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December 22, 2022

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

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: FortisBC Energy Inc. (FEI)

2022 Long Term Gas Resource Plan (LTGRP) – Project No. 1599324

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

On May 9, 2022, FEI filed the LTRP referenced above. In accordance with the amended regulatory timetable established in British Columbia Utilities Commission Order G-287-22 for the review of the LTGRP, FEI respectfully submits the attached response to CEC IR No. 1.

In its responses, FEI has identified responses which were provided by, contributed to, or developed with its consultants, the Posterity Group and Guidehouse.

For convenience and efficiency, if FEI has provided an internet address for referenced reports instead of attaching the documents to its IR responses, FEI intends for the referenced documents to form part of its IR responses and the evidentiary record in this proceeding.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

EXECUTIVE SUMMARY

1. Reference: Exhibit B-1, Page ES-3

> ***2. PLANNING ENVIRONMENT***
>
> This LTGRP involves forecasting and planning to 2042, during a time of rapid change and uncertainty in market forces, energy technologies and government policy, and at the early stages of FEI's journey to a low-carbon energy future. British Columbians, represented by all levels of

1.1 Please explain the present state of incorporation of low-carbon supply in FEI's system, and a brief description of its evolution from the start of FEI's journey on this path.

<u>Response:</u>

Please refer to the Response to BCUC IR 52.5.

1.2 Please confirm the present supply of low-carbon gas in FEI's system, as percentage of average daily total system supply; the type(s) of low-carbon gas that are offered; and to which customer groups.

<u>Response:</u>

Currently, FEI is only purchasing RNG, or gas derived from the decomposition of organic waste. In 2021 FEI purchased approximately 0.7 PJ of RNG, which is less than one percent of FEI's 2021 total gas throughput of 227.5 PJ. Currently, RNG is available to all FEI customers except for those in Revelstoke and Fort Nelson.

1.3 What is FEI's present footprint of its low-carbon gas supply in the various BC and non-BC regions? Are there any regional variations to FEI's ability to supply low-carbon gas to the credit of the FEI gas delivery system?

<u>Response:</u>

The present footprint of FEI's renewable and low-carbon gas supply is spread across BC, Canada, and the United States, as RNG is currently being delivered from six operational projects within BC as well as six operational projects outside of BC. There are no regional variations to FEI's ability to acquire and own the environmental attributes of this low-carbon gas supply.

1.4 Does the present supply of low-carbon energy in FEI's system, contribute to meeting seasonal or peak system demands or deter FEI's ability to meet its peak demand requirements? Please explain.

Response:

Presently, FEI's supply of low-carbon energy only provides contributions to annual demand on a planning basis. These resources do not currently contribute to FEI's planned peak demand and seasonal requirements, as illustrated in Table 6-2 of the Application, nor are they included in quantifying system capacity to support peak demand. This is because physical delivery of these resources directly into FEI's system is currently not material enough for FEI to rely upon for peak demand requirements. This will change as FEI transitions more of its conventional gas supply to renewable and low-carbon gas. The transition to renewable and low-carbon energy will not deter FEI's ability to meet peak demand requirements because FEI will make any changes as required through the Annual Contracting Plan.

2. References: Exhibit B-1, Page ES-4 (Lines 13-16) and Page ES-2, Table ES-1

> The competitive environment for FEI's products has grown more complex as a multitude of pricing and non-price considerations are influencing customer energy choices. Capital costs, installation requirements, operating and maintenance costs, government policies and public perception all play a role in this regard.

Table ES-1: FEI Service Statistics

	2016	2021	Percentage Increase Since 2017 LTGRP
Number of Customers	994,004	1,064,800	7.1%
Annual Demand (PJ)[1]	197	228	15.7%
Peak Day Demand (TJ/day)[2]	1,334	1,399	4.9%
Length of Transmission Pipeline (km)	2,959	2,970	0.4%
Length of Distribution Pipeline* (km)	45,741	47,523	3.9%

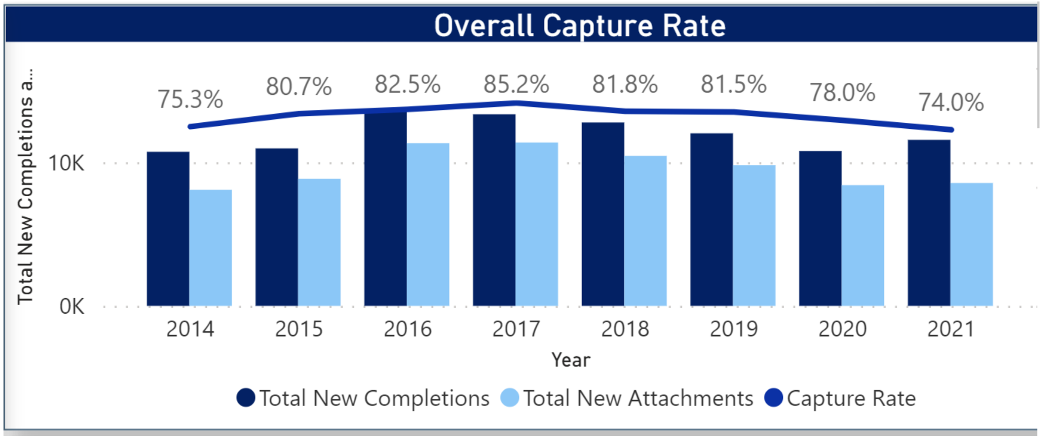
** Includes both distribution and intermediate pressure pipelines.*

2.1 On lines 13 & 14 referenced above, FEI states 'the competitive environment for FEI's products has grown more complex as a multitude of pricing and non-price considerations are influencing customer energy choices'. Yet, from Table ES-1 above, it is evident that from 2016 to 2021 FEI's number of customers increased by 7.1%, and its annual demand (PJ) increased by 15.7%. Please reconcile the above-mentioned statement with the growth story illustrated in Table ES-1, in terms of how the growing complexity has impacted FEI's ability to grow its system service delivery.

<u>Response:</u>

FEI's growth from 2016 to 2022 is due to a number of factors, including customer satisfaction, growth of BC's population and economy, favourable commodity prices, among other factors.

The trend, however, is slowing and there is market activity and fundamental changes to the operating and political environment that are creating more uncertainty regarding FEI's customer growth going forward. Notably, the increase in the number of customers (net customers) since 2016 masks a decline in the market share (capture rate) of new residential (gross customer additions) construction as shown the graph below.



Housing construction has remained strong, but due to climate related policy actions by governments, FEI's share of the new residential construction market is declining and expected to decline further in the near term. Further, these policy actions will also impact existing customers potentially resulting in a further slowing of net customer growth.

The following discussion provides a high-level overview of some of the key uncertainties facing FEI's future outlook which illustrate the growing complexity of FEI's competitive environment.

Energy and Climate Policy Developments

The urgency for climate action has resulted in environmental regulation, plans and policies from all three levels of government (i.e., federal, provincial and municipal) to promote decarbonization. The majority of policies have been implemented from 2016 onwards, representing considerable change since the submission of the 2017 LTGRP. The Canadian Net-Zero Emissions Accountability Act (CNZEAA) was passed in 2021 with a large focus on green building strategies. The CleanBC Roadmap to 2030 represents BC's commitment to achieve a GHG reduction target of 40 per cent below 2007 levels by 2030, including a GHG cap for natural gas utilities (GHGRS). This sets the course for BC to reach ambitious net-zero by 2050 targets. Local governments are applying increasingly stringent regulations on buildings. Critical consultation with Indigenous groups on potential projects may result in longer lead times for development and collaboration in clean energy projects. Although FEI recognizes the urgent call to action for decarbonization, together, these GHG mitigation regulations, will have a significant impact on FEI's customer rates, competitiveness (ability to attach new customers and keep existing customers) and ultimately throughput.

Energy Pricing and Customer Rate Impact Considerations

Energy price forecasts for natural gas, renewable and low-carbon gas, electricity, and carbon taxes influence FEI's competitive positioning. Market uncertainties, such as socio-political and environmental risks, will influence North American and world energy prices. The costs for renewable and low-carbon gas are expected to go down over time and will be influenced by technological improvements that will positively impact production volumes and associated benefits resulting from economies of scale. The share of carbon tax as a proportion of FEI's total effective rate is 16 percent in 2022. Once the federally-announced carbon tax increase to $170 per tonne is in place in 2030, the carbon tax rate will have increased by more than 5.5 times, to the equivalent of $8.40 per GJ, since 2015. FEI expects the price differential between natural gas and electricity to continue to decline in the coming years. However, electricity rates may also rise due to the need for more transmission, distribution, and substation infrastructure to meet increases in electricity peak demand.

Non-Price Considerations

Consumer, builder and developer, commercial and industrial end user energy preferences influence the use of gas versus electricity and the choice among alternative energy solutions. Customer preferences, GHG emission concerns, capital costs, incentives and equipment availability for upgrades are but a few of the factors influencing customer energy choice and, ultimately, FEI's competitive position.

Summary

In summary, the competitive environment for FEI's products has grown more complex as a multitude of pricing and non-price considerations are influencing customer energy choices. Decarbonizing FEI's gas supply in response to climate policy will result in higher rates for FEI customers, reducing FEI's price competitiveness when compared to other energy alternatives. Unfortunately, if municipal and provincial policy does not change it may be difficult to attach new customers and keep existing customers despite a low-carbon offering. However, action is necessary to meet the GHG emission targets set out in the CleanBC Roadmap and to respond with urgency to address climate change, just as electrification will also result in increased costs for ratepayers and taxpayers.

2.2 To what does FEI attribute the differential between the growth rate in annual demand (15.7%) and the growth rate in the number of customers (7.1%) between 2016 and 2021? Please explain the contributing factors.

Response:

The annual demand reflected in row 2 of Table ES-1 is actual consumption and is therefore impacted by weather. 2021 was colder[1] than 2016, which resulted in increased energy consumption. Once weather-normalized data is used for residential and commercial customers, the increase in 2021 demand relative to 2016 is only 7.2 percent, which closely matches the increase in the number of customers over the same period.

[1] The annual heating degree day (HDD) total for 2016 was 2,532 compared to 2,870 in 2021. A higher number of HDDs indicates colder weather.

2.3 Which region(s) contributed to or drove the 3.9% growth in the distribution pipeline segment (as among the VITS, CTS, and ITS)?

Response:

Over this period, about 37 percent of the growth in distribution pipelines occurred in the Vancouver Island region served by the VITS, about 28 percent occurred in the Southern Region largely served by the ITS and some transmission pipeline laterals supplied by TC Energy Inc., 28 percent occurred in the Lower Mainland and Fraser Valley served by the CTS, and about 7 percent occurred in the Northern Region downstream of transmission pipeline laterals supplied by Enbridge.

3. Reference: Exhibit B-1, Page ES-5

> a larger share of the fuel mix. In parallel, electricity rates associated with electrification may also rise due to the need for more transmission, distribution, and substation infrastructure required to meet increases in electricity peak demand. However, decarbonization is necessary to meet the GHG emission targets set out in the Roadmap and to respond with urgency to climate change. The 2022 LTGRP demonstrates how the Clean Growth Pathway has the advantage of leveraging the resilience and reliability of the provincial energy system as a whole, achieving GHG reductions aligned with the provincial government's objectives, and being a more affordable and practical pathway for BC than relying on electrification alone.

3.1 When FEI speaks of building system resilience in its 2022 LTGRP, does FEI refer to building the resilience of its own system or the resilience of both its system and the BC Hydro system?

<u>Response:</u>

In the Application, FEI speaks about both building resiliency on its own system (see Appendix E, for example) and the need to consider the resilience of the BC's energy system as a whole, taking into consideration the need to optimize both the gas and electric systems. The excerpt cited in the preamble, however, is intended to discuss the resiliency of BC's energy system as a whole. In this context, resiliency is best achieved through a diversified approach to long-term resource planning in the interest of providing safe, reliable and affordable energy. Reliable and resilient energy delivery is especially critical on the coldest days of the year when British Columbians are most reliant on a secure energy supply to heat their homes and businesses as well as during severe weather events that can impact energy infrastructure for extended periods of time. The value of resilience should not be overlooked or jeopardized in an electrification-centric policy environment in which a simplistic approach to decarbonization could cause unintended consequences such as increased outages to customers and the associated societal impacts.

Technological advances in renewable and low-carbon gas will make decarbonization a reality, and long-term planning can recognize the importance of both gas and electric infrastructure as critical components in providing a strong future energy system for British Columbia. In the Application, Section 3.2.2.3 further discusses BC energy system resiliency as a benefit in the Clean Growth Pathway and FEI's Gas System Resiliency Plan is provided in Appendix E.

3.2 At what system level does FEI define resilience, and how does it propose to measure it in the context of the 20-year horizon of its 2022 LTGRP efforts?

Response:

FEI interprets the question as referring to measuring the resilience of FEI's own systems over the 20-year planning horizon. FEI's portfolio approach to resiliency is discussed in detail in Sections 6, 7 and FEI's Gas System Resiliency Plan (Appendix E) of the Application. FEI implicitly considers resilience at all levels of the system. For new projects, FEI integrates an assessment of the incremental cost of alternative solutions against the incremental project benefits for resilience. Though this may be one of many considerations for the project, it embeds the consideration of resilience within the project planning activities.

FEI measures resilience based on its ability to provide reliable service, by maintaining the integrity of its assets, and ensuring the adequacy and security of gas supply. Gas system resilience depends on a combination of pipeline diversity, ample storage, and the ability to manage load. Establishing system resilience enables the gas transmission and distribution systems to effectively respond to system disruptions and avoid or minimize impacts of those disruptions. FEI applies and leverages two of the three key elements, storage and pipeline diversity, in both the transmission and distribution systems to build infrastructure that along with the third element, load management support, provide end-to-end resilience while connecting FEI consumers with the region's gas supplies.

3.3 The term 'resilience' as featured in the above reference, has resurfaced as a significant consideration for long-term system planning efforts of energy utilities in BC. The above reference also points at 'the resilience and reliability of the provincial energy system as a whole'. As it concerns FEI's resiliency objectives, do considerations of other provincial energy systems (in addition to its own) drive its long-term planning evaluations and planning determinations?

Response:

FEI confirms that its resiliency objectives do include other provincial energy systems (in addition to its own) as considerations during long-term planning. The Clean Growth Pathway is a "Diversified Pathway", as it envisions a mix of expanded electrification and renewable and low-carbon gas, with a prominent role for FEI's infrastructure to achieve decarbonization objectives. To reach long-term emissions reductions, the decarbonization potential of both the gas and electric energy systems must work in parallel to support provincial GHG emission reductions, as well as the affordability, reliability, resiliency, and economic development advantages in pursuing a diversified approach to decarbonization.

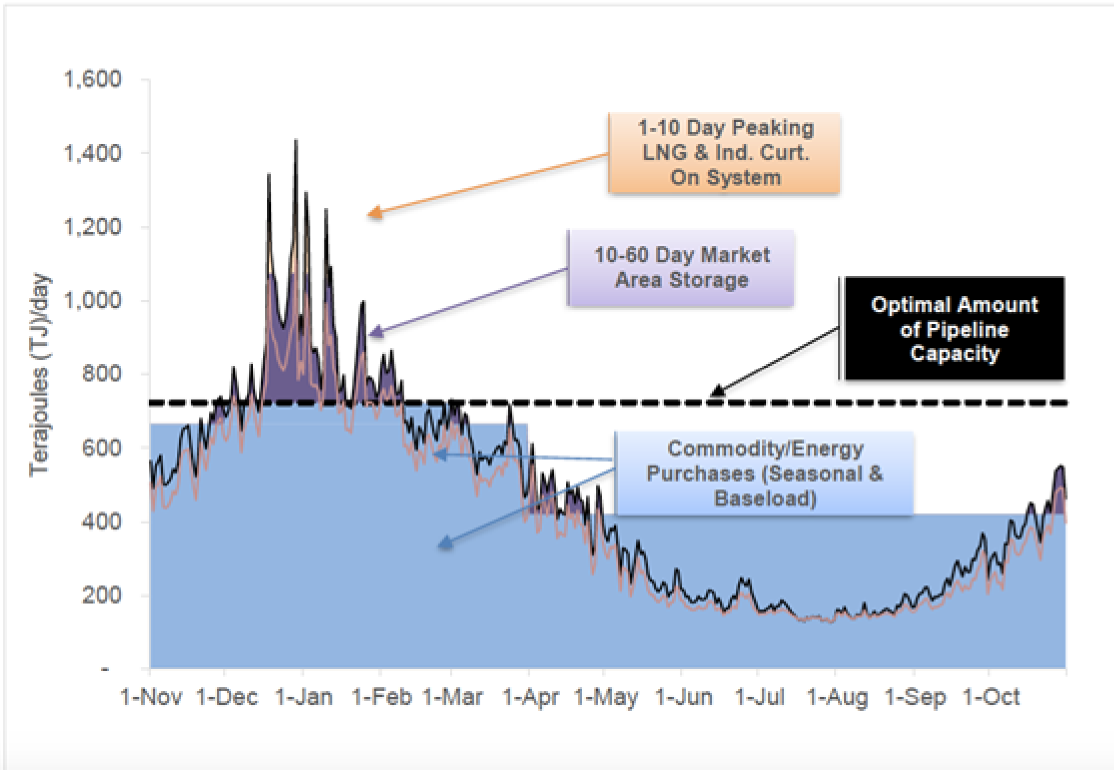
3.4 Where it concerns customer service, particularly for commercial, industrial and remote customers, would a closer integration of electricity and gas systems typically lead to increased (or decreased) resiliency of systems and/or solutions? Please explain why with quantification where possible.

Response:

FEI considers that customer service for commercial, industrial and remote customers could benefit from a closer integration of electricity and gas systems leading to increased resiliency of systems and/or solutions. The increasing volume of extreme weather events witnessed in recent years leads FEI to conclude that the use of the gas system, combined with increasing integration of energy systems closer to and at the end-use location, will be critical for decarbonizing BC's economy. Decarbonization initiatives must ensure continued access to reliable, resilient, and cost-effective energy service to FEI customers, and to the benefit of non-customers who rely on the services and products delivered by FEI customers. Therefore, the integration of electricity and gas systems, resulting in increased resiliency for BC's energy system as a whole, will benefit all British Columbians.

4. Reference: Exhibit B-1, Page ES-10, Figure ES-6

Figure ES-6: 2021/2022 FEI Forecast Design and Normal Loads vs. Resources[10]



4.1 Please discuss how the use of Peaking LNG vs. Industrial Curtailment vs. Area Storage on the FEI system has evolved over the last decade for optimal system design.

<u>Response:</u>

FEI notes that Figure ES-6 is an illustration of the resources that were planned to be used in the 2021/22 gas year and how their duration fits the forecast annual design and normal load for Core customers. The gas supply requirements for the remaining portion of the total system are the responsibility of customers who elected to take service under FEI's Transportation Service Model.

The amount of peaking LNG, industrial curtailment, and market area storage designed to meet the "planned" peak demand requirements of FEI's Core customers has not materially changed over the past decade, as illustrated in the table below. The actual utilization of these resources will change year over year, depending on the winter weather conditions.

Planned Supply Portfolio Compared to Peak Day Demand (2012/13 to 2022/23)

Peak Day Portfolio	2012/13 (TJ/day)	2014/15 (TJ/day)	2016/17 (TJ/day)	2018/19 (TJ/day)	2020/21 (TJ/day)	2022/23 (TJ/day)
Fort Nelson Supply	5	5	5	5	5	5
Baseload Supply	331	345	331	374	416	417
Seasonal Supply	132	115	175	151	134	127
Seasonal Storage	195	197	195	197	201	201
Spot Supply	105	91	46	49	109	128
Market Area Storage	213	215	211	211	211	211
Peaking LNG (Mt.Hayes & Tilbury)	326	326	326	326	326	326
Industrial Curtailment	26	28	28	28	29	26
Total Resources (TJ/day)	**1,333**	**1,322**	**1,317**	**1,341**	**1,431**	**1,441**
Peak Day Demand (TJ/day)	**1,333**	**1,322**	**1,317**	**1,341**	**1,431**	**1,441**
% of Peak Day Demand (Market Area Storage/ Industrial Curtailment/Peaking LNG)	**42%**	**43%**	**43%**	**42%**	**40%**	**39%**

*FEI has the right to curtail Rate Schedule 22A customers and use their gas during each gas year (5-days maximum). The supply fluctuation is a result of industrial customers swiching rate schedules or closing their facilities.

As the table above illustrates, between 39 and 43 percent of FEI's peak day load has been met using a variety of market area storage, peaking LNG, and industrial curtailment over the past decade. The remaining amount has been met with spot supply, seasonal supply (including seasonal storage), and baseload supply, which is generally delivered through FEI's contracted capacity with Westcoast and TC Energy's NGTL and Foothills BC pipeline systems.

4.2 Where applicable, please provide figures to support the narrative of FEI's reliance on each of these three system resources to meet the 'above-system design' demand.

Response:

Please refer to the response to CEC IR1 4.1.

5. Reference: Exhibit B-1, Page ES-10

> Constrained pipeline and storage resources in the PNW during the winter season continues to be a major concern, and market developments have caused significant supply and pricing risks in the region. Geo-political risks have added greater market uncertainty at this time. FEI has increased resiliency to a degree within the existing portfolio by holding contingency resources; however, resiliency needs to be further improved through new infrastructure projects. With the advancement of renewable and low-carbon gas supply resource in the region, FEI's future infrastructure is being planned to support the transition to a lower-carbon future by providing increased resiliency and supporting a broader range of supply resources.

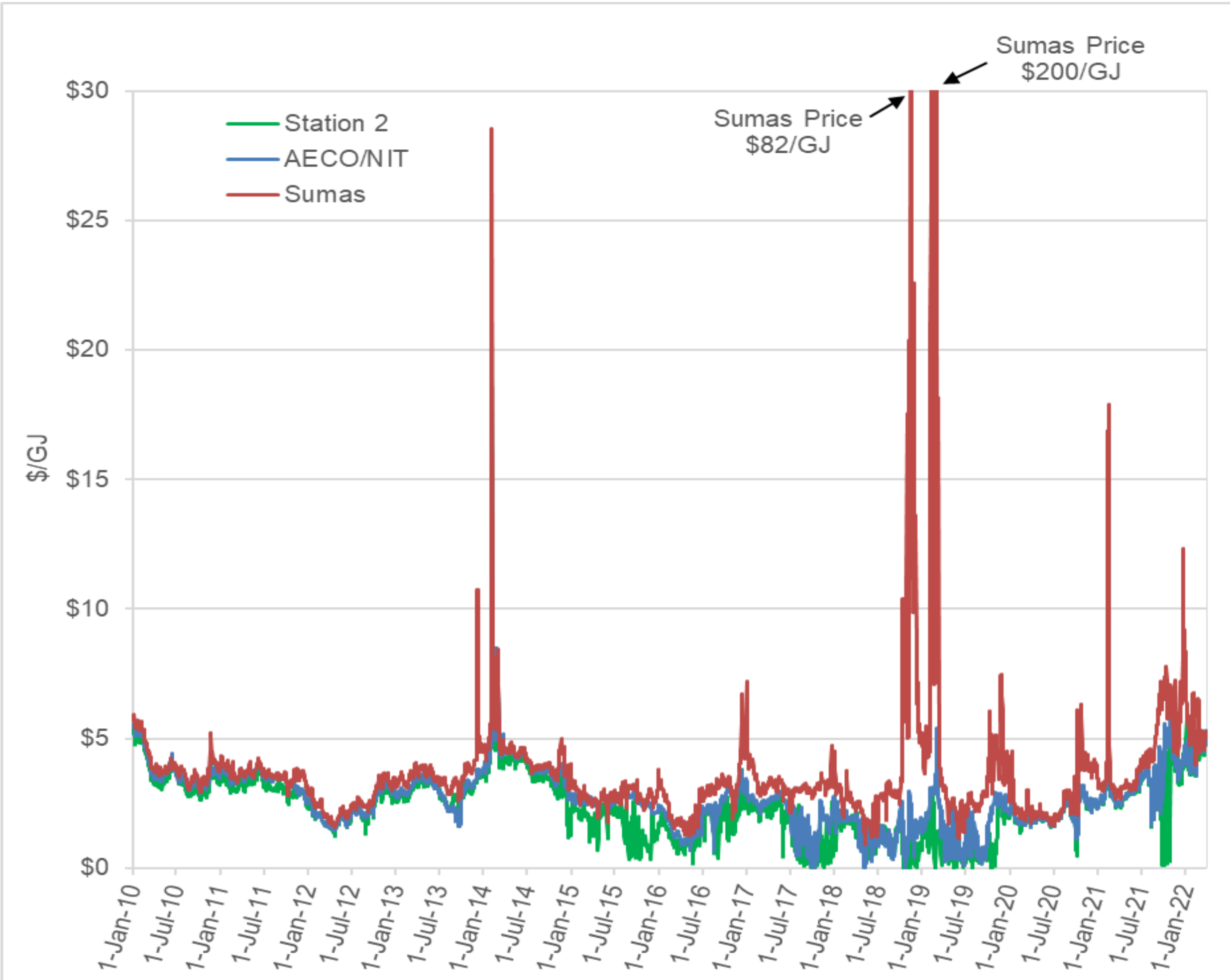
5.1 Please explain in more detail, and with quantification, if possible, the supply and pricing risks facing the PNW region during the winter season.

Response:

The supply and pricing risks facing the PNW region during the winter season are due to constrained pipeline infrastructure to the Huntingdon/Sumas market and the I-5 Corridor (Vancouver, Seattle and Portland). The market conditions causing the regional transportation and storage constraints were discussed in detail in Section 6.2.4 of the Application (Managing Long-Term Supply Risks within the Gas Supply Portfolio). FEI quantifies this risk by comparing the supply market hub prices at AECO/NIT and Station 2 to the Sumas price (historical and forward prices). This was illustrated in Figures 6-4 and 6-5 of the Application, which are reproduced below.

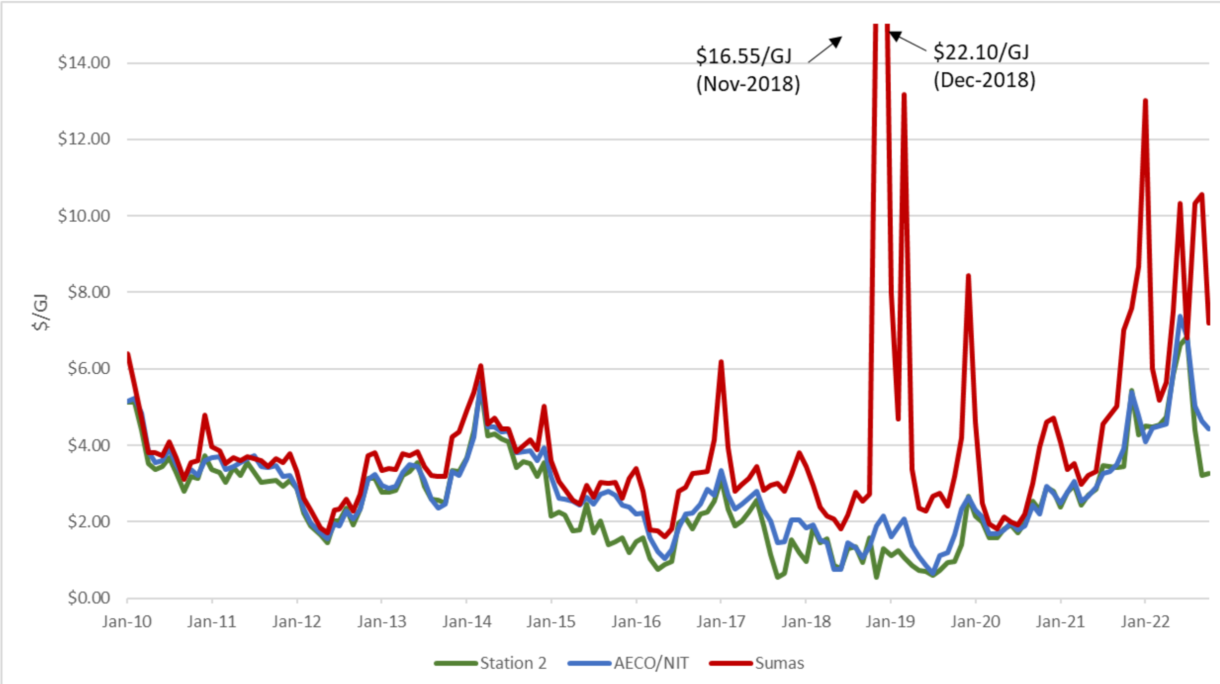
Figure 6-4 illustrates several periods of pricing volatility at the Huntingdon/Sumas spot (i.e., day) market, which typically occurs when increased demand in the PNW exceeds the delivery capacity of pipelines into the region. Any supply disruption can also cause prices spikes, as occurred during the T-South Incident in the 2018/19 winter, as well as after the T-South pipeline operated at 75 percent capacity for parts of the 2021/22 winter due to extensive flooding.

