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Our File: 23841/0183

April 6, 2018

VIA ELECTRONIC MAIL

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C. V6Z 2N3

Attention: Patrick Wruck, Commission Secretary and Manager, Regulatory Support

Dear Sirs/Mesdames:

Re: FortisBC Energy Inc. – 2017 Long Term Gas Resource Plan ~ Project No. 1598946

We are counsel to the Commercial Energy Consumers Association of British Columbia (the "CEC"). Attached please find the CEC's first set of Information Requests to FortisBC Energy Inc. with respect to the above-noted matter.

If you have any questions regarding the foregoing, please do not hesitate to contact the undersigned.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer

CPW/jj
cc: CEC
cc: FortisBC Energy Inc.
cc: Registered Interveners

COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (the "CEC")

INFORMATION REQUEST NO. 1 TO FORTISBC ENERGY INC.

FortisBC Energy Inc. – 2017 Long Term Gas Resource Plan
Project No. 1598946

April 6, 2018

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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?

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

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

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.

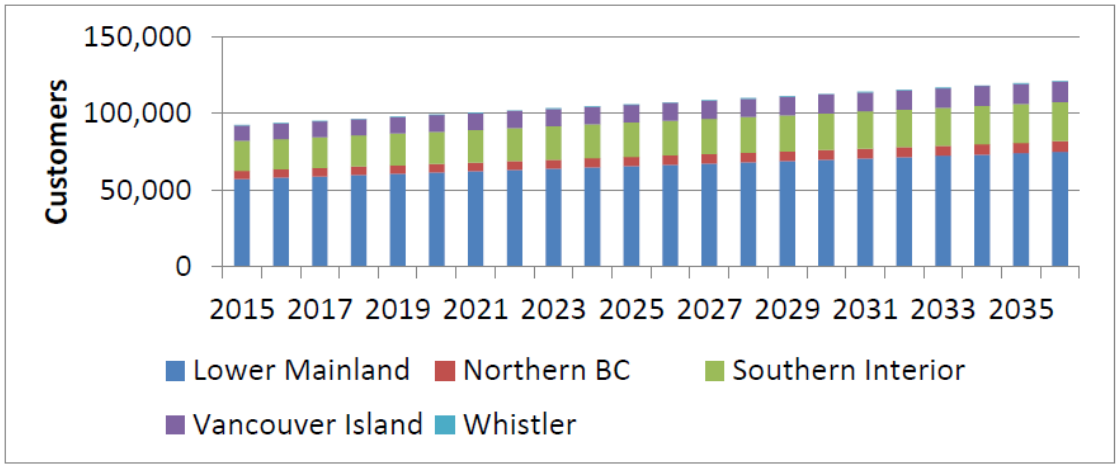
2. Reference: Exhibit B-1, page 61 and 62

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.

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

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

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

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

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.

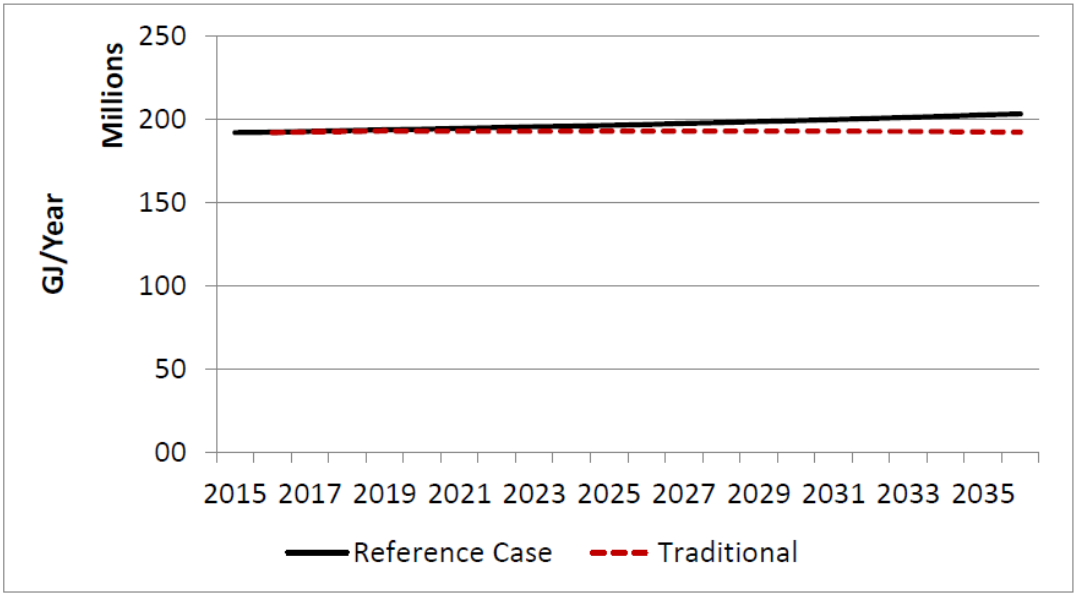
4. Reference: Exhibit B-1, page 67

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.

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.

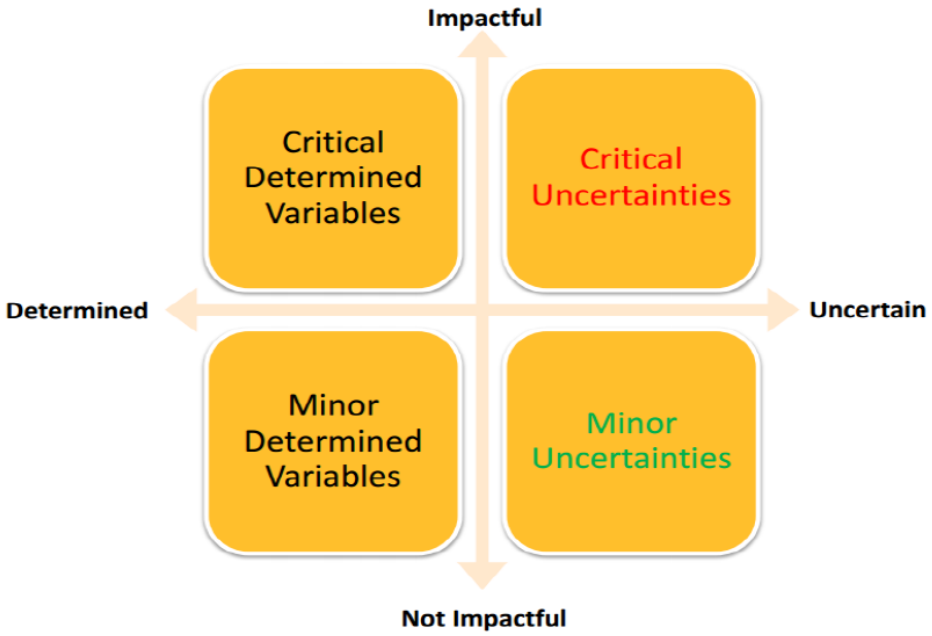
4.3 Please provide a graph of FEI actual demand against FEI's previous end use reference case forecasts.

