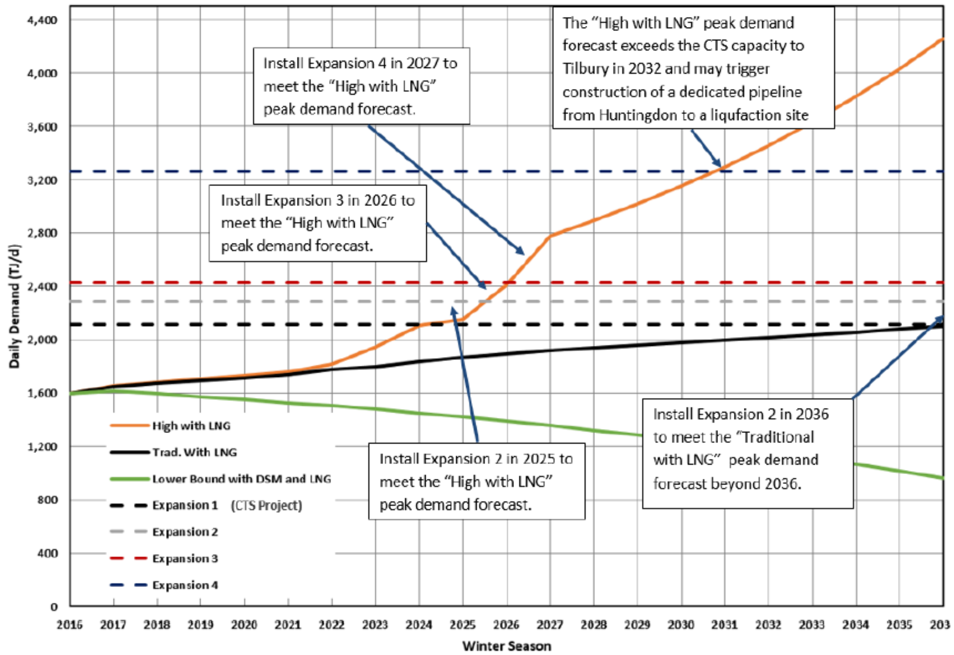
60.2 Please provide the above graph (with system capacity) with DSM and No LNG.

Response:

Please refer to the response to CEC IR 1.60.1.

61. Reference: Exhibit B-1, page 172

Figure 6-11: Phased Expansion of the CTS to meet LNG forecasts



Potential Large New Industrial Loads

The High forecast with high LNG demand includes forecasted industrial account additions distributed proportionally throughout the CTS. This captures generic typical industrial demand increases. However, a single large industrial customer can be large enough to disrupt this forecast and have an impact on any potential expansion plans. The specific requirements for system facility expansion are very dependent on the magnitude and location of any proposed large industrial consumer on the system. As discussed previously, the Woodfibre LNG Project facility, should it proceed, will be served from the VI Transmission System. This facility would impact the CTS as the CTS delivers the VITS requirements to the Eagle Mountain compressor facility in Coquitlam. Table 6-3 shows examples of how deliverability to the Tilbury, or other adjacent South Delta or Richmond locations might change should the Woodfibre LNG Project

61.1 Please briefly discuss how FEI's views have changed with regard to expected capacity constraints on the CTS system since the last LTRP.

<u>Response:</u>

As discussed in Section 6.3.2, page 166 of the Application, in the intervening years since the 2014 LTRP FEI has commissioned the CTS Project, 10.9 kilometres of transmission pipe looping key sections of the CTS. The CTS Project loops single points of failure that were identified in the 2014 LTRP. Each loop improves the security of supply to large numbers of customers in the CTS and VITS. The CTS Project enables the expansion of LNG at the Tilbury site and included the pipeline loop required to address the capacity constraint identified in the

2014 LTRP. BC Hydro's Burrard Thermal power generation plant was decommissioned in 2016. The capacity that was used to serve the Burrard Thermal load will now be used to serve the first phase of expansion of the Tilbury LNG facility (Phase 1A) in 2017 and the potential future Woodfibre LNG load. As a result, the CTS has sufficient capacity to meet the load growth projected in the Traditional Peak Demand Forecast and all other Peak Demand Scenarios representing Core and Transportation customer growth on the system with some additional capacity to meet some of the LNG or other large industrial demand as depicted in Figures 6-11 and 6-13 of the Application.