Figure 6-4 of the Application: Historical Daily Market Spot Prices



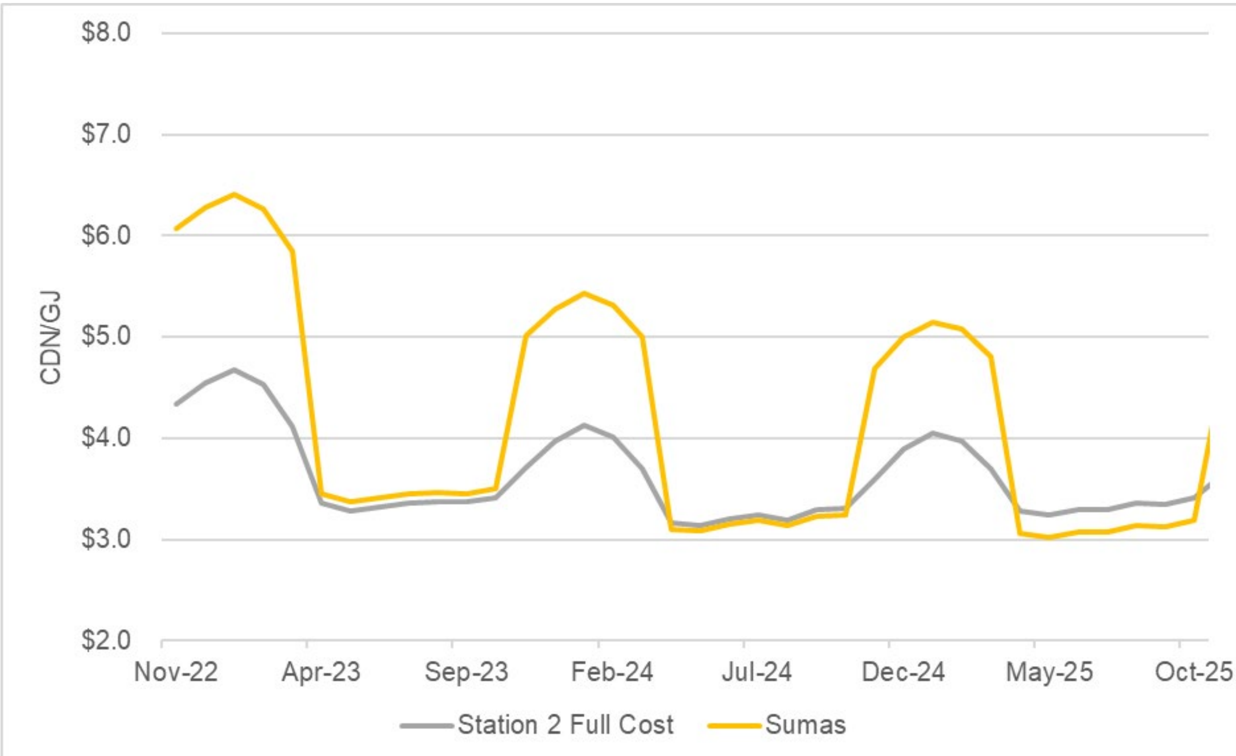
FEI has also included an additional figure below to show the historical monthly priced settlements. The impacts of price spikes to the monthly prices are typically less significant than with daily prices because daily prices typically react to immediate supply and demand events, while monthly prices are set based on the market expectations of supply and demand for the upcoming month. However, as the figure below illustrates, Sumas monthly settled price volatility has been increasing since 2017, as many counterparties are not willing to sell Huntingdon/Sumas monthly supply during the winter. This confirms FEI's view that there is a limited amount of supply available at the Huntingdon/Sumas market.

Additional Figure: Historical Monthly Price Settlements



FEI expects that the Huntingdon/Sumas market will continue to have significant supply risks and pricing volatility going forward until a new pipeline and/or storage resource is added to the region. These risks are reflected in the forward market prices (Figure 6-5 of the Application) as the Sumas price is significantly higher in the winter than the Station 2 price plus the fixed transportation costs to get to the Huntingdon/Sumas market.

Figure 6-5 of the Application: Station 2 Full Costs and Sumas Forward Price Comparison[2]



It is important to note that Section 6.2.4 also details how FEI's gas contracting strategy for its Core customers in today's market features limited supply priced off the Huntingdon/Sumas market. FEI's strategy, as accepted by the BCUC in past Annual Contracting Plans, is to hold firm pipeline capacity and mitigate its fixed costs for holding such capacity whenever possible. FEI began to implement this strategy as far back as 2014, given the unfolding market conditions in the region and the broader western region. This was a prudent strategy that provided protection to customers from large price spikes, higher overall gas costs and limited availability of gas at the Huntingdon/Sumas market.

5.2 What planned or anticipated market developments, if any, are on the regional horizon, which may help mitigate some of supply and pricing risks for FEI and please quantify the gap to be closed and the % of the gap for which specific developments will enable closing, where possible?

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2 Graph is based off indicative forward pricing provided by Amerex on January 24, 2022. Station 2 Full Cost includes Station 2 forward monthly price, T-South fuel, Westcoast 2021 Final Tolls, Motor Fuel and Carbon Tax.

Response:

The following projects are planned or anticipated resource additions that may help mitigate some of the supply and pricing risk in the PNW region:

- FEI, RGSD Project
- Westcoast Energy Inc., T-South Expansion
- Trans Canada Energy (TC Energy), West Path Delivery
- TC Energy, Gas Transmission Northwest (GTN) Express Project
- FEI, Tilbury LNG Storage Expansion (TLSE) Project
- NW Natural, Mist Expansion

FEI is not able to quantify the gap in supply and pricing that FEI needs to close, nor what the percentage of gap would close through a market development, as markets and prices are subject to a number of factors and dynamics. However, certain projects listed above are a better fit for FEI in terms of mitigating supply and pricing risks.

The RGSD project would substantially mitigate the supply and pricing risks for FEI as it would create a flow path separate from the T-South system, thus providing a new route to supply FEI's customers. The design of the RGSD would be optimally sized to facilitate load growth and to form a cost-effective resiliency solution in combination with FEI's other gas supply assets.

A T-South expansion could potentially mitigate some of the pricing risks at the Huntingdon/Sumas market; however, it would not mitigate the supply risk for FEI because an expansion would not reduce FEI's reliance on the T-South pipeline for the majority of its daily gas supply. Another consideration is that a T-South expansion would substantially increase T-South tolls, with minimal benefit to FEI's customers.

TC Energy's West Path Delivery and GTN Express Projects would increase supply into Stanfield and Malin and would not directly nor substantially mitigate the supply and pricing risks for FEI at Huntingdon/Sumas.

The remaining projects listed above would mitigate supply and pricing risks for FEI's customers, as detailed in Section 6.3 of the Application.

The TLSE Project would mitigate the risk of a pipeline failure resulting in a no-flow event, significantly improving FEI's ability to maintain continuity of service to customers. Further, the TLSE Project would also replace the Tilbury Base Plant, which is currently part of FEI's gas supply portfolio, as shown in Table 6-2 of the Application. This is important because absent the Tilbury Base Plant, FEI would have to find a replacement for this storage in the open market, which would be both challenging and costly.

The Mist Expansion would help mitigate some of the future supply and pricings risks for FEI, given that NW Natural will likely recall a portion of FEI's existing market area storage capacity at

Mist, as discussed in the response to the BCUC IR1 52.20. The market area storage resources are essential to FEI's gas supply portfolio, especially when colder-than-normal winter loads are greater than supply available from seasonal storage and pipeline capacity. Participating in this type of expansion will provide additional long-term supply security for FEI's customers.

The steps that FEI has already undertaken to mitigate supply and pricing risks for its Core customers in the region are described in Sections 6.2.4 and 6.2.5 of the Application. Going forward, the "best-case scenario" for FEI is that the RGSD, TLSE and a Mist Expansion are built in the region as soon as possible to alleviate any pricing and supply risks, especially the risks from Woodfibre LNG being online and in-service before any major regional expansion could occur, as discussed in the response to CEC IR1 5.1. The "best-case scenario'" for the region as a whole would be new infrastructure to alleviate regional constraints and Sumas price volatility at the Huntingdon/Sumas market.

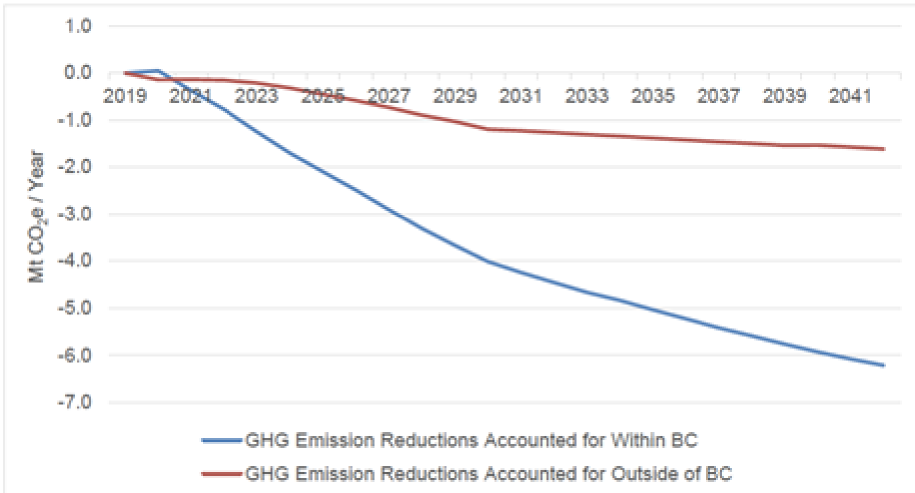
5.3 What is FEI's 'best-case scenario' timeline for the duration of these supply and pricing risks and for the mitigation steps FEI will be taking?

Response:

Please refer to the response to CEC IR1 5.2.

6. Reference: Exhibit B-1, Page ES-18

Figure ES-9: Total GHG Emission (Life Cycle) Reductions for the Diversified Energy (Planning) Scenario - BC and Outside of BC



6.1 Please explain the difference in magnitude between the 'GHG Emission Reductions Accounted for Within BC' and 'GHG Emission Reductions Accounted for Outside of BC', as measured in MtCO2/Year and the optimization process used that creates this distribution.

Response:

Figure ES-9 in the Executive Summary (which is a reproduction of Figure 9-5 on page 9-6 in Section 9) of the Application, shows total emission reductions resulting from all pillars of FEI's clean growth pathway, not just those from the transportation and global LNG sectors.

The difference in magnitude between the 'GHG Emission Reductions Accounted for Within BC' and 'GHG Emission Reductions Accounted for Outside of BC' reflects the case where, for the Application, FEI anticipates achieving more emission reductions through DSM activities and conversion of customer loads within BC to renewable and low-carbon gas than it anticipates achieving through serving transportation and global LNG markets outside of BC. For clarity, emission reductions accounted for within BC consist of initiatives to reduce emissions from residential, commercial, industrial, and low-carbon transportation customers. Emission reductions accounted for outside of BC consist of initiatives to reduce emissions from global LNG and marine fueling.

For a view of just those emission reductions from serving transportation within and outside of BC as well as global LNG, please refer to Figure 9-3 on page 9-6 of the Application, showing that for this category of customer demand, anticipated emission reductions outside of BC are greater than emission reductions within BC.

FEI recognizes that the magnitude of the potential for GHG emissions outside of BC could be much larger than presented in the Application. However, FEI took a conservative approach in its estimates of the market share captured by its service to the marine fueling and global LNG sectors. If higher demand in these sectors emerges in the coming years, FEI would identify those changes in a subsequent LTGRP filing. With respect to the optimization process, FEI considers that selling as much LNG as it has available through the planning horizon optimizes the use of its assets.

6.2 Please discuss the factors that contribute to the difference in GHG reduction, accumulated over the 20-yr horizon of FEI's 2022 LTGRP.

Response:

FEI notes that these emission reductions are annual reductions not cumulative as suggested by the question of 'accumulated' GHG reduction. The difference is explained in the response to CEC IR1 6.1. Please also refer to the responses to BCUC IR1 72.1, 72.2 and 74.2 for further discussion on FEI's emission reduction initiatives.

6.3 Please provide a graphic similar to Figure ES-9 but showing the % of 2007 emissions baseline being reduced over time by each of the within-BC and outside-of-BC strategies, and show this against the BC Provincial targets FEI is going to need to meet.

Response:

FEI is unable to provide a graphic similar to ES-9 of the Application in relation to the percentage of 2007 emissions baseline because FEI's understanding is that 'GHG Emission Reductions Accounted for Outside of BC' cannot be counted against (or shown as a reduction to meet) BC-legislated GHG emission targets over the 2007 baseline. However, the percentage of 2007 emissions baseline being reduced through the DEP Scenario for residential, commercial, and industrial customer types is illustrated in Table 1 below. Table 1 is based on using end use emission factors, as these factors are what BC provincial targets are being measured against. This table aligns with Figure 9-1 in the Application.

Table 1: Percentage GHG Emission Reductions (End Use) Over the 2007 Emissions Baseline for FEI's Residential, Commercial and Industrial Customer Types for Milestone Years in the DEP Scenario

		Diversified Energy (Planning) - GHG Emissions (Mt CO_2e) Residential, Commercial and Industrial Customer Types			
	2007	2019	2030	2040	2042
FEI Total GHG Emissions (Mt CO2e)	10.9	10.7	5.7	4.3	3.9
Percent Reduction over 2007 Base Level		1.3%	47.6%	60.8%	64.4%

The DEP Scenario for residential, commercial and industrial customer types meets the BC-legislated GHG emissions reduction target of 60 percent reduction over the 2007 baseline by 2040, as illustrated in Table 1.

7. Reference: Exhibit B-1, Page ES-19

> transforming and influencing energy supply service markets. Maintaining BC's gas and electric infrastructure will enable ongoing innovation and accelerate decarbonization such that provincial GHG emission reduction targets will be met at a more rapid pace. In this pathway, the gas infrastructure continues to grow and thrive by adding new customers, communities, and commercial and industrial processing. Sharing costs across a diverse set of customer segments ensures that individual customers can more readily absorb the additional costs incurred through the low-carbon transition.

7.1 Please clarify what is meant by 'individual customers' on line 32 in the above reference: does this term denote an 'individual' account, i.e. most commonly associated with a residential customer? Or is it meant to denote any type of individual customer more broadly, no matter the type of customer? Please explain.

Response:

The term "individual customers" on line 32 cited above was intended to denote an "individual" account for all customer types within residential, commercial or industrial sectors. The costs associated with gas infrastructure and decarbonization initiatives will ultimately be borne by FEI's customers. The greater the number of total customers, the less each individual customer will need to contribute to the costs associated with operating and maintaining the gas system.

7.2 To what extent, if any, would 'sharing costs, between electric and gas systems, across a diverse set of customer segments' be a departure from past practices or present planning anticipated?

Response:

FEI clarifies that "sharing costs across a diverse set of customer segments" as referenced in the preamble is referring to FEI's DEP Scenario which would allow British Columbians to benefit from an overall reduced level of costs by maintaining both BC's gas and electric infrastructure while sharing the costs of ongoing innovation and acceleration of decarbonization to both systems. The costs and the resulting rate impact of decarbonization of the gas system will be borne by FEI's customers while the costs and the resulting rate impact for the electric system will be borne by the electric customers.

Sharing costs between electric and gas systems, or a single common rate for both gas and electric systems, as suggested by the question, would be a departure from past practices, especially given that the gas and electric systems are owned by different entities and shareholders.

FEI notes one key benefit to the DEP Scenario is the potential contribution to energy affordability for British Columbians. The DEP scenario is a lower-cost approach than the Deep Electrification Scenario primarily because it optimizes both the gas and electric systems by fully utilizing the energy delivery infrastructure of FEI's gas system while avoiding the need for extensive build-out of the electricity system. The cost savings are significantly more pronounced after 2030 when new electric infrastructure would expect to be required. This emphasizes the importance of having a longer-term view beyond 2030 for decarbonization strategies employed today. According to the Pathways Report, pursuing a diversified pathway is approximately $100 billion less costly by 2050 than a deep electrification pathway. Even though renewable and low-carbon gases are more costly compared to conventional natural gas, maintaining a role for the gas distribution system is less costly than sole reliance on firm electric power capacity given the extensive existing assets already in-place. Both pathways will require significant levels of investment, and collaboration across all stakeholders will be required to make decarbonization a reality.

7.3 Would 'sharing costs across a diverse set of customer segments' apply to sharing of costs as among FEI's customers? Or more broadly, customers that benefit from 'maintaining BC's gas and electric infrastructure' to 'enable ongoing innovation and accelerate decarbonization' (see lines 27 & 28 in the reference above).

<u>Response:</u>

Please refer to the response to CEC IR1 7.2.

INTRODUCTION

8. References: Exhibit B-1, Page 1-4 and Page 1-5

> Consultation and engagement, which includes technical feedback from the Resource Planning Advisory Group (RPAG), engagement with Indigenous groups and community consultation, is an important element of FEI's long-term resource planning. The decisions made in long-term resource planning ultimately impact FEI's customers in terms of rates and fuel choices in the
>
> **Figure 1-1: Map of FortisBC Service Areas (FEI Gas and Propane and FBC Electric)**

> SECTION 1: INTRODUCTION PAGE 1-4

8.1 As per the above reference, consultation and engagement is an important element of FEI's long-term resource planning. For the purposes of developing its LTGRPs, does FEI conduct consultation and engagement in areas and/or communities which are not presently served by FEI?

8.1.1 If no, please elaborate.

8.1.2 If yes, please explain if the nature of such consultation and engagement is any different from the activities that FEI undertakes in areas and/or communities where it is already present through the provision of its services.

Response:

FEI engages a wide range of customer groups, stakeholders, local governments, Indigenous communities and others through the LTGRP development process. FEI received input and feedback through the RPAG and community engagement sessions from regional or provincial organizations which represent multiple communities served and not presently served by FEI. These organizations provided feedback based off the energy priorities of the communities, customers, stakeholders and rights holders they represent.

In addition, FEI invites regional districts and Indigenous communities located within proximity to the FEI service territory to participate in community and Indigenous engagement workshops. In some instances, regional districts or Indigenous communities may only be partially served by FEI given the proximity of FEI's system infrastructure to community lands. These communities were invited to the engagement process and had the opportunity to identify their energy priorities to FEI. Some communities with partial or no FEI energy service participated in community engagement sessions, and provided input to FEI on their energy priorities, such as but not limited to, extending FEI service to their communities.

A common sentiment from these attendees that is different from attendees from locations within FEI's service area, and one which FEI takes into consideration, is the desire to connect their communities to FEI's gas system. This includes communities that are just outside of the current FEI service area and communities where large transmission pipes pass close to or through the respective communities, but where demand from the community is insufficient under current system extension policy to undertake the investment in the needed infrastructure to provide service.

Further, through other business activities (besides LTGRP-specific engagement), FEI does receive feedback from representatives of more remote communities and industrial operations concerning the potential for providing service through deliveries of LNG via truck, rail or ship in order to, for example, reduce reliance on diesel as a fuel for heavy transportation or electricity generation. Such feedback is taken into account in the Application where these potential services are discussed. Finally, a growing consideration for Indigenous and other communities near or beyond the current limits of FEI's service territory is the potential opportunity to develop production facilities for renewable and low-carbon gas that could be acquired by FEI.

9. Reference: Exhibit B-1, Pages 1-6 and 1-7, Table 1-2

Table 1-2: Fuel Types and Decarbonization Technologies Used in the 2022 LTGRP

Fuel Type	Description[19]	Life cycle Emission Factor (tCO_2e/GJ)	End use cycle Emission Factor (tCO_2e/GJ)
Natural gas	Natural gas is a naturally occurring hydrocarbon. Hydrocarbons are a class of organic compounds consisting of carbon and hydrogen. Raw natural gas (before processing) is composed primarily of methane.[20]	0.0598	0.04987[21]
Renewable natural gas (RNG)	Upgraded biogas produced from farm or municipal organic biomass. Upgraded synthesis gas (syngas) produced from wood biomass at pulp mills and some municipal organic biomass.	0.0100	0.0003
Syngas	Produced from wood to displace natural gas used in lime kilns at pulp mills. Can also be upgraded to green hydrogen.	0.0100	0.0000
Lignin	Produced from black liquor to displace natural gas used in lime kilns at pulp mills.	0.0100	0.0000
Green Hydrogen	Produced via water electrolysis using renewable electricity feedstock.	0.0000	0.0000
Blue Hydrogen	Reformed from hydrocarbon feedstock with up to 90 percent carbon sequestered.	0.0200	0.0000[22]
Natural Gas with Associated Carbon Capture, Utilization and Storage (CCUS)	Applying the carbon reduction benefits of CCUS to the delivery of natural gas on FEI's gas network.[23]	0.0148	0.0148

9.1 Please augment this table with a fuel type being green hydrogen produced by electrolysis and then converted to synthetic natural gas.

<u>Response:</u>

Formation of synthetic methane from green hydrogen was not individually modelled as part of the Application and, as such, was not included in Table 1-2. Synthetic methane from green hydrogen is, however, described in Table 3 of Appendix A-2. The lifecycle emission factor and end use emission factor synthetic methane from green hydrogen would be similar to renewable natural gas, as reflected in Table 1-2.

9.2 Aside from availability of supply and cost considerations, please discuss and detail what other considerations, if any, FEI takes into account as part of its long-term planning efforts for each of the low-carbon fuel types included in Table 1-2.

9.2.1 Please provide this discussion in a table format, if available.

Response:

In general, when assessing low-carbon fuel types as part of its supply options for long-term planning, FEI's main considerations relate to the LTGRP planning objectives, as outlined in Section 1.4 of the Application. These objectives include consideration of cost-effectiveness, security and reliability of supply, and lifecycle carbon intensity to meet long-term demand scenarios while adhering to BC government policy and regulation. Other considerations for low-carbon fuels include contract length, terms and conditions within the contract. For hydrogen specifically, FEI also examines production technology and capacity and how hydrogen supply volumes can be integrated into the energy system and the potential for any risk factors such as system capacity constraints. The nature of this discussion is not suited to a table format.

9.3 Aside from availability of supply and cost considerations, please discuss and detail what other considerations, if any, FEI takes into account as part of its system design and optimization efforts for each of the low-carbon fuel types included in Table 1-2.

9.3.1 Please provide this discussion in a table format, if available.

Response:

For all the renewable and low-carbon gas supplies, FEI considers the technical requirements for the system to be able to incorporate physical delivery of these energy supplies to customers. In Section 7.4.1 and Table 7-2 of the Application, FEI provided a discussion of the considerations taken into account. For example, various renewable and low-carbon supplies can have different heat contents per volume of gaseous fuel that must be considered in system design. Renewables like RNG, as well as syngas and lignin, can be produced near or at consumer locations at local hubs and, as a result, can offset the need for pipeline capacity that would otherwise be required to serve that local demand. RNG can also be blended with conventional gas without adversely impacting the capacity to deliver to downstream consumers. Hydrogen can be produced at local hubs and through a variety of means, some of which can require methane as a feedstock that could be supplied by upstream pipelines and then injected into downstream systems. This can impact both upstream pipeline capacity and downstream pipeline capacity. The table below summarizes the considerations. Since many of these considerations continue to evolve as FEI pursues various renewable and low-carbon gas supplies, this list of considerations may adjust over time.

1 **Table 1: Overview of Considerations for Integrating Renewable and Low-Carbon Gas**

Fuel Type	Considerations
RNG	• Has comparable physical properties, including energy content, to conventional natural gas and, therefore, exhibits similar flow characteristics and therefore does not affect pipeline capacity when compared to conventional natural gas. • Can be produced locally within FEI systems. This local supply and delivery can offset the need for pipeline capacity to serve that local demand. • Steady production of RNG requires access to consistent consumer demand so that RNG production is not constrained. If located in distribution systems, this may require local system upgrades (pipeline or local storage) to enable access to sufficient consumer demand.
Syngas / Lignin	• Can be produced locally within FEI systems. This local supply and delivery can offset the need for upstream pipeline capacity to serve that local demand.
Green Hydrogen	• Can be produced locally within FEI systems. This local supply and delivery can offset the need for pipeline capacity to serve that local demand. • Has different physical properties, including energy content, from conventional natural gas and, therefore, exhibits flow characteristics that reduce pipeline capacity compared to conventional natural gas. • Steady production of hydrogen requires access to consistent consumer demand so that hydrogen production is not constrained. Green hydrogen production has a better ability than RNG production to turn down or shut down production in periods of low consumer demand. If located in distribution systems, this may require local system upgrades (pipeline or local storage) to enable access to sufficient consumer demand. • Need to consider interactions with downstream LNG production or other industrial processes using natural gas as a feedstock. • Need to consider material compatibility, allowable blend percentages with existing and future facilities and operating conditions.
Blue/Turquoise Hydrogen	• Can be produced locally within FEI systems but could require additional upstream pipeline capacity to provide natural gas feedstock for production by various reformation or pyrolytic processes. • Has different physical properties, including energy content, from conventional natural gas and, therefore, exhibits flow characteristics that reduce pipeline capacity downstream of injection locations compared to conventional natural gas. • Steady production of hydrogen requires access to consistent consumer demand so that hydrogen production is not constrained. This may require local system upgrades (pipeline or local storage) to enable access to sufficient consumer demand. • Need to consider interactions with downstream LNG production or other industrial processes using natural gas as a feedstock. • Need to consider material compatibility, allowable blend percentages with existing and future facilities and operating conditions.
Natural Gas with associated CCUS	• Systems continue to deliver natural gas and, therefore, considerations for system design and capacity are unchanged.

2

PLANNING ENVIRONMENT

10. Reference: Exhibit B-1, Page 2-3

> industry). However, while natural gas is one of the most widely used fuels in Canada, there is no specific federal climate policy direction on the future of the gas delivery system.
>
> The policies, targets and initiatives discussed below illustrate that the conversation around the role of the gas system in decarbonizing Canada's GHG emissions is undefined. While public opinion and governmental objectives have become more stringent regarding climate change, there remains a lack of clarity regarding the specific actions expected of energy utilities such as FEI.

10.1 Please discuss how FEI's understanding (on line 6 in the above reference that 'there remains a lack of clarity regarding the specific actions expected of energy utilities such as FEI') influenced the development of FEI's Diversified Energy (Planning) Scenario.

Response:

The lack of clarity from governments did not influence the development of the DEP Scenario. In developing the DEP Scenario as part of the Pathways to 2050 Report, FEI commissioned Guidehouse to define two scenarios whereby the provincial government's targets and policies at the time were met: one significantly leveraged FEI's infrastructure and climate solutions; the other relied predominantly on electrification. FEI simulated a scenario where policy makers envisioned a strong role for the gas system in decarbonization and enabled that through supportive policies to achieve that outcome. The purpose of the DEP Scenario is to evaluate the outcomes of such an approach, assuming that energy utilities such as FEI are looked to as primary implementers of the government's climate policy objectives.

10.2 In FEI's understanding, how are other gas utilities (in BC and Canada) approaching the development of their long-term planning scenarios, given that 'the role of the gas system in decarbonizing Canada's GHG emission's is undefined' (see lines 3 & 4 in the above reference).

Response:

FEI understands that few gas utilities across Canada undertake integrated resource planning with a 20-year planning horizon similar to FEI's. For those that do, FEI has not completed a survey of all BC and Canadian gas utilities on how specifically they are developing their future scenarios and so can only provide general observations on this topic. Subjectively, FEI understands that gas utilities that are more advanced in considering the long-term need to shift to low-carbon and renewable fuels recognize the key considerations in developing future scenarios in which to examine their long-term plans. These considerations include policy and regulations in that jurisdiction (such as emission reduction targets), system reliability and energy system resilience, access to supplies, implications of emerging physical system constraints, the extent of integration with the electricity system and energy affordability. In FEI's view, gas utilities in Canada that undertake long-term integrated resource planning are leaders in considering and examining alternative future scenarios in which to consider system planning alternatives.

10.3 Is FEI's body of work in developing the Diversified Energy Planning Scenario and the other five scenarios presented in Table 4-1 (on Page 4-21 of the Application: Alternate Future Scenario Summary), a leading or a lagging body of work as compared to FEI's peers in Canada and the PNW?

Response:

FEI believes that it is at the forefront of climate action among its utility peers in Canada and the PNW. FEI first introduced a climate compliance scenario in Appendix E of the 2017 LTGRP and since developed its Clean Growth Pathway, its 30BY30 target, the Pathways Report and now the DEP Scenario in the Application. FEI is not aware of any utility resource planning effort in Canada or the PNW with as ambitious a scenario as the DEP Scenario. This is because the policy framework outlined in the CleanBC Roadmap is the most ambitious and stringent climate policy impacting gas utilities anywhere in Canada or the PNW.

11. Reference: Exhibit B-1, Page 2-13

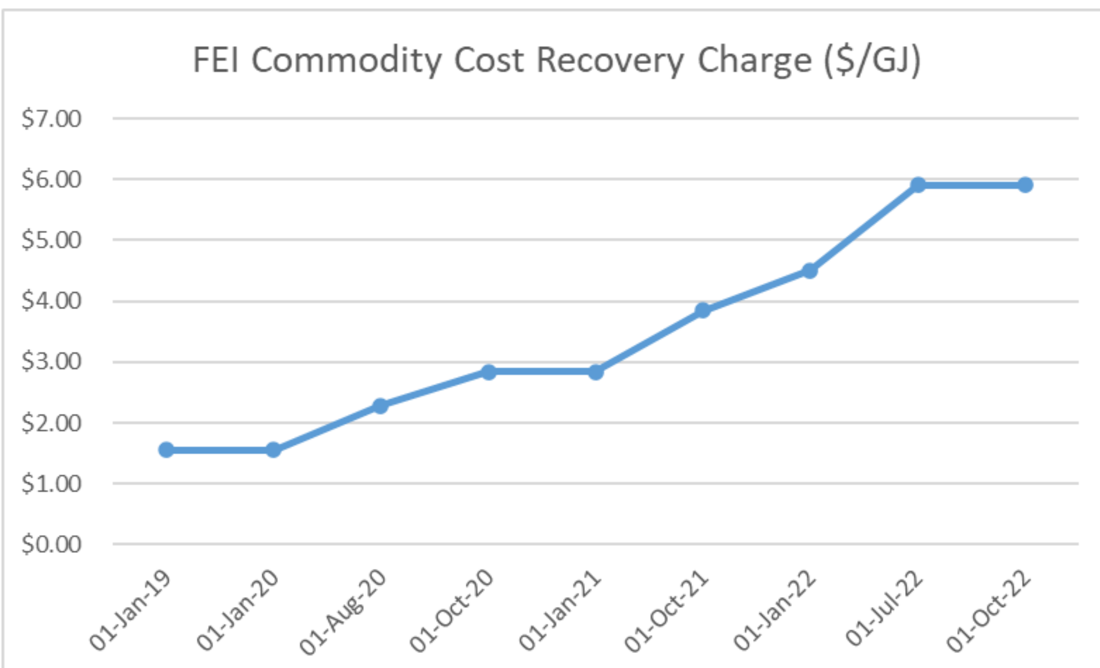
> The GGRR enables FEI to be more flexible, stimulates investment in renewable energy and accelerates growth of renewable and low-carbon gas supply in the gas system and acquire renewable and low-carbon gases from $30 to $31 per GJ for contracts. The changes to the GGRR enable FEI to help to achieve the CleanBC Plan objectives, which call for a 15 percent renewable and low-carbon gas content in the natural gas system by 2030. Further, with the recent introduction of the Roadmap in October 2021, FEI expects supply volumes to exceed 15 percent.

