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May 3, 2018

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

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

Dear Mr. Wruck:

Re: FortisBC Energy Inc. (FEI)

Project No. 1598946

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

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

On December 14, 2017, FEI filed the Application referenced above. In accordance with Commission Order G-33-18 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 1.

If further information is required, please contact Ken Ross at (604) 576-7343.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

Table of Contents **Page no.**

A. INTRODUCTION

1.0 Reference: INTRODUCTION

Exhibit B-1, Section 1, p. 1

Fort Nelson

In footnote 8 on page 1 of Exhibit B-1, FortisBC Energy Inc. (FEI) states:

> "Where applicable, FEI's LTGRP analysis includes data for Fort Nelson. FEI does not expect any system capacity constraints in Fort Nelson during the 2017 LTGRP forecast horizon. FEI's gas supply portfolio planning and DSM activities do include Fort Nelson customers."

1.1 Please confirm that the Application includes a long-term analysis of: (i) annual and peak demand forecasts for Fort Nelson; (ii) Demand Side Management (DSM) activities regarding Fort Nelson and their impact to Fort Nelson annual and peak demand; and (iii) system needs and alternatives for Fort Nelson.

Response:

Confirmed. Fort Nelson is included with the rest of FEI in Sections 3 (Annual Energy Demand Forecasting, as stated in footnote 8 of Section 1, page 1, and in footnote 139 of Section 5, page 135 of the 2017 LTGRP) and 4 (Demand-Side Resources) of the Application. Fort Nelson is included in the Northern BC region of this study as stated by Navigant in the B.C. Conservation Potential Review Report (Appendix C-1), which provides a mapping of FEI regions to the CPR regions in Section 2.1.1.1, page 6.

Fort Nelson has sufficient existing capacity to meet forecast peak demand requirements. Fort Nelson is served by a transmission lateral and its peak demand was analyzed along with all other transmission laterals. Any discussion of peak demand analysis and system needs, had they been required in the forecast period, would have been addressed in Section 6.3.4 of the LTGRP.

1.1.1 If not confirmed, please provide any sections that were not included.

Response:

Please refer to the response to BCUC IR 1.1.1.

2.0 Reference: INTRODUCTION

Exhibit B-1, Section 1.2, Table 1-1, p. 3

FEI Service Statistics

In Table 1-1 of Exhibit B-1, FEI presents service statistics in a table for 2015 and 2016.

2.1 Please provide an updated version of this table which includes the figures for the service statistics for 2014 through to 2017 inclusive and which uses numbers for each of the years rounded to the nearest whole number.

Response:

An updated version of Table 1-1 of Exhibit B-1 with figures for 2014 and 2017 added is provided below.

Table 1: FEI Service Statistics

	2014	2015	2016	2017
Number of Customers	967,000	982,000	994,000	1,008,000
Annual Demand (TJ)	195,000	186,000	197,000	221,000
Peak Day Demand (TJ/d)	1,324	1,074	1,334	1,336
Length of Transmission Pipeline (km)	2,958	2,958	2,959	2,970
Length of Distribution Pipeline* (km)	44,541	45,242	45,741	46,041

* includes both low and intermediate pressure pipelines

3.0 Reference: INTRODUCTION

Exhibit B-1, Section 1.3, p. 5; Section 5.3.1, p. 137;

FortisBC Energy Utilities (FEU) 2014 Long Term Resource Plan, Exhibit B-1, pp. 8-9

FEI's Long Term Resource Planning Objectives

On page 5 of Exhibit B-1, FEI states:

> FEI's resource planning objectives form the basis for identifying and evaluating potential resources in the LTGRP, including major infrastructure projects, gas supply alternatives and demand side programs. These objectives reflect the Utility's commitment to providing customers with the highest level of quality energy services.

FEI then lists its key resource planning objectives as:

1. Ensure Cost Effective, Secure and Reliable Energy for Customers
2. Provide Cost Effective DSM [Demand-Side Management] Initiatives
3. Ensure Consistency with Provincial Energy Objectives

FEI lists the following resource planning objectives on pages 8 and 9 of the FEU 2014 Long Term Resource Plan:

1. Ensure a Safe, Reliable and Secure Energy Supply
2. Provide Innovative and Cost-Effective Energy Solutions
3. Provide Cost-Effective Energy Efficiency and Conservation Initiatives
4. Contribute to Provincial Energy Objectives and Emission Targets
5. Consider a Range of Possible Future Conditions.

3.1 Please provide a discussion that compares the FEI 2017 Long Term Gas Resource Plan (LTGRP) objectives with the FEU 2014 Long Term Resource Plan objectives. Please include in your discussion an explanation supporting any changes that were made to the objectives since the FEU 2014 Long Term Resource Plan.

Response:

While the 2017 LTGRP planning objectives are less numerous than the 2014 LTRP planning objectives, they are consistent. After careful consideration and input from internal and external stakeholders, FEI believes that all five objectives of the 2014 LTRP are encompassed in the more simply stated three objectives of the 2017 LTGRP. For example, safety is a core corporate value of FEI and is implicit in 2017 LTGRP planning objective 1. Similarly, 2014 LTRP objective 2 is implicit in 2017 LTGRP objectives 1 and 2. 2014 LTRP planning objective 5 is implicit in the aggregation of 2017 LTGRP planning objectives 1 through 3 as uncertainty in the evolving planning environment emphasizes examining multiple futures in order to identify risks. FEI's 2017 LTGRP resource planning objectives are the product of an evolution through past Long Term Resource Plans, including stakeholder engagement processes that have taken place as part of FEI's resource planning activities. Each of FEIs planning objectives have customer interests at its core.

On page 137 of Exhibit B-1, FEI states:

> Key objectives of the ACP [Annual Contracting Plan] are:
>
> 1) To contract for resources that appropriately balance 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.

3.2 Please provide a discussion that compares the FEI 2017 LTGRP objectives with the ACP objectives.

Response:

The objectives set out in the Annual Contracting Plan (ACP) are consistent with the objectives of the LTGRP. For instance, both the ACP and the LTGRP seek to ensure cost effective, secure and reliable energy for customers. However, the LTGRP objectives are broader given its longer term planning horizon (20 years) and wider complement of topics compared to the ACP with a planning horizon of one to five years.

3.2.1 Please explain whether or not FEI considers that the ACP objectives should stem from the LTRP objectives.

<u>Response:</u>

FEI considers that the ACP and LTGRP objectives should be aligned. Section 5.1.1 of the 2017 LTGRP discusses the relationship between FEI's ACP, LTGRP and the Price Risk Management Plan (PRMP). In that section, FEI discusses how the LTGRP objectives align with the ACP and PRMP on a long term basis, noting the following:

> The LTGRP establishes long term planning principles, objectives, and a framework that is used to help ensure the long term provision of safe, reliable, and cost effective service to all customers. In doing so, the LTGRP also sets out gas supply contracting and price risk management principles within the context of a 20-year outlook. The ACP and the PRMP each describe more detailed strategies and tactics for managing either the physical availability of natural gas supply or the impact of gas costs on rates. The ACP is an annual plan that focuses on the next gas year's resource requirements but also looks out beyond the next gas year at any market conditions that may impact future supply procurement strategies.[1]

[1] Application, Section 5 Page 133.

B. PLANNING ENVIRONMENT

4.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1, Section 2.2.1, Figure 2-1, p. 18; Figure 2-2, p. 19

Natural Gas Prices

Figure 2-1 on page 18 of Exhibit B-1 contains a graph showing the Henry Hub historical natural gas spot prices, in USD$/MMBTU, from January 1, 2008 to approximately June 1, 2017 for the Henry Hub pricing point.

4.1 Please provide an updated version of this chart, to include historical natural gas spot prices from January 1, 2008 to January 31, 2018 in: (i) USD$/MMBTU; and (ii) CAD$/GJ. Please state the relevant conversion factors.

<u>Response:</u>

The following figures are updated versions of Figure 2-1 showing the Henry Hub historical natural gas spot prices from January 1, 2008 to March 31, 2018 in (i) USD$/MMBtu; and (ii) CAD$/GJ. Historical daily spot exchange rates and the conversion rate of 1.055056 for MMBtu to GJ was used to convert the Henry Hub prices to from USD$/MMBtu to CAD$/GJ.

(i) USD$/MMBTU

(ii) CAD$/GJ

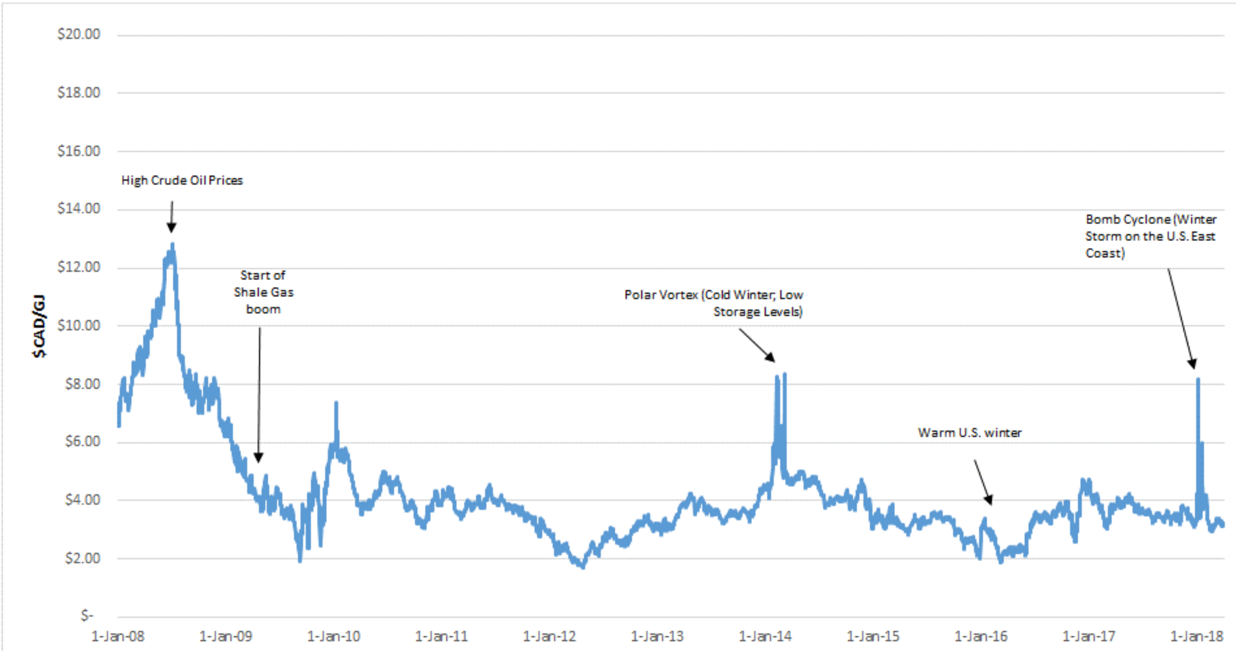
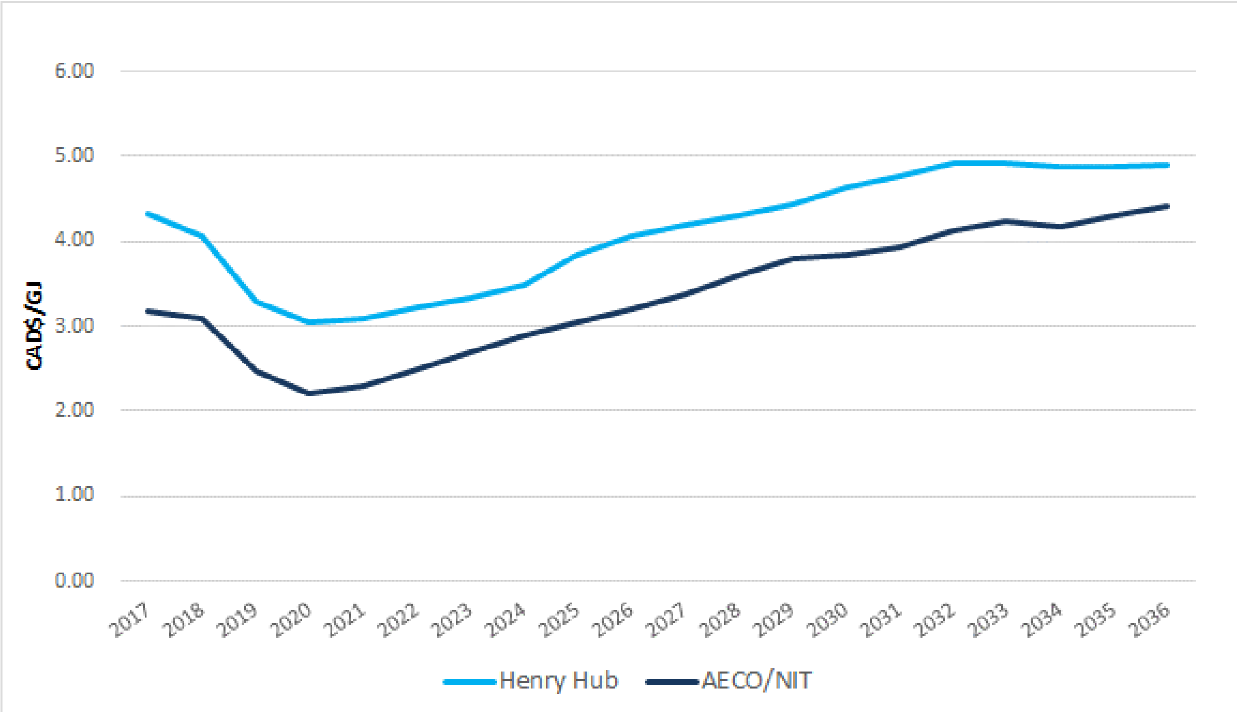


Figure 2-2 on page 19 of Exhibit B-1 contains a graph showing Wood Mackenzie's natural gas price forecast for the Henry Hub and for Alberta (AECO/NIT) in 2016 USD$ from 2017 through to 2036.

4.2 Please provide another version of the graph with the prices expressed in 2016 CAD$ per GJ. Please state the relevant conversion factors.

Response:

The following shows Figure 2-2 with prices expressed in 2016 CAD$ per GJ. The prices were converted using Wood Mackenzie's Foreign Exchange rate from the Global Exchange Rate Outlook for Q4 2016 and the conversion rate of 1.055056 for MMBtu to GJ was used to convert the prices from USD$/MMBtu to CAD$/GJ.



6.00
5.00
4.00
3.00
2.00
1.00
0.00
CAD$/GJ
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
Henry Hub
AECO/NIT

5.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1, Section 2.2.2.1, Figures 2-10 and 2-11, p. 27

Natural Gas and Electricity Rates

Figures 2-10 and 2-11 on page 27 of the Application provides a cost comparison, in $/kWh, between FEI's natural gas, FEI's 100 percent renewable natural gas and BC Hydro's electricity.

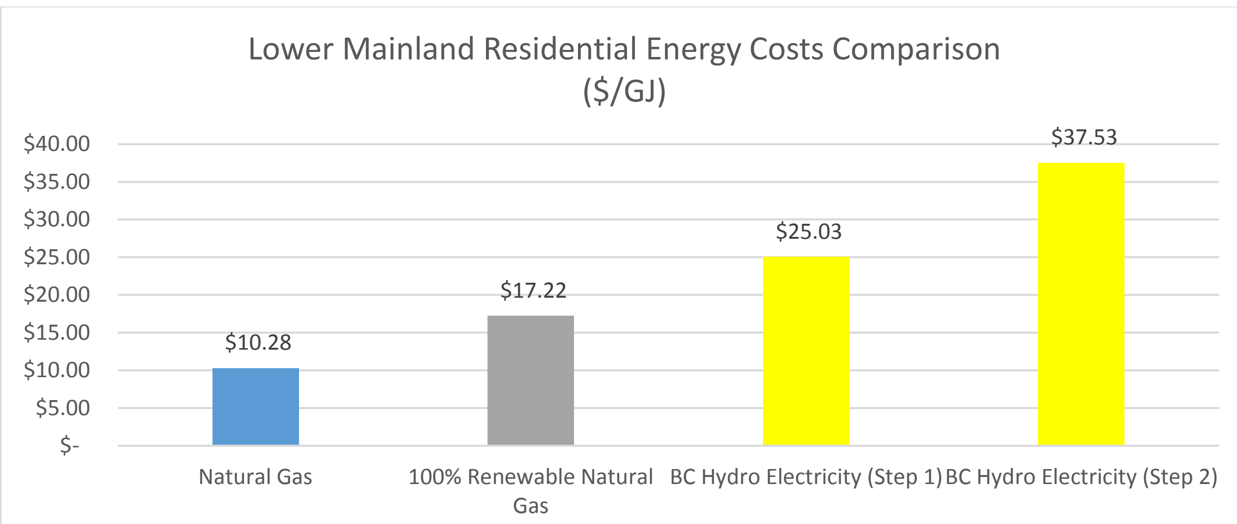
5.1 Please reproduce each graph (Figure 2-10 and Figure 2-11) using CAD$/GJ instead of $/kWh.

<u>Response:</u>

This response addresses BCUC IR 1.5.1 and IR 1.5.2

Please refer to the updated Figures 2-10 and 2-11 and tables below which show the FEI and BC Hydro effective rates in CAD$/GJ.

Figure 2-10 Updated: Residential



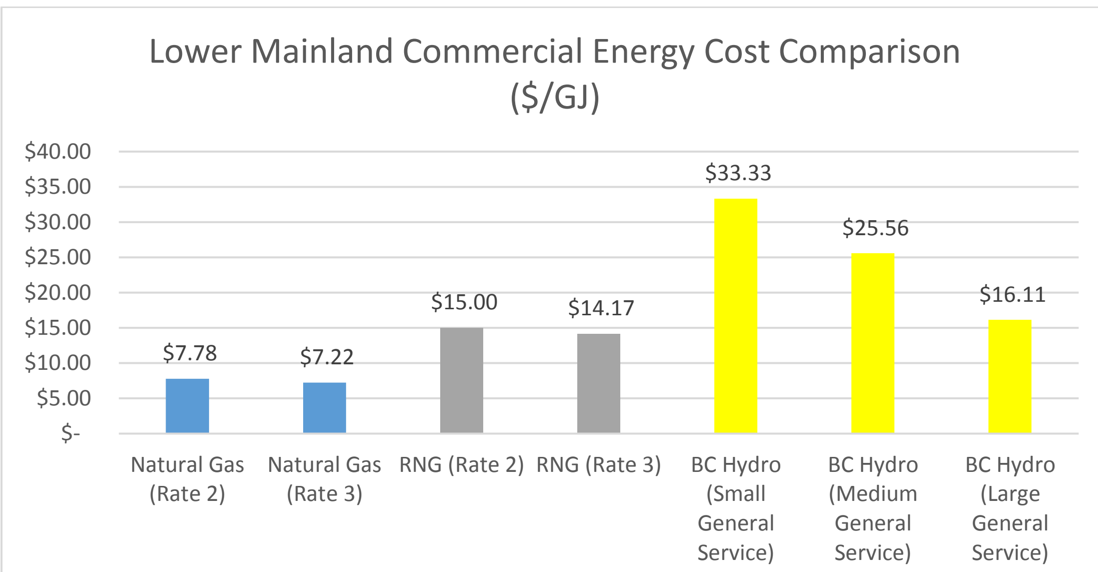
Energy	Rate ($/kWh)	Conversion	Rate ($/GJ)
Rate Schedule 1 (Residential) Conventional Natural Gas	$0.037	277.78	$10.28
Rate Schedule 1B (Residential) RNG	$0.062	277.78	$17.22
BC Hydro 1101 Residential (Tier 1)	$0.0901	277.78	$25.03
BC Hydro 1101 Residential (Tier 2)	$0.1351	277.78	$37.53

Assumptions:

- *FEI rates are:*
  - effective January 1, 2017;
  - inclusive of all applicable delivery and commodity charges and rate riders, including the daily basic charges (based on average annual usages of 90 GJ for Rate Schedules 1 and 1B);
  - the BC Carbon Tax (for Rate Schedule 1 only); and
  - exclusive of any other applicable taxes.

- *BC Hydro rates are:*
  - effective April 1, 2017;
  - inclusive of the applicable 5 percent deferral account rate rider; and
  - exclusive of the applicable daily basic charge and any applicable taxes.

Figure 2-11 Updated: Commercial



Energy	Rate ($/kWh)	Conversion	Rate ($/GJ)
Rate Schedule 2 (Small Commercial) Conventional Natural Gas	$0.028	277.78	$7.78
Rate Schedule 3 (Large Commercial Conventional Natural Gas	$0.026	277.78	$7.22
Rate Schedule 2B (Small Commercial) RNG	$0.054	277.78	$15.00

Energy	Rate ($/kWh)	Conversion	Rate ($/GJ)
Rate Schedule 3B (Large Commercial) RNG	$0.051	277.78	$14.17
BC Hydro 1300 (Small General Service)	$0.120	277.78	$33.33
BC Hydro 1500 (Medium General Service)	$0.092	277.78	$25.56

Assumptions:

- *FEI rates are:*
  - effective January 1, 2017;
  - inclusive of all applicable delivery and commodity charges and rate riders;
  - the BC Carbon Tax (for Rate Schedules 2 and 3 only); and
  - exclusive of daily basic charges and any other applicable taxes.

- *BC Hydro rates are:*
  - effective April 1, 2017;
  - Inclusive of the applicable 5 percent deferral account rate rider;
  - Exclusive of the applicable basic charges, kW demand charge, power factor surcharge; and transformer or primary potential discounts and any applicable taxes.

5.2 Please explain if Figures 2-10 and 2-11 contain fixed charges or delivery charges.

Response:

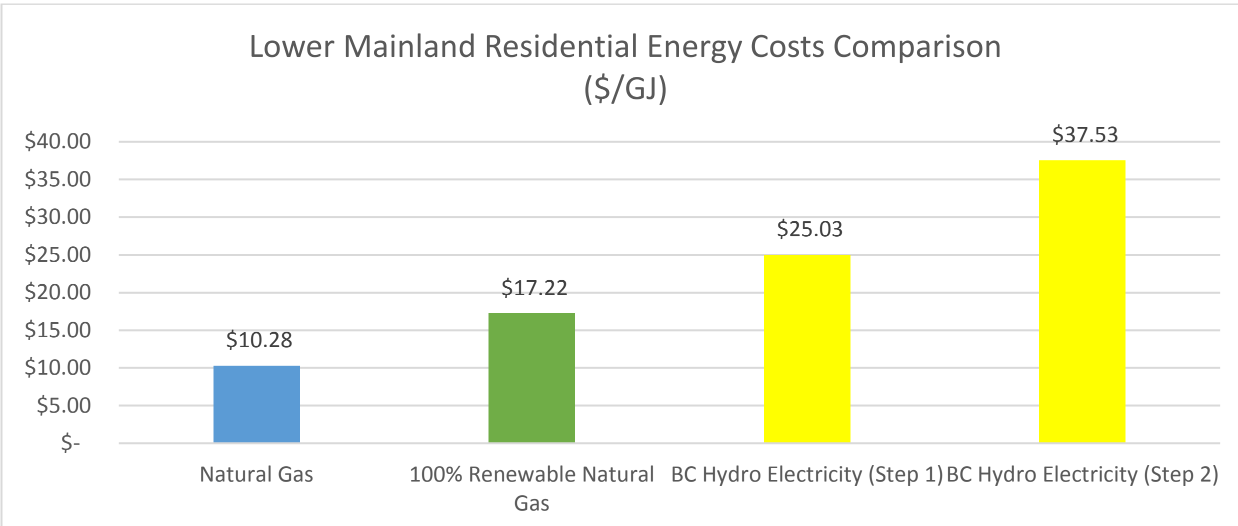
Please refer to the response to BCUC IR 1.5.1.

5.3 Please reproduce each graph (Figure 2-10 and Figure 2-11) to show the effective CAD$/GJ rate comparison based on the 2016 average annual consumption of a FEI Mainland residential, small commercial and large commercial customer with the fixed and delivery charges included.

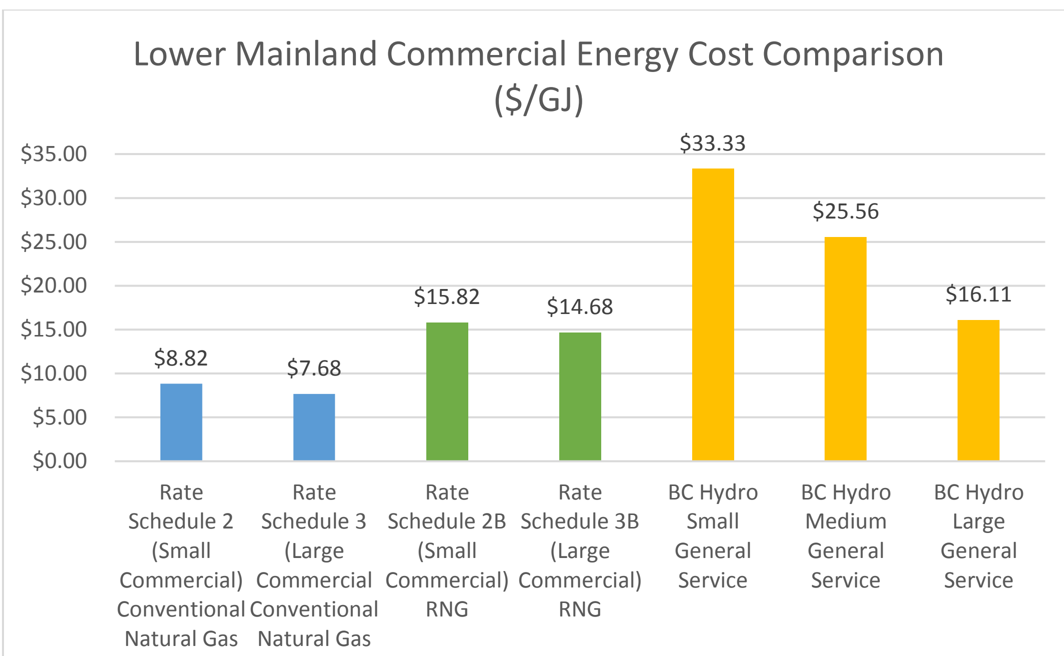
<u>Response:</u>

Please refer to revised Figures 2-10 and 2-11 below which update the FEI effective rates provided in the Application with 2016 average annual use rates for FEI Rate Schedules 1 (residential), 2 (small commercial) and 3 (large commercial).

Revised Figure 2-10: Residential



Revised Figure 2-11: Commercial



Energy	Rate ($/GJ)	2016 Average Consumption (GJ)
Rate Schedule 1 (Residential) Conventional Natural Gas	$10.28	90 (no change from 2017)
Rate Schedule 2 (Small Commercial) Conventional Natural Gas	$8.82	326
Rate Schedule 3 (Large Commercial Conventional Natural Gas	$7.68	3,459
Rate Schedule 1B (Residential) RNG	$17.22	90
Rate Schedule 2B (Small Commercial) RNG	$15.82	
Rate Schedule 3B (Large Commercial) RNG	$14.68	
BC Hydro Small General Service	$0.120	
BC Hydro Medium General Service	$0.092	
BC Hydro Large General Service	$0.058	

Assumptions:

- *FEI rates are:*
    - effective January 1, 2017;
    - the BC Carbon Tax (for Rate Schedules 1, 2 and 3 only); and
    - exclusive of any other applicable taxes.

6.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1, Section 2.3.4, p. 48

BC Energy Step Code

On page 48 of Exhibit B-1, FEI states:

> The BC Energy Step Code provides a consistent provincial standard for energy efficiency and replaces the various existing policies that various municipal governments had enacted previously. As such, the BC Energy Step Code poses a risk of downward pressure on natural gas demand but also provides an opportunity for FEI's C&EM [Conservation and Energy Management] programs.

6.1 Please elaborate on the opportunity for FEI's C&EM programs presented by the BC Energy Step Code.

Response:

The BC Energy Step Code provides an opportunity for FEI to expand its new construction C&EM programs in support of the BC Energy Step Code. Opportunities also exist for FEI to support education and awareness of this new voluntary building standard such as through FEI's Codes and Standards activities.

7.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1, Section 2.3.3.1, p. 43

Energy and Emission Policy – BC Climate Leadership Plan

On page 43 of Exhibit B-1, FEI states:

> The CLP [BC Climate Leadership Plan] included 21 action items intended to help put BC on course to meet the target of an 80 percent reduction in GHG emissions from 2007 levels by 2050. The CLP stated that the carbon tax rate could be increased from the current level ($30 per tonne) in the future but only once other jurisdictions catch up.

On page 43 of Exhibit B-1, FEI also lists actions outlined in the CLP that FEI states: "if implemented, may impact FEI and provincial natural gas use patterns."

7.1 Please explain if and how the BC CLP's 21 action items and statement on carbon tax was incorporated into FEI's: (i) End-Use Annual Demand Reference case forecast; and (ii) Traditional Peak Demand Forecast used to inform system needs and alternatives.

Response:

FEI's end-use annual demand scenario planning approach distinguishes declarations of policy vision from policy implementation. FEI reviewed this approach in some detail with its Resource Planning Advisory Group (RPAG) and received RPAG support for its approach. In accordance with this approach, the end-use annual demand Reference Case forecast keeps existing end-use patterns unchanged and accounts for energy and emissions policy only where implementation mechanisms are manifest or legally enshrined and mandatory. As such, the Reference Case only accounts for CLP action items that refer to policy implementation levers that are already manifest or legally enshrined (e.g. references to increasing carbon taxes in light of the Government of Canada's carbon pricing backstop mechanism). FEI created multiple alternate end-use annual demand scenarios specifically to account for critical uncertainties, such as how the policy recommendations, as described in the CLP, might be pursued.

FEI's Traditional Peak Method forecast intrinsically accounts for factors that influence its existing customer natural gas demand. As such, the Traditional Peak Method forecast only includes CLP action items where they refer to policy that is currently represented in FEI's customer natural gas demand. FEI updates its Traditional Peak Method forecast annually in order to account for customer natural gas demand changes that might occur as a result of, for example, changes in energy and emissions policy. The 2017 LTGRP includes an exploratory peak demand forecast method which illustrates how FEI's peak demand might link to the alternate future scenarios developed by the end-use annual demand forecast method. At this point, the exploratory peak demand forecast is theoretical in nature and unsupported by direct measurement. As such, FEI's infrastructure planning continues to rely on the Traditional Peak Method. The exploratory end-use method does, however, provide a means of assessing a range of peak demand forecast possibilities and the potential impact on system capacity upgrade project scope and timing and suggests that further exploration is warranted.

7.1.1 If not, please explain how FEI accounted for the BC CLP's 21 action items and statement on carbon tax in FBC's long term resource planning.

Response:

Please refer to the response to BCUC IR 1.7.1.

8.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1, Section 2.3.3.5, pp. 46-47

Tilbury LNG Facility

On page 46 of Exhibit B-1, FEI states:

> OIC 749 permitted additional expenditures, exempt from CPCN review by the BCUC, of up to $400 million for Phase 1B expansions of the Tilbury LNG facility subject to overall contracting levels averaging 70 percent of the facilities production capacity over a period of 15 years. … Subsequently, on March 21, 2017, the BC Government further amended Direction No. 5 through OIC 162/2017. The key amendments under OIC 162 were an increase to the Tilbury Phase 1A capital expenditure limit from $400 million to $425 million, removing the 70 percent average contracting requirement over 15 years pertaining to the Phase 1B expansion facility and removing the two lower priced tiers from Rate Schedule 46.

8.1 Please explain if and when FEI plans to: (i) begin construction; and (ii) put into service the Phase 1B expansion of the Tilbury LNG facility.

<u>Response:</u>

FEI is assessing potential timing for Phase 1B of the Tilbury LNG facility, and has not yet decided when to begin construction. The earliest in-service date for the 1B expansion is 2020, but is dependent on construction timing. In addition please refer to the response to BCUC IR 1.38.1 for high level information on project planning and construction timelines.

8.2 Please describe the factors that FEI monitored in order to determine whether or not to build Phase 1B expansions. For example this could include capacity on the CTS, NGT LNG demand, non-NGT LNG demand and other various factors.

<u>Response:</u>

FEI expects to build Phase 1B and is currently assessing scope, scale and timing. FEI has monitored demand growth and has forecast the potential demand on Tilbury as illustrated in the total annual demand graph seen in Figure 3-19, Section 3.4.8 in the LTGRP. All of the foreseeable demand has been taken into consideration.

9.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1, Section 2.4.1, pp. 52-53

Marine Bunkering

On page 52 of Exhibit B-1, FEI states:

> … there are global environmental regulations that are scheduled to be implemented in the next couple of years that are expected to materially impact the current mix of fuels that have traditionally been consumed by the global marine market. Due to these tighter restrictions on marine vessel emissions, natural gas in the form of LNG is expected to emerge as a choice alternative fuel for vessel operators to comply with these tighter restrictions.

On page 53 of Exhibit B-1, FEI states:

> Capitalizing on the LNG marine bunkering opportunity is a key part of FEI's strategy to leverage pre-existing Company-owned assets and operational expertise to drive growth in new markets. While the Tilbury LNG facility primarily serves as a winter peaking facility, over time, the facility has also evolved to serve a variety of new LNG markets.

9.1 Please confirm, or otherwise explain, that FEI's strategy involves capitalizing on LNG marine bunkering opportunities with organizations and companies that are not based in BC or do not have operations in BC.

Response:

FEI currently has customers under contract under Rate Schedule 46 (RS46) that are not based in BC that use LNG not only for marine bunkering, but for a variety of end uses in other parts of Western North America and in Asia.

FEI provides LNG through RS46 to customers that satisfy the contracting requirements as outlined in RS46. This means that customers that are eligible to receive LNG dispensing service under RS46 may or may not be based in BC. FEI does not differentiate between BC-based companies and those based outside of BC in terms of LNG supply under RS46.

With respect to the marine bunkering market, the nature and makeup of the LNG bunkering industry means that FEI expects to have customers that are based outside of BC.

9.2 Please explain the benefits for FEI's BC sales customers, of FEI pursuing this strategy.

Response:

By pursuing the strategy of developing natural gas for marine bunkering FEI expects to realize benefits for all FEI customers. For example, demand from this market segment would be incremental and year-round, and would increase the overall utilization of FEI's pipeline system. Since the demand from this market segment typically has a flatter load profile with very little seasonality associated with it, FEI can more predictably and efficiently operate its pipeline system as a result.

In addition to the more effective utilization of FEI's pipeline system, demand from the marine market segment (or for any market segment for that matter) would have incremental benefits for FEI's customers such as:

- reduced upward rate pressure for all non-bypass customers through rate pressure mitigation;
- reduced local air pollution where marine vessels are operating due to the lower air contaminants of LNG when compared to marine petroleum fuels; and
- GHG emissions reductions that would benefit not only FEI customers, but BC and Canada as a whole through reduced overall emissions.

Although some of the emissions reductions that would occur as a result of developing these marine markets would happen outside the geographic boundaries of BC or Canada, there would still be other tangible and material benefits that would be realized by all of FEI's customers. As a result, FEI should continue to develop these markets to adopt natural gas as a fuel for transportation.

9.3 Please explain: (i) the incremental costs; and (ii) the risks to FEI's BC Core customers of pursuing this strategy. Please provide calculations where necessary.

Response:

The Tilbury Phase 1A LNG facility is part of FEI's natural gas class of service. This means that any over or under recovery of costs are returned to or recovered from all of FEI's non-bypass customers through rates. Any and all demand that FEI serves under Rate Schedule 46 serves to recover the cost of service of providing the LNG service from FEI's LNG facilities.

As a result of this, there are no known incremental risks to FEI's BC Core customers by capitalizing on or pursuing the LNG marine bunkering opportunity using existing assets. As outlined in response to BCUC IR 1.9.2, the new incremental load on the system would increase the overall utilization of FEI's existing assets, which includes Tilbury Phase 1A.

Beyond existing Tilbury 1A assets, any incremental FEI costs are addressed under the Province's Direction No. 5 to the BCUC or the GGRR and will be included in future revenue requirements as applicable.

On page 53 of Exhibit B-1, FEI also states:

> LNG supply and delivery contracts are in place for three BC Ferries and two Seaspan Ferries vessels, with two more BC Ferries Spirit-class vessels expected to begin operational service, beginning mid-2018 for the first vessel and mid-2019 for the second vessel. … FEI will continue to advance its interests in the LNG marine bunkering market as an LNG fuel and logistics provider.

9.4 Please explain if BC Ferries and Seaspan Ferries are/will be customers served under a negotiated contract with FEI or served under a rate schedule in the tariff.

Response:

LNG dispensing and transportation delivery service to BC Ferries and Seaspan Ferries is provided under the terms and conditions of Rate Schedule 46 (RS46), which is an existing rate schedule in FEI's tariff.

9.4.1 If BC Ferries and Seaspan Ferries are served under a rate schedule in the tariff please identify the rate schedule.

Response:

Please refer to the response to BCUC IR 1.9.4.

9.5 Please state the: (i) aggregate annual demand; (ii) average daily demand; and (iii) peak day demand required to serve the five BC Ferries and two Seaspan Ferries vessels identified above.

Response:

The aggregate annual contracted demand for the five BC Ferries and two Seaspan Ferries vessels is 1,177,000 GJ per year. The average daily demand is 3,225 GJ per day (1,177,000 GJ / 365 days). Due to the relative flat load profile and non-seasonality of this marine demand, the average daily demand is assumed to be the same as the peak day demand.

9.5.1 Please confirm that the forecast demands for BC Ferries and Seaspan Ferries were incorporated into the Reference Case forecast developed using the: (i) End-Use Method; (ii) Traditional Demand Method; and (iii) the Traditional Peak Demand Method.

Response:

Regarding item (i), FEI confirms that the End-use Method annual demand forecast Reference Case includes forecast demands for BC Ferries and Seaspan Ferries. Regarding item (ii), FEI notes that the Traditional Annual Method does not contain forecast demands for BC Ferries and Seaspan Ferries because the Traditional Annual Method simply extends FEI's short-term forecast method across the 20-year planning horizon. Regarding item (iii), FEI confirms that the Traditional Peak Demand Method forecast includes the Tilbury Phase 1A installed liquefaction capacity operating on a peak day starting in 2017 and continuing through the rest of the forecast period. The Phase 1A expansion accommodates the identified BC Ferries and Seaspan Ferries demand and has room for future growth in demand. FEI emphasizes that the 2017 LTGRP plans to the End-Use Method annual demand Reference Case and the Traditional Peak Demand Method.

9.5.1.1 If not, please update the Reference Case forecasts listed in the question above with the forecast demands for BC Ferries and Seaspan Ferries.

Response:

Please refer to the response to BCUC IR 1.9.5.1.

9.6 Please explain FEI's role as a "logistics provider" as quoted from the statement in the preamble.

Response:

FEI's role as a "logistics provider" as quoted from the statement in the preamble is referring to provisions providing this service under FEI's RS 46. This includes the transporting of LNG from FEI's LNG facilities to the two marine customers as well as the unloading of LNG to the marine vessels.

9.7 Which of FEI's LNG facilities (Mt. Hayes and Tilbury) will serve marine vessel customers?

Response:

LNG supply for FEI's existing marine customers (BC Ferries and Seaspan Ferries) is being provided from both the Mt. Hayes and Tilbury LNG facilities.

C. ANNUAL ENERGY DEMAND FORECASTING

10.0 Reference: ANNUAL ENERGY DEMAND FORECASTING

Exhibit B-1, Section 3.1, p. 59; Section 3.3, pp. 60-61

Customer Additions Forecast – Residential

On page 59 of Exhibit B-1, FEI states:

> Sections 3.2 and 3.3 set the stage by outlining FEI's base year customer distribution and annual demand and by discussing FEI's customer forecast which serves as the basis for both of the 2017 LTGRP's two annual demand forecast methods.

10.1 Please confirm, or otherwise explain that FEI's traditional annual demand forecast method and FEI's end-use annual demand forecast method both utilize the same year end customer forecasts for residential, commercial and industrial customers.

Response:

Confirmed.

10.1.1 If confirmed, please explain if the differences between the annual results of the traditional annual demand forecast method and the end-use annual demand method are attributable to the use-per-customer.

Response:

Both forecast methods combine customer forecast and UPC in order to derive annual demand for each year across the forecast horizon. Each method uses a different approach for deriving its UPC and combining it with the customer forecast. As such, the root cause of the difference between the two forecast methods extends beyond UPC only. Please refer to FEI's response to BCUC IR 1.17.2 for a detailed discussion of the differences across the two forecast methods.

On pages 60 and 61 of Exhibit B-1, FEI states:

> FEI uses a well-established method to forecast customer additions that remains consistent with previous LTRP filings. The forecast of residential customer additions is grounded in the Conference Board of Canada housing starts forecast for BC.

10.2 Please provide a detailed explanation of the methodology used to forecast residential customer additions based on the Conference Board of Canada housing starts forecast.

Response:

The residential net customer additions forecast was developed based on housing starts data from CBOC forecast of November 24, 2014 Provincial Medium Term Forecast: 15 Run: 15, Table LTPF156 and LTPF157. The CBOC forecast provides growth rates for the full 20 years of the LTRP forecast so all the years in the forecast are calculated using the same method.

The Lower Mainland region is used below to demonstrate the calculations. All other regions are calculated the same way. The residential customer additions forecast for the Lower Mainland region is shown in the following table and then described in detail below:

1	Region	**Lower Mainland**
2	2014 Rate 1 Customers	537,104
3	2015 Rate 1 Customers	542,379
4	2015 Additions	5,275
5	SFD %	44.236%
6	MFD %	55.764%
7	2015 SFD Additions	2,333
8	2015 MFD Addiitons	2,942

Row	Item
2,3	The total rate schedule 1 customers recorded at the end of the year
4	The 2015 residential customer additions calculated by subtracting row 2 from row 3: $5{,}275 = 542{,}379 - 537{,}104$
5,6	The split between single and multi-family premises is based on historical percentages from internal FEI data.
7,8	The actual 2015 FEI customer additions by dwelling type. The customer additions from row 4 are multiplied by the percentages from rows 5 and 6. For example: $2015\ SFD\ Additions = 2{,}333 = 5{,}275\ \times 44.236\%$

Once the starting values are calculated the CBOC growth rates are used to develop forecasts by dwelling type for the duration of the forecast. The details are shown and described below.

	A	B	C	D	E	F
	Year	CBOC SFD Growth Rate (%)	CBOC MFD Growth Rate (%)	SFD Additions	MFD Additions	Total Additions
1	2016	-6.6	2.4	2,179	3,012	5,192
2	2017	-6.3	-0.2	2,042	3,006	5,048
3	2018	-0.7	2	2,028	3,066	5,094
4	2019	-0.4	0.8	2,020	3,091	5,111
5	2020	-0.2	0.1	2,016	3,094	5,110
6	2021	-5.3	-5.2	1,909	2,933	4,842
7	2022	-8.8	-8.5	1,741	2,684	4,425
8	2023	-5.5	-5.2	1,645	2,544	4,189
9	2024	-4	-3.7	1,579	2,450	4,029
10	2025	3.4	3.2	1,633	2,528	4,161
11	2026	1.3	1.3	1,654	2,561	4,216
12	2027	-1.9	-1.7	1,623	2,518	4,141
13	2028	0.4	0.7	1,629	2,535	4,165
14	2029	-1.5	-1	1,605	2,510	4,115
15	2030	-1.8	-1.3	1,576	2,477	4,053
16	2031	-1.8	-1.7	1,548	2,435	3,983
17	2032	-2.2	-2.1	1,514	2,384	3,898
18	2033	-1.4	-1.3	1,492	2,353	3,845
19	2034	-2.1	-2	1,461	2,306	3,767
20	2035	-3.1	-3	1,416	2,237	3,653
21	2036	-3.1	-3	1,372	2,170	3,542

Column	Item
B,C	The provincial housing starts growth rates by dwelling type from the CBOC forecast: November 24, 2014 Provincial Medium Term Forecast: 15 Run: 15
D	The SFD additions for 2016 (row 1) are calculated by using the CBOC growth rate for 2016 (column B) and the 2015 year end actual additions as follows: $2016\ SFD\ Additions = 2{,}179 = 2{,}333 \times (100 - 6.6)\%$
E	The MFD additions for 2016 (row 1) are calculated using the CBOC MFD growth rate for 2016 (column C) and the 2015 year end actual additions as follows: $2016\ MFD\ Additions = 3{,}012 = 2{,}942 \times (100 + 2.4)\%$
F	The total additions are calculated by summing the single and multi-family additions as follows: $2016\ Residential\ Customer\ Additions = 5{,}192 = 2{,}179 + 3{,}012$ Note that results are rounded to the nearest whole customer.

Subsequent years use the result from the prior year along with the appropriate CBOC growth rate. For example the value in row 2, column D is calculated as follows:

$$2017\ SFD\ Customer\ Additions\ Forecast = 2{,}042 = 2{,}179 \times (100 - 6.3)\%$$

11.0 Reference: ANNUAL ENERGY DEMAND FORECASTING

Exhibit B-1, Section 3.3, p. 61

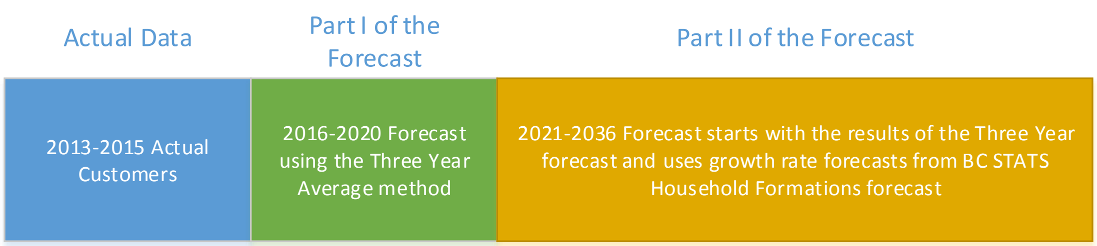
Customer Additions Forecast – Commercial

On page 61 of Exhibit B-1, FEI states: "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."

11.1 Please provide a detailed explanation of the methodology, with calculations where relevant, used to forecast customer commercial additions for each of the service regions.

Response:

Conceptually, the method for forecasting the commercial customer additions can be visualized in three parts as shown in the table below. These parts do not represent a chronological flow. Rather, they tend more to represent the source data that feed the forecast method.