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.

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.

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?

5.1.2 Please explain why they were rejected.

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

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.

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

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

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?

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

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?
  7.1.1 If yes, please identify and explain why FEI rejected these potential model levers.
  7.1.2 If not, please explain why not.

7.2 Please explain what FEI means by 'Industrial Facilities'.

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

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

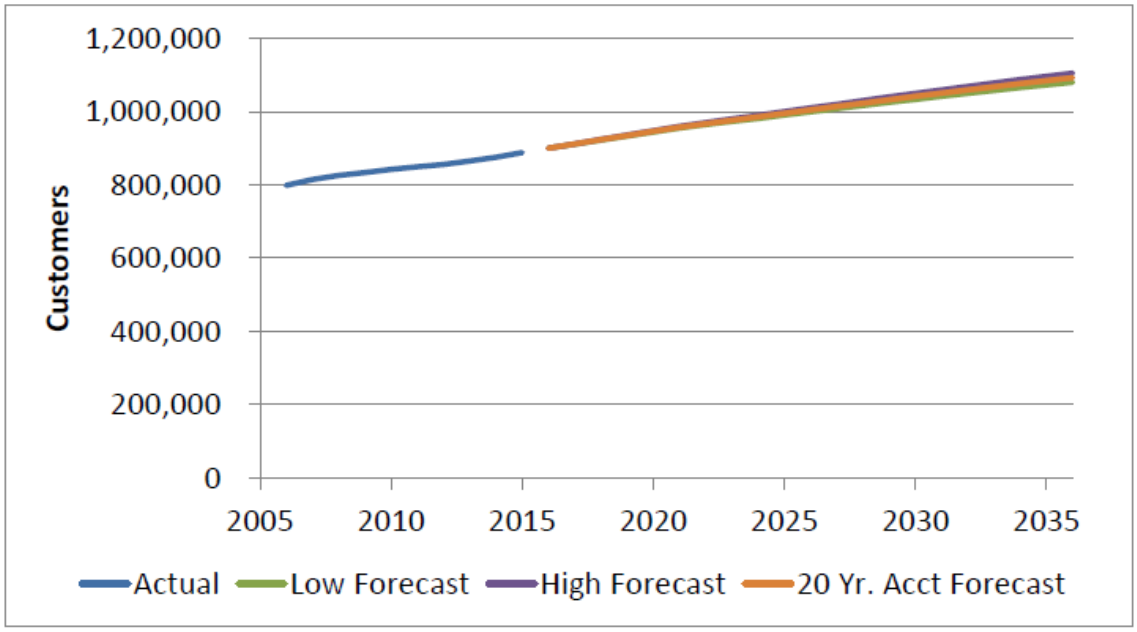
7.5 Please provide the source of information for the Commercial floor area metric.

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

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.

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.

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

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.

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

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

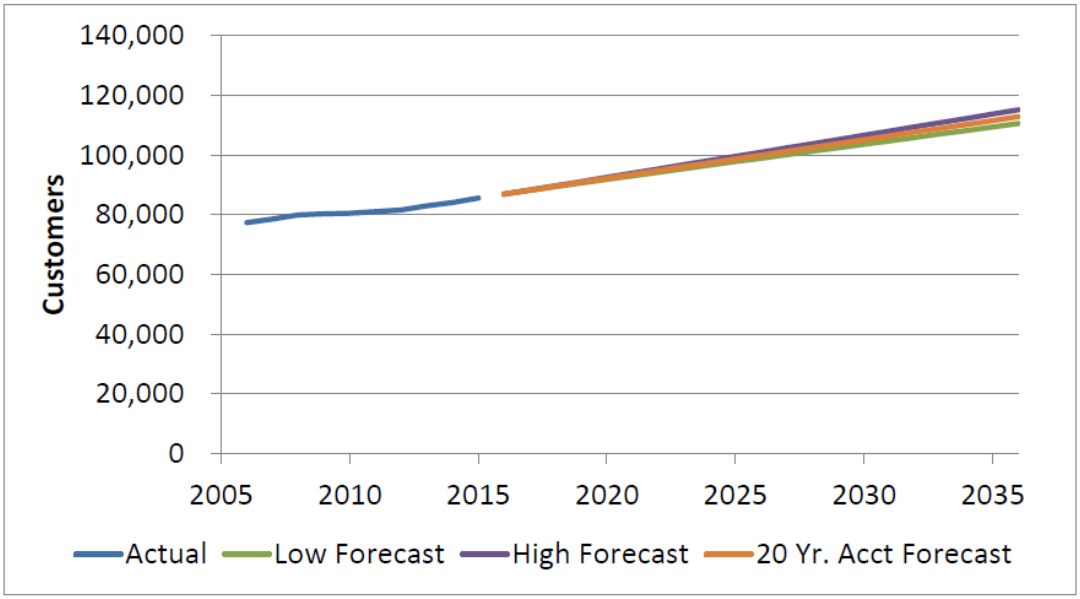
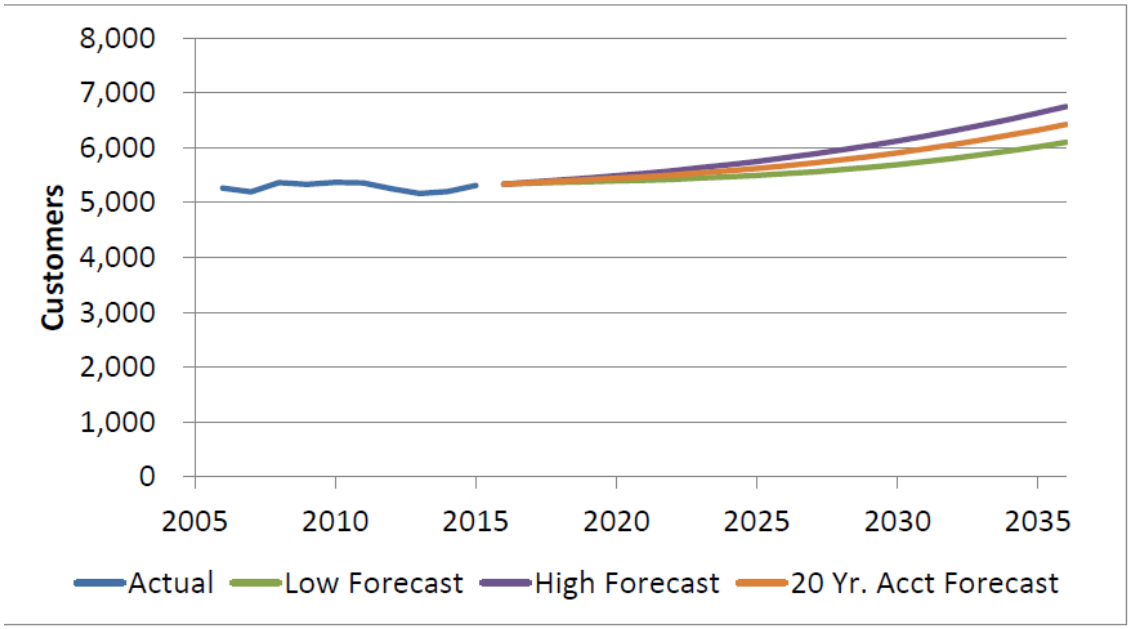