11.1 Please provide the equivalent price or price ranges (in $/GJ) that FEI would have typically paid to acquire natural gas for the needs of its customers in recent years.

<u>Response:</u>

The "equivalent price" that FEI would have typically paid to acquire natural gas, excluding any carbon tax impacts,[3] is on average reflected in FEI's Commodity Cost Recovery Charge (CCRC).[4]

The figure below illustrates that in recent years, the CCRC for Lower Mainland, Vancouver Island, North and South Interior customers, has ranged from $1.55 per GJ to $5.91 per GJ.



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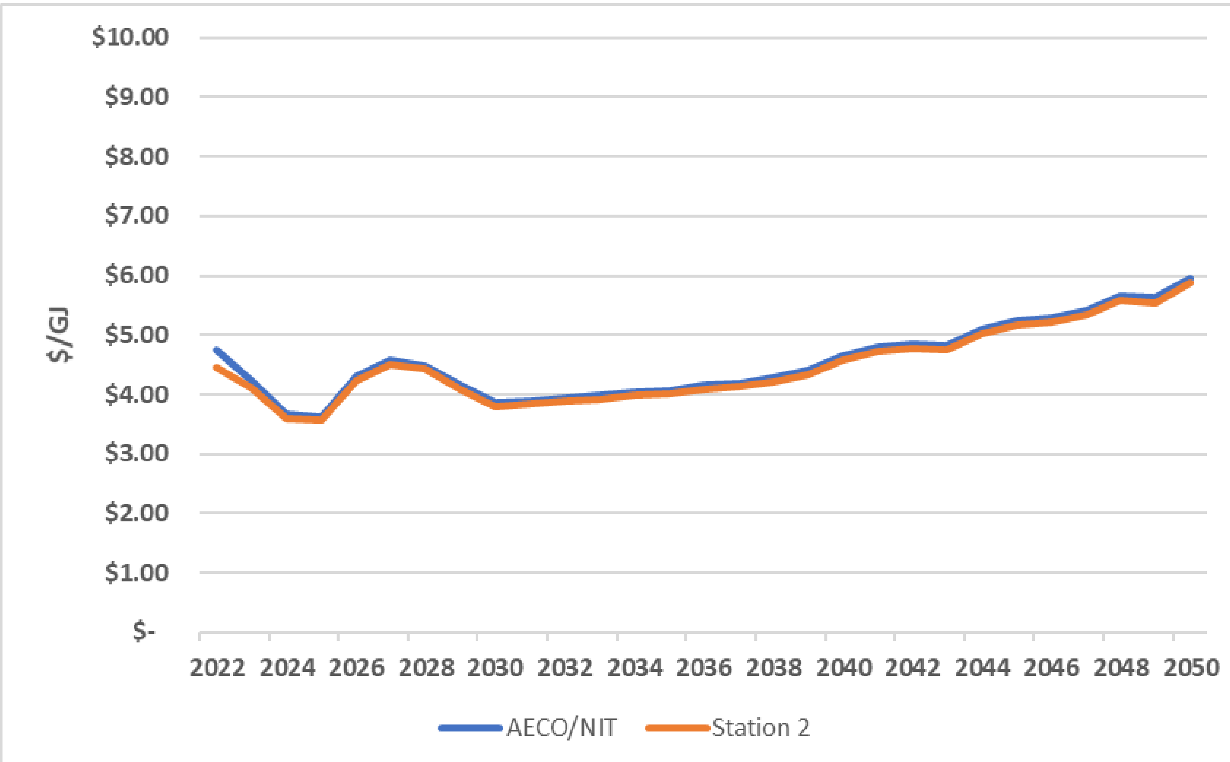
[3] The carbon tax applied to natural gas is not included in the figure. Additionally, the $30 to $31 per GJ in the preamble for renewable and low-carbon gases does not include the credit equal to the carbon tax payable on the specified volume or percentage of biomethane.

[4] FEI purchases gas on behalf of its Core customers and passes these costs through to Core customers without markup.

It is important to note that the renewable and low-carbon gas supply that FEI can acquire at $30 to $31 per GJ is primarily through future investments as well through long-term contracts that are 20 to 25 years in length. Therefore, the more relevant comparison should be the long-term natural gas price forecasts for Station 2 and AECO/NIT, as illustrated below. For a proper comparison, the cost of carbon would also need to be considered.

Station 2 and AECO/NIT Natural Gas Price Forecast (2021 Real Dollars) [5]



11.2 Please comment on the price acceleration or decline (in $/GJ) that FEI may have observed annually (in recent years) for such acquisitions.

<u>Response:</u>

FEI is seeing an overall increase in the market price for RNG. Though FEI does not have a mathematical correlation, FEI believes the increased price for RNG is due to both increased demand as well as increased capital and operating costs for these projects which is generally in line with inflation.

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[5] Source: © 2022 S&P Global. All rights reserved. The use of this content was authorized in advance. Any further use or redistribution of this content is strictly prohibited without prior written permission by S&P Global. As discussed in Section 6.2.2 of the Application, FEI procures most of its conventional gas supply from the Station 2 and AECO/NIT supply hubs.

11.3 Where available (from experience, i.e. commercial transactions), please provide the prices or price ranges anticipated for years into the future, i.e. cost curves, (in $/GJ) for each of the other low-carbon fuel types described in Table 1-2, on page 1-6 of the Application.

<u>Response:</u>

The BC Renewable and Low-Carbon Gas Supply Potential Study[6]developed scenarios that model the cost and availability of a portfolio of renewable and low-carbon gas production pathways, including the fuel types described in Table 1-2. These scenarios are based on models that represent a possible outcome based on a set of criteria.

Please also refer to the responses to BCUC IR1 71.8.1 and MetroVan IR1 2.2.1 and 2.2.2 for additional discussion of FEI's consideration of renewable and low-carbon gas costs over the planning horizon in the Application.

6 Exhibit B1-1, 2022 LTGRP Application, Appendix D-2.

12. Reference: Exhibit B-1, Page 2-20

> Overall, the policy preference at all three levels of government for the use of electricity across many end uses puts downward pressure on FEI's demand and upward pressure on FEI's rates. Demand is reduced though the focus on energy efficiency of buildings and appliances, and policies which limit FEI's ability to attach new customers. Rates are increased by the need to invest in higher cost gaseous energy in response to emission reduction pressures and these costs are borne across the energy value chain. Taxes add additional upward rate pressure. Downward pressure on FEI's ability to add customer attachments could eventually result in a smaller customer base resulting in higher costs per customer to support decarbonization initiatives.

12.1 Please confirm or otherwise explain that what FEI describes in the referenced paragraph is the potential for elements of systemic risk arising for FEI's customer base.

Response:

FEI does not consider this to be an appropriate interpretation of systemic risk for the FEI customer base. Systemic risk represents structural risk elements that impact multiple entities within sectors with instability in one sub-sector, leading to instability and potential severe impacts across a broad section of the economy. While the move to decarbonize will require structural transitions, there will always be the need for energy and the services it provides.

When the paragraph referenced in the above preamble is read in the context of the paragraphs that preceded it in the Application, it is clear that climate and energy policies are impacting FEI's ability to cost-effectively supply reliable energy to the FEI customer base. The set of circumstances described call for action from all levels of governments to determine the right set of policies needed for the future of the gas delivery system and its role in reducing GHG emissions. From a systemic risk lens, this should be interpreted as risks to the whole utility sector, including electric utilities, and impacts to a broad section of utility customers.

FEI notes that decarbonizing the BC energy system will require increased costs to energy consumers in order to meet the decarbonization goals as set out by the Province, regardless of whether a diversified pathway or electrification pathway is pursued. If FEI is unable to mitigate the risk of increased cost to its customers, and customers switch away from the gas system due to increased rates during the coming decades, a larger share of the cost would need to be absorbed by customers who remain on the system and there would be an increased risk of systemic failure risks that go along with that scenario.

12.2 Please describe how systemic risk does (in theory) play out over time and discuss the inter-play dynamics as among the costs of service borne by commercial, industrial, and residential customers and the effects thereof on these customer groups, including description of the electricity system costs and price impacts for the electricity account of those same customers.

Response:

With regard to how systemic risk (in theory) plays out over time, please refer to the response to CEC IR1 12.1.

With regard to the inter-play dynamics as among the cost of service borne by commercial, industrial, and residential customers, the allocation of costs between the different customer classes will depend on the types of customers remaining on the gas system and their usage characteristics. Cost allocations between FEI's customer classes and revenue to cost ratios for each rate class are periodically reviewed in separate proceedings before the BCUC.

As for the costs and impacts for the electricity accounts of the same customers, the cost allocation amongst FEI's gas customer classes would have no impact on the electric system and the electric rates.

12.3 Please confirm that economic price increase impacts could occur for the FEI gas system if its growth exceeded its ability to make customer bills more affordable by reducing consumption if the growth triggers significant additional investments requirements in expansion.

Response:

FEI is unable to confirm the potential for economic impacts due to gas rate increases exceeding customers' ability to reduce consumption. However, please refer to Section 3.4 of the Application which discusses investment in DSM programs to reduce FEI's existing customers' energy consumption, thus reducing the bill impact due to decarbonization. Please also refer to Section 3.6 of the Application, where FEI discusses investment in LNG for marine fueling and global markets, which will bring offsetting revenues that will be a benefit to FEI's customers through their rates. Both of these solutions will limit the potential economic impact, if they materialize.

In addition, as discussed in the response to CEC IR1 12.2, there will be increased costs due to decarbonization whether it is through the diversified pathway or the electrification pathway. FEI's view is that the diversified pathway will be less expensive than the electrification pathway, i.e., by about $100 billion less according to the Pathways Report.[7] This is consistent with the rate impact analysis described in Section 9.4 of the Application, where the Deep Electrification Scenario results in higher rate impacts for gas customers than the DEP Scenario.

7 Exhibit B-1, Application, Appendix A-2, Pathways for British Columbia to Achieve its GHG Reduction Goals.

13. Reference: Exhibit B-1, Page 2-24

> potential use of other sources of energy. Factors influencing non-price considerations may include the following:
>
> - GHG emission concerns;
> - Type of housing mix, the size of new dwellings, and commercial building requirements;
> - Builder and developer preferences;
> - Capital costs, installation requirements, operating and maintenance costs over the lifetime of the equipment;
> - Customer perceptions;
> - Availability of new technologies;
> - Availability of utility and government incentives and rebates for new construction, retrofits, commercial buildings and industrial facilities;
> - Commercial and industrial end user requirements; and
> - Government policies (such as local governments' support for non-fossil fuel alternatives through updates to building codes and bylaws, which is discussed in Section 2.2.3).

13.1 Please describe FEI's understanding of any geographical variations in customer perceptions as between the different service areas that FEI serves, which FEI may have acquired through its consultation and engagement activities for the development of its 2022 LTGRP.

<u>Response:</u>

As discussed in Sections 8.2 to 8.5 of the Application, FEI received a range of feedback through consultation and engagement activities. Common themes were identified across all regional engagement sessions, including the need for decarbonization of the gas supply in response to climate action initiatives, balancing decarbonization with affordable energy solutions, and the resiliency of BC's energy system.

Local energy projects were a key point of interest from participants in the Vancouver Island, Coastal and Interior regions of FEI's service territory. These were raised as both an economic development opportunity and a need to ensure reliability and resilience for energy delivery in the region. Given the geographical distance from traditional energy supply sources, community representatives from Vancouver Island were particularly interested in supporting local energy projects to enhance regional resilience of their energy systems. These engagement sessions took place in November 2021, when BC was experiencing unprecedented flooding, and resiliency was top of mind.

Community representatives from the Interior continued to emphasize the importance of affordable energy and concerns over rising energy costs. Representatives of rural communities in the region were particularly interested in opportunities for FEI to extend gas service to community members. Energy efficiency was identified as a key priority for FEI to continue to focus on and expand, as a means to reduce the cost of energy bills for customers and to reduce overall energy usage.

Community representatives from the Lower Mainland were more concerned with electrification and decarbonization initiatives and how the LTGRP is addressing climate change. Concerns were raised on the continued use of traditional natural gas as an energy source. Participants inquired about FEI's renewable gas supply options and asked FEI a range of questions on renewable gases and FEI's plans for scaling low-carbon energy solutions over the planning horizon.

Indigenous involvement in the utility planning process, partnership opportunities for local clean energy projects, employment opportunities, and support for FEI's DSM programs to address affordable housing and energy affordability were key considerations. Indigenous community representatives in multiple regions identified the importance for FEI to consider the UN Declaration for the Rights on Indigenous Peoples and Reconciliation initiatives within the context of the Application process and future utility planning initiatives.

A summary of all input and feedback from engagement sessions can be found within Sections 8.2-8.5 of the Application. FEI continues to expand its community outreach to further understand the unique needs of geographical variations in customer perceptions and energy needs.

13.2 Please discuss if and how such an understanding may have informed the development of FEI's 2022 LTGRP and more specifically its Diversified Energy (Planning) Scenario.

<u>Response:</u>

An understanding of geographical variations in customer perceptions informed many aspects of the development of the Application and, more specifically, the DEP Scenario. Examples of geographical variations influencing the Application include the following:

- Interest in local clean energy projects supported the DEP Scenario and the considerations for the integration of renewable and low-carbon gas allocations to regional distribution systems (please refer to Section 7.4 in the Application). The VITS and ITS distribution systems were posed by participants as potential supply location opportunities for syngas and lignin, hydrogen supplies and distribution hubs. Vancouver Island participants are particularly interested in energy security, and these opportunities may play a future role.
- Participants from the Lower Mainland were somewhat focused on climate action initiatives, and interested in FEI's aggressive approach to the acquisition of renewable and low-carbon gas projects to meet the GHGRS cap.

- Energy affordability was top of mind for rural communities and the rate impacts in Section 9.4 demonstrate the need for ongoing dialogue about the costs of decarbonization and how to balance affordability with climate action. Interest in DSM programs was expressed by a number of community participants and representatives from Indigenous groups to address energy affordability. The High DSM Setting was selected to ensure sufficient funding was available for future DSM program expansion.

Although the Application did not designate specific locations or regions to bring forward some of these specific solutions (hydrogen production locations, for example), the information acquired through the engagement sessions supported the scenario analysis and the selection of the DEP Scenario as FEI's planning scenario and has helped to inform ongoing LTGRP analysis and other planning considerations. As resource planning is an ongoing process, FEI plans to continuously improve opportunities for community outreach to further understand the unique needs of geographical variations in customer perceptions and energy needs in resource planning and other aspects of FEI's energy distribution business.

13.3 Please discuss if and how such an understanding may inform FEI's pursuit of opportunities for serving BC communities that are not presently served by FEI.

<u>Response:</u>

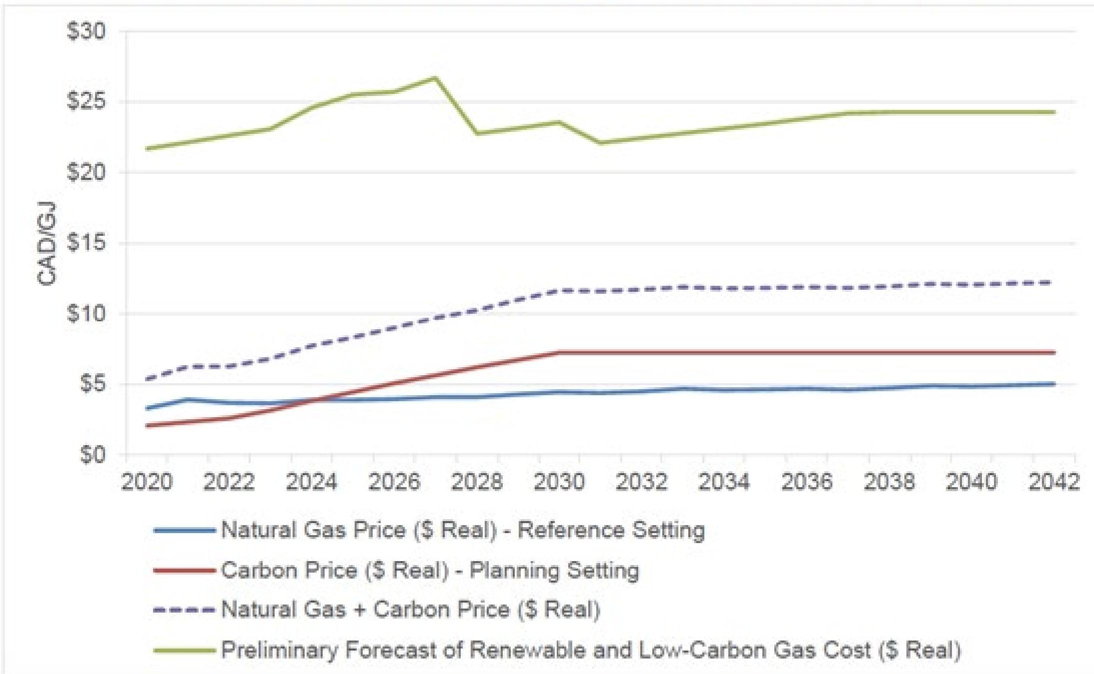
FEI assesses both price and non-price based factors unique to each opportunity in order to determine the feasibility of expanding FEI service to communities or customer groups not currently served by FEI. FEI engages with local communities to understand their energy needs to identify opportunities for expanding gas service. As identified at page 2-24 of the Application, customers are considering a wide range of price and non-price based factors in their decision-making process for energy service.

FEI seeks to understand these factors and how they apply to each opportunity, as each community may value the factors differently or require different solutions in order to meet their energy needs. FEI performs a mains extension (MX) test on a case-by-case basis to determine if a service extension is economically feasible without requiring a contribution in aid of construction (CIAC) from the customer. In instances where potential projects do not pass the MX test and a sizeable CIAC is required from the customer, FEI and/or the customer may explore external funding options to support the project. Additionally, if FEI is aware of additional high-load end users, such as commercial or industrial customers in a specific region that are currently not connected, to help the economics of an extension project, FEI will work to bring relevant stakeholders together to identify if there are opportunities to extend service to multiple customers and communities through a combined project.

Throughout the LTGRP engagement process, expanding FEI service was a key area of interest, particularly during Indigenous community engagement workshops. In recognition of this, FEI is continually assessing funding and program options available to make energy connections more economically feasible, particularly to under-served remote Indigenous communities in BC.

14. Reference: Exhibit B-1, Page 2-25, Figure 2-3

Figure 2-3: Outlook of Energy Costs for Fuel Types Used in the Development of the LTGRP[85,86]



14.1 Please provide the discount rate(s) used in estimating the $ Real prices provided in Figure 2-3.

Response:

The forecast shown in Figure 2-3 for the "Preliminary Forecast of Renewable and Low-Carbon Gas Cost" was created in real dollars and, therefore, no discount rate was used in the calculation. However, the carbon price forecast and natural gas price forecast, which is derived from an average of third-party price forecasts from the Northwest Power and Conservation Council (NPCC) and IHS Markit, does include discount rates calculated from inflation forecasts. The carbon price forecast and NPCC gas price forecast use discount rates that were calculated based on the inflation forecasts from the Canadian chartered banks and an economic outlook prepared by the Conference Board of Canada, while IHS Markit provided a gas price forecast in real dollars. The following table shows the discount rates used in calculating the carbon price forecast and the NPCC gas price forecast in 2020 real dollars.

	Discound Rate (2020 base year)
2020	1.00
2021	1.02
2022	1.04
2023	1.06
2024	1.08
2025	1.10
2026	1.13
2027	1.15
2028	1.17
2029	1.19
2030	1.22
2031	1.24
2032	1.27
2033	1.29
2034	1.32
2035	1.34
2036	1.37
2037	1.40
2038	1.43
2039	1.46
2040	1.48
2041	1.51
2042	1.54

14.2 Please provide a Carbon pricing scenario on the Figure 2-3 graphic showing potential prices increases being proposed by the federal government.

Response:

The carbon pricing scenario represented by the red line in Figure 2-3 in the Application represents the impact per GJ of carbon price for the Planning Setting applied to FEI's DEP Scenario. This value matches the federal carbon price announcement and grows to $170 per tonne in 2030 (in nominal dollars) which equates to an additional cost of approximately $8.50 per GJ ($7.20 real) over the current carbon price and remaining constant thereafter. The dashed purple line in the figure represents the combined natural gas plus carbon tax cost forecast. Appendix B-3, Section 1.1.1.1.3 of the Application, contains a discussion of the range of carbon prices examined and used in the development of scenarios in the Application and the related outcomes.

14.3 Please discuss any potentials FEI will be examining to lower the Renewable and low carbon gas costs in the future.

Response:

In preparing the "Preliminary Forecast of Renewable and Low-Carbon Gas Cost" in Figure 2-3, FEI already considered procurement options to lower the renewable and low-carbon gas costs, including:

- Continued acquisition of RNG (biomethane) supply at competitive pricing available through access to the North American production base;
- Acquisition of new forms of on-system renewable gas supply such as syngas and lignin which require less refining during production and end-use compared to RNG and are therefore expected to be lower cost compared to RNG;
- Acquisition of on-system and off-system renewable and low-carbon hydrogen supply from proposed large-scale state-of-the-art production facilities, which would be delivered by displacement; and
- Acquisition of carbon-abated natural gas with reduced carbon intensity through structuring of carbon credits and gas volumes utilizing carbon capture and storage.

FEI will continue to monitor developments in the marketplace for renewable and low-carbon gas production and capture further opportunities for lowering costs for these supplies in future LTGRPs.

14.4 Please discuss whether FEI will be seeking consultations on how these costs might be significantly lowered and increase the FEI clean gas competitiveness with electrification alternatives in the future.

Response:

FEI will consider all feasible options to lower the cost of renewable and low-carbon gas supply, including seeking consultations with key stakeholders in strategic energy forums that could be material to achieving lower cost renewable gas supply.

15. Reference: Exhibit B-1, Page 2-26

> Renewable and low-carbon gas will play an integral role in allowing FEI to meet its GHG reduction targets. The blend of fuel types is currently expected to be more expensive than natural gas plus carbon tax and, as more is incorporated into FEI's energy portfolio, fuel costs and rates will face upward pressure.

15.1 Aside from cost considerations, please indicate where in the Application does FEI provide the assumptions it has used to determine the expected availability of RNG for absorption into FEI's system or credited to the FEI system, over the forecasting horizon?

Response:

Please refer to the responses to BCUC IR1 52.4 through 52.6 and BCUC 77 series for supporting assumptions used to determine the expected availability of renewable and low-carbon gas over the planning horizon.

15.2 Has FEI canvassed its own service territory and those of the PNW or does it rely on third-party research for determining the expected availability of RNG for absorption into FEI's system? Please explain.

Response:

FEI assumes the information request is referring to the expected availability of RNG (biomethane) derived from upgrading biogas produced by anaerobic digestion of farm and municipal waste streams and derived from upgrading landfill gas.

FEI has not specifically canvassed the PNW; however, FEI has developed future potential estimates using knowledge in several areas. First, based on its experience and ongoing engagement with the biogas community in these regions, FEI is able to form general conclusions on the expected availability of RNG. Second, FEI is an active buyer of RNG in the regional marketplace and observes market signals in terms of near-term RNG supply potential; this is based on executed supply agreements, supply agreements in advanced stages of negotiation, and potential opportunities in the form of supply prospects. Lastly, FEI has engaged qualified third-party experts over the past decade to complete longer-term RNG supply potential outlooks. Most recently, FEI worked with the BC Bioenergy Network to complete the BC Renewable and Low-Carbon Gas Supply Potential Study[8] to assess BC, Canada, and North American RNG supply. This latest body of work integrates numerous previous RNG potential studies and estimates for BC's RNG feedstock availability using predicted agricultural and

[8] Exhibit B1-1, 2022 LTGRP Application, Appendix D-2.

population growth rates for BC, Canada and the US were extrapolated using population data from the past 20 years. The Renewable and Low-Carbon Gas Supply Potential Study also included landfill gas potential based on existing landfill gas model estimates.

15.3 Does the body of work to this effect consider BC population growth scenarios? BC housing starts scenarios? BC per capita consumption trends? BC per capita waste-generation trends? Growth in landfills and landfill gas generation in BC or the PNW? Please explain.

Response:

Please refer to the response to CEC IR1 15.2.

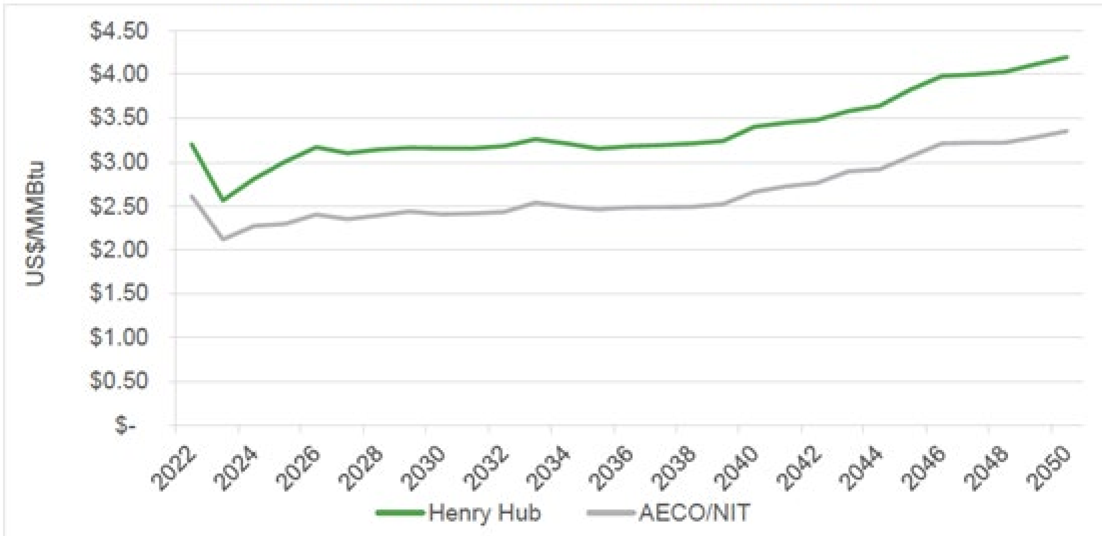
15.4 Please provide a discussion of the drivers that inform the expected availability of RNG for absorption into FEI's system; or the reference(s) to the studies used.

Response:

Please refer to the recent BC Renewable and Low-Carbon Gas Supply Potential Study for a comprehensive discussion of the potential for RNG and other renewable and low-carbon gases to enable decarbonization of the gas supply in BC and BCUC IR1 77 series describing renewable and low-carbon gas supply potential.

16. Reference: Exhibit B-1, Page 2-27, Figure 2-4

Figure 2-4: Natural Gas Price Forecast (2021 Real Dollars) [87]



16.1 Please provide the discount rate(s) used in estimating the $ Real prices provided in Figure 2-4.

Response:

The following table shows the discount rates (US GDP deflator) used in calculating the 2021 real dollar prices provided in Figure 2-4.

	US GDP deflator (2021 base year)
2021	1.00
2022	1.03
2023	1.06
2024	1.08
2025	1.11
2026	1.14
2027	1.16
2028	1.19
2029	1.22
2030	1.25
2031	1.28
2032	1.31
2033	1.33
2034	1.36
2035	1.40
2036	1.43
2037	1.46
2038	1.49
2039	1.53
2040	1.56
2041	1.60
2042	1.63
2043	1.67
2044	1.71
2045	1.75
2046	1.79
2047	1.83
2048	1.87
2049	1.92
2050	1.96

16.2 Are AECO/NIT and Station 2 prices settled in USD or CAD?

Response:

AECO/NIT and Station 2 prices can be settled in either US dollars or Canadian dollars.

16.3 Please provide the CAD/USD Exchange Rate assumptions embedded in Figure 2-4 US$/MMbtu estimates (where applicable).

Response:

The price forecast from IHS Markit was provided in US dollars per MMBtu and, as such, there were no exchange rate assumptions embedded in Figure 2-4.

16.4 In Figure 2-4, to what does FEI attribute the 'dip' in forecast prices for the 2022-2024 timeframe?

Response:

The drop in forecast prices during the 2022 – 2024 timeframe is due to increased production coming online and supply being above demand in 2023; however, prices rebound the following year and remain flat over the long term, with prices above $3.00 US per MMBtu and steadily increasing from 2040 to 2050 to above $4.00 US per MMBtu.

16.5 What assumptions, if any, do AECO/NIT and Station 2 prices incorporate with regard to LNG production in BC over the forecasted period?

Response:

The AECO/NIT price forecast from IHS Markit, released in February 2022, assumes that LNG export demand begins in late 2025, starting with Phase 1 of LNG Canada and then followed by Woodfibre LNG in 2027. Additional LNG exports are not expected to begin operating in Canada until 2035. Increasing demand from LNG helps to provide some upside pressure on forecast prices, helping to offset the assumption of declining residential and commercial demand for natural gas after 2033. IHS Markit assumes that there is a minimal price increase from LNG exports due to the assumption of increasing natural gas production; however, prices may have further upside pressure if actual natural gas production does not increase to meet the marginal LNG demand.