61.2 What criteria will FEI use to make the determination as to whether or not it needs to proceed with any expansion scenarios to meet the 'High with LNG' forecast?

Response:

Similar to the discussion in the responses to CEC IRs 1.59.5 and 1.59.6 regarding future expansion phases of Tilbury LNG, the necessary expansion of the CTS will occur when demand materializes that exceeds the present capacity of the system. Expansions occur on the system when there is insufficient capacity to meet current and projected loads during peak or extreme weather due to core load growth and additions of new loads such as liquefaction expansion at Tilbury or other large industrial demand.

Expansions may also be conducted to reinforce parts of the system in areas where the loads have increased on a consistent basis so that the system can be operated reliably, while also allowing the flexibility to shift gas flows to accommodate necessary maintenance and inspections of system assets. System reliability is a vital part of FEI's core values in order to ensure that customer and stakeholder disruptions are minimized or avoided altogether especially during the winter months and cold weather extremes.

61.3 What size of potential large new industrial loads would be required to influence the construction or construction timing of the Expansion scenarios?

Response:

The first row in Table 6-3, page 174 of the Application provides some indication of the loads that would trigger an expansion of the CTS now that the CTS Project has been commissioned. In this table, Row 1 is valid if the new load is in the vicinity of Richmond/South Delta in the Lower Mainland and additional loads on the VITS are as described in the column headers in the table. If load is added at other locations in the CTS, the effect on capacity and the need for expansion may be different. Please also refer to the response to CEC IR 1.61.2.

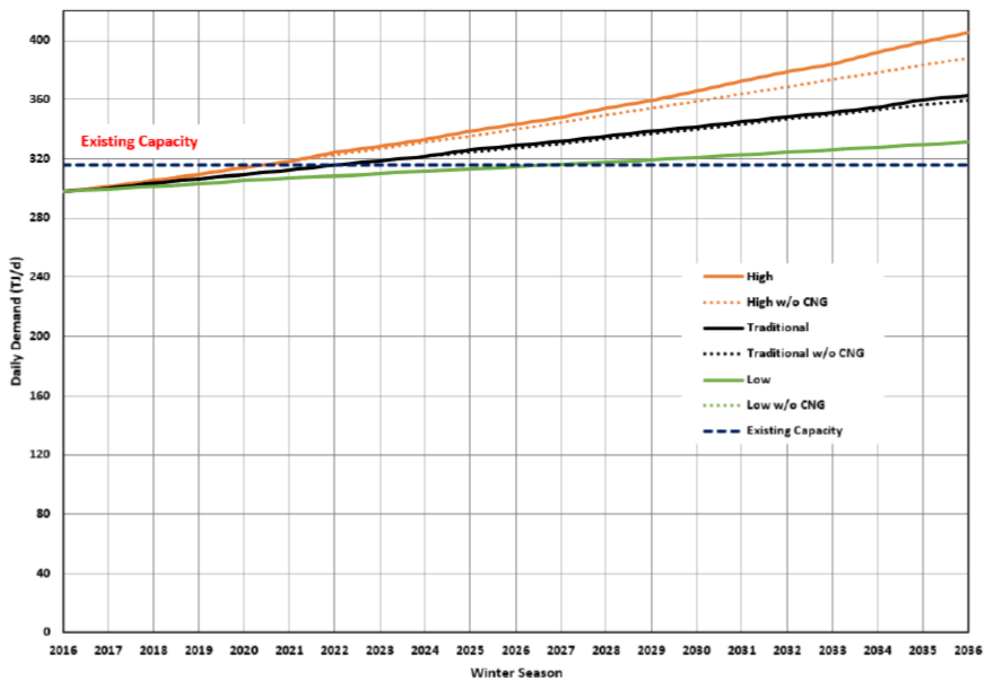
61.4 When will FEI make the determination that it will use the expansion scenarios meet the 'High with LNG' peak demand forecast?