The customer forecasting process is completed in five steps. Steps I and II use the Household Formations forecast (HHF) from BC STATS. This forecast provides long-term regional (Local Health Area) growth rates. These steps start with the last known actual customer totals (2015) and applies the HHF growth rates for the full 20 years of the forecast. Steps III through V demonstrate how FEI maintains consistency between the Short Term and Long Term forecasts for the first five duration of the Short Term forecast. An explanation of each step follows.

Step I

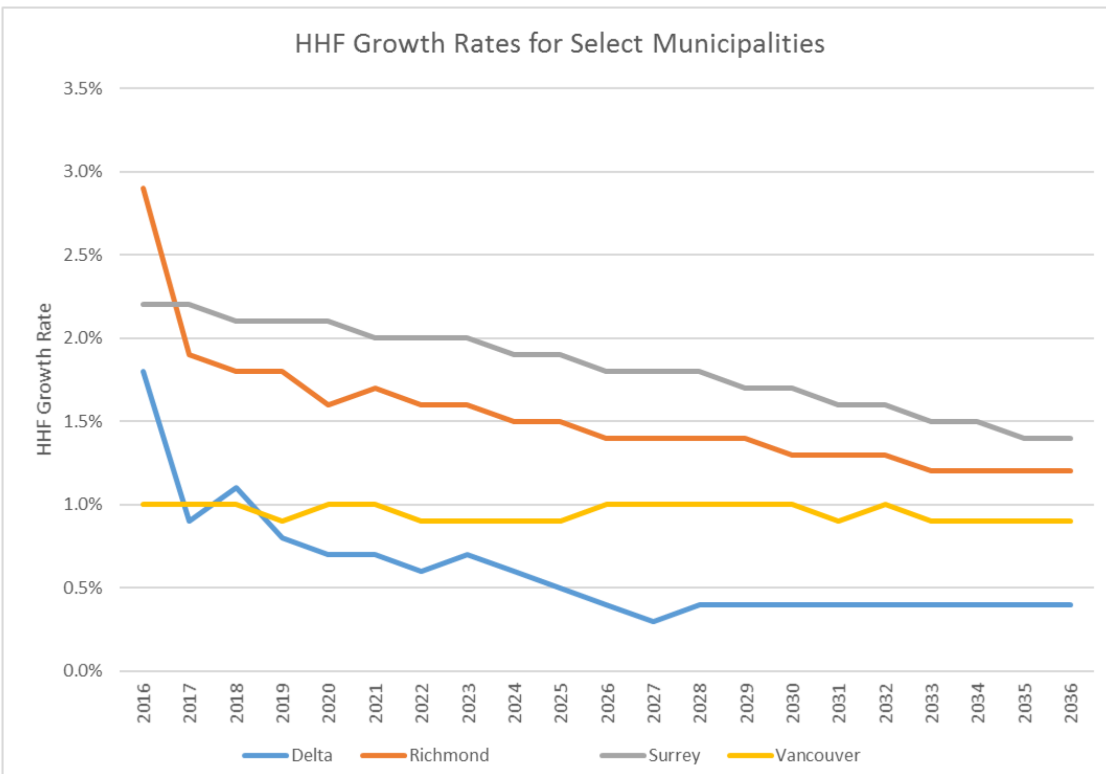
The FEI commercial customer forecast method starts with the growth rates from the BC STATS HHF forecast to establish the commercial customer forecast for the period from 2016 to 2036. BC STATS publishes the growth rates in the HHF forecast for each Local Health Area. FEI groups customers similarly, and then applies the growth rates. The growth rate table for Lower Mainland is shown below. All commercial rate schedules use these same growth rates.

Table 1: HHF Growth Rates by LHA

Local Health Area	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Abbotsford	1.8%	1.4%	1.3%	1.3%	1.3%	1.3%	1.3%	1.3%	1.3%	1.2%	1.2%	1.2%	1.3%	1.3%	1.2%	1.2%	1.2%	1.2%	1.1%	1.1%	1.1%
Burnaby	1.9%	1.7%	1.6%	1.6%	1.6%	1.6%	1.6%	1.7%	1.6%	1.6%	1.6%	1.7%	1.6%	1.5%	1.5%	1.4%	1.4%	1.4%	1.3%	1.3%	1.3%
Chilliwack	2.2%	2.3%	2.0%	1.9%	2.0%	1.9%	1.9%	1.9%	1.8%	1.8%	1.8%	1.8%	1.7%	1.7%	1.7%	1.6%	1.6%	1.6%	1.6%	1.5%	1.5%
Coquitlam	2.7%	2.0%	1.8%	1.7%	1.7%	1.7%	1.6%	1.6%	1.6%	1.6%	1.5%	1.5%	1.5%	1.5%	1.5%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%
Delta	1.8%	0.9%	1.1%	0.8%	0.7%	0.7%	0.6%	0.7%	0.6%	0.5%	0.4%	0.3%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
Hope	1.3%	0.1%	0.3%	0.2%	-0.3%	0.1%	0.1%	-0.1%	0.0%	-0.2%	0.1%	-0.1%	-0.1%	-0.1%	-0.4%	-0.3%	-0.1%	-0.1%	-0.2%	-0.3%	-0.2%
Langley	2.6%	2.2%	2.0%	2.0%	1.9%	1.9%	1.9%	1.9%	1.8%	1.8%	1.8%	1.8%	1.7%	1.7%	1.7%	1.6%	1.6%	1.6%	1.5%	1.5%	1.4%
Maple Ridge	3.3%	2.4%	2.1%	2.2%	2.0%	1.9%	1.9%	1.9%	1.7%	1.8%	1.7%	1.7%	1.6%	1.6%	1.5%	1.5%	1.4%	1.4%	1.4%	1.4%	1.4%
New Westminster	1.8%	2.0%	1.8%	1.9%	1.7%	1.9%	1.7%	1.7%	1.6%	1.6%	1.7%	1.6%	1.6%	1.5%	1.5%	1.4%	1.4%	1.3%	1.3%	1.3%	1.2%
North Vancouver	1.4%	1.3%	1.0%	1.1%	1.0%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%
Richmond	2.9%	1.9%	1.8%	1.8%	1.6%	1.7%	1.6%	1.6%	1.5%	1.5%	1.4%	1.4%	1.4%	1.4%	1.3%	1.3%	1.3%	1.2%	1.2%	1.2%	1.2%
Howe Sound	2.5%	2.0%	1.8%	2.0%	1.7%	1.7%	1.7%	1.5%	1.4%	1.4%	1.3%	1.5%	1.3%	1.3%	1.3%	1.3%	1.3%	1.2%	1.2%	1.2%	1.2%
Surrey	2.2%	2.2%	2.1%	2.1%	2.1%	2.0%	2.0%	2.0%	1.9%	1.9%	1.8%	1.8%	1.8%	1.7%	1.7%	1.6%	1.6%	1.5%	1.5%	1.4%	1.4%
Vancouver	1.0%	1.0%	1.0%	0.9%	1.0%	1.0%	0.9%	0.9%	0.9%	0.9%	1.0%	1.0%	1.0%	1.0%	1.0%	0.9%	1.0%	0.9%	0.9%	0.9%	0.9%
Surrey	2.2%	2.2%	2.1%	2.1%	2.1%	2.0%	2.0%	2.0%	1.9%	1.9%	1.8%	1.8%	1.8%	1.7%	1.7%	1.6%	1.6%	1.5%	1.5%	1.4%	1.4%

Figure 1 below shows an example of the HHF growth rates for four municipalities for the test period:

Figure 1: Select Growth Rates from the HHF Forecast



These growth rates are used in the customer additions forecast to grow the customer totals in each region at different rates. For example, the growth rate in Surrey is expected to decline steadily from 2.2 percent in 2016 to 1.4 percent by 2036. On the other hand, the Vancouver growth rate is expected to remain constant at around 1 percent.

Step II

FEI's 2015 Lower Mainland Rate Schedule 2 year-end customer counts by Local Health Area are shown in Table 2 below.

Table 2: FEI Lower Mainland Rate Schedule 2 Customers by LHA

LHA #	Local Health Area	Municipality	Year End 2015 Customers
34	Abbotsford	Abbotsford/Aldergrove/Mission	4,372
41	Burnaby	Burnaby	4,421
33	Chilliwack	Chilliwack/Agassiz/Cultus Lake/Harrison Hot Springs/Lindell Beach/Rosedale	2,543
43	Coquitlam	Coquitlam/Anmore/Belcarra/Port Coquitlam/Port Moody	3,680
37	Delta	Delta/Tsawwassen	2,351
32	Hope	Hope	254
35	Langley	Langley	3,429
42	Maple Ridge	Maple Ridge/Pitt Meadows	1,595
40	New Westminster	New Westminster	1,103
44	North Vancouver	North Vancouver/West Vancouver	2,914
38	Richmond	Richmond	4,879
48	Howe Sound	Squamish/Brackendale	407
36	Surrey	Surrey	8,215
39	Vancouver	Vancouver	11,579
36	Surrey	White Rock	382
	Total		52,124

FEI applies the growth rates from Table 1 to the Year End Customer counts from Table 2 to develop the customer forecast in Table 3 as follows.

Table 3: HHF Forecast for 2016

Household Formation Method (HHF) Local Health Area	Year End 2015 Customers	2016
Abbotsford	4,372	79
Burnaby	4,421	84
Chilliwack	2,543	56
Coquitlam	3,680	99
Delta	2,351	42
Hope	254	3
Langley	3,429	89
Maple Ridge	1,595	53
New Westminster	1,103	20
North Vancouver	2,914	41
Richmond	4,879	141
Howe Sound	407	10
Surrey	8,215	181
Vancouver	11,579	116
Surrey	382	8
Total	52,124	1,023

For example, Abbotsford 2016:

$$Abbotsford\ 2016 = 4{,}372 \times 1.8\% = 79$$

The total Lower Mainland Rate Schedule 2 annual additions is the sum of the HHF additions and is 1,023 in the table above.

Step III

The HHF-based forecast in Step II will not match the results from FEI's Short Term forecast method. At this point a reconciliation calculation is introduced to align the first five years of the HHF based forecast with the first five years of the Short Term forecast. This step is critical to make sure that FEI has a single consistent forecast for the short term. The Short Term forecast method follows for 2016:

$$2016\ Customers = 2015\ Customers\ + 3\ Yr\ Avg\ Customer\ Additions$$

For Lower Mainland Rate Schedule 2:

Table 4: Lower Mainland Rate Schedule 2 Short Term Customer Additions Forecast

Year	Year End Customers	Customer Additions	3 Yr Average
2013	50,749	869	
2014	51,423	674	
2015	52,124	701	748
2016	52,872	748	
2017	53,620	748	
2018	54,368	748	
2019	55,116	748	
2020	55,864	748	

The three-year average additions was 748, so customer additions for each year are set at 748.

Recall that the HHF forecast was 1,023 customers. These two forecasts are reconciled such that the Short Term result replaces the HHF forecast for the first five years of the long term forecast. This step is accomplished by developing a reconciliation factor.

Table 5: 2016 Reconciliation Factor

3 Yr Avg Method Additions		748
HHF Method		1,023
Reconciliation Factor		0.731

$$Reconciliation\ Factor = \frac{748}{1{,}023} = 0.731$$

Step IV

The reconciliation factor is applied to the HHF forecast of customer additions. The sum of the customer additions is then guaranteed to match the short-term forecast. While FEI could simply replace the first five years of the forecast with the Short Term forecast the development of reconciliation factors is applicable for latter years of the forecast where there is no direct short-term replacement.

The results and accompanying calculation for 2017 are shown in Table 6:

Table 6: HHF Forecast for 2016

Household Formation Method (HHF) Local Health Area	Year End 2015 Customers	2016	2017
Abbotsford	4,372	4,430	4,482
Burnaby	4,421	4,482	4,547
Chilliwack	2,543	2,584	2,634
Coquitlam	3,680	3,753	3,816
Delta	2,351	2,382	2,400
Hope	254	256	257
Langley	3,429	3,494	3,559
Maple Ridge	1,595	1,633	1,667
New Westminster	1,103	1,118	1,136
North Vancouver	2,914	2,944	2,976
Richmond	4,879	4,982	5,063
Howe Sound	407	414	421
Surrey	8,215	8,347	8,503
Vancouver	11,579	11,664	11,763
Surrey	382	388	395
Total	52,124	52,872	53,620

For Abbotsford:

$$\boldsymbol{Abbotsford = 4,430 + (0.731 \times 79) = 4,482}$$

Step V

The final reconciliation factor for the fifth year of the Short Term forecast (0.895 in Table 7, below) is held constant for the remainder of the long-term forecast. This step avoids the discontinuity in the sixth year that would otherwise result. The sixth year is the first year of the HHF forecast and is normally higher in value than the corresponding fifth year of the short-term forecast. The HHF forecast is predicting household formations while the purpose of the commercial forecast is to predict net commercial customer additions. The growth trends (slopes) are expected to be similar but the starting point is lower because fewer commercial customers attach than households are formed. The concept is similar to the use of the CBOC growth rates for residential additions, rather than using the CBOC housing starts. FEI does not attach every household that forms or dwelling that is constructed.

The complete reconciliation factor table follows:

Table 7: Reconciliation Factors

3 Yr Avg Method Additions	748	748	748	748	748	748	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
HHF Method	1,023	883	839	833	832	836	822	839	816	822	822	832	835	829	825	793	814	791	784	778	781
Reconciliation Factor	0.731	0.847	0.891	0.898	0.899	0.895	0.895	0.895	0.895	0.895	0.895	0.895	0.895	0.895	0.895	0.895	0.895	0.895	0.895	0.895	0.895

The final net additions are shown below:

Table 8: Lower Mainland Rate Schedule 2 Customer Additions by LHA and Total

Household Formation Method (HHF) Local Health Area	Year End 2015 Customers	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Abbotsford	4,372	4,430	4,482	4,534	4,587	4,641	4,695	4,749	4,804	4,860	4,913	4,965	5,019	5,077	5,136	5,191	5,247	5,303	5,360	5,413	5,466	5,520
Burnaby	4,421	4,482	4,547	4,612	4,678	4,745	4,813	4,882	4,957	5,028	5,100	5,173	5,251	5,326	5,398	5,470	5,539	5,608	5,679	5,745	5,811	5,879
Chilliwack	2,543	2,584	2,634	2,681	2,727	2,776	2,823	2,871	2,920	2,967	3,015	3,063	3,113	3,160	3,208	3,257	3,304	3,351	3,399	3,448	3,494	3,541
Coquitlam	3,680	3,753	3,816	3,877	3,937	3,997	4,058	4,116	4,175	4,234	4,295	4,353	4,411	4,470	4,530	4,591	4,649	4,707	4,766	4,826	4,886	4,947
Delta	2,351	2,382	2,400	2,424	2,441	2,456	2,472	2,485	2,501	2,514	2,525	2,534	2,541	2,550	2,559	2,569	2,578	2,587	2,596	2,606	2,615	2,624
Hope	254	256	257	257	258	257	257	258	257	257	257	257	257	257	256	255	255	255	254	254	253	253
Langley	3,429	3,494	3,559	3,623	3,688	3,751	3,815	3,880	3,945	4,009	4,074	4,139	4,206	4,270	4,335	4,401	4,464	4,528	4,592	4,654	4,717	4,776
Maple Ridge	1,595	1,633	1,667	1,698	1,731	1,763	1,793	1,823	1,854	1,882	1,913	1,942	1,971	1,999	2,028	2,055	2,083	2,109	2,135	2,162	2,189	2,217
New Westminster	1,103	1,118	1,136	1,155	1,174	1,192	1,213	1,231	1,250	1,268	1,286	1,305	1,324	1,343	1,361	1,379	1,397	1,414	1,431	1,447	1,464	1,480
North Vancouver	2,914	2,944	2,976	3,003	3,032	3,060	3,084	3,109	3,134	3,159	3,185	3,211	3,234	3,257	3,280	3,304	3,327	3,351	3,375	3,399	3,423	3,448
Richmond	4,879	4,982	5,063	5,144	5,227	5,302	5,383	5,460	5,538	5,613	5,688	5,759	5,831	5,904	5,978	6,048	6,118	6,189	6,256	6,323	6,391	6,460
Howe Sound	407	414	421	428	436	443	449	456	462	468	474	479	486	492	497	503	509	515	520	526	532	537
Surrey	8,215	8,347	8,503	8,662	8,825	8,992	9,153	9,317	9,483	9,645	9,809	9,967	10,127	10,290	10,447	10,606	10,758	10,912	11,058	11,207	11,347	11,489
Vancouver	11,579	11,664	11,763	11,867	11,963	12,071	12,179	12,277	12,376	12,476	12,576	12,689	12,802	12,917	13,032	13,149	13,255	13,373	13,481	13,590	13,699	13,809
Surrey	382	388	395	403	410	418	426	433	441	448	456	463	471	479	486	493	500	507	514	521	528	534
Total	52,124	52,872	53,620	54,368	55,116	55,864	56,612	57,347	58,098	58,829	59,564	60,300	61,044	61,791	62,533	63,271	63,981	64,709	65,417	66,119	66,815	67,514

The net additions are aggregated to the Lower Mainland regional level, resulting in the regional rate schedule forecast. System wide additions are calculated by simply summing the regional forecasts.

The customer additions forecast developed using the Short Term Method are shown to remain quite consistent with the HHF method.

Figure 2: Lower Mainland Rate Schedule 2 Customer Forecast

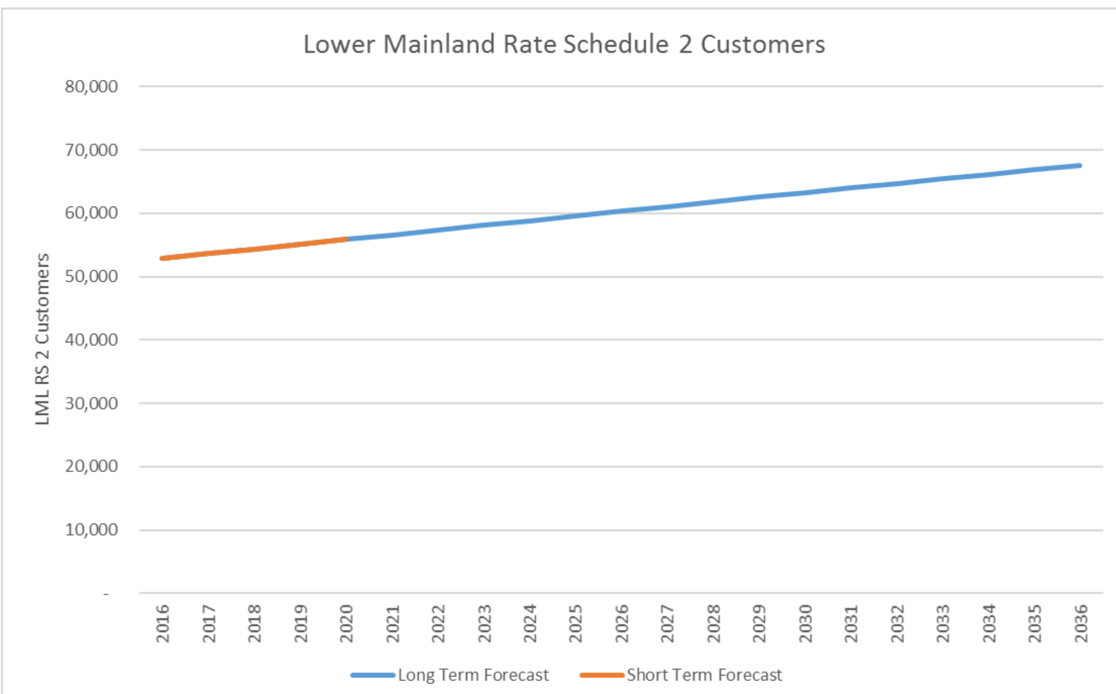


Figure 3 shows the Lower Mainland Rate Schedule 2 customer additions forecast:

Figure 3: Lower Mainland Rate Schedule 2 Customer Additions Short and Long Term Forecasts

Year	Long Term Forecast	Short Term Forecast
2,016	748	748
2,017	748	748
2,018	748	748
2,019	748	748
2,020	748	748
2,021	748	-
2,022	735	-
2,023	751	-
2,024	730	-
2,025	735	-
2,026	736	-
2,027	744	-
2,028	747	-
2,029	742	-
2,030	739	-
2,031	709	-
2,032	728	-
2,033	708	-
2,034	702	-
2,035	696	-
2,036	699	-

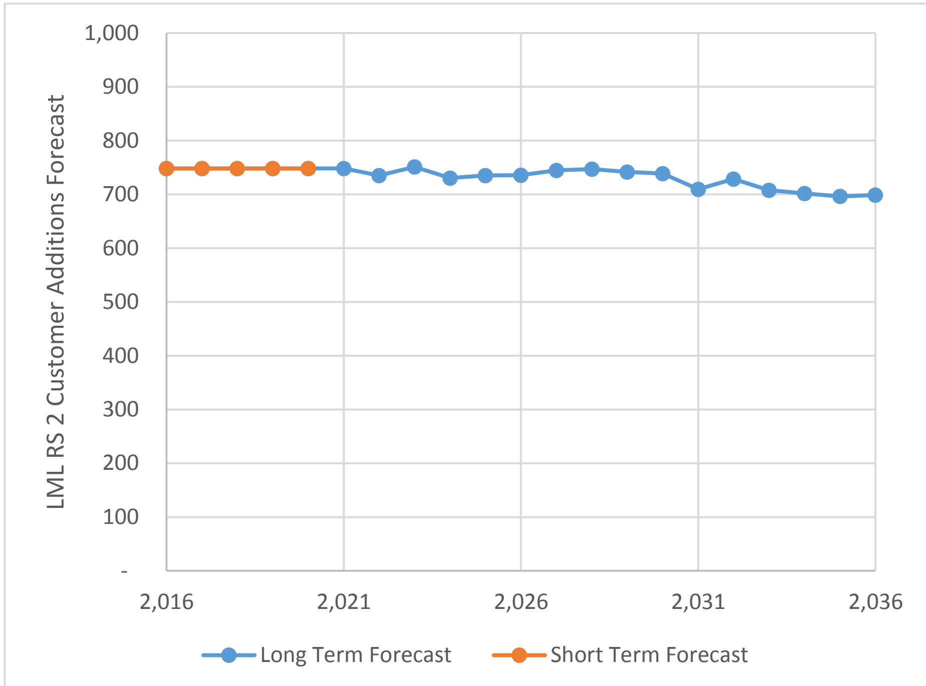


Figure 3 highlights three key features of the method:

1. The first five years (orange points) are consistent with the short term forecast because the same method is used.
2. The start of the long-term portion of the forecast (2021, blue point) is reconciled to be consistent with the end of the short-term portion of the forecast.
3. The latter 15 years of the forecast (blue points) is shaped by the long term BC STAT Household Formations Forecast.

All other commercial rate schedules and regions are calculated using the same method.

11.2 Please explain how a three year observation period accurately reflects growth over the long term forecast period. Please include in your response a discussion of the extent that the three year observation period accurately captures the effects of exogenous factors, including but not limited to long term economic cycles.

Response:

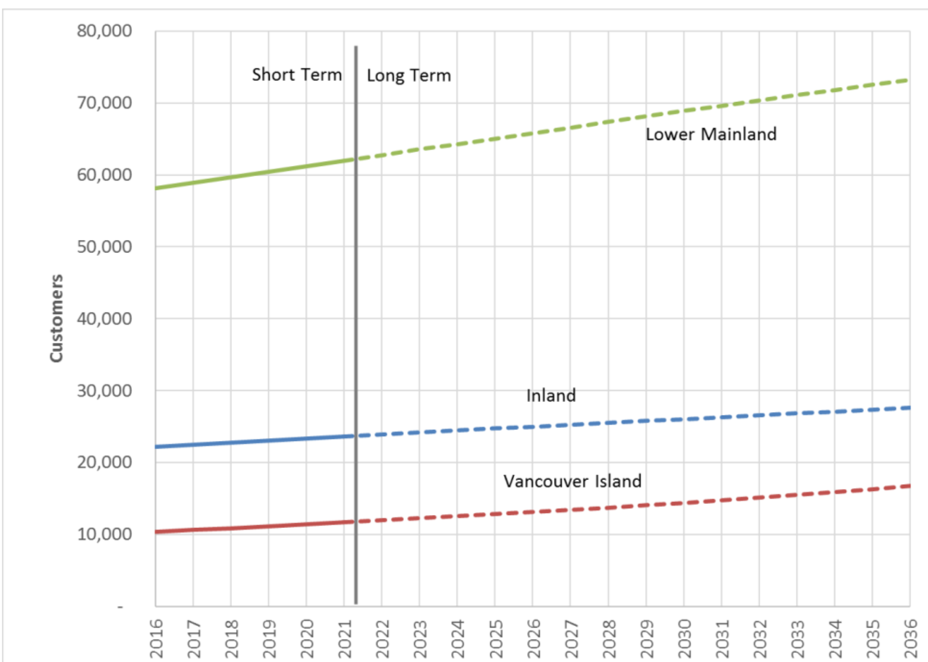
The 2017 LTGRP commercial customer forecast not only considers historical data but is also informed by BC STATS forecasting of long-term household formations. In addition, the 2017 LTGRP scenario analysis addresses the potential impact of variances in exogenous factors on the account forecast.

Consistent with the short-term forecast method three years of actual customer additions were used to develop the first five years of the customer forecast.

Consistent with past practice FEI then developed forecasts for years six through 20 using the BC STATS long-term household formations forecast. FEI assumes that the BC STATS forecast properly accounts for all external long term factors.

Future uncertainty is further modelled by calculating prediction intervals for each forecast. The prediction interval calculation used historic data from 2006 through 2015.

The result (as shown at the April 11, 2017 RPAG presentation) is shown below.



12.0 Reference: ANNUAL ENERGY DEMAND FORECASTING
Exhibit B-1, Section 3.3.1.3, p. 62
Customer Additions Forecast – Industrial

On page 62 of Exhibit B-1, FEI states:

> The Company had 979 industrial customers in 2015. At the time the long term forecast was prepared, there were no firm commitments for new industrial customers to take natural gas service or for existing customers to close their accounts. Hence, no material growth or decline in industrial customers has been forecasted.

12.1 Please confirm that this remains true. If not confirmed, please provide updates to the relevant sections of the Application that would occur as a result.

<u>Response:</u>

There was a typographical error in the number of industrial customers in 2015. The correct count is 995 industrial customers in 2015.

Otherwise, confirmed.

In 2017 there were 997 industrial customers, which is an increase of two customers compared to the 2015 data used to prepare the forecast.

13.0 Reference: ANNUAL ENERGY DEMAND FORECASTING

Exhibit B-1, Appendix B-4, p. 1

End-use Model Use per Customer Forecast – Residential

On page 1 of Appendix B-4 of Exhibit B-1, FEI presents the customer additions, use per customer and annual demand forecasts broken down by rate schedule. The data shows that the use per customer for the residential rate class (Rate 1) is forecasted to decrease from 83.7 GJ per year in 2015 to 70.8 GJ per year in 2036.

13.1 Please state which service areas are included in the forecasts on page 1 of Appendix B-4.

Response:

Page 1 of Appendix B-4 includes data for the following regions:

- Lower Mainland
- Northern BC
- Southern Interior
- Vancouver Island
- Whistler.

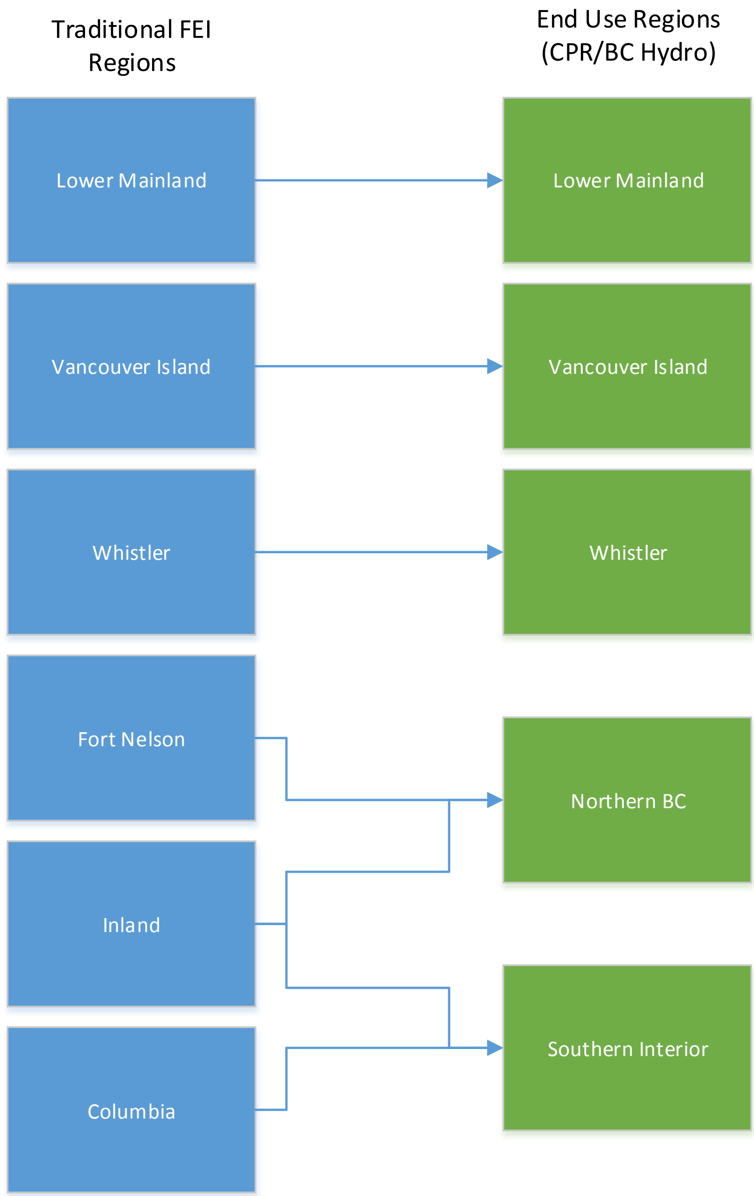
Northern BC and Southern Interior are not traditional FEI regions, but were required because FEI used data from the BC CPR project where FEI collaborated with FBC, BC Hydro and PNG. To make use of the BC CPR results FEI had to use the same regional conventions as BC Hydro. The Lower Mainland, Vancouver Island and Whistler regions are defined identically in both the CPR and traditional FEI regions. However, the BC CPR used “Northern BC” and “Southern Interior” to identify customers in the FEI Fort Nelson, Inland and Columbia regions.

Both approaches describe service areas encompassing all customers. For convenience a mapping convention was created to convert from one definition to the other.

The traditional FEI regions are:

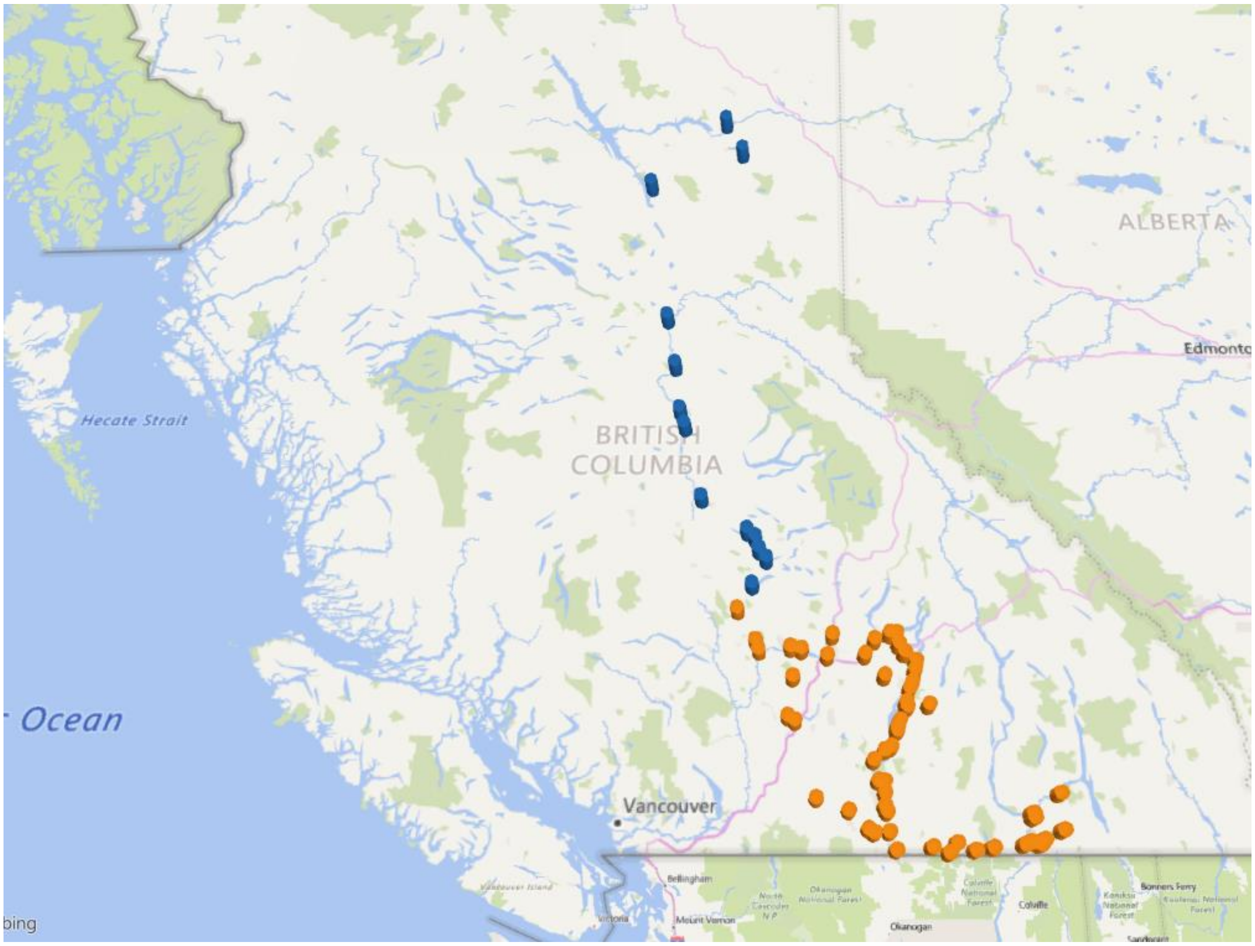
- Lower Mainland
- Inland
- Columbia
- Vancouver Island
- Whistler
- Ft. Nelson.

The mapping between the two region definitions is shown in the following figure:



Fort Nelson was mapped to “Northern BC” while Columbia was assigned to “Southern Interior”

The Inland region was divided between “Northern BC” and “Southern Interior” as shown in the following map:



In the map, only cities in the FEI Inland region are shown. The blue dots indicate cities mapped to "Northern BC" for the End Use forecast. Cities identified by the orange dots are associated with the "Southern Interior" for the purpose of the End Use forecast.

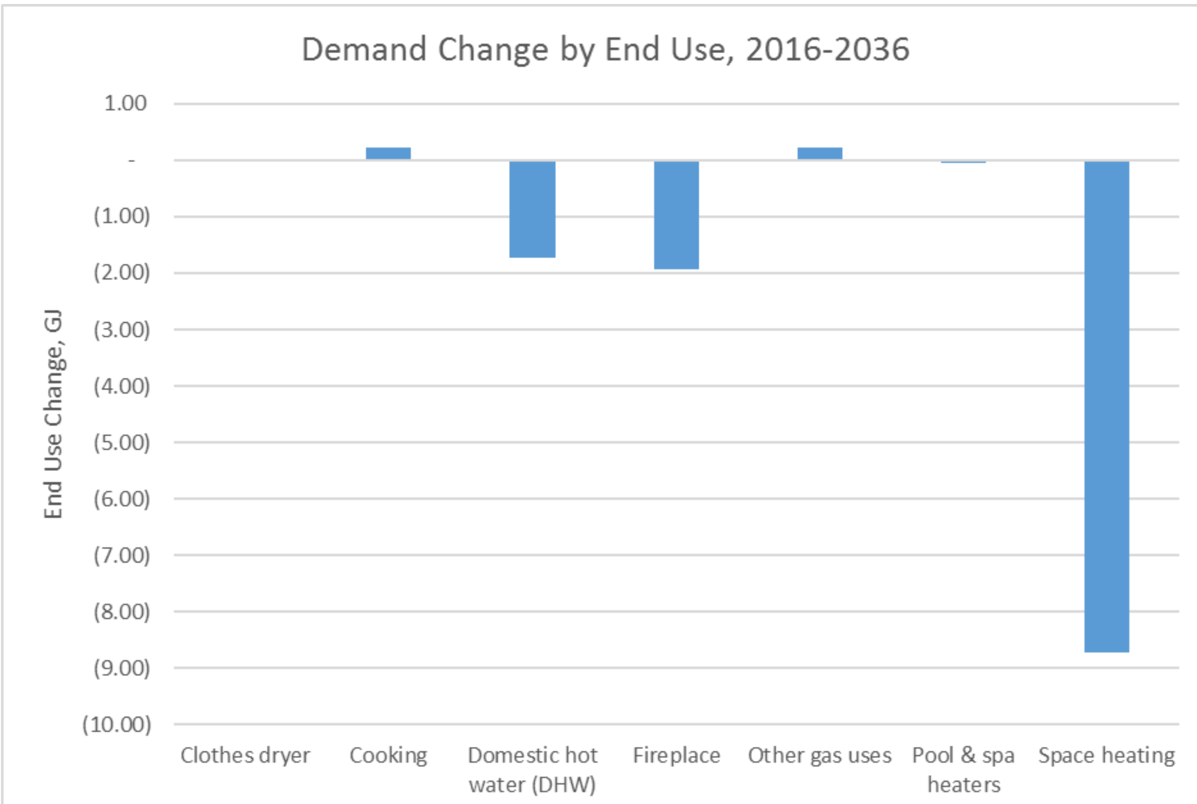
The most northern Inland city mapped to the "Southern Interior" was Clinton. The most southern Inland city mapped to the "Northern BC" region was 70 Mile House. These two cities define the dividing line between the "Southern Interior" and "Northern BC".

13.2 Please explain, with rationale, what is contributing to the forecast reduction in the residential use per customer as seen in Appendix B-4.

Response:

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

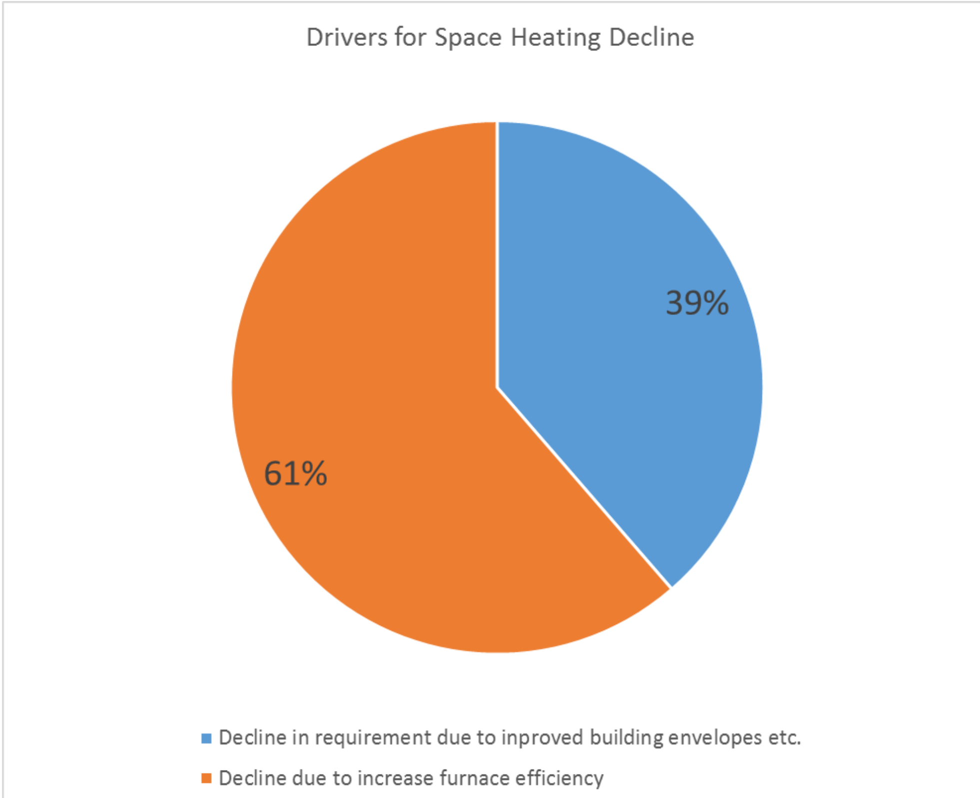
The reference case residential use rate forecast is comprised of multiple end uses, each with its own trajectory. The net decline in the aggregate residential use rate is driven primarily by the decline in the space heating load. In 2016 the average space heating demand in the reference case end use forecast is 51.7 GJ. By 2036 the space heating end use is forecast to decline to 43 GJ, a reduction of 8.7 GJ. The aggregate decline shown in Appendix B4 from 2016 to 2036 is 12 GJ. Space heating represents 73% of this decline. The following chart shows the change for each end use over the 20 year forecast period:



A further examination of the space heating decline, using the results from the End Use model, reveals that the 8.7 GJ reduction is due to a reduced requirement resulting from improvements in building envelopes as well as an increase in furnace efficiency. The End Use model provides the following proportions:

	GJ	Percent
Decline in Space Heating demand	8.72	
Decline in requirement due to inproved building envelopes etc.	3.37	39%
Decline due to increase furnace efficiency	5.35	61%

The above table is shown in the following chart:



Drivers for Space Heating Decline
39%
61%
Decline in requirement due to inproved building envelopes etc.
Decline due to increase furnace efficiency

14.0 Reference: ANNUAL ENERGY DEMAND FORECASTING

Exhibit B-1, Appendix B-3, p. 1

Traditional Model Use per Customer Forecast – Residential

On Page 1 of Appendix B-3 in Exhibit B-1, FEI states:

> The Company's Traditional Annual Method for forecasting residential and commercial demand involved determining a forecast natural gas Use per Customer (UPC) and multiplying it by the number of customers forecasted for each year of the study period. … The analysis was conducted for each residential and commercial rate class, based on the most recent three years of data. The trends were then extended into the next 20 years for the purposes of providing a long term forecast.

14.1 Please explain the pros and cons of using 3 years of historical data to forecast 20 years, when compared to using more years of historical data (for example 5 or 10 years) to forecast 20 years.

Response:

Consistent with past practice, FEI uses the results from the most recent short-term use rate forecast for the start of the long-term forecast. This is the only way to ensure consistency between short and long-term filings so that use rate predictions for future years match. If FEI were to use different methods for the short and long-term forecasts then multiple use rate forecasts would exist for the same year, regions and rate schedules.

Using different inputs to the time series methods will certainly result in different forecasts (for example using 10 years of historic data instead of three years) but it is not clear that a different result would also be a more accurate result.

The traditional forecast presented in the LTRP is intended to provide a check on the end use forecast results. If FEI were to start using untested methods (such as a 10 year time series) then it is not clear if the results would form a reliable check on the end use method.

14.2 Have there been any significant changes observed in historical UPC trends more recently that caused FEI to use a 3 year observation period?

Response:

No. Please refer to the response to BCUC IR 1.11.2. for the reasoning behind using a three year period.

15.0 Reference: ANNUAL ENERGY DEMAND FORECASTING

Exhibit B-1; Section 3.4.1, p. 64; Appendix B-1, Section 1.2.1.4.2, p.12

End-use Reference Case forecast

On page 64 of Exhibit B-1, FEI states: "The end-use forecast process starts with developing a Reference Case forecast. The Reference Case is based on end-use patterns observed in the base year and keeps these patterns constant throughout the planning period."

On page 12 of Appendix B-1, FEI states that:

> The Reference Case assumes that currently mandatory or legally enshrined appliance standards continue across the entire planning period. The Reference Case also accounts for some natural change in average appliance efficiencies across the planning period, such as commercial domestic hot water tanks changing from 0.75 Thermal Efficiency (TE) to 0.80 TE as they are replaced.

15.1 Please explain what FEI means by "end-use patterns" as referenced above.

Response:

Please refer to the response to BCUC IR 1.15.2.

15.1.1 Please explain how and why end-use patterns observed in the base year are kept constant throughout the planning period.

Response:

Please refer to the response to BCUC IR 1.15.2.

15.2 Please explain how the end-use Reference Case accounts for natural change in average appliance efficiencies across the planning period while "end-use patterns" are kept constant throughout the planning period?

Response:

FEI consulted with Posterity to provide the following response.

FEI's use of the term "end-use patterns" refers to the energy user's expectations for the service provided by the end use. For example, if the amount of clothes drying is not expected to change, the end use pattern is not changing. However, the way the service is delivered may change. Improved equipment efficiency through natural end-of-life replacement is a good example of reducing energy demand without reducing the service provided to the energy user. The user still gets the same service, so the end use pattern is not changed.

The Reference Case also holds constant both end use saturation (e.g., percentage of households with a clothes dryer) and fuel share (e.g., percentage of clothes dryers that are natural gas-fired). Thus, the proportion of existing detached homes, of a given vintage and in a given region, using natural gas to dry clothes would remain unchanged throughout the forecast period. New detached homes built in that region throughout the forecast period would all have the market share for natural gas dryers as new homes currently being built in that region. In the Reference Case, the average user continues to dry the same amount of clothing, is just as likely to use a dryer in their own home, and is just as likely to use a gas dryer. The only parameter that changes over time is the average equipment efficiency, as appliances age and are naturally replaced with new ones.

16.0 Reference: ANNUAL ENERGY DEMAND FORECASTING

Exhibit B-1, Section 1.4.3.2, p. 12; Section 3.4.1, pp. 63-64

Developing the end-use Reference Case demand forecast

On page 12 of Exhibit B-1, FEI states that the Commission Panel directed the FEU to file their next long term resource plan on or before June 30, 2017 and that this filing date was extended to November 30, 2017 through Order G-99-17.