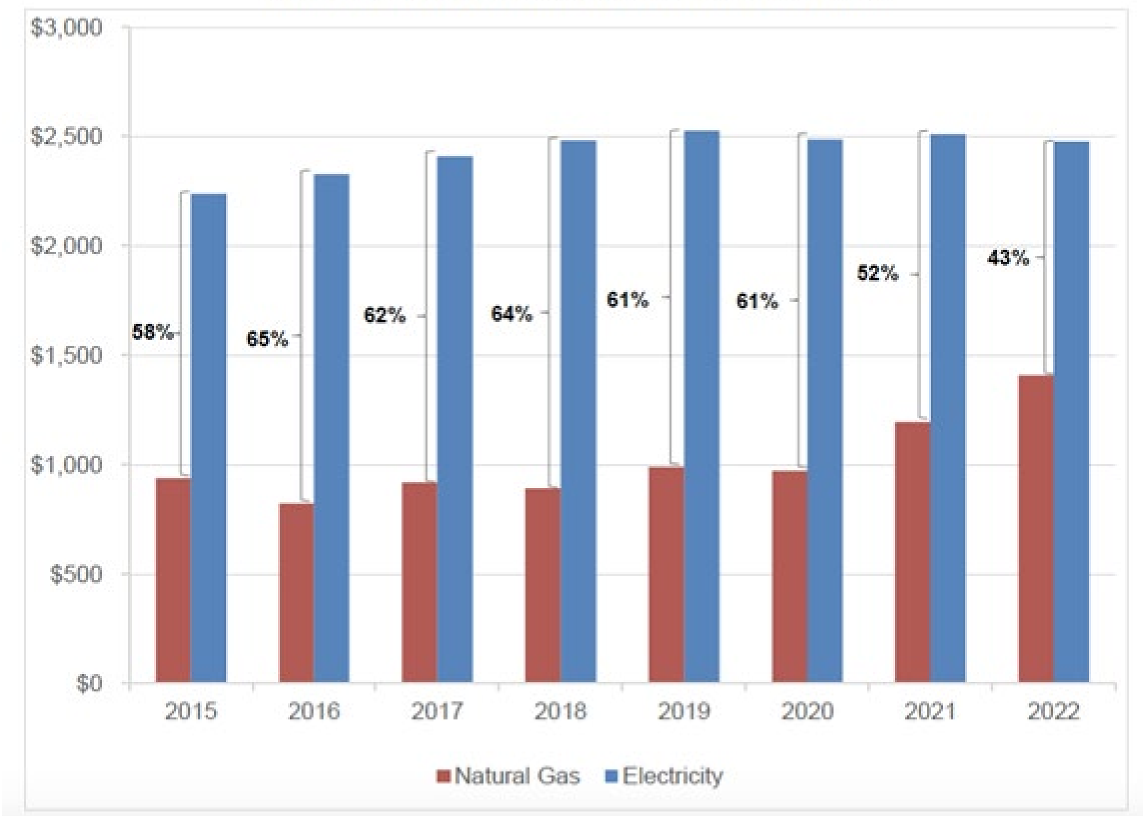
16.6 Does FEI observe any correlation between BC LNG production forecasts and AECO/NIT and Station 2 price forecasts over the forecasted period? Please explain.

Response:

Please refer to the response to CEC IR1 16.5.

17. Reference: Exhibit B-1, Page 2-30, Figure 2-5

Figure 2-5: Residential Annual Bill Amount Trend in BC



17.1 Please provide the equivalent to Figure 2-5 to show the Commercial Annual Bill Amount Trend in BC.

Response:

FEI does not have a source for the historical annual bill amounts of BC Hydro's commercial and industrial customers and therefore is not able to respond to this question. Further, unlike the residential rate class where the need for space and hot water heating allows for an apples-to-apples comparison, the end-uses for commercial and industrial customers are significantly more diverse with efficiency information that is less certain. Gas and electricity applications as well as the consumption pattern for commercial and industrial customers are different and their respective rate schedules have different eligibility criteria, which makes an apples-to-apples comparison not possible and less meaningful.

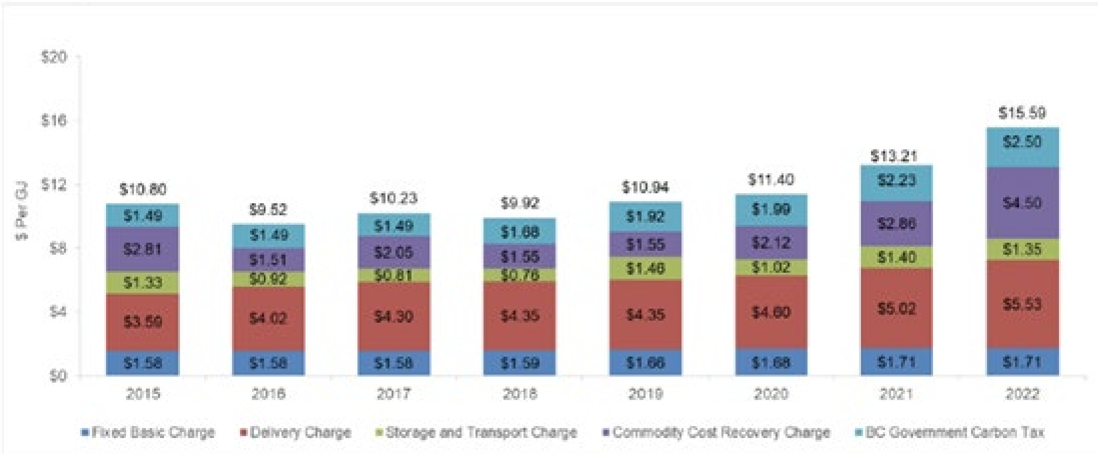
17.2 Please provide the equivalent to Figure 2-5 to show the Industrial Annual Bill Amount Trend in BC.

Response:

Please refer to the response to CEC IR1 17.1

18. Reference: Exhibit B-1, Page 2-31, Figure 2-6

Figure 2-6: Breakdown of FEI's Historical Total Effective Rate for Residential Customers



18.1 Please provide the average percentage rate of increase for FEI's Historical Total Effective Rate for Residential Customers for the period 2016-2022.

Response:

The compound annual growth rate (CAGR) of FEI's effective rate, inclusive of carbon tax, for residential customers (RS 1) between 2016 and 2022 is 8.5 percent.[9] If the annual average is calculated for the entire period shown in the chart above (2015-2022), the CAGR of FEI's effective rate is approximately 5.4 percent.

18.2 Please provide the average percentage rate of increase for the 'Commodity Cost Recovery Charge' component of FEI's Historical Total Effective Rate for Residential Customers for the period 2016-2022.

Response:

The CAGR of the Commodity Cost Recovery Charge component only in Figure 2-6 of the Application from 2016 to 2022 is approximately 20 percent[10] for RS 1 customers. FEI notes this is largely due to the sharp increase in commodity prices during the 2021-2022 period which increased by approximately 57 percent. North American natural gas prices started to rise in 2021, as prices experienced greater connection to global markets due to LNG exports comprising of a much larger proportion of US demand. Regionally, cold weather during winter

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[9] The calculation is [(15.59/9.52)^(1/6)]-1*100.

[10] The calculation is [(4.50/1.51)^(1/6)]-1*100.

2021/22 and increased natural gas for power generation due to retiring coal plants in the Pacific Northwest caused prices to rise.

18.3 During the 2016-2022 timeframe, which factors contributed more significantly to the increase in the 'Commodity Cost Recovery Charge' component?

Response:

Please refer to the response to CEC IR1 18.2.

18.4 Please provide similar data as found in Figure 2-6 for Commercial and Industrial customers.

Response:

Please refer to Tables 1 to 3 below for the breakdown of FEI's historical (2015 to 2022) total effective rate for RS 2 (Small Commercial), RS 3 (Large Commercial), and RS 5 (General Firm Service), respectively.

Table 1: Breakdown of FEI's Historical Total Effective Rate for RS 2 Small Commercial

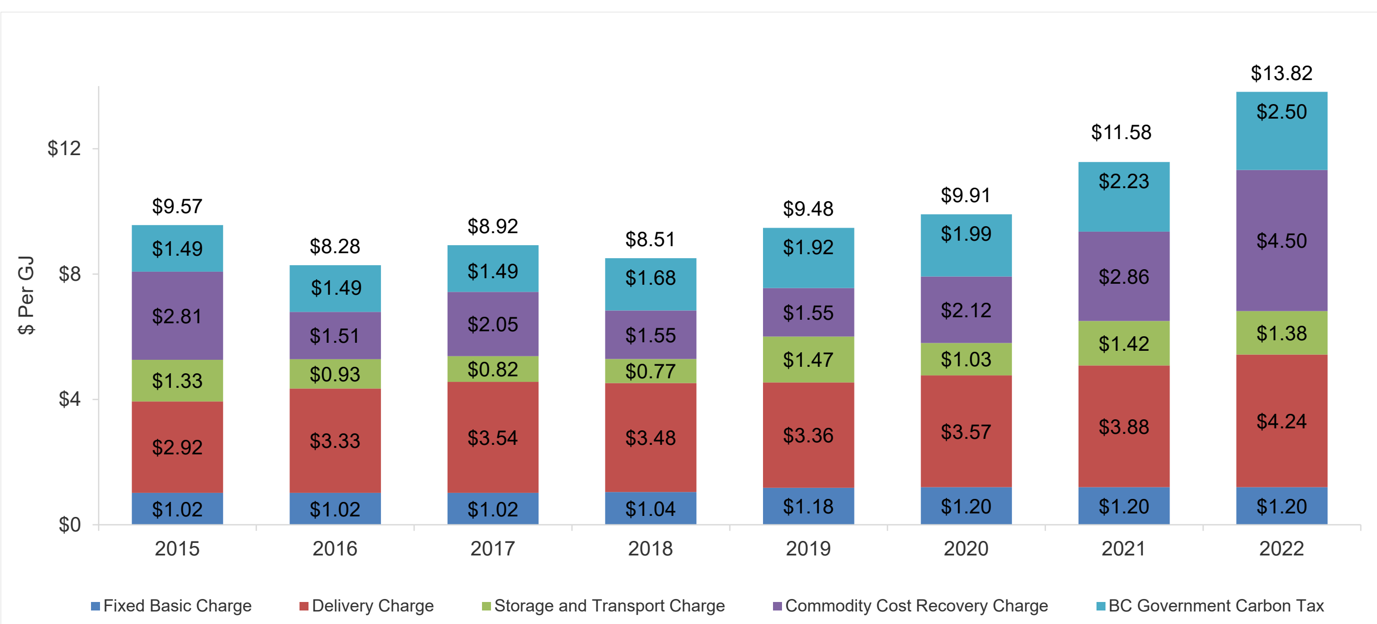


Table 2: Breakdown of FEI's Historical Total Effective Rate for RS 3 Large Commercial

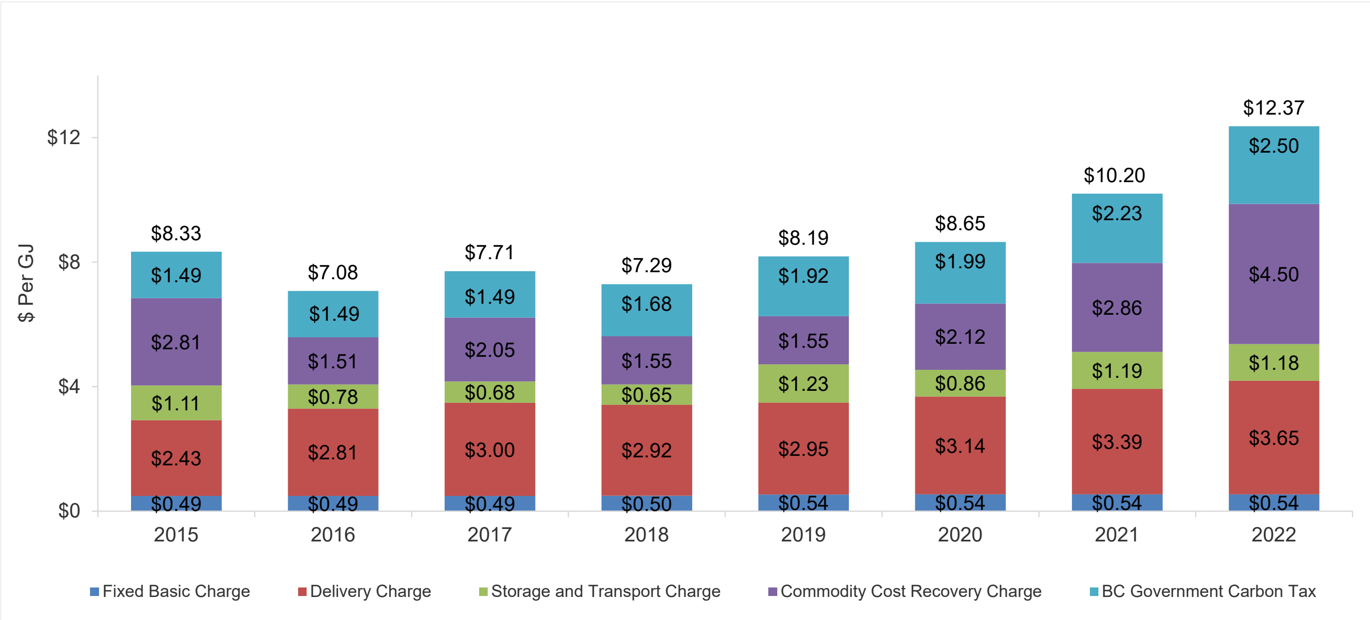
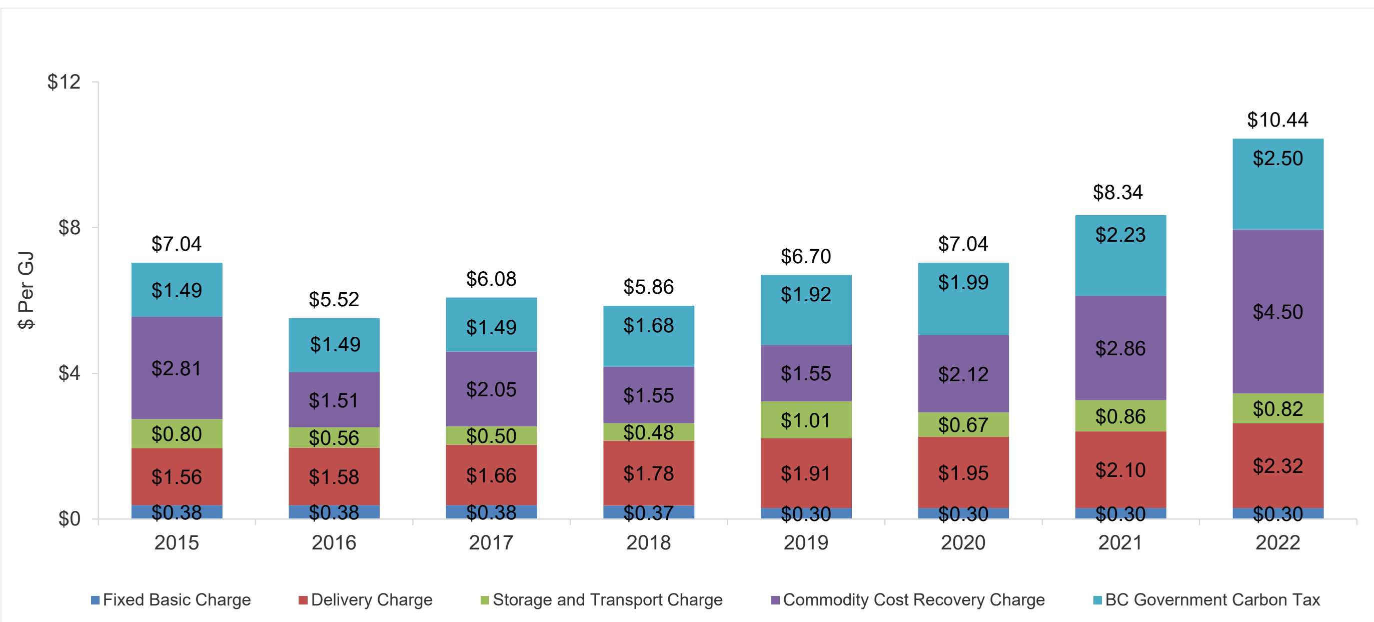


Table 3: Breakdown of FEI's Historical Total Effective Rate for RS 5 General Firm Service



CLEAN GROWTH PATHWAY – FOUR PILLARS TO A LOW CARBON FUTURE

19. Reference: Exhibit B-1, Page 3-6

3.2.2.3 The Clean Growth Pathway Offers Energy System Resilience

BC's energy system resilience is best achieved through keeping both gas and electric energy systems thriving to ensure British Columbians are not relying on a single energy system. A diversified approach is of even greater importance with the advent of extreme weather events caused by climate change, which can catalyse unanticipated system outages. Where one system is experiencing a supply disruption, other systems can supplement energy to meet customer demand in the interim. The deep electrification pathway requires reliance on only one source of supply, whereas the Clean Growth Pathway leverages the supply potential of both gas and

[104] BC Hydro Operational Update December 28, 2021, described that between 5 and 6 PM on December 27, 2021, demand for electricity hit an all-time high of 10,902 megawatts.

[105] Peak gas demand in equivalent MW using standard unit conversion of 1 MW = 3.6 GJ/hour.

[106] The gas system is also superior at meeting prolonged or multiple peaks due to its energy density and storage capacity. In contrast, the emergence of summer and winter peak events on BC's electric systems represents a growing challenge given the seasonal replenishment of storage reservoirs.

SECTION 3: CLEAN GROWTH PATHWAY – FOUR PILLARS TO A LOW-CARBON FUTURE PAGE 3-6

19.1 As per footnote 106 in the above reference, please discuss in more detail the emergence of summer peak events on BC's electric systems, and the service challenges arising therefrom.

<u>Response:</u>

Climate change has substantially increased the probability of extreme heat events. FBC's prior historical peak load of 746 MW was set on December 20, 2008. On June 29, 2021, FBC recorded its now-highest-ever peak load of 764 MW. While FBC typically experiences its highest system loads for the summer during July or August and for winter during December or January, the June 2021 extreme heat event occurred outside of the usual windows for peak load. The system was able to meet this peak demand without experiencing any power supply or system reliability issues in this case, but this event highlighted the need for operational flexibility and resiliency going forward.

Further, it is widely recognized that the Pacific Northwest region is facing a period of resource adequacy concerns and price and reliability uncertainty in terms of the electric grid. Natural gas fired-generation, increased renewable generation projects, and regional, provincial and state developments are changing the regions' resource dynamics. The regional power marketplace has recently been in an energy and capacity surplus due to hydropower and gas-fired combined-cycle power generation. However, due to coal plant retirements, lower hydro-generation, and greater summer demand, the Pacific Northwest is facing a potential shortfall in capacity resources. Capacity shortfalls could result in less reliability and greater price volatility in the wholesale market, creating uncertainty and market reliability risk for FBC over the long term.

19.2 Does FEI believe that summer A/C demand related to warmer weather events in BC, is best served by the electric systems or by the gas systems, in the long run? Please explain.

Response:

FEI anticipates that there will be increased customer demand to retrofit homes and buildings without cooling with air conditioning solutions. Although FEI believes that summer cooling is appropriately served by the electric system (as opposed to a gas system), there will likely be circumstances where it is impractical or cost-prohibitive for the customer to upgrade their electrical service in order to support it. In those cases, providing customers with gas-powered options that can also provide cooling (such as gas heat pumps) could be a viable solution. Also, FEI considers that both the gas and electric system must complement each other throughout the year. To this end, FEI has been evaluating hybrid heating systems which use both an electric heat pump and a gas heating appliance, with an integrated controller to engage either system in an optimal manner. FEI sees potential with hybrid systems and gas heat pumps to meet summer cooling and winter peak heating demand while reducing customer costs and GHG emissions.

Additionally, cooling loads may require a greater role for the gas system and renewable gaseous fuels to generate the electrical energy required. As discussed in FBC's 2021 Long-Term Electric Resource Plan (LTERP), cooling will potentially be a significant load driver and renewable natural gas used for electric peaking generation is a resource that is considered to meet load.

19.3 Does the availability and/or the capability of storage on the respective electric and gas systems best dictate which system is best suited to serve emerging summer peak events in BC, or do customer-driven solutions and the state of end user technologies play a more dominant role going forward? Please explain.

Response:

FEI believes that end use technology will play the more dominant role in the adoption of cooling technologies. Notably, electric heat pumps and traditional electric air conditioning units are incumbent technologies for cooling services. In FBC's 2021 LTERP, cooling load is identified as a long-term load driver, but that the electric system will overall remain a winter peaking system. Notwithstanding this, the gas system may still have a role to play in meeting peak energy demand for cooling load as discussed in the response to CEC IR1 19.2.

19.4 As it regards the long-term resilience of electric and gas systems in BC, does FEI presume that sharing of load servicing needs (as between the electric and gas systems) across the winter and summer peaks is best? Or do electric and gas systems evolve over time (i.e. specialize) to respectively assume more of the load servicing needs of either the winter or summer seasons or perhaps other forms of specialization of service? Please explain.

Response:

FEI believes that the strengths of each of BC's gas and electric distribution systems should continue to be leveraged together as part of the province's pathway to achieve its GHG emissions targets. The benefits of such an approach are discussed in the LTGRP's DEP Scenario. Using both gas and electric distribution infrastructure to continue to meet loads while reducing GHG emissions improves overall cost-effectiveness, reliability, resilience, and feasibility, particularly in meeting winter demand peaks and higher demand periods.

Both BC Hydro and FBC are winter-peaking utilities. One of the strengths of the gas system is its ability to meet peak heating demands on the coldest days with comparatively less infrastructure than the electric system. This is due to the lower costs of storing gas, which provides for short-term storage in the distribution system itself and longer-term storage through dedicated storage facilities like Jackson Prairie, Mist, Mt. Hayes and Tilbury. Electricity cannot be similarly stored for the duration and scale that is enabled by the gas system, barring future advances in cost-effective utility-scale seasonal electricity storage. For the electric system to accommodate a similar peaking load that the gas system is forecasted to accommodate as part of the Clean Growth Pathway, the electric system would need to significantly expand its generation capacity, and transmission and distribution systems (please refer to the responses to BC Hydro IR1 4.1 and 4.2). This expanded electric system would still be more vulnerable to extreme weather events such as fires, drought, and flooding.

Under the DEP Scenario, more customers retain their gas heating equipment.[11] During winter peak demand events and some service disruptions to electric utility customers, heating needs could still be met with gas equipment. Utility Distributed Energy Resource Managements Systems (DERMS) may increasingly provide load switching services in the near future to participating customers that connect with smart thermostats or Building Management Systems (BMS), further improving system resilience.

[11] FEI notes that it is also evaluating the potential for some customers to have dual gas and electric heating equipment. Please also refer to the BCUC IR1 9.2 and 9.3 series of responses.

19.5 How do the resilience objectives play out at sub-regional levels?

Response:

A sub-regional scope is important when considering energy resiliency objectives and impacts to specific communities. When sub-regional locations experienced extreme weather patterns in 2021, such as the flooding events in the fall of 2021, there were direct impacts on the proper functioning of their energy systems for short periods of time. Diversified energy systems, as discussed in the responses to CEC IR1 3.1 and 3.2, strengthen resilience. FEI continues to plan the future of its energy system to ensure that the regions it serves have a high level of diversification that increases resilience.

20. Reference: Exhibit B-1, Page 3-11

> FEI has offered a Renewable Gas Program since 2010, with cost recovery of the acquired renewable gas volume from voluntary program participants through the Biomethane Energy Recovery Charge (BERC) which was set to match projected supply costs. In February 2020, the BCUC accepted FEI's first acquisition of renewable gas outside of BC as a prescribed undertaking under the GGRR. In May 2021, the provincial government amended the GGRR, increasing the acquisition cost cap and volumes and expanding acquisition opportunities for FEI as discussed previously in Section 2.2.2.3.

20.1 Please identify the out-of-province jurisdiction(s) that presently supply FEI's acquisition of renewable gas from outside of BC.

Response:

FEI is currently acquiring out-of-province RNG from Alberta, Ontario and the United States.

20.2 Please identify out-of-province jurisdiction(s) which may prove more attractive in the future for FEI Renewable Gas programs.

Response:

FEI is only considering jurisdictions that connect directly to the existing natural gas system across Canada and the United States. RNG supplied onto the existing natural gas system can directly displace conventional natural gas and thus be delivered to FEI. FEI is impartial to the location where the RNG is injected into the system.

21. Reference: Exhibit B-1, Page 3-13

> **3.3.3 FEI's Clean Growth Pathway Supports BC's Hydrogen Economy**
>
> FEI's vision for a hydrogen economy is built around evolving policy and technology developments in BC,[111] Canada[112] and internationally. Hydrogen is a versatile energy source and carbon-free at the point of use. It broadens opportunities for renewable and low-carbon fuels, as it can be used as an energy carrier, energy storage medium, gaseous fuel alternative to natural gas, and as a chemical feedstock to address difficult-to-decarbonize end use applications such as high temperature industrial processes, space heating, and long-haul transportation. As the BC Hydrogen Study indicates, it has the potential to be produced at scale in BC using commercially available technology. Developing and delivering hydrogen through or enabled by existing gas infrastructure would give FEI the opportunity to create new partnerships, expand business

21.1 On lines 13 and 14 above, FEI states 'Hydrogen is a versatile energy source and carbon-free at the point of use'. What is the carbon footprint of hydrogen at the point(s) of production based on different production methods?

Response:

There are numerous recently published reference studies that present estimated life cycle carbon intensity ("carbon intensity") of various renewable and low-carbon hydrogen production pathways. Some of these reference studies are listed below and include a range of assumptions as inputs when calculating the carbon intensity. In general, the carbon intensity varies from zero kilograms of carbon dioxide equivalent per gigajoule (0 kg CO_2e per GJ) of hydrogen produced from the electrolysis of water using off-grid wind generated electricity, to a carbon intensity of 27 kgCO_2e per GJ for hydrogen produced from steam reforming of methane (SMR) utilizing carbon capture that captures and sequesters 90 percent of the carbon dioxide produced in the SMR process.

- The Hydrogen Strategy for Canada: Figure 17 - Carbon Intensities of Hydrogen from Different Production Pathways for the range of CI of hydrogen from different production methods.[12]
- The BC Hydrogen Study: Figure 26 – Carbon Intensity of Hydrogen Production Pathways in BC.[13]
- The BC Renewable and Low-Carbon Gas Supply Potential Study: Section 3.4, Hydrogen Production from Solid Biomass, and Section 4, Hydrogen From Non-Biomass Resources.[14]

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12 Exhibit B-1, Appendix A-2.
13 Exhibit B-1, Appendix A-6.
14 Exhibit B-1, Appendix D-2.

21.2 Where in the Application does FEI include carbon footprint information related to hydrogen fuel production? Please provide references.

Response:

FEI referenced various resources including recent industry research study data, examples of which are referenced in the response to CEC IR1 21.1, to assume an average hydrogen carbon intensity. This was used to determine the expected volume of hydrogen required as part of FEI's low-carbon gas portfolio to meet its greenhouse gas reduction targets over the LTGRP planning period.

21.3 Please provide the carbon footprint of the various types of hydrogen fuel (green, waste, blue, turquoise, etc.) that FEI considers in its 2022 LTGRP.

Response:

Please refer to the response to CEC IR1 21.1, which lists the references that FEI utilized in understanding the carbon intensity of the various types of hydrogen fuel considered in the Application.

22. Reference: Exhibit B-1, Page 3-16

> Currently, there is an opportunity to start transitioning pulp mills and cement manufacturing facilities to using low-carbon hydrogen. This transition can be initiated with minimal upgrades and process impacts by blending low-carbon hydrogen into the end user's existing natural gas supply, starting at as low as 2 percent by volume. An industrial hydrogen blending test program will be conducted, administering appropriate safety and impact assessments in order to allow for safe incremental increases of hydrogen blending, by up to 20 percent.
>
> During the blending period, existing technology for 100 percent hydrogen burners is to be investigated and piloted for use in cement kilns. Once commercialized, hydrogen burner technology can be tested and rolled out at industrial facilities, with the goal of converting pulp mills

22.1 What is the timing for the start of the industrial hydrogen blending test program?

Response:

Please refer to the response to BCUC IR 52.5.

22.2 Please provide information as to the type of facility or facilities that will participate in this pilot in BC.

Response:

Please refer to the response to CEC IR1 22.1.

22.3 Are similar test programs being undertaken elsewhere in the PNW region? Please explain.

Response:

FEI is not aware of similar trials being undertaken elsewhere in the PNW. However, FEI is actively engaged with other utility companies, industry associations and other forums, such that if FEI becomes aware of similar trials, then FEI will endeavor to engage to support the most efficient approach to avoid duplication of effort.

23. Reference: Exhibit B-1, Page 3-20

> - Activities to accelerate market transformation to gas heat pump technology, dual-fuel hybrid heating systems, and other innovative technologies that will reduce GHG emissions while enhancing resiliency to utilize the strengths of both the gas and electric systems during periods of peak demand;

23.1 How far advanced in the development spectrum (i.e. months, years away from commercialization) is gas heat pump technology?

Response:

In 2021, the Energy Solutions Center (ESC) produced a publicly-available gas heat pump guide[15] that provides an overview of gas heat pumps (GHP), benefits associated with such systems, and market opportunities.

As part of this guide, ESC provided information on GHP product status as shown below. To date, nine technologies for the commercial sector are available to purchase and implement today, while four technologies for the residential sector (Vicot, SMTI, Robur and Heat Amp) are pre-commercial, undergoing field demonstrations.

[15] https://consortia.myescenter.com/GHP/ESC-GHP_Guide.pdf.