Figure B1-4: Customer Forecast Parameters – Rate Schedule 3



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

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.

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

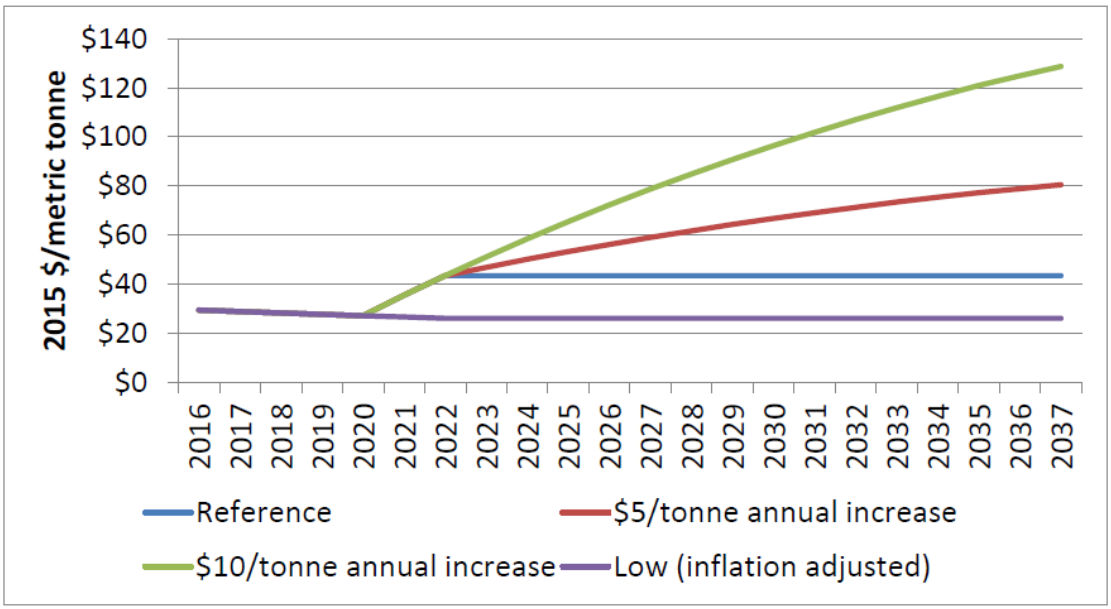
1.2.1.3 Carbon Price

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?

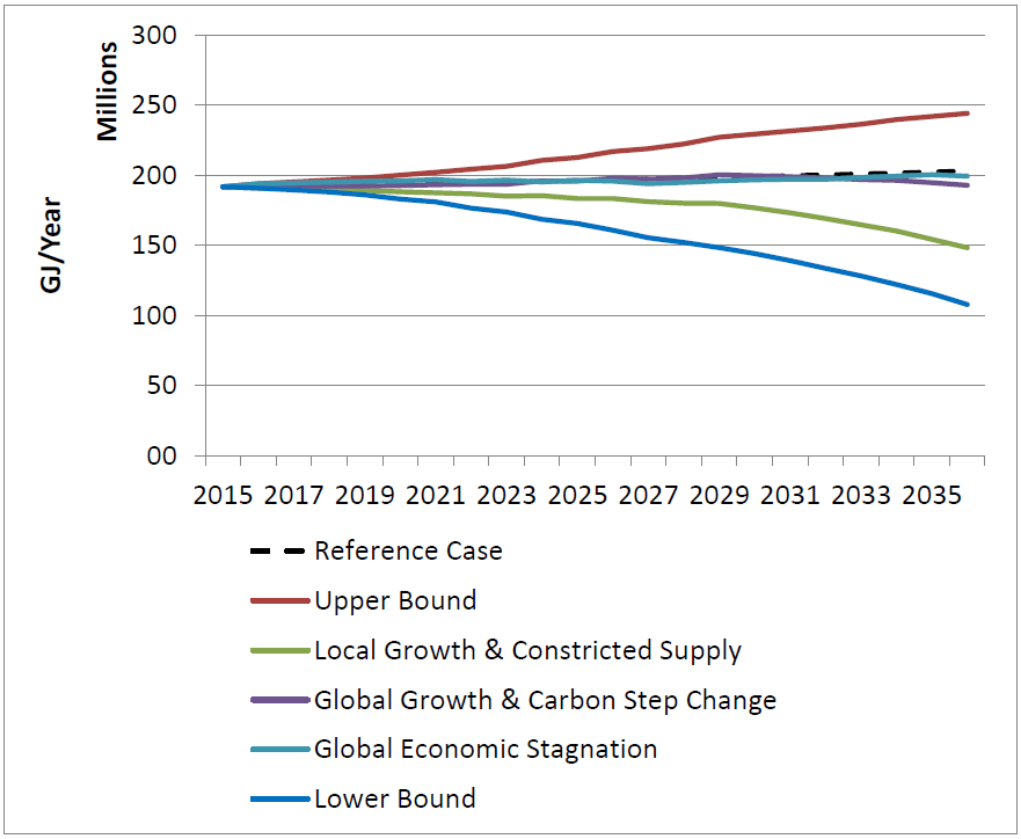
10.2 The Low scenario seems to assume that BC would not proceed with the $5/tonne increase commencing in 2018 which is already established in the BC Budget update. Please discuss the likelihood of this occurring.

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

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.

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.