On pages 63-64 of Exhibit B-1, FEI states:

> To prepare the 2017 LTGRP end-use forecast, the Company used the following data sources to calibrate the forecast model to FEI's 2015 base year actuals and to identify Reference Case end-use changes across the forecast horizon:
>
> - The BC Conservation Potential Review (BC CPR) which represents a collaborative provincial forecast (sponsored by FEI, FBC, BC Hydro, and Pacific Northern Gas) of energy conservation potential and thus benefits from data supplied by all sponsors as well as the rigour of multiple entities acting as reviewers;
> - FEI's 2012 Residential End-use Survey (REUS); FEI's 2017 REUS is not complete at the time of filing the 2017 LTGRP;
> - FEI's 2015 Commercial End-use Survey (CEUS) which represents FEI's most recent study of its commercial customers; and
> - Research and data analysis from the 2014 LTGRP which FEI included to utilize and build upon work that had already been completed for the 2014 LTRP.

16.1 Please state the purpose(s) for which FEI commissioned the Residential and Commercial End-use Surveys.

Response:

FEI uses the Residential and Commercial End-use Surveys for a variety of purposes including the BC Conservation Potential Review, for input into the design of conservation and energy efficiency programs, demand forecasting, and sales and marketing initiatives.

16.1.1 Please discuss the reason(s) why FEI's 2017 REUS was not complete at the time of filing the 2017 LTGRP.

Response:

The 2017 REUS was delayed for the following reasons:

- The need to address privacy and cybersecurity issues. Vendors were required to submit to our Legal and Information System departments detailed plans as to how their processes and procedures for handling customer information comply with privacy legislation and FortisBC policies;
- Changes in the questionnaire to maintain a level of consistency with the BC Hydro REUS questionnaire. FEI needed to undertake this activity to ensure that on joint projects, such as the Conservation Potential Review, that data from both organizations is compatible; and
- To address data quality issues identified in the 2012 REUS. For example, some 2012 REUS participants misidentified heating appliances in the survey (e.g., a gas hot water tank was identified as an electric hot water tank or vice versa). Although these issues were rectified during the data clean up activity, FEI added questions to the 2017 REUS to help identify and address any heating appliance classification mistakes reported by participants.

16.2 Please explain how often FEI intends to have End-use Surveys conducted.

Response:

FEI intends to conduct End-use Surveys every two to three years. The Residential End-use study takes approximately 30 months from start to finish, while the Commercial End-use study takes approximately 24 months. Projects typically span two to three calendar years depending upon project start date. FEI believes this represents a suitable frequency, reflecting the relative longevity of natural gas appliances and that changes in appliances happen slowly when reflected across the total customer base.

16.3 Please state the amount of time required to perform: (i) a residential end-use survey; and (ii) a commercial end-use survey.

Response:

Please refer to the response to BCUC IR 1.16.2.

16.4 Please provide an estimated cost of conducting the 2017 REUS.

Response:

The estimated final cost of the 2017 REUS is $325,000. This includes costs attributable to both FEI ($275,000) and FBC ($50,000). The final amount is still subject to change, as the project is still in progress.

16.4.1 Please compare this estimate to the cost of the 2012 REUS.

Response:

The 2012 REUS cost $330,000, which includes $72,000 charged to FBC.

16.5 Please complete the tables below to provide residential and commercial survey information for each of the regions associated with the end-use demand forecast.

Residential End-Use Surveys			
Region	**Number Targeted**	**Number of Responses**	**Response Rate (%)**
Lower Mainland			
Vancouver Island			
Whistler			
Southern Interior			
Northern Interior			
Total			

Commercial End-Use Surveys			
Region	**Number Targeted**	**Number of Responses**	**Response Rate (%)**
Lower Mainland			
Vancouver Island			
Whistler			
Southern Interior			
Northern Interior			
Total			

Response:

Residential End-Use Surveys			
Region	**Number Targeted**	**Number of Responses**	**Response Rate (%)**
Lower Mainland	6,250	793	12.7%
Vancouver Island	3,704	752	20.3%
Whistler	1,650	85	5.2%
Southern Interior	13,465 [2, 3]	1,065	13.5% [1, 2, 3]
Northern Interior		749	
Total	25,069	3,444	13.7%

Commercial End-Use Surveys			
Region	**Number Targeted**	**Number of Responses**	**Response Rate (%)**
Lower Mainland			
Vancouver Island			
Whistler			
Southern Interior			
Northern Interior			
Total [4]	10,000	866	8.7 [5]

1. FEI is unable to provide the number of surveys mailed out to customers in interior south and interior north separately. While the 2012 REUS response data was broken down by Southern Interior and Northern Interior in the crosstabs, in the methodology section of the main report the response rate is calculated for the interior region combined. This was done to reflect the separate utility structure in place at that time and to allow for comparisons with the 2008 data. FEI is unable to retroactively separate the response rate for Southern Interior and Northern Interior.

2. As the 2012 REUS was a combined FEI and FBC survey, the sample frame for the Interior was derived from the FEI and FBC customer information systems, and a sample of residential addresses for the municipalities that operated separate electric utilities including Penticton, Kelowna, Summerland, Nelson and Grand Forks. FEI is unable to

determine beforehand how many of the FBC and municipal customers were also FEI customers. The sample size is therefore the total number of surveys sent while the response rate is based on the number of respondents who indicated that they were natural gas customers. This has the potential effect of making the FEI only response rate appear somewhat lower than actual.

3. 1,294 surveys were sent to Fort Nelson customers with a response rate of 8.3%.

4. The CEUS sample was not broken down by region as there was no intention to report the results by region.

5. The response rate shown for the CEUS is for FEI customers. The total sample is for both FEI and FBC customers.

16.6 Please explain if and how the 2012 REUS accurately captures changes in customer end-uses and appliance efficiencies that occurred between 2012 and 2017.

Response:

The 2012 REUS report compares findings from the 2012 survey with those from the 2008 REUS to show changes in the types of appliances installed and the efficiency levels of those appliances over that period. Looking at the trends noted in the 2012 REUS it was possible to deduce what changes occurred in the following years due to natural attrition and energy regulations. This insight combined with other information from the Conservation Potential Review and an analysis of actual consumption in the 2015 base year provides an indication of what changes were occurring between 2012 and 2017.

16.6.1 Please explain how changes in customer end-uses and appliance efficiency that occurred between 2012 and 2017 could directionally impact the annual demand reference case.

Response:

As noted in Section 3.4.1 of the Application, FEI used multiple data sources (not just its end-use studies) to prepare its end-use annual demand forecast. As such, the end-use annual demand Reference Case may already take into account some changes in customer end-uses and appliance efficiency that are not captured in the end-use studies themselves. The following discussion illustrates this complexity:

The 2012 REUS indicated a change in the overall efficiency levels of natural gas furnaces when compared to 2008 with a significant decline in the percentage of standard efficiency furnaces (19.1 vs. 38.6 percent in 2008) and a corresponding change in the percentage of high-efficiency furnaces (31.7 vs. 14.1 percent in 2008). This trend will continue due to regulations mandating that only furnaces with 95 percent Annual Fuel Utilization Efficiency (AFUE) can be installed and would tend to depress natural gas demand. The end-use annual demand Reference Case already accounts for this because it does account for legally enshrined policy requirements.

The percentage of customers using natural gas as their primary heating fuel dropped from 91 percent in 2008 to 86.5 percent in 2012, whereas the percentage of customers using natural gas as a supplementary heating fuel rose from 11.9 to 16.2 percent. Overall the percentage of customers using natural gas for heating remained unchanged (95.3 vs. 96.3 percent in 2008). Given the consistent low cost of natural gas since 2012 this is likely to remain unchanged. A shift from using natural gas as a primary to using natural gas as a supplementary space heating fuel may tend to depress natural gas demand. The end-use annual demand Reference Case does not account for this because it keeps end-use patterns (including fuel shares and equipment saturation) unchanged. FEI prepared end-use alternate future scenarios to account for the directional impact of such changes.

There is a decline in the percentage of customers using natural gas for DHW from 2008 (88.8 percent) to 2012 (82.5 percent). This appears to be driven somewhat by a lower penetration rate in homes built after 2005 (65.8 vs. 82.5 percent for all homes). Such a decline may depress natural gas demand but, given the consistent low cost of natural gas since 2012, it is likely that this trend is not continuing. The end-use annual demand Reference Case does not account for this because it keeps end-use patterns (including fuel shares and equipment saturation) unchanged. FEI prepared end-use alternate future scenarios to account for the directional impact of such changes.

17.0 Reference: ANNUAL ENERGY DEMAND FORECASTING

Exhibit B-1, Section 3.4.2, Figure 3-4, p. 66; Appendix B-3, p. 2; Appendix B-4, p. 1

Comparison of the end-use and traditional method Reference Case forecasts

Figure 3-4 on page 66 of Exhibit B-1 presents FEI's end-use Reference Case annual demand forecast broken down into customer groups. Figure 3-4, copied below, shows the residential annual demand increasing steadily over the 20 year planning period while the industrial demand decreases.

Figure 1: FEI's End-Use Reference Case Annual Demand (Figure 3-4 in Exhibit B-1)

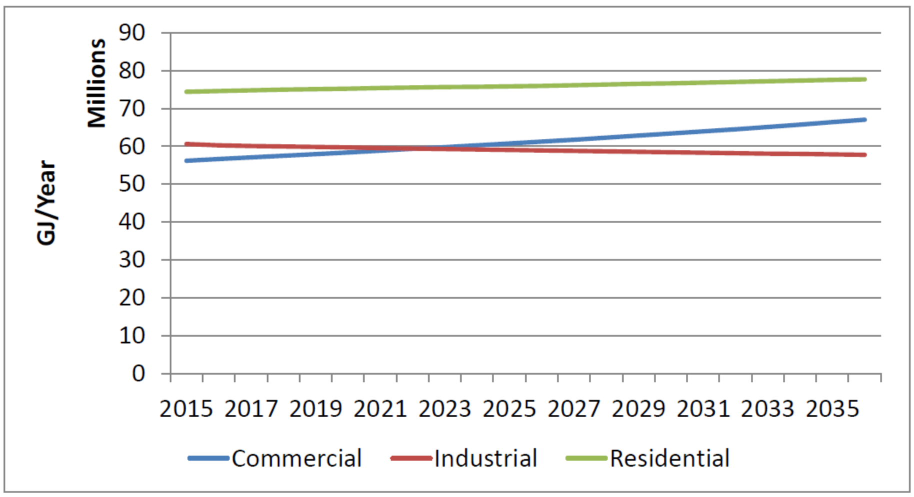
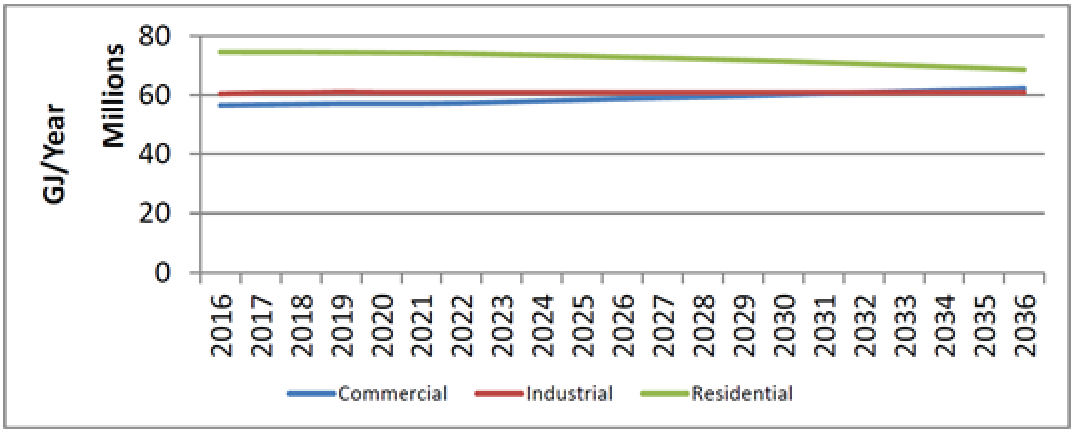


Figure B3-1 on page 2 of Appendix B-3 presents FEI's traditional Reference Case annual demand forecast broken down into customer group. Figure B3-1, copied below, shows the residential annual demand declining steadily over the 20-year planning period, while the industrial demand remains flat.

Figure 2: FEI's Traditional Reference Case Annual Demand (Figure B3-1 in Exhibit B-1)



17.1 In the same manner as was presented in Appendix B-4 for the End-use Annual Method, please provide tables showing for the Traditional Annual Method reference case the:

i. Year End Customers by Rate Schedule;

ii. Annual Use Rate per Customer by Rate Schedule (GJ);

iii. Annual Demand by Rate Schedule (GJ).

<u>Response:</u>

The following tables show the Traditional Annual forecasts in the manner requested.

i. Year End Customers by Rate Schedule;

Traditional

Year End Customers by Rate Schedule

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
RATE1	888,132	900,169	911,692	923,243	934,797	946,341	957,275	967,262	976,708	985,786	995,167	1,004,671	1,014,001	1,023,378	1,032,632	1,041,734	1,050,677	1,059,427	1,068,056	1,076,508	1,084,701	1,092,644
RATE2	85,076	86,394	87,712	89,030	90,347	91,665	92,983	94,276	95,600	96,878	98,157	99,451	100,751	102,037	103,334	104,630	105,911	107,226	108,517	109,807	111,095	112,388
RATE2_1	474	476	478	480	482	484	486	488	490	492	495	497	500	502	504	506	508	510	512	513	515	516
RATE2_2	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
RATE3	5,301	5,328	5,354	5,381	5,407	5,434	5,460	5,493	5,533	5,574	5,616	5,662	5,713	5,771	5,832	5,899	5,971	6,051	6,134	6,223	6,315	6,415
RATE4	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
RATE5	243	233	233	233	233	233	233	233	233	233	233	233	233	233	233	233	233	233	233	233	233	233
RATE6	13	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
RATE7	6	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
RATE22	48	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
RATE23	1,724	1,742	1,760	1,778	1,796	1,814	1,832	1,850	1,867	1,885	1,904	1,922	1,939	1,956	1,973	1,988	2,003	2,019	2,035	2,051	2,067	2,083
RATE25	557	562	562	562	562	562	562	562	562	562	562	562	562	562	562	562	562	562	562	562	562	562
RATE27	108	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107
Grand Total	981,691	995,083	1,007,970	1,020,886	1,033,803	1,046,712	1,059,010	1,070,343	1,081,172	1,091,589	1,102,313	1,113,177	1,123,878	1,134,618	1,145,249	1,155,731	1,166,044	1,176,207	1,186,228	1,196,076	1,205,667	1,215,020

ii. Annual Use Rate per Customer by Rate Schedule (GJ);

Annual Use Rate per Customer by Rate Schedule (GJ)

Rate Schedule	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
RATE1	83.7	82.8	81.8	80.7	79.6	78.6	77.5	76.6	75.6	74.5	73.5	72.5	71.5	70.5	69.5	68.6	67.6	66.6	65.6	64.7	63.7	62.8
RATE2	329.1	327.3	325.2	323.2	321.2	319.2	317.2	317.8	315.6	313.4	311.2	308.9	306.7	304.4	302.1	299.8	297.4	295.0	292.5	290.0	287.5	285.0
RATE2_1	469.8	462.1	443.3	424.5	405.6	386.8	367.9	349.8	330.9	312.1	293.2	274.3	255.4	236.5	217.7	198.8	179.9	161.0	142.1	123.3	104.4	85.5
RATE2_2	9,274.8	8,059.7	8,081.4	8,103.2	8,125.1	8,147.1	8,169.2	8,164.2	8,186.0	8,207.9	8,229.7	8,251.5	8,273.4	8,295.2	8,317.0	8,338.9	8,360.7	8,382.5	8,404.4	8,426.2	8,448.0	8,469.9
RATE3	3,617.4	3,540.6	3,489.0	3,431.4	3,390.1	3,299.3	3,225.5	3,191.4	3,173.1	3,160.0	3,141.4	3,121.6	3,100.7	3,079.1	3,055.7	3,032.0	3,006.5	2,980.1	2,953.1	2,926.5	2,898.6	2,870.2
RATE4	74,058.1	74,223.6	74,058.1	74,058.1	74,058.1	74,058.1	74,058.1	74,058.1	74,058.1	74,058.1	74,058.1	74,058.1	74,058.1	74,058.1	74,058.1	74,058.1	74,058.1	74,058.1	74,058.1	74,058.1	74,058.1	74,058.1
RATE5	9,460.2	9,396.1	9,394.3	9,394.8	9,391.7	9,389.8	9,387.8	9,387.8	9,387.8	9,387.8	9,387.8	9,387.8	9,387.8	9,387.8	9,387.8	9,387.8	9,387.8	9,387.8	9,387.8	9,387.8	9,387.8	9,387.8
RATE6	3,819.0	6,264.7	6,264.7	6,264.7	6,264.7	6,264.7	6,264.7	6,264.7	6,264.7	6,264.7	6,264.7	6,264.7	6,264.7	6,264.7	6,264.7	6,264.7	6,264.7	6,264.7	6,264.7	6,264.7	6,264.7	6,264.7
RATE7	28,034.8	29,680.5	29,738.7	30,144.0	30,085.3	30,185.3	30,085.3	30,085.3	30,085.3	30,085.3	30,085.3	30,085.3	30,085.3	30,085.3	30,085.3	30,085.3	30,085.3	30,085.3	30,085.3	30,085.3	30,085.3	30,085.3
RATE22	777,972.4	761,140.4	764,522.8	761,643.5	765,599.8	762,255.5	762,932.0	762,932.0	762,932.0	762,932.0	762,932.0	762,932.0	762,932.0	762,932.0	762,932.0	762,932.0	762,932.0	762,932.0	762,932.0	762,932.0	762,932.0	762,932.0
RATE23	4,966.7	5,195.0	5,213.4	5,233.3	5,254.6	5,277.3	5,301.3	5,125.2	5,150.7	5,178.1	5,206.1	5,233.5	5,264.7	5,297.4	5,331.2	5,364.5	5,401.7	5,439.5	5,477.7	5,516.8	5,556.9	5,597.9
RATE25	24,689.8	24,204.3	24,565.5	24,580.7	24,655.6	24,741.7	24,811.0	24,811.0	24,811.0	24,811.0	24,811.0	24,811.0	24,811.0	24,811.0	24,811.0	24,811.0	24,811.0	24,811.0	24,811.0	24,811.0	24,811.0	24,811.0
RATE27	66,263.6	60,166.9	59,949.3	61,460.1	61,416.0	60,800.5	60,805.7	60,805.7	60,805.7	60,805.7	60,805.7	60,805.7	60,805.7	60,805.7	60,805.7	60,805.7	60,805.7	60,805.7	60,805.7	60,805.7	60,805.7	60,805.7

iii. Annual Demand by Rate Schedule (GJ).

Annual Demand by Rate Schedule (GJ)

Rate Schedule	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
RATE1	74,378,040	74,554,961	74,534,854	74,482,985	74,418,310	74,338,946	74,222,824	74,069,699	73,791,438	73,474,619	73,166,953
RATE2	27,995,631	28,273,252	28,526,998	28,775,498	29,018,721	29,256,684	29,489,745	29,956,937	30,169,253	30,360,566	30,544,805
RATE2_1	222,697	219,977	211,897	203,742	195,511	187,198	178,816	170,717	162,165	153,537	145,127
RATE2_2	64,924	56,418	56,570	56,722	56,876	57,030	57,184	57,149	57,302	57,455	57,608
RATE3	19,175,661	18,864,189	18,680,184	18,464,373	18,330,197	17,928,220	17,611,351	17,530,375	17,556,542	17,613,789	17,642,010
RATE4	148,116	148,447	148,116	148,116	148,116	148,116	148,116	148,116	148,116	148,116	148,116
RATE5	2,298,834	2,189,288	2,188,873	2,188,982	2,188,273	2,187,817	2,187,365	2,187,365	2,187,365	2,187,365	2,187,365
RATE6	49,647	50,117	50,117	50,117	50,117	50,117	50,117	50,117	50,117	50,117	50,117
RATE7	168,209	148,402	148,693	150,720	150,426	150,926	150,426	150,426	150,426	150,426	150,426
RATE22	37,342,676	38,057,020	38,226,140	38,082,177	38,279,988	38,112,774	38,146,598	38,146,598	38,146,598	38,146,598	38,146,598
RATE23	8,562,634	9,049,609	9,175,540	9,304,739	9,437,215	9,572,974	9,712,024	9,481,661	9,616,410	9,760,660	9,912,415
RATE25	13,752,223	13,602,823	13,805,801	13,814,334	13,856,423	13,904,832	13,943,793	13,943,793	13,943,793	13,943,793	13,943,793
RATE27	7,156,472	6,437,861	6,414,570	6,576,236	6,571,510	6,505,656	6,506,209	6,506,209	6,506,209	6,506,209	6,506,209
Grand Total	191,315,763	191,652,364	192,168,355	192,298,743	192,701,683	192,401,290	192,404,569	192,399,162	192,485,733	192,553,250	192,601,542

Rate Schedule	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
RATE1	72,855,379	72,519,237	72,173,910	71,807,840	71,419,298	71,008,088	70,572,243	70,116,861	69,638,589	69,132,551	68,599,798
RATE2	30,725,119	30,899,593	31,061,090	31,217,370	31,363,217	31,495,423	31,628,471	31,743,587	31,849,182	31,945,036	32,031,407
RATE2_1	136,329	127,711	118,744	109,701	100,582	91,388	82,118	72,773	63,229	53,751	44,113
RATE2_2	57,761	57,914	58,066	58,219	58,372	58,525	58,678	58,831	58,983	59,136	59,289
RATE3	17,674,309	17,714,459	17,769,570	17,820,844	17,885,950	17,952,015	18,032,832	18,114,371	18,211,571	18,304,461	18,412,109
RATE4	148,116	148,116	148,116	148,116	148,116	148,116	148,116	148,116	148,116	148,116	148,116
RATE5	2,187,365	2,187,365	2,187,365	2,187,365	2,187,365	2,187,365	2,187,365	2,187,365	2,187,365	2,187,365	2,187,365
RATE6	50,117	50,117	50,117	50,117	50,117	50,117	50,117	50,117	50,117	50,117	50,117
RATE7	150,426	150,426	150,426	150,426	150,426	150,426	150,426	150,426	150,426	150,426	150,426
RATE22	38,146,598	38,146,598	38,146,598	38,146,598	38,146,598	38,146,598	38,146,598	38,146,598	38,146,598	38,146,598	38,146,598
RATE23	10,058,801	10,208,252	10,361,781	10,518,434	10,664,603	10,819,650	10,982,292	11,147,061	11,315,007	11,486,131	11,660,433
RATE25	13,943,793	13,943,793	13,943,793	13,943,793	13,943,793	13,943,793	13,943,793	13,943,793	13,943,793	13,943,793	13,943,793
RATE27	6,506,209	6,506,209	6,506,209	6,506,209	6,506,209	6,506,209	6,506,209	6,506,209	6,506,209	6,506,209	6,506,209
Grand Total	192,640,323	192,659,790	192,675,785	192,665,032	192,624,645	192,557,713	192,489,258	192,386,108	192,269,186	192,113,691	191,939,774

17.2 Please explain differences in long term demand forecast trends between the End-use Annual Method results and the Traditional Annual Method results for: (i) residential; and (ii) industrial customers.

Response:

The differences are summarized as:

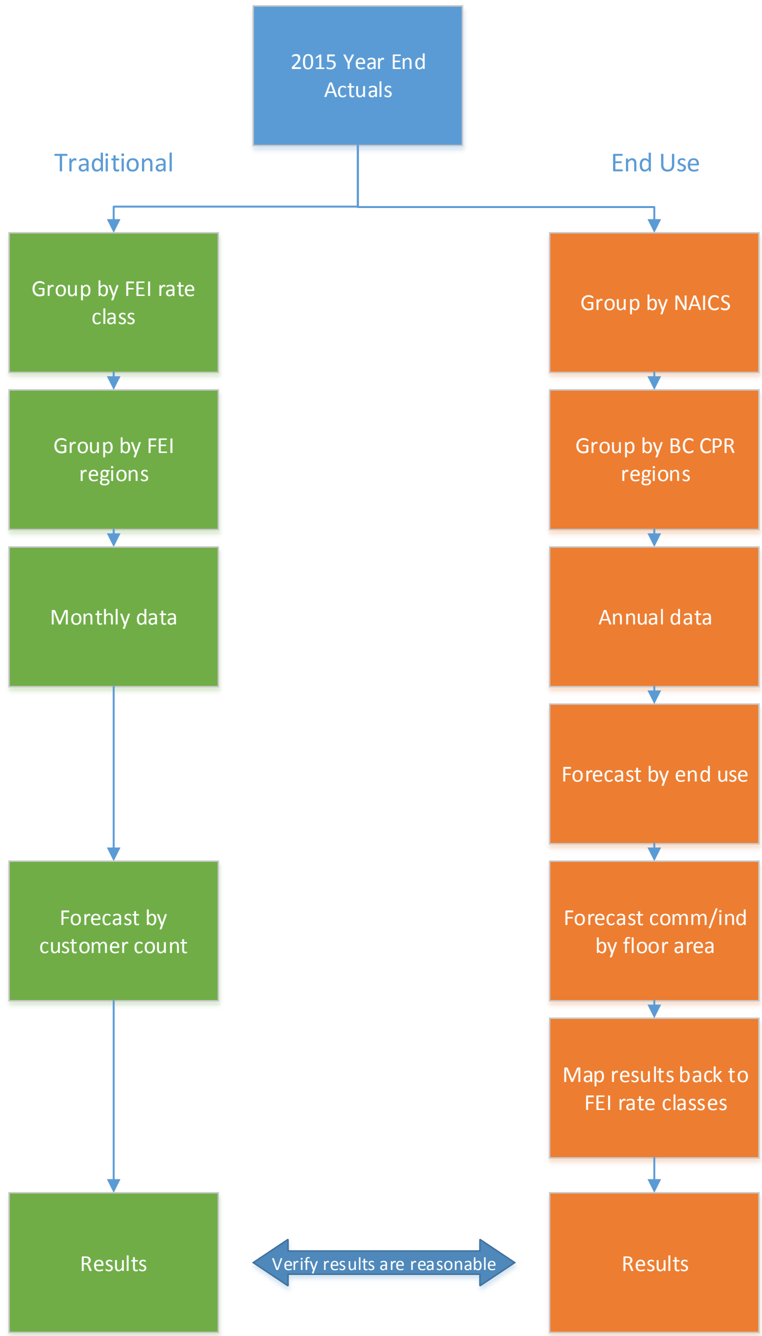
(i) The Traditional Annual Method residential demand forecast trends lower over the long term while the residential End-Use Annual Method demand forecast trends slightly higher.

(ii) The Traditional Annual Method industrial demand forecast remains flat over the long term while the industrial End-Use Annual Method demand forecast trends slightly lower.

Due to the differences in the methods and inputs, differences in the long-term trends are expected.

The Traditional Annual Method is fundamentally different from the End-Use Annual Method and, as a result, yields different forecast results. The Traditional Annual Method is based on historical time-series statistical methods while the End-Use Annual Method relies on potential future changes in trends.

The key differences in the methods are illustrated in the following flow chart:



If the forecasts were developed with identical methods then the Traditional forecast would not provide any value as a check against the End Use forecast. The singular purpose of the Traditional forecast is to provide an independent check of the End Use forecast. The fact that multiple aspects of the data and methods are different serves to make the comparison more valuable.

On page 2 of Appendix B3-1, FEI states:

> Declining residential UPC in the FEI service territories is resulting in an overall decline in residential annual demand, even though the Company continues to add residential customers through the forecast period. This decline in residential UPC is now a common occurrence affecting mature natural gas utilities across North America.

17.2.1 Please explain why the declining residential UPC in the Traditional Annual Method reference case results in an overall decline in the Traditional Annual Method residential demand forecast, whereas the End-use Annual Method forecasts an increase in residential reference case demand despite a declining residential UPC.

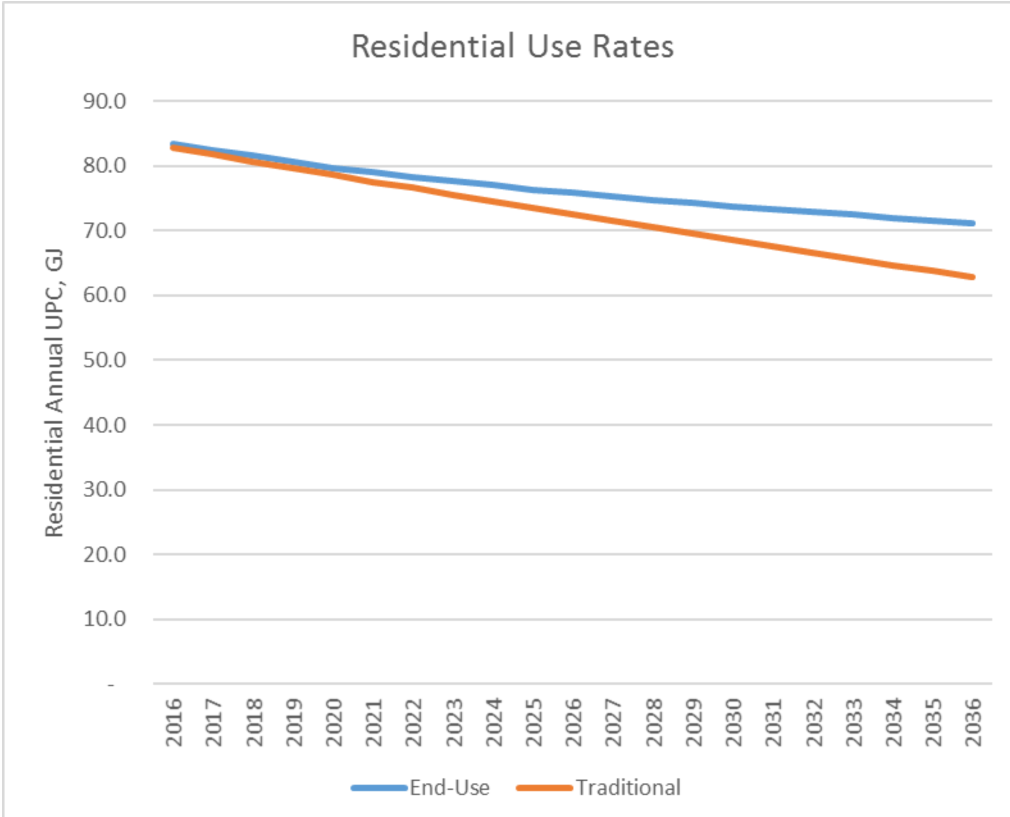
Response:

FEI consulted with Posterity to provide the following response.

In the Reference Case, average residential UPC is expected to decline over the course of the forecast period by just over 15 percent. This reflects improvements in average equipment efficiency and the effect of new construction gradually accounting for a larger share of the overall residential sector.

The traditional method is based on the continuation of UPC trends observed over the past three years.

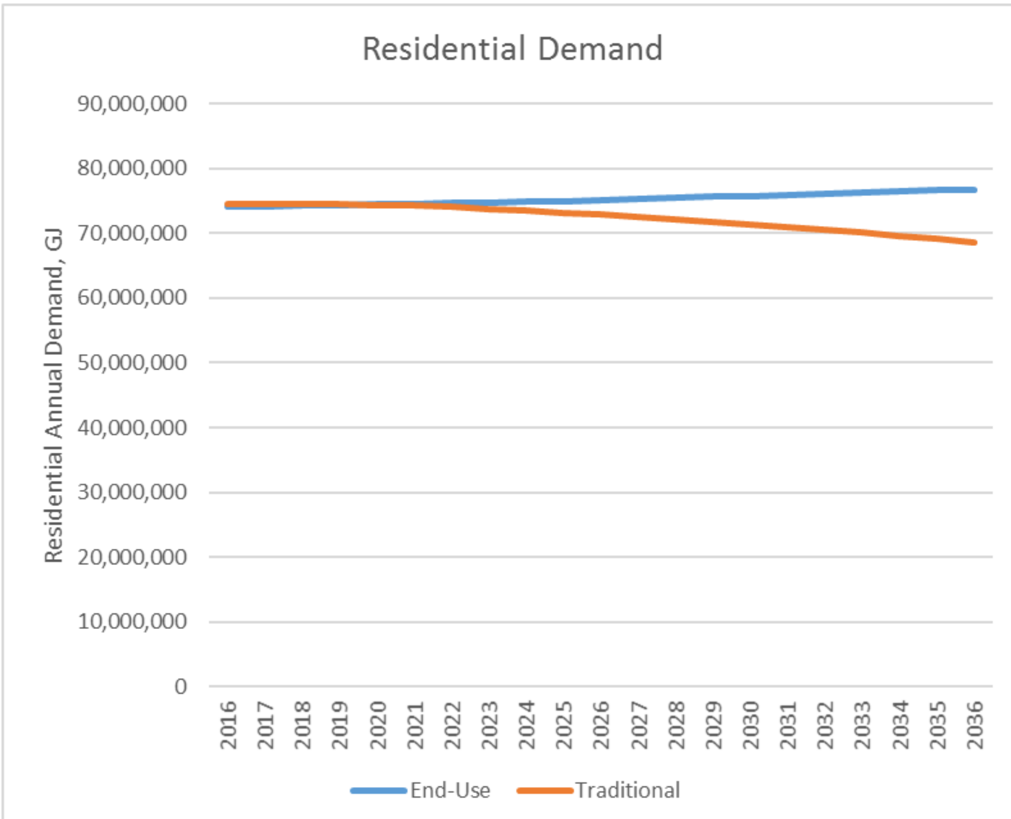
As expected the two forecast methods produce slightly different use rate forecast trajectories as shown below. Both trajectories predict a decline in the residential use rate over the forecast period. While the slope of the lines are slightly different, the Traditional line slopes further downwards over the forecast period than the End-Use line.



The customer count forecasts are very similar. The End Use forecast considers some customers in commercially served multi-family dwellings as residential customers. This leads to the slightly different forecasts. Directionally both forecasts are the same. The customer forecasts are:

The slightly steeper negative slope of the Traditional End Use forecast coupled with the positive slope of the Traditional customer forecast results in a slightly declining Traditional demand forecast.

The slope of the End Use UPC forecast is negative but not quite as steep as the Traditional forecast. The End Use UPC forecast coupled with the increasing End Use customer forecast results in a slightly increasing End Use demand forecast.



17.2.2 Please explain if and how the reference case End-use demand forecast captures the decline in residential UPC as referenced in the preamble.

Response:

FEI consulted with Posterity to provide the following response.

In the Reference Case, average residential UPC is expected to decline by just over 15 percent throughout the forecast horizon. This reflects improvements in average equipment efficiency and the effect of new construction gradually accounting for a larger share of the overall residential sector. As discussed in the response to BCUC IR 1.15.2, this does not include changes in end use patterns for a given end use and type of dwelling.

The assumed decline in residential UPC in the end-use Reference Case varies by dwelling type and by region. For example, FEI included different baseline furnace efficiencies for different regions, based on information from the 2012 REUS. Regions with a higher incidence of standard efficiency furnaces are assumed to have a lower average baseline furnace efficiency. They therefore experience a greater average improvement in efficiency as these old furnaces reach their end of life and are replaced by condensing units. UPC therefore declines more rapidly in existing dwellings in those regions.

Regions with a higher rate of new construction also experience a greater rate of decline in residential UPC. New homes have more efficient building envelopes and energy systems and, in some regions, they are more likely to use electric space heating and water heating. Furthermore, the rate of new construction for attached homes (row houses and townhouses) is greater than for detached homes. Attached homes have lower average annual energy consumption, particularly for space heating, and are somewhat more likely than detached homes to be heated with electricity.

17.3 Please provide graphs showing annual actual residential and commercial UPC for the 20 years preceding 2017.

Response:

Please see graphs showing annual actual[2] (normalized) residential and commercial historical UPC below, back to 2005[3].

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[2] FEI assumes the Commission is referring to weather normalized UPC when it requests actual UPC.

[3] Amalgamated historical electronic data records are limited to 2005.

Chart 1: Normalized Residential UPC 2005-2016

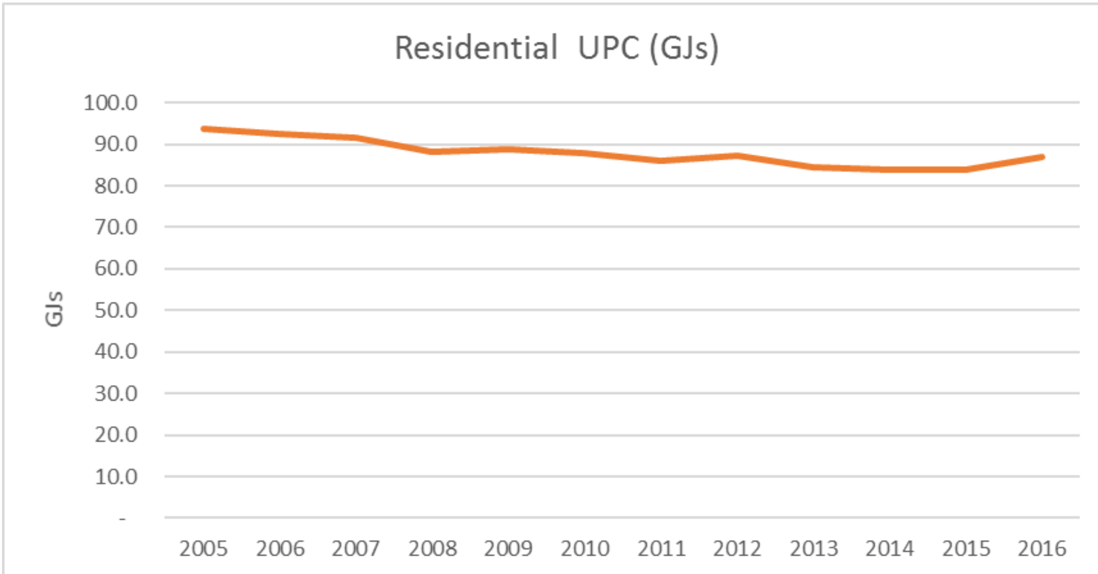
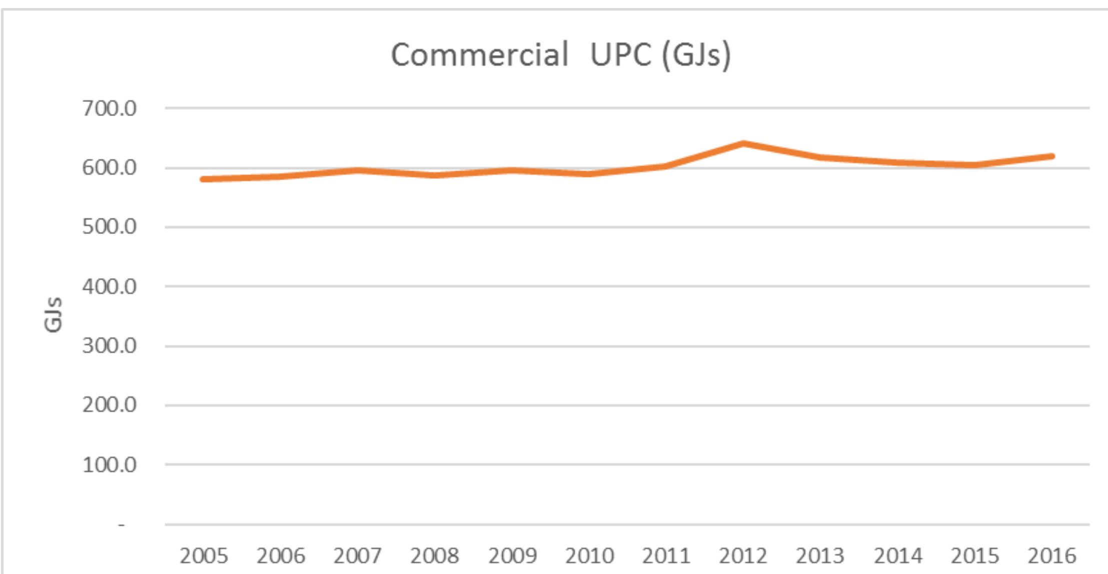


Chart 2: Normalized Commercial UPC 2005-2016



17.3.1 Please provide tables containing the data used in the graphs.

Response:

Please see the following table showing annual actual[4] (normalized) residential and commercial historical UPC, back to 2005[5].

Table 1: FEI Residential and Commercial[6] Normalized UPCs (including Ft. Nelson)

FEI Normalized UPC	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Residential UPC (GJs)	93.8	92.5	91.5	88.2	88.7	88.0	86.0	87.3	84.3	83.9	83.7	86.9
Commercial UPC (GJs)	580.6	586.0	595.6	587.9	596.8	589.1	601.4	641.9	617.4	609.0	605.3	619.4

[4] FEI assumes the Commission is referring to weather normalized UPC when it requests actual UPC.
[5] Amalgamated historical data records are limited to 2005.
[6] Commercial UPC includes Rates 2, 2.1, 2.2, 3 and 23

18.0 Reference: ANNUAL DEMAND FORECASTING

Exhibit B-1, Section 3.4.3, p. 67; Appendix B-3, p.3

Annual end-use demand forecast comparison

On page 67 of Exhibit B-1, FEI states that:

> 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.

18.1 Please explain what FEI considers "reasonably aligned" and against what parameters is the alignment assessed?

Response:

No mathematical parameters are implicit in FEI's use of "reasonably aligned" in this context. By "reasonably aligned" FEI is simply confirming that the end-use method Upper Bound and Lower Bound scenarios bound both the Traditional Annual Method and the end-use method Reference Case demand forecast trajectories. For example, if the Traditional Annual Method forecast trajectory were to lie outside either the end-use method Upper Bound or Lower Bound scenario trajectories, FEI would need to investigate what would cause such a divergence of forecasts between the two methods and further consider the reasonableness of the forecasts. This illustrates the Traditional Annual Method's value in providing a reasonableness check for the results of the end-use method annual demand Reference Case and alternate future scenarios.

18.1.1 How were these parameters defined?

Response:

Please refer to the response to BCUC IR 1.18.1.

18.2 How does the variance between FEI's Traditional Annual Method and the end-use Reference Case forecast compare to other utilities?

Response:

FEI is unable to comment on how the variance between its Traditional Annual Method and the end-use method Reference Case compares to other utilities. FEI's research to date indicates that other utilities in North America typically do not publish separate econometric and end-use method forecasts in their integrated resource plans. As noted in Appendix B-2 of the Application, numerous North American utilities, in fact, combine econometric and end-use methods in their long-term forecasts.

19.0 Reference: ANNUAL DEMAND FORECASTING

Exhibit B-1, Section 3.4.6, p. 80; Figure 3-14, p. 81

Renewable Natural Gas (RNG) Demand

On page 80 of Exhibit B-1, FEI states:

> The links between the core end-use forecast and the RNG annual demand forecast are qualitative only because RNG represents an emerging market. FEI provided the core end-use forecast scenario parameters to its RNG program team and requested this team to prepare three forecast trajectories (Reference Case, Low, High) based on these scenario parameters.

19.1 Please explain with calculations where relevant, the method used to calculate the reference case RNG annual demand forecast.

Response:

For the RNG annual demand forecast, FEI used a method consistent with its established practices for the RNG program. FEI has used this practice as part of the regular course of reporting for the RNG program.

At a high-level, the forecast is compiled from the estimated RNG use from the various rate classes that FEI serves. For residential and commercial customers, FEI uses historical participation to project future participation and combines that with calculated RNG use per customer. FEI then identifies specific prospective RNG customers that represent significant loads – such as the University of British Columbia - and adds those customers to the total. Over time, the participation rates are inflated for the various rate classes and a future load for larger customers is added.

19.2 Please elaborate on the parameters that were provided to the RNG program team.

Response:

FEI's integrated resource planning team provided to FEI's RNG program team the information contained in 2017 LTGRP Appendix B-1, exclusive of the pieces of information represented about RNG and NGT in the Appendix.

19.3 Please provide in a table format the reference case RNG annual demand forecast in GJ for each year from 2017 through to 2036.

Response:

Please see the table below. The Reference Case experiences 195 percent cumulative growth from 2017 until 2036. As noted in Section 3.4.6 of the Application, RNG annual demand displacing conventional natural gas demand for individual customers does not change the total volume of annual demand that FEI's infrastructure provides to such customers. FEI's forecast RNG trajectories in Section 3.4.6 of the Application assume current RNG supply technologies.

Forecast Year	Reference Case RNG Annual Demand Forecast (GJ)
2017	238,016
2018	338,135
2019	502,948
2020	572,956
2021	628,180
2022	633,538
2023	638,960
2024	644,439
2025	649,991
2026	655,629
2027	661,340
2028	666,797
2029	671,568
2030	675,960
2031	680,366
2032	684,774
2033	689,184
2034	693,596
2035	698,011
2036	702,426

19.4 Please explain why the: (i) Upper Bound; (ii) Local Growth & Constricted Supply; and (iii) Global Growth & Green Step Change scenarios shown in Figure 3-14 experience a steep increase in annual demand from 2016 until approximately 2025, after which the demand flattens to approximately 2.75 million GJ/Year.

Response:

FEI consulted with Posterity to provide the following response.

The highest RNG demand scenarios assume that in the medium term (the next 5 to 10 years), demand steeply increases for the following reasons:

1. Two customers with large annual demand are included (combined addition of about 1.5 PJ);
2. Additional institutional and government owned entities are becoming more interested in RNG;
3. NGT demand for RNG will grow as the NGT market grows and there is a higher adoption rate; and
4. Residential demand grows at a steady rate.

With respect to the flattening effect, this is a result of the forecast assuming that demand in all segments would saturate. More recent events and changes in consumer behaviour have shown that demand is increasing.

There has been a sharp increase in interest from large, sophisticated customers over the past year. FEI believes that this is due to awareness, ease of adoption, government policy and the current price. In addition we have seen a steady increase in residential and small commercial demand since the price of RNG dropped and the marketing efforts were increased.

Each of these influencing factors are explained more fully here:

Awareness: FEI has observed a general increased interest in RNG over the past year which is assumed to be partly due to awareness of the product. FEI has increased its market awareness efforts in a response to research that indicated that customers were not aware of the RNG product.

Ease of Adoption: FEI has observed that the decision to adopt RNG as an energy source is easy for customers because there is no required change in day to day operations and all the necessary supporting tariffs and billing systems are in place. As opposed to switching to a fuel source such as biomass, which would require new boilers, customers can simply switch to RNG and achieve GHG emission targets.