Response:

FEI would like to emphasize that, with the exception of Expansion 1 that represents the CTS Project, already commissioned in 2017, the expansion scenarios shown in Figure 6-11 are hypothetical. These scenarios were used to illustrate the effect of certain combinations of pipe and compression to address load additions at specific locations in the CTS. Determination of the scope and timing of a future expansion of the CTS will be based on the magnitude and timing and location of any load additions that firmly materialize in the future. It is unlikely that future expansion of the CTS will align in scope directly with any of these hypothetical expansion scenarios. Please also refer to the reply to CEC IR 1.61.2.

62. Reference: Exhibit B-1, page 177 and 179

Figure 6-15: ITS Forecast Demand and Capacity Curves - Traditional, High and Low Scenarios



ITS System Expansion Alternatives

Four reinforcement alternatives have been identified to meet the Traditional case demand forecast:

OPTION 1 – OKANAGAN REINFORCEMENT SOUTH LOOP FROM ELLIS CREEK WITH ADDITIONAL COMPRESSION

The first alternative solution to address the capacity constraint in 2022 is installation of a NPS 20, or 508 mm, diameter pipeline loop that follows the existing pipeline right of way, running from Ellis Creek (Penticton) to north of Naramata, a distance of approximately 28 kilometres. This pipeline looping would be accompanied by an additional compressor unit at Kitchener-B compressor station and would increase gas supply delivered from the TransCanada Pipeline at Yahk via the SCP. In 2035, the Kelowna #1 lateral (consisting of both 4 and 8 NPS pipelines on the lateral) would have to be upgraded to dual NPS 8 pipeline (i.e. remove existing NPS 4 and replace with NPS 8)

62.1 Please provide a rough estimate of the costs associated with each option.

Response:

ITS reinforcement alternatives to meet the Traditional case demand forecast are currently being evaluated to determine feasibility and cost. Preliminary estimates indicate that the various options being considered range in cost from $50 million to $140 million. These costs are very high level at this time and do not consider routing or site specific conditions that could have significant impacts on the cost. A CPCN application for this project is anticipated to be filed in 2020 and will contain additional details and cost estimates for each of the alternatives being considered.

62.1.1 Please briefly discuss how FEI's view of the ITS system capacity has changed since the last LTRP.

Response:

FEI's assessment of the ITS capacity and the capacity constraint has changed between FEI's 2014 LTRP and the current 2017 LTGRP. In the 2014 LTRP, FEI was projecting that the load growth on the ITS would exceed the capacity of the ITS and require capacity upgrades before the winter of 2018-19. Currently, in the Application upgrades are required before the winter of 2022-23. Between resource plan filings, FEI's annual updates to the forecast indicated that new account/load growth projections supported a deferral of the project and also that the peak load estimate in the Central Okanagan region needed revision. Delivery pressures to Gate Stations delivering gas to the communities of the Okanagan region are the trigger to defining the capacity of the ITS. This is because the Okanagan is remote from the major supply points on the system, Savona in the West and Yahk in the East Kootenays. Pressures on a peak day are therefore the lowest in the system at Gate Station locations in the Okanagan. In the period between 2014 and 2017, FEI adjusted the peak hour factor (PHF) for the Central Okanagan. An assessment of the peak hour to peak day ratio of flow at the local gate stations that determines the PHF no longer supported the larger ratio, so the number was revised to reflect a slightly smaller peak. Another significant change was a reduction to the design temperature or design degree day (DDD) for the region. This change resulted from an extreme value analysis of the last 60 years of weather data. For the central Okanagan, updating this analysis resulted in a reduction in the DDD of 1.1 degrees Celsius and a corresponding reduction in the UPC_{peak}. The result of these various factors has adjusted how load growth and distribution on the system influences available capacity and has resulted in FEI adjusting the timing of the infrastructure investments required to address the capacity constraint.