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

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

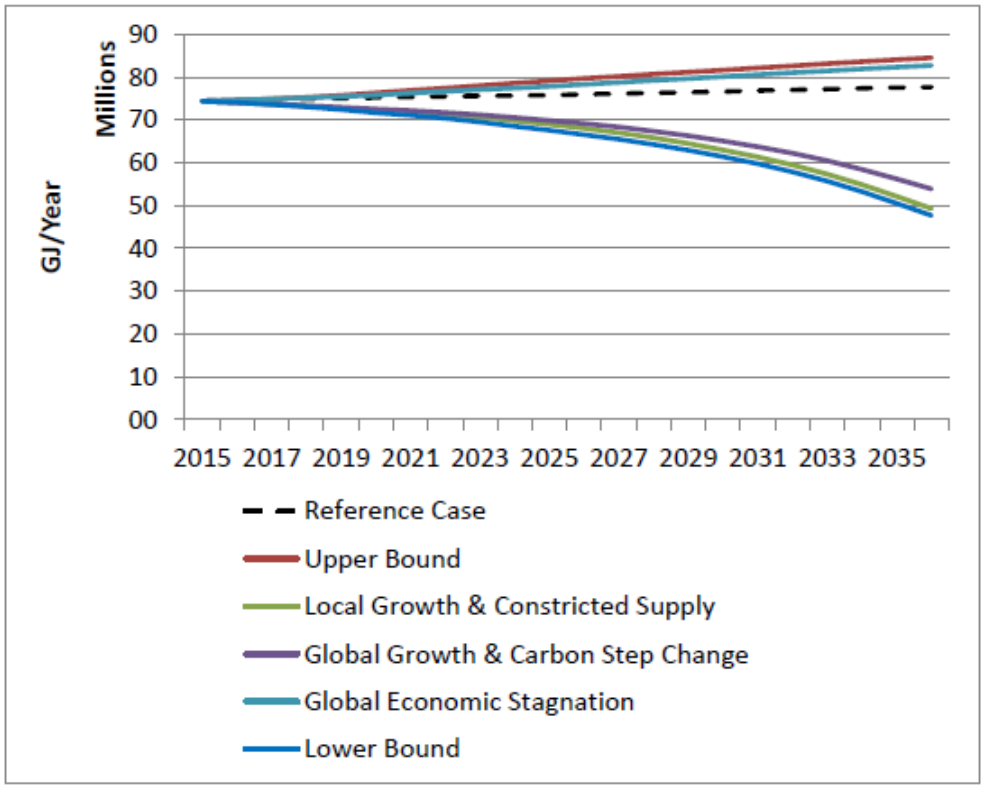
11.4 Could the various scenarios also be applied to the 'traditional' forecast?

11.5 If no, please say why not.

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

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

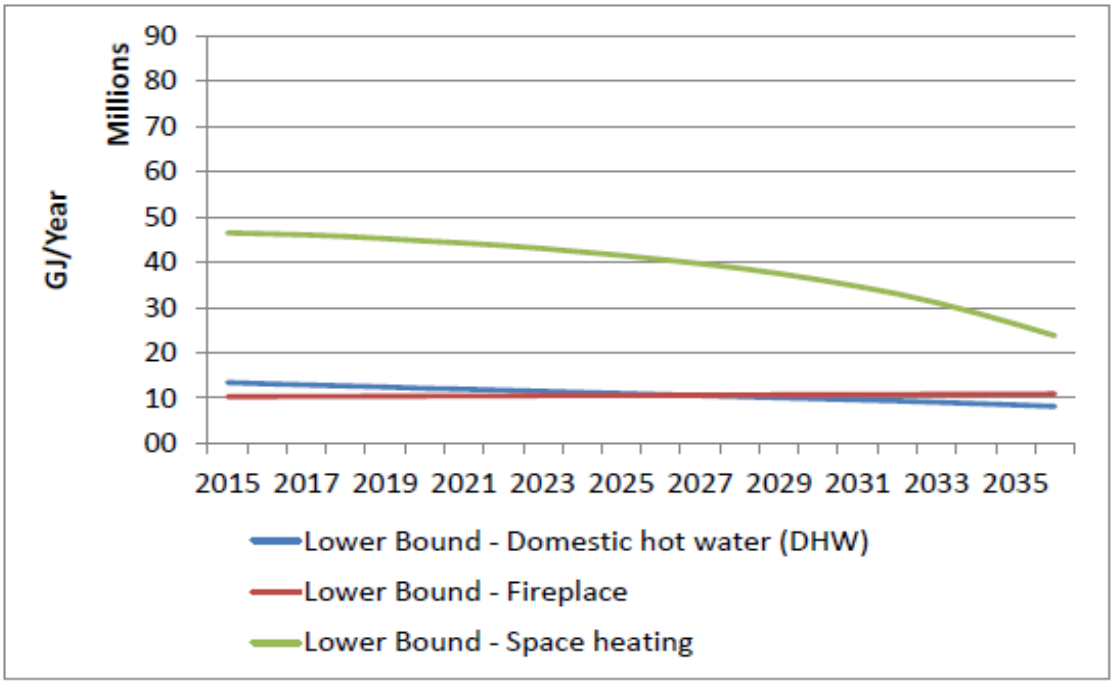
Figure 3-9: Annual Demand Scenarios – Residential Sector



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.

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

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.