Government Policy: Under the British Columbia Low Carbon Fuel Requirements Regulation (BC LCFRR), RNG is an ultra-low carbon fuel option for transport consumers. FEI is currently validating the carbon intensity of RNG for the BC LCFRR but based on analyses in other jurisdictions RNG could be up to 90% less carbon intensive than the current transport fuel intensity in the province and would generate more than double the emissions credits compared to compressed natural gas. With recent average credit prices of $170 per tonne in the BC LCFRR, RNG would be a very attractive option for fleet operators with natural gas vehicles.

Current Price: In 2016 the Commission approved a new lower price for RNG. At the time FEI had put forth an argument that the price was too high for market uptake. Since the time of the price change, FEI has seen a steady increase in the overall number of RNG customers. This suggests to FEI that price was a factor in the slowing uptake.

FEI believes that the demand will more likely continue upward rather than flatten in the future but demand may be constrained by supply.

On page 80 of Exhibit B-1, FEI states: "FEI is aware that pilot projects exist for proving the commercial scalability of RNG from wood waste. If such cellulosic biogas does become available at reasonable prices, it could dramatically increase RNG supply and thus potentially enable FEI to substantially increase RNG annual demand via its RNG program."

19.5 Please describe the effects, if any, fuel switching from conventional gas to RNG has on the Reference Case Annual Demand forecast.

Response:

Fuel switching to RNG does not have any net effects on the Reference Case Annual Demand forecast. The total consumption in the Reference Case Annual Demand remains the same. Only the relative proportion of RNG to conventional natural gas changes within the given Reference Case Annual Demand totals.

19.6 Please provide a chart, and accompanying data table, forecasting the potential effects cellulosic biogas could have on RNG demand. Please explain the assumptions used to calculate this forecast.

Response:

FEI has not forecast an increase in demand as a direct result of the addition of cellulosic RNG in Section 3 of the Application.

FEI does not believe that the addition of cellulostic RNG would increase the rate of demand – the addition of more RNG (regardless of source) and demand are not related.

However, the addition of cellulostic RNG would increase the total available supply in the province which ultimately would reduce the overall emissions of the natural gas portfolio in British Columbia (as outlined in Appendix E of the Application).

20.0 Reference: ANNUAL DEMAND FORECASTING

Exhibit B-1, Section 3.4.7, pp. 82-83

Compressed Natural Gas (CNG) Demand

On page 82 of Exhibit B-1, FEI states: "CNG is positioned as a fuel for on-road transport applications such as transit buses, waste haulers and heavy duty on-road trucks."

20.1 Please discuss the possibility of all-electric vehicles, specifically all-electric trucks having an impact on FEI's CNG demand over the 20-year planning period.

Response:

The response below interprets the question to refer to battery-electric trucks, as it is this technology that has been in the news recently with such announcements as the Tesla truck project.

Although there have been recent announcements in the press about emerging heavy-duty battery electric trucks, FEI has learned, through discussions with various companies and consulting firms familiar with the transportation industry, that significant uptake of battery electric heavy-duty trucks will occur further out in time.

Over the 20-year planning period of the LTGRP, battery electric technology could advance to a point that significant uptake could occur, however FEI did not take this factor into consideration when forecasting the Base Scenario market penetration of natural gas trucks. This was due in part to the relatively early development stage and information available on battery electric heavy-duty trucks when FEI prepared and submitted the 2017 LTGRP to the BCUC.

Furthermore, in the Base Scenario of the CNG demand for the on-road truck market segment, FEI assumed a CNG market capture rate of 4 percent of the overall truck market. This represents a relatively modest market capture rate for CNG and would leave significant room for other transportation technologies to capture the existing diesel based trucking market. These other technologies could include hydrogen fuel, diesel-electric hybrid or other forms of energy for transportation fuel.

20.1.1 Please state if FEI has performed any analysis on how this technology could impact the Reference Case CNG demand forecast.

Response:

Please refer to response to BCUC IR 1.20.1.

On page 83 of Exhibit B-1, FEI states: "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."

20.2 Please provide details on how FEI forecasted annual growth of 85 additional CNG vehicles (100,000 GJ) per year in the CNG base scenario demand forecast.

Response:

FEI has forecast an annual growth of 85 additional CNG vehicles per year in the CNG base scenario demand forecast by applying what FEI believes is a reasonable growth factor based on past experiences and also based on current market conditions and discussions with NGT customers. These 85 forecasted CNG vehicles are expected to add about 100,000 GJ per year of incremental demand. Based on this growth forecast, FEI is able to achieve a 4 percent market capture rate of the overall diesel based transportation market by 2036.

Please refer to the response to BCUC IR 1.20.1 for further explanation.

20.3 Please provide details of the core end-use forecast scenario parameters FEI provided to its NGT programs department and the methodology used to obtain the base, high and low forecast demand trajectories.

Response:

FEI's integrated resource planning team provided to FEI's NGT programs department the information contained in 2017 LTGRP Appendix B-1 in order to inform the NGT programs department about the core scenario assumptions for the 2017 LTGRP. FEI's NGT programs department was informed by these core scenario assumptions when it developed the NGT forecast for the 2017 LTGRP.

The specific method used to obtain the base, high and low forecast demand trajectories was to first determine the existing transportation fuel consumption for diesel and natural gas fuel in British Columbia. Diesel fuel is the primary incumbent fuel against which natural gas would compete for the on-road heavy duty transportation segment, thus it is important to determine the overall size of the diesel fuel market in BC. This was obtained from data produced by Natural Resources Canada.[7]

Second, to understand the growth pattern of transportation fuel consumption in BC, FEI obtained data on the forecast market growth based on the National Energy Board's energy supply and demand projections.[8] These growth projections were applied to the current diesel fuel and natural gas market out to 2036 to understand the overall addressable fuel market over the LTGRP planning horizon.

Last, in order to forecast the three different natural gas demand scenarios, FEI applied different natural gas market capture rates for each of the three scenarios and an assumed growth factor per year in order to obtain this overall natural gas market capture rate over the planning horizon to 2036.

For reference, the Low demand scenario assumes an overall market capture rate of 1 percent, the Base scenario assumes an overall market capture rate of 4 percent and the High scenario assumes an overall market capture rate of 15 percent.

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[7] Natural Resource Canada, Comprehensive Energy Use Data Base: http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive/trends_tran_bct.cfm

[8] National Energy Board, Canada's Energy Future 2016 Update: https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016updt/index-eng.html.

21.0 Reference: ANNUAL ENERGY DEMAND FORECASTING

Exhibit B-1, Section 3.4.7.2 p. 85; Section 2.4.1.2, pp. 53-54;

BCUC 2014 LTRP Decision, Section 3.1.2.3, p. 18

LNG Demand Forecast

On page 85 of Exhibit B-1, FEI states:

> The key markets that have emerged over the past number of years as consumers of LNG fuel have been high horsepower applications such as marine vessels, mine haul trucks, locomotives, and remote industrial power and heat generation applications. Similar to CNG demand forecasts, FEI formulated the LNG demand forecasts by accounting for commitments that have been made by customers to take LNG supply under RS46, then applying inflation and forecasting the impacts of a variety of factors.

21.1 Please explain how FEI uses inflation to develop LNG demand forecasts.

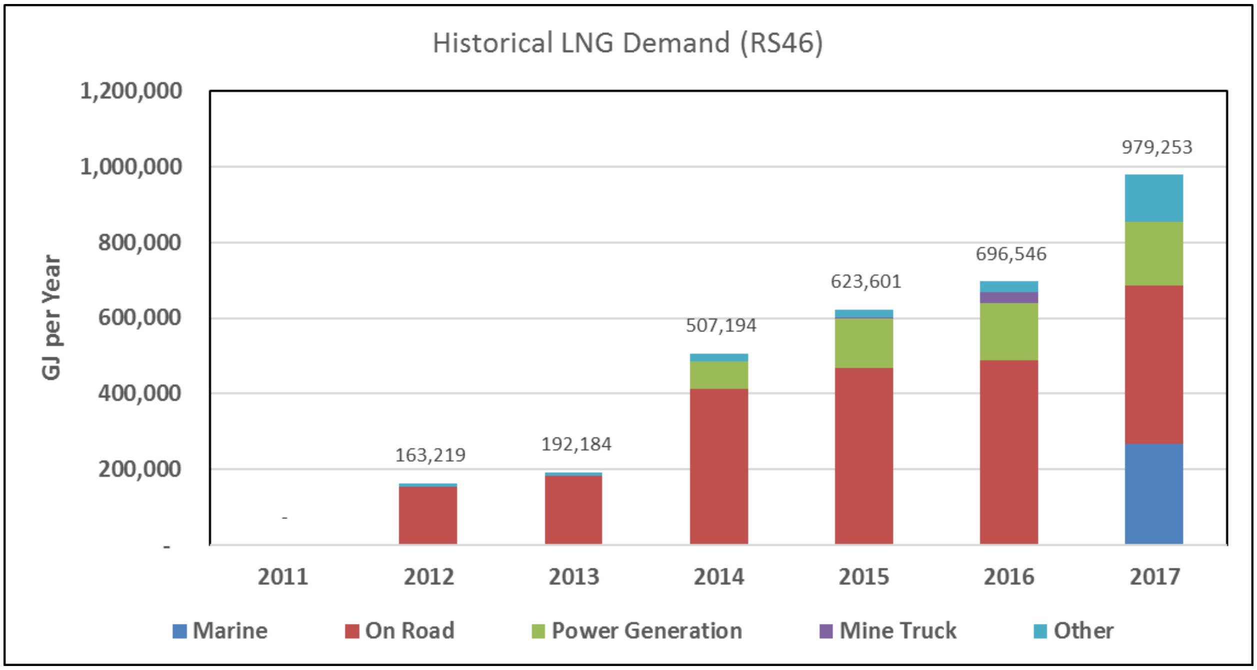
<u>Response:</u>

FEI clarifies that the reference to 'inflation' pertains to market demand inflators that were applied to each market segment to develop the LNG demand forecasts. Inflation in this context is not related to the traditional understanding of inflation of price or commodity indices.

21.2 Please provide a graph detailing historic demand of LNG, grouped by each market.

<u>Response:</u>

The graph below illustrates historic demand of LNG grouped by each market since 2011 to end of 2017. The compound annual growth rate of LNG demand is about 43% for the period of 2012 to end of 2017.



21.3 In the LNG base scenario demand forecast, please explain how FEI calculated an annual growth rate of about 5 percent per year beyond 2028?

Response:

FEI has a reasonable degree of information regarding emerging LNG demand into the latter half of the 2020s. However, visibility on emerging demand beyond this period is more uncertain. Therefore, FEI applied what it believes to be a reasonable annual growth factor over the planning horizon for the LNG base scenario.

21.3.1 Please explain the assumptions that FEI uses in the base scenario prior to 2028?

Response:

FEI is currently in discussions with a number of customers in each of the identified market segments regarding potential adoption of natural gas as a fuel choice. Based on these discussions and interactions to date, FEI has forecast what this known emerging demand would be and when it would expect to materialize. FEI only included market demand that it currently is aware of based on actual interactions with various customers in each of the identified market segments; there is no "unknown" demand included.

On pages 53 and 54 of Exhibit B-1, FEI states:

> The International Maritime Organization (IMO) is scheduled to implement a global cap on sulfur emissions from the shipping industry to take effect on January 1, 2020. … The global cap on sulfur in marine fuels is expected to have a material impact on marine vessel operators as they must weigh a number of options in order to comply with these emission limits.

On page 85 of Exhibit B-1, FEI states that: "[t]hrough 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."

21.4 Considering the LNG base case scenario demand forecast includes some capture rate of trans-Pacific marine vessels as LNG fuel early adopters, please explain why the base scenario forecast does not display accelerated LNG demand after the IMO sulfur cap is implemented in 2020?

Response:

FEI consulted with Posterity to provide the following response.

FEI took a less aggressive view in the base case scenario regarding adoption of natural gas for the trans-Pacific market to be consistent with FEI's view of the other market segments also contained in the base case scenario.

In actuality, if FEI were to develop LNG bunkering for a trans-Pacific vessel customer, this would provide the necessary market confidence to other potential marine customers that LNG bunkering is available in the Pacific Northwest reliably and cost effectively and could accelerate the adoption of natural gas a marine fuel.

FEI assumed accelerated LNG adoption in FEI's High Scenario to account for this relative uncertainty and the potential impact of the IMO sulfur cap being implemented in 2020.

21.4.1 Please update the following figures to account for a LNG base scenario forecast that contains accelerated LNG demand after the IMO sulfur cap is implemented in 2020:

i. Figure 3-16 on page 86 of Exhibit B-1;

ii. Figure 3-17 on page 87 of Exhibit B-1;

iii. Figure 3-19 on page 89 of Exhibit B-1.

Response:

Please refer to the response to BCUC IR 1.21.4. FEI's High Scenario for CNG and LNG accounts for this accelerated LNG demand.

On page 18 of the FEU 2014 Long Term Resource Plan (LTRP) Decision, the Commission "encourages the FEU in their next LTRP filing to provide a more complete and fulsome analysis of the potential for new Industrial LNG Demand over the entire forecast horizon."

21.5 Is FEI aware of other potential LNG developments, other than the Woodfibre LNG plant, that will impact annual demand from Industrial LNG customers over the next 20-year planning period?

Response:

The only potential LNG developments that FEI is aware of, at this time, are the Tilbury and Woodfibre LNG sites. However, FEI has identified significant LNG demand growth potential in the transportation sector, which it continues to analyze as discussed in Sections 3.4.7 and 6.3.2 of the Application.

21.6 Please describe the extent of FEI's discussions and activities to develop new and existing markets for LNG to be supplied by FEI.

Response:

FEI's development of new and existing markets for LNG is completed through a range of initiatives, which demonstrate the extent of FEI's activities. This would include direct engagement with end-use customers, aggregators of end-use customer demand (i.e. fuel service providers), engineering/procurement/construction firms that respond to Requests for Proposals (RFPs) and involvement in industry organizations that influence decision makers to evaluate natural gas as a fuel option.

As noted in Section 3.4.9 of the Application, FEI's ability to expand its analysis of large industrial point loads is limited by three factors:

1. Significant uncertainty about when and where such demand would materialize in absence of FEI having firm commitments from prospective customers;
2. FEI must protect the confidentiality of negotiations with prospective large point load customers as a result of contractual obligations; and
3. The uniqueness of each such industrial point load customer, which makes extrapolating potential average impacts of such customers across the planning period difficult.

However, FEI has provided a more fulsome analysis of potential new industrial LNG demand by examining the annual demand impacts of its NGT forecast (in addition to the Woodfibre LNG Project) in Section 3 of the Application, and directionally discussing in Section 6.3.2 of the Application how point load natural gas demand served from FEI's Coastal Transmission System might interact with point load natural gas demand served by FEI's Vancouver Island Transmission System to impact FEI's transmission system infrastructure requirements.

22.0 Reference: ANNUAL ENERGY DEMAND FORECASTING

Exhibit B-1, Appendix B-1, p. 5; Section 3.4.4, p. 70

End-use demand forecast scenario parameters

On page 5 of Appendix B-1, FEI states:

> 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).

22.1 Please describe the statistical approach using Prediction Intervals (PI) the 2017 LTGRP relies upon.

<u>Response:</u>

The definition of a prediction interval is: "A prediction interval is an estimate of an interval in which future observations will fall, with a certain probability, given what has already been observed."

For a given dataset the prediction interval (PI) is calculated as follows:

$$PI = t^*_{n-2} s_y \sqrt{1 + \frac{1}{n} + \frac{(x^* - \bar{x})^2}{(n-1)s_x^2}}$$

Where (for customer count):

PI	The prediction interval. This value is either added to or subtracted from the forecast value.
x	The x values in the formula are years
y	The y values are customers
t^*_{n-2}	Value of the t statistic at 95% confidence = 2.306
s_y	$The\ standard\ deviation\ in\ y: s_y = \sqrt{\frac{\sum(y_i - \hat{y}_i)^2}{n-2}}$
n	Count of years. FEI used data from 2006 to 2015. (n=10).
x^*	The year for which the PI is being calculated
$\bar{x}$	The average of the years in the historic record. ($\bar{x}$ = 2010.5)
s_x^2	The square of the sample standard deviation in x (years). (s_x^2 =3.03)

y_i	The actual customers in year i
$\hat{y}_i$	The trend estimate of the customers in year i

The first step is to calculate s_y . The calculation for Lower Mainland Rate Schedule 1 follows (all other rates and regions are identical and not shown in this this response):

	A	B	C	D	E
1	**Year (x)**	**Actual Customers (y)**	**Trend est. y'**	**Error, Y-Y'**	**SE, (Y-Y')^2**
2	2006	501,977	504,836	(2,859)	8,173,034
3	2007	510,030	508,936	1,094	1,196,539
4	2008	514,666	513,036	1,630	2,656,458
5	2009	517,849	517,136	713	507,924
6	2010	522,423	521,236	1,187	1,408,515
7	2011	525,779	525,336	443	196,055
8	2012	528,192	529,436	(1,244)	1,548,150
9	2013	532,463	533,536	(1,073)	1,151,919
10	2014	537,104	537,636	(532)	283,346
11	2015	542,379	541,736	643	413,024
12					SSE = 17,534,964
13					**Sy = 1,480**
14					

S_y is the square root of the sum of squared errors between the actual and predicted customer values for each of ten years. Column B contains the actual customers. FEI used a simple linear regression to determine the predicted customers in column C. Column D contains the error (the simple difference between the actual and predicted customers). Column E contains the squared error. Cell E12 contains the sum of the squared errors. S_y is the square root of the sum of squared errors divided by the count of observations minus two as defined above. Cell E13 contains the value of S_y which is constant for all calculations of the prediction interval for all future years for this region and rate schedule.

The x values in these calculations are years.

As an example the calculation of the PI for 2024 is:

	A	B	C	D	E	F	G
1	**Year**	**Prediction Interval**	**Low Prediction**	**20 Yr. Acct Forecast**	**High Prediction**	**Low Forecast**	**High Forecast**
10	2024	6,210	579,209	585,419	591,629	583,343	587,495

$$PI = 6{,}210 = 2.306 \times 1{,}480 \sqrt{1 + \frac{1}{10} + \frac{(2024 - 2010.5)^2}{(10-1) \times 3.03}}$$

FEI added and subtracted the PI from the forecast value for the year (585,419) to establish the high and low predictions. For example:

$$2024\ Low\ Prediction = 579{,}209 = 585{,}419 - 6{,}210$$

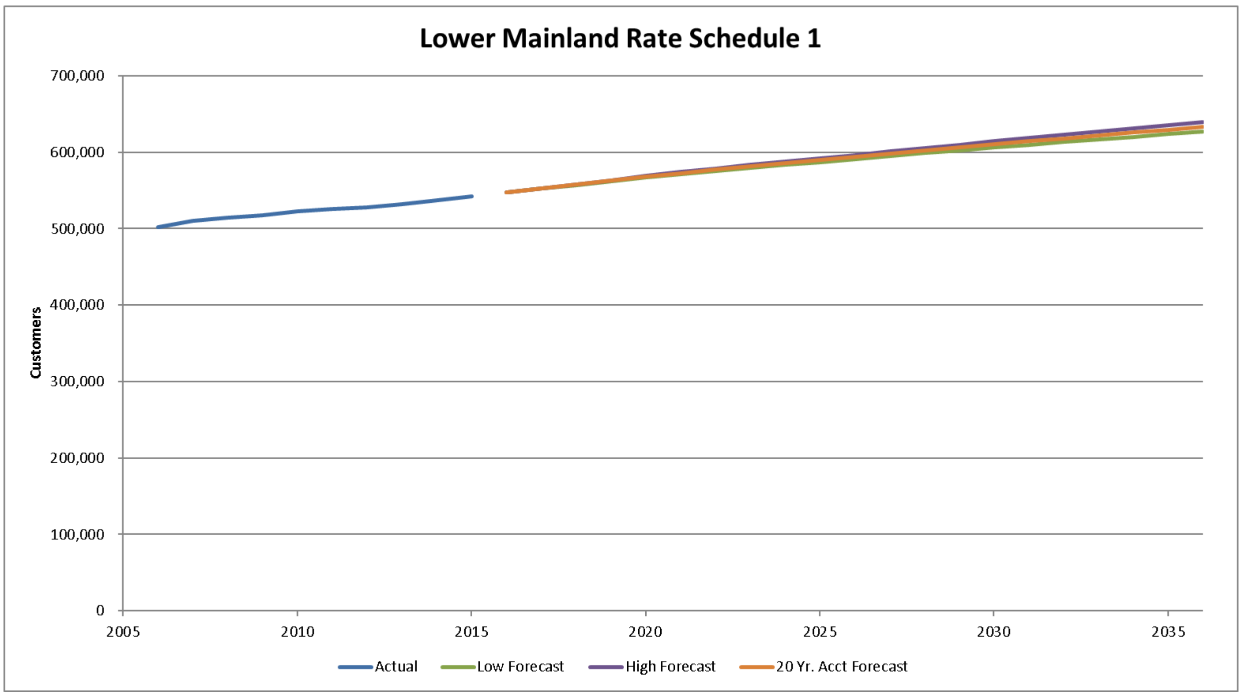
The first year of the forecast (2016) is assumed to have no uncertainty so the 2016 prediction interval is assumed to be zero. High and low forecasts are developed using the high and low predictions and the constraint that the uncertainty in the first forecast year is zero. FEI calculated the 2024 low forecast as follows:

$$2024\ Low\ Forecast = 2024\ Low\ Prediciton + (2016\ Forecast - 2016\ Low\ Prediction)$$

$$2024\ Low\ Forecast = 583{,}343 = 579{,}209 + (547{,}571 - 543{,}436)$$

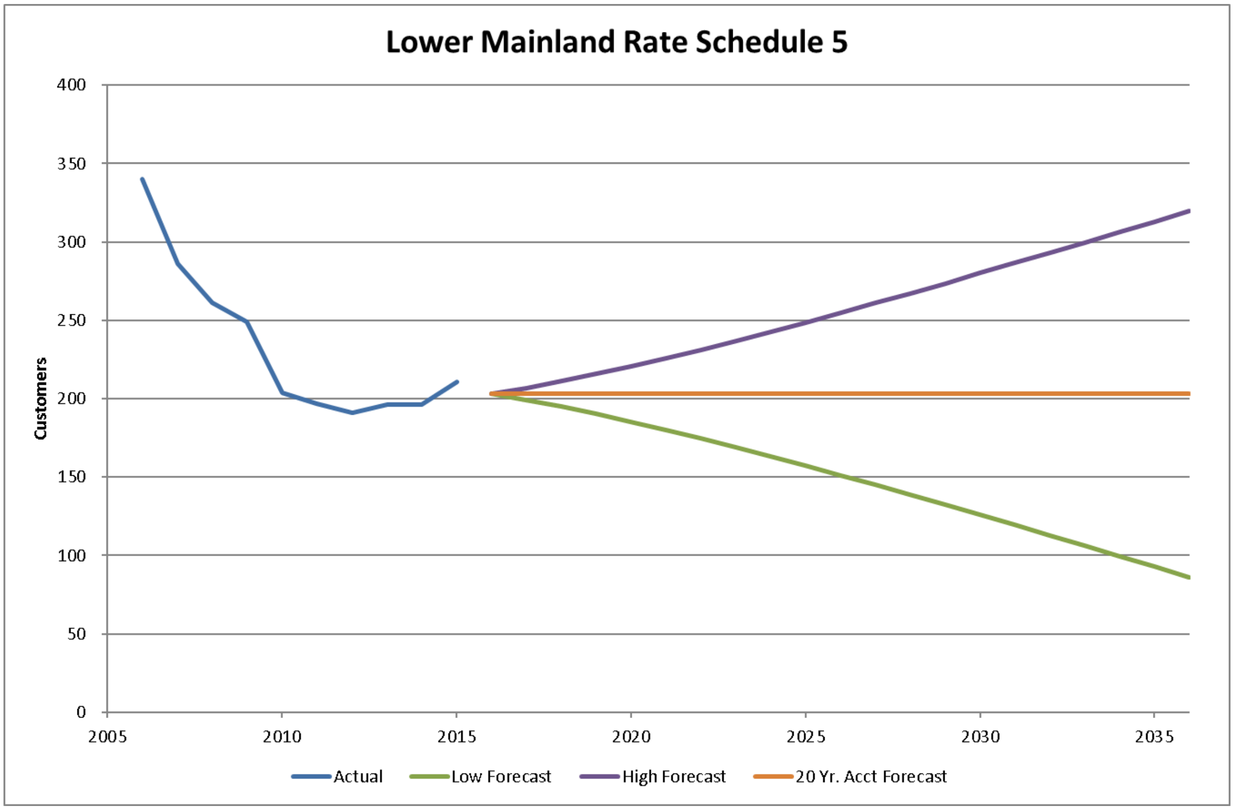
FEI completed identical calculations for all years of the forecast and for each region and rate class.

The following chart shows the upper and lower forecasts for Lower Mainland Rate Schedule 1:



The volatility of the Lower Mainland Rate Schedule 1 customer total is very low so the standard deviations are low. As a result, the prediction intervals are relatively small compared to the total customer count. The high and low customer forecasts are very close to the reference forecast.

In other rates and regions, the volatility in the historic data is higher so the high and low forecasts exhibit more uncertainty, as expected. The following chart shows the high and low forecasts for Lower Mainland Rate Schedule 5:



22.1.1 Please explain how these PI were calculated.

Response:

Please refer to the response to BCUC IR 1.22.1.

22.1.2 Please explain how FEI uses these PI to calculate a High and Low customer forecast.

Response:

Please refer to the response to BCUC IR 1.22.1.

22.2 How does the above statement reflect how the economic growth critical uncertainty is implemented in each of the alternate future scenarios of the 2017 LTGRP?

Response:

Figures B1-2 to B1-6 of the Application which follow the above-noted preamble illustrate the customer forecast outcomes for the economic growth critical uncertainty. Table B1-1 of the Application explains that three critical uncertainty outcomes exist for Economic Growth and Table 3-1 of the Application outlines which of the three outcomes applies to each forecast scenario. New residential dwellings are added to the end-use model in each forecast year, based on the forecast customer growth rate for the applicable scenarios. 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 schedule 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 schedule. 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 schedule 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 segment and rate schedule.

22.3 Please explain how forecast variability in new customer additions incorporates different economic growth assumptions.

Response:

All the growth patterns and drivers experienced in FEI's service territory over the last 10 years are intrinsic in the ten-year historic data set used to develop the prediction intervals. FEI assumes that future growth will occur in a similar manner and as such the prediction interval method coupled with the end use model and scenarios is a robust way to model future uncertainty.

22.4 Please provide a summary of the existing research by FEI and Posterity that concludes a -0.2 long run price sensitivity value for residential customers is suitable for use in the 2017 LTGRP.

Response:

FEI and Posterity have reviewed the following materials:

National Renewable Energy Laboratory (2006). Regional Differences in the Price-Elasticity of Demand for Energy, available at https://www.osti.gov/biblio/877655.

U.S. Energy Information Administration (2014). Price Elasticities for Energy Use in Buildings of the United States, available at https://www.eia.gov/analysis/studies/buildings/energyuse/pdf/price_elasticities.pdf.

Sustainable Prosperity (2012). The Likely Effect of Carbon Pricing on Energy Consumption in Canada, available at http://institut.intelliprosperite.ca/sites/default/files/likely-effect-carbon-pricing-energy-consumption-canada.pdf.

Gholami, Z (2014). Estimating the impact of carbon tax on natural gas demand on British Columbia. Doctoral Dissertation: University of British Columbia.

These materials either conduct primary research or represent reviews of numerous third-party studies. They indicate a range of elasticity values across a variety of regions, sectors and study publication dates. Overall, FEI and Posterity conclude from these studies that residential natural gas demand is relatively inelastic to natural gas prices, that residential natural gas demand should decline with increases in the natural gas price, and that residential elasticity has not changed materially over time.

FEI used the -0.2 long run price sensitivity value for residential customers in the 2014 LTRP. From the aforementioned research, FEI concluded that no material impetus exists for updating this value for the 2017 LTGRP. FEI thus determined that this value remains suitable for use in the 2017 LTGRP. FEI reported the residential and commercial long run price sensitivity values to its Resource Planning Advisory Group (RPAG) before solidifying them in its end-use method scenario analysis.

On page 70 of Exhibit B-1, FEI states:

> The extraneous variables of RNG demand, NGT demand, and demand from large industrial point loads (FEI's scenario analysis assumes that the RNG and NGT markets are still emerging and thus primarily depend on policy and stakeholder action rather than other macroeconomic factors).

22.5 Please explain why extraneous variables primarily depend on policy and stakeholder action rather than other economic factors.

Response:

FEI's end-use demand scenario analysis models the extraneous variables (referred to on page 70 of Exhibit B-1) to primarily depend on policy and stakeholder action not by virtue of them being extraneous variables but by virtue of their individual characteristics. FEI proceeded with this modelling approach after presenting this approach to its Resource Planning Advisory Group.

RNG, NGT and industrial point loads (such as LNG export terminals) are emerging markets in BC. This limits the availability and applicability of historical econometric trend data to forecasting the behaviour of these markets over the long term. Since these markets are emerging, FEI believes that they require concerted action by multiple stakeholders to achieve success. FEI also believes that government policy can support concerted stakeholder action. As such, FEI's end-use annual demand scenario analysis models the RNG and NGT annual demand trajectories linked to the Non-Price Carbon Policy critical uncertainty.

In Section 3.4.9 of Exhibit B-1, FEI defines that large industrial point loads consume more natural gas than FEI's existing industrial customers (e.g. pulp mills). The emergence of such large point loads is very uncertain and the impacts of even a single load addition is significant. As such, FEI's scenario analysis layers its forecast industrial point loads on top of the alternate future scenario results.

22.6 Please provide an update to, "Table 3-1: Alternate Future Scenario Summary" explicitly discussing the impact on NGT, LNG and RNG for each scenario. Please differentiate between LNG for NGT and non-NGT LNG in your discussion.

Response:

The links between FEI's core end-use annual demand forecast and the NGT and RNG annual demand forecast are qualitative only. FEI provided the core end-use forecast scenario parameters to its NGT programs department and RNG program team and requested them to prepare three forecast demand trajectories. FEI's NGT programs department provided a Base, a Low, and a High annual demand forecast for LNG and CNG, respectively. FEI's RNG program team provided a Reference Case, a Low, and a High annual demand forecast.

The rightmost column in the updated Table 3-1 below outlines which of these trajectories FEI modelled for each alternate future scenario. Please note FEI's added emphasis in the Description column of Table 3-1 for the Upper Bound and Lower Bound scenarios. Please see FEI's response to BCUC IR 1.22.5 for FEI's rationale behind these modelling linkages.

FEI layered annual demand for large industrial point loads (such as LNG export terminals) on top of the end-use Reference Case and Upper Bound annual demand trajectories to illustrate their impact on the range of annual demand across the alternate future scenarios.

Table 3-1 [Updated]: Alternate Future Scenario Summary

Scenario	Description	Input Settings		Discussion	Updated Discussion
A (Upper Bound)	The BC economy experiences higher-than-average growth. Infrastructure development in other regions, coupled with extraction infrastructure development in BC, keep regional gas supply abundant. Continued political opposition to carbon pricing and non-price carbon policy action cause governments to focus on issues other than carbon policy but the BC government keeps supporting NGT and RNG as cost effective existing carbon solutions.	Economic Growth	High	In general, the outcomes of the multiple critical uncertainties can offset each other's impact on annual demand but this scenario combines all outcomes that would increase annual demand. As such, this scenario represents one of two boundary scenarios that frame the scenario analysis. The combination of outcomes on each critical uncertainty is plausible and has occurred in the past.	NGT = High RNG = High. Assumes highest general voluntary adoption rates among residential and commercial customers. Also includes some NGT adoption of RNG and multiple large consumers.
		Natural Gas Price	Low		
		Carbon Price	Low		
		Non-Price Carbon Policy Action	Delayed		

Scenario	Description	Input Settings		Discussion	Updated Discussion
B (Local Growth & Constricted Supply)	The BC economy experiences higher-than-average growth. This is paralleled by moderate growth elsewhere which continues fueling existing demand for natural gas and constricts BC's natural gas demand balance. High natural gas prices and continued political opposition to carbon pricing and non-price carbon policy action cause government policy to implement energy performance standards upgrades published in their existing vision documents but to avoid imposing carbon costs that exceed annual increases of $5 per metric tonne.	Economic Growth	High	This represents one of the three intermediate scenarios in which outcomes of the multiple critical uncertainties do offset each other's impact on annual demand. Economic growth creates upward pressure on annual demand which is more strongly felt in the commercial and industrial sectors than in the residential sector. Price signals counteract this upward pressure on annual demand (these signals, again, more strongly impact the commercial and industrial sector in relation to the residential sector). Carbon policy action also dampens annual demand. Non-price carbon policy levers more significantly impact residential sector demand than commercial and industrial sector demand.	NGT = High RNG = High. See above.
		Natural Gas Price	High		
		Carbon Price	Medium Increase		
		Non-Price Carbon Policy Action	Accelerated		
C (Global Growth & Carbon Step Change)	The BC economy experiences higher-than-average growth as part of a global economic upturn. Infrastructure development in other regions (such as a strong focus on renewable fuel sources which reduces natural gas export opportunities), coupled with extraction infrastructure development in BC, keep BC's gas demand balance abundant. Global economic performance contributes to a political climate that is favourable to carbon pricing and non-price carbon policy action. This provides governments confidence to	Economic Growth	High	This represents the second of the three intermediate scenarios. This scenario differs from Scenario B in the natural gas and carbon price settings. The annual demand impacts in this scenario versus Scenario B show the trade-off between the natural gas and carbon price trajectories. The directional implications of each critical uncertainty on annual demand in this scenario are identical to Scenario B.	NGT = High RNG = High. See Above
		Natural Gas Price	Low		
		Carbon Price	High Increase		
		Non-Price Carbon Policy Action	Accelerated		

Scenario	Description	Input Settings		Discussion	Updated Discussion
	strongly focus on carbon policy.				
D (Global Economic Stagnation)	The BC economy experiences lower-than-average growth as part of global economic stagnation which also reduces excess regional demand for natural gas and keeps BC's gas demand balance abundant. Global economic performance contributes to a political climate that is not favourable to carbon pricing and non-price carbon policy action. This causes governments to focus on areas other than carbon policy.	Economic Growth	Low	This represents the third of the three intermediate scenarios and examines the possible impact of further economic stagnation. The annual demand impact of low economic growth is offset by low natural gas and carbon pricing and delayed carbon policy action. As in Scenarios B and C, price signals and the economy are more impactful for the commercial and industrial sector, whereas carbon policy action more significantly impacts the residential sector.	NGT = Low RNG = Low. Lowest growth in residential and commercial customer adoption rates. No adoption of RNG by NGT customers and no additional large customers.
		Natural Gas Price	Low		
		Carbon Price	Low		
		Non-Price Carbon Policy Action	Delayed		
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.	NGT = Low RNG = Low. See above.
		Natural Gas Price	High		
		Carbon Price	High Increase		
		Non-Price Carbon Policy Action	Accelerated		

23.0 Reference: ANNUAL ENERGY DEMAND FORECASTING

Exhibit B-1, Section 3.4, pp. 62-63

Development of the end-use demand forecasts

23.1 Please provide a detailed analysis of the costs of producing the reference and scenario forecasts using the end-use methodology.

Response:

FEI does not track its internal forecasting labour costs broken down by discrete forecast activities. As such, FEI's discussion of forecast costs includes external contractor labour only. FEI produces the Traditional Annual Method by extending its short-term forecast across the 20-year LTGRP planning horizon. This means the external labour cost for producing the Traditional Annual Method forecast is zero.

The table below outlines how external contractor costs for producing the end-use method Reference Case and scenario forecasts as well as C&EM analysis compare across the 2014 LTRP and the 2017 LTGRP.[9] The table shows that external contractor costs for producing the end-use forecast have declined from the 2014 LTRP to the 2017 LTGRP. In addition to the Reference Case, the 2014 LTRP produced four alternate future scenarios, whereas the 2017 LTGRP produced five alternate future scenarios. The 2017 LTGRP end-use method also contains important new features that FEI added in response to feedback it received from the BCUC and FEI's resource planning stakeholder engagement activities as part of the 2014 LTRP process and regulatory proceeding. These features include the ability to examine estimated C&EM expenditures and granular cost effectiveness test results (by program area) across alternate future scenarios and an exploratory method for linking the end-use method annual demand scenarios to peak demand.

Category	2014 LTRP	2017 LTGRP
End-Use Forecast Scenarios (Including Reference Case)	$150,000	$145,000
C&EM Analysis	$130,000	$67,600

In theory, forecast costs are a function of multiple factors. Two important drivers are the number of forecast features and scenarios as well as the cost per forecast feature and scenario. FEI cannot predict how the interplay between these drivers will evolve for individual future iterations of the end-use demand forecast method. From its experience with the Forecast Information System (FIS), FEI speculates that total end-use forecast costs could stabilize or

[9] These costs exclude FEI's expenditures for establishing and maintaining the information systems required for storing and visually illustrating the forecast results.

even decline in the long term if the feature set and scenario output of the end-use forecast method stabilizes.

23.1.1 Please compare these costs to the costs associated with producing demand forecasts based on the traditional method?

Response:

Please refer to the response to BCUC IR 1.23.1.

23.1.2 How has the cost of the end-use method varied between the FEU 2014 LTRP and the FEI 2017 LTGRP?

Response:

Please refer to the response to BCUC IR 1.23.1.

23.1.3 Is it likely the cost of the end-use method will remain constant or increase/decrease over time? Please explain your response.

Response:

Please refer to the response to BCUC IR 1.23.1.

D. DEMAND SIDE RESOURCES

24.0 Reference: DEMAND SIDE RESOURCES

Exhibit B-1, Section 4.2.1.1, p. 95; Section 4.2.1.2, pp. 96 to 97; Section 4.2.3, p. 102; Demand-Side Measures Regulation B.C. Reg. 326/2008, Section 3

Adequacy Measures

Table 4-2 of Exhibit B-1 outlines the adequacy requirements of a plan portfolio, pursuant to Section 3 of the Demand-Side Measures Regulation (DSM Regulation), that must be included to be considered adequate for the purposes of section 44.1 (8)(c) of the *Utilities Commission Act* (UCA).

On pages 96 to 97 of Exhibit B-1, FEI states:

> The new adequacy requirements that are not met within the existing portfolio will be addressed in the upcoming expenditure schedule application to be filed after the 2017 LTGRP. The 2017 LTGRP C&EM analysis contains measures that are included in FEI's existing portfolio but also adds new measures. In general, many measures are applicable to adequacy situations but their adequacy implications depend on their specific program packaging and delivery (including marketing) which is determined during program design.

On page 102 of Exhibit B-1, FEI states:

> The 2017 LTGRP's C&EM analysis results are informed by both the BC CPR and existing program experience. The results maintain the BC CPR's segmentation into residential, commercial, and industrial program areas. These do not break out individual adequacy programs specifically (this breakdown will occur in the forthcoming 2018 and future C&EM expenditure schedule submissions)

24.1 Please confirm if all scenarios presented in the 2017 LTGRP C&EM analysis contain all adequacy measures required under section 3 of the DSM Regulation including amendments up to BC Reg. 117/2017, March 24, 2017.

<u>Response:</u>

FEI's response to this question also addresses BCUC IRs 1.24.1.1, 1.24.2, 1.24.2.1, 1.24.3, and 1.27.6.2.

The 2017 LTGRP C&EM analysis addresses all adequacy measures required under section 3 of the DSM Regulation including amendments up to BC Reg. 117/2017, March 24. 2017. Within the 2017 LTGRP C&EM scenario analysis framework, the Reference Case, Upper Bound, and Lower Bound C&EM scenarios contain all such measures that result in specific energy savings.

The 2017 LTGRP C&EM analysis is informed by the BC CPR results. On page 5 of its market potential report, the BC CPR (Appendix C-1 of the Application) indicates that:

> Market potential differs from program potential in that market potential does not specifically take into account the various delivery mechanisms that can be used by program managers to tailor their approach depending on the specific measure or market. Rather, market potential represents a high-level assessment of savings that could be achieved over time, factoring in broader assumptions about customer acceptance and adoption rates that are not dependent on a particular program design.

In accordance with the BC CPR's approach, the Application indicates on page 96 that its C&EM analysis includes measures that can be used for adequacy purposes and, on page 97, that many measures are applicable to adequacy situations but their adequacy implications depend on their specific program packaging and delivery (including marketing) which is determined during program design.

As exemplified by the measures in the table below, the aforementioned C&EM scenarios contain forecast energy savings and estimated C&EM expenditures for C&EM measures that, once operationalized during program design, will contribute to meeting adequacy requirements. These measures are standalone measures within the approach of the 2017 LTGRP C&EM analysis because they represent discrete technical or operational changes (e.g. replacement of individual appliances) and are not yet enrobed in specific program packaging and delivery mechanisms (which are added in FEI's DSM expenditure schedules and program design). Given this approach, measures that are applicable to the Low Income program area are included in the Residential program area of the 2017 LTGRP C&EM analysis.

The table below contains no specific measures addressed at educating students enrolled in schools or post-secondary institutions in FEI's service area or financial or other resources provided to standards-making, regulatory or government bodies (requirements 3(1)(c), (d) and (e), respectively, of the DSM Regulation). This is due to the 2017 LTGRP C&EM energy savings forecast and expenditure estimates specifically excluding non-incentive expenditures that support or enable C&EM programs at the portfolio level, such as Enabling Activities (which includes resources provided to standards-making, regulatory or government bodies) and Conservation Education Outreach expenditures. However, as noted in Section 4.2.4 of the Application, FEI will conduct the following activities to meet the applicable adequacy requirements and will operationalize these across the 2017 LTGRP planning horizon via successive DSM expenditure schedules which will address program packaging and delivery:

- Continue to perform residential, commercial, industrial, low income, innovative technologies, *conservation education and outreach as well as enabling C&EM activities* [emphasis added]; and
- Continue monitoring the cost effectiveness of its C&EM activities and identify any new measures that can be included in these activities.

Please note that the table measures in green font are also applicable to rental accommodations (requirement 3(1)(b) of the DSM Regulation) based on FEI's current measure suite in the Rental Apartment Efficiency Program.

Scenario	C&EM Measures	Applicable Adequacy Situations from the DSM Regulation
Reference Case	• Com | NC measure 30 %>code • Com | NC measure 45 %>code • Res | Energy Efficient Building 30% better than code • Res | Energy Efficient Building 45% better than code • Res | ENERGY STAR Home • Res | R-2000 Standard New Home • Res | Passive House • Res | Net Zero Home	3 (1)(f) to result in the adoption by local governments and first nations of a step code or more stringent requirements within a step code[10]
	• Res | Central High Eff Boiler Replace • Res | Faucet Aerators • Res | Low Flow Showerheads • Res | Wall Insulation • Res | Furnace Early Retirement	• (a) intended specifically (i) to assist residents of low-income households to reduce their energy consumption, or (ii) to reduce energy consumption in housing owned or operated by (A) through (E) • (b) intended specifically to improve the energy efficiency of rental accommodations
Upper Bound	• Com | NC measure 30 %>code • Com | NC measure 45 %>code • Res | ENERGY STAR Home • Res | R-2000 Standard New Home • Res | Passive House • Res | Net Zero Home	3 (1)(f) to result in the adoption by local governments and first nations of a step code or more stringent requirements within a step code
	• Res | Central High Eff Boiler Replace • Res | Faucet Aerators • Res | Low Flow Showerheads • Res | Wall Insulation	• (a) intended specifically (i) to assist residents of low-income households to reduce their energy consumption, or (ii) to reduce energy consumption

[10] All new construction measures in the table are based on the information that FEI could access about the *BC Energy Step Code* in time for preparing the BC CPR and the 2017 LTGRP for its submission date to the BCUC. FEI's C&EM expenditure schedules will consider updated information about the *BC Energy Step Code* when FEI prepares such schedules.

Scenario	C&EM Measures	Applicable Adequacy Situations from the DSM Regulation
	• Res | Furnace Early Retirement • Res | Air Infiltration • Res | Attic Insulation • Res | Basement Insulation • Res | Ceiling Insulation	in housing owned or operated by (A) through (E) • (b) intended specifically to improve the energy efficiency of rental accommodations
Lower Bound	• Com | NC measure 30 %>code • Com | NC measure 45 %>code • Res | Energy Efficient Building 30% better than code • Res | Energy Efficient Building 45% better than code • Res | R-2000 Standard New Home • Res | Passive House	3 (1)(f) to result in the adoption by local governments and first nations of a step code or more stringent requirements within a step code
	• Res | Central High Eff Boiler Replace • Res | Faucet Aerators • Res | Low Flow Showerheads • Res | Wall Insulation • Res | Furnace Early Retirement • Res | Air Infiltration • Res | Attic Insulation • Res | Basement Insulation • Res | Ceiling Insulation	• (a) intended specifically (i) to assist residents of low-income households to reduce their energy consumption, or (ii) to reduce energy consumption in housing owned or operated by (A) through (E) • (b) intended specifically to improve the energy efficiency of rental accommodations

24.1.1 If not confirmed, please explain why the adequacy measures are not included in the 2017 LTGRP C&EM analysis.

Response:

Please refer to the response to BCUC IR 1.24.1.

24.2 Please confirm, or explain otherwise, that adequacy measures required under section 3 of the DSM Regulation have not been included as standalone measures in the LTGRP C&EM analysis.

Response:

Please refer to response to BCUC IR 1.24.1.

24.2.1 For each of the adequacy requirements in Table 4-2, please outline which C&EM measures contained in the 2017 LTGRP C&EM analysis are "applicable to adequacy situations", and where appropriate please briefly describe the activities that will be undertaken to meet the adequacy requirement.

Response:

Please refer to the response to BCUC IR 1.24.1.

Section 3(e) of the DSM Regulation requires that a portfolio plan include:

> one or more demand-side measures to provide resources as set out in paragraph (e) of the definition of "specified demand-side measure", representing no less than
>
> (i) an average of 1% of the public utility's plan portfolio's expenditures per year over the portfolio's period of expenditures, or
>
> (ii) an average of $2 million per year over the portfolio's period of expenditures;

24.3 Please indicate the forecasted expenditure on section 3(e) measure(s) for the planning horizon of the 2017 LTGRP, as either the average percentage of overall plan expenditures, or dollar per year average, for all C&EM scenarios.

Response:

Please refer to the response to BCUC IR 1.24.1.