The types of alternatives presented in the current Application are similar to those in the FEI 2014 LTRP with some adjustment to scope and timing reflecting the forecast changes in the intervening years. The 2017 Application identifies another alternative, identified as Option 2, which is also currently being assessed. This alternative addresses the constraint through targeted upgrades to segments of the ITS in the south Okanagan that limit operating pressure. By increasing operating pressure longer pipeline loops may be avoided.

63. Reference: Exhibit B-1, page 184

> FEI has identified Revelstoke's satellite propane system as a potential opportunity to convert the community from propane to natural gas. FEI has conducted an internal pre-feasibility study on using LNG from Tilbury for a possible conversion from propane to natural gas using a satellite LNG station at Revelstoke. Converting the town of Revelstoke from propane to natural gas could provide GHG emission reduction benefits. Based on current propane consumption levels of FEI's Revelstoke customers, the community's GHG emissions would fall by 2,019 metric tonnes of carbon dioxide equivalent (CO_2e) per year.[149] At this point, economics do not support this conversion but FEI will keep monitoring this potential opportunity.

63.1 Please provide a brief overview of the economics and cost-effectiveness of converting Revelstoke's satellite propane system to natural gas and provide a total expected cost.

Response:

A determination on whether to convert Revelstoke's Propane system to natural gas is complex and is affected by factors such as energy policy and greenhouse gas impacts, strategic direction, energy prices, capacity requirements, demand, capital costs, operational costs and logistics. At the time (2015/2016) that FEI was assessing the conversion project the estimated capital cost was approximately $22 million which included LNG storage, vaporization and conversion of customer appliances to be able to accept natural gas, as well as operational and transport costs of LNG to Revelstoke from FEI's LNG production facility at Tilbury. The economics and cost-effectiveness evaluation considered involved a comparison of the decrease in Revelstoke customers' annual energy costs and the cost to all FEI ratepayers from the incremental capital and operational costs.

At this time, converting Revelstoke's distribution system to piped natural gas and installing an LNG storage and vaporization plant in place of the propane plant is not being considered; therefore FEI cannot provide a date as to when a determination will be made for this project. At this time FEI is reviewing other alternatives.

63.2 When does FEI expect to make a determination as to the appropriateness of converting the satellite propane system to natural gas.

Response:

Please refer to the response to CEC IR 1.63.1.

64. Reference: Exhibit B-1, page 197

> Another important limitation to describing FEI's long term vision is the degree of detail that can be included. The Commission's directive was made at a time when the outlook for natural gas supply resources and long term gas price forecasts was different than it is today. The 20-year vision directive does not appear to have contemplated the government's shift in emphasis to the development of natural gas resources and a provincial LNG strategy, for exports, economic development, job creation and global emission reductions. As outlined in Section 2, FEI has developed the current 2017 LTGRP within a planning environment that is characterized by continued high policy uncertainty. A long term vision thus cannot be made so specific that it does not allow for changes in the planning environment.

64.1 Please elaborate on FEI's views as to the current provincial LNG strategy.

Response:

FEI supports the current provincial LNG strategy. The Government of British Columbia has stated it welcomes investment in natural resource projects provided that they:

- Guarantee a fair return for B.C.'s natural resources.
- Guarantee jobs and training opportunities for British Columbians.
- Respect and make partners of First Nations.
- Protect B.C.'s air, land and water, including living up to the Province's climate commitments.

FEI believes that LNG export from the Company's Tilbury facility meets the criteria listed above. Furthermore, the BC Government has announced a provisional framework to enhance the competitiveness of BC's LNG Sector that includes the following:

- PST exemption on construction costs of the LNG facility. However, the government will recapture foregone revenues once the project is up and running.
- Carbon tax treatment consistent with that provided to all large industry: rebate on new / additional carbon tax.
- Supply electricity at the standard industrial rate.
- Repeal the LNG income tax.

These commitments are provisional based upon LNG Canada making a positive final investment decision by November 2018. Preliminary indication from Government is that any LNG proponent, including FEI, will operate under the same fiscal framework.