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

13. Reference: Exhibit B-1, page 77

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

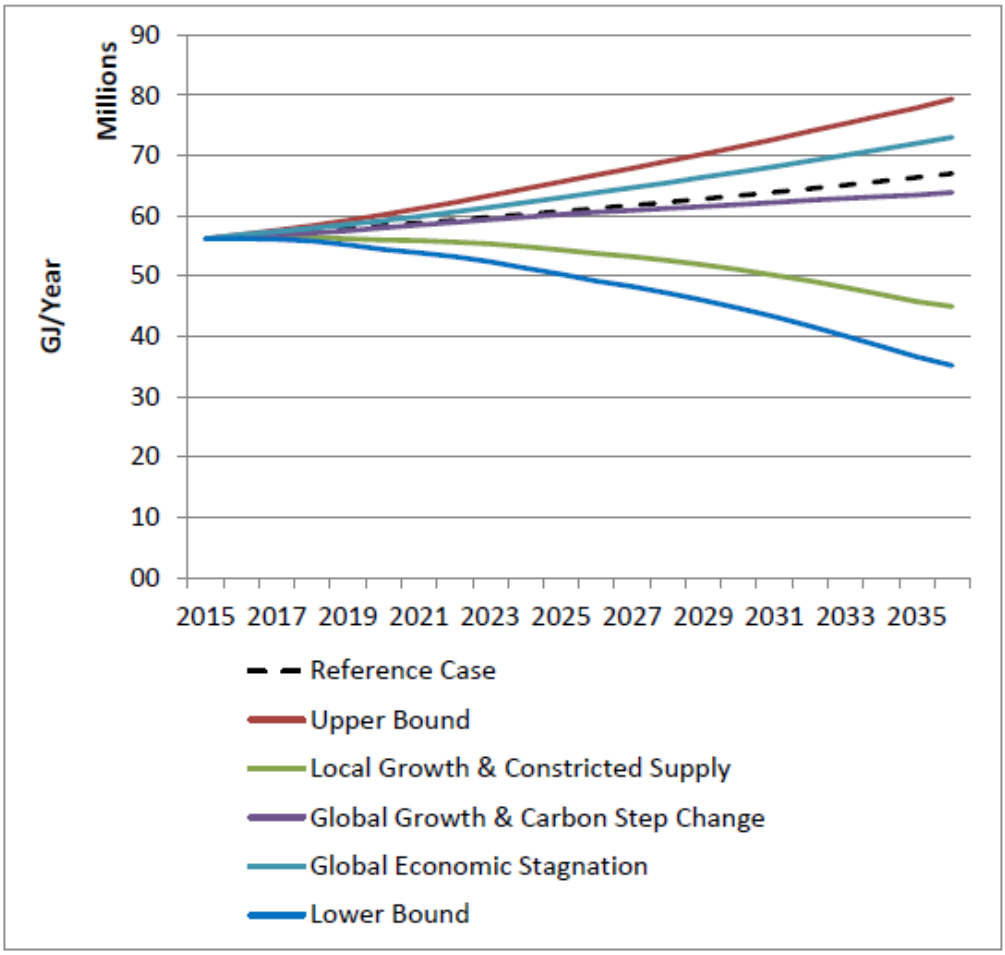


Figure 3-11 illustrates the following effects for the commercial sector:

- 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.

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

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.

14. Reference: Exhibit B-1, page 77

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

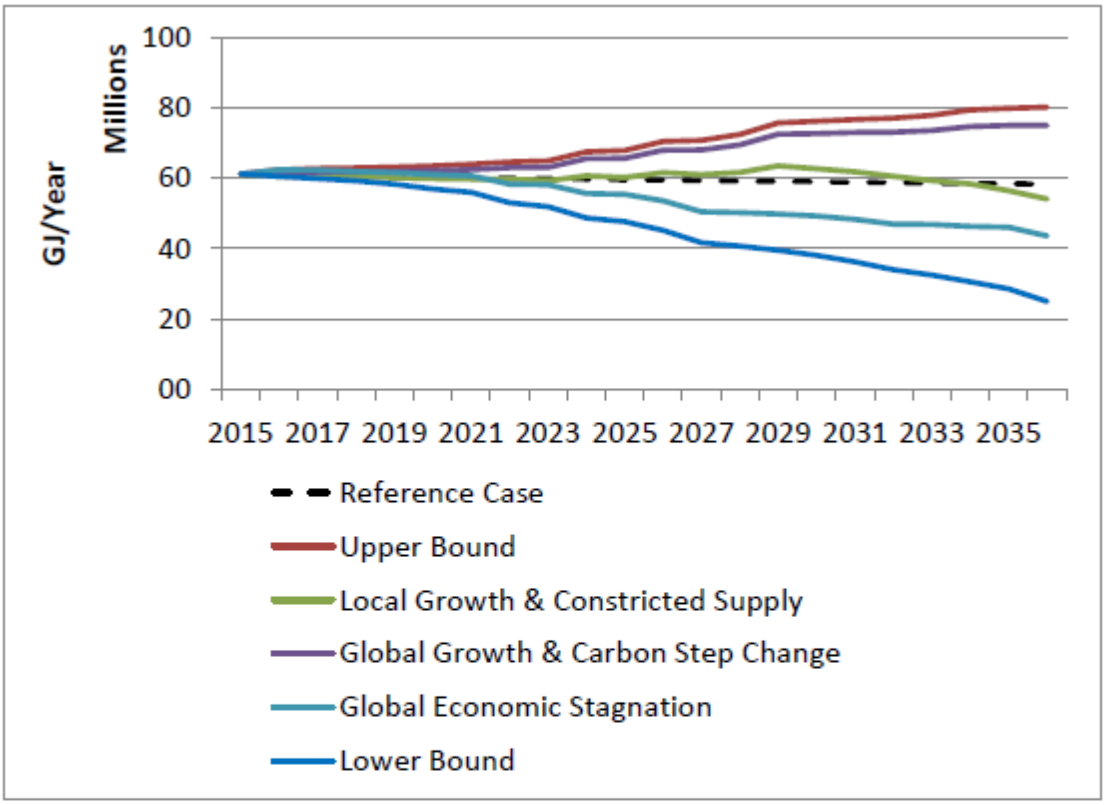


Figure 3-12 illustrates the following effects for the industrial sector:

- 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.

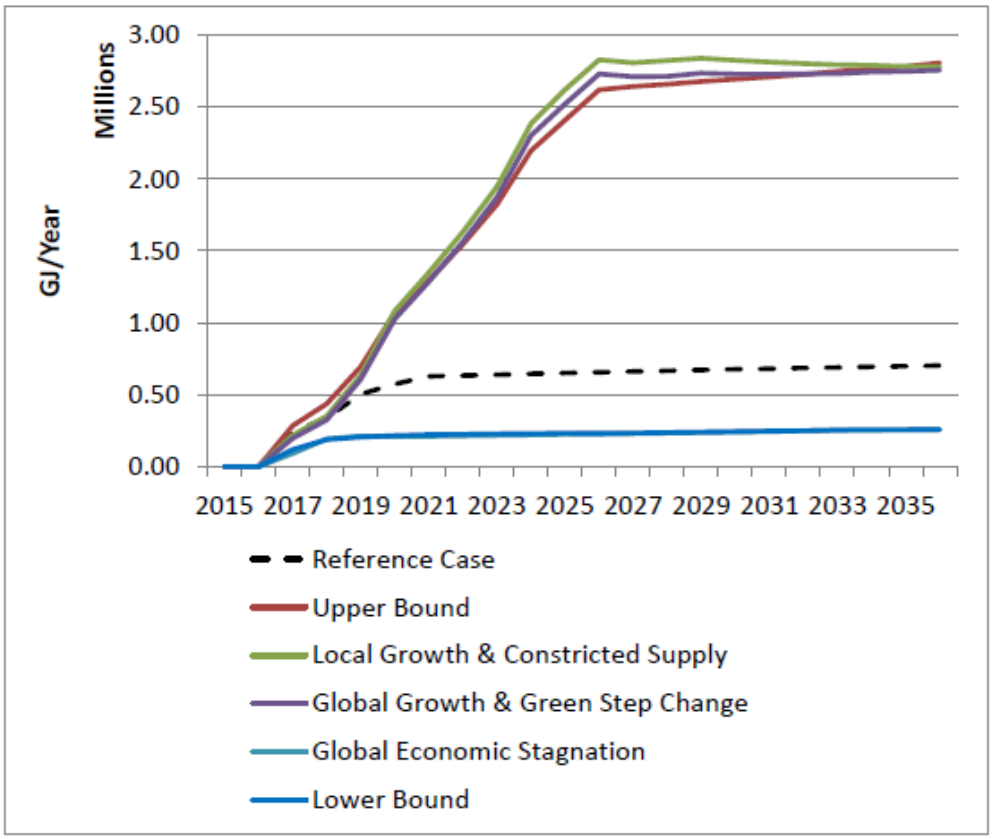
15. Reference: Exhibit B-1, page 79, page 80 and page 81 and page 70

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.