25.0 Reference: DEMAND SIDE RESOURCES

Exhibit B-1, Section 4.2.2, p. 99 to 100; Section 4.2.2.2; p. 102; Section 4.2.3, p. 102; Section 4.2.3.4, p. 119

C&EM scenarios

On page 99 of Exhibit B-1, FEI states:

> The 2017 LTGRP's C&EM analysis displays results for the Reference Case, Upper Bound and Lower Bound scenarios presented in Section 3. The C&EM analysis selected these scenarios to display the impact of forecast C&EM activity on the Reference Case but to also illustrate the potential range of this impact across the Upper Bound and Lower Bound scenarios which resulted in the lowest and highest forecast of annual demand for natural gas.

Table 4-3 of Exhibit B-1 summarizes the input settings (economic growth, natural gas price, carbon price and non-price carbon policy action) for the Reference Case and Lower and Upper Bound scenarios, and the impact upon potential savings from C&EM is described in section 4.2.2.2 of Exhibit B-1.

On page 102 of Exhibit B-1, FEI states:

> The C&EM analysis results indicate the outcome of pursuing all cost effective energy savings potential.

On page 119 of Exhibit B-1, FEI states:

> FEI's forthcoming 2018 and future C&EM expenditure schedules will be informed by the measure data from the 2017 LTGRP's C&EM analysis and will make program design and delivery decisions in accordance with changing customer needs, regulatory requirements and technology evolution.

25.1 Please confirm whether FEI is seeking acceptance of the C&EM element of the LTGRP with respect to the Reference Case only, all scenarios, or otherwise, as part of its 2017 LTGRP Application.

Response:

FEI interprets the "C&EM element" in the question to refer to the entire 2017 LTGRP C&EM analysis whose inputs and results vary across the different scenarios. FEI seeks acceptance of the 2017 LTGRP, including the C&EM analysis and its scenarios, pursuant to 44.1(6)(a) of the Utilities Commission Act (*UCA*).

25.1.1 Please confirm that all scenarios (Reference Case, Upper Bound and Lower Bound) include all C&EM measures that are cost-effective for the respective scenario.

Response:

FEI consulted with Posterity to provide the following response.

Confirmed. The 2017 LTGRP C&EM analysis includes all C&EM measures that are cost-effective in a given scenario. The BC CPR results and FEI's C&EM program experience inform the 2017 LTGRP C&EM analysis about how much C&EM participation cost-effective measures experience in each year of each scenario.

25.1.1.1 If not confirmed, please explain.

Response:

Please refer to the response to BCUC IR 1.25.1.1.

25.2 Please discuss whether there is a combination of input settings (economic growth, natural gas price, carbon price and non-price carbon policy action) that would generate forecasted C&EM energy savings on a portfolio basis at a level that is:

a) higher than the forecasted C&EM energy savings under the Upper Bound scenario;

b) lower than the forecasted C&EM energy under the Lower Bound scenario.

Response:

FEI consulted with Posterity to provide the following response.

Across the 2017 LTGRP alternate future scenarios, the Upper Bound scenario generates the highest forecast C&EM energy savings and the Lower Bound scenario generates the lowest C&EM energy savings on a portfolio basis. In theory, it is possible that a combination of economic growth, natural gas price, carbon price, and non-price carbon policy actions exists that would result in higher or lower forecast C&EM energy savings. However, a scenario that may feature such a combination would be in addition to and separate from the 2017 LTGRP alternate future scenarios. As noted on page 99 of the Application:

> The 2017 LTGRP's C&EM analysis displays results for the Reference Case, Upper Bound and Lower Bound scenarios presented in Section 3. The C&EM analysis selected these scenarios to display the impact of forecast C&EM activity on the Reference Case but to also illustrate the potential range of this impact across the Upper Bound and Lower Bound scenarios which resulted in the lowest and highest forecast of annual demand for natural gas. This enables the Company to present the widest range of potential demand for natural gas after energy savings from cost effective demand-side measures.

As such, the 2017 LTGRP scenario analysis seeks to determine a suitable level of resources across the range of alternate future scenarios that it constructs. Although a theoretical scenario might exist that has somewhat higher or lower energy savings from C&EM activity, such a scenario would either be outside of the future scenarios deemed reasonable to model as reviewed with the Resource Plan Advisory Group, or would be captured within the range of the total demand, including energy savings from C&EM, that have been modelled and presented in the 2017 LTGRP. As noted in Section 4.2.4 of the Application, FEI will operationalize its C&EM activity via successive C&EM expenditure schedule applications that will consider the planning environment that applies at the time of preparation.

25.2.1 If yes, please provide a comparison of energy savings with the Upper Bound and/or Lower Bound scenarios.

Response:

Please refer to the response to BCUC IR 1.25.2.

25.3 Please confirm the key outputs of the 2017 LTGRP C&EM analysis that will be used to inform FEI's future C&EM expenditure schedules to be filed with the Commission.

Response:

This response also addresses BCUC IRs 1.25.3.1 and 1.25.3.1.1.

FEI has used the 2017 LTGRP C&EM analysis for directional input into program development to help determine where there may be new opportunities for DSM programs and to help assess the future potential of existing programs to help guide expenditures for those programs.

FEI has also used the 2017 LTGRP C&EM analysis as a "reasonableness check" in its development of the 2019-2022 Demand Side Management Expenditures Plan (DSM Plan). FEI builds its DSM Plans from the measure level and program level up and then compares the results of this process to the LTGRP results to see if there are any significant inconsistencies. Any inconsistencies identified then prompt a further review of DSM Plan data inputs to determine if adjustments are required.

Future LTGRPs will include new C&EM analyses that will inform future expenditure schedule applications. Ideally, a new LTGRP will be submitted to the Commission prior to submitting each successive C&EM expenditure application; however, many factors influence the timing of each submission and it is not always possible to line up all the studies that inform each application so that this sequence of filing can always be achieved.

FEI DSM Plans do not incorporate scenarios hence they use the Reference Case as the key directional guidance. The Reference Case is not considered to be a "preferred portfolio", rather it is used as the base case scenario.

25.3.1 Please discuss the extent that the C&EM analysis under the Reference Case, Upper Bound scenario and Lower Bound scenario, respectively, will be used by FEI as inputs or guidance to future C&EM expenditure schedules.

Response:

Please refer to the response to BCUC IR 1.25.3.

25.3.1.1 Please discuss whether FEI considers that the Reference Case represents a "preferred portfolio" for informing future C&EM expenditure schedules.

Response:

Please refer to the response to BCUC IR 1.25.3.

On page 102 of Exhibit B-1, FEI states:

> Although customer demand is price inelastic over the short term, higher gas pricing over the long term, while holding all other variables constant, may cause some customers to switch away from natural gas for certain end uses… Higher economic growth tends to increase the potential for savings due to its impact on the customer forecast; lower economic growth tends to decrease it.

25.4 Please discuss whether FEI believes that persistent high gas prices, all other variables being constant, could increase customer awareness of C&EM programs and participation rates. Please discuss if this effect is modelled in the 2017 LTGRP C&EM analysis.

Response:

FEI has not conducted any research into the relationship between (1) gas prices and customer awareness of C&EM programs and participation rates, and (2) changing customer spending power, resulting from economic growth, and contributing to C&EM participation. Since FEI is unable to rely on any research results, the end-use forecast method scenario analysis framework does not model any direct relationship between these variables.

However, the 2017 LTGRP C&EM analysis is informed by the results of the BC Conservation Potential Review (BC CPR) and FEI's C&EM program experience. The BC CPR model was calibrated to reflect historic participation (in the form of programmatic energy savings) as a function of assumed gas prices, which would inherently capture some observed consumer sensitivity to prices. Moreover, the modelled customer willingness to adopt efficient measures will increase as gas prices increase, since the economic attractiveness improves. An increase in the population's adoption levels spurs increased awareness via word-of-mouth dynamics. Thus, there would be an increase in consumers' propensity to adopt under higher gas prices. As such, the BC CPR was able to capture some dynamics related to increased awareness and participation resulting from higher gas prices. However, it did not specifically model a high gas price scenario to examine its effects.

25.5 Please discuss whether FEI believes that changing customer spending power as a result of economic growth contributes to C&EM participation rates. Please discuss if this effect is modelled in the 2017 LTGRP C&EM analysis.

Response:

Please refer to the response to BCUC IR 1.25.4.

26.0 Reference: DEMAND SIDE RESOURCES

Exhibit B-1, Section 4.2.1.1, p. 96; Section 4.2.2.1, p. 101; Section 4.2.2.2, p. 102; Section 4.2.3.2, p. 111; Section 4.2.3.3, p. 115; Appendix C-1, pp. 2, 5

Cost effectiveness tests

On page 96 of Exhibit B-1, FEI states:

> Effective March 24, 2017, BC Reg. 117/2017 increased from 33 to 40 percent the cap on the ratio of public utility DSM portfolios that may rely on the MTRC [Modified Total Resource Cost] for cost effectiveness testing …

On page 102 of Exhibit B-1, FEI states:

> Following the BC CPR's [Conservation Potential Review] approach, the 2017 LTGRP C&EM analysis applies the TRC [Total Resource Cost] test to commercial and industrial program areas but the MTRC test to the residential program area to simulate the current DSM landscape.

The Conservation Potential Review appended to the Application, on page 5 states:

> To date, FortisBC Gas's experience is that, typically, most programs in the residential sector require the mTRC.

26.1 Please explain why FEI applies the MTRC to the entire residential program area, rather than only applying the MTRC to measures that are not cost-effective under the TRC.

<u>Response:</u>

FEI consulted with Navigant Consulting Ltd. (Navigant) to provide the following response.

The 2017 LTGRP C&EM analysis is informed by the BC CPR which applies the MTRC to the entire residential program area rather than only applying the MTRC to measures that are not cost-effective under the TRC. Also, the 2017 LTGRP is a long-term forecast and thus refrains from manually prioritizing which measures should be subject to the MTRC test. Such manual prioritization is akin to program design and is addressed in FEI's DSM expenditure schedules. The following paragraphs explain this further by providing more detail on the BC CPR's approach:

The BC CPR, Appendix C of the Application, in Section 5.1 states:

> Hybrid mTRC/TRC case: This case uses the mTRC test for the residential sector and the TRC test for the commercial and industrial (C&I) sectors, which is most

> analogous to FortisBC Gas's actual DSM program environment. [In footnote:] Model limitations prevented the team from implementing a strict 33% cap on spending directed towards measures requiring the mTRC screen. However, the cap was approximated by only allowing residential measures to screen the mTRC test for cost-effectiveness.[11]

Only applying the MTRC to measures that are not cost-effective under the TRC and staying within the spending cap would require iteratively selecting different measures to which the MTRC screening would be applied, and evaluating whether the cap had been met. It was determined that this process was more labour-intensive than the BC CPR project timeline and budget allowed. Additionally, prioritization of which specific measures to evaluate under the MTRC is more akin to program design as noted above, and this was outside of the original intent of the BC CPR market potential assessment.

Applying the MTRC only to measures that are not cost-effective under the TRC rather than the entire residential sector would have no material difference on technical, economic, or market potential. If a measure was already cost-effective under the TRC, then it continues to be cost-effective under the MTRC. If a measure was non-cost-effective, then the MTRC would be applied. The value of the avoided cost benefits does not factor into customer adoption, so market potential would be unchanged. The only impact would be on the TRC, RIM, and UCT ratios and net benefits.

Given that most programs in the residential sector require the MTRC in FEI's experience, FEI and Navigant determined that application of the MTRC to the entire residential sector in the Hybrid TRC/mTRC case was a reasonable assumption for the purposes of the market potential assessment.

26.1.1 Please explain whether only applying the MTRC to measures that are not cost-effective under the TRC would result in the C&EM portfolios containing additional C&EM measures compared to the analysis in the 2017 LTGRP.

<u>Response:</u>

FEI consulted with Posterity to provide the following response.

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[11] At the time of this analysis, the cap on the ratio of public utility DSM portfolios that may rely on the MTRC had not yet change to 40 percent.

Applying the MTRC only to measures that are not cost-effective under the TRC may result in 2017 LTGRP C&EM portfolios that contain additional C&EM measures. However, when considering the Reference Case, Lower Bound, and Upper Bound 2017 LTGRP C&EM scenarios, this effect is applicable to the Reference Case and Upper Bound only, since the Lower Bound applies the MTRC to all program areas. The 2017 LTGRP C&EM analysis also selected its MTRC approach in alignment with the BC CPR's approach. As noted in FEI's response to BCUC IR 1.26.1, the BC CPR indicates that the impact of applying the MTRC to measures that are not cost-effective under the TRC (rather than the entire residential sector) would be immaterial on technical, economic, or market potential.

26.1.2 Please explain why most programs in the residential sector require the MTRC to be cost-effective.

Response:

Residential programs generally require the MTRC to be cost effective because in comparison to other program areas, the residential sector tends to have a higher incremental cost, for the incremental energy saved, than measures in the commercial or industrial sector. This is illustrated by comparing costs and savings for the residential and commercial heating system programs in the table below based on data extracted from the Natural Gas Demand-Side Management Programs 2017 Annual Report. The commercial boiler program yields almost 17 GJs per $1,000 in incremental costs. The residential heating system program yields less than 4 GJs per $1,000 in incremental costs.

	Commercial boiler	Residential furnace (Early replacement of Standard efficiency)	Residential furnace (Early replacement of Mid-efficiency)	Residential boiler
Incremental measure cost	$ 24,227	$ 1,840	$ 1,840	$ 3,540
Savings (GJs)	407	6.9	5	8.7
GJ savings per $1,000 incr. cost	16.8	3.8	2.7	2.5

26.2 Please confirm for each C&EM scenario the percentage of the portfolio where the MTRC has been applied.

Response:

FEI consulted with Posterity to provide the following response.

As explained in the response to BCUC IR 1.26.1, the 2017 LTGRP C&EM analysis is informed by the BC CPR. The BC CPR applied the MTRC to the entire residential program area because only applying the MTRC to measures that are not cost-effective under the TRC and staying within the spending cap would require iteratively selecting different measures to which the MTRC screening would be applied. Once this is done the CPR team could evaluate whether the cap had been met. It was determined that this process was more labour-intensive than the BC CPR project timeline and budget allowed. Additionally, prioritization of which specific measures to evaluate under the MTRC is more akin to program design, which was outside of the original intent of the BC CPR market potential assessment.

The table below details what percentage of the 2017 LTGRP forecast C&EM portfolio (by estimated C&EM expenditure) relies on the MTRC rather than the TRC cost effectiveness test as an outcome of the MTRC approach in the LTGRP scenario analysis and the Reference Case applying the MTRC to the residential program area. For readability, FEI provided this data for five milestone years, but data for all years does exist in the 2017 LTGRP forecast model. The MTRC ratio fluctuates between 0 and 52 percent across the years and scenarios displayed in the table. FEI recognizes that, in some cases, this percentage exceeds the current MTRC cap in the DSM Regulation. This result is simply an outcome of the method that FEI used (in alignment with the BC CPR) and was not foreseeable to FEI at the outset of the 2017 LTGRP C&EM analysis.

Scenario	Percentage of The Estimated C&EM Portfolio where the MTRC Has Been Applied				
	2017	2020	2025	2030	2036
Reference Case	10%	20%	31%	41%	36%
Upper Bound	14%	23%	52%	52%	48%
Lower Bound	0%	24%	25%	35%	4%

26.2.1 If below the 40 percent cap, please explain why FEI did not apply the MTRC to additional measures that are not cost-effective under the TRC test.

Response:

Please refer to the response to BCUC IRs 1.26.1 and 1.26.2.

On page 115 of Exhibit B-1, FEI states:

> 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 [Zero Emissions Energy Alternative] for its avoided cost of gas. In the 2017 LTGRP, the ZEEA is not impacted by the natural gas and carbon cost critical uncertainties.

26.3 Please confirm the values assumed for the avoided cost of gas under the TRC test for each C&EM scenario, in $/GJ.

Response:

The tables below provide the values (in $/GJ) used for the avoided cost of gas under the TRC test for the Upper Bound, Reference Case and Lower Bound scenarios.

Avoided Cost of Gas:

Year	Upper Bound	Reference Case	Lower Bound
2016	5.11	5.48	5.85
2017	5.41	5.84	6.32
2018	5.29	6.12	6.93
2019	5.27	6.33	7.34
2020	5.21	6.46	7.57
2021	5.27	7.09	8.27
2022	5.51	7.72	9.10
2023	5.57	7.95	10.03
2024	5.60	8.09	10.73
2025	5.61	8.21	11.29
2026	5.67	8.33	11.96
2027	5.75	8.45	12.37
2028	5.81	8.57	12.94
2029	5.87	8.70	13.52
2030	5.92	8.83	14.09
2031	5.96	8.97	14.63
2032	6.03	9.10	15.18
2033	6.10	9.24	15.72
2034	6.18	9.38	16.21
2035	6.26	9.52	16.75
2036	6.35	9.67	17.16
2037	6.45	9.82	17.58

Commodity Cost

Year	Upper Bound	Reference Case	Lower Bound
2016	2.31	2.69	3.06
2017	2.63	3.06	3.54
2018	2.51	3.34	4.15
2019	2.50	3.56	4.58
2020	2.45	3.70	4.80
2021	2.51	3.88	5.06
2022	2.75	4.08	5.47
2023	2.79	4.28	5.98
2024	2.79	4.40	6.28
2025	2.78	4.49	6.46
2026	2.81	4.59	6.76
2027	2.87	4.68	6.82
2028	2.89	4.78	7.05
2029	2.92	4.88	7.30
2030	2.95	4.98	7.56
2031	2.96	5.09	7.79
2032	3.00	5.19	8.06
2033	3.05	5.30	8.33
2034	3.09	5.41	8.54
2035	3.14	5.52	8.83
2036	3.20	5.64	9.01
2037	3.27	5.75	9.20

Carbon Tax

Year	Upper Bound	Reference Case	Lower Bound
2016	1.49	1.49	1.49
2017	1.46	1.46	1.46
2018	1.43	1.43	1.43
2019	1.40	1.40	1.40
2020	1.37	1.37	1.37
2021	1.35	1.79	1.79
2022	1.32	2.20	2.20
2023	1.32	2.20	2.59
2024	1.32	2.20	2.96
2025	1.32	2.20	3.31
2026	1.32	2.20	3.66
2027	1.32	2.20	3.98
2028	1.32	2.20	4.30
2029	1.32	2.20	4.59
2030	1.32	2.20	4.88
2031	1.32	2.20	5.15
2032	1.32	2.20	5.41
2033	1.32	2.20	5.66
2034	1.32	2.20	5.89
2035	1.32	2.20	6.12
2036	1.32	2.20	6.32
2037	1.32	2.20	6.51

Year	*Midstream* all Scenarios	*Distribution* all Scenarios
2016	1.09	0.21
2017	1.11	0.21
2018	1.14	0.21
2019	1.16	0.21
2020	1.18	0.21
2021	1.21	0.21
2022	1.23	0.21
2023	1.25	0.21
2024	1.28	0.21
2025	1.31	0.21
2026	1.33	0.21
2027	1.36	0.21
2028	1.38	0.21
2029	1.41	0.21
2030	1.44	0.21
2031	1.47	0.21
2032	1.50	0.21
2033	1.53	0.21
2034	1.56	0.21
2035	1.59	0.21
2036	1.62	0.21
2037	1.66	0.21

26.3.1 Please explain the methodology and key assumptions behind the calculation of the avoided cost of gas for the purposes of the TRC test.

Response:

FEI's Energy Supply group provides the avoided cost of gas calculation for evaluating FEI's C&EM programs. FEI developed the method several years ago. The Commission reviewed this method during prior C&EM funding request proceedings and accepted FEI's calculation in Order G-138-14, dated September 15, 2014. FEI continues to use this method to update the avoided cost of gas annually. FEI's method for determining the avoided cost of gas for the purposes of the TRC cost effectiveness test in the 2017 LTGRP C&EM analysis is consistent with FEI's approach for calculating the avoided cost of gas for the TRC test in its annual DSM Programs report to the Commission.

The avoided cost on a per unit basis includes two components – an estimate of the commodity cost and an estimate of the midstream cost. FEI calculates the commodity cost based on the 10-year Alberta Energy Company/Nova Inventory Transfer (AECO/NIT) price forecast according to GLJ Petroleum Consultants, and then a Station 2 discount factor and a T-South transportation fuel are applied to derive a Sumas price. FEI estimates the midstream costs by calculating an approximation of the pipeline transportation charges required by FEI to move the commodity supply to core markets as well as the storage costs associated with meeting winter load requirements. The midstream costs after the first year are increased by an assumed annual inflation factor of two percent to account for the expected future cost increases of these resources. The avoided costs calculated based on the commodity and midstream costs represent the expected marginal costs of gas for each year.

The TRC tests in the LTGRP C&EM analysis include three scenarios which were constructed by using a combination of different assumptions across a range of critical uncertainties. When calculating the TRC tests, the components used in the avoided cost of gas include the commodity cost, midstream cost, carbon cost and the distribution adder. These scenarios adjusted the commodity component of the cost of gas. The carbon cost, though separate from the avoided cost of gas calculation, was also adjusted in each scenario. Please refer to FEI's response to BCUC IR 1.26.3 for details of which carbon cost and commodity cost assumptions are used across the Reference Case, Upper Bound, and Lower Bound scenarios, respectively.

26.4 Please confirm and briefly explain the calculation of ZEEA value (in $/GJ equivalent) that FEI has assumed for the MTRC in its 2017 LTGRP C&EM analysis.

Response:

The ZEEA value used is $27.78 $/GJ. FEI used $100 per MWh, which was the published LRMC value for BC Hydro at the time the analysis was conducted, as the ZEEA value and applied a conversion ratio of $1 per MWh = $0.2778 per GJ. The ZEEA value is used for the avoided cost of energy in the MTRC. The method for calculating the ZEEA value is identical to the method used for FEI's annual DSM Programs report to the Commission. Please refer to FEI's response to BCUC IR 1.26.5 for further background on the ZEEA.

26.5 Please summarize the analysis undertaken by FEI to conclude that the ZEEA does not fluctuate in response the 2017 LTGRP scenario parameters.

Response:

FEI's ZEEA is informed by BC Hydro's LRMC of procuring renewable electricity. Within the evidentiary update submitted as part of their 2015 Rate Design Application, BC Hydro stated that potential further changes to the Load Resource Balance are "not expected to impact the LRMC any further because those changes are unlikely to change the marginal energy and capacity resources over the next ten years. Furthermore, managing overall acquisitions can be done by limiting acquired volumes without modifying price limits".[12] Therefore, FEI presumed the ZEEA would likely be stable and no further analysis was conducted for the LTGRP.

26.5.1 Please confirm that FEI considers that the ZEEA will be unaffected by changes in economic growth, natural gas price, carbon price and/or non-price carbon policy action.

Response:

The main factor that would result in changes to the ZEEA would be a change in BC Hydro's LRMC or a legislative change to the way the ZEEA is defined or calculated (i.e. a change to the BC Demand-side Measures Regulation). It is possible that conditions influencing changes in economic growth, natural gas price, carbon price and/or non-price carbon policy action might

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[12] BC Hydro. 2015 Rate Design Application. Evidentiary Update on Load Resource Balance and LRMC. February 18, 2016.

also influence BC Hydro's LRMC value, however, FEI has no way of predicting how much, in which direction or when such changes might occur. At this time, FEI does not have reason to be believe that legislative changes to the ZEEA are being contemplated. For these reasons, and because the ZEEA is already a substantial increase above the avoided cost of energy used for the TRC calculation, FEI believes it is reasonable to use a consistent ZEEA throughout the planning horizon.

26.6 Please explain the consequences of any changes to the ZEEA value in the next five years with regards to FEI's planned C&EM portfolio.

Response:

Directionally speaking, a higher ZEEA could enable more measures to become cost effective under the MTRC and a lower ZEEA could have the opposite effect. However, FEI's C&EM portfolio would, under the current DSM Regulation, still be subject to the MTRC cap. This means that enabling more measures to become cost effective under the MTRC would not necessarily result in more energy savings opportunities for the portfolio as there would be an expenditure limit to how much those measures could be pursued. It should be noted that the 2017 LTGRP does not contain FEI's planned C&EM portfolio for the next 5 years. Rather it provides a forecast of available energy savings from C&EM activities under a range of scenarios. FEI's upcoming 2019-2022 DSM Expenditures application will contain the planned portfolio and will account for any known changes to the ZEEA over that period of time.

26.6.1 Please explain the main factors that contribute to fluctuations in the ZEEA.

Response:

Please refer to the responses to BCUC IRs 1.26.5 and 1.26.5.1.

26.6.1.1 Please explain whether FEI has undertaken sensitivity analysis to model the effect of changes to the ZEEA upon the 2017 LTGRP C&EM analysis.

Response:

FEI has not undertaken any sensitivity analysis to model the effect of changes to the ZEEA upon the 2017 LTGRP C&EM analysis for the reasons discussed in the responses to BCUC IRs 1.26.5 and 1.26.6.

26.7 Please confirm the discount rate used for the TRC/MTRC calculation.

Response:

The FEI discount rate used for the TRC/MTRC calculation is 5.9 percent.

On page 101 of Exhibit B-1, FEI states:

> The 2017 LTGRP's C&EM analysis requires each measure to meet the cost effectiveness test threshold and does not package measures into programs (where individual non-cost effective measures could be rendered cost effective by other measures). This approach for pursuing all cost effective DSM is consistent with the analysis in the BC CPR. The 2017 LTGRP's C&EM analysis represents a long term directional forecast of addressable C&EM initiatives; FEI's C&EM expenditure schedules bundle measures into specific programs, consider operational program deployment factors, and request BCUC permission for specific DSM expenditures.

The Conservation Potential Review appended to the Application, on page 2 states:

> This study models energy efficiency measures independently. As a result, the total aggregated energy efficiency potential estimates may be different from the actual potential available if a customer installs multiple measures in their home or business.

26.8 Please confirm whether FEI's C&EM expenditure schedules will consider measures that are not cost-effective on a standalone basis as part of "bundled" programs, where the bundled program is cost-effective.

Response:

FEI interprets "not cost-effective on a standalone basis" in the context of the 2017 LTGRP C&EM analysis to mean Commercial and Industrial measures that have a TRC below 1.0 and Residential measures that have an MTRC under 1.0.

FEI anticipates that the forthcoming 2019-2022 DSM Expenditures application will include allowance for some measures that are not cost-effective on a standalone basis within a bundled program. C&EM programs being considered for this type of model include a commercial custom design performance program where incentives would be offered for non-cost-effective measures within a bundled project in which the project as a whole would have a TRC of 1.0 or larger. The Low Income area is also considering a non-profit custom program that takes a similar approach.

FEI also anticipates pursuing measures in the DSM Plan that will not be cost effective on a standalone basis but fall under the definition of "specified DSM". Examples of this include energy management and technology innovation programs.

As noted in Section 4.2.3 of Exhibit B-1, there are several key differences in the approach with the 2017 LTGRP and FEI's approach to developing a C&EM expenditure schedule. The 2017 LTGRP C&EM analysis results maintain the BC CPR's segmentation into residential, commercial, and industrial program areas. These do not break out individual adequacy programs specifically. This breakdown will occur in the forthcoming DSM Expenditures application. Also, 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 applications which include 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.

FEI cannot speak at this time to future C&EM expenditure schedules beyond the 2019-2022 timeframe as those expenditure schedules have not been considered yet beyond the analysis put forward in the 2017 LTGRP.

26.8.1 If confirmed, please discuss whether FEI considers the bundling of measures, all other factors being equal, would increase or decrease:

a) overall energy savings, compared to the 2017 LTGRP C&EM analysis;

b) cost-effectiveness values, compared to the 2017 LTGRP C&EM analysis.

Response:

FEI consulted with Posterity to provide the following response.

FEI interprets that the “bundling of measures” in this context refers to the bundling of non-cost effective measure(s) with cost effective measure(s) to produce a C&EM program or portfolio that is net cost effective but includes measures that are not individually cost effective.

All other factors being equal, if the 2017 LTGRP C&EM analysis had included the assumption of incenting measures that are not cost effective but still return measurable energy savings the overall energy savings projected would have been a larger number. The cost effectiveness values, all other factors being equal, would have been less.

Refer to the response to BCUC IR 1.26.8 for explanation on why bundled measures were not included in the 2017 LTGRP C&EM analysis.

26.9 Please explain whether FEI will consider pursuing measures that are not cost-effective (within an overall portfolio that is cost-effective) in its forthcoming C&EM expenditure schedules.

Response:

Please refer to the response to BCUC IR 1.26.8.

26.9.1 If confirmed, please explain the difference in approach with the 2017 LTGRP.

Response:

Please refer to the response to BCUC IR 1.26.8.

27.0 Reference: DEMAND SIDE RESOURCES

Exhibit B-1, Section 2.3.2.2, pp. 35 - 36; Section 4.2.3.1, pp. 103 to 106;

Section 4.2.3.2, p. 107; Section 4.2.3.3, pp. 116 to 119; Section 8.6, pp. 210 to 215; Appendix C-2 pp. 3 - 4; Application for Acceptance of the 2014 Long Term Resource Plan Decision, Order G-189-14, Section 4.3, p. 27

C&EM Analysis

Figures 4-1 to 4-4 illustrates natural gas demand before and after estimated C&EM savings (excluding NGT) for all sectors, and by each customer program area.

On page 103 of Exhibit B-1, FEI states:

> Forecast 2036 Reference Case energy savings account for 7.89 percent of projected sales. This ratio changes to 6.79 percent and 5.92 percent for the Upper and Lower Bound scenarios, respectively.

On pages 35 to 36 of Exhibit B-1, FEI states:

> Energy Efficiency Resource Standards (EERS) aim to increase utility investment in energy efficiency measures to meet a share of their total load. Under an EERS, electric and gas utilities are regulated to demonstrate annual energy savings as a percentage of their total load. These savings are achieved through investment in utility energy efficiency programs. Annual savings targets range from 0.5 percent to 3 percent of total utility sales depending on the state. …
>
> Averaged over all state programs, EERS are saving an estimated 1.2 percent of utility load. However, should this annual savings rate persist, it would lead to a 15 percent reduction in utility energy demand by 2030, all else remaining equal.

27.1 Please reproduce Figures 4-1 to 4-4 in table form.

Response:

The reproduced Figures 4-1 to 4-4 in table form are provided below.

Figure 4-1 [in table form]: Natural Gas Demand Before and After Estimated C&EM Savings (Excluding NGT) – All Sectors (GJ)

Year	Reference Case		Upper Bound		Lower Bound	
	Scenario Annual Demand	Scenario Annual Demand after C&EM	Scenario Annual Demand	Scenario Annual Demand after C&EM	Scenario Annual Demand	Scenario Annual Demand after C&EM
2015	191,738,754	191,738,754	191,738,754	191,738,754	191,738,754	191,738,754
2016	192,012,307	192,012,307	193,846,528	193,846,528	190,790,190	190,790,190
2017	192,240,096	190,972,506	194,937,321	193,693,609	189,440,809	188,177,491
2018	192,642,932	190,381,325	196,107,170	193,865,184	187,872,246	185,653,232
2019	192,899,700	189,756,975	197,381,162	194,277,583	185,665,523	182,665,192
2020	193,249,740	189,231,616	198,907,946	194,918,677	182,834,472	179,056,197
2021	193,684,523	188,683,463	200,731,952	195,916,765	180,649,174	176,043,999
2022	194,132,108	188,180,033	202,762,816	197,137,720	176,332,630	171,019,760
2023	194,569,468	187,627,264	204,456,431	198,031,931	173,551,747	167,620,667
2024	194,986,558	187,113,721	208,396,291	201,182,673	168,317,967	161,989,505
2025	195,438,057	186,709,699	210,175,286	202,099,348	165,282,019	158,528,562
2026	195,991,649	186,436,275	214,282,556	205,386,984	160,637,333	153,548,783
2027	196,529,588	186,159,585	216,202,447	206,495,979	155,205,948	147,841,981
2028	197,104,356	185,933,929	219,530,560	208,523,659	151,927,610	144,298,555
2029	197,678,086	185,722,290	224,420,566	212,620,716	148,215,489	140,375,732
2030	198,275,517	185,516,567	226,551,514	213,907,688	143,920,345	135,931,574
2031	198,916,020	185,442,364	228,788,433	215,387,216	138,988,173	131,029,971
2032	199,560,318	185,536,754	231,019,146	217,042,572	133,268,039	125,504,032
2033	200,219,329	185,691,187	233,551,659	218,787,862	127,937,693	120,406,439
2034	200,901,688	185,885,236	236,786,010	221,466,815	121,876,858	114,665,485
2035	201,585,020	186,092,500	239,031,438	223,175,225	115,410,562	108,557,101
2036	202,261,704	186,312,636	241,245,597	224,859,327	107,595,062	101,228,368

Figure 4-2 [in table form]: Natural Gas Demand Before and After Estimated C&EM Savings (Excluding NGT) – Residential Sector (GJ)

Year	Reference Case		Upper Bound		Lower Bound	
	Scenario Annual Demand	Scenario Annual Demand after C&EM	Scenario Annual Demand	Scenario Annual Demand after C&EM	Scenario Annual Demand	Scenario Annual Demand after C&EM
2015	74,379,270	74,379,270	74,379,270	74,379,270	74,379,270	74,379,270
2016	74,579,659	74,579,659	74,624,717	74,624,717	74,020,655	74,020,655
2017	74,662,138	74,273,270	74,805,228	74,412,064	73,517,097	73,135,036
2018	74,805,331	74,051,071	75,113,371	74,350,648	72,950,986	72,244,614
2019	74,868,580	73,787,004	75,470,178	74,372,890	72,328,600	71,306,500
2020	74,974,925	73,585,361	75,866,499	74,451,045	71,586,289	70,250,005
2021	75,130,739	73,385,115	76,345,548	74,567,801	70,977,354	69,376,191
2022	75,253,932	73,162,559	76,795,183	74,649,069	70,268,105	68,357,975
2023	75,350,446	72,909,950	77,225,271	74,709,297	69,417,718	67,251,872
2024	75,430,212	72,595,604	77,641,422	74,767,034	68,441,831	66,039,253
2025	75,533,121	72,362,453	78,086,259	74,801,409	67,481,130	64,856,353
2026	75,703,893	72,202,497	78,590,073	74,948,120	66,445,622	63,618,429
2027	75,867,631	72,041,465	79,084,633	75,090,188	65,369,506	62,356,737
2028	76,037,096	71,889,485	79,587,590	75,242,305	64,178,948	60,992,159
2029	76,202,189	71,728,684	80,086,161	75,381,573	62,830,341	59,486,896
2030	76,362,195	71,548,963	80,576,224	75,492,604	61,309,136	57,821,591
2031	76,555,037	71,466,755	81,097,606	75,702,626	59,646,733	56,096,173
2032	76,738,549	71,528,091	81,606,512	76,057,921	57,743,664	54,248,884
2033	76,917,592	71,620,843	82,108,678	76,441,235	55,578,328	52,195,141
2034	77,088,535	71,711,387	82,602,728	76,822,983	53,138,989	49,891,707
2035	77,246,914	71,788,162	83,082,523	77,187,414	50,400,156	47,309,978
2036	77,392,346	71,853,141	83,545,691	77,535,162	47,574,422	44,635,949

Figure 4-3 [in table form]: Natural Gas Demand Before and After Estimated C&EM Savings (Excluding NGT) – Commercial Sector (GJ)

Year	Reference Case		Upper Bound		Lower Bound	
	Scenario Annual Demand	Scenario Annual Demand after C&EM	Scenario Annual Demand	Scenario Annual Demand after C&EM	Scenario Annual Demand	Scenario Annual Demand after C&EM
2015	56,167,695	56,167,695	56,167,695	56,167,695	56,167,695	56,167,695
2016	56,610,067	56,610,067	56,873,136	56,873,136	56,223,660	56,223,660
2017	56,967,338	56,439,813	57,524,151	56,983,906	56,060,655	55,542,511
2018	57,391,799	56,517,873	58,241,142	57,327,746	55,767,687	54,884,455
2019	57,786,709	56,557,522	58,991,859	57,718,575	55,099,593	53,927,144
2020	58,198,770	56,635,471	59,852,003	58,248,986	54,348,678	52,904,678
2021	58,638,123	56,661,929	60,796,405	58,915,238	53,793,723	51,984,293
2022	59,104,285	56,735,829	61,763,126	59,612,192	53,150,772	51,099,217
2023	59,583,716	56,828,793	62,817,425	60,391,507	52,319,258	50,055,059
2024	60,049,487	56,967,090	63,869,720	61,168,652	51,253,054	48,888,360
2025	60,524,774	57,130,485	64,915,576	61,955,816	50,218,602	47,770,080
2026	61,032,477	57,347,627	66,016,221	62,788,110	49,083,315	46,573,487
2027	61,529,861	57,558,434	67,124,161	63,631,909	48,198,317	45,625,107
2028	62,056,498	57,806,886	68,256,047	64,505,045	47,067,093	44,476,020
2029	62,583,728	58,073,158	69,417,719	65,407,803	45,910,516	43,315,484
2030	63,137,803	58,358,843	70,614,399	66,342,529	44,591,850	42,019,091
2031	63,700,273	58,672,633	71,824,610	67,303,993	43,166,589	40,636,354
2032	64,274,058	59,004,651	73,168,042	68,394,205	41,595,276	39,129,115
2033	64,865,215	59,357,833	74,402,365	69,385,797	39,961,724	37,579,467
2034	65,486,812	59,745,288	75,678,633	70,412,250	38,268,329	35,983,108
2035	66,120,936	60,151,246	76,933,277	71,431,763	36,537,323	34,342,876
2036	66,769,103	60,578,361	78,389,787	72,635,865	35,073,688	32,954,206

Figure 4-4 [in table form]: Natural Gas Demand Before and After Estimated C&EM Savings (Excluding NGT) – Industrial Sector (GJ)

Year	Reference Case		Upper Bound		Lower Bound	
	Scenario Annual Demand	Scenario Annual Demand after C&EM	Scenario Annual Demand	Scenario Annual Demand after C&EM	Scenario Annual Demand	Scenario Annual Demand after C&EM
2015	61,191,788	61,191,788	61,191,788	61,191,788	61,191,788	61,191,788
2016	60,822,581	60,822,581	62,348,675	62,348,675	60,545,875	60,545,875
2017	60,610,620	60,259,422	62,607,942	62,297,639	59,863,056	59,499,945
2018	60,445,802	59,812,381	62,752,656	62,186,790	59,153,574	58,524,163
2019	60,244,411	59,412,449	62,919,124	62,186,118	58,237,329	57,431,548
2020	60,076,046	59,010,784	63,189,444	62,218,647	56,899,504	55,901,514
2021	59,915,661	58,636,419	63,589,999	62,433,726	55,878,097	54,683,515
2022	59,773,892	58,281,645	64,204,508	62,876,460	52,913,753	51,562,568
2023	59,635,306	57,888,522	64,413,735	62,931,126	51,814,771	50,313,736
2024	59,506,858	57,551,027	66,885,149	65,246,987	48,623,082	47,061,892
2025	59,380,162	57,216,761	67,173,451	65,342,124	47,582,288	45,902,130
2026	59,255,278	56,886,152	69,676,262	67,650,754	45,108,396	43,356,867
2027	59,132,097	56,559,685	69,993,653	67,773,882	41,638,125	39,860,138
2028	59,010,762	56,237,558	71,686,922	68,776,310	40,681,569	38,830,376
2029	58,892,169	55,920,447	74,916,686	71,831,340	39,474,632	37,573,351
2030	58,775,518	55,608,761	75,360,890	72,072,555	38,019,359	36,090,892
2031	58,660,711	55,302,975	75,866,217	72,380,597	36,174,850	34,297,444
2032	58,547,712	55,004,012	76,244,592	72,590,446	33,929,099	32,126,034
2033	58,436,521	54,712,511	77,040,616	72,960,830	32,397,641	30,631,831
2034	58,326,341	54,428,561	78,504,649	74,231,582	30,469,541	28,790,670
2035	58,217,170	54,153,092	79,015,638	74,556,048	28,473,082	26,904,247
2036	58,100,255	53,881,134	79,310,119	74,688,301	24,946,951	23,638,213

27.2 Please express energy savings (as a percentage of projected sales) as an annual average across the 20 years covered by the LTGRP for each C&EM scenario.

Response:

Expressing the forecast C&EM energy savings as a percentage of projected sales (noted on page 103 of Exhibit B-1) as an annualized average across 20 years yields the following results: 0.36 percent for the Reference Case, 0.29 percent for the Upper Bound, and 0.26 percent for the Lower Bound. The data noted on page 103 of Exhibit B-1 but expressed for 2030 yields the following results: 5.39 percent for the Reference Case, 4.36 percent for the Upper Bound, and 5.07 percent for the Lower Bound.

27.3 Please compare FEI's expected energy savings to the annual savings targets and 2030 reduction in energy demand summarized for EERS states. Please discuss the differences.

Response:

As indicated by the values provided in the response to BCUC IR 1.27.2, the 2017 LTGRP C&EM analysis annual and cumulative energy savings as a percentage of sales results are lower than the respective values discussed in the EERS on pages 35 and 36 of Exhibit B-1. The policy framework by which FEI achieves savings through its C&EM programs is different than in jurisdictions that use an EERS. FEI is enabled to pursue any cost-effective savings from C&EM program spending, meaning generally that FEI's volume of saved energy is predicated on the cost of C&EM programs relative to the cost of energy. This differs from the general approach of an EERS which typically mandates savings as a percentage of sales. Utilities operating under an EERS are obliged to pursue the most cost-effective pathway to achieve those savings. The differences between these two systems is that FEI optimizes the total savings it can achieve in its C&EM activities under the cost-effectiveness constraint while utilities under an EERS are mandated a total volume of savings and are optimizing on the costs to achieve those savings. As such, FEI's volume of energy savings targets depends on assumptions like the price of energy and the costs of C&EM interventions. Under an EERS, the volume of savings is more certain while the costs to achieve those savings programs are variable.

Table 4-4 of Exhibit B-1 displays estimated annual C&EM expenditures for all program areas. FBC submits estimated expenditures are expected to almost double from 2016 levels by 2023, and gradually decline after this year towards the end of the planning horizon as available energy savings opportunities are depleted. Figure 4-9 shows the estimated TRC results by scenario for all program areas, indicating that the TRC values level off around halfway through the planning horizon covered by the 2017 LTGRP.

Figures C2-1 to C2-3 of Appendix C-2 in Exhibit B-1, illustrate cost-effectiveness results for the residential program area.

27.4 Please explain if annual energy savings for all program areas also gradually decline from 2023 towards the end of the planning horizon.

Response:

Estimated annual C&EM energy savings for all program areas do decline from 2023 towards the end of the planning horizon. For the Reference Case, the annualized decline from 2023 until 2036 is 4.2 percent per year. The declines are 2.6 and 13.8 percent for the Upper and Lower Bound Scenarios respectively.

27.5 Please explain why the cost-effectiveness values for the residential program area begin to increase at around 2031.

Response:

FEI consulted with Posterity to provide the following response.

The cost effectiveness values referenced in BCUC IR1.27.5 are primarily dependent on levelized measure costs and the avoided cost of gas. FEI’s 2017 LTGRP C&EM analysis models the residential program area under the Modified Total Resource Cost (MTRC) test. The MTRC relies on the Zero-Emission Energy Supply Alternative (ZEEA) for the avoided cost of gas. The ZEEA remains constant across the 2017 LTGRP forecast horizon. As such, cost-effectiveness values for the residential program area begin to increase at around 2031 because the levelized cost of the residential measure bundle begins to decrease.

Table 4-8 of Exhibit B-1 summarizes the Reference Case cost effectiveness test results for all program areas, while Figures 4-9, 4-10, 4-11 and 4-12 illustrate how cost effectiveness test results vary across scenarios for the TRC, MTRC, Utility Cost Test (UCT) and Cost of Conserved Energy (CCE) respectively.

On page 116 of Exhibit B-1, FEI states:

> 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. CCE results increase over time …

Figure 8-8 of Exhibit B-1, displays delivery rate direction for all rate schedules with C&EM (without NGT). Table 8-2 Exhibit B-1 provides a summary and comparison of average projected delivery rate changes. Figures 8-10 to 8-12 show the estimated total bill impact of projected C&EM activity on residential customers for each C&EM scenario. Table 8-3 shows the estimated total bill impact of projected C&EM activity on commercial and industrial customers.

The FortisBC Energy Utilities (FEU) 2014 Long Term Resource Plan (LTRP) Decision on page 27 states:

> The Panel therefore considers that in order for the Commission to evaluate the FEU's LTRP against BC's energy objectives, the FEU LTRP should include a broader analysis of the BC costs and benefits of different levels of DSM funding. The Panel is satisfied that, given that the FEU is not a traditional vertically integrated utility, this information should also satisfy the requirements of section 44.1(2)(f) as it relates to the FEU's own planned energy purchases and the DSM scenario analysis related requirements from the 2010 LTRP Decision.
>
> The Panel therefore directs the FEU to include, in its next LTRP, the following information:
>
> - The development of DSM funding scenarios, reflecting the results of the most recent CPR. At a minimum, this should include a 'reference' DSM funding scenario with 'high DSM' and 'low DSM' scenarios that are relative to the reference scenario;

- Analysis of each DSM scenario, at a portfolio level and for each DSM category (residential, low income, commercial etc.), including:
    - Total Resource Cost/modified Total Resource Cost test results;
    - Utility Cost Test result, expressed as a ratio and $/GJ;
    - Delivery rate impact;
    - Estimated total bill impact (including delivery and commodity), $ and %, with residential split between high and low use gas customers; and
    - Estimated gas (GJ) and GHG emission reductions.

27.6 Please confirm if the values in the TRC column of Table 4-8 and Figure 4-9 are calculated using the MTRC test for the residential program area.

Response:

Confirmed. The values in the TRC column of Table 4-8 and Figure 4-9 of the Application represent the aggregated TRC results of the residential, commercial, and industrial program area measures that account for C&EM uptake in the 2017 LTGRP C&EM analysis.[13] In order to determine this C&EM uptake, the 2017 LTGRP C&EM analysis Reference Case applies, among other factors, the MTRC cost effectiveness test to technical potential measures in the residential program area and the TRC cost effectiveness test to technical potential measures in the commercial and industrial program areas. As explained in Section 4.2.2.2 of the Application, alternate future scenarios that are subject to the Accelerated outcome of the Non-Price Carbon Policy Action critical uncertainty apply the MTRC cost effectiveness test to technical potential measures across the residential, commercial and industrial program areas. Please also refer to the response to BCUC IR 1.26.2, which explains how the MTRC was applied.