65. Reference: Exhibit B-1, page 200

8.2.4 RNG and other Innovative Natural Gas Technologies

Section 3.4.6 discusses the annual demand impact of RNG across the 2017 LTGRP's alternate future scenarios. Even FEI's high assumption of RNG demand results in RNG accounting for a small proportion of FEI's total annual demand (less than three million GJ, compared to a maximum allowance of approximately 8.9 million GJ under the GGRR, as discussed in Section 2.3.3.4) by the end of the planning horizon. However, this analysis assumes current RNG supply technologies. If cellulosic biogas technologies become commercially scalable at reasonable cost, RNG demand may account for a significant share of FEI's demand within 20 years.

Similarly, other technologies exist that may decarbonize the natural gas stream and enable the natural gas infrastructure to store electric energy (indirectly by injecting into the pipeline system hydrogen derived via electrolysis), decarbonize natural gas end-use appliances or increase beyond 100 percent the efficiency of natural gas appliances. Section 2.4.3 outlines how FEI is

monitoring and, where applicable, supporting the evolution of such technologies. If such technologies become commercially scalable at reasonable cost, they may mitigate policy-driven risks of downward pressure on natural gas demand (identified in Section 2) and create an investment opportunity for the Company. As such, FEI, its customers, and the public would benefit from FEI having access to a funding envelope that FEI can use to monitor, and where applicable, support such innovative natural gas technologies. FEI's 2017 LTGRP stakeholder engagement activities suggest that stakeholders support FEI monitoring and, where appropriate, supporting such technologies.

65.1 Please provide FEI's views as to what would constitute a 'reasonable cost' such that RNG demand may increase significantly.

<u>Response:</u>

To FEI, a reasonable cost means an appropriate overall cost that considers the production price of the RNG commodity, while also accounting for Company and societal benefits such as support for government policy, ability to achieve Provincial GHG reduction objectives, avoidance of infrastructure duplication, and supporting the viability of alternative renewable energy sources. FEI cannot specifically state what that price or price range is at this time as it depends on many changing variables and will change over time.

65.2 Please provide a brief discussion of the types of technologies that are being developed that could potentially become scalable at reasonable cost.

Response:

Please refer to the response to BCSEA IR 1.1.1.

65.3 What size of funding envelope would FEI consider appropriate to assist in supporting innovative natural gas technologies? Please provide an order of magnitude estimate.

Response:

The magnitude of any future funding envelope has not been established at this time.

Attachment 29.1

Diane Roy
Director, Regulatory Affairs

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September 24, 2014

Via Email
Original via Mail

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. (FEI or the Company)

Amendment to the 2014/2015 Annual Contracting Plan (2014/15 ACP)

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On May 1, 2014, FEI filed, on a confidential basis, its 2014/15 Annual Contracting Plan. The Commission accepted the 2014/15 ACP on July 17, 2014.

Due to recent changes in market conditions affecting the future level of firm transportation contracting on the Spectra T-South system, FEI requests approval to amend the 2014/15 ACP in order to secure additional firm T-South transportation capacity for Rate Schedule 46 and industrial transportation customers seeking to return to bundled service.

Changing market conditions are occurring in response to a number of new industrial projects wanting to secure T-South transportation capacity on the Spectra system. In response to this change, Spectra is considering introducing a new service that would allow shippers to secure T-South capacity in the future. This new service will facilitate the orderly marketing of existing uncontracted T-South Huntingdon capacity and provide prospective markets with greater certainty that pipeline capacity will be available for future needs. This new service would provide shippers with another means of securing capacity for future use, in addition to the Bid Week process (13 month service) that is currently available.

It is expected that this new service from Spectra will require parties to make a commitment for a minimum of 10 years to secure T-South capacity and will provide the option to defer the commencement date of the first flow for a period of up to a maximum of 48 months. This commitment level is considerably greater than the two year renewable service that is currently available to parties under the 13 month Bid Week process. This new service should be of interest to shippers who need to secure firm transportation capacity to support industrial projects that will bring significant incremental loads to the region. However, committing to a 10 year contract may be difficult for some industrial customers currently participating in the FEI transportation model given the need to demonstrate credit worthiness that is required to secure firm transportation capacity.