Gas Heat Pump Product Status 2021

Company	Type	Technology	Best Applications	Status	Heat Sizes	Cooling Sizes
Aisin	Heating, Cooling, Water Heating	IC Engine	Residential, Commercial, Industrial	Commercially available	103,000 to 410,000 BTU/h	8, 15, and 30 Tons
Blue Mountain Energy	Heating, Cooling, Water Heating	IC Engine	Residential, Commercial, Industrial	Commercially available, 5 & 11 Ton, field testing others	91,000 to 410,000 BTU/h	5, 8, 11, 15, and 30 Tons
boostHEAT	Heating, Water Heating	Thermal Compressor	Residential	Field test 2022	68,000 BTU/h	n/a
Broad USA	Heating, Cooling, Water Heating	Absorption	Commercial, Industrial	Commercially available	962,000 BTU to 57,800,000 BTU/h	30 to 3,968 Tons
Energy Concepts	Heating, Cooling, Water Heating	Absorption	Commercial, Industrial	Commercially available	396,000 to 40,000,000 BTU/h	20 Tons to 2,000 Tons, down to -50°F
Gridiron	Heating, Cooling, Water Heating	IC Engine	Commercial	Commercially available	70,000 BTH/h	5 Tons
HeatAmp	Heating, Water Heating	Adsorption (Chemisorption)	Residential	Field test 2023	Up to 50,000 BTU/h	n/a
Robur	Heating, Cooling, Water Heating	Absorption	Residential, Commercial	Commercially available	120,000 BTU/h	5 Tons
Stone Mountain Technologies	Heating, Water Heating	Absorption	Residential, Commercial	Commercially available 2022	10,000 to 140,000 BTU/h	Future cooling 1-4 tons
Tecogen	Heating, Cooling, Water Heating	IC Engine	Commercial, Industrial	Commercially available	527,500 Btu/h	22 Tons
ThermoLift	Heating, Cooling, Water Heating	Thermal Compressor	Residential	Field demos	55,000 to 75,000 BTU/h	3 Tons
Yanmar	Heating, Cooling, Water Heating	IC Engine	Residential, Commercial, Industrial	Commercially available	108,000 to 198,000 BTU/h	8, 10, 12, and 14 tons
Vicot	Heating, Water Heating	Absorption	Residential, Commercial	Commercially available. Resid. units: Field Trial	68,000 BTU to 290,000 BTU/h	n/a

Key: Residential Commercial Industrial Heating Cooling Water Heating

Through industry consultations with residential gas heat pump manufacturers, FEI expects residential GHPs to enter the market as early as 2024. FEI is currently involved in several residential GHP pilot programs to determine technology performance, installation challenges and customer acceptance, in order to reduce risk of the technology and to identify cost-effective opportunities to support Demand-Side Management incentives for 2024.

23.2 What technology development milestones will be observed to assess viability of commercialization of gas heat pump technology?

Response:

FEI plans to observe gas heat pump development milestones specific to the following manufacturer activities:

- Achievement of codes and standards certifications
- Successful lab testing results verified by third parties
- Successful field performance verified by third parties
- Establishment of production facilities
- Establishment of supply chain
- Education of local trades
- Education of target market

In parallel, FEI milestones to support commercialization of technologies will include:

- Approval of regulatory funding to support third party lab testing, field demonstrations and DSM incentives;
- Receipt and verification of lab testing and pilot results
- Internal business case approval of a DSM rebate offer/incentives to support gas heat pump adoption
- Completion of contractor training and awareness workshops
- Development of customer educational materials

23.3 Are dual-fuel hybrid heating systems available at present, or is this technology still under development?

Response:

Please refer to the responses to the BCUC IR1 9.2 series for discussion about FEI's research into dual-fuel hybrid heating systems. The gas savings potential from this technology is currently not well understood.

While electric heat pumps and natural gas furnaces are both established technologies, operating them sequentially with sophisticated controls is still an emerging concept. FEI is currently considering direct support for pilots of hybrid heating systems with two companies (Homy and Stone Mountain Technologies). FEI is also aware of programs underway with Enbridge and Energir and is working collaboratively with these utilities to support research into customer behaviour, technology limitations, system performance and controls strategies.

23.4 Please discuss combined heat and power systems as they may become factors in the solutions for gas systems to decarbonize and then supply power and heat.

Response:

Combined heat and power systems (CHPs) use a fuel such as natural gas, renewable natural gas or hydrogen to generate both heat and electricity. CHP systems typically operate with combustion engines (piston or turbine), or fuel cells. These systems have been used for many years typically in commercial applications that have a simultaneous need for both heat and electricity, and areas where the cost differential between natural gas and electricity is substantial enough to offset the capital and operating expense of the CHP system. As residential systems become available on the market, FEI expects that residential customers may also be interested in CHP systems as a way to improve electric supply resiliency while heating their home with gaseous fuel.

CHP systems fueled with low-carbon gaseous fuels such as biomethane or hydrogen can assist with reducing GHG emissions. Alternatively, CHP systems can be used to reduce emissions in jurisdictions where it displaces electricity generated from a higher GHG-emitting source.

CHP systems using low-carbon gas could be used to allow the gas and electric systems to work together to provide customers with affordable energy while reducing emissions. For example, greenhouses, which have a requirement for heat, electricity, and CO_2, could potentially make use of CHP systems to reduce the demand placed on the electrical grid and/or avoid investments in electrical infrastructure, which may result in reduced costs for greenhouse operators, and help further enable the electric grid to displace other sources of emissions such as those related to transportation.

24. Reference: Exhibit B-1, Page 3-21

> Supplying fuel for LCT and remote power generation for non-grid connected communities and industrial sites currently using higher carbon fuels are key opportunities for FEI to serve the energy needs of customers and help reach the ambitious GHG reduction targets legislated by the province. In the LCT and remote power generation sectors, FEI is looking to displace petroleum fuels such as diesel with cleaner-burning natural gas and RNG. Natural gas is a lower-carbon alternative to conventional transportation and remote power generation fuels and can play a significant role in reducing emissions and reducing reliance on petroleum-based fuels. Where opportunities exist, substituting conventional natural gas with RNG can increase emission reductions further. RNG is a direct substitute for conventional natural gas in vehicles, and requires no incremental capital investment to the vehicles or infrastructure that are already capable of operating on natural gas.

24.1 Please further detail FEI's efforts to support remote power generation for industrial sites and non-grid connected communities in BC.

<u>Response:</u>

FEI's efforts to support remote power generation for industrial sites and non-grid connected communities in BC involves having discussions with industrial site operators and logistics providers to assess the viability of supplying LNG to these locations. FEI attends local mining conferences and association events to further develop this line of business and promote fueling alternatives to diesel. FEI is also currently providing LNG service to customers who deliver LNG for remote power generation customers, and FEI is supporting their attempts to increase demand.

24.2 What is the scope of this effort at present, and looking out in the next four years?

<u>Response:</u>

The scope of FEI's efforts to support remote power generation for industrial sites and non-grid connected communities is highly dependent on opportunities and customer trends. Currently there have not been any opportunities that have developed beyond conceptual discussions. FEI will continue to make efforts to advance and grow this market and will increase its efforts over the next four years if material opportunities arise.

25. Reference: Exhibit B-1, Page 3-22

> The Province of BC and FEI are strategically positioned to be leaders in this transition and help reduce global GHG emissions. BC has significant natural gas resources, with remaining raw reserves of approximately 1.165 trillion cubic metres. Over 60 billion cubic metres of natural gas were produced in 2018.[117] However, domestic use of conventional natural gas may possibly decrease over time to reach CleanBC's 2050 domestic target. In that scenario, BC's natural gas could then be exported as LNG to Asia to displace higher carbon and higher polluting fuels such as coal and oil, which could result in a net reduction of global GHG emissions.

25.1 Please comment on the expected longevity of BC's natural gas resources (estimated in years) if annual domestic (BC) natural gas production were to remain at the same level as the 2018 production (60 bcm), everything else equal.

Response:

The expected longevity of BC's natural gas resources is difficult to determine as it can be affected by a number of factors, such as the actual amount of natural gas produced, changes to technically recoverable resources (proved versus unproved), certainty of recoverability based on current economic conditions and operating ability.

For example, the U.S. Energy Information Administration (EIA) reports in the Annual Energy Outlook 2022 that as of January 1, 2020, there are 2,926 trillion cubic feet (Tcf) of technically recoverable resources, 464 of that which are proved resources (or commercially recoverable reserves).[16] Assuming the same annual rate of US dry natural gas production in 2020 of 30 Tcf, the US has enough dry natural gas to last around 100 years, or 15 years based on proved resources.

Similarly, according to the 2018 Oil and Gas Reserves and Production Report from the BC Oil and Gas Commission as referenced in the preamble, BC has marketable resources of 15.058 trillion cubic metres, and remaining raw reserves of 1.165 trillion cubic metres.[17] Assuming the same annual rate of BC natural gas production in 2018 of 60 billion cubic metres, BC has enough natural gas to last around 250 years, or 19 years based on raw reserves.

25.2 What are FEI's expectations for natural gas production levels in BC over the 20-year horizon of its 2022 LTGRP?

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16 https://www.eia.gov/tools/faqs/faq.php?id=58&t=8.

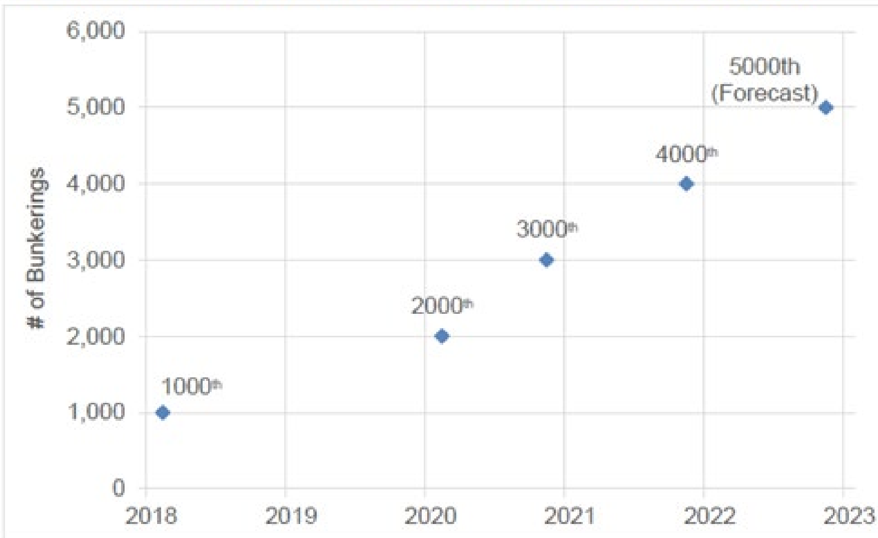
17 BC Oil and Gas Commission, *British Columbia Oil and Gas Reserves and Production Report* (2018) at p. 6, online:https://www.bcogc.ca/files/reports/Technical-Reports/2018-oil-and-gas-reserves-and-production-reportfinal.pdf.

Response:

Please refer to Section 1.3.2 of Appendix D-1 of the Application. This graph illustrates that BC production was approximately 5.7 Bcf per day in 2021, and is forecast by the CER to increase to 12.1 Bcf per day in 2041, which is a 113 percent increase over the 20-year horizon of the Application.

26. Reference: Exhibit B-1, Page 3-24, Figure 3-9

Figure 3-9: Timeline of FEI's Annual Bunkering Milestones (2018-2023)



26.1 To what factors (domestic or otherwise) does FEI attribute the quasi-exponential growth observed in its marine bunkering activities over the 2018-2022 period?

__Response:__

The growth in marine bunkering operations was due to the increase in "short sea" vessels operated by BC Ferries and Seaspan Ferries that use LNG, which increased the amount of bunkering events and the total volume of LNG sold between 2018 and 2022. FEI is now providing service to 10 BC Ferries and Seaspan Ferries LNG-powered vessels. The increase in the number of vessels can be partially attributed to the success of the introduction of LNG to the BC Ferries and Seaspan Ferries fleets, provision of financial incentives by FEI, as enabled under the GGRR to support emission reductions in BC, and the transition of short sea vessels away from diesel and other heavy marine fuels.

Additionally, LNG is currently the primary alternative to heavy marine fuels and diesel as evidenced by the rapid growth in global LNG fuelled vessel orders (See Figure 1). The Society for Gas as Marine Fuel lists the following LNG benefits as the main reasons for the rapid global LNG adoption:[18]

- "Well to Wake" LNG marine fuel GHG reductions: up to 23 percent;
- SOx reduction: 99 percent;
- NOx reduction: 95 percent; and
- PM reduction: 99 percent.

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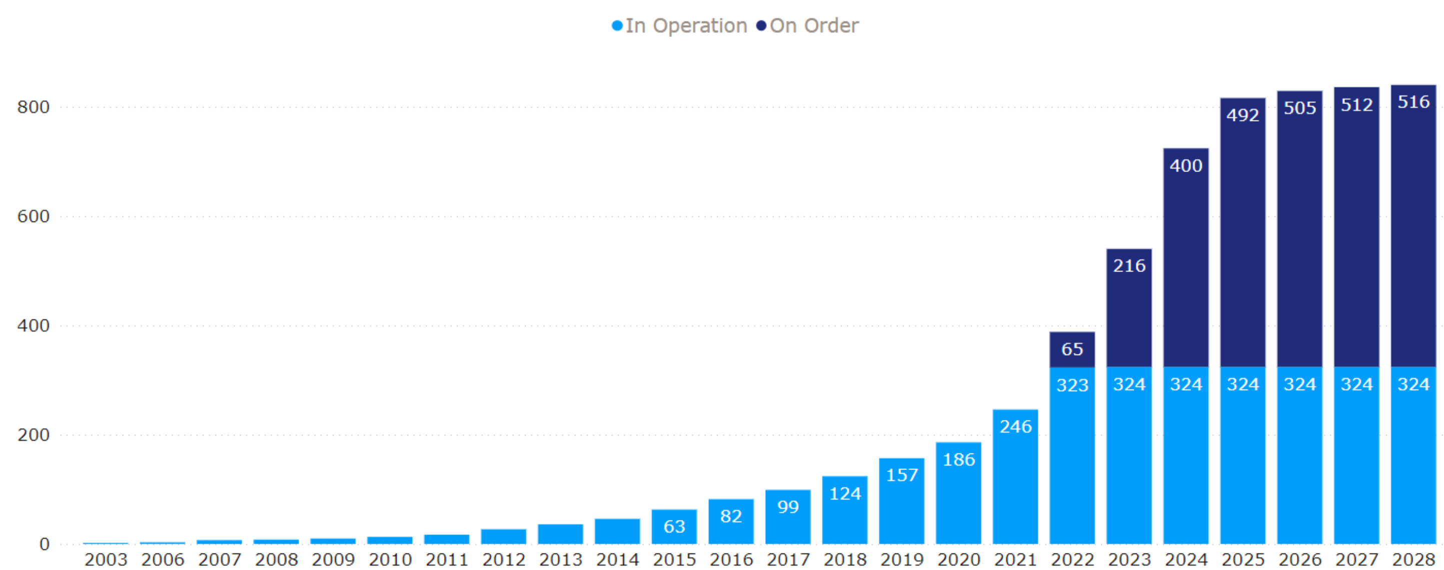
[18] Source: https://s3-eu-west-1.amazonaws.com/sgmf-live/ml/data/a49de2307fe2e907892cd4b190bef4ee.pdf.

26.2 Please provide the potential for this bunkering market to grow in BC and discuss where the limits for the growth may appear and at what levels.

Response:

The potential for the bunkering market to grow in BC is significant. According to a study commissioned by the Port of Vancouver, the market potential could exceed 1.2 million tons of LNG per year by 2030.[19] The Port of Vancouver is a significant hub for transpacific vessels, and the marine industry is starting to transition away from heavy marine fuels and diesel. In April 2018, the IMO agreed on its first strategy to reduce GHG emissions in the international shipping sector to meet the Paris Agreement goals. The IMO strategy includes a target to reduce carbon emissions by at least 50 percent compared with 2008 levels by 2050. LNG is currently the only commercially viable, scalable alternative to heavy marine fuels and diesel as evidenced by the rapid growth in LNG fuelled vessel orders. The figure below shows the LNG vessels in operation and on order based on information from DNV, an international maritime service company. Due to the large market potential identified in the Port of Vancouver's report and the rapid growth in orders of LNG powered vessels, the LNG demand in the Port of Vancouver may exceed FEI's currently capacity, making FEI's planned liquefaction expansion necessary to meet the growing demand in the domestic marine segment.

Figure: DNV Projected Growth in LNG Powered Vessels [20]



19 https://www.portvancouver.com/marine-operations/lng-bunkering/.
20 Source: https://store.veracity.com/alternative-fuels-insight-platform-afi.

ANNUAL ENERGY DEMAND FORECASTING

27. Reference: Exhibit-B1, Page 4-4

> **4.3.1 Residential, Commercial and Industrial Customers**
>
> As an input into the annual demand forecast for Residential, Commercial and Industrial demand FEI establishes a base customer forecast for these customer segments. FEI uses a well-established method that remains consistent with previous LTGRP filings. The forecast of residential customers is based on the Conference Board of Canada housing starts forecast for BC, while commercial customers are forecast based on recent trends in growth for the commercial customer group. The forecast of industrial customers includes existing customers at the end of the base year (2019 year-end) along with any known commitments from customers to either join or leave the system. Explanation of the customer forecast method is provided in Appendix B-1.

27.1 Please provide the Conference Board of Canada (CBC) forecast (including BC population growth, housing starts and/or GDP projections) that inform the development of the Diversified Energy (Planning) Scenario.

Response:

The Conference Board of Canada (abbreviated as CBOC in the filing) forecasts for BC population, single and multi-family housing starts and GDP projections are provided below.[21]

[21] Data provided from the December 5th, 2019 Provincial Medium Term forecast #20, run #20.

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
GDP at basic prices (2012 $ millions)	260,151	265,098	269,093	272,279	275,524	280,784	285,831	290,941	295,983	301,019	306,286	311,781	317,350	322,693	327,951	333,391	338,809	344,373	350,263	356,249	362,560
Population (000s)	5,116.8	5,171.8	5,227.1	5,282.0	5,337.2	5,392.2	5,446.6	5,500.1	5,552.7	5,604.2	5,654.5	5,703.7	5,751.8	5,798.6	5,843.9	5,887.6	5,929.9	5,970.7	6,010.1	6,048.2	6,085.0
Housing starts (units)																					
Single Family Dwelling	9,063	7,957	7,103	6,394	5,906	5,367	5,185	4,950	4,732	4,528	4,342	4,168	4,006	3,850	3,703	3,561	3,423	3,291	3,162	3,041	2,930
Multi Family Dwelling	28,789	26,933	25,771	25,006	24,405	22,883	21,716	21,017	20,353	19,735	19,161	18,629	18,131	17,654	17,185	16,719	16,258	15,808	15,378	14,971	14,594

The single and multi-family housing starts forecast from the CBOC is used to develop the residential portion of the long-term customer forecast, and that forecast underlies both the BAU forecast and the scenario forecasts including the DEP Scenario.

The CBOC population forecast for BC and the GDP forecast are not used for the development of any portion of the BAU or end use scenario forecasts.

27.2 Does FEI use a single CBC economic forecast (including BC population growth, housing starts and/or GDP projections) to drive the development of the 6 scenarios presented in Table 4-1 of the Application on Page 4-22 (Alternate Future Scenario Summary)? Or are some of the Alternate Future Scenarios driven by higher and/or lower CBC projections than those included in the Diversified Energy (Planning) Scenario?

Response:

FEI used the economic forecast of single and multi-family housing starts from the December 5, 2019, Provincial Medium Term CBOC forecast for the development of the residential customer forecast. The same residential customer forecast was used in all six scenarios.

FEI does not use CBOC forecasts of BC population growth or GDP projections in the development of the long-term customer forecast, the BAU forecast or any of the six scenarios.

FEI notes that the Provincial medium-term (20-year) CBOC forecasts used by FEI do not contain high or low scenarios.

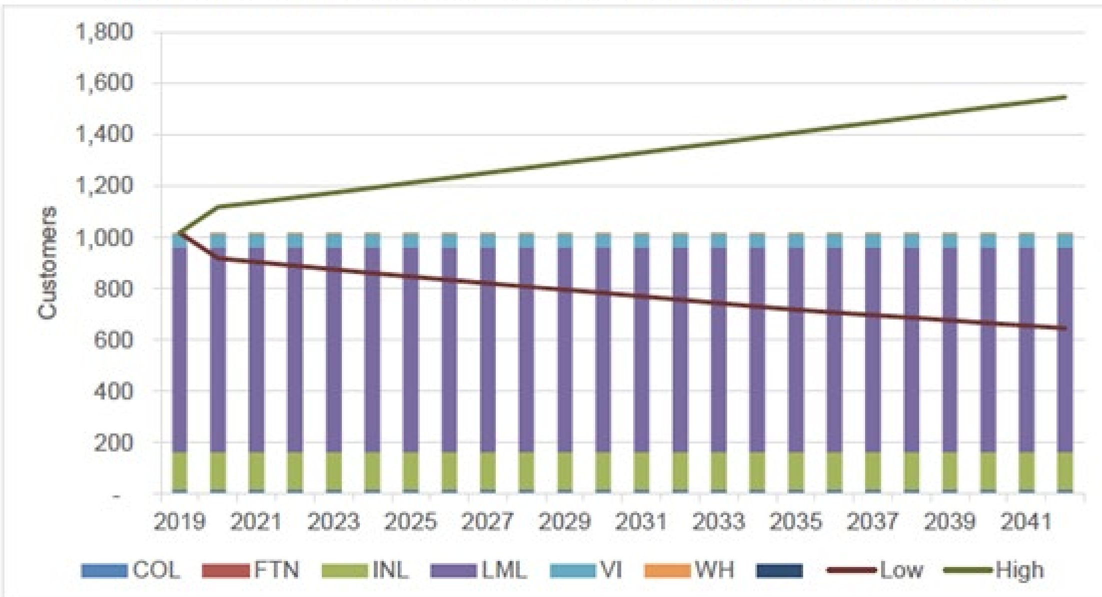
27.3 If more than one CBC forecast is used in the development of the Alternate Future Scenarios, please provide the information.

Response:

Please refer to the response to CEC IR1 27.2.

28. Reference: Exhibit B-1, Page 4-7

Figure 4-4: Long-Term Industrial Customer Forecast by Region (Excluding LCT)



28.1 Please provide a commentary on the factors contributing to the uncertainty interval associated with the Long-Term Industrial Customer Forecast.

<u>Response:</u>

The uncertainty interval is based on the volatility of the historical industrial customer totals. As the volatility of annual customer totals goes up, so does the width of the uncertainty bands.

FEI cannot definitively associate any factors to the uncertainty level associated with the long-term Industrial customer forecast in a given year, as the changes are a result of many factors that may be both compounding and offsetting. Customers in FEI's Industrial rate schedules operate in 67 different sectors. These industry sectors and the customers within them each have heterogeneous requirements because they are all affected differently by many different factors and energy uses. In addition, one-time or infrequent events (e.g. recessions) also impact customers and sectors in different ways.

Please see the Application, Appendix B-3, Section 1.1.1.1.1 for more information.

28.2 Please provide commentary as to why the uncertainty should be symmetrical.

Response:

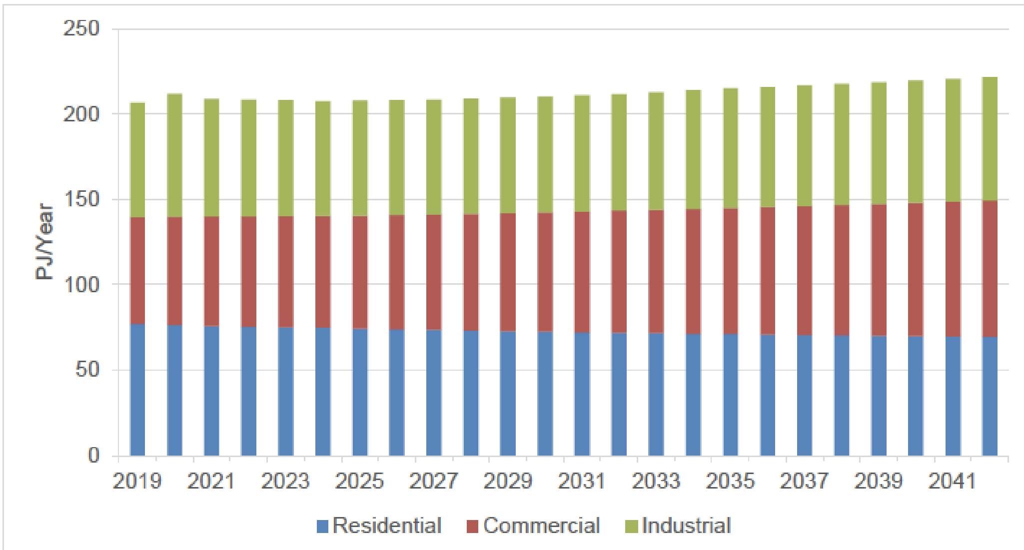
The mathematical formula used for the uncertainty calculation is based on the standard deviation of 10 years of historical actual customer totals. The standard deviation itself is based on how far each annual customer total is from the average customer total. Half of the annual customer totals are less than the average while the other half are greater. As a result, the mathematical formula provides a single uncertainty value that is both subtracted from and added to the forecast value to provide the upper and lower uncertainty bands. The use of a single value that is added to and subtracted from the forecast results in symmetrical uncertainty bands and recognizes that deviations from the forecast have an equal chance of being greater than or less than the forecast values. This is the common way to calculate uncertainty intervals whether from a textbook, analytics software package, or Microsoft Excel "wizard".

29. Reference: Exhibit B-1, Appendix B-1, Page 3; & Page 4-12

1.1.1.5 UPC Forecast

Ten years of weather normalized actual use rate data is used to calculate the UPC forecast using

Figure 4-5: Reference Case Annual Demand Forecast for Residential, Commercial and Industrial by Rate Schedule



29.1 Please detail some of the broad changes in consumption patterns for the residential demand that were observed for the 10-year period ending with the base forecast year (2019), based on 10 years of weather normalized actual use rate data.

Response:

The following table shows the weather normalized residential use rates for the ten-year period ending in 2019. The CAGR over the period was -0.7 percent per year. The 2019 UPC was 6 GJ lower than 2010.

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	CAGR
FEI RS 1 UPC, GJ	88.4	86.3	87.6	84.7	84.2	84.4	87.5	85.8	85.1	82.4	-0.70%

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

29.2 Please discuss the main trends that were observed for the residential demand, including in the number of accounts and UPC's over the 10-year period ending with the base forecast year (2019), at the FEI system level and regionally.

Response:

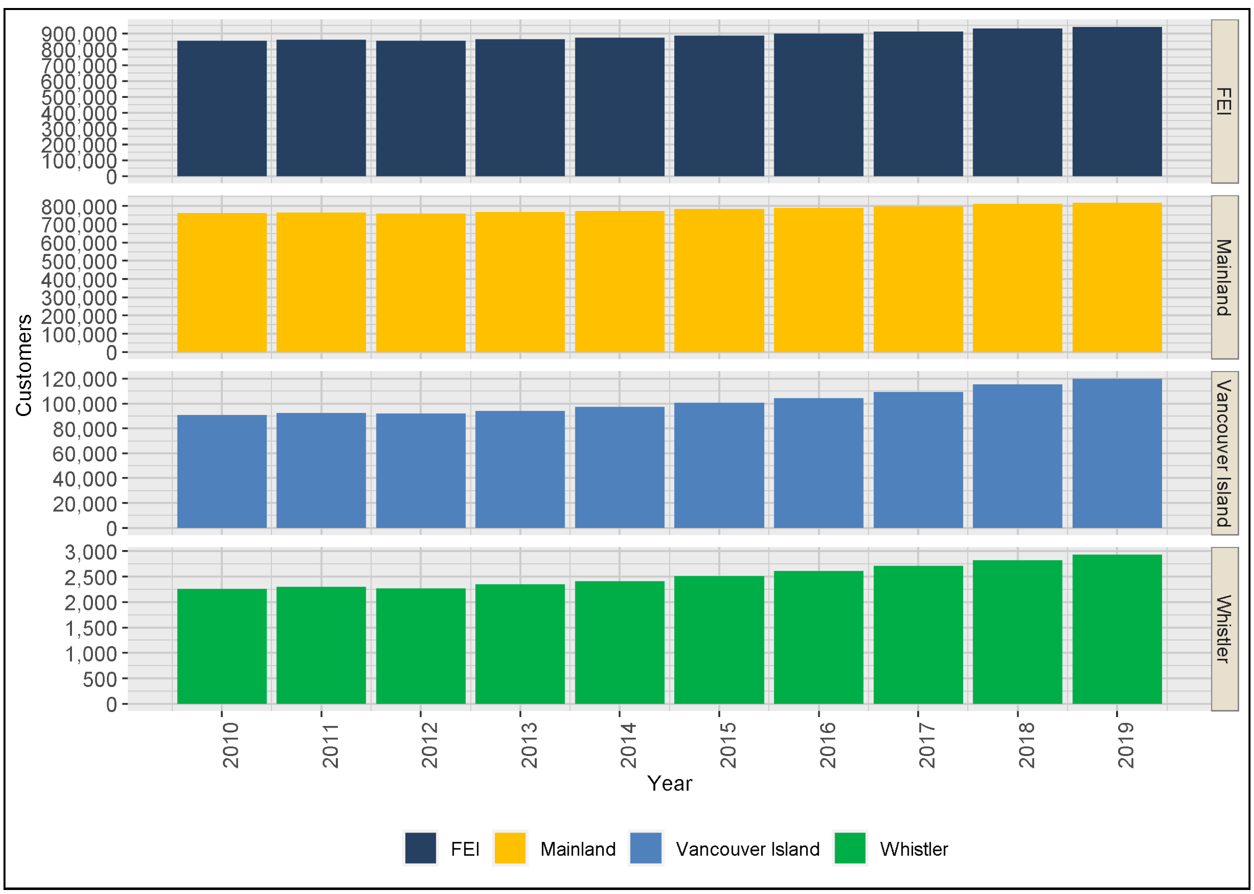
The table and figure below show the annual residential customer totals for FEI's overall system, as well as for the Mainland, Vancouver Island and Whistler regions. FEI notes the following:

- The CAGR for the Mainland region is significantly lower than other regions;
- The low Mainland CAGR results in a low blended CAGR for FEI; and
- Between 2010 and 2019, FEI added 87,259 residential customers.