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

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

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

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

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.

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.

17. Reference: Exhibit B-1, page 84

3.4.7.1.3 CNG HIGH SCENARIO DEMAND FORECAST

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?
17.1.1 If not, please explain why not.
17.1.2 If yes, please elaborate on the EV assumptions and their impact on CNG.

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

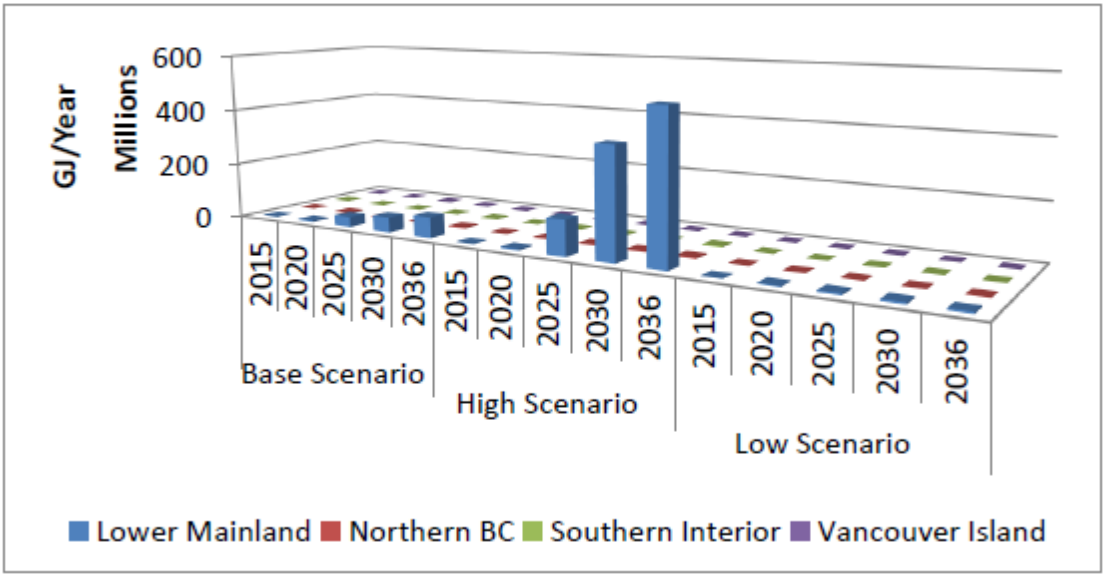
In the Base forecast scenario, FEI built upon the Low scenario but included some capture rate of trans-Pacific marine vessels as LNG fuel adopters. Through market intelligence and industry research, FEI has identified a certain segment of the trans-Pacific marine segment (international car and vehicle 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.
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.
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.

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?

19.2 Please provide figure 3-18 without LNG.

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?

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.

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.

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

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

21.3.2 If no, please explain why not.

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.

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.

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.

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.

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.

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.

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.

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.

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?

29.2 What is the contract term of these resources?

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

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.

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?

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

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.

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.

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?

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.

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.

33. Reference: Exhibit B-1, page 133

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

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

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.

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.

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.

35. Reference: Exhibit B-1, page 135

27 • The significant supply potential in NEBC, specifically in the Montney region, has
28 prompted the development of competing infrastructure initiatives to provide greater
29 access to existing and new markets. These developments could impact FEI's future
30 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.

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.

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.

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

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.

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.

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.

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

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.

40.2 Who are the largest land owners in the Montney?

40.3 What is the strategy with these producers?

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

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

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.

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

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

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

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

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.

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?

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.

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.

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

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.

44.2 What are the strategies of the top gas producers?

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

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

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

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

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

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

14 As a result of the size of this resource and its attractive production economics, production of
15 natural gas from basins located in NEBC has the potential to grow significantly in the coming
16 years. This supply will be able to support existing markets in BC, as well as support potentially
17 new markets (LNG and methanol exports) and meet growing industrial demand in Alberta,
18 specifically from continued oil sands growth. However, the impact of these developments for FEI
19 customers remains difficult to foresee with any accuracy because the quantity and timing of
20 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?

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

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

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

46.1 Please give quantitative evidence of the production efficiency improvement.

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?

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

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

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

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

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?

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

48.2.1 Please describe how FEI intends to manage these risks.

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

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).

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

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

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

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?

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

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

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.

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?

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.

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.

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?

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.

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.

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.

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.

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.

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.

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.

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.

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

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?

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

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

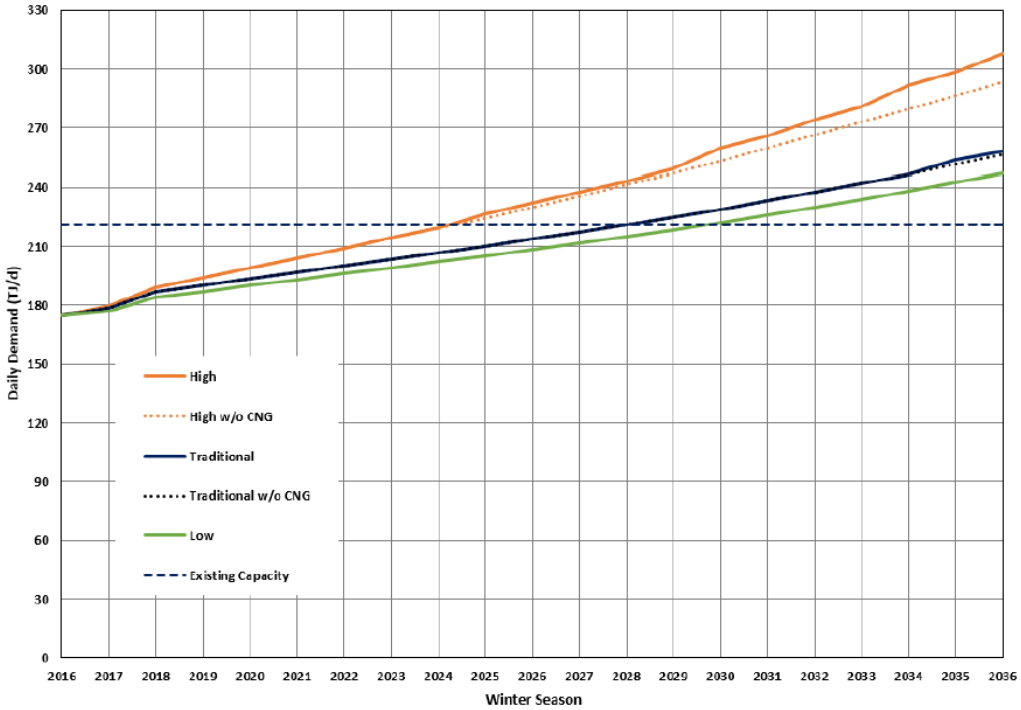
54.2.2 If concentrated, does FEI expect the fuelling stations to continue to be concentrated in certain regions, or does FEI expect them to be more broadly based in the future? Please explain.