Request for Acceptance

FEI seeks Commission approval to secure an additional 75 TJ/d of firm Spectra T-South transportation capacity for the winter of 2015/16 for Rate Schedule 46 and industrial customers. This new capacity would be secured either entirely during the next Bid Week or in stages over future Bid Weeks depending on developments affecting current market conditions. The next opportunity to bid for firm capacity on T-South is during the Bid Week that commences on October 1, 2014 and ends on October 7, 2014. Following this Bid Week in October, future Bid Weeks start on the first Wednesday of each month.

The total biddable capacity is adjusted for each Bid Week to reflect the amount of non-firm capacity remaining after accounting for firm capacity commitments. The advantage of securing firm capacity during these periods is that it will not start for 13 months. For example, for firm capacity secured during the October 2014 Bid Week, capacity will start to flow on November 1, 2015. Thus, there are no costs until the service starts. Although the service only has a two year commitment in order to secure renewal rights, FEI would secure this capacity for a minimum five year term in order to receive the maximum discount available at this time.

FEI requests an expeditious review of this request and requires a Decision no later than Friday, October 3, 2014. This timing is critical because it would allow FEI to participate in the next Bid Week before it closes (October 7, 2014).

Reasons for the Request

Earlier this month Spectra proposed a new service that involves offering shippers the ability to lock-in existing non-firm T-South Huntingdon capacity for the long term and well before the service commencement date. The offering of this service is driven by new demand from projects either announced or being considered in the Lower Mainland and US PNW that will require pipeline capacity as early as 2016/17.

A significant volume serving industrial customers in the Lower Mainland flows on an interruptible basis today. Any major decrease in the future availability of transportation capacity risks leaving these customers without adequate gas supply or they will need to pay significantly higher commodity prices at Huntingdon before any infrastructure expansions can be completed[1]. Given that these industrial customers may not generally have sufficient credit to secure long term firm transportation capacity, and have not made a commitment to

[1] This industrial load includes Rate Schedule 22, 23, 25, and 27 customers.

hold transportation capacity in the past, FEI faces the potential that these industrial customers will seek to return to it for bundled service. Importantly, this industrial load competes for T-South transportation capacity with industrial load located in the US PNW, which underscores the urgency in being in a position to be able to secure capacity soon.

The availability of sufficient T-South transportation capacity could also affect Rate Schedule 46 customers given the timing of when incremental supply is needed to serve them. The market change driven by Spectra's new service offering requires additional transportation capacity for these customers to be contracted for now rather than waiting. Rate Schedule 46 customers are forecast to require approximately 4 TJ/d by November 2015 and 9 TJ/d by November 2016. This volume is expected to increase as more customers enter into agreements for Rate Schedule 46 service. To serve this new demand, requires FEI to secure the equivalent transportation capacity to match the 35 TJ liquefaction capacity that is being constructed at Tilbury to serve this market.

It is for these reasons that FEI believes it is appropriate to secure new T-South capacity now for these two markets.