Table 1: Residential Customer Count

Residential Customers											
Region	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	CAGR
FEI	853,492	860,403	854,050	863,189	873,661	886,169	897,528	910,885	930,142	940,751	0.98%
Mainland	760,559	765,553	759,712	766,668	774,083	782,914	790,562	798,917	811,696	817,817	0.73%
Vancouver Island	90,671	92,554	92,067	94,173	97,162	100,747	104,358	109,259	115,618	119,998	2.84%
Whistler	2,262	2,296	2,271	2,348	2,416	2,508	2,608	2,709	2,828	2,936	2.64%

Figure 1: Residential Customer Count



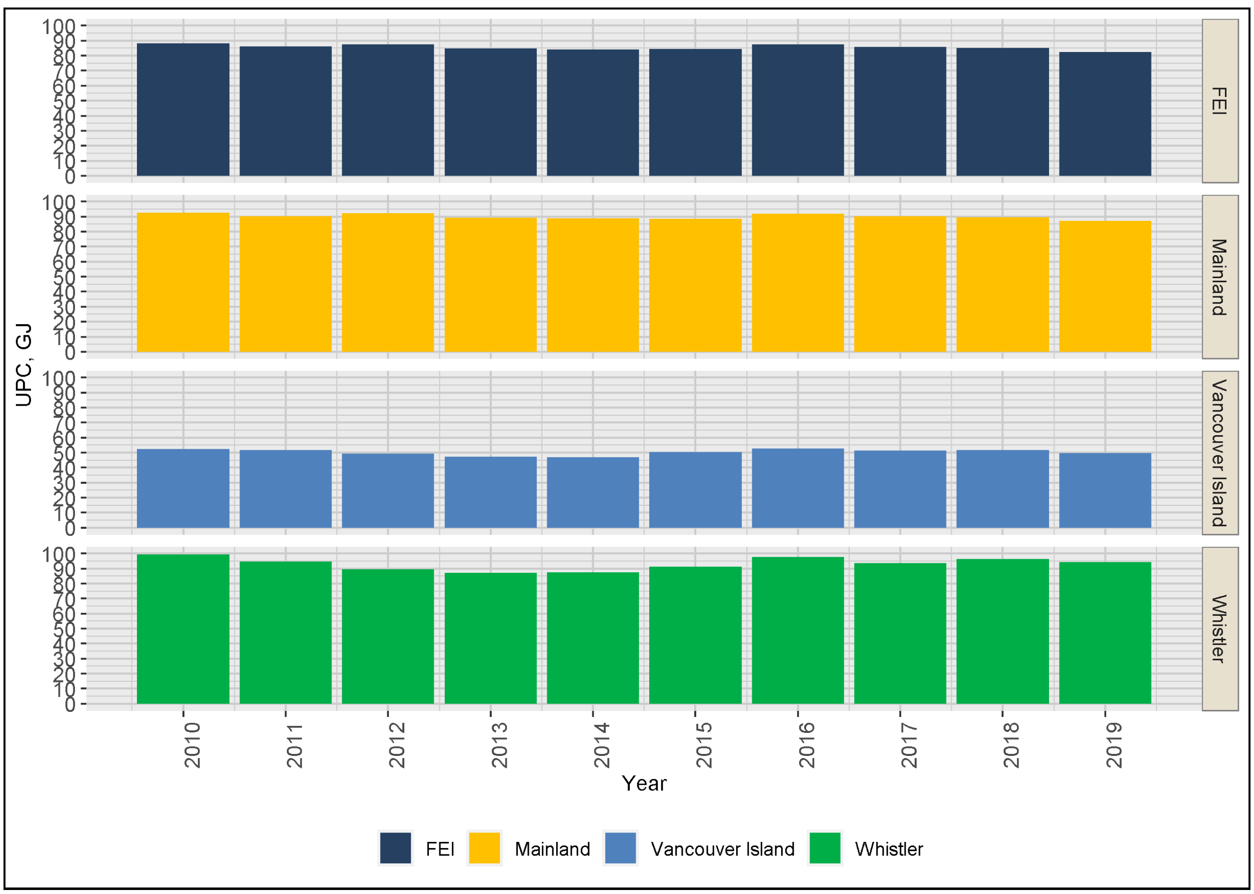
The following table and figure show the annual residential use rates for FEI as well as for the Mainland, Vancouver Island and Whistler regions. FEI notes the following:

- The CAGR for the Mainland region is similar to the FEI regional CAGR;
- The residential UPC in all regions declined by more than 0.5 percent per year;
- Vancouver Island UPCs are significantly lower than use rates in other regions; and
- The FEI blended use rate is heavily influenced by the Mainland use rate.

Table 2: Residential UPC

Residential UPC, GJ											
Region	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	CAGR
FEI	88.4	86.3	87.6	84.7	84.2	84.4	87.5	85.8	85.1	82.4	-0.70%
Mainland	92.6	90.4	92.2	89.3	88.8	88.7	92.0	90.4	89.7	87.1	-0.62%
Vancouver Island	52.5	51.8	49.5	47.3	47.1	50.5	52.6	51.5	51.6	49.7	-0.55%
Whistler	99.5	94.7	89.4	87.3	87.6	91.3	97.7	93.5	96.3	94.2	-0.54%

Figure 2: Residential UPC



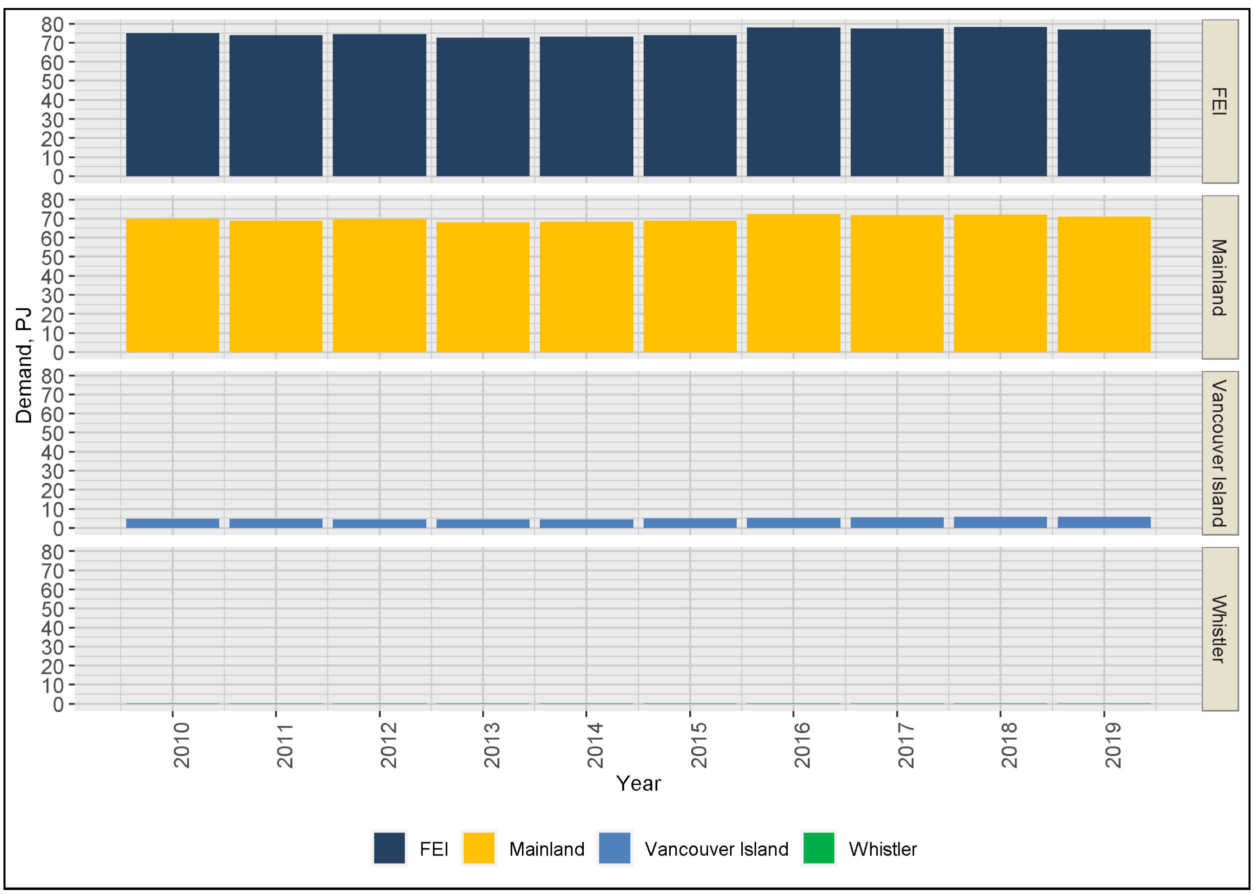
The following table and figure show the annual residential demand for FEI overall, as well as for the Mainland, Vancouver Island and Whistler regions. FEI notes the following:

- The demand CAGR for the Mainland region is significantly lower than for the other regions;
- Customer growth in the Mainland region is nearly offset by the declining use rate, resulting in the lower demand CAGR;
- The residential demand CAGR for both Whistler and Vancouver Island is 15 to 18 times greater than for the Mainland region—this is caused by higher customer growth rates and slower UPC declines;
- The FEI blended demand CAGR is heavily influenced by the Mainland region;
- Whistler and Vancouver Island demand is much lower than Mainland demand, so higher CAGR values in these regions has little impact on the FEI blended demand CAGR.

Table 3: Residential Demand

Residential Demand, PJ											
Region	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	CAGR
FEI	75.0	73.9	74.5	72.7	73.2	74.1	77.9	77.5	78.3	77.0	0.27%
Mainland	70.0	68.9	69.8	68.1	68.5	68.9	72.3	71.8	72.2	70.9	0.12%
Vancouver Island	4.7	4.7	4.5	4.4	4.5	5.0	5.4	5.5	5.8	5.9	2.21%
Whistler	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	1.88%

Figure 3: Residential Demand

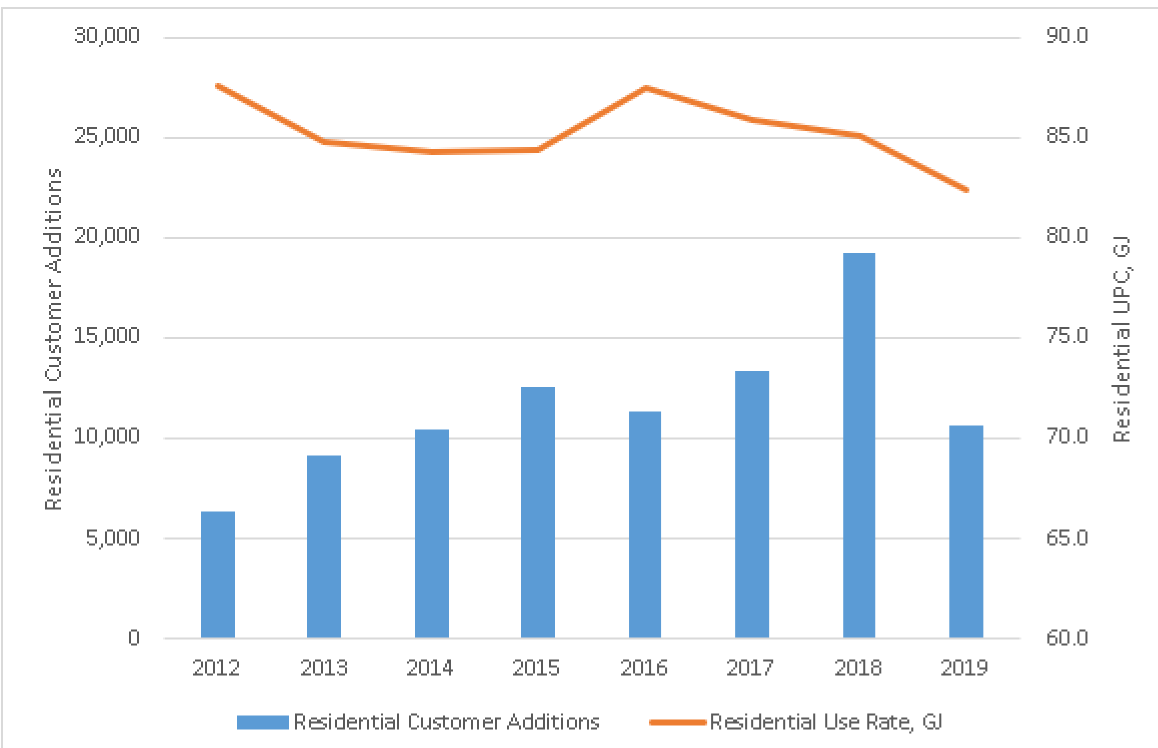


29.3 Please provide a discussion of the main factors behind the observed trends, and the extent to which FEI expects these trends (in either number of residential accounts or UPCs) to carry over in the forecast period.

Response:

As shown in the following figure, the historical trend for residential use rates continues to decline while the historical trend for residential customer additions (and, therefore, customers) was steadily increasing through 2018, before dropping back to about 10,000 additions per year.

As a result of newer homes being more energy efficient, requiring less energy to heat, along with ongoing efforts through FEI's DSM initiatives to update existing homes with more efficient equipment, FEI expects to see the residential UPC to continue to decline over time.



FEI notes that this question and preamble refer to Appendix B-1 where the Traditional Annual Method is described and the results of the BAU forecast are presented. From the perspective of the Traditional Annual Method and the BAU forecast, these trends are expected to continue. The figure presented in the preamble is from Section 4 where the End Use Forecast is discussed. Figure 4-5 in the preamble reflects the Reference Case scenario and each scenario intentionally represents different expectations which may or may not be related to the observed historical trends.

29.4 Please detail some of the broad changes in consumption patterns for the commercial demand that were observed for the 10-year period ending with the base forecast year (2019), based on 10 years of weather normalized actual use rate data.

Response:

The following table shows the FEI weather-normalized commercial use rates for the ten-year period ending in 2019 by rate schedule. The CAGRs over the period for Rate Schedules 2 and 3 were almost flat at 0.06 percent and 0.09 percent, respectively, indicating very little year-over-year change to the use rates for these classes. The CAGR for the large commercial class (Rate Schedule 23) was 0.41 percent per year.

Commercial Use Rates											
Region	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	CAGR
Rate Schedule 2	316.2	317.7	341.2	331.6	330.6	332.6	339.1	336.8	332.5	318.1	0.06%
Rate Schedule 3	3,485	3,588	3,684	3,610	3,573	3,587	3,721	3,692	3,550	3,517	0.09%
Rate Schedule 23	4,850	5,138	5,238	5,149	5,260	5,174	5,279	5,361	5,345	5,051	0.41%

FEI cannot definitively explain any change in UPC as it is a result of many factors that may be both compounding and offsetting. FEI commercial customers operate in dozens of industry sectors. These industry sectors and the customers within them each have heterogeneous requirements because they are all affected differently by many different factors and energy uses. In addition, one-time or infrequent events (e.g. recessions) also impact customers and sectors in different ways.

FEI expects that its load will continue to be influenced by many factors that may have affected load variances in the past, including customer behavior, economic activity, DSM, government policies (such as environmental policy), new technology, housing formations, etc.

29.5 Please discuss the main trends that were observed for the commercial demand, including in the number of accounts and UPC's over the 10-year period ending with the base forecast year (2019), at the FEI system level and regionally.

Response:

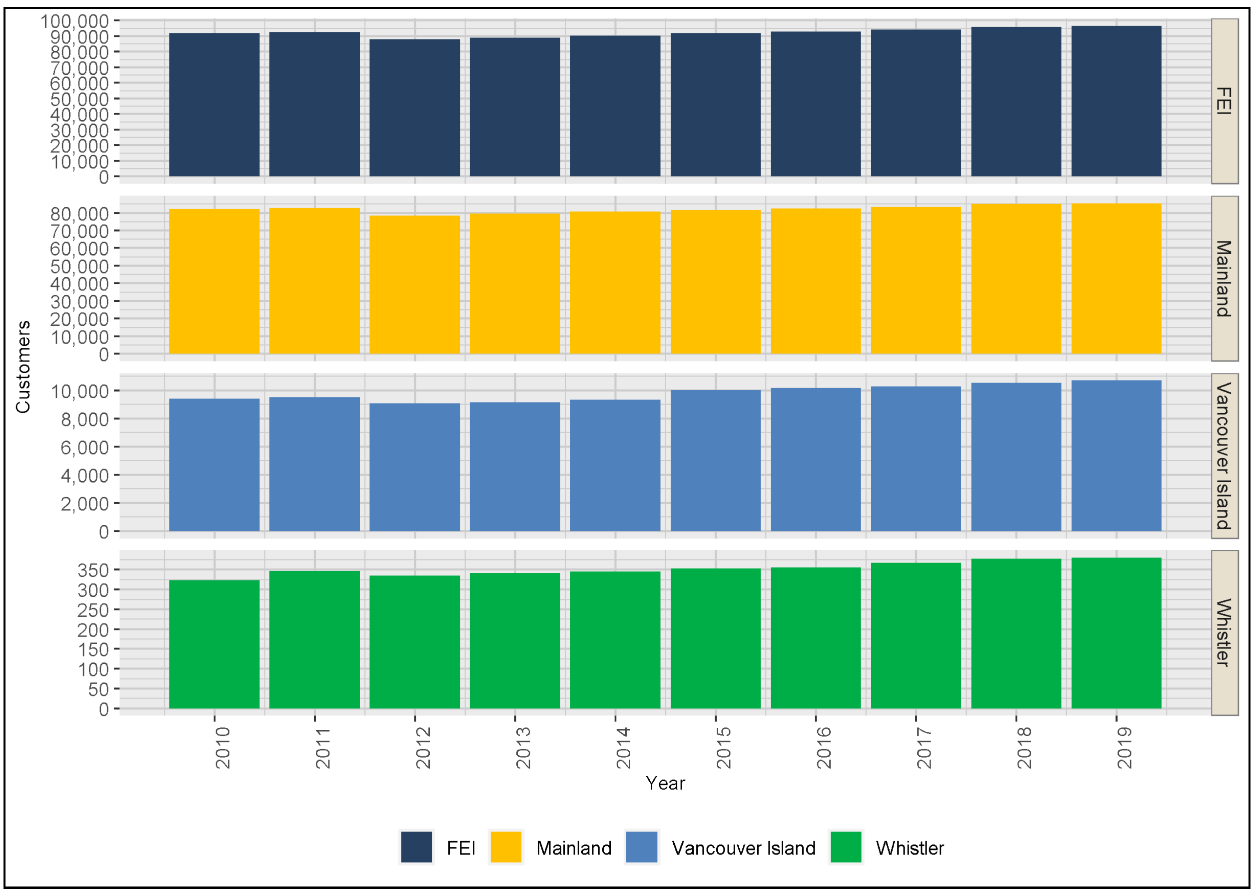
The following table and figure show the annual commercial customer totals for FEI overall, as well as for the Mainland, Vancouver Island and Whistler regions. FEI notes the following:

- The CAGR for the Mainland region is significantly lower than other regions;
- The low Mainland CAGR results in a low blended CAGR for FEI; and
- Between 2010 and 2019, FEI added 4,465 commercial customers.

Table 1: Annual Commercial Customer Totals

Commercial Customers											
Region	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	CAGR
FEI	92,065	92,587	87,863	89,115	90,315	92,101	93,066	94,126	95,920	96,530	0.47%
Mainland	82,316	82,733	78,430	79,607	80,611	81,695	82,545	83,460	84,980	85,442	0.37%
Vancouver Island	9,425	9,508	9,097	9,167	9,359	10,053	10,165	10,298	10,562	10,708	1.28%
Whistler	324	347	335	341	345	353	356	368	378	380	1.61%

Figure 1: Annual Commercial Customer Totals



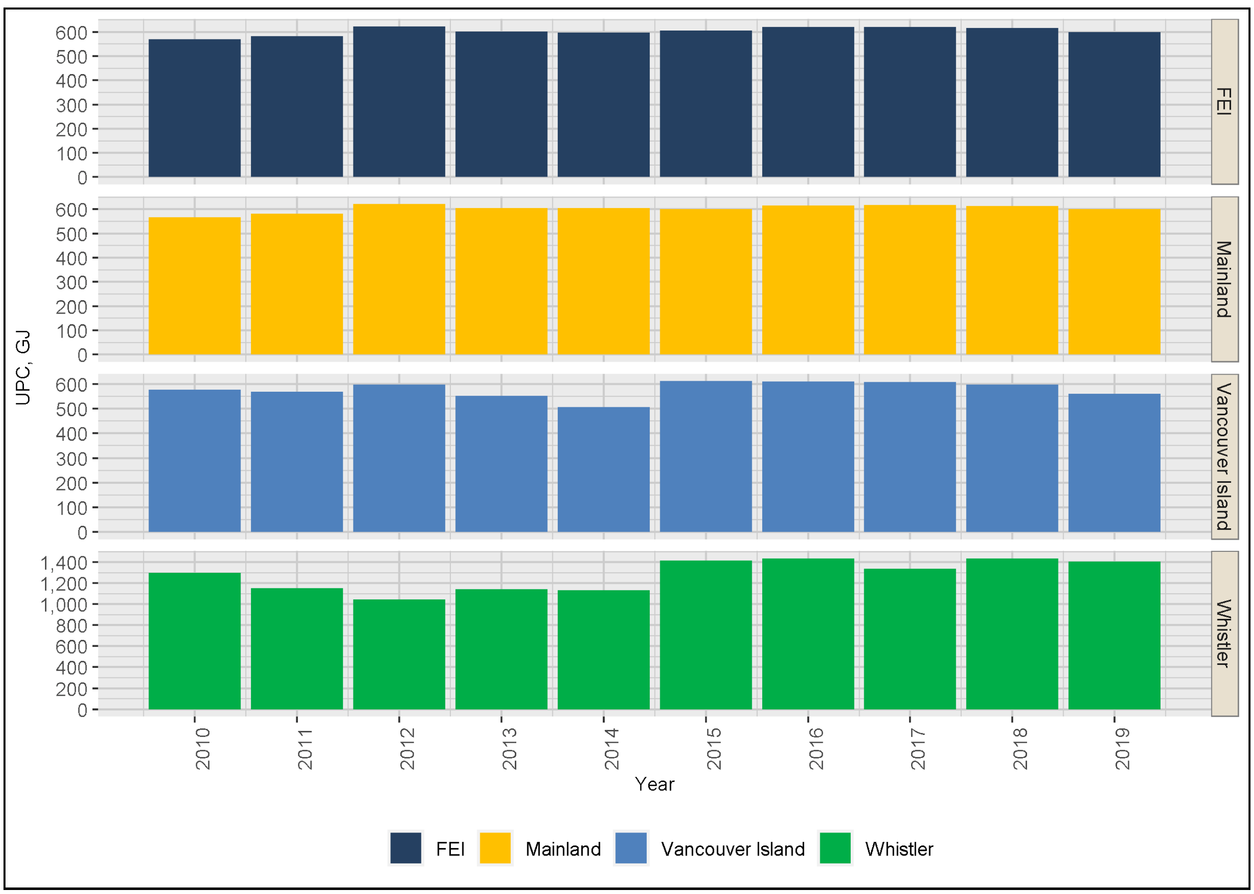
The following table and figure show the annual commercial blended use rates for FEI overall, as well as for the Mainland, Vancouver Island and Whistler regions. FEI notes the following:

- The CAGR for the Mainland region is similar to the FEI blended CAGR;
- The commercial UPC on Vancouver Island is declining, while the UPCs in all other regions are increasing;
- The Whistler UPC is higher due to a higher proportion of large commercial customers included in the UPC; and
- The FEI blended use rate is heavily influenced by the Mainland use rate.

Table 2: Annual Commercial Blended Use Rates

Commercial UPC, GJ											
Region	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	CAGR
FEI	570.4	582.7	622.2	600.6	596.9	605.1	619.7	619.9	615.4	599.7	0.50%
Mainland	566.3	582.4	622.4	604.5	605.0	600.8	615.4	618.1	613.7	601.0	0.60%
Vancouver Island	578.2	570.0	599.1	553.1	507.5	611.8	609.9	609.2	599.3	560.6	-0.31%
Whistler	1,296.3	1,152.7	1,044.8	1,143.7	1,130.4	1,416.4	1,432.6	1,334.6	1,433.3	1,403.0	0.79%

Figure 2: Annual Commercial Blended Use Rates



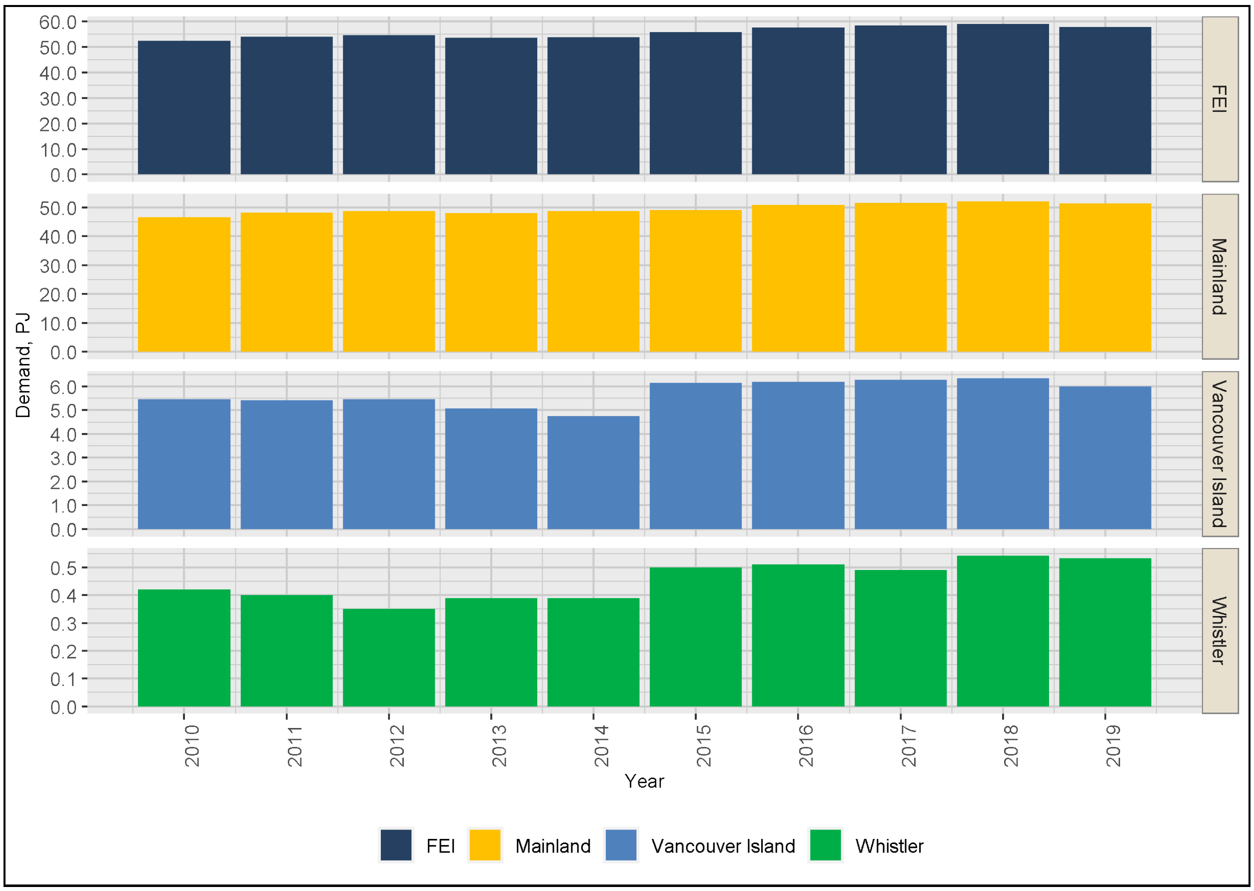
The following table and figure show the annual commercial demand for FEI overall, as well as for the Mainland, Vancouver Island and Whistler regions. FEI notes the following:

- The commercial demand CAGR for the Whistler region is significantly higher than for the other regions; and
- The commercial demand growth in the Mainland and Vancouver Island regions is approximately 1 percent per year.

Table 3: Annual Commercial Demand

Commercial Demand, PJ											
Region	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	CAGR
FEI	52.5	54.0	54.7	53.5	53.9	55.7	57.7	58.3	59.0	57.9	0.98%
Mainland	46.6	48.2	48.8	48.1	48.8	49.1	50.8	51.6	52.2	51.3	0.97%
Vancouver Island	5.5	5.4	5.5	5.1	4.8	6.2	6.2	6.3	6.3	6.0	0.97%
Whistler	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	2.41%

Figure 3: Annual Commercial Demand



29.6 Please provide a discussion of the main factors behind the observed trends, and the extent to which FEI expects these trends (in either number of commercial accounts or UPC's) to carry over in the forecast period.

Response:

The main factors present in the UPC forecast are consistent with the broad historical factors, namely energy efficiency, economic activity, policies and efficiency standards. FEI also surveys large commercial and industrial customers to receive their perspectives on anticipated gas demand to help inform the forecast. Commercial Account Managers also regularly discuss gas demand, gas usage, impacts of policies, competitiveness of other energies, and emissions reductions policies. These consultations help shape programs and products such as renewable gas and DSM to ensure that FEI's offerings are consistent with the historical and future customer trends. Based on these customer discussions and consistency of the underlying factors, FEI expects the trends to continue over the forecast period.