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.

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

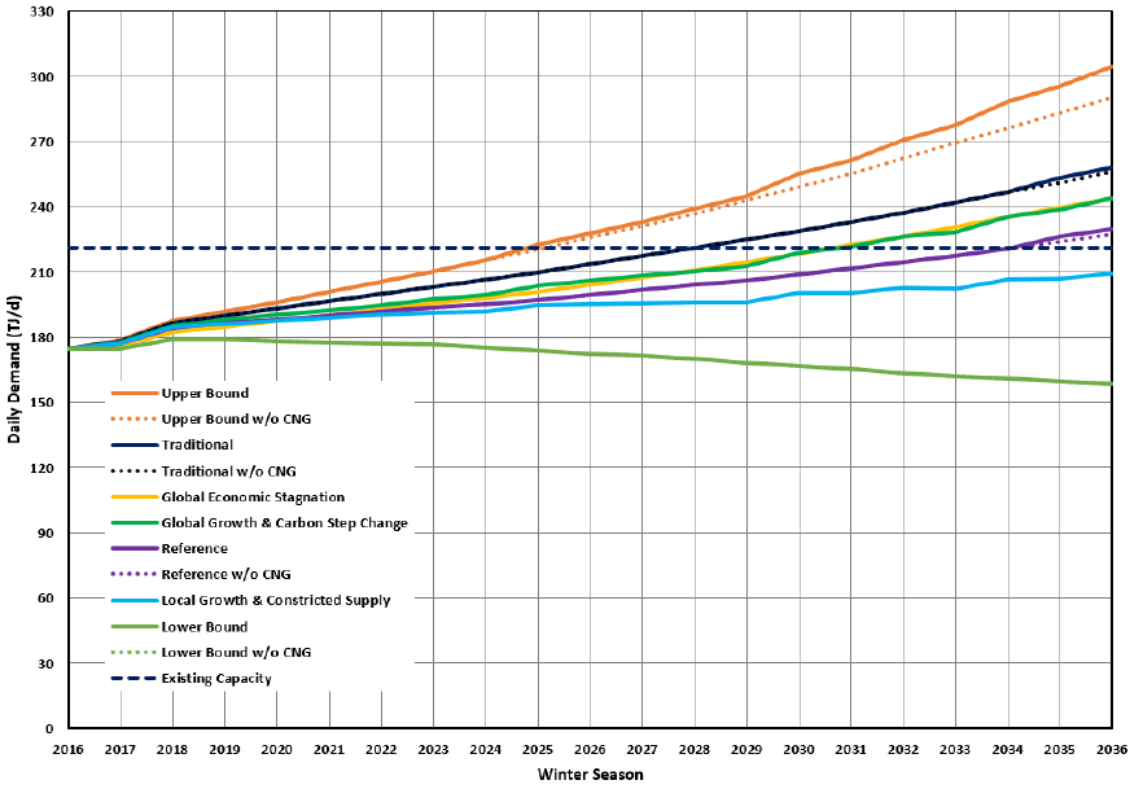
55.3 Please discuss FEI's potential options for providing future capacity and FEI's best estimates of costs for these options at this time.

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?

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

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.

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.

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

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.

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?

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

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.

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.

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

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

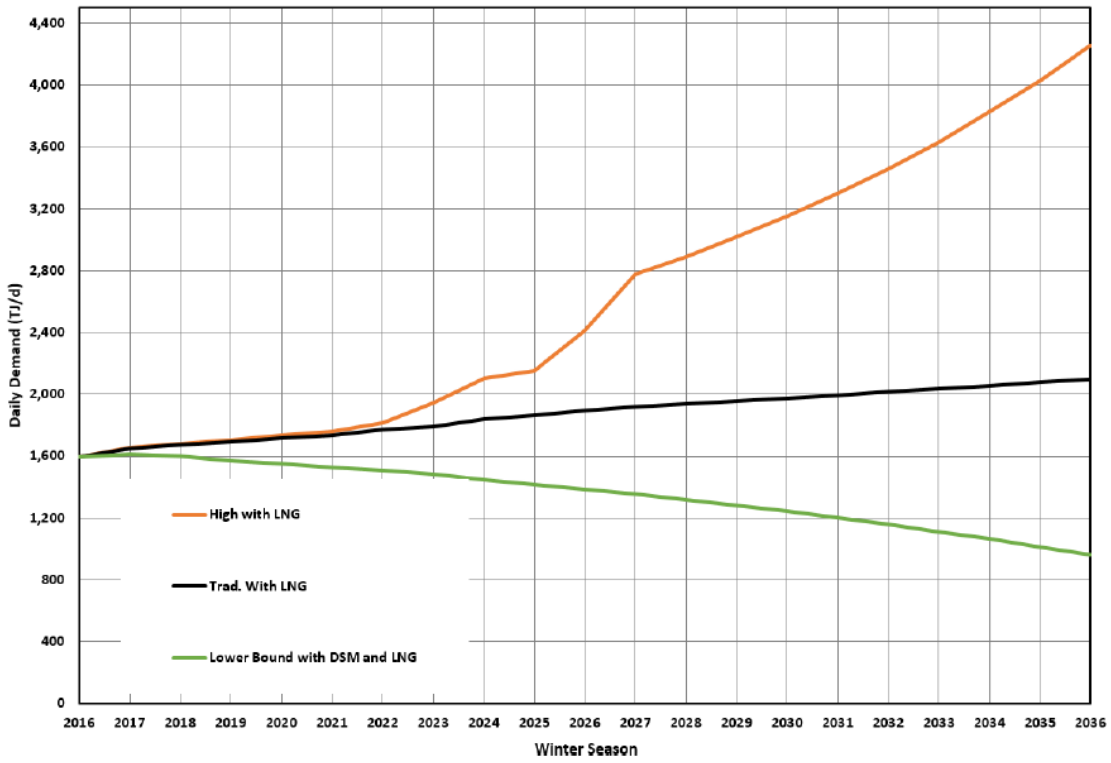
59.4 Please outline the circumstances under which FEI's demand forecast for LNG would not materialize.