27.6.1 If not confirmed, please add a column to Table 4-8 and reproduce Figure 4-9 using the MTRC for the residential program area and TRC for the commercial and industrial program areas.

[13] Within the parameters outlined in Section 4.2.3.3 of the Application.

Response:

Please refer to the response to BCUC IR 1.27.6.

27.6.2 Please confirm if FEI's low income program area is included in the analysis for the residential program area.

Response:

Please refer to the response to BCUC IR 1.24.1.

27.7 Please explain why in Figure 4-10 there is little variation in MTRC values between scenarios.

Response:

FEI consulted with Posterity to provide the following response.

The variation in MTRC between scenarios in Figure 4-10 is due to the varying mixture of technical potential measures that pass the cost effectiveness test and experience participant uptake in each C&EM scenario. Generally, the MTRC results are driven by measure costs compared with measure benefits. Under the MTRC test, measure benefits apply the Zero-Emission Energy Supply Alternative (ZEEA). The ZEEA does not vary across scenarios in the 2017 LTGRP C&EM analysis. As such, the remaining differences between scenarios in Figure 4-10 are due to variations in the measure costs of the varying mixture of measures across the C&EM scenarios.

Since the aggregate measure costs of the varying mixture of measures across C&EM scenarios vary little from one scenario to another, there is little variation in MTRC values between scenarios. This small magnitude in variation, of aggregate measure costs across scenarios, appears to be due to the following: even though the number of gas-consuming dwellings and the magnitude of annual demand vary across scenarios (which impacts the relative size of addressable C&EM energy savings potential), the scenarios remain relatively similar to each other regarding the types of C&EM energy savings opportunities that they offer. For example, even though the Lower Bound scenario may present much less space heating annual demand as a baseline for energy savings than the Upper Bound scenario, space heating demand in both scenarios is addressable by a similar set of measures with similar measure costs.

27.8 Please provide analysis in table format of the UCT expressed as the CCE ($/GJ) for each C&EM scenario, at a portfolio level and at residential, commercial and industrial program area level, for each year of the planning horizon covered by the 2017 LTGRP.

Response:

The three tables below summarize the estimated CCE results for each C&EM scenario, at a portfolio level (for all program areas), for the residential, for the commercial, and for the industrial program area, for each year of the planning horizon. Please refer to the response to BCUC IR 1.27.8.1 for a discussion of key factors that influence CCE evolution over time.

All Program Areas

2017 LTGRP C&EM Analysis - Estimated CCE Results ($/GJ)			
Year	**Reference Case**	**Upper Bound**	**Lower Bound**
2017	2.8	2.7	2.9
2018	3.4	3.3	3.5
2019	3.7	3.7	4.0
2020	4.0	4.0	4.4
2021	4.3	4.1	4.7
2022	4.5	4.3	5.0
2023	4.6	4.3	5.2
2024	4.8	4.4	5.2
2025	4.8	4.5	5.3
2026	4.8	4.5	5.3
2027	4.9	4.5	5.3
2028	4.9	4.5	5.3
2029	4.9	4.5	5.3
2030	4.9	4.5	5.3
2031	4.8	4.5	5.2
2032	4.8	4.4	5.2
2033	4.8	4.3	5.1
2034	4.7	4.3	5.1
2035	4.7	4.3	5.0
2036	4.7	4.2	4.9

Residential

2017 LTGRP C&EM Analysis - Estimated CCE Results ($/GJ)			
Year	**Reference Case**	**Upper Bound**	**Lower Bound**
2017	7.4	7.4	7.4
2018	7.2	7.2	7.5
2019	7.0	7.0	7.5
2020	7.0	6.9	7.5
2021	6.9	6.9	7.5
2022	6.8	6.8	7.7
2023	6.7	6.7	7.5
2024	6.8	6.5	7.3
2025	6.7	6.7	7.2
2026	6.6	6.6	7.0
2027	6.5	6.5	6.8
2028	6.4	6.4	6.7
2029	6.4	6.3	6.6
2030	6.3	6.2	6.4
2031	6.2	6.2	6.3
2032	6.1	6.1	6.2
2033	6.0	5.9	6.0
2034	5.9	5.9	5.9
2035	5.8	5.8	5.7
2036	5.7	5.7	5.5

Commercial

2017 LTGRP C&EM Analysis - Estimated CCE Results ($/GJ)			
Year	**Reference Case**	**Upper Bound**	**Lower Bound**
2017	1.3	1.3	1.3
2018	1.6	1.6	1.7
2019	2.2	2.1	2.3
2020	2.6	2.5	2.7
2021	3.0	2.7	3.3
2022	3.3	2.8	3.7
2023	3.7	2.9	4.0
2024	3.8	3.0	4.1
2025	3.9	3.1	4.3
2026	4.0	3.2	4.4

2017 LTGRP C&EM Analysis - Estimated CCE Results ($/GJ)			
Year	**Reference Case**	**Upper Bound**	**Lower Bound**
2027	4.1	3.2	4.4
2028	4.1	3.3	4.5
2029	4.2	3.4	4.6
2030	4.2	3.4	4.6
2031	4.3	3.4	4.7
2032	4.3	3.4	4.7
2033	4.3	3.5	4.7
2034	4.3	3.5	4.8
2035	4.4	3.5	4.8
2036	4.4	3.5	4.7

Industrial

2017 LTGRP C&EM Analysis - Estimated CCE Results ($/GJ)			
Year	**Reference Case**	**Upper Bound**	**Lower Bound**
2017	3.2	2.8	3.7
2018	3.3	2.8	3.8
2019	3.3	2.8	3.8
2020	3.3	2.8	3.8
2021	3.3	2.8	3.8
2022	3.3	2.8	3.7
2023	3.3	2.8	3.7
2024	3.3	2.8	3.8
2025	3.3	2.8	3.8
2026	3.3	2.8	3.8
2027	3.3	2.8	3.7
2028	3.3	2.8	3.7
2029	3.3	2.8	3.7
2030	3.3	2.8	3.7
2031	3.3	2.8	3.7
2032	3.3	2.8	3.8
2033	3.3	2.8	3.8
2034	3.3	2.8	3.8
2035	3.3	2.8	3.8
2036	3.3	2.8	3.7

27.8.1 Please explain why the CCE results increase over time.

Response:

FEI consulted with Posterity to provide the following response.

FEI's 2017 LTGRP C&EM analysis calculates the average CCE for each scenario by the mixture of technical potential measures that pass the cost effectiveness test and thus result in participant uptake in each C&EM scenario. As such, the increase in CCE over time appears to be due to the mix of measures in the portfolio containing more measures with lower measure costs at the beginning of the forecast horizon. CCE changes as these measures play a decreasing role in the measure mixture over time.

As a concrete example, in 2017 in the Market Potential under the Reference Case, most of the top five measures that contribute to the market potential savings are relatively low cost:

- Efficient Fireplaces, with CCE of 0.9 $/GJ, accounts for 5.7% of the 2017 market potential;
- Home Energy Reports, with CCE of 1.0 $/GJ, accounts for 13.2% of the 2017 market potential;
- Recirculation Demand Controls for Commercial DHW, with CCE of 1.3 $/GJ, accounts for 11.9% of the 2017 market potential;
- Heat Control Systems for Boilers in MURBS, with CCE of 1.3 $/GJ, accounts for 28.2% of the 2017 market potential; and
- Industrial Energy Management, with CCE of 2.5 $/GJ, accounts for 5.5% of the 2017 market potential.

In contrast, in 2030 in the Market Potential under the Reference Case, many more measures contribute to the savings and they are more diverse in terms of cost, with a higher average CCE than the 2017 measures:

- Efficient Fireplaces, with CCE of 0.9 $/GJ, are still an important measure, accounting for 6.0% of 2030 market potential;
- Residential Smart Thermostats, with CCE of 4.0 $/GJ, account for 5.7% of the 2030 market potential;

- Commercial New Construction 45% Better than Code, with CCE of 4.3 $/GJ, accounts for 7.7% of 2030 market potential;
- Commercial HVAC Control Upgrades with Direct Digital Data Control, with CCE of 4.7 $/GJ, accounts for 5.3% of 2030 market potential; and
- Furnace Early Retirement, with CCE of 6.9 $/GJ, accounts for 5.7% of 2030 market potential.

27.9 Please reproduce Table 8-2 to include a column which shows the compound annual delivery rate change and cumulative rate change for C&EM programs only. Please also provide separate tables that perform this analysis at a residential, commercial and industrial program area level, for each C&EM scenario.

Response:

Please see the table below for the cumulative and compound annual delivery rate change with breakdown between BASE and C&EM:

	Rate Change (2015-2036, %)					
	Base		C&EM		Base + C&EM	
	Cumulative	Compound Annual	Cumulative	Compound Annual	Cumulative	Compound Annual
Reference Case	60%	2.2%	18%	0.5%	78%	2.8%
Upper Bound	36%	1.5%	12%	0.4%	48%	1.9%
Lower Bound	201%	5.4%	17%	0.3%	217%	5.6%

Please see the table below for the breakdown of the cumulative and compound annual delivery rate change contributed by the C&EM expenditures in each of the residential, commercial, and industrial program areas as shown in Section 4.2.3.2 of the Application. It is important to note that within FEI's Revenue Requirement the annual cost of the C&EM expenditures is not allocated separately to the individual non-bypass delivery rate schedules based on the expenditures of different program areas. The table below is to illustrate the portion of the rate impact in percentage that is attributed to each of the three C&EM program areas. In fact, all non-bypass customers will experiences the same rate impact in percentage as shown in the table above which is based on the total C&EM expenditures across all program areas.

	Rate Change by C&EM (2015-2036, %)	
	Cumulative	**Compound Annual[14]**
Reference Case		
Residential Programs	10%	0.29%
Commercial Programs	6%	0.18%
Industrial Programs	2%	0.06%
Total Reference Case	***18%***	***0.53%***
Upper Bound		
Residential Programs	7%	0.22%
Commercial Programs	4%	0.13%
Industrial Programs	1%	0.04%
Total Upper Bound	***12%***	***0.39%***
Lower Bound		
Residential Programs	10%	0.15%
Commercial Programs	5%	0.09%
Industrial Programs	2%	0.03%
Total Lower Bound	***17%***	***0.27%***

The table above shows overall cumulative and compound annualized delivery rate changes from 2015 to 2036 are for the most part attributed to the residential programs while industrial programs contributed the least under all three scenario (Reference, Upper Bound, and Lower Bound). This is expected as the C&EM expenditures as shown in Section 4.2.3.2 of the Application for the residential sector are the highest across the 22-year period while the C&EM expenditures for industrial sector are the lowest.

27.9.1 Please briefly describe any significant differences between program areas.

<u>Response:</u>

Please refer to the response to BCUC IR 1.27.9.

[14] The compound annualized rate impact is shown with the nearest hundredths in percentage for the individual program areas while the overall total rate impact shown in the first table is rounded to the nearest tenths.

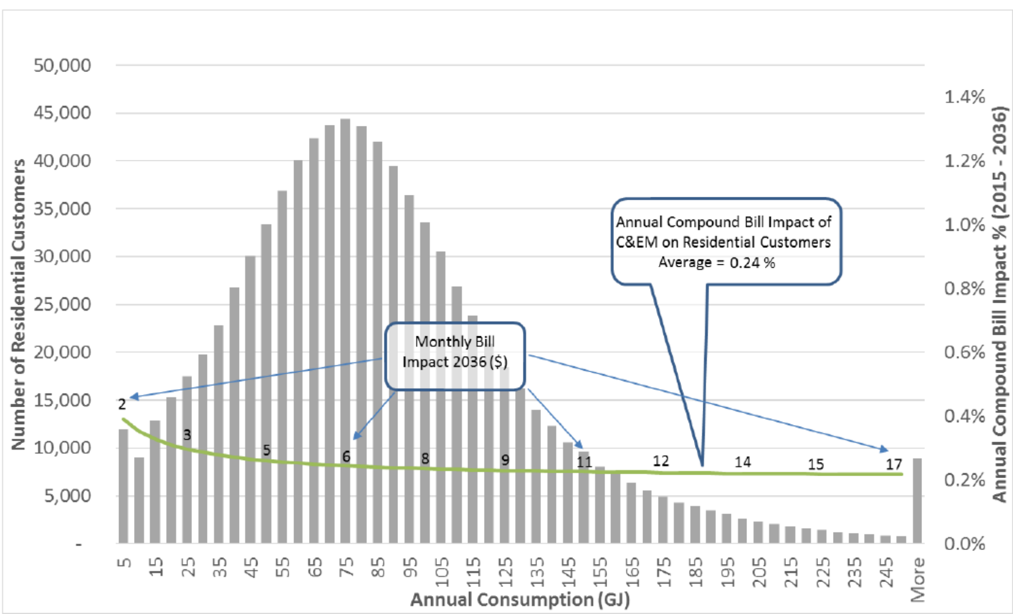
27.10 Please explain why the annualized percentage compound 2015-2036 bill impacts of C&EM activity for residential customers, peaks at around consumption levels of 75 GJ/ year.

Response:

FEI clarifies that the grey-coloured bars in Figure 8-10 (included below), 8-11, and 8-12 of the Application are histograms showing the number of residential customers versus the annual consumption in GJs. The histograms show that most of FEI's residential customers consume approximately 75 GJ annually. The grey-coloured bars do not represent the annual compound bill impact against the annual consumptions in GJs.

The green-coloured line in the Figures, on the other hand, shows the annual compound bill impact in percentage for annual residential consumption between 5 to 245 GJ, which shows that residential customers with low annual consumption (i.e. 5 GJ/yr) will experience the highest total bill impact in percentage. FEI also notes that the numbers on top of the green-coloured line are the monthly bill impact in year 2036 dollars at that annual consumption range. As expected, the lowest annual consumption groups will see the smallest monthly bill impact in dollars and the highest annual bill impact in percentage, while the highest annual consumption groups will see the largest monthly bill impact in dollars but with the smallest annual bill impact in percentage.

Figure 8-10: Estimated Total Bill Impact of Projected C&EM Activity on Residential Customers – Reference Case



27.11 Please explain why the annualized percentage compound 2015-2036 bill impacts of C&EM activity for Rate Schedule 22 are significantly lower than for other rate classes.

Response:

FEI clarifies that Table 8-3 of the Application shows the estimated total bill impacts, which includes delivery, commodity, storage and transport, and taxes for average customers in select commercial and industrial rate schedules. Rate Schedule 22 (RS 22) is a transportation service where customers under this Rate Schedule only pay the delivery portion to FEI while commodity, storage and transport, as well as carbon taxes generally will be paid to the customers' commodity supplier or shipper agent separately. In order to have an equivalent and fair total bill impact comparison with other rate schedules, FEI included commodity, storage and transport, and carbon taxes to the total bill impact analysis shown in Table 8-3[15].

The reason that RS 22, as shown in Table 8-3 of the Application, has significantly lower annualized percentage compound 2015-2036 total bill impacts due to projected C&EM activities than other rate schedules is because the delivery portion of the total bill for customers in RS 22 is relatively lower than other rate classes once commodity, storage and transport, and carbon tax components are added. This effect is further emphasized by the fact that the annual use per customer (UPC) in GJs for customers in RS 22 is much higher than other rate schedules. For example, using the actual 2015 rates and the annual UPC for each rate schedule in Appendix B-4 under the Reference Case, the table below shows the delivery portion of the total bill for customers of RS 22 is at approximately 17 percent of the total bill (where the total bill includes commodity, storage and transport, and carbon tax) while other rate schedules range from 25 percent to 49 percent of the total bill. Given that C&EM activities by FEI impact the delivery rates only, the effect of a small increase/decrease to the delivery rates will become diluted at the total bill level, especially in the case of RS 22 where 80 percent of the bill is not impacted by the delivery rates and combined with a very high UPC for these customers.

[15] Per footnote 162 of the Application, the total bill impact analysis for Rate Schedule 22 assumes the same commodity cost values, midstream and distribution adders as other industrial rate schedules shown in Table 8-3 (i.e. Rate Schedule 7).

	RS22	RS7	RS3	RS2	RS6
Annualized % Compound Bill Impact (2015-2036) of C&EM, Table 8-3 of Application, ***Reference Case***	0.08%	0.23%	0.25%	0.28%	0.35%
Use per Customer (2015), Appendix B-4, ***Reference Case*** (GJ)	771,870	28,035	3,627	329	4,243
Percentage breakdown of total bill (Based on 2015 Actual Rates and UPC)					
Delivery (Basic & Variable)	**17%**	**25%**	**38%**	**43%**	**49%**
Storage and Transport	14%	12%	13%	14%	4%
Cost of Gas	46%	41%	32%	28%	30%
Carbon Tax	24%	22%	17%	15%	16%
Total	100%	100%	100%	100%	100%

28.0 Reference: DEMAND SIDE RESOURCES

Exhibit B-1, 4.2.1.3, p. 99; Section 4.2.2.1, p. 101; Section 4.2.3.5, p. 121;

Appendix C-1, p. 3

Conservation Potential Review

On page 101 of Exhibit B-1, FEI states:

> 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 …;
>
> 7. Apply the 2017 LTGRP Reference Case and produce the market potential energy savings, benefit-cost, and expenditure results.

On page 121 of Exhibit B-1, FEI states:

> FEI instructed the consultant that prepared the BC CPR to use the BC CPR's Bass Diffusion model to explore how different levels of incentive value impact projected energy savings and estimated C&EM expenditures. While the BC CPR model is separate from FEI's 2017 LTGRP forecast model and the 2017 LTGRP Reference Case differs from the BC CPR, the BC CPR's results provide directional insight into this sensitivity.

28.1 Please confirm if the "2017 LTGRP CPR Reference Case" is the same as the "2017 LTGRP Reference Case."

Response:

FEI consulted with Posterity to provide the following response.

The 2017 LTGRP CPR Reference Case is almost identical to the 2017 LTGRP Reference Case but one difference exists. The 2017 LTGRP Reference Case holds fuel shares constant per building type and region, while the 2017 LTGRP CPR Reference Case assumes some fuel shares to change over time. The 2017 LTGRP CPR Reference Case does so to match as closely as possible the rate of change in the BC CPR Reference Case. FEI constructed the 2017 LTGRP CPR Reference Case in order to check whether FEI had reasonably imported BC

CPR results into the 2017 LTGRP forecast model. FEI did not use the 2017 LTGRP CPR Reference Case for any other purpose. FEI used the end-use method to prepare alternate future scenarios that investigate how varying outcomes across a set of critical uncertainties impact parameters, such as fuel shares, forecast annual natural gas demand, and forecast C&EM activity.

28.1.1 Please describe the key differences between the 2017 LTGRP CPR Reference Case, 2017 LTGRP Reference Case and the BC CPR Reference Case.

Response:

FEI consulted with Posterity to provide the following response.

Please refer to the response to BCUC IR 1.28.1 for a description of the difference between the 2017 LTGRP Reference Case and the 2017 LTGRP CPR Reference Case.

The key differences between the 2017 LTGRP CPR Reference Case and the BC CPR Reference Case are as follows:

- The 2017 LTGRP CPR Reference Case uses FEI's 2015 base year customer and annual demand data, whereas the BC CPR Reference Case uses a 2014 base year.
- The 2017 LTGRP CPR Reference Case is built at a more granular level than the BC CPR Reference Case, with more rate classes, building segments, and energy end uses (The 2017 LTGRP Reference Case is also constructed at this more granular level).
- Although the rates of change in consumption for the end uses are calibrated to match between the 2017 LTGRP CPR Reference Case and the BC CPR Reference Case, absolute annual demand generally does not match exactly because the base year for the 2017 LTGRP CPR Reference Case was constructed with 2015, as opposed to 2014, base year data.

28.1.1.1 Please explain the impact of these differences upon:

a) Estimated C&EM energy savings;

b) The sensitivity analysis of incentive value impact;

c) Estimated annual C &EM expenditures.

Response:

FEI consulted with Posterity to provide the following response.

a) The C&EM energy savings estimates generally calibrated well to the BC CPR results within the 2017 LTGRP CPR Reference Case. Since the 2017 LTGRP Reference Case holds fuel shares constant over time its resulting natural gas consumption is generally slightly higher than in the 2017 LTGRP CPR Reference Case. Estimated C&EM energy savings in the 2017 LTGRP Reference Case are slightly greater than in the 2017 LTGRP CPR Reference Case because the same savings percentages were applied to somewhat greater annual natural gas demand. This difference is much smaller than the variation in estimated C&EM energy savings across the 2017 LTGRP C&EM scenarios.

b) The sensitivity analysis for incentive value impact was conducted in the BC CPR model and hence the BC CPR Reference Case. The analysis shows directionally that an increase in incentive levels results in an increase in energy savings, but at progressively increasing cost per unit of savings. These results were not available when FEI concluded the 2017 LTGRP C&EM analysis (within the schedule for the 2017 LTGRP submission date) but the response of the 2017 LTGRP C&EM analysis would be directionally identical

c) The impact of the difference between reference cases on the estimated annual C&EM expenditures is relatively small. Just like the C&EM energy savings themselves, C&EM expenditures in the 2017 LTGRP Reference Case are slightly higher than in the 2017 LTGRP CPR Reference Case because the 2017 LTGRP Reference Case's baseline fuel shares are slightly higher and therefore more opportunities exist for C&EM measures to be applied and incentivized. The variation in expenditure between the two reference cases is much smaller than the variation in estimated C&EM expenditures across the 2017 LTGRP C&EM scenarios.

28.2 Please summarize how the sensitivity analysis of incentive value impact will be used by FEI in the development of future C&EM expenditure schedules.

Response:

Development of the FEI 2019-2022 DSM Expenditures application to date has relied primarily on past program data, stakeholder consultations, reference program data from other utilities, and FEI-funded studies to determine projected program incentive values. The incentive sensitivity analysis conducted through the 2017 LTGRP forecast model has and will be used as a "reasonableness checkpoint" on the proposed incentive values for the 2019-2022 DSM Plan.

FEI cannot speak at this time to future C&EM expenditure schedules beyond the 2019-2022 timeframe as those expenditure schedules have not been considered beyond the analysis put forward in the 2017 LTGRP.

On page 99 of Exhibit B-1, FEI states:

> The BC CPR summary report does not recommend specific programs or targets to be implemented. However, the report does identify technology and market opportunities as well as the scope of market energy savings potential across the study period. The range of potential C&EM measures from the BC CPR results informs the 2017 LTGRP C&EM forecast.

The Conservation Potential Review appended to the Application, on page 3 states:

> Navigant and BC Utilities agreed to show savings from this study at the gross level, whereby natural change and free ridership, as it relates to program implementation, are not included in the savings estimates but rather are estimated separately.

28.3 Please confirm and explain if the 2017 LTGRP C&EM analysis includes the effects of free-riders and spillover, where these effects are applicable.

Response:

FEI consulted with Posterity to provide the following response.

Confirmed. The BC CPR results and the 2017 LTGRP end-use annual demand forecast method include natural change in appliance use over time. Since the 2017 LTGRP C&EM analysis is informed by the BC CPR results and applied to the 2017 LTGRP end-use annual demand scenarios, the 2017 LTGRP C&EM analysis includes natural change. FEI uses the term natural change to draw a distinction between forecast changes in appliance use (absent C&EM activity) over the long term and C&EM program free ridership or spillover that are verified via program-specific analysis or impact evaluations. FEI's 2019-2022 DSM Plan will include program-specific considerations of free ridership and spillover.

28.4 Please discuss whether the 2017 LTGRP C&EM analysis accounts for lost opportunities that would be more expensive to address at a later time.

Response:

The 2017 LTGRP C&EM analysis does not model lost opportunities that would be more expensive to address at a later time. As informed by the BC CPR results and FEI's C&EM program experience, the 2017 LTGRP C&EM analysis simply models the impacts of technical potential C&EM measures that pass the applicable cost effectiveness test and experience participant uptake in each C&EM scenario.

However, when preparing C&EM expenditure schedules and performing program design, FEI evaluates market potential and adoption barriers, and modifies programs to address new opportunities that become available.

29.0 Reference: DEMAND SIDE RESOURCES

Exhibit B-1, Section 4.3, p. 124; Section 6.3, pp. 155 to 188;

FEU Application for Acceptance of the 2014 Long Term Resource Plan Decision,

Order G-189-14, Section 4.4; p. 28

C&EM and peak demand

In the FEU Application for Acceptance of the 2014 Long Term Resource Plan Decision (2014 LTRP Decision), p. 28, the Commission stated:

> The Commission Panel agrees with the interveners that future filings would benefit from additional analysis focused on identifying potential DSM strategies that could favourably affect peak demand. Accordingly, in the next LTRP the FEU are directed to provide a more fulsome analysis of opportunities for DSM to be cost-effectively used to replace or defer infrastructure investments.

On page 124 of Exhibit B-1, FEI states:

> Load Management: Programs that may either reduce peak demand or shift demand from peak to non-peak periods. Since the largest portion of natural gas demand in BC is for space and water heating which are more difficult to shift, and because the natural gas system acts to store energy allowing it to be drawn down over a longer period of time than with electricity, programs that reduce or shift peak demand for natural gas are more challenging in BC.

On page 154 of Exhibit B-1, FEI states:

> FEI has since commissioned Posterity, a consultant, to develop an exploratory process linking peak demand forecasts to the end-use scenarios used in the annual demand forecasts. At this point, the exercise is theoretical in nature and unsupported by direct measurement.

Section 6.3 of Exhibit B-1 describes FEI's Regional Transmission System Capacity Plans, which includes analysis of the impact of FEI's planned C&EM activity upon peak demand, and the potential impact on infrastructure expansion requirements.

29.1 Please confirm, or explain otherwise, that the 2017 LTGRP does not include any C&EM programs/measures that specifically target peak demand (as opposed to targeting annual energy reductions).

Response:

Confirmed. The 2017 LTGRP does not contain any C&EM programs/measures whose primary purpose is to target peak demand (as opposed to targeting annual energy reductions). The CPR, on which the C&EM analysis contained in the LTGRP is based, did not identify conservation measures specifically targeted at peak demand reductions. The reason for this in part is because FEI was not able to provide the CPR consultant with equipment load shapes for its customers nor for any new measures being considered in the CPR analysis. Such load shapes would be required to allow the impacts of existing measures or proposed new measures on peak demand to be adequately examined. Advanced customer metering that could provide demand data at the end use much more frequently than the current monthly meter reads for most FEI customers would be required in order to provide the necessary load shapes for FEI's own customer base.

A number of issues make the impact of C&EM activities on peak demand uncertain and the determination of such impacts difficult. The location of installed DSM measures on the gas system, the mix of natural gas uses in any given area, the frequency of DSM measure installations within a gas service area and the potential installation of measures that decrease overall demand while increasing peak demand are all uncertainties that make reliable estimation of peak reductions very challenging.

The only measure that FEI is aware of that can provide firm peak reduction is curtailment of service (also refer to the response to BCUC IR 1.29.2). FEI does employ curtailment practices for its larger industrial customers who choose to take an interruptible service. While the purpose of this type of curtailment is to reduce capacity requirements of the system by allowing FEI to curtail service during extreme cold weather, it is not considered part of the C&EM portfolio of activities at this time. Industrial curtailment is also already taken to account in identifying peak capacity requirements of the natural gas system.

In order to more fully analyze potential opportunities for DSM to reduce peak and address the Commission's directive as noted in the preamble, FEI does present an exploratory peak demand forecast method in Section 6 of the Application that uses approximated load shapes. This exploration provides a means for relating annual demand more directly to peak demand and thus enables a review of theoretical future effects of C&EM programs on peak demand and infrastructure requirements. Since the exploratory end-use peak demand forecast method is a new, theoretical approach that still requires validation; the results are not relied upon for calculating firm reductions in peak demand. This exploration was initiated after the CPR work was undertaken and was not used to attempt to identify DSM measures specifically targeted at peak reductions.

As described in Section 6.2.1.3 on pages 154 and 155 of the 2017 LTGRP, the exploratory peak analysis work that has been completed remains theoretical because it is not supported by direct measurement of FEI's customer end-use trends and many broad assumptions are incorporated in order to facilitate the analysis (please also refer to the response to BCUC IR 1.29.3). For much of FEI's temperature sensitive, residential and commercial load, FEI obtains customer demand data via monthly meter reading. This frequency of measuring consumption is insufficient to reliably understand what use trends are occurring that could impact peak demand. The historic peak UPC graph derived from system level measurement provided in the response to BCUC IR 40.1.1 shows that peak use per customer has not declined in recent years, and FEI is not certain if this is caused by factors other than C&EM offsetting potential peak reductions that might be due to C&EM programs, or if C&EM programs are having an immaterial impact on peak consumption.

It should be noted that FEI is conducting a pilot project on advanced meters for residential and commercial customers that could provide hourly or more frequent meter readings. As part of that pilot, FEI will be examining the ability of such meters to provide improved data for analyzing end use trends which might lead to a better understanding of the impacts of C&EM activities on peak demand. Such data would provide more insight into customer overall behaviour but will still be somewhat limited in providing insights on usage trends for individual appliances. FEI is not currently aware of any cost-effective metering solutions that can identify individual appliance demand in homes and businesses, but intends to continue monitoring the marketplace for cost effective metering solutions that could be employed to better understand demand trends by appliance type. If FEI can obtain more granular data by customer or by appliance it will be in a better position to determine if its C&EM measures are impacting peak demand in either direction. FEI expects that this pilot will also provide insights into whether or not demand response programs (please also refer to the response to BCUC IR 1.29.1.1), other than industrial curtailment as noted above, would potentially be effective in reducing or shifting peak demand.

29.1.1 If confirmed, please summarize analysis of any load management measures that were considered for the 2017 LTGRP, and explain why these measures were ultimately not included in the 2017 LTGRP.

Response:

Please refer to the response to BCUC IR 1.29.1.

29.1.2 Please discuss whether FEI has plans to include load management programs in forthcoming expenditure schedules submitted during the period covered by the 2017 LTGRP.

Response:

FEI assumes that the Commission intends "load management programs" to mean energy management programs (a program to assist customers to optimize energy use) as defined in the DSM Regulation, including demand response programs that specifically target peak demand reduction. FEI confirms that consideration of energy management programs will be included in the upcoming 2019-2022 DSM Expenditures application although it cannot be confirmed at this time if any of these energy management programs will have a demand response component or be able to specifically target peak demand reductions. FEI's review of demand response programs for natural gas users indicates that this is a new and emerging area of DSM among gas utilities and FEI intends to remain vigilant and engaged in discussions and results of the industry's exploration into this new area of DSM.

29.2 Please explain why natural gas demand for space and water heating is "more difficult to shift."

Response:

As discussed in the response to BCUC IR 1.29.1, demand response programs that could shift the timing of peak demand (beyond traditional industrial load curtailment) are a new and emerging area of DSM for gas utilities that FEI intends to monitor and explore. Currently, the energy use infrastructure and appliance technology across the FEI service region and in many other gas utility jurisdictions in North America is insufficient to enable firm demand response programs. The bulk of current customer metering is manually read on a monthly basis and appliances with the communication technology to allow remote response during a peak event have not been tested by FEI. Please also refer to the response to BCUC IR 1.29.1 regarding the difficulty in targeting peak demand reductions or determining if peak demand reductions are resulting from C&EM activities.

29.2.1 Please summarize any programs in other jurisdictions that FEI is aware of that aim to reduce and/or shift peak natural gas demand for space and water heating.

Response:

FEI is aware that some other jurisdictions include interruptible rates and curtailment as demand side resources for reducing peak demand. An industry review conducted by E Source (an energy industry analytics consultancy) for FEI indicates that National Grid, CenterPoint Energy, Xcel Energy and Alliant Energy are among other entities that use these types of programs. FEI also has interruptible rates available for industrial customers and in this way uses curtailment to reduce peak demand; however, this is not part of FEI's C&EM portfolio as discussed in the response to BCUC IR 1.29.1.

FEI is also aware that natural gas utilities in some jurisdictions are exploring the potential for demand response (other than industrial curtailment) to reduce peak demand. E Source notes that SoCal Gas, Commonwealth Edison, Berkshire Gas and Independent System Operator of New England are exploring demand response initiatives. In three of these cases, Southern California Gas, Commonwealth Edison and Berkshire Gas), the demand response studies are centred on smart thermostats. It should be noted, however, that recent work done by ICF Consultants for Enbridge Gas Distribution indicates that smart learning thermostats may result in increased peak demand, although they have potential to reduce annual demand.

FEI is also aware that NW Natural is proposing a pilot project to determine if targeted DSM has potential to reduce peak demand and influence infrastructure requirements in a given area on their system. The proposal is outlined in its 2016 IRP. Enbridge Gas Distribution has conducted some initial investigations into the potential to employ targeted DSM to influence future natural gas infrastructure investment.

29.2.1.1 Please explain whether similar programs could be applicable in BC in future.

Response:

FEI is not able to determine at this time if similar programs could be applicable to BC. FEI will continue to monitor industry developments on these types of programs and will explore their applicability in BC and their potential impacts on FEI's customers. As stated in the response to BCUC IR 1.29.1, measuring the real impact of such programs on peak demand would require advanced metering solutions that would provide more frequent (hourly) usage data.

FEI is currently conducting a Smart Learning Thermostat (SLT) pilot through the C&EM Innovative Technologies program area. If the results from the pilot are positive, FEI anticipates offering Smart Learning Thermostats as an incented measure in the future. FEI cannot say at this time if a SLT program can have an impact on peak demand as there is some indication from work done for Enbridge Gas Distribution in Ontario that, although SLTs might reduce annual demand, they could result in an increase in peak demand (refer also to the response to BCUC IR 1.29.2.1).

29.3 Please identify and describe the limitations of the "theoretical nature" of the peak demand analysis with respect to the impact of DSM initiatives upon peak demand.

Response:

At present the theoretical nature of the exploratory peak demand method for DSM initiatives and for any of the end-use forecasts presented in the Application has the following three limitations:

1. This approach is new for FEI. The forecasts produced for the Application are the first opportunity to examine and question the results of an exploratory process that consolidates a great deal of complex information and interactions. As described on page 154 of the Application, the process Posterity Group developed to apply the end use scenarios to peak demand relies on a series of appliance load shapes. The load shapes characterize types of appliances serving each end-use and their contribution to annual, peak monthly and finally peak day and peak hour demand. As in the annual demand end-use scenarios, the appliance load shapes were combined by region, sector, segment (dwelling type, use, size etc.) and end-use to collectively represent customer premises' UPC_{peak} and how they were projected to change through the forecast for the various scenarios and for the various scenarios with the planned C&EM programs. The process provides the basis for further development and refinement, however due to its complex nature and compounding assumptions is not developed to the point that results can be used to predict the deferral of capacity constraints in a transmission system with confidence.

2. The results are based on outside data sources. The peak load shapes used originate from a variety of data sources and in many cases were adapted from electrical data and represent a variety of geographic regions around North America and the world. The peak load shape information is not developed from FEI customer consumption data directly which at present is largely collected on a monthly basis. How well this process reflects the behaviour of FEI consumers is yet to be validated and will require more specific consumption measurement than is currently available in the customer billing history.

3. The process is currently exploratory. The outcome of relying on the process, as developed to date, to time infrastructure projects based on DSM may be to risk eroding the planning and execution times necessary to complete these projects when required should the DSM contributions prove to be too optimistic in their ability to impact and reduce peak demand.

29.3.1 Please confirm if the analysis considers regional effects.

Response:

Confirmed.

29.3.2 Please discuss if FEI plans to undertake direct measurement in future to support the exploratory analysis.

Response:

Yes. FEI believes that in order to refine the end-use peak demand process, and to develop a level of confidence in the results with respect to peak day and peak hour demand, the collection of FEI customer consumption data at hourly intervals and analysis of that data for implications on peak demand is required. FEI is currently in the process of conducting a pilot study of AMI with hourly metering and pressure measurement. The study also includes installing some check meters within the system on single feed gas supplies into moderate sized neighbourhoods that will allow more accurate balancing of the flows into and then consumed within the local area on an hourly basis. Examination of the preliminary information as it becomes available in 2018 will assist in defining future study and process development.

29.4 Please comment and explain the extent to which, in the view of FEI, the C&EM measures contained in the 2017 LTGRP analysis can be considered “firm” in the context of resource planning for the reduction of peak demand.

Response:

FEI does not consider the C&EM measures contained in the 2017 LTGRP to be "firm" with respect to the reduction of peak demand forecasts and certainty in deferral of infrastructure projects to meet peak day demand. To the extent that existing C&EM measures and efficiencies influence current consumption, the measures are intrinsically represented in the UPC_{peak} values generated annually and used to construct load forecasts for infrastructure planning. FEI's traditional peak demand forecasting method does not project further future reductions due to C&EM measures. Additionally, measures that rely on voluntary participation are considered too uncertain for planning of infrastructure projects designed to ensure capacity to meet peak demand under very infrequent and severely cold weather conditions. Please also refer to the reply to BCUC IR 1.40.1.1 that shows no discernable historic downward trend on peak UPC based on system measurements.

30.0 Reference: DEMAND SIDE RESOURCES

Exhibit B-1, Section 4.3, p. 124

Load building measures

On page 124 of Exhibit B-1, FEI states:

> Load Building: Programs that increase the annual consumption of electricity or natural gas by increasing sales of electricity, natural gas or both. In the broader context of DSM, FEI's fuel switching program and NGT initiatives are also examples of load building demand side activities in that they increase the annual use of natural gas.

30.1 Excluding fuel switching and NGT, please identify any measures included in the 2017 LTGRP C&EM analysis that could be classified as load building.

<u>Response:</u>

The 2017 LTGRP C&EM analysis does not contain any measures that could be classified as load-building.

NGT and fuel switching, which are not included in the 2017 LTGRP C&EM analysis, can be classified as load-building and thus fall within the broader context of DSM (as articulated, for example, in the California Standard Practice Manual[16]) outside the statutory definition of DSM in BC.

[16] California Public Utilities Commission and California Energy Commission. 2001. "California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects". p. 2.

E. GAS SUPPLY PORTFOLIO PLANNING

31.0 Reference: GAS SUPPLY PORTFOLIO PLANNING
Exhibit B-1, Section 5, Table 5-1, p. 130
Rate Schedules included in Gas Supply Planning

Table 5-1 on page 130 of Exhibit B-1 shows the rate schedules included in or excluded from FEI's gas supply portfolio planning and FEI's system capacity planning.

In the cell that represents Firm Transportation Rate Schedules FEI states: "Contracted firm delivery component of 22 (including 22A and 22B) and other special Rate Schedules." In row 3 of the same table FEI also uses the term "special Rate Schedules."

31.1 Please list the "special Rate Schedules" which: (i) is relevant to Firm Transportation in row 2; and (ii) is included in row 3 regarding interruptible customers.

Response:

The special Rate Schedules referred to in Table 5-1 of the Application are Byron Creek, BC Hydro Island Generation (IG), and Vancouver Island Generation Joint Venture (VIGJV). All of these special Rate Schedules are applicable to both Firm Transportation and Interruptible as they all have contracted firm delivery and interruptible components.

31.2 Please state whether: (i) rate schedule 22A has a firm delivery component; and (ii) rate schedule 22B has a firm delivery component.

Response:

Both Rate Schedules 22A and 22B have firm and interruptible delivery components. Only the firm delivery component (e.g. contract demand) is included in FEI's system capacity planning.

31.3 Please confirm, or otherwise explain, that Rate Schedule 46 demand is included in: (i) Gas Supply Portfolio Planning; and (ii) System Capacity Planning.

Response:

Confirmed. FEI should have included Rate Schedule 46 (RS 46) in Table 5-1 of the Application. RS 46 is under both Core and Firm Transportation service type as customers under RS 46 can secure their commodity supply through FEI (i.e. considered as Core) or through their own supply via a shipper agent (i.e. considered as Firm Transportation). The Core customer service type is included in both Gas Supply Portfolio Planning and System Capacity Planning, while the Firm Transportation customer service type is included in System Capacity Planning only.

32.0 Reference: GAS SUPPLY PORTFOLIO PLANNING

Exhibit B-1, Section 4.2.3.6, p. 123; Section 5.3.1, p. 137

Demand Forecasts used for Gas Supply Portfolio Planning

On page 123 of Exhibit B-1, FEI states:

> 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).

32.1 Does FEI agree with Posterity that the 2017 C&EM forecast decreases peak demand? Please explain your response.

Response:

Posterity did not draw conclusions related to whether C&EM program impacts forecast decreases in peak demand. Posterity was commissioned by FEI to develop a process where changes to end-uses described in the annual demand end-use scenarios could be applied to peak demand to assess possible outcomes. The outputs of Posterity's analysis that include forecast C&EM activity when applied to the account forecast produced the peak demand forecasts presented in Section 6 of the Application. The peak demand end-use forecasts with C&EM do indicate that there is potential to reduce peak demand through C&EM that should be explored further. FEI's position is that further process development and verification is required before determining that the process can be used to forecast peak demand more reliably than the Traditional Peak Demand method. Please refer to FEI's response to BCUC IR 1.29.3 for additional discussion.

32.2 Please explain if, and how, FEI has accounted for the impact of its 2017 LTGRP C&EM reference case forecast in its peak demand forecast associated with Gas Supply Portfolio Planning.

Response:

FEI has not accounted for the impact of its 2017 LTGRP C&EM reference case forecast in its peak demand forecast associated with Gas Supply Portfolio Planning.

The Gas Supply Portfolio Planning is conducted using a 1 to 5 year planning horizon and therefore determines its portfolio of resources using a short to medium term load duration forecast of its Core customers, based off intrinsic historical end-use trends observed in recent years (i.e. Traditional Annual Method). Moreover, Gas Supply Portfolio Planning also takes into account regional market developments that have a bearing on future portfolio strategies. This approach allows for optimization of the portfolio over the near term, considering a number of potential outcomes while providing adequate lead time to be able to implement any decisions that need to be made for future contract years. While the LTGRP reference case forecast is focused on the longer term peak day or hourly UPC demand planning horizon (20 year outlook) using a broad range of long term demand forecast scenarios and assumptions, FEI's Gas Supply Portfolio can't be determined based solely off a peak day, as the portfolio needs to be shaped to meet the Core customer's seasonal and annual load requirements for a gas contracting year. Moreover, FEI is in a resource constrained environment and there are significant market factors that may affect gas supply planning over the long term, as discussed in Section 5.1.3 of the Application. Therefore making a change to the Gas Supply Portfolio based on peak day alone, or on long term forecasting scenarios and/or assumptions embedded in the LTGRP C&EM reference case forecast could result in unnecessary costs to customers.

32.2.1 If not, please explain why.

Response:

Please refer to the responses to BCUC IR 1.32.1 and BCUC IR 1.32.2.

On page 137 of Exhibit B-1, FEI states:

> FEI's portfolio is designed to provide secure and reliable daily gas supply to Core customers so that system-wide forecasted normal, design and peak design day demand is met.

32.3 Please use the following template to produce tables showing the forecast peak day demand and forecast annual normal demand for each year of the planning period before and after the impacts of FEI's 2017 LTGRP C&EM reference case forecast.

Service Regions	Forecast Peak Day Demand used for Gas Supply Portfolio Planning (TJ/d) (before C&EM)				
	2017	2018	...	2035	2036
Columbia					
Lower Mainland					
Inland					
Whistler					
Vancouver Island					
Sub-total Peak Day Demand (A)					
Ft. Nelson (B)					
Total Peak Day Demand (A + B)					

System-wide	Forecast Annual Normal Demand used for Gas Supply Portfolio Planning (PJ/yr) (before C&EM)				
	2017	2018	...	2035	2036
Annual Normal Load (PJ/yr) - FEI					
Annual Normal Load (PJ/yr) - Fort Nelson					

Service Regions	Forecast Peak Day Demand used for Gas Supply Portfolio Planning (TJ/d) (after C&EM)				
	2017	2018	...	2035	2036
Total Peak Day Demand (TJ/d)					

System-wide	Forecast Annual Normal Demand used for Gas Supply Portfolio Planning (PJ/yr) (after C&EM)				
	2017	2018	...	2035	2036
Annual Normal Load (PJ/yr) - FEI					
Annual Normal Load (PJ/yr) - Fort Nelson					

Response:

FEI is unable to provide the requested information for the reasons explained in the responses to BCUC IRs 1.32.1 and 1.32.2.

32.3.1 Please produce graphs with the forecasts before C&EM for: (i) Sub-total Peak Day Demand; (ii) Total Peak Day Demand; and (iii) Annual Normal Load for FEI for the 20 year planning period.

Response:

FEI is unable to provide the requested graphs for the reasons explained in the responses to BCUC IRs 1.32.1 and 1.32.2.

32.3.1.1 Please discuss possible reasons for any significant trends identified.

Response:

Please refer to the responses to BCUC IRs 1.32.1 and 1.32.2.

32.3.2 Please produce graphs with the forecasts after C&EM for: (i) Sub-total Peak Day Demand; (ii) Total Peak Day Demand; and (iii) Annual Normal Load for FEI for the 20 year planning period.

Response:

Please refer to the responses to BCUC IRs 1.32.1 and 1.32.2.

32.3.2.1 Please discuss possible reasons for any significant trends identified.

Response:

Please refer to the responses to BCUC IRs 1.32.1 and 1.32.2.

32.3.3 Please list all rate schedules whose demand was included in response to the above questions.

Response:

Please refer to the responses to BCUC IRs 1.32.1 and 1.32.2.

32.4 Please explain if a reduction in peak demand due to FEI's 2017 LTGRP C&EM could impact the resources required for FEI's Gas Supply Portfolio Planning.

Response:

Please refer to the responses to BCUC IRs 1.32.1 and 1.32.2.

32.4.1 Using FEI's 2017 LTGRP C&EM Reference Case forecast and FEI's peak demand forecast used for Gas Supply Portfolio Planning please calculate and explain any impacts to the following forecast resources:

(i) commodity supply (baseload, seasonal and winter);

(ii) storage capacity (market area and on-system storage); and

(iii) transportation capacity.

Response:

Please refer to the response to BCUC IR 1.32.2.

32.5 Please discuss the flexibility of FEI's gas supply resources identified in Figure 5-3 of Exhibit B-1, to respond to a possible reduction to the peak demand and normal demand due to the impacts of FEI's C&EM.