29.7 Please provide a discussion of the main trends that were observed for the industrial demand, for the 10-year period ending with the base forecast year (2019).

Response:

Over the 10-year period ending with the base forecast year (2019), the main trend that FEI observed was that, in addition to a fairly consistent number of industrial customers, the overall industrial volumes remained relatively flat for the first 6 years at around 80 PJ and then slowly increased by approximately 10 PJ over the remaining 4 years. The main reason for the increase was related to fuel switching to natural gas from higher-carbon fuels for a small subset of large industrial customers, as well as customer growth more broadly.

29.8 Based on the observed trends, what are FEI's expectations regarding future Use per Customer (UPC) in the Industrial Sector?

Response:

With many different customer types and sectors that take service under industrial rate classes, it is not possible to extract trends or to apply a use per customer number that is relevant to all industrial customers. Each customer and sector will have different reasons for increasing or decreasing load. FEI expects that energy efficiency will help to reduce load all things equal, but load can also increase due to business or GDP growth. Conversely, industrial loads (UPC) could decrease as a result of GHG policies or declines in provincial economic activity.

DEMAND-SIDE RESOURCES

30. Reference: Exhibit B-1, Page 5-5

5.2.1.3 *Commercial Program Area*

FEI's Commercial Program Area encourages commercial customers to reduce their overall consumption of natural gas and associated energy costs. These programs enable commercial and institutional customers to conduct both simple and comprehensive energy efficiency upgrades at their buildings. The combination of financial incentives, consultant and contractor outreach, and effective marketing in these programs is instrumental to the ongoing success of these programs in generating natural gas savings and fostering market transformation in the commercial sector.

5.2.1.4 *Industrial Program Area*

FEI's Industrial Program Area offers a number of industrial programs that encourage industrial customers to reduce their overall consumption of natural gas and associated energy costs. Industrial initiatives can be large projects with significant energy savings that span multiple years. These programs have been successful in the manufacturing, agricultural, mining and other sectors, which use large amounts of natural gas and therefore provide substantial energy savings opportunities.

30.1 Please provide in table format FEI's Program Spending in the Commercial and Industrial Program Areas, for the past five years, along with associated energy cost savings to be derived from the spending.

Response:

The tables below provide FEI's Commercial and Industrial Program Area expenditures and associated energy savings for the 2016 to 2021 program years.

	2016	2017	2018	2019	2020	2021	Total
Commercial							
Utility Expenditures ($000s)	$10,637	$10,834	$10,098	$11,709	$13,571	$21,309	$78,159
Incremental Annual Gas Savings, Net (GJ)	255,408	238,688	234,228	281,205	334,485	413,589	1,757,603
Industrial							
Utility Expenditures ($000s)	$1,003	$2,099	$3,195	$6,481	$6,124	$5,438	$24,340
Incremental Annual Gas Savings, Net (GJ)	18,349	105,516	123,356	301,668	269,354	297,760	1,116,003

30.2 For large industrial customers, to what extent do FEI and BC Hydro coordinate their demand-side efforts, in providing customer solutions to achieving energy cost savings, in their respective offerings?

Response:

For large industrial customers, FEI collaborates with BC Hydro by offering the Strategic Energy Management (SEM) program which provides those customers with energy modeling, energy efficiency coaching and strategic planning support to achieve both operational savings and to encourage larger capital upgrades. The program is administered in collaboration with BC Hydro and FBC. The SEM program has two tracks:

- Individual Support for large industrial customers, where FEI provides customer-specific incentives and support for energy modeling, monitoring, targeting, reporting and coaching where there is an existing energy manager; and
- Cohort Support for medium-sized industrial customers without dedicated energy managers, where FEI brings together a group of industrial customers to work together and share knowledge related to energy management in their facilities and process improvements and receive group energy coaching and training.

30.3 FEI lists agriculture as one of the sectors that can benefit from significant energy savings due to them undertaking large industrial initiatives. What trends is FEI observing in this sector, and what type of initiatives does FEI have on the horizon, as it concerns its program spending for agriculture?

Response:

In its 2021 Conservation Potential Review Report,[22] FEI has identified the agriculture sector to have the second-highest natural gas consumption (13 per cent) of total industrial natural gas consumption, based on the 2019 base year data. As part of its 2021 Conservation Potential Review, FEI also identified the agricultural sector to have one of the highest energy savings potential;[23] therefore, FEI sees the agriculture sector as one of its priorities in FEI's Industrial Program Area.

Under the Industrial Prescriptive Program, which provides rebates for measures where the savings are well understood and their installation is not typically part of a larger, more complex upgrade, FEI offers incentives, such as greenhouse curtains (also known as thermal curtains), specifically for its agricultural customers. FEI plans on adding other measures, such as boiler tune-ups, combustion testing, greenhouse envelope measures and integrated greenhouse

[22] Appendix C-1, Exhibit 105: 2019 Industrial Natural Gas Consumption (GJ) by Segment.
[23] Appendix C-1, Exhibit 126 – Economic Potential Savings by Segment in 2025 – Industrial, TRC and Exhibit 127 – Economic Potential Savings by Segment in 2025 – Industrial, MTRC.

control measures to the Industrial Prescriptive Program, which are all of relevance to agricultural customers.

Under the Industrial Performance Program, which provides customers with a one-stop program to evaluate and implement complex industrial energy efficiency projects, FEI provides rebates on boiler plant retrofits and heat recovery projects. FEI plans to expand its Performance Program to include recommissioning and comprehensive heating plant optimization measures for all industrial customers, including the agricultural customers.

Under the SEM program, FEI runs a number of cohorts for industrial customers without dedicated energy managers to bring together a group of industrial customers to work together and share knowledge related to energy management in their facilities and processes and to receive group energy coaching and training. A number of FEI's agricultural customers are expected to participate in this program in future offerings.

31. Reference: Exhibit B-1, Page 5-12

> 4. ***Calculate economic potential*** based on the economic screen specified in the DSM Setting for the scenario and the avoided costs. These inputs affect measure potential in the following ways:
>
>   - For scenarios in which MTRC is the economic screen, more measures will pass than for those in which TRC is the screen. Where the Medium UCT is the economic screen, measures must also pass a UCT screen.
>   - The avoided cost of conventional natural gas varies from one scenario to another. Higher avoided costs for natural gas, due to commodity cost increases or higher carbon price, results in more measures passing the TRC and UCT tests. Note that this mechanism does not affect the MTRC results, as MTRC uses the Zero-Emission Energy Supply Alternative avoided cost, rather than the natural gas avoided cost.

31.1 What type of feedback does FEI receive from its commercial and industrial customers as it concerns its use of the three economic screens in assessing measure potential (i.e.: TRC, MTRC and UCT)?

Response:

FEI's commercial and industrial customers do not generally provide specific feedback on the economic screens FEI uses in assessing measure potential. Industrial and commercial customers have provided feedback on program eligibility criteria, incentive amounts, and program processes which have been informative in designing commercial and industrial programs.

31.2 Do higher avoided costs for natural gas and carbon price increases cause any reconsideration as to FEI's processes for the economic screening of DSM measure potential?

Response:

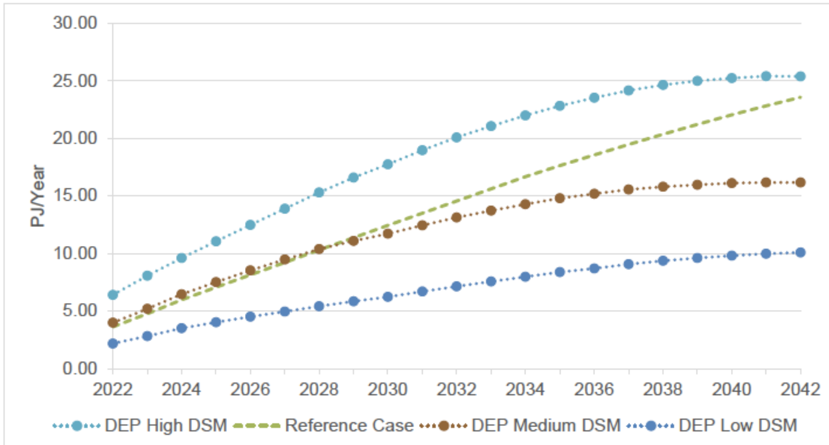
The following response has been provided by Posterity Group in consultation with FEI.

Yes, higher avoided natural gas and carbon price increases impact the economic screening of DSM measures in the following ways:

- Measures that were previously not cost-effective may become cost-effective, and therefore would be proposed for inclusion for future DSM activities.
- Measures that were previously cost-effective will have their payback period decreased, thereby increasing their forecasted rate of market adoption in the DSM model.

32. Reference: Exhibit B-1, Page 5-15, Figure 5-2

Figure 5-2: Diversified Energy (Planning) or DEP Scenario DSM Savings Potential – 3 DSM Settings



Energy savings from the Reference Case (Medium DSM Setting) is 24 PJ which is almost equivalent to the DEP High Scenario. This is due to the high proportion of conventional natural gas and very limited electrification in this scenario and therefore there is a relatively higher potential for DSM savings.

32.1 Please explain what is meant by 'very limited electrification' on line 13 of the reference.

<u>Response:</u>

"Very limited electrification" described in the preamble refers to the Reference Case baseline fuel switching to electricity and natural efficiency.[24] It demonstrates the demand that would occur over the planning horizon based on the expectation of what would happen if conditions for critical uncertainties remained as they were as of the base year (2019). Therefore, the degree of electrification based on 2019 levels is "very limited" as described above. In contrast, the DEP setting is for moderate electrification, thereby having greater impact on total demand, and reduced opportunity for incremental DSM savings over the Reference Case.

For further information on how the fuel switching settings impacted the alternate scenarios , please refer to the response to BCUC IR1 69.1 which provides a breakdown of the demand reductions in volume (PJ) and GHG emission reductions (Mt CO_2e) and BCUC IR1 69.2 which further describes methodologies and assumptions that were used in scenario modeling.

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[24] Efficiency improvements that occur through the natural replacement of older, less efficient equipment with newer, more efficient equipment without the influence of DSM incentives.

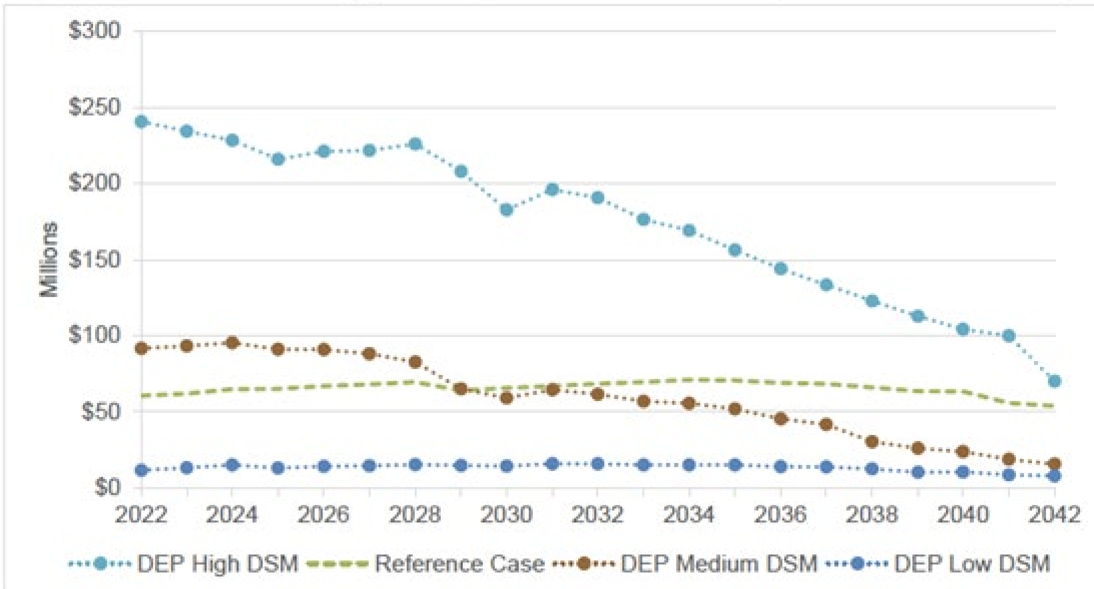
32.2 Is this electrification scenario strictly describing a limited case for gas-to-electricity conversion in BC? Or is the statement made in consideration of broader electrification factors? Please explain.

Response:

The "limited electrification" in the Reference Case described above refers to BC-based gas-to-electricity conversion modeled for FEI customers in the LTGRP modeling software. The fuel switching setting encompasses somewhat broader demand reduction, combining the impacts of both natural efficiency and fuel switching to electricity. The changes in demand are impacted by price- and policy-driven fuel switching, building codes and equipment standards, and declining customer account forecasts.

33. Reference: Exhibit B-1, Page 5-16, Figure 5-3

Figure 5-3: Diversified Energy (Planning) or DEP Scenario DSM Expenditures – 3 DSM Settings



33.1 What component of DSM expenditures for each of the DSM settings presented in Figure 5-3 is non-incentive spending versus incentives?

Response:

The following response has been provided by Posterity Group in consultation with FEI.

In the LTGRP model, the non-incentive costs were generated by using a factor of 15 percent of incentive costs in all scenarios as described in Table 1 below. Note that non-incentive spending does not include fixed costs, but rather only program administration costs that scale on a per-measure basis.

Table 1: Proportion of Non-Incentive Expenditures Over the Planning Horizon for the Reference Case and High, Medium and Low Budget Settings in the Diversified Energy (Planning) Scenario

DSM Setting	Incentive Expenditures ($,000s)	Non-Incentive Expenditures	Non-Incentives as % of Incentive Expenditures
Reference Case	$1,307	$196	15%
Diversified Energy (Planning) - Low	$3,649	$547	15%
Diversified Energy (Planning) - Medium	$1,255	$188	15%
Diversified Energy (Planning) - High	$274	$41	15%

Tables 2 through 5 provide the details of annual DSM expenditures by incentive and non-incentive spending for the scenarios presented in Figure 5-3. Any differences between the sum of incentive and non-incentive total and the total expenditures for the forecast period are due to rounding.

Table 2: Proportion of Non-Incentive Expenditures Over the Planning Horizon for the Reference Case

Reference Case Annual DSM Expenditures (million CAD) by Expenditure Type			
Year	Incentive	Non-Incentive	Total Expenditures
2020	$51	$8	$59
2021	$52	$8	$60
2022	$53	$8	$61
2023	$54	$8	$62
2024	$57	$9	$65
2025	$57	$9	$66
2026	$59	$9	$67
2027	$60	$9	$68
2028	$61	$9	$70
2029	$56	$8	$65
2030	$58	$9	$66
2031	$59	$9	$67
2032	$60	$9	$69
2033	$61	$9	$70
2034	$62	$9	$72
2035	$62	$9	$71
2036	$60	$9	$70
2037	$60	$9	$69
2038	$58	$9	$67
2039	$56	$8	$64
2040	$56	$8	$64
2041	$49	$7	$56
2042	$47	$7	$54
Total	**$1,307**	**$196**	**$1,503**

Table 3: Proportion of Non-Incentive Expenditures Over the Planning Horizon for the High Budget Settings in the DEP Scenario

DEP High DSM Setting Annual DSM Expenditures (Million CAD) by Expenditure Type			
Year	Incentive	Non-Incentive	Total Expenditures
2020	$216	$32	$249
2021	$218	$33	$250
2022	$211	$32	$242
2023	$205	$31	$236
2024	$200	$30	$230
2025	$190	$28	$218
2026	$195	$29	$224
2027	$195	$29	$224
2028	$199	$30	$229
2029	$184	$28	$211
2030	$160	$24	$184
2031	$172	$26	$198
2032	$167	$25	$193
2033	$155	$23	$178
2034	$149	$22	$171
2035	$138	$21	$158
2036	$127	$19	$146
2037	$118	$18	$136
2038	$108	$16	$125
2039	$99	$15	$114
2040	$92	$14	$106
2041	$88	$13	$102
2042	$63	$9	$72
Total	**$3,649**	**$547**	**$4,197**

Table 4: Proportion of Non-Incentive Expenditures Over the Planning Horizon for the Medium Budget Setting in the DEP Scenario.

DEP Medium DSM Setting Annual DSM Expenditures (Million CAD) by Expenditure Type			
Year	Incentive	Non-Incentive	Total Expenditures
2020	$75	$11	$86
2021	$80	$12	$92
2022	$80	$12	$92
2023	$82	$12	$94
2024	$84	$13	$96
2025	$80	$12	$92
2026	$80	$12	$92
2027	$78	$12	$89
2028	$73	$11	$84
2029	$58	$9	$66
2030	$52	$8	$60
2031	$56	$8	$65
2032	$54	$8	$62
2033	$50	$7	$57
2034	$49	$7	$56
2035	$46	$7	$52
2036	$40	$6	$46
2037	$37	$6	$42
2038	$27	$4	$31
2039	$23	$3	$27
2040	$22	$3	$25
2041	$17	$3	$19
2042	$14	$2	$16
Total	**$1,255**	**$188**	**$1,443**

Table 5: Proportion of Non-Incentive Expenditures Over the Planning Horizon for the Low Budget Setting in the DEP Scenario

DEP Low DSM Setting Annual DSM Expenditures (million CAD) by Expenditure Type			
Year	Incentive	Non-Incentive	Total Expenditures
2020	$9	$1	$11
2021	$10	$1	$11
2022	$11	$2	$12
2023	$12	$2	$14
2024	$14	$2	$16
2025	$12	$2	$14
2026	$13	$2	$15
2027	$13	$2	$15
2028	$14	$2	$16
2029	$13	$2	$15
2030	$13	$2	$15
2031	$14	$2	$16
2032	$14	$2	$16
2033	$14	$2	$16
2034	$14	$2	$16
2035	$14	$2	$16
2036	$13	$2	$15
2037	$13	$2	$14
2038	$11	$2	$13
2039	$10	$1	$11
2040	$10	$1	$11
2041	$8	$1	$9
2042	$8	$1	$9
Total	**$274**	**$41**	**$315**

33.2 Please provide a breakdown of the annual DSM expenditures by customer type (residential, commercial, industrial) for each of the DSM settings presented in Figure 5-3.

Response:

The following response has been provided by Posterity Group.

The following tables provide total annual DSM expenditures by customer type for the Reference Case and DSM Settings presented in Figure 5-3. Total annual DSM expenditures is the sum of annual incentive and non-incentive DSM spending. Note that non-incentive spending does not include fixed costs, only program administration costs that scale on a per-measure basis.

Table 1: Total Annual DSM Expenditures by Customer Type for the Reference Case

Reference Case DSM Expenditures (million CAD) by Customer Type			
Year	**Residential**	**Commercial**	**Industrial**
2020	$47	$1	$10
2021	$48	$2	$10
2022	$48	$4	$9
2023	$48	$5	$9
2024	$50	$7	$8
2025	$48	$9	$8
2026	$48	$11	$8
2027	$49	$12	$8
2028	$48	$13	$9
2029	$42	$13	$9
2030	$44	$13	$9
2031	$45	$14	$9
2032	$46	$14	$9
2033	$47	$13	$9
2034	$49	$13	$9
2035	$49	$13	$9
2036	$47	$13	$9
2037	$46	$13	$9
2038	$44	$13	$10
2039	$42	$13	$10
2040	$41	$13	$10
2041	$39	$12	$5
2042	$38	$12	$5
Total	**$1,053**	**$248**	**$202**

1 **Table 2: Total Annual DSM Expenditures by Customer Type for the DEP High DSM Setting**

DEP – High DSM Setting DSM Expenditures (million CAD) by Customer Type			
Year	**Residential**	**Commercial**	**Industrial**
2020	$197	$11	$40
2021	$193	$20	$37
2022	$180	$31	$32
2023	$164	$44	$28
2024	$144	$61	$26
2025	$118	$76	$24
2026	$110	$91	$22
2027	$104	$101	$20
2028	$101	$108	$20
2029	$85	$107	$18
2030	$75	$103	$6
2031	$85	$105	$8
2032	$82	$103	$7
2033	$77	$94	$7
2034	$74	$90	$7
2035	$70	$82	$7
2036	$63	$77	$7
2037	$59	$70	$7
2038	$57	$62	$6
2039	$53	$57	$4
2040	$48	$53	$4
2041	$50	$47	$4
2042	$25	$43	$4
Total	**$2,214**	**$1,637**	**$345**

2

1 **Table 3: Total Annual DSM Expenditures by Customer Type for the DEP Medium DSM Setting**

DEP – Medium DSM Setting DSM Expenditures (million CAD) by Customer Type			
Year	Residential	Commercial	Industrial
2020	$71	$1	$14
2021	$74	$2	$15
2022	$74	$4	$15
2023	$74	$5	$14
2024	$75	$7	$14
2025	$70	$9	$13
2026	$69	$10	$13
2027	$66	$11	$12
2028	$60	$12	$12
2029	$52	$12	$3
2030	$46	$11	$2
2031	$51	$12	$2
2032	$48	$12	$2
2033	$44	$11	$2
2034	$44	$11	$2
2035	$40	$10	$2
2036	$35	$9	$2
2037	$32	$9	$2
2038	$21	$8	$2
2039	$18	$7	$2
2040	$16	$7	$2
2041	$12	$6	$1
2042	$9	$6	$2
Total	**$1,100**	**$192**	**$151**

2

Table 4: Total Annual DSM Expenditures by Customer Type for the DEP Low DSM Setting

DEP - Low DSM Setting DSM Expenditures (million CAD) by Customer Type			
Year	Residential	Commercial	Industrial
2020	$6	$1	$4
2021	$6	$2	$4
2022	$6	$3	$3
2023	$7	$4	$3
2024	$8	$5	$2
2025	$5	$7	$2
2026	$5	$8	$2
2027	$5	$9	$2
2028	$5	$9	$2
2029	$5	$9	$2
2030	$5	$8	$2
2031	$5	$9	$2
2032	$5	$9	$2
2033	$5	$8	$2
2034	$6	$8	$2
2035	$6	$8	$2
2036	$6	$7	$2
2037	$6	$7	$2
2038	$5	$6	$2
2039	$4	$6	$2
2040	$4	$5	$2
2041	$3	$5	$1
2042	$3	$5	$2
Total	**$118**	**$147**	**$50**

33.3 Further to 33.1 and 33.2, please provide a breakdown of the 'non-incentive spending' versus 'incentive spending' component of the annual DSM expenditures by customer type (residential, commercial, industrial) for each of the DSM settings presented in Figure 5-3.

Response:

The following response has been provided by Posterity Group in consultation with FEI.

The following tables provide annual DSM expenditures by incentive and non-incentive spending and by customer type for the Reference Case and DEP Scenario DSM Settings presented in Figure 5-3 of the Application. Any differences between the incentive and non-incentive total and the total expenditures for the forecast period are due to rounding. Note that non-incentive spending does not include fixed costs, only program administration costs that scale on a per-measure basis.

Reference Case - Residential Sector

	Reference Case Residential Sector DSM Expenditures (million CAD)		
Year	Incentive	Non-Incentive	Total Expenditures
2020	$ 41	$6	$ 47
2021	$ 42	$6	$ 48
2022	$ 42	$6	$ 48
2023	$ 42	$6	$ 48
2024	$ 43	$7	$ 50
2025	$ 42	$6	$ 48
2026	$ 42	$6	$ 48
2027	$ 42	$6	$ 49
2028	$ 42	$6	$ 48
2029	$ 37	$6	$ 42
2030	$ 38	$6	$ 44
2031	$ 39	$6	$ 45
2032	$ 40	$6	$ 46
2033	$ 41	$6	$ 47
2034	$ 42	$6	$ 49
2035	$ 42	$6	$ 49
2036	$ 41	$6	$ 47
2037	$ 40	$6	$ 46
2038	$ 38	$6	$ 44
2039	$ 36	$5	$ 42
2040	$ 36	$5	$ 41
2041	$ 34	$5	$ 39
2042	$ 33	$5	$ 38
Total	**$ 916**	**$137**	**$1,053**

1 **Reference Case - Commercial Sector**

	Reference Case Commercial Sector DSM Expenditures (million CAD)		
Year	Incentive	Non-Incentive	Total Expenditures
2020	$1	$0	$1
2021	$2	$0	$2
2022	$3	$0	$4
2023	$5	$1	$5
2024	$6	$1	$7
2025	$8	$1	$9
2026	$9	$1	$11
2027	$10	$2	$12
2028	$11	$2	$13
2029	$12	$2	$13
2030	$12	$2	$13
2031	$12	$2	$14
2032	$12	$2	$14
2033	$12	$2	$13
2034	$12	$2	$13
2035	$11	$2	$13
2036	$11	$2	$13
2037	$11	$2	$13
2038	$11	$2	$13
2039	$11	$2	$13
2040	$11	$2	$13
2041	$11	$2	$12
2042	$11	$2	$12
Total	**$215**	**$32**	**$248**

2

1 **Reference Case - Industrial Sector**

	Reference Case Industrial Sector DSM Expenditures (million CAD)		
Year	**Incentive**	**Non-Incentive**	**Total Expenditures**
2020	$9	$1	$10
2021	$9	$1	$10
2022	$8	$1	$9
2023	$7	$1	$9
2024	$7	$1	$8
2025	$7	$1	$8
2026	$7	$1	$8
2027	$7	$1	$8
2028	$8	$1	$9
2029	$8	$1	$9
2030	$8	$1	$9
2031	$8	$1	$9
2032	$8	$1	$9
2033	$8	$1	$9
2034	$8	$1	$9
2035	$8	$1	$9
2036	$8	$1	$9
2037	$8	$1	$9
2038	$8	$1	$10
2039	$8	$1	$10
2040	$8	$1	$10
2041	$4	$1	$5
2042	$4	$1	$5
Total	**$176**	**$26**	**$202**

2

DEP – High DSM Setting - Residential Sector

	DEP High DSM Setting Residential Sector DSM Expenditures (million CAD)		
Year	**Incentive**	**Non-Incentive**	**Total Expenditures**
2020	$172	$26	$197
2021	$168	$25	$193
2022	$156	$23	$180
2023	$142	$21	$164
2024	$125	$19	$144
2025	$103	$15	$118
2026	$96	$14	$110
2027	$90	$14	$104
2028	$88	$13	$101
2029	$74	$11	$ 85
2030	$65	$10	$ 75
2031	$74	$11	$ 85
2032	$71	$11	$ 82
2033	$67	$10	$ 77
2034	$65	$10	$ 74
2035	$61	$9	$ 70
2036	$55	$8	$ 63
2037	$52	$8	$ 59
2038	$49	$7	$ 57
2039	$46	$7	$ 53
2040	$42	$6	$ 48
2041	$44	$7	$ 50
2042	$21	$3	$ 25
Total	**$1,926**	**$289**	**$ 2,214**

DEP – High DSM Setting - Commercial Sector

	DEP High DSM Setting Commercial Sector DSM Expenditures (million CAD)		
Year	**Incentive**	**Non-Incentive**	**Total Expenditures**
2020	$10	$1	$11
2021	$17	$3	$ 20
2022	$27	$4	$ 31
2023	$39	$6	$ 44
2024	$53	$8	$ 61
2025	$66	$10	$ 76
2026	$79	$12	$ 91
2027	$87	$13	$101
2028	$94	$14	$108
2029	$93	$14	$107
2030	$90	$13	$103
2031	$91	$14	$105
2032	$90	$13	$103
2033	$82	$12	$ 94
2034	$78	$12	$ 90
2035	$71	$11	$ 82
2036	$67	$10	$ 77
2037	$60	$9	$ 70
2038	$54	$8	$ 62
2039	$50	$7	$ 57
2040	$46	$7	$ 53
2041	$41	$6	$ 47
2042	$38	$6	$ 43
Total	**$1,423**	**$214**	**$1,637**

DEP – High DSM Setting - Industrial Sector

	DEP High DSM Setting Industrial Sector DSM Expenditures (million CAD)		
Year	Incentive	Non-Incentive	Total Expenditures
2020	$35	$5	$ 40
2021	$32	$5	$ 37
2022	$28	$4	$ 32
2023	$24	$4	$ 28
2024	$22	$3	$ 26
2025	$21	$3	$ 24
2026	$19	$3	$ 22
2027	$17	$3	$ 20
2028	$18	$3	$ 20
2029	$16	$2	$18
2030	$6	$1	$6
2031	$7	$1	$8
2032	$6	$1	$7
2033	$6	$1	$7
2034	$6	$1	$7
2035	$6	$1	$7
2036	$6	$1	$7
2037	$6	$1	$7
2038	$5	$1	$6
2039	$4	$1	$4
2040	$4	$1	$4
2041	$3	$1	$4
2042	$3	$1	$4
Total	**$300**	**$45**	**$345**

1 **DEP – Medium DSM Setting - Residential Sector**

	DEP Medium DSM Setting Residential Sector DSM Expenditures (million CAD)		
Year	**Incentive**	**Non-Incentive**	**Total Expenditures**
2020	$62	$9	$ 71
2021	$65	$10	$ 74
2022	$64	$10	$ 74
2023	$65	$10	$ 74
2024	$65	$10	$ 75
2025	$61	$9	$ 70
2026	$60	$9	$ 69
2027	$58	$9	$ 66
2028	$52	$8	$ 60
2029	$45	$7	$ 52
2030	$40	$6	$ 46
2031	$44	$7	$ 51
2032	$42	$6	$ 48
2033	$39	$6	$ 44
2034	$38	$6	$ 44
2035	$35	$5	$ 40
2036	$30	$5	$ 35
2037	$27	$4	$ 32
2038	$18	$3	$ 21
2039	$15	$2	$18
2040	$14	$2	$16
2041	$10	$2	$12
2042	$8	$1	$9
Total	**$957**	**$144**	**$1,100**