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

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?

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



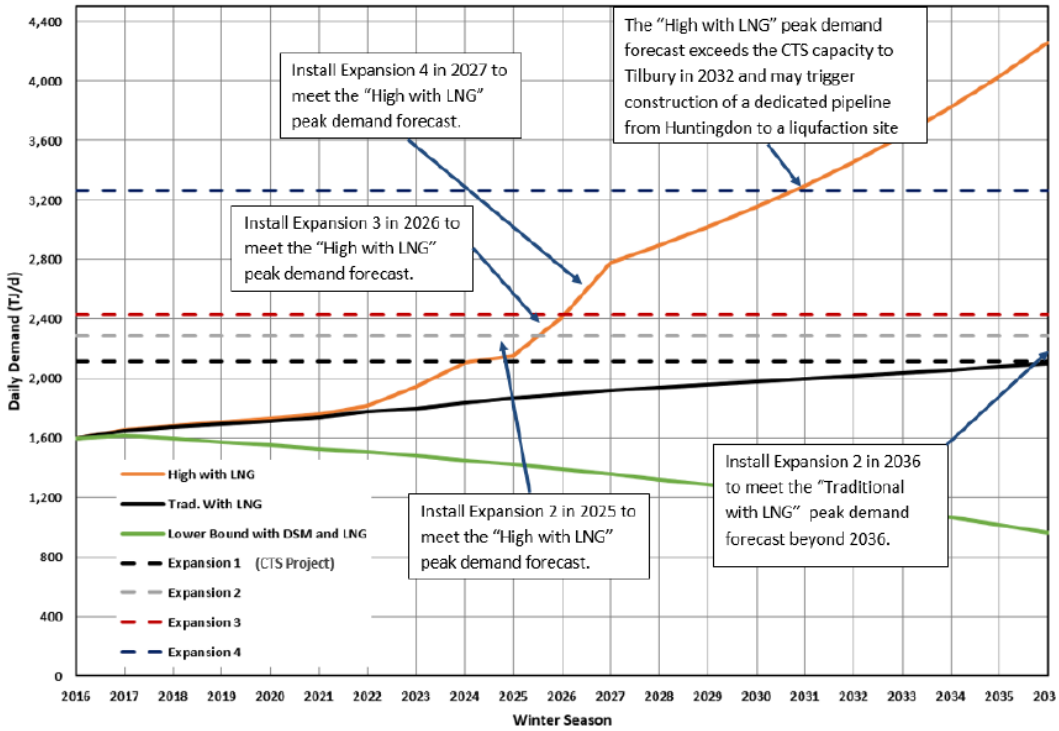
The peak demand forecasts shown have a very similar profile to the annual demand with LNG forecasts shown in Figure 3-18. The production of LNG is consistent throughout any day of the year and has no seasonal or daily peak. In practice, the actual peak demand that may occur on the CTS in any given period 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.

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

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.

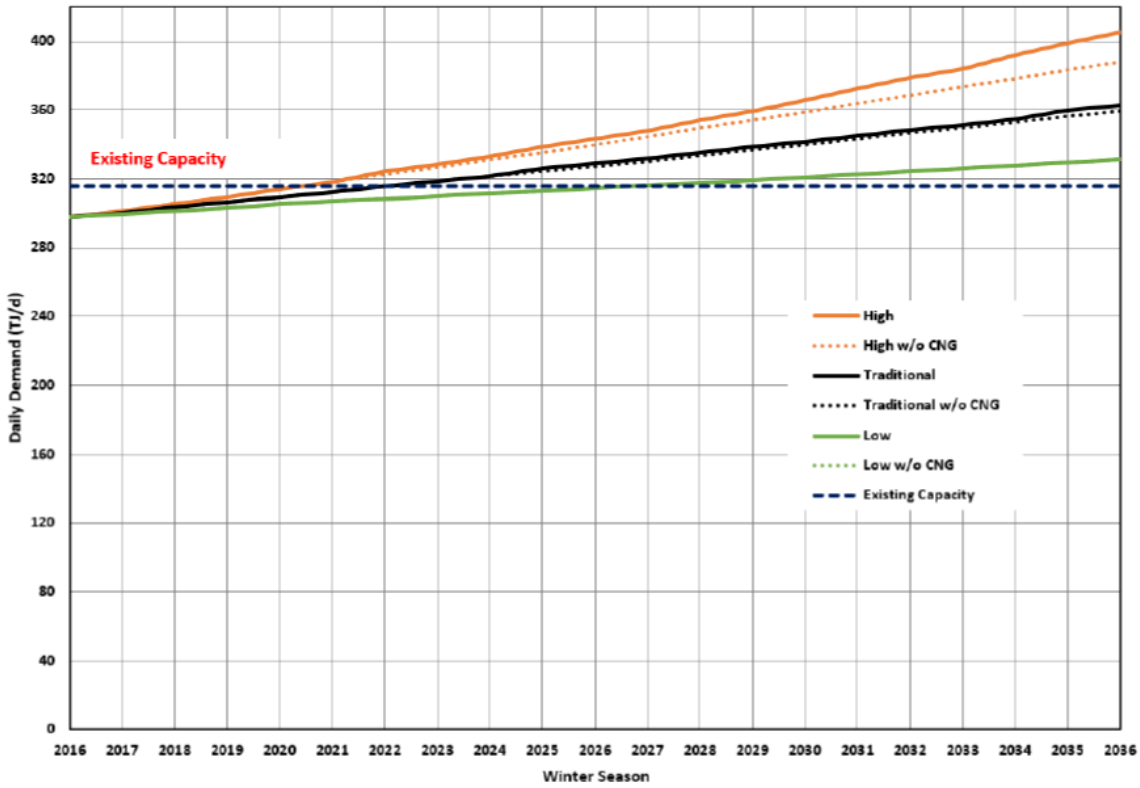
61.2 What criteria will FEI use to make the determination as to whether or not it needs to proceed with any expansion scenarios to meet the 'High with LNG' forecast?

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

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

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.

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

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.

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

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.

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.

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

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.