Response:

Please refer to the responses to BCUC IRs 1.32.1 and 1.32.2. Moreover, the flexibility of FEI's gas supply resources was discussed in Section 5.4 of the 2017 LTGRP. On Pages 140-141 in Section 5.4 of the LTGRP, FEI indicates that:

> This 2017 LTGRP presents FEI's contingency planning considerations, which illustrate how FEI may be able to respond to market conditions that differ from the Reference Case assumptions.
>
> A reduction in FEI's demand forecast will not create a major risk to FEI's long term planning strategy because of the contracting flexibility of FEI's portfolio:

1) Commodity Purchases – Although FEI has entered into some long-term supply commitments with counterparties, a majority of the gas supply purchased for the Core customers is negotiated on an annual basis and priced off a market index. Therefore, FEI could easily reduce or resell the amount of commodity purchases, if Core demand declines.

2) Transportation Capacity – FEI's transportation portfolio has been designed so that portions of capacity on third-party pipelines is up for renewal each year. This would allow FEI to de-contract most of its transportation capacity over a five-year period if it encounters a future with significantly lower demand than expected in the Reference Case.

3) Storage Portfolio – FEI's approach to storage contracts is similar to the transportation portfolio; however, the contract terms may not necessarily expire on an annual basis but on a two or three-year period. Storage contracts are harder to manage because there are no renewal rights embedded in the contract terms so FEI must balance term length versus the risk of losing access to storage supply. In any case, if the load duration curve changes over time such that less storage supply is needed, FEI will still have the ability to determine, as a long term solution, an approach to de-contracting storage resources.

33.0 Reference: GAS SUPPLY PORTFOLIO PLANNING

Exhibit B-1, Section 5, p. 135; NW Natural 2016 Integrated Resource Plan, p. 8.1

Mist contracts for market area storage

On page 135 of Exhibit B-1, FEI states that one of the major market factors that may affect FEI's gas supply planning over the long term includes the risk of "FEI's shorter duration market storage assets, specifically Mist, being recalled by approximately 2021/22."

In a footnote on page 135 of Exhibit B-1, FEI provides a hyperlink to the NW Natural 2016 Integrated Resource Plan. Page 8.1 of NW Natural 2016 Integrated Resource Plan states: "Mist Recall is the primary resource addition to meet growing peak loads. The next Mist Recall is projected to be for 30,000 Dth/day for the 2019-2020 gas year."

33.1 Please explain the nature of Mist's ability to recall storage capacity. In addition to your explanation, please discuss:

i. Whether FEI has the option of negotiating the volume of the recall;

ii. How much notice in days/months/years would FEI get if NW Natural were to recall Mist storage contracted to FEI.

Response:

NW Natural owns and operates the Mist storage facility in Oregon with its primary purpose to serve its core utility customers over the long term. However, these customers do not require all of the Mist storage capacity at this time, so NW Natural has been able to release a portion of the storage capacity to customers such as FEI.

FEI has several storage contracts at the Mist storage facility which are managed through the Annual Contracting Plan. Each contract has different capacities, expiry dates and injection and withdrawal capabilities. FEI's contracts at Mist have always been recallable (i.e. non-renewable), however this has not been an issue in the past because demand within NW Natural's service regions in the Pacific Northwest has not grown at a pace for which NW Natural would need to recall its storage capacity.

NW Natural's 2016 Integrated Resource Plan (IRP), discusses the potential recall of portions of Mist storage capacity from the interstate storage account effective May 2019[17] due to resource deficiencies over the planning horizon. The resource deficiency is "due to load growth, changes in peak day demand, and changes in the near term resource stack while being partially offset by an increase in demand-side resources."[18]

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17 This is subject to review based on updated load forecasts (summer 2018).
18 NW Natural. "2016 Integrated Resource Plan." Page 1.13.

FEI has ongoing discussions with NW Natural to better understand the estimated timing of when FEI may have its capacity re-called. Based on these discussions NW Natural would likely provide at least one year notice if they chose to recall a portion of FEI's contracted storage at Mist. Given that the storage resource is based off the demand requirements of NW Natural's core utility customers, FEI would not be able to negotiate with NW Natural regarding the volume of capacity to be recalled.

33.2 How likely is it for all or a significant portion of FEI's storage capacity at Mist to be recalled during the planning period (highly likely, somewhat likely, highly unlikely)? Please explain your response.

Response:

Given the significant resource deficiency by 2035-2036 laid out in NW Natural's 2016 IRP, it is highly likely that a significant portion of FEI's storage Mist capacity will be recalled during the 20 year planning period.

33.3 If all or a significant portion of FEI's storage capacity at Mist is recalled during the 4-year period covered by the Action Plan, please explain FEI's contingency plan for its Gas Supply Portfolio Plan in order to minimize both supply and price risk to ratepayers?

Response:

Based on ongoing discussions with NW Natural, FEI does not expect to have a significant portion of Mist storage capacity recalled during the 4-year period covered by the Action Plan. However, as part of its ongoing resource planning, FEI evaluates the gas supply alternatives surrounding the potential recall of its Mist contracts on an annual basis in its confidential[19] Annual Contracting Plan (ACP), the most recent of which was accepted by Letter L-15-17 on June 28, 2017.

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[19] FEI's ACP is filed in confidence in order to ensure that market sensitive information is protected. Regional resources are currently constrained, and to access them FEI competes with other counterparties or utilities and disclosure of the confidential information would impair FEI's ability to obtain favourable commercial terms for future natural gas contracts.

34.0 Reference: GAS SUPPLY PORTFOLIO PLANNING

Exhibit B-1, Section 5.4, p. 142

Excess resources

On page 142 of Exhibit B-1, FEI states:

> … 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.

34.1 Please calculate the cost to Core customers in 2017, if any, for <u>only</u> the excess gas supply portfolio resources contracted by FEI.

<u>Response:</u>

The excess resources that FEI references in Section 5.4 of the 2017 LTGRP are the 75 Terajoules/day (TJ/d) of T-South Huntingdon Delivery Capacity. Of this 75 TJ/d, a portion has been used to optimize FEI's portfolio by purchasing more Station 2 supply in the winter and moving away from the Kingsgate market temporarily. FEI's customers have benefitted from this move as Station 2 typically trades well below the Kingsgate price. FEI has assigned the remaining capacity to the marketplace. Since the 2016/17 gas contracting year FEI has released between 35 to 40 TJ/day to Marketers on behalf of the transportation service customers. The capacity has been assigned at a cost higher than the Westcoast T-South toll, therefore it has been a net benefit to the Core Customers. In 2017, the net benefit to the Core Customers from the T-South release to Marketers on behalf of the transportation service customers was approximately $1.7 million.

34.1.1 Please calculate what percentage of the cost for only the excess resources was mitigated throughout 2017.

<u>Response:</u>

Please refer to the response to BCUC IR 1.34.1.

F. PRICE RISK MANAGEMENT

35.0 Reference: PRICE RISK MANAGEMENT

Exhibit B-1, Section 5.5.1, p. 142, 143;

Decision on FortisBC Energy Utilities 2014 Long Term Resource Plan dated

December 3, 2014 (FEU 2014 LTRP Decision), p. 37;

FEI 2017 Price Risk Management Plan (PRMP) proceeding, Exhibit B-1-2 (2018 PRMP Application), Section 2, p. 4

Price risk management objectives

Page 37 of the FEU 2014 LTRP Decision states:

> The Commission Panel considers that the LTRP should inform the PRMP on price risk management principles, and not vice versa. The UCA requires that, when considering utility filing of energy supply contracts under section 71 of the UCA, the Commission must consider the most recent LTRP filed by the utility. The Panel therefore directs the FEU to include in the next LTRP a description of its long-term vision for price risk management and provides broad principles, which can be used to inform the PRMP.

FEI states on page 142 of the Application:

> FEI has developed diversified procurement strategies and utilized [Price Risk Management Plans (PRMPs)] to manage commodity price risk and facilitate competitive and affordable natural gas rates" [emphasis added]. FEI further states on page 143 of the Application that "FEI's price risk management objectives include mitigating market price volatility to support rate stability and capturing favourable prices to provide customers with more affordable rates. [emphasis added]

FEI states on page 143 of the Application that: "the objectives for medium and longer term are the same, but the tools for managing price risk management are different."

On June 13, 2017, FEI filed its 2017 Price Risk Management Application. On January 5, 2018, FEI submitted its revised application titled 2018 Price Risk Management Plan Application (2018 PRMP Application). FEI states on page 4 of FEI's 2018 PRMP Application that: "FEI's objectives for its price risk management, which includes hedging, include the following:

- Mitigate market price volatility to support rate stability, and

- Capture opportunities to maintain commodity rates at historically low levels."

35.1 Please reconcile the differences between the PRMP objectives stated in the LTGRP and in the 2018 PRMP Application, and clarify what are FEI's PRMP objectives.

Response:

In the 2018 PRMP, FEI has revised its second objective regarding capturing favourable prices to provide customers with more affordable rates to make it more specific and relevant to the current low market price environment rather than the affordability in rates. The affordability in rates can be somewhat subjective and difficult to measure as it will vary among different customers. Maintaining commodity rates at historically low levels is less subjective and easier to define since information regarding historical commodity rates is available and observable and can be used for comparison or as part of benchmarking in a hedging strategy.

As stated in the 2018 PRMP, FEI's price risk management objectives do not explicitly include achieving affordable and competitive rates. However, achieving the objective of capturing opportunities to maintain low commodity rates may, at the same time, help provide some customers with more affordable rates than in the past and help with the competitiveness of natural gas compared to other energy sources.

For clarification, FEI's PRMP objectives are as follows:

- Mitigate market price volatility to support rate stability, and
- Capture opportunities to maintain commodity rates at historically low levels.

35.2 In light of FEI's statement that: "the objectives for medium and longer term are the same," please explain whether FEI has one set of PRMP objectives that are consistently applied to inform its planning and operational decisions. If not, please explain why not.

Response:

FEI has one set of PRMP objectives that are consistently applied to inform its planning and operational decisions. As discussed in Section 5.1.1 of the Application, however, each PRMP includes more detailed strategies and tactics for managing price risk and its impact on gas costs on customer rates. For example, while capturing opportunities to maintain commodity rates at historically low levels is an overall price risk management objective, the PRMP may include updated hedgeable volumes and hedging price targets based on consideration of changing market factors, such as gas producer break-even costs.

35.2.1 Please confirm that FEI's responses to information requests filed in the FEI 2017 PRMP proceeding regarding price risk management objectives also speaks to the price risk management objectives contained in the 2017 LTGRP, and can be included as part of the evidentiary record on the 2017 LTGRP proceeding. If not confirmed, please elaborate.

Response:

Confirmed. The specific 2017 PRMP IR responses that address this issue and can be included as part of the evidentiary record in the 2017 LTGRP proceeding are the following BCUC information requests, which are provided in Attachment 35.2.1:

- 1.1.1
- 1.1.2
- 1.1.3
- 1.1.3.1
- 1.1.3.2
- 1.1.4
- 1.2.1
- 1.2.2
- 1.2.2.1

35.3 Please provide FEI's views on the Commission's comment in the FEU 2014 LTRP Decision that the LTRP should inform the PRMP on price risk management principles, and not vice versa.

Response:

FEI agrees with the Commission's comment in the FEU 2014 LTRP Decision that the LTRP should inform the PRMP on price risk management principles, and not vice versa. As discussed in Section 5.1.1 of the Application, the LTGRP sets out gas supply contracting and price risk management principles within the context of a 20-year outlook while the ACP and the PRMP each describe more detailed strategies and tactics for managing either the physical availability of natural gas supply or the impact of gas costs on rates for core sales customers.

35.3.1 Going forward, does FEI consider that the review of the LTRP should conclude prior to FEI's filing of its PRMP, if possible? Please explain your response.

Response:

FEI agrees that, given the LTGRP should inform the PRMP on price risk management principles, ideally the review of the LTGRP should conclude prior to the filing of the PRMP. However, given that the LTGRP is typically filed less frequently than the PRMP, it may not always be possible for the review of the last-submitted LTGRP to conclude prior to FEI submitting a PRMP. If FEI did wait for the LTGRP review to conclude prior to filing a PRMP, it may miss out on opportunities to mitigate market price risk on behalf of customers, given that gas market conditions are constantly changing. Therefore, in this case, FEI is of the opinion that its most recently filed LTGRP could be used to provide context for FEI's latest PRMP.

As the Commission notes on page 37 of the FEU 2014 LTRP Decision, "the UCA requires that, when considering utility filing of energy supply contracts under section 71 of the UCA, the Commission must consider the most recent LTRP **filed** *[emphasis added]* by the utility." This does not include the requirement of the review of the long-term resource plan to conclude prior to the review of energy contracts.

36.0 Reference: PRICE RISK MANAGEMENT

Exhibit B-1, Section 5.5.1, p. 143; FEI 2017 PRMP Application, Exhibit B-1-2 (FEI 2018 Application), p. 34

Volumetric Production Purchase (VPP)

On page 143 of Exhibit B-1, FEI states:

> FEI plans to continue to investigate longer term strategies such as VPPs and, if warranted, will bring forward any requests to the Commission for approval in the future." FEI further states that "the objectives for medium and longer term, are the same, but the tools for managing price risk management are different.

On page 34 of FEI's 2018 PRMP Application, FEI elaborates on the VPP under section 4.5.3. Specifically, FEI states that: "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 capital investment would be included in FEI's rate base and earn a rate of return for shareholders."

36.1 Please elaborate on FEI's investigation process into VPPs as a long term PRMP strategy, and provide the timing of when FEI will conclude its investigation.

Response:

FEI has been exploring VPPs and other possible arrangements with gas producers as potential long-term price risk management tools. This includes arrangements where FEI would provide an upfront lump sum payment to a gas producer in exchange for long-term cost-based supply. FEI has discussed these arrangements internally and has recently been assisted by TD Bank, at no cost, in order to assess potential structures and counterparties in terms of supply availability and creditworthiness. FEI plans to continue its investigation, and may request acceptance in a future application for implementation of such strategies.

36.2 Please elaborate on VPPs, including a discussion of the following:

- the requirements (e.g. market condition, financial commitment, counterparty financial standing) to execute VPP investments;
- whether additional resources (external or in-house) and costs is required to enter into and monitor VPPs;
- the risk exposures that VPPs are designed to reduce;

- any additional risks that FEI could be exposed to by entering into VPPs; and
- any other pros and cons of VPPs in meeting FEI's price risk management objectives relative to its existing tools.

Response:

VPPs or other arrangements with gas producers, including prepayment options where FEI would provide an upfront lump sum payment to a gas producer for long-term (i.e. 10 to 20 years) cost based supply, would be favorable in the current gas market conditions. The current low-priced gas environment in Western Canada is largely a result of gas producers having improved drilling and production techniques and reduced costs to produce supply, and lack of pipeline capacity to move excess supply to markets. At the current time, gas producer break-even costs are at historically low levels, with some producers earning additional revenue from oil and liquids sales to help lower break-even costs even further. However, this is not the case for all producers, particularly those drilling in dry gas areas where market prices may be below their break-even costs. Based on its contracted pipeline resources as defined within the ACP, FEI has sufficient pipeline capacity to move supply from market hubs to its customers, thereby putting FEI in a favourable market position in potentially capturing this low-cost production.

In this current low market price environment, some gas producers may be looking for capital injections from third parties to support their operations, particularly if they do not want to take on more debt or issue more equity. The amount of capital needed to secure such long-term arrangements with producers could be in the range of $200 million to $500 million. This amount would vary based on the amount of supply delivered per day and the length of the term of the arrangement - the more supply or longer the term, the higher the amount of capital needed to secure the arrangement. As with any arrangement with a counterparty, FEI would require that the counterparty is in good financial standing. However, FEI recognizes that it is likely that some interested counterparties in this particular type of arrangement, i.e. those counterparties requiring capital, may not have strong credit ratings. Therefore, any arrangement would need to balance adequate credit protection for FEI with a counterparty in need of capital.

So far, FEI has managed its exploration of VPPs and other long term arrangements through internal resources as well as with external consultation. FEI's assessment and future monitoring of any long-term arrangements is managed internally within Gas Supply and with Finance and Legal departments providing support. So far, TD Bank has also provided external support in assessing deal structures and counterparty potential at no cost to FEI, however this could potentially change if more support and resources from TD Bank or other external resources are required.

VPPs or other long-term arrangements align with the PRMP objectives to mitigate market price volatility to support rate stability and capture opportunities to maintain commodity rates at historically low levels. The long-term arrangements would provide gas cost certainty and security of supply for a portion of the commodity supply portfolio for the length of the term, from

10 to 20 years. This would provide longer term benefits in terms of helping provide rate stability and maintaining low commodity rates more than any of FEI's other price risk management tools, which are shorter to medium term in nature. Furthermore, customers can benefit if market prices increase above the long-term arrangement contract price/cost. Customers would not benefit, from a cost perspective, if market prices decrease below the long-term arrangement contract price/cost. They may still benefit from a security of supply perspective.

As with any type of long-term supply arrangement, counterparty credit risk may be greater than for supply arrangements with shorter and medium terms given that there is more uncertainty regarding counterparty viability further out in time. By providing a producer with upfront capital and entering into a long term arrangement for supply, FEI may actually help improve the financial outlook for the producer by providing more certainty in terms of the producers' cash flow, thus reducing counterparty risk.

37.0 Reference: PRICE RISK MANAGEMENT
Exhibit B-1, Section 5.5.2, pp. ES-7, 145;
FEI 2017 PRMP proceeding, Exhibit B-1-2, pp. 33-34
Investment in natural gas reserves

FEI states on page ES-7 of its Application:

> FEI plans to continue to investigate longer term strategies such as investing in reserves, and if warranted, will bring forward any requests to the Commission for approval in the future." FEI also states on page 145 of the Application that: "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.

On pages 33 to 34 of FEI's 2018 PRMP, FEI states:

> Managing the risk associated with reserves would be of paramount importance to FEI in a reserves arrangement. While it may seem that the risk associated with drilling, completing, and operating wells would differ from typical regulated utility assets, there may be ways to mitigate these risks through contractual arrangements and effective due diligence. One important feature of any deal would be the ability to transfer risks to producers that are appropriate for a producer to manage, such as drilling risks and most operating risk. However, this transfer of risks may not be acceptable to the producer or increase the capital investment required by the producer. Because of this, *FEI is not planning to explore this option further at this time.* [emphasis added]

37.1 Please reconcile FBC's statement contained in its Application and in its 2018 PRMP on whether FEI plans to further explore the option of investing in natural gas reserves.

Response:

After reviewing potential long term price risk management alternatives since filing the Application, FEI has determined that long term supply arrangements other than investing in natural gas reserves may be more appropriate in terms of balancing meeting the price risk management objectives and mitigating any potential risks and costs. However, FEI is not completely ruling out the alternative of investing in gas reserves should FEI be able to mitigate the risks associated with drilling and production at an acceptable cost. Therefore, while FEI is considering all long term alternatives, it is not actively exploring this option at this time. For a detailed list of long-term price risk management alternatives please refer to the response to CEC IR 1.26.1.

G. SYSTEM RESOURCE NEEDS AND ALTERNATIVES

38.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Section 6.2, p. 150

Projects to address system capacity constraints

On page 150 of Exhibit B-1, FEI states:

> Infrastructure projects on transmission systems to address system capacity constraints are often large and take many years to plan and execute. As a result, securing infrastructure resources is not as responsive as securing gas supply resources.

38.1 Using high-level estimates, please provide the various types of infrastructure projects for transmission systems meant to address system capacity constraints and the:

(i) time to plan the project;

(ii) time to execute the project; and

(iii) total time to plan and execute the project by bringing it into service.

Please use a table format for your response and please exclude the time required to obtain regulatory approvals from the relevant organizations.

Response:

The table below reflects FEI's experience in the planning and execution of infrastructure projects. The table provides very high-level time estimates for major projects (generally in excess of $60 million). Apart from regulatory approvals which are not included, the planning time includes front end engineering design, detailed engineering, permitting and procurement of long lead materials and equipment and construction contractors. Planning is assumed to progress sequentially and is continuous until commencement of construction with no delays due to external factors. Regulatory approval timeframes not included would be those from organizations such as the BCUC, First Nations, the NEB, the BC Oil and Gas Commission, municipal permitting and provincial and federal environmental bodies such as BC Environmental Assessment Office or the Canadian Environmental Assessment Agency. The timeframes identified are broad as there can be a wide range of considerations that can affect the overall project time including but not limited to; does the project require new facilities or extensions and modifications to existing facilities, the number and complexity of alternatives solutions to be considered, land and ROW requirements and the degree and complexity of community and stakeholder engagement and consultation required.

Type of Capacity Upgrade Project	High Level Project Time Requirements - Excluding Regulatory Approvals		
	Project Planning	**Project Construction**	**Total Project Time**
Transmission Pipeline Loop or Replacement	1 to 4 Years	1 to 5 Year	2 to 9 Years
Compressor Facility Addition or Expansion	6 Months to 4 Years	1 to 5 Years	18 Months to 9 Years
LNG Peak Shaving Facility	2 to 4 years	3 to 5 Years	5 to 9 years

39.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Section 6.2.1.3, p. 153; Section 6.1, p. 149

Peak demand forecast for system capacity planning

On page 153 of Exhibit B-1, FEI states:

> FEI's Traditional Peak Method forecast is built from a "load gather" process that determines unique daily and hourly UPC_{peak} values for each customer. Values for most customers are based on regression analysis of average consumption against local temperature using the most recent 24 months of consumption information extracted from monthly meter read data. … For customers where hourly consumption data is available (typically large commercial and industrial customers) UPC_{peak} is determined directly from that data. These unique hourly UPC_{peak} values for each customer are then grouped by rate and region to determine average hourly UPC_{peak} for each region and rate schedule that can then be applied to an account forecast to determine a peak demand forecast. A unique UPC_{peak} for residential, small commercial and large commercial rate schedules in 66 separate regions across the province is developed in FEI's Traditional Peak Method.

On page 149 of Exhibit B-1, FEI defines UPC_{peak} as "peak hour use per customer."

39.1 Please explain, with calculations and examples where relevant, how the UPC_{peak} is determined for residential, small commercial and large commercial customers whose consumption meters are read monthly.

Response:

FEI determines peak hour use per customer (UPC_{peak}) for customers whose consumptions meters are read monthly through an annual load gather assessment.

In the load gather process, billing information for the preceding two year period is extracted for all customers. With a custom software application, the billing information for each customer and temperature information from the local weather zone index weather stations is reduced to a daily average demand for the customer for each billing period and an average mean daily temperature for the same billing period. For customers billed monthly twenty-four "daily demand" versus "mean daily temperature" data points are determined from their most recent biannual consumption. A linear regression for each customer is performed on this data and a base load and slope (standard m^3/day/degree Celsius) are determined. The peak day demand for the customer equates to the customer's demand projected to the Design Degree Day (DDD) temperature value for the weather zone the customer resides in. For capacity planning purposes FEI currently divides its service territory into twenty-two unique weather zones with

DDD values ranging from 27.8DD (mean daily temperature = -9.8°C) in the Comox (Vancouver Island) region to a 60.4DD (mean daily temperature = -42.4°C) in Fort Nelson (Northeast BC). The DDD peak day demand values are converted to a peak hourly demand by applying a peak hour factor (peak hour/peak daily demand) determined from a periodic assessment of local gate station hourly and daily flow variations under winter load conditions. From the uniquely calculated hourly UPC_{peak} determined for each customer a "roll up" determining the current local regional average for each rate class is determined. FEI calculates UPC_{peak} values in sixty-six different local regions each composed of one or more municipal districts. To smooth the data, these regional average UPC_{peak} values for each rate schedule are averaged with the results of the preceding two years' annual load gather assessment values to produce a three year "rolling average" UPC_{peak} for each rate class within the region. These three year rolling average UPC_{peak} values are combined with current accounts and account addition forecasts to produce peak-hour load forecasts over a forecast period.

39.2 Please state if FEI's system capacity planning approach is based on a coincident peak approach or a non-coincident peak approach for each system (Vancouver Island Transmission System (VITS), Coastal Transmission System (CTS) and Interior Transmission System (ITS)).

Response:

FEI's system capacity planning approach is based on a coincident peak approach for the customers whose UPC_{peak} is determined from monthly consumption. The load gather process for these customers described in BCUC IR 1.39.1 is designed to derive the peak demand that coincides with the system peak. For customers where hourly billing is available the maximum observed peak hourly measured value for those customers is used even though the value used may be non-coincident with the system peak. This approach is taken unless there are requirements within the rate schedule or other documented reasons that prevent the customer from taking the observed consumption during the system peak. An example of this non-coincident peak would be a customer with a CNG fueling compressor facility that might under normal conditions fuel in late evening and early overnight hours, but may (without requiring notice to FEI) operate during the morning peak demand.

At the system-wide level, the systems are independent of each other. For system infrastructure requirements and for the timing of system constraints appearing in the forecast, the results would not change if the three systems were considered to have coincident peaks or non-coincident peaks. As noted on page 130 of the Application, FEI's analysis of system resource needs and alternatives relies on location-specific (not system-wide peak demand).

39.2.1 Please explain the reason for the approach chosen.

Response:

Please refer to the response to BCUC IR 1.39.2.

40.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Section 5, p. 130; Section 6.1, p. 149

Peak demand forecasts

On page 154 of Exhibit B-1, FEI states:

> 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, <u>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</u>. 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. (Underline Emphasis Added)

40.1 For each of the: (i) VITS; (ii) CTS; and (iii) ITS, please provide a table that shows: (a) the UPC_{peak} for each rate schedule and applicable contract customer; and (b) the combined UPC_{peak} for the system for each of the 10 years from 2007 to 2016.

<u>Response:</u>

The 10 year historical UPC_{peak} in GJ/hr of core customers Rate 1, Rate 2 and Rate 3 for each transmission system as well as the combined (customer weighted average) UPC_{peak} for these customer rate schedules across each system are presented in Table 1 and Table 2, respectively. There are no other rates schedules or applicable contract customers for which FEI prepares average UPC_{peak} values using the Traditional Peak Method forecast. By “contract customers” FEI assumes the Commission means larger industrial customers such as Rate Schedule 5, 25, 22A/B. These customer classes have hourly metering and the traditional forecast is based on observed hourly data or contractual limits for peak day quantities. As the peak values within these rate schedules has a wide variation and FEI does not traditionally forecast customer account growth or decline due to account additions or losses, an average UPC for the rate schedule is not calculated and has not been used historically to forecast in the Traditional Peak Method. Therefore FEI has not included these rate schedules in the tables.

As described in the response in BCUC IR 1.39.1, FEI calculates UPC_{peak} in sixty-six different local regions each composed of one or more municipal districts. The UPC_{peak} of each rate class presented here represents the customer weighted average of the local regions that are served by the corresponding transmission system.

Table 1: Historical UPC_{peak} - Core Customers for VITS, CTS and ITS

Year	CTS UPC_{peak} (GJ/hr)			ITS UPC_{peak} (GJ/hr)			VITS UPC_{peak} (GJ/hr)		
	Rate 1	Rate 2	Rate 3	Rate 1	Rate 2	Rate 3	Rate 1	Rate 2	Rate 3
2007	0.0614	0.1911	1.6881	0.0473	0.1639	1.7391	0.0325	0.0854	0.9556
2008	0.0614	0.1987	1.7305	0.0495	0.1765	1.8602	0.0324	0.0875	0.9710
2009	0.0614	0.2025	1.7326	0.0487	0.1763	1.8831	0.0320	0.0892	0.9693
2010	0.0605	0.2007	1.6904	0.0479	0.1758	1.8749	0.0312	0.0889	0.9985
2011	0.0605	0.2058	1.6817	0.0470	0.1739	1.8718	0.0318	0.0966	0.8843
2012	0.0613	0.2236	1.7010	0.0475	0.1857	1.9181	0.0346	0.1183	0.9128
2013	0.0622	0.2425	1.7364	0.0485	0.1975	1.9629	0.0343	0.1215	0.8971
2014	0.0617	0.2569	1.7966	0.0494	0.2113	2.0586	0.0340	0.1149	0.8264
2015	0.0607	0.2559	1.8165	0.0499	0.2155	2.1111	0.0335	0.2169	1.6405
2016	0.0575	0.2447	1.7790	0.0454	0.1978	2.0123	0.0325	0.2071	1.6247

Table 2: Historical Combined UPC_{peak} - Core Customers for VITS, CTS and ITS

Year	Transmission Combined UPC_{peak} (GJ/hr)		
	CTS	ITS	VITS
2007	0.0850	0.0627	0.0620
2008	0.0863	0.0662	0.0617
2009	0.0869	0.0657	0.0600
2010	0.0864	0.0650	0.0551
2011	0.0856	0.0639	0.0533
2012	0.0873	0.0652	0.0582
2013	0.0896	0.0670	0.0586
2014	0.0904	0.0689	0.0556
2015	0.0897	0.0698	0.0607
2016	0.0857	0.0637	0.0563

40.1.1 Please discuss any significant trends identified over the 10 years by rate schedule.

Response:

The historical trending of UPC_{peak} for Rate 1, Rate 2 and Rate 3 of each transmission system is illustrated in the figures below.

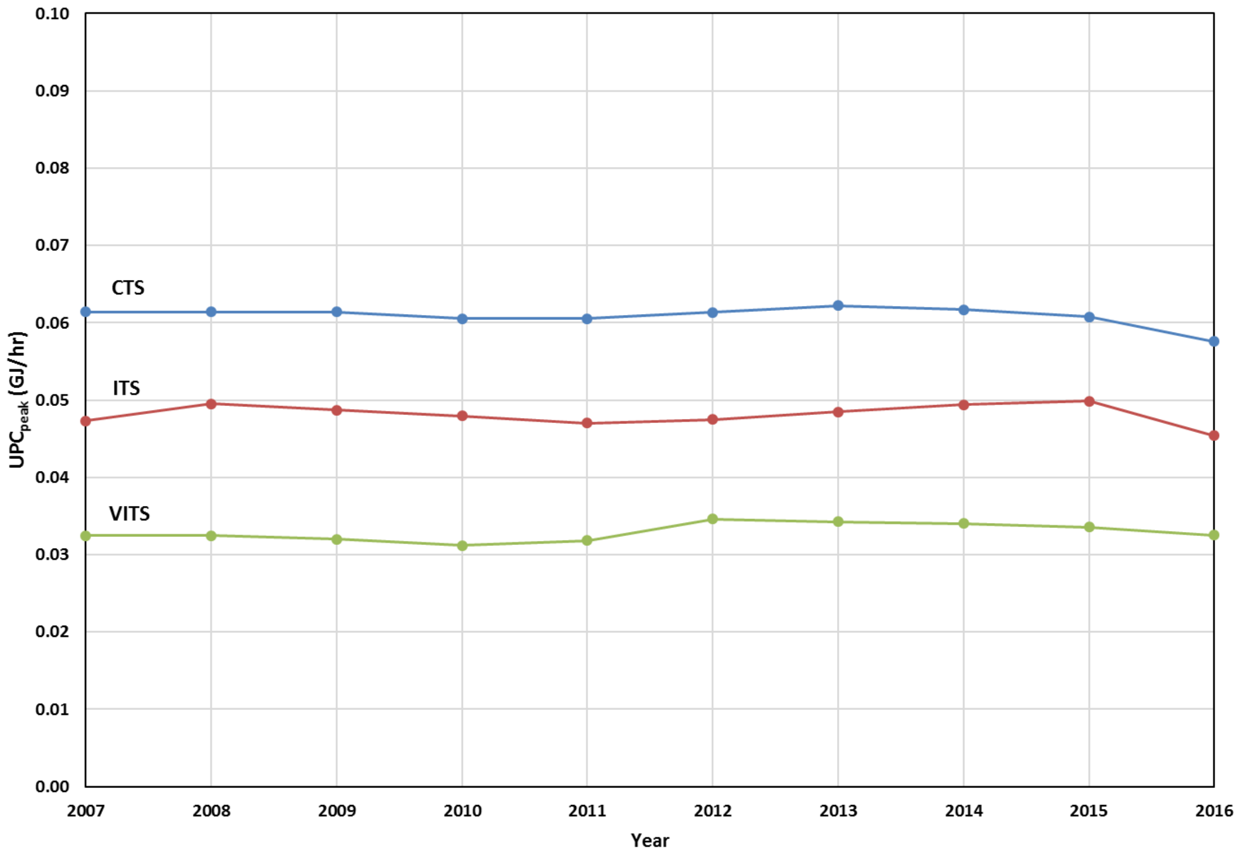
The UPC_{peak} trends for each rate schedule are fairly consistent and similar for the CTS and ITS. For the VITS the Rate 1 schedule trend looks similar to the other transmission systems, however there is significant variation in the Rate 2 and Rate 3 schedules. The reason for the variation in these rate schedules is related to the amalgamation of FEVI with FEI. Over the 10-year history presented here, the VITS system moved from 3 separate rate schedule systems representing Whistler, Squamish and the Sunshine Coast/Vancouver Island (FEVI) to the rate schedule system used by the rest of FEI. Prior to amalgamation, in order to develop FEI's Traditional Peak Method forecast the previous Whistler, Squamish and FEVI rate schedules were grouped to approximate the FEI Rate 1, Rate 2 and Rate 3 schedules. Upon amalgamation, for the 2015 load gather process there was a settling of customer accounts that differed from the groupings previously assumed up until that point and this migrated significant numbers of customers between rate schedules. All rate classes had some impact, but the resulting changes to Rate 2 and Rate 3 schedules were most noticeable. Post amalgamation the numbers of customers identified as Rate 2 increased and the numbers identified as Rate 3 decreased. This change is noticeable in Figures 2 and 3. Between 2014 and 2015m UPC_{peak} values for Rate 3 customers increased as a smaller number of customers with a higher average consumption settled into the rate class. The UPC_{peak} values for Rate 2 also increased slightly as the numbers of customers identified in that rate schedule increased (migrating from those considered Rate 3 prior to amalgamation). From 2015 on, the VITS UPC_{peak} rate schedule trends begin to align with what is seen in the CTS and ITS.

Another change of note occurred in the 2016 data which explains the noticeable drop in UPC that year. For that year and for future years, System Capacity Planning has reduced the design temperatures or design degree day (DDD) values used in most weather zones to account for the slight warming trends that are reflected in the 60 years of weather data used to derive these values. The slightly reduced design temperatures resulted in slightly reduced UPC_{peak} values.

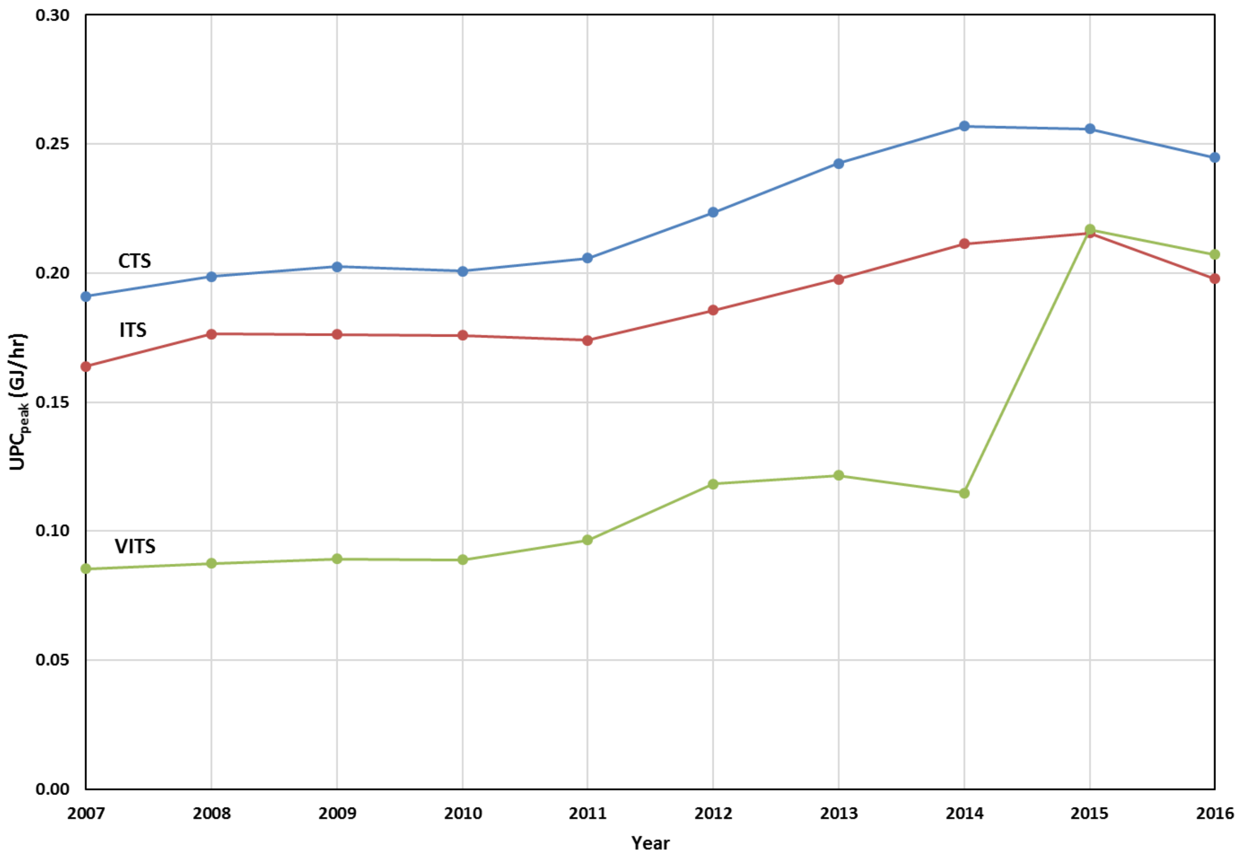
The historical Rate 1 UPC_{peak} values for residential customers does not present a clear trend that would indicate that the UPC_{peak} value is increasing or decreasing consistently in the period. The UPC_{peak} value for Rate 2 and Rate 3 schedules which consists of the small and large commercial customers shows similar trending in the past ten years with periods of both decreasing and increasing UPC_{peak}. The trend recently had been increasing but seems to have flattened in 2014-2016.

Finally, the combined impact of these rate classes in each system as a whole is presented in Figure 4. There is no clear trend that combined UPC_{peak} is either increasing or decreasing. Also note that the trend for the combined rate schedules for the VITS is smooth, as the effect of the resettling between the rate schedules due to rate amalgamation is removed when considered at the system level.

Figure 1: 10 Year Historical Rate 1 UPC_{peak} for VITS, CTS and ITS



1 **Figure 2: 10 Years Historical Rate 2 UPC_{peak} for VITS, CTS and ITS**



2

Figure 3: 10 Year Historical Rate 3 UPC_{peak} for VITS, CTS and ITS

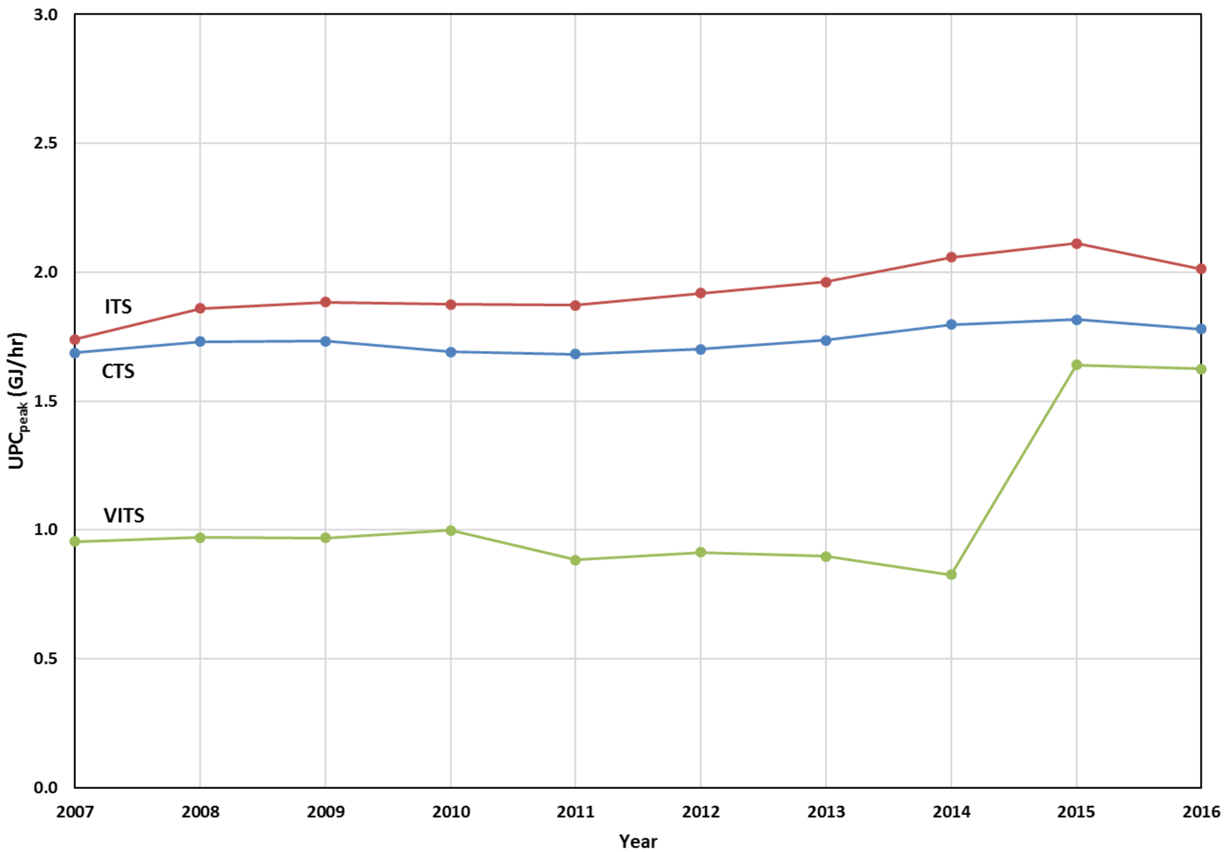
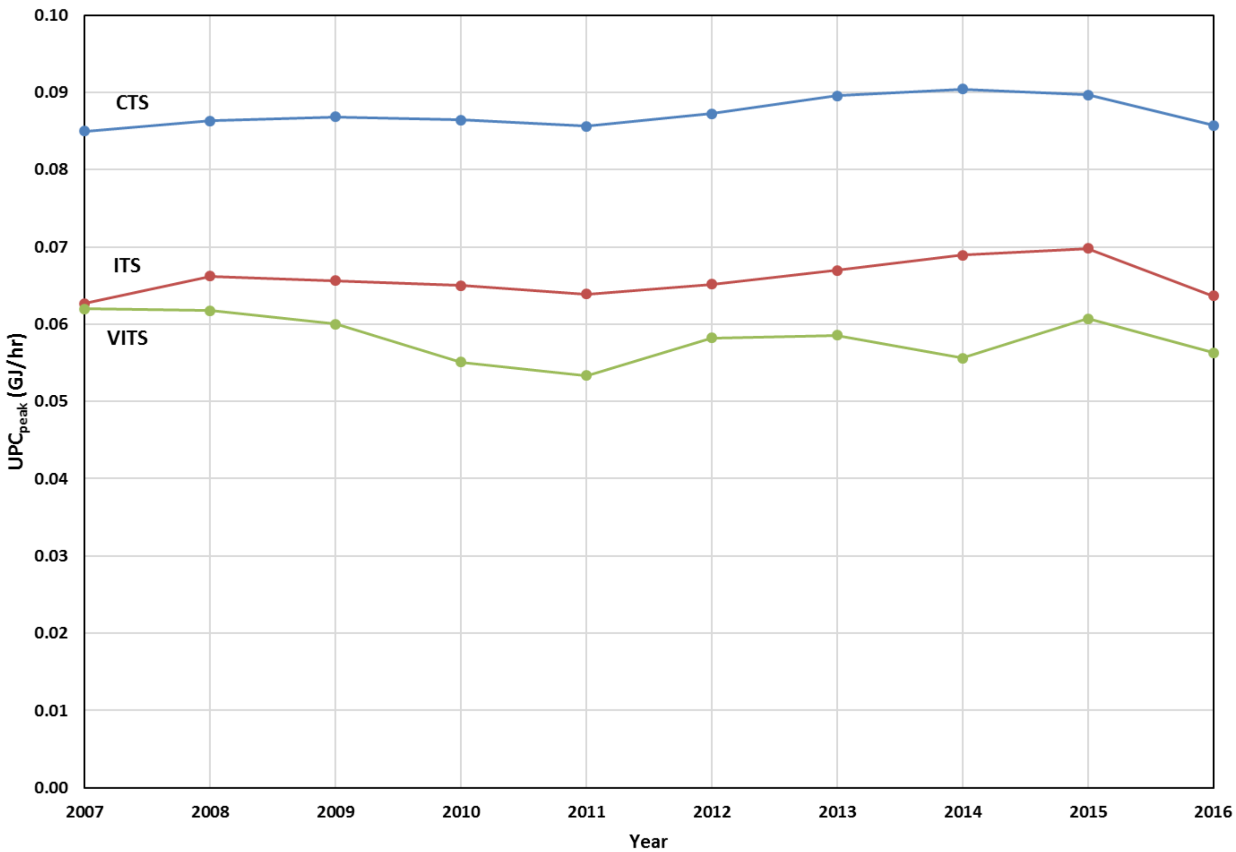


Figure 4: 10 Year Historical Combined UPC_{peak} of Core Customers for VITS, CTS and ITS



40.2 Please explain if FEI considers that holding the UPC_{peak} values constant for the 20 year planning period accurately reflects historical data.

<u>Response:</u>

As discussed in the response to BCUC IR 1.40.1.1, FEI sees no evidence that historical UPC_{peak} data used in the Traditional Peak Method forecast is increasing or decreasing consistently over time. FEI therefore considers that holding UPC_{peak} value constant at this time for the 20-year planning period is consistent with historical data.

40.3 Taking into consideration the planning environment, in particular FEI's discussion regarding energy and emissions policy in Section 2.3 of the Application, please discuss the likelihood of UPC_{peak} for residential, small commercial and large commercial customers remaining unchanged for the 20 years from 2017 to 2036.