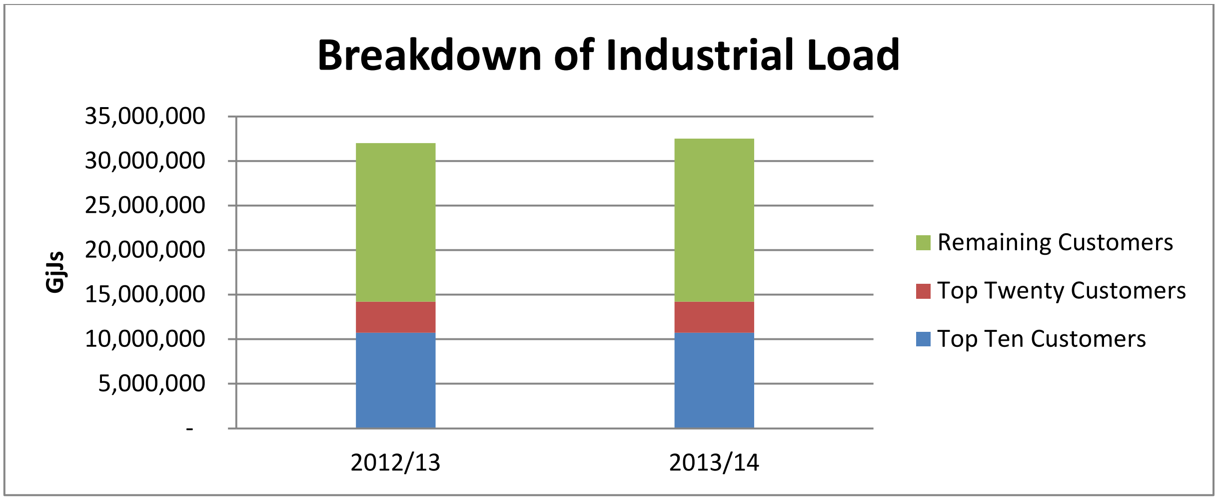
Analysis

The industrial demand under consideration is for Rate Schedule 22, 23, 25 and 27 customers located in the Lower Mainland only. Large industrial customers on Vancouver Island, like the Joint Venture and BC Hydro, are assumed to be directly involved in evaluating Spectra's new service offering and in a position to adequately respond to the pending market change. As a result, FEI has not included their volumes in its analysis.

Interior industrial customers on the FEI system are not at risk because alternatives are in place to serve their loads. Additionally, the competition for T-South Long Haul should not impact their ability to secure additional T-South Interior capacity should they chose to do so.

A review of actual consumption of Rate Schedule 22, 23, 25 and 27 customers located in the Lower Mainland over the last two years indicates that peak demand day occurred on February 5, 2014 when it reached 160 TJ. Although peak demand day reached 160 TJ, FEI does not believe is it necessary to pick up additional firm transportation capacity to match this full amount.

As shown in the following graph, the top 10 Lower Mainland industrial customers consume approximately 11 PJ annually or 30 TJ/d, which accounts for 33 percent of the total load. The combined top 20 industrial customers account for approximately 15 PJ or 40 TJ/d, which accounts for 44 percent of the total load. Given their size, FEI assumes that it is likely that these customers will be proactive in ensuring they have supply secured so that the entire load represented by these customers will not need to be served by FEI. Although these large volume customers are expected to adequately respond to this issue, FEI still faces the possibility that a lack of sufficient credit worthiness by some of these customers will result in them seeking to return to bundled service.



After adjusting the recent peak day demand of 160 TJ for load from larger customers, indicates that a portion of approximately 120 TJ would most likely need to be served. Given the uncertainty in estimating how many industrial customers may elect to return to bundled service, FEI believes it is reasonable to secure firm transportation capacity only for approximately one-third of this industrial demand, or 40 TJ/d, combined with the 35 TJ liquefaction capacity for Rate Schedule 46 service. Combined, these two requirements total 75 TJ/d and would be contracted for on a firm basis for a minimum five year term.

FEI will continue to monitor this situation, and as pointed out earlier, this new capacity would be secured either entirely during the next Bid Week or in stages over future Bid Weeks depending on developments affecting current market conditions. Furthermore, depending on how the market unfolds, FEI may need to secure still further T-South capacity in the future to serve this industrial demand. For now the request for additional T-South capacity is limited and would only serve a portion of the load if all of these customers return to a bundled service from FEI.

Incremental Costs

The following table sets out the total cost and the estimated mitigation value of the 75 TJ/d in incremental T-South transportation.