2

1 **DEP – Medium DSM Setting - Commercial Sector**

	DEP Medium DSM Setting Commercial Sector DSM Expenditures (million CAD)		
Year	**Incentive**	**Non-Incentive**	**Total Expenditures**
2020	$1	$0	$1
2021	$2	$0	$2
2022	$3	$0	$4
2023	$4	$1	$5
2024	$6	$1	$7
2025	$8	$1	$9
2026	$9	$1	$10
2027	$10	$1	$11
2028	$10	$2	$12
2029	$10	$2	$12
2030	$10	$1	$11
2031	$10	$2	$12
2032	$10	$2	$12
2033	$9	$1	$11
2034	$9	$1	$11
2035	$9	$1	$10
2036	$8	$1	$9
2037	$8	$1	$9
2038	$7	$1	$8
2039	$6	$1	$7
2040	$6	$1	$7
2041	$5	$1	$6
2042	$5	$1	$6
Total	**$167**	**$25**	**$192**

2

1 **DEP – Medium DSM Setting - Industrial Sector**

	DEP Medium DSM Setting Industrial Sector DSM Expenditures (million CAD)		
Year	Incentive	Non-Incentive	Total Expenditures
2020	$12	$2	$14
2021	$13	$2	$15
2022	$13	$2	$15
2023	$12	$2	$14
2024	$12	$2	$14
2025	$12	$2	$13
2026	$11	$2	$13
2027	$10	$2	$12
2028	$10	$2	$12
2029	$3	$0	$3
2030	$2	$0	$2
2031	$2	$0	$2
2032	$2	$0	$2
2033	$2	$0	$2
2034	$2	$0	$2
2035	$2	$0	$2
2036	$2	$0	$2
2037	$2	$0	$2
2038	$2	$0	$2
2039	$1	$0	$2
2040	$2	$0	$2
2041	$1	$0	$1
2042	$1	$0	$2
Total	**$131**	**$20**	**$151**

2

DEP – Low DSM Setting - Residential Sector

	DEP Low DSM Setting Residential Sector DSM Expenditures (million CAD)		
Year	**Incentive**	**Non-Incentive**	**Total Expenditures**
2020	$5	$1	$6
2021	$5	$1	$6
2022	$5	$1	$6
2023	$6	$1	$7
2024	$7	$1	$8
2025	$4	$1	$5
2026	$4	$1	$5
2027	$4	$1	$5
2028	$4	$1	$5
2029	$4	$1	$5
2030	$4	$1	$5
2031	$5	$1	$5
2032	$5	$1	$5
2033	$5	$1	$5
2034	$5	$1	$6
2035	$5	$1	$6
2036	$5	$1	$6
2037	$5	$1	$6
2038	$4	$1	$5
2039	$3	$1	$4
2040	$3	$0	$4
2041	$3	$0	$3
2042	$2	$0	$3
Total	**$103**	**$15**	**$118**

1 **DEP – Low DSM Setting - Commercial Sector**

	DEP Low DSM Setting Commercial Sector DSM Expenditures (million CAD)		
Year	Incentive	Non-Incentive	Total Expenditures
2020	$1	$0	$1
2021	$2	$0	$2
2022	$2	$0	$3
2023	$3	$1	$4
2024	$5	$1	$5
2025	$6	$1	$7
2026	$7	$1	$8
2027	$7	$1	$9
2028	$8	$1	$9
2029	$8	$1	$9
2030	$7	$1	$8
2031	$8	$1	$9
2032	$8	$1	$9
2033	$7	$1	$8
2034	$7	$1	$8
2035	$7	$1	$8
2036	$6	$1	$7
2037	$6	$1	$7
2038	$6	$1	$6
2039	$5	$1	$6
2040	$5	$1	$5
2041	$4	$1	$5
2042	$4	$1	$5
Total	**$128**	**$19**	**$147**

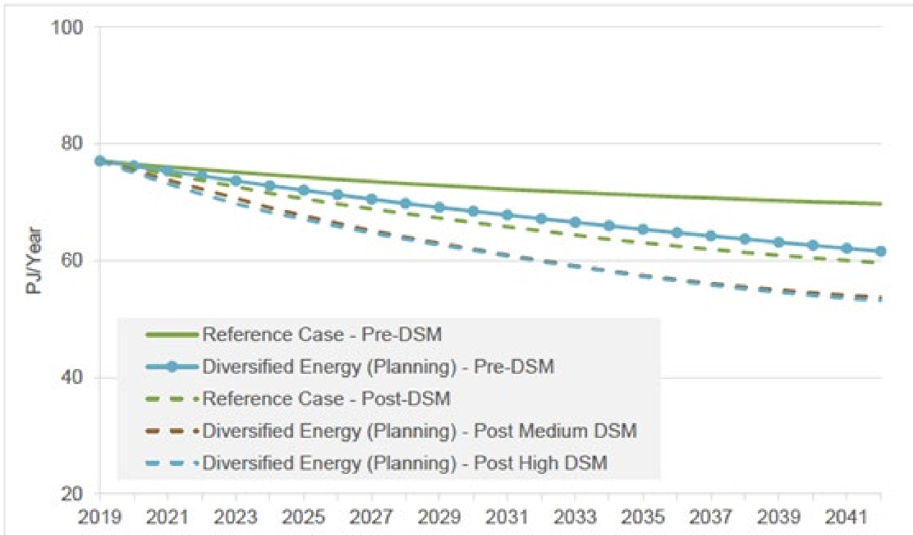
1 **DEP – Low DSM Setting - Industrial Sector**

	DEP Low DSM Setting Industrial Sector DSM Expenditures (million CAD)		
Year	**Incentive**	**Non-Incentive**	**Total Expenditures**
2020	$3	$0	$4
2021	$3	$0	$4
2022	$3	$0	$3
2023	$2	$0	$3
2024	$2	$0	$2
2025	$2	$0	$2
2026	$2	$0	$2
2027	$1	$0	$2
2028	$2	$0	$2
2029	$1	$0	$2
2030	$2	$0	$2
2031	$2	$0	$2
2032	$2	$0	$2
2033	$2	$0	$2
2034	$2	$0	$2
2035	$2	$0	$2
2036	$2	$0	$2
2037	$2	$0	$2
2038	$2	$0	$2
2039	$1	$0	$2
2040	$2	$0	$2
2041	$1	$0	$1
2042	$1	$0	$2
Total	**$43**	**$6**	**$ 50**

2

34. Reference: Exhibit B-1, Page 5-22, Figure 5-10

Figure 5-10: Annual Demand Before and After Estimated DSM Savings (Excluding LCT) – Residential Sector



34.1 Approximately what component of residential sector DSM savings (in PJ/Year) would be attributable to deep energy retrofits for residential buildings in each of the post-medium and post-high DSM settings?

<u>Response:</u>

The following response has been provided by Posterity Group in consultation with FEI.

In the 2021 CPR and the 2022 LTGRP, deep energy retrofits were not modeled as their own standalone measure. Instead, their potential was estimated by adding the savings from CPR individual measures that would typically be part of a deep retrofit.

The residential deep energy retrofit package in the CPR and LTGRP consists of the individual CPR measures described in Table 1 below.

Table 1: List of Individual Measures Included in the Residential Deep Energy Retrofit Package

Deep Retrofit Package– Residential
Attic Duct Insulation
Attic Insulation (R-12.6 Baseline)
Basement or Crawlspace Insulation
Comprehensive Air Sealing
Drain Water Heat Recovery
Exposed Floor Insulation
Gas Heat Pump Combination System - Type 1 and 2
High Performance Windows and Doors
High-Efficiency Heat Recovery Ventilator
Wall Insulation - Cavity (R-3 baseline)
Wall Insulation - Sheathing (R-7 baseline)

These measures would more typically be installed individually and not as part of a deep energy retrofit package. However, this package of measures is what FEI envisions will most closely resemble a future deep energy retrofit package. Program eligibility would be based on reducing energy consumption by at least 50 percent to fit the deep energy retrofit definition.

Accordingly, the following analysis does not provide a direct estimate of the potential savings from a deep energy retrofit program. However, at this early stage in FEI's deep retrofit program development, this analysis provides the best approximation for future program potential once the program is established. The deep retrofit program savings would likely be over and above these savings from individual measures, as the incentive levels under consideration for deep retrofits are anticipated to drive further adoption of these measures.

The estimated cumulative savings from the above-mentioned measures are shown in Table 2 below.

Table 2: Estimated Annual Savings Attributable to the Measures in the Deep Energy Retrofit Package for Residential Customers the DEP Scenario – High and Medium DSM Setting

Year	DEP - Medium DSM	DEP - High DSM
	(PJ/ Year)	
2020	0.18	0.3
2021	0.4	0.6
2022	0.5	0.9
2023	0.7	1.1
2024	0.9	1.3
2025	1.0	1.4
2026	1.2	1.4
2027	1.3	1.5
2028	1.4	1.5
2029	1.5	1.6
2030	1. 6	1.6
2031	1.6	1.7
2032	1.7	1.7
2033	1.7	1.8
2034	1.8	1.8
2035	1.8	1.9
2036	1.8	1.9
2037	1.8	2.0
2038	1.8	2.0
2039	1.7	2.1
2040	1.7	2.1
2041	1.7	2.1
2042	1.7	2.1

In 2042, the demand reduction due to the cumulative energy savings attributable for measures in the Deep Energy Retrofit Package for the residential sector represents:

- 1.7 PJ of 7.9 PJ total energy savings for the Medium DSM Setting or 21 percent; and
- 2.1 PJ of 8.4 PJ total energy savings for the High DSM Setting or 25 percent of residential sector savings.

34.2 Approximately what component of residential sector DSM savings (in PJ/Year) will be attributable to the commercialization and successful adoption of gas heat pumps for single occupancy housing in each of the post-medium and post-high DSM settings?

Response:

The following response has been provided by Posterity Group in consultation with FEI.

The estimated cumulative energy savings attributed to the installation of gas heat pumps in the residential sector is shown in Table 1 below.

Table 3: Estimated Savings Attributable to Gas Heat Pump Measures in the DEP Scenario for the High and Medium DSM Setting

Year	DEP Medium DSM	DEP High DSM
	(PJ/Year)	
2020	-	-
2021	-	-
2022	-	-
2023	0.01	0.01
2024	0.02	0.01
2025	0.03	0.02
2026	0.04	0.03
2027	0.05	0.04
2028	0.06	0.05
2029	0.07	0.06
2030	0.08	0.08
2031	0.10	0.09
2032	0.12	0.11
2033	0.14	0.13
2034	0.16	0.16
2035	0.18	0.18

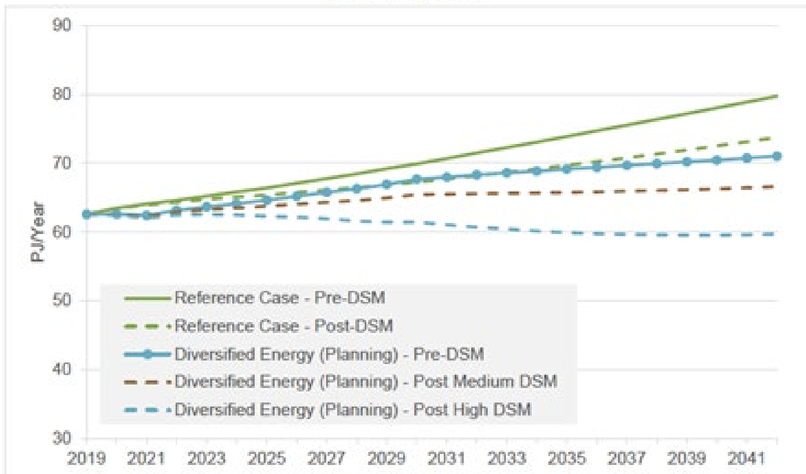
Year	DEP Medium DSM	DEP High DSM
	(PJ/Year)	
2036	0.20	0.21
2037	0.22	0.25
2038	0.24	0.28
2039	0.26	0.32
2040	0.29	0.37
2041	0.31	0.41
2042	0.33	0.44

In 2042, the demand reduction due to the cumulative energy savings attributable to gas heat pump installations in the residential sector represents:

- 0.33 PJ / 7.9 PJ energy savings for the Medium DSM Setting or 4 percent; and
- 0.44 PJ / 8.4 PJ energy savings for the High DSM Setting or 5 percent.

35. Reference: Exhibit B-1, Page 5-23

Figure 5-11: Annual Demand Before and After Estimated DSM Savings (Excluding LCT) – Commercial Sector



35.1 Approximately what component of commercial sector DSM savings (in PJ/Year) would be attributable to deep energy retrofits for commercial buildings, in each of the post-medium and post-high DSM settings?

<u>Response:</u>

The following response has been provided by Posterity Group in consultation with FEI.

In the 2021 CPR and the 2022 LTGRP, deep energy retrofits were not modeled as standalone measures. Instead, their potential was estimated by adding the savings from CPR individual measures that would typically be part of a deep retrofit. The commercial deep energy retrofit packages in the CPR and LTGRP consist of the following individual CPR measures described in Table 1 below, with the associated annual energy savings described in Table 2, below.

Table 4: List of Individual Measures Included in a Commercial Deep Energy Retrofit Package

Deep Retrofit Package– Commercial
Air Sealing
Condensing Boiler (Early Replacement)
Condensing Boiler (Replace On Burnout)
Condensing On-Demand Hot Water
Condensing Storage Hot Water
Energy Recovery Ventilator
Faucet Aerators
Gas Heat Pumps
Heat Recovery Ventilator
Low Flow Showerhead
Residential Furnace (Early Replacement)
Residential Furnace (Replace On Burnout)
Roof Insulation
Wall Insulation
Window Upgrade

This bundle of measures is what FEI envisions will most closely resemble a future deep energy retrofit package. Program eligibility would be based on reducing energy consumption by at least 50 percent to fit the deep energy retrofit definition. Based on FEI's research, most of these measures would need to be implemented in a commercial building to achieve this minimum threshold.

Accordingly, the following analysis does not provide a direct estimate of the potential savings from a deep energy retrofit program. However, at this early stage in FEI's deep retrofit program development, this analysis provides the best approximation for future program potential once the program is established.

The estimated cumulative savings from the above-mentioned measures included in the Deep Retrofit Package are shown in Table 2 below.

Table 5: Estimated Annual Savings Attributable to the Measures in the Deep Energy Retrofit Package for Commercial Customers in the DEP Scenario – High and Medium DSM Setting

Year	DEP Medium DSM	DEP High DSM
	(PJ/Year)	
2020	0.01	0.03
2021	0.03	0.09
2022	0.05	0.17
2023	0.07	0.27
2024	0.10	0.40
2025	0.12	0.56
2026	0.15	0.76
2027	0.18	0.99
2028	0.21	1.26
2029	0.24	1.55
2030	0.26	1.85
2031	0.29	2.15
2032	0.32	2.43
2033	0.35	2.70
2034	0.38	2.95
2035	0.41	3.17
2036	0.44	3.37
2037	0.47	3.55
2038	0.50	3.70
2039	0.53	3.83
2040	0.56	3.94
2041	0.59	4.03
2042	0.61	4.11

In 2042, the demand reduction due to the cumulative energy savings attributable for measures in the Deep Energy Retrofit Package for the commercial sector represents:

- 0.61 PJ of 4.4 PJ total energy savings for the Medium DSM Setting or 14 percent; and
- 4.11 PJ of 11.3 PJ total energy savings for the High DSM Setting or 36 percent of commercial sector savings.

35.2 What other types of energy efficiency programs for commercial customers, would most significantly contribute to DSM savings in each of the post-medium and post-high DSM settings?

Response:

The following response has been provided by Posterity Group in consultation with FEI.

FEI interprets this question as referring to the types of commercial energy efficiency measures, rather than programs, that would most significantly contribute to DSM savings for commercial customers. Table 1 below illustrates the top 15 measures by savings potential in 2042 for both the Medium and High DSM Settings.

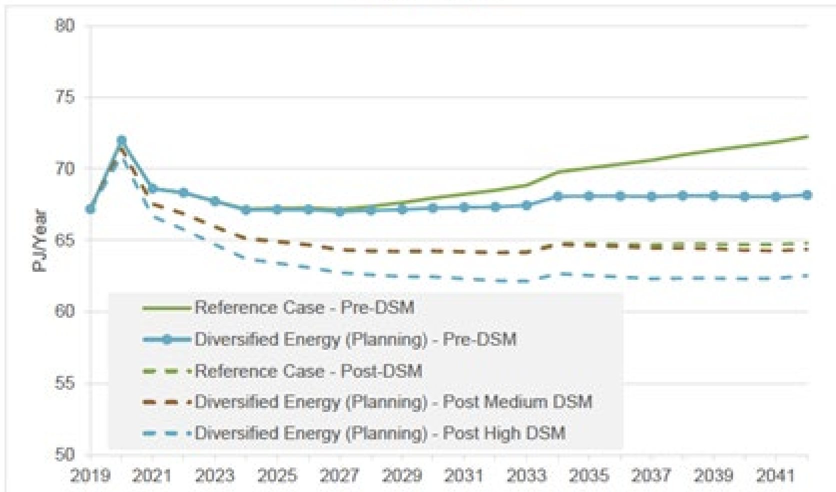
Table 6*:* Top 15 Commercial Program Measures by Savings Potential in 2042

DEP Medium DSM Setting	DEP High DSM Setting
Advanced Thermostat	Gas Heat Pumps
Occupant Behaviour	Energy Recovery Ventilator
Heat Transfer Technology	Commercial New Construction - Step 3
Boiler Cycling Controls	Advanced Thermostat
Boiler / Furnace Tune-Up	Occupant Behaviour
Business Energy Report	Commercial New Construction - Step 2
Reverse Flow Energy Recovery Ventilator	New Construction Step 2 - MURB
Energy Recovery Ventilator	Heat Transfer Tech
Efficient Cook Equipment	New Construction Step 4 - MURB
Commercial New Construction - Step 2	New Construction Step 3 - MURB
Commercial New Construction - Step 3	Business Energy Report
Gas Heat Pumps	Recirculation Demand Control
New Construction Step 2 - MURB[25]	Window Upgrade
Boiler Zoning Controls	Boiler / Furnace Tune-Up
Solar Preheat	Comprehensive Retro-Commissioning

[25] MURB - Multi-unit residential building.

36. Reference: Exhibit B-1, Page 5-24, Figure 5-12

Figure 5-12: Annual Demand Before and After Estimated DSM Savings (Excluding LCT) – Industrial Sector



36.1 Approximately what component of industrial sector DSM savings (in PJ/Year) would be attributable to the successful adoption of hydrogen applications for pulp mills and steel production processes, in each of the post-medium and post-high DSM settings?

Response:

The following response has been provided by FEI in consultation with Posterity Group.

For the 2021 CPR and 2022 LTGRP, DSM savings include energy efficiency measures only. Hydrogen processes discussed in the preamble are not included.

Renewable and low-carbon gas supply, including hydrogen, contributes to GHG reductions in the DEP Scenario. Section 9.2 of the Application discusses sources of GHG emission reductions in the DEP Scenario, including the contribution of renewable and low-carbon gas supply. However, these emission reductions are separate to the DSM emission reduction estimates.

36.2 What other types of energy efficiency programs for industrial customers would most significantly contribute to DSM savings in each of the post-medium and post-high DSM settings?

Response:

The following response has been provided by Posterity Group.

FEI interprets this question as referring to types of industrial energy efficiency measures, rather than programs, that would most significantly contribute to DSM savings. Table 1 below illustrates the top 15 industrial customer measures by savings potential in 2042 for both the DEP medium and high DSM settings.

Table 7: Top 15 Measures by Savings Potential in 2042

DEP Medium DSM Setting	DEP High DSM Setting
Steam to Hot Water Conversion (District Energy)	Energy Management
Heat Recovery Systems	Heat Recovery Systems
Energy Management	High Efficiency Dryers
Process Boiler Load Control	Steam to Hot Water Conversion (District Energy)
High Efficiency Dryers	Direct Contact Hot Water Heater
Direct Contact Hot Water Heater	Boiler Tune-Up
Boiler Tune-Up	Process Boiler Load Control
Integrated Greenhouse Environmental Controls	Replace Steam Traps
Greenhouse Envelope	Greenhouse Envelope
Replace Steam Traps	Integrated Greenhouse Environmental Controls
Condensing Boiler	Process Control
Improved Condensate Return (Retrofit)	Greenhouse Curtains
Process Control	Air Compressor Heat Recovery (Process Heating)
Air Compressor Heat Recovery (Process Heating)	Venturi Steam Trap
Venturi Steam Trap	Condensing Boiler

GAS SUPPLY PORTFOLIO PLANNING

37. Reference: Exhibit B-1, Page 6-10, Table 6-2

Table 6-2: FEI's 2021/2022 Planned Core Peak Day Portfolio[183]

Peak Day Portfolio	2021/2022 Portfolio-Planned (TJ/day)
Fort Nelson Supply	**5**
Alberta Baseload Supply	103
Station 2 Baseload Supply	308
Total Commodity Supply	**411**
Seasonal Supply	135
Seasonal Storage	201
Market Area Storage	211
Spot Supply	120
Mt. Hayes LNG	163
Tilbury LNG	163
Industrial Curtailment	26
Total Midstream Supply	**1020**
Total Resources	**1,436**
Peak Day Demand	**1,436**

37.1 Has the contribution to the Peak Day Portfolio changed materially over the last five years, as to among the various components of the portfolio?

37.1.1 If yes, please provide a discussion of the most significant changes in contribution, and whether the trend(s) are anticipated to continue.

Response:

The contribution of each supply component (commodity, storage, LNG, etc.) in FEI's Peak Day Portfolio, relative (as a percentage of) to the other various components, or overall total resources, of the portfolio has not changed materially over the last five years.

The more notable change is the increase in peak day demand from 1,325 TJ per day in 2017/2018 to 1,436 TJ per day in 2021/22, a growth of 111 TJ per day or 8 percent. This increase is largely due to the return of Transportation customers to FEI's bundled service or Core customer portfolio, as well as due to customer growth. As the load has increased, and the supply contribution from FEI's LNG facilities and Market Area Storage have remained roughly the same since 2017/2018, baseload, seasonal and spot supply have all increased to provide resources for the increased peak load.

38. References: Exhibit B-1, Page 6-12 and Page 5-25

Figure 6-3: Forecast Renewable and Low-Carbon Gas Supply

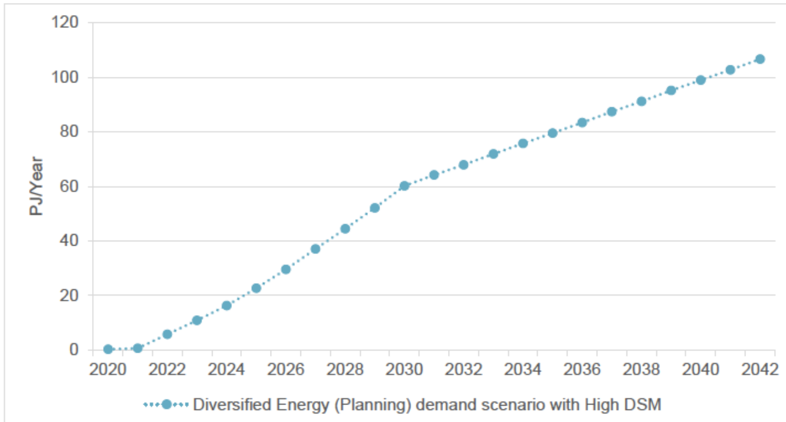
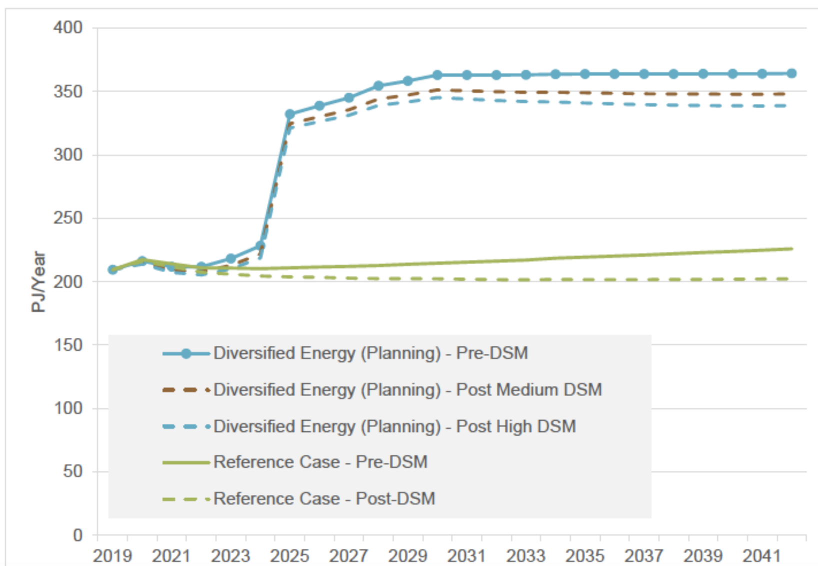


Figure 5-13: Total Annual Demand After DSM - Including LCT



38.1 Please confirm that the order-of-magnitude amount of 'Forecast Renewable and Low-Carbon Gas Supply' as envisioned for FEI's system in the Diversified Energy Planning Demand scenario by 2041, is equal to about 50% of FEI's present year's energy supply (as measured in PJ/Year).

<u>Response:</u>

FEI confirms that the amount of renewable and low-carbon gas supply forecast for FEI's system, as illustrated in Figure 6-3, is in the range of about 50 percent of FEI's present demand for energy from customers. FEI notes that Figure 5-13 represents the demand forecast under the DEP Scenario for all customers, not just FEI's Core customers, for the purposes of planning FEI's gas supply portfolio.

38.2 What component of this amount is expected to come from the incorporation of RNG supply over the course of the forecast?

Response:

Please refer to the response to BCUC IR1 52.6.

39. References: Exhibit B-1, Pages 6-13, 6-14 and 6-23

> As RNG volumes continue to increase each year, FEI will monitor and make any adjustments that are required to the remainder of the gas supply portfolio through each ACP. Additionally, as FEI begins to integrate other low-carbon gas supply such as hydrogen, syngas or lignin, as discussed in Sections 3.3 and 6.2.2.2, FEI will annually assess the impact to the portfolio in each ACP. Although there is still uncertainty as to what the impact will be to each of FEI's service regions,
>
> many of these projects will continue to utilize the existing regional natural gas infrastructure (pipelines and storage) in a significant way.
>
> **6.2.6 Short-Term Actions**
>
> FEI will continue to develop a portfolio that provides its customers secure and reliable supply for the short to medium term. FEI's efficient supply portfolio consists of natural gas commodity contracts, third-party pipeline capacity and storage resources, and FEI will continue to assess the regional market for renewable and low-carbon gas volumes and adjust the portfolio annually as needed through the ACP. Near term efforts in acquiring renewable and low-carbon gases are aimed at accelerating the transition to a low-carbon energy future to meet 2030 provincial emission reduction targets.

39.1 Please reconcile FEI's objective that 'Many of these [low carbon fuel] projects will continue to utilize the existing regional natural gas infrastructure (pipelines and storage) in a significant way', with its other objective 'to continue to develop a portfolio that provides its customers secure and reliable supply for the short to medium term'.

Response:

FEI's contracted pipeline and storage assets of the existing regional natural gas infrastructure help to provide its customers secure and reliable supply. FEI contracts 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. As FEI anticipates that the majority of RNG supply will be delivered by way of displacement, FEI will still require transportation contracts with third parties to move the gas to the FEI's system, utilizing existing and future infrastructure to provide secure and reliable supply.

39.2 In light of the concern expressed on line 38 on Page 6-13 of the Application, 'Although there is still uncertainty as to what the impact will be to each of FEI's service regions', what is FEI's confidence that the two objectives are well-aligned in their imperative to provide 'secure and reliable supply'.

Response:

Throughout the transition to a low-carbon energy future, methane (both renewable and conventional natural gas) will continue to play a significant role in providing secure and reliable energy service to FEI's customers. A significant amount of RNG will be incorporated into FEI's resource mix by 2030, with the majority being acquired outside of FEI's service territory and delivered by displacement. As RNG is interchangeable with conventional sources of natural gas, FEI will still utilize existing third-party pipelines and storage resources.

Over the longer-term planning horizon (between 2030 and 2042), FEI expects additional low-carbon energy projects, such as those that produce hydrogen for use in place of natural gas, to be incorporated into the resource mix. Although there still is uncertainty as to what the impact will be to each of FEI's service regions, many of these projects will continue to utilize the upstream infrastructure in a significant way. For instance, while the appropriate amounts are yet to be determined, there is a major opportunity to inject hydrogen into the gas supply to create a blended product within the existing upstream gas infrastructure. Further, there is also the opportunity to create hydrogen from methane closer to the demand centres with pyrolysis technologies. FEI will monitor the impact that these low-carbon energy projects will have to each of FEI's service regions, to ensure that regardless of the gas supply type, secure and reliable supply is provided to its customers.

SYSTEM RESOURCE NEEDS AND ALTERNATIVES

40. Reference: Exhibit B-1, Page 7-4

> In general, system demand growth is determined by region and applied to hydraulic models which determine resulting pressures at critical locations throughout the system. In the context of growing demand, demand will eventually exceed capacity, which typically manifests by the pressure at critical locations falling below minimum values, and a system expansion is required.
>
> FEI's continuously monitors these factors that can impact capacity requirements to determine if there is a need to advance or delay proposed capacity expansions. Section 7.3 discusses factors that might increase peak demand and thus advance capacity requirements, as well as alternatives for addressing system constraints. Potential for lower than expected peak demand delaying the timing of system constraints is also discussed. As such, contingency planning for system capacity requirements is inherently included in FEI's regional system capacity plans.