Response:

As discussed and illustrated in BCUC IR1.40.1.1 the UPC_{peak} for residential, small commercial and large commercial customers does change from year to year. It is not unreasonable to expect the values to continue to vary over time. The FEI trends presented over 10 years do show periods where UPC_{peak} was trending upwards and also periods when UPC_{peak} was trending downwards. Over time, improvements in energy efficiency, changing end-use applications and possibly fuel switching will impact UPC_{peak}. Currently there are no implemented government policies designed to stimulate greater rates of retrofit that would generate notable improvements in energy efficiency. On fuel switching, there are some early indications that the federal Clean Fuel Standard may incentivize fuel switching, but it is still too early for certainty, as draft regulations of the policy have not been published and the stringency of the policy is currently unknown. Regardless, the policy environment will likely change and may create downward pressures on gas demand in buildings. However, FEI emphasizes that the scope and scale of this activity is also currently unknown. Also important to this discussion, there remains considerable uncertainty in the directional impacts on UPC_{peak} of some efficiency technologies like smart learning thermostats. The exploratory end-use peak demand method is an avenue FEI is currently pursuing to gain additional insight on how the planning environment might impact estimates of UPC_{peak} used in forecasting infrastructure requirements.

In the present environment FEI believes that the Traditional Peak Demand Forecast method that holds UPC_{peak} constant through the forecast remains appropriate. The biggest risk to FEI and FEI ratepayers is in underestimating peak demand and not recognizing a potential capacity deficit with sufficient time to respond effectively and efficiently. The traditional method mitigates risk to FEI and FEI ratepayers through a process of continual re-evaluation throughout the planning period. The UPC_{peak} values are refreshed annually, providing a regular check on the current state of peak demand requirements. In an environment where UPC_{peak} is increasing, the planning process identifies, year over year, the likely advance in timing. The forecast method provides sufficient notice to initiate the project planning and execution, such that the project can be installed to meet the identified capacity deficit. The likelihood of UPC_{peak} alone eroding the necessary planning and execution time for projects 4-7 years out in the planning period where detailed planning has begun is low. The risk to FEI and its ratepayers of potentially large-scale peak day outages or projects being more costly (due to insufficient planning or execution time) is managed through the traditional method. In an environment where UPC_{peak} is decreasing, the planning method again identifies, year over year, any deferral in project need, so reprioritization or re-evaluation of the scope of projects can be undertaken. The traditional planning method in this way mitigates the risk to FEI and its ratepayers of investing in capacity projects planned and executed before the need it present.

40.4 Please explain if, and how, there is any risk to FEI or FEI ratepayers of actual UPC_{peak} increasing during the planning period while FEI's system capacity plans are made using a constant UPC_{peak} during the planning period.

Response:

Please refer to the response to BCUC IR 1.40.3.

40.5 Please explain if, and how, there is any risk to FEI or FEI ratepayers of actual UPC_{peak} decreasing during the planning period while FEI's system capacity plans are made using a constant UPC_{peak} during the planning period.

Response:

Please refer to the response to BCUC IR 1.40.3.

40.6 Please describe how FEI could mitigate the risks to both FEI and FEI's ratepayers identified in response to the above questions.

Response:

Please refer to the response to BCUC IR 1.40.3.

41.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Section 6.3.1, p. 158; Figure 6-2, p. 159

Vancouver Island (VI) demand and capacity balance

On page 158 of Exhibit B-1, FEI states:

> The Mt. Hayes facility has a storage capacity of 1.5 Bcf (approximately 1,614 TJ), a liquefaction capacity of 7.5 million standard cubic feet per day (MMscfd), and a send-out deliverability of 150 MMscfd (161 TJ/d).Traditionally, the capacity of the VITS is represented by allocating one third of the Mt. Hayes sendout capacity to the VITS, with the balance remaining available for the rest of the FEI system. The peak day capacity on the following figures reflects this arrangement.

41.1 Please provide the figure in TJ/d for the design day system capacity, identified by a red line in Figure 6-2 on page 159 of the Application.

<u>Response:</u>

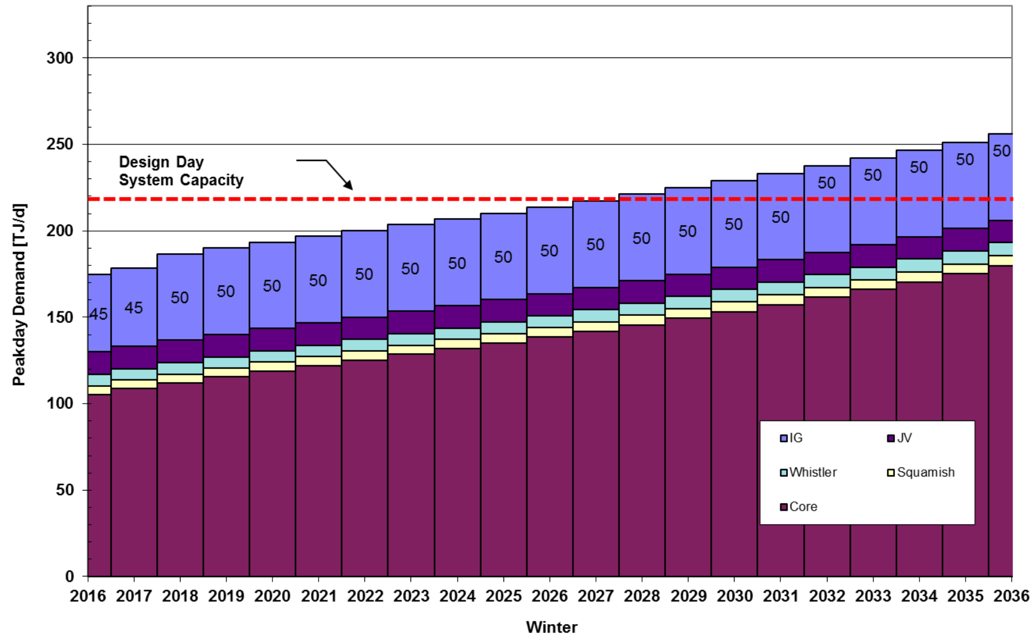
The red line shows the capacity of the VITS, allocating one third of Mt. Hayes sendout capacity to the VI system, as 218 TJ/d.

41.2 Please provide an updated version of Figure 6-2 which shows any forecast demand above the VI design day system capacity line for each of the years from 2028 to 2036.

<u>Response:</u>

A revised Figure 6-2 provided here that shows the Traditional forecast demand above the VI design day system capacity line from 2028 to 2036. This demand forecast when presented as requested is identical to the Traditional Forecast that was provided in Figure 6.3 on page 160 of the Application.

Figure 6-2 (Revised): VI Demand-Capacity Balance with Mt. Hayes Facility (Traditional Case)



41.2.1 Please state the VI system capacity deficit (Demand minus Capacity) in TJ/d for each year from 2028 to 2036.

Response:

The capacity deficit from 2028 to 2036 is shown in the table below.

VI System Capacity Deficit from 2028 to 2036 for Traditional Forecast

Year	Traditional Forecast Peak Demand (TJ/d)	Existing System Capacity (TJ/d)	System Capacity Deficit (TJ/d)
2028	221	218	3
2029	225	218	7
2030	229	218	11
2031	233	218	15
2032	238	218	19
2033	242	218	24
2034	247	218	28
2035	253	218	35
2036	258	218	40

On page 158 of the application FEI states:

> Traditionally, the capacity of the VITS is represented by allocating one third of the Mt. Hayes send out capacity to the VITS, with the balance remaining available for the rest of the FEI system.

41.3 Please explain how flexible the Mt. Hayes storage facility is in its allocation of supply between VITS and the rest of the FEI system.

<u>Response:</u>

The Mt. Hayes storage facility has flexibility to reallocate supply between the VITS and the rest of the FEI system. The need for reallocation can be reasonably foreseen in the peak demand forecast and planned for years in advance so the allocation can be considered very flexible. Current gas supply strategy allocates a certain proportion of Mt. Hayes to the rest of the FEI system, however this allocation is not firmly fixed or capped. Capability is limited only by the peak vaporization capacity and the total tank volume at Mt. Hayes. There is availability to increase the allocation from Mt. Hayes to the VITS. As Mt. Hayes is located within the VITS its send out capability could be allocated solely to the VITS on a peak day and the entire tank volume reserved for support of the VITS during the winter.

41.4 Please explain if the amount contributed to the rest of the FEI system is fixed or capped.

Response:

Please refer to the response to BCUC IR 1.41.3.

41.5 Is there availability to increase the allocation from Mt. Hayes to the VITS?

Response:

Please refer to the response to BCUC IR 1.41.3.

41.6 What is the maximum capacity that can be allocated from Mt. Hayes to VITS?

Response:

Please refer to the response to BCUC IR 1.41.3.

42.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Section 6.3.1, p. 158; pp. 162-163;

FEI 2016 Rate Design Application proceeding, Exhibit B-1-5, Section 9.8, p. 9-37;

Exhibit B-5, BCUC IR 34.7.1, p. 174; Exhibit B-7, BC Hydro IR 1.1, p. 1

BC Hydro Island Generation contract

On page 158 of Exhibit B-1, FEI states:

> Prior to installation of the Mt. Hayes LNG storage facility, the VITS was fully subscribed and relied upon a right to call back capacity from BC Hydro Island Generation during design weather events in order to serve its Core and Firm Transportation market design day (i.e. peak demand) requirements.

42.1 Does FEI still retain the right to call back capacity from BC Hydro Island Generation (IG) during design weather events?

Response:

Yes.

42.1.1 If yes, please explain if FEI expects that it will retain this right for the duration of: (i) the period spanning FEI's Action Plan; and (ii) the 20-year LTGRP planning period.

Response:

Yes. FEI expects to retain this right through the period of the action plan and throughout the 20-year LTGRP planning period.

42.1.2 If yes, please state the maximum capacity in TJ/d that FEI would be able to call back from BC Hydro IG during design weather events.

Response:

FEI has the capacity right (CR) to call-back up to the full contract demand (CD) on any day and can execute the CR on additional days in any given year until the curtailment volume (CV) is reached. The maximum CV that can be withheld from BC Hydro at the IG location is 100 TJ.

On pages 162 and 163 of Exhibit B-1, FEI discusses two options for addressing the identified capacity constraint on the VI system. FEI then notes that a key input is the renegotiation of the contract with BC Hydro IG. FEI states:

> Renegotiating the existing peaking agreement with BC Hydro in 2022 may allow curtailment of flows to IG to meet Core and Firm Transportation market requirements. Depending on the peaking agreement reached with IG, reduction of the peak day firm quantity has the potential to defer the capacity constraint within the planning horizon or move it beyond the 20-year forecast horizon altogether. The final agreement will be a key factor in determining the requirement and timing of the preferred option for capacity expansion.

In the FEI 2016 Rate Design Application proceeding, FEI proposes on page 9-37 of Exhibit B-1-5: "to create a firm rate for RS 22, VIGJV and BC Hydro IG based on a cost of service allocation from the COSA model." In response to BCUC IR 34.7.1, FEI stated:

> If BC Hydro elects not to become a RS 22 customer, BC Hydro could elect to become an RS 50 customer, if they meet the requirements of that rate schedule. BC Hydro could also elect to extend their current agreement, which would require negotiation of a rate that would need to be approved by the Commission.

42.2 Please explain and calculate the impact, if any, to the VI system capacity requirements and the identified capacity constraint for the VI system if BC Hydro IG becomes a RS 22 customer. Please include a discussion of FEI's ability for flow curtailment of BC Hydro IG's demand in this scenario.

Response:

If BC Hydro IG elects to become an RS 22 customer, FEI would need to negotiate an RS 22 tariff supplement that would require Commission approval pertaining to any special terms that may be required for this customer. FEI anticipates that for IG, BC Hydro would seek to maintain the same capacity right and curtailment volume as it currently has. Therefore FEI does not expect any impact on the capacity requirements or timing of identified capacity constraints related to the change by BC Hydro IG to RS 22.

42.3 Please explain and calculate the impact, if any, to the VI system capacity requirements and the identified capacity constraint for the VI system if BC Hydro IG becomes a RS 50 customer. Please include a discussion of FEI's ability for flow curtailment of BC Hydro IG's demand in this scenario.

Response:

If BC Hydro IG elects to become an RS 50 customer, FEI would need to establish a transportation service agreement under the terms of the RS 50 tariff. If BC Hydro required any special or non-standard terms for IG, a tariff supplement would have to be negotiated that would require Commission approval. FEI anticipates that BC Hydro would seek to maintain the same capacity right and curtailment volume as it currently has for IG. Therefore, FEI does not expect any impact to the capacity requirements or timing of identified capacity constraints related to the BC Hydro IG migrating to RS 50.

In the FEI 2016 Rate Design Application proceeding, FEI confirmed on page 1 of Exhibit B-7 that BC Hydro's existing Transportation Service Agreement (TSA) contains a renewal term provision that allows BC Hydro to extend the existing TSA up to 2042. FEI further stated:

> The current renewal provision in the BC Hydro Transportation Service Agreement effective January 1, 2008 allows for a maximum term of 35 years. If BC Hydro chooses to extend the agreement beyond April 2022, the rates applicable to the extension need to be approved by the Commission.

42.4 Please explain if FEI has the option to renegotiate terms other than the rate, should BC Hydro choose to extend the current agreement through the renewal provision.

Response:

FEI does not have the option to renegotiate terms, should BC Hydro choose to extend the current agreement through the renewal provision.

43.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Section 6.3.1, p. 164

Woodfibre LNG Limited

On page 164 of Exhibit B-1, FEI states:

> Woodfibre LNG Limited has presently indicated that it expects to require Firm Transportation service from FEI of up to 236 MMscfd on the VITS. Should a final investment decision be made, the estimated in-service date of this facility is currently projected no earlier than 2021.

43.1 Please explain the timeframe associated with building Woodfibre LNG Limited's LNG plant, beginning with the planning stages and ending with the plant being put into service. Please use timeline diagrams where appropriate.

<u>Response:</u>

The following response was provided by Woodfibre LNG Limited at FEI's request:

Broadly speaking, the following steps are required for Woodfibre LNG to make a final investment decision (FID) as to whether to build its LNG export terminal:

1. Engineering for the LNG plant – Woodfibre continues to progress the engineering for the LNG Plant.
2. First Nations– Woodfibre LNG and / or FEI continue to work with the First Nations whose traditional territories are impacted by the LNG plant and the Eagle Mountain Pipeline.
3. BC Hydro – Woodfibre LNG continues to work on the Electricity Supply Agreement (ESA) and Facilities Agreement with BC Hydro.
4. Gas Supply Agreements and LNG Offtake Agreements– Woodfibre LNG continues to work with suppliers of natural gas for natural gas supply for the LNG plant. Woodfibre LNG also continues to work with potential buyers of LNG.
5. Pipeline – Woodfibre LNG is working with FEI to increase the capacity of the pipeline that brings gas to the Woodfibre LNG site.
6. Financing – When each of the preceding steps is complete, Woodfibre LNG will enter into financing arrangements with banks for debt financing of the LNG export project. The equity required for the project is already committed by Woodfibre LNG's parent company, Pacific Oil & Gas.

Following the successful completion of each of those steps, Woodfibre LNG will make a decision to proceed with the project.

Construction of the LNG plant is expected to take 4 years. Construction of the Eagle Mountain Pipeline looping project and the BC Hydro interconnect is expected to take less than four years.

43.2 Please provide an estimate of the earliest in-service date of this facility if it is longer 2021.

Response:

Woodfibre LNG advises that it would require the Firm Transportation service from FEI to be in-service approximately four years following a positive final investment decision to coincide with commissioning of the LNG plant.

43.3 Please reproduce Figure 6-3 and Figure 6-5 to show the impact of Woodfibre LNG Limited's facility entering into service in 2021.

Response:

Based on the responses provided by Woodfibre LNG Limited to BCUC IR 1.43.2, if Woodfibre reaches FID in 2018, the earliest in-service date for the pipeline expansion would be required approximately 48 months later or mid to late 2022. As such, the revised figures below have been prepared to show a potential 2022 in-service date.

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

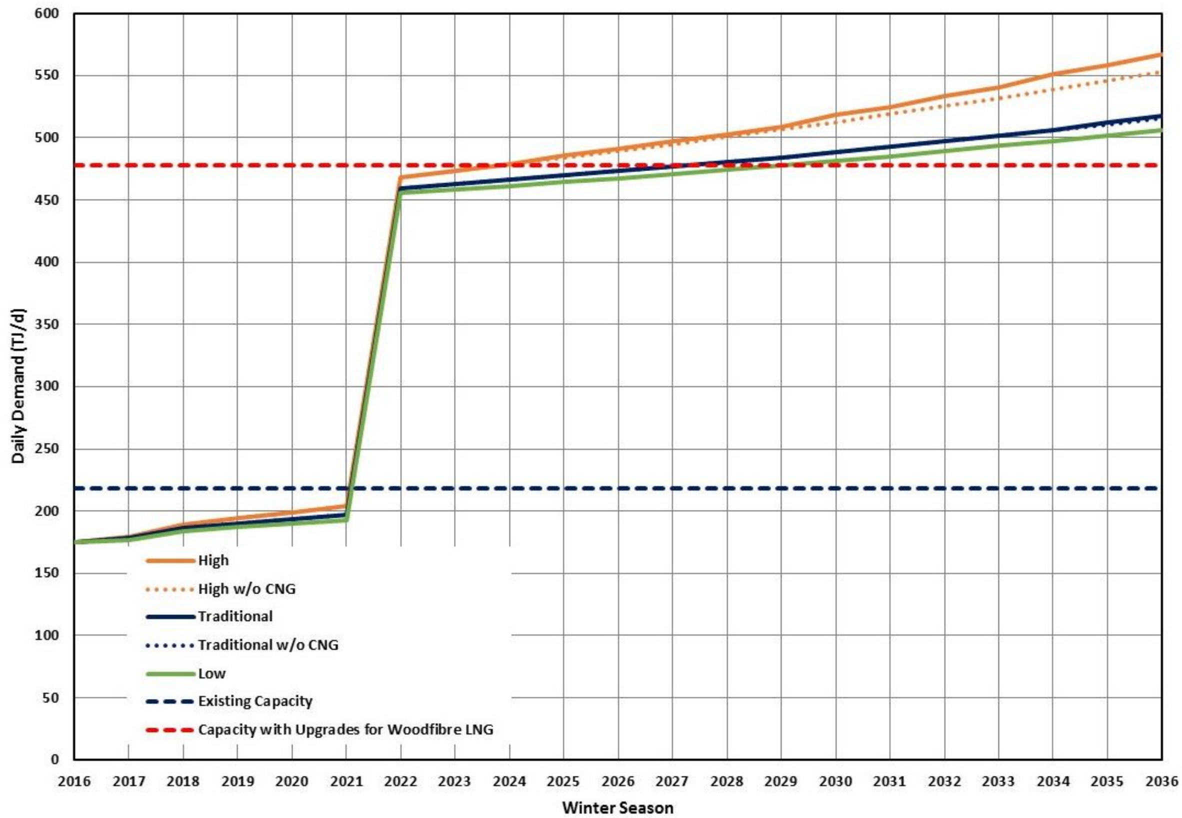
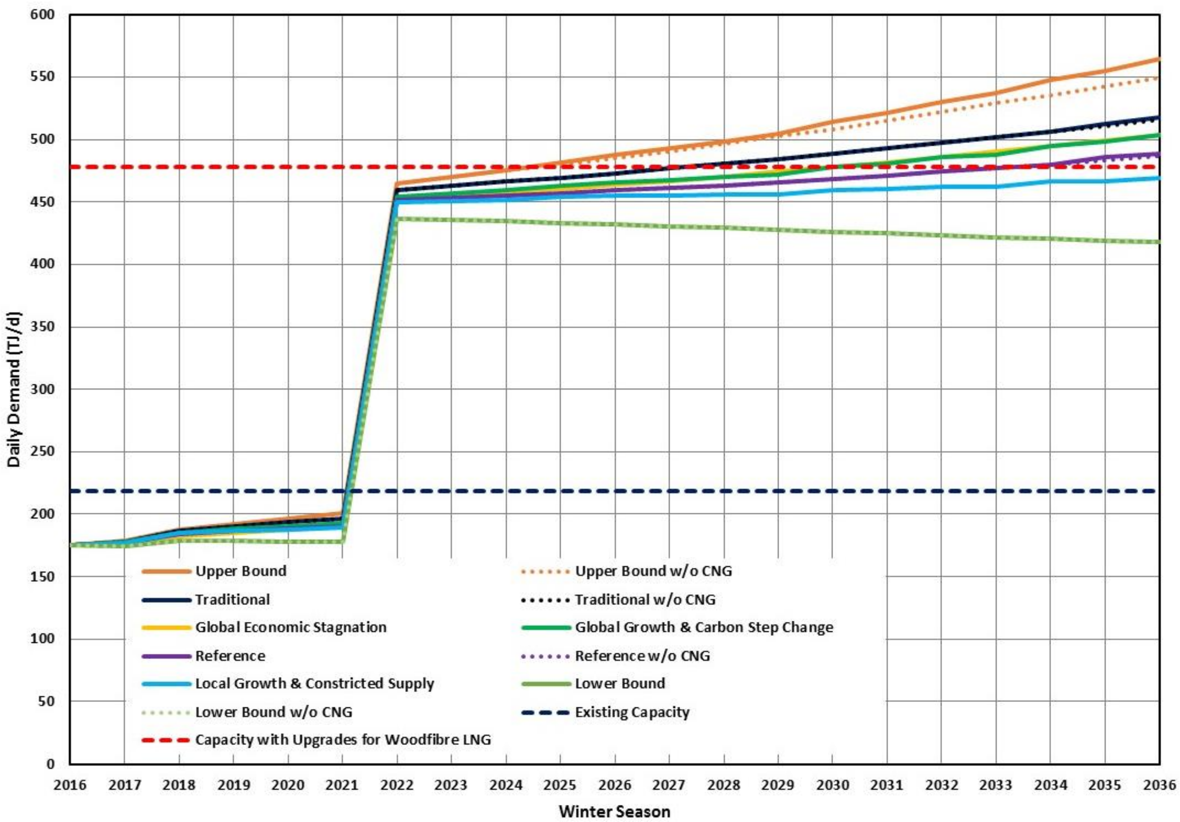


Figure 6-5 (Revised): VI Demand-Capacity Balance Using Traditional and End-Use Peak Demand Scenarios with DSM



On page 164 of Exhibit B-1, FEI states:

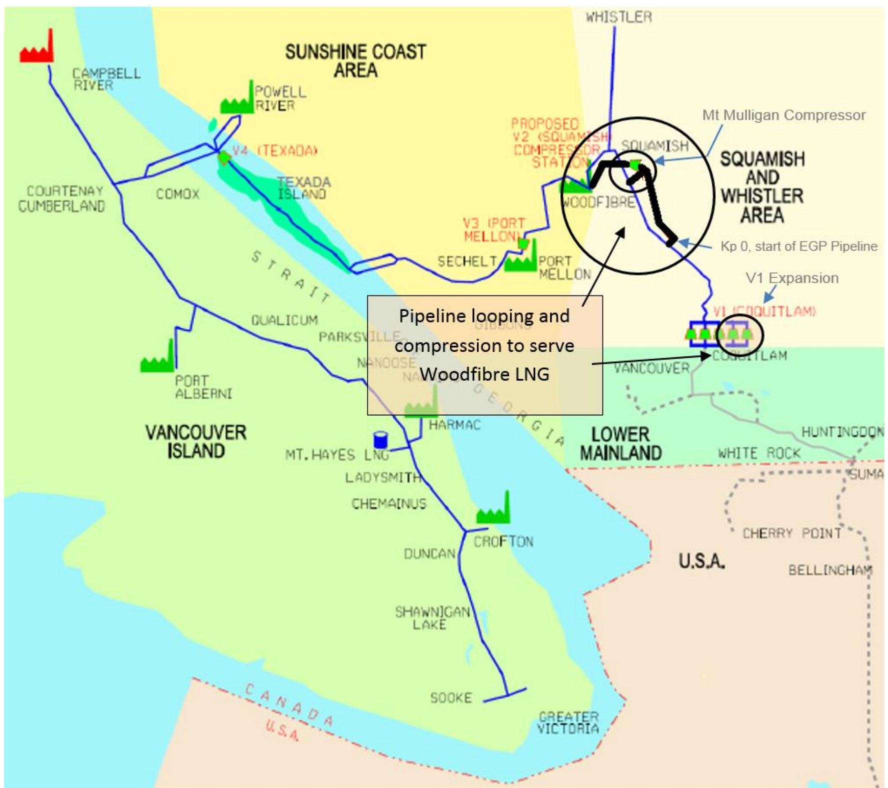
> To accommodate this load addition, there is a need to reinforce the existing VITS with pipeline looping and added compression near Squamish. This infrastructure expansion would match the Firm Transportation capacity contracted by Woodfibre LNG Limited under peak demand, preserving available capacity for existing customers, but would allow large volumes of interruptible capacity to be available for much of the year.

43.4 Please update Figure 6-1 to show where pipeline looping and added compression would be required in order to accommodate the addition of the Woodfibre LNG Limited's LNG plant.

Response:

Figure 6-1 has been updated to indicate, in the circled areas, approximately where the proposed project pipeline looping (bold black lines) and compression (V1 expansion and proposed Mt. Mulligan site) would be located on the VITS to accommodate the proposed addition of the Woodfibre LNG Plant.

Figure 6-1 (Revised)

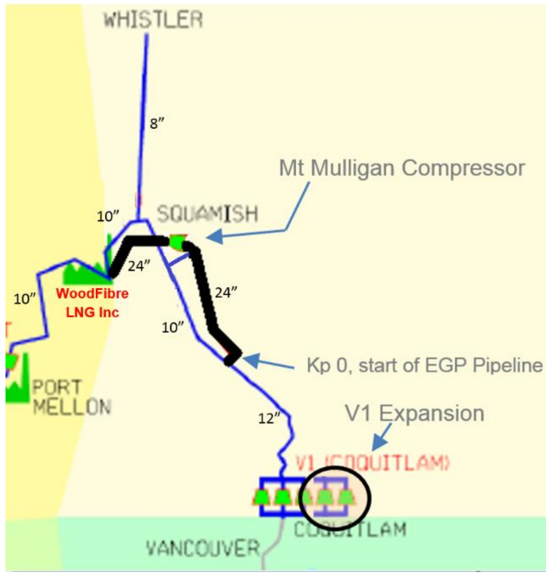


43.4.1 Please provide a schematic diagram similar in nature to Figure 6-6 which shows where the pipeline looping and added compression would be required in order to accommodate the addition of the Woodfibre LNG Limited's LNG plant.

Response:

As indicated in the preamble to this question, FEI plans to expand its VITS to meet the Woodfibre load. The location of required pipeline looping and compression additions associated with the VITS that are required to serve Woodfibre LNG are shown in the revised Figure 6-1 provided in the response to BCSEA IR 1.43.4.

Below is a schematic similar in nature to Figure 6-6 showing the pipeline looping segments and compression additions in relation to the existing system.



44.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Section 6.3.2, p. 170

Interior Transmission System Demand-Capacity Balance

Figures 6-15, 6-16 and 6-17 present the Interior Transmission System (ITS) demand-capacity balance using various peak demand forecasts. Figure 6-15 shows that the Traditional Case peak demand forecast for this region reveals a capacity constraint occurring in 2022. Figure 6-17 shows that the Traditional Case peak demand forecast for this region reveals a capacity constraint occurring in 2022 and includes end-use scenarios with DSM.

44.1 Please update Figure 6-15 to show the impact of DSM on the Traditional Case peak demand forecast.

Response:

The Traditional peak demand forecast as stated in Section 6.2.1.3 of the Application has no allowance for evolving customer utilization including the effects of DSM other than what is present inherently in the recently measured customer consumption used to create current UPC_{peak} values. The exploratory end-use peak demand method developed by Posterity does not include the analysis necessary to examine the impact of DSM directly on the Traditional peak demand forecast. As a result, FEI has not updated the Figure 6-15 with modeled results. However, the forecasts with DSM shown in Figure 6-17 provides an indication that if the Traditional Case Forecast had been included in Posterity's analysis there would be deferral of the capacity constraint predicted by the result, to some time beyond 2022.

As stated in the Application this process is theoretical and has limitations as described in the response to BCUC IR 1.29.3. While still considered theoretical by FEI the impact of DSM on forecasts where Posterity's analysis can be applied shows reductions in peak demand. This is an interesting and important possible outcome of DSM on the forecast, an outcome with a potential impact on deferring capacity constraints that will continue to be assessed in the results of future annual calculations of UPC_{peak} and forecasting for the Interior Transmission System.

44.1.1 Please provide a discussion regarding the timing of the capacity constraint on the ITS after taking into consideration the impact of DSM.

Response:

Please refer to the response to BCUC IR 1.44.1.

H. 20-YEAR VISION FOR FEI

45.0 Reference: 20-YEAR VISION FOR FEI

Exhibit B-1, Section 8.3.2, Table 8-1, p. 206

FEI's contributions to BC's Greenhouse Gas (GHG) Emissions Targets

On page 206 of Exhibit B-1, FEI states: "Table 8-1 below compares 2036 emissions reductions of FEI's initiatives with the calculated 2036 emissions reductions target. … Some forecast NGT emissions reductions are realized outside the current boundaries of the BC emissions inventory." Table 8-1 is reproduced below.

GHG Reductions Required to Meet the Calculated 2036 Target ($MtCO_2e$, 2014 Base)	Forecast Emissions Reductions in 2036 ($MtCO_2e$, 2015 Base)		
29.3	Reference Case	Upper Bound	Lower Bound
RNG	0.04	0.14	0.01
C&EM	0.8	0.8	0.3
NGT	2.3	14.9	0.2

45.1 Please provide a copy of Table 8-1 which excludes NGT emissions reductions that are realized outside the current boundaries of the BC emissions inventory.

<u>Response:</u>

Limiting the scope of GHG reductions to BC's boundaries significantly reduces the scale of GHG emissions reductions from British Columbia's natural gas transport solutions. This is because the largest potential for GHG reductions in transportation exists in the international marine sector which is not included in either of Canada's or BC's GHG emissions inventory. GHG emissions from the international marine sector are responsible for approximately 3 percent of total global GHG emissions or 1 billion tonnes of CO_2e.[20] However, the emissions associated with this sector are not accounted for in any one country's national GHG inventory. If the international marine sector was considered a country, it would be the 6th largest global emitter of GHG emissions. The vast majority of fossil fuel consumption from ships into BC ports are from international shippers on trans-pacific routes. It is estimated that the emissions associated with

[20] ICCT, (2017). Greenhouse Gas Emissions from Global Shipping, 2013-2015. Washington. https://www.theicct.org/sites/default/files/publications/Global-shipping-GHG-emissions-2013-2015_ICCT-Report_17102017_vF.pdf

international marine shipping into and out of BC ports are on the same order as BC's total domestic GHG emissions.

In the upper bound scenario, the GHG emissions *reductions* associated with the conversion and adoption of LNG-powered international marine vessels are over 20% of BC's total domestic GHG emissions. In other words, actions in the international marine sector alone would be enough to move BC one quarter of the way to achieve its 2050 emissions reductions target of 80% below 2007 levels.

The International Marine Organization announced that it was, for the first time, adopting GHG emissions targets consistent with the goals of the Paris Agreement. The IMO aims to reduce carbon emissions by 50 percent compared with 2008 levels by 2050. Based on analysis from the International Energy Agency (which informed the IMO's target-making) low carbon fuels including LNG make up the second-largest GHG emission reducing action needed to achieve this target.

The table below excludes NGT emissions reductions that are realized outside the boundaries of the BC emissions inventory by excluding international marine shipping emissions, specifically this excludes emissions estimated from the coastal freight and trans-pacific marine market segments. The emissions from both of these market segments are not captured in BC's emissions inventory. However, marine vessels bunkered with LNG from BC represents a sizeable opportunity to reduce net global GHG emissions. BC's LNG sector has a number of factors that make it very low emissions intensity compared to other jurisdictions, including its colder climate, low formation CO2 gas in the Montney gas basin, and a clean power grid powering electrified LNG plants such as at FEI's Tilbury LNG facility.

GHG Reductions Required to Meet the Calculated 2036 Target ($MtCO_2e$, 2014 Base)	Forecast Emissions Reductions in 2036 ($MtCO_2e$, 2015 Base)		
29.3	**Reference Case**	**Upper Bound**	**Lower Bound**
RNG	0.04	0.14	0.01
C&EM	0.8	0.8	0.3
NGT	0.3	0.5	0.1

46.0 Reference: 20-YEAR VISION FOR FEI

Exhibit B-1, Section 8.3.1, Figure 8-4, p. 201

Application for Acceptance of the 2014 Long Term Resource Plan Decision,

Order G-189-14, Section 4.3, p. 27

GHG emission reductions

The FEU 2014 LTRP Decision on page 27 states:

> The Panel therefore directs the FEU to include, in its next LTRP, the following information: … Analysis of each DSM scenario, at a portfolio level and for each DSM category (residential, low income, commercial etc.), including: … Estimated gas (GJ) and GHG emission reductions.

46.1 Please explain why in Figure 8-4 the curve for the Lower Bound scenario trends upwards in the later years of the planning horizon.

<u>Response:</u>

FEI consulted with Posterity to provide the following response.

The curve for the Lower Bound scenario trends upwards because this scenario experiences an erosion in the amount of C&EM savings towards the end of the forecast horizon. GHG reductions from C&EM follow the trend in the natural gas savings. The Lower Bound scenario includes a significant shift away from natural gas consumption and towards other fuel types. This shift is due to this scenario's critical uncertainty outcomes and is built into the scenario before the application of C&EM.

The 2017 LTGRP C&EM analysis multiplies C&EM measure energy savings by measure participation to calculate percent savings for the measure per year. The analysis then multiplies this percentage by the applicable scenario natural gas consumption per year to calculate the total energy savings estimate per year. If the applicable scenario's natural gas consumption declines significantly, total C&EM energy savings will begin to shrink even if the savings percentage per C&EM measure continues rising.

As a practical example, if building envelope improvements are incentivized in a gas-heated home early in the forecast horizon, under the Lower Bound scenario that home may later switch to an electric heat pump when the furnace reaches its end of life. The initial gas savings from the early C&EM activity in that house would then disappear from the C&EM savings for the years after the conversion from gas to electricity.

46.2 Please provide analysis in table format of the estimated GHG emission reductions for each C&EM scenario by residential, commercial and industrial program area, for each year of the planning horizon covered by the 2017 LTGRP.

Response:

Please see the three tables below for analysis of the estimated GHG emission reductions for each C&EM scenario for each year of the 2017 LTGRP planning horizon for the residential, commercial and industrial rate schedules, respectively.

The C&EM emissions reductions are consistent with the C&EM energy savings described in Section 4.2.3.1 of the Application as C&EM GHG reductions follow the trend in natural gas savings. As noted in Section 4.2.3.2 of the Application, the 2017 LTGRP C&EM analysis does not include data for 2015 and 2016 since these years are in the past and FEI filed annual reports on this historical C&EM activity with the BCUC already. Each group of rate schedules impacts GHG emissions in a similar order of magnitude and with a similar curve of energy savings in the Lower Bound scenario as discussed in FEI's response to BCUC IR1.46.1. For the commercial rate schedules, Reference Case GHG impacts outpace Upper Bound GHG impacts by the end of the 2017 LTGRP planning horizon. As noted in Section 4.2.3.1 of the Application, this appears to be due to low natural gas and carbon price costs in the Upper Bound scenario depressing the avoided cost of gas in this scenario and thus rendering commercial energy efficiency measures uneconomic. This effect appears to outweigh the Upper Bound having more technical energy savings opportunities than the Reference Case (by virtue of having more natural gas consumption than the Reference Case).

Table 1: Annual GHG Emissions Impact of Estimated C&EM Energy Savings Only (metric tonnes) – Residential Sector

Year	Reference Case	Upper Bound	Lower Bound
2015	0	0	0
2016	0	0	0
2017	-20,066	-20,287	-19,714
2018	-38,920	-39,357	-36,449
2019	-55,809	-56,620	-52,740
2020	-71,701	-73,037	-68,952
2021	-90,074	-91,732	-82,620
2022	-107,915	-110,739	-98,563
2023	-125,930	-129,824	-111,758
2024	-146,266	-148,318	-123,973

Year	Reference Case	Upper Bound	Lower Bound
2025	-163,606	-169,498	-135,439
2026	-180,672	-187,925	-145,883
2027	-197,430	-206,113	-155,459
2028	-214,017	-224,217	-164,438
2029	-230,833	-242,757	-172,522
2030	-248,363	-262,315	-179,957
2031	-262,555	-278,381	-183,209
2032	-268,860	-286,307	-180,331
2033	-273,312	-292,440	-174,572
2034	-277,461	-298,235	-167,560
2035	-281,672	-304,188	-159,453
2036	-285,823	-310,143	-151,625

Table 2: Annual GHG Emissions Impact of Estimated C&EM Energy Savings Only (metric tonnes) – Commercial Sector

Year	Reference Case	Upper Bound	Lower Bound
2015	0	0	0
2016	0	0	0
2017	-27,220	-27,877	-26,736
2018	-45,095	-47,131	-45,575
2019	-63,426	-65,701	-60,498
2020	-80,666	-82,716	-74,510
2021	-101,972	-97,068	-93,367
2022	-122,212	-110,988	-105,860
2023	-142,154	-125,177	-116,833
2024	-159,052	-139,375	-122,018
2025	-175,145	-152,724	-126,344
2026	-190,138	-166,571	-129,507
2027	-204,926	-180,200	-132,778
2028	-219,280	-193,552	-133,699
2029	-232,745	-206,912	-133,904
2030	-246,594	-220,429	-132,754
2031	-259,426	-233,264	-130,560
2032	-271,901	-246,330	-127,254
2033	-284,181	-258,855	-122,924
2034	-296,263	-271,745	-117,917

Year	Reference Case	Upper Bound	Lower Bound
2035	-308,036	-283,878	-113,233
2036	-319,442	-296,902	-109,365

1 **Table 3: Annual GHG Emissions Impact of Estimated C&EM Energy Savings Only (metric tonnes)**
2 **– Industrial Sector**

Year	Reference Case	Upper Bound	Lower Bound
2015	0	0	0
2016	0	0	0
2017	-18,122	-16,012	-18,737
2018	-32,685	-29,199	-32,478
2019	-42,929	-37,823	-41,578
2020	-54,967	-50,093	-51,496
2021	-66,009	-59,664	-61,640
2022	-77,000	-68,527	-69,721
2023	-90,134	-76,503	-77,453
2024	-100,921	-84,529	-80,557
2025	-111,631	-94,496	-86,696
2026	-122,247	-104,516	-90,379
2027	-132,736	-114,540	-91,744
2028	-143,097	-150,188	-95,522
2029	-153,341	-159,204	-98,106
2030	-163,405	-169,678	-99,509
2031	-173,259	-179,858	-96,874
2032	-182,855	-188,554	-93,038
2033	-192,159	-210,517	-91,116
2034	-201,125	-220,490	-86,630
2035	-209,706	-230,115	-80,952
2036	-217,707	-238,486	-67,531

3
4

5 46.2.1 Please provide a brief explanation of the results.
6

7 **Response:**

8 Please refer to the response to BCUC IR1.46.2.

Attachment 35.2.1

A. PRICE RISK MANAGEMENT OBJECTIVES

1.0 Reference: PRICE RISK MANAGEMENT OBJECTIVES

Exhibit B-1-2, p. 4; FEI 2015 Price Risk Management (PRM) Application, Exhibit B-1, p. 1; FEI 2015 PRM Order E-10-16, Letter L-15-16 and Decision dated June 17, 2016 (FEI 2015 PRM Decision), p. 9

Price risk management plan objective

FortisBC Energy Inc. (FEI) states on page 4 of its 2018 Price Risk Management Plan Application (Revised Application) that:

> FEI's objectives for its price risk management, which includes hedging, include the following:
>
> - Mitigate market price volatility to support rate stability [objective 1], and
> - Capture opportunities to maintain commodity rates at historically low levels [objective 2].

FEI stated on page 1 of its 2015 Price Risk Management (PRM) Application that:

> FEI believes that the workshop process has helped to re-affirm its price risk management objectives which include the following:
>
> - Mitigate market price volatility to support rate stability; and
> - Capture opportunities to provide customers with more affordable rates [2015 objective 2].

FEI stated on page 9 of the FEI 2015 PRM Decision that "the Panel is not persuaded that the objective of capturing opportunities to provide customers with more affordable rates has application beyond the current market-pricing environment."

1.1 Please explain 1) why and 2) how objective 2 contained in the Revised Application has been modified from those contained in the 2015 PRM Application.

Response:

FEI has revised objective 2 to make it more specific and relevant to the current low market price environment rather than the affordability in rates. The affordability in rates can be somewhat subjective and difficult to measure as it will vary among different customers. Maintaining commodity rates at historically low levels is less subjective and easier to define since information regarding historical commodity rates is available and observable and can be used for comparison or as part of benchmarking in a hedging strategy.

1.2 Please provide FEI's view on the difference in interpretation between objective 2 in the Revised Application and objective 2 in the 2015 PRM Application.

Response:

Please refer to the response to BCUC IR 1.1.1.

1.3 In the Revised Application, would it be fair to say that FEI is ultimately striving for two objectives: (i) rate stability and (ii) low commodity rates? If not confirmed, please elaborate.

Response:

In the 2018 PRMP, FEI is striving to mitigate price volatility to support rate stability and capture opportunities to maintain commodity rates at historically low levels. As discussed in Section 4 of the 2018 PRMP, there are other programs or activities (e.g. physical gas contracting strategies, rate setting mechanisms, Customer Choice Program or Equal Payment Plan) which take different actions to increase rate or bill stability or achieve low commodity rates.

1.3.1 Please confirm that (a) mitigating market price volatility and (b) capturing opportunities are actionable items to achieve the two objectives, and that FEI could take other actions to achieve those objectives. If not confirmed, please explain otherwise.

Response:

Mitigating market price volatility and capturing opportunities are actions that support rate stability and lower commodity rates in a way that other actions or tools cannot replicate.

As summarized in Section 4.6 of the 2018 PRMP, FEI can and does take other actions by using other tools to increase rate stability and support low commodity rates. These other tools include physical supply contracting strategies, rate setting mechanisms and deferral accounts.

However, these other tools are not as effective as hedging in meeting these objectives. Hedging, unlike the other tools, locks in forward market prices which affects the underlying market prices and their impacts on FEI's gas costs, which ultimately flow through to customers in commodity rates. The use of deferral accounts, for example, while effective in reducing some short-term rate volatility, merely shift gas costs to other periods where they will ultimately need to be recovered or refunded from customers through rate changes.

1.3.2 Please clarify whether FEI's objectives are to achieve low and stable overall rates or commodity rate (e.g. cost of gas) only.

Response:

One of FEI's price risk management objectives is to maintain commodity rates at historically low levels. However, given that commodity rates can be a significant portion and typically the most variable component of the overall rates, achieving this objective for the commodity rate will also help with achieving it for overall customer rates.

1.4 Please clarify whether FEI's two PRM objectives in the 2018 PRM must be considered jointly, have certain priority sequence, or should be considered in isolation (i.e. achieving one of the two is sufficient).

Response:

FEI considers both objectives equally important with neither one having priority over the other. FEI's customer research (provided in Appendix A of the 2018 PRMP) and discussions with stakeholders (described in Section 6 of the 2018 PRMP) indicate that both of the objectives are important to customers. FEI notes that achieving the objective of capturing opportunities to maintain commodity rates at historically low levels can also help with the objective of supporting rate stability. However, achieving the objective of supporting rate stability does not necessarily achieve the objective of capturing opportunities to maintain low rates. FEI discusses in the 2018 PRMP (page 5) that market price conditions could change in the future and FEI may no longer have the opportunity to capture opportunities to maintain low commodity rates for customers. Therefore, FEI notes that this objective is applicable in the current low market price environment. As FEI discusses on page 4 of the 2018 PRMP, the objective related to mitigating market price volatility is applicable in both high and the current low gas price environment as there can be market price volatility in either.

2.0 Reference: PRICE RISK MANAGEMENT OBJECTIVES

Exhibit B-1-2, p. 4; FEI 2017 Long Term Gas Resource Plan (LTGRP), Exhibit B-1 pp. 142–143; FEI and FortisBC Energy (Vancouver Island) Inc. 2011-2014 Price Risk Management Plan, Order G-120-11 and Reasons for Decision, dated July 12, 2011, Appendix A, pp. 20–21

Consistency with the FortisBC Energy Inc. 2017 Long Term Gas Resource Plan

FEI states on page 4 of its Revised Application:

> FEI's objectives for its price risk management, which includes hedging, include the following: Mitigate market price volatility to support rate stability [objective 1], and Capture opportunities to maintain commodity rates at historically low levels [objective 2].

FEI states on page 142 of its 2017 LTGRP Application that "FEI has developed diversified procurement strategies and utilized PRMPs to manage commodity price risk and <u>facilitate competitive and affordable natural gas rates"</u> [emphasis added]. FEI further states on page 143 of its LTGRP that "FEI's price risk management objectives include mitigating market price volatility to support rate stability and capturing favourable prices to provide customers with <u>more affordable rates</u>" [emphasis added].

On page 21 of Appendix A to Order G-120-11 it was stated that:

> The Commission Panel finds that the need for an objective related to the competitiveness of natural gas with other energy sources has not been established" It further states on page 21 that "Considering only the commodity price and ignoring the potential for responding to competitive threats more broadly is in our view an inadequate response.

2.1 Please reconcile the PRMP objectives stated in the Revised Application with those stated in the FEI 2017 LTGRP Application. In particular, please explain whether "affordable and competitive rates" as stated in the LTGRP is one of the objectives of PRMP.

<u>Response:</u>

Please refer to the response to BCUC IR 1.1.1 regarding FEI's update to its objective regarding achieving more affordable rates. As stated in the 2018 PRMP, FEI's price risk management objectives do not explicitly include achieving affordable and competitive rates. However, achieving the objective of capturing opportunities to maintain low commodity rates may, at the same time, help provide some customers with more affordable rates than in the past and help with the competitiveness of natural gas compared to other energy sources.

2.2 Please explain whether the PRMP objectives stated in the Revised Application in effect “facilitate competitive and affordable natural gas rates.”

Response:

Please refer to the response to BCUC IR 1.2.1.

2.2.1 If yes, please comment on how FEI has considered the findings contained in Order G-120-11 in reaching the objectives proposed in the Revised Application.

Response:

Please refer to the response to BCUC IR 1.2.1.