Cost Analysis for Additional Volume on T-South (Future Increase in T-South Capacity)			
$0.36/GJ *(Spectra Toll)*	75,000 GJ/d *(Incremental Volume)*	365 *(Days)*	$9.86 million (Approx. before mitigation)
$0.36/GJ *(Winter Mitigation)*	75,000 GJ/d *(Incremental Volume)*	151 *(Days)*	$4.08 million
Net Incremental Cost			$5.78 million

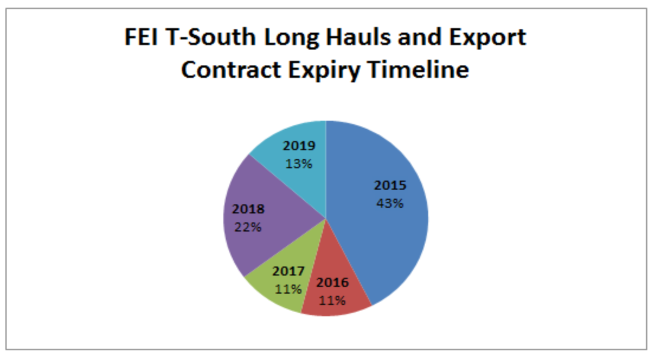
The addition of 75 TJ/d of incremental T-South transportation capacity will result in a total cost of approximately $10 million. FEI expects that T-South will continue to hold value in the winter time so it is reasonable to expect full recovery of the demand charge in the winter period. FEI has not assumed any summer mitigation value, even though some value was realized over the last few summers. Net of the recovery during the winter, the incremental cost of the entire 75 TJ/d in T-South transportation capacity is estimated to be approximately $6 million. The impact of the incremental volume to midstream costs, considering an estimated total volume of 126 PJ, would be approximately 5 cents /GJ.

Additional Capacity Mitigation Options

Should market developments proceed at a pace that do not result in a significant increase in additional firm transportation capacity being contracted, then FEI is able to defer entering into firm contracts and defer this for one or more Bid Weeks. This delay would result in avoiding the payment of firm transportation tolls for one or more months after November 2015.

Alternatively, should industrial customers not return to FEI in sufficient numbers to use the full 75 TJ/d in transportation capacity, FEI's contract portfolio offers the flexibility to either allow existing contracts to roll off, or decrease the contracted amounts once they are up for renewal. The table below shows the existing profile of T-South Long-Haul and Export Contracts, and when they would be renewed.

FEI T-South Contract Expiry Timeline			
Year	10^3M^3	GJ	%
2015	4,126.40	157,835	43%
2016	1,108.70	42,408	11%
2017	1,045.10	39,975	11%
2018	2,109.40	80,685	22%
2019	1,310.10	50,111	14%
Total	9,699.70	371,014	100%



Summary

With the recent changes occurring in the market for firm transportation capacity on T-South, FEI recommends acting proactively by contracting for an additional 75 TJ/d of capacity on T-South for a minimum five year term. Contracting for this capacity may occur as early as during the next Bid Week that is planned to start on October 1, 2014, with the actual contracted volume to be determined by FEI based on evolving market circumstances faced when the Bid Weeks take place. FEI has flexibility in its contracting portfolio to manage this additional transportation capacity by using it to replace expiring future contracts if sufficient demand does not materialize for all of this capacity.

This approach to securing additional firm transportation capacity is appropriate given the changing market conditions faced at this time.

~~CONFIDENTIALITY~~

Consistent with past practice, previous discussions and positions on the confidentiality of selected filings (and further emphasized in FEI's January 31, 1994 submission to the Commission), FEI is requesting that this information be filed on a confidential basis pursuant to Section 71(5) of the Utilities Commission Act and requests that the Commission exercise its discretion under Section 6.0 of the Rules for Natural Gas Energy Supply Contracts and allow these documents to remain confidential. FEI believes this will ensure that market sensitive information is protected, and the ability of FEI to obtain favourable commercial terms for future natural gas contracting is not impaired.

FEI further believes that the Core Market could be disadvantaged and may well shoulder incremental costs if utility gas supply procurement strategies as well as contracts are treated in a different manner than those of other gas purchasers, and believes that since it continues to operate within a competitive environment, there is no necessity for public disclosure and risk prejudice or influence in the negotiations or renegotiation of subsequent contracts.

If you require further information or have any questions regarding this submission, please contact Hans Mertins at (604) 592-7856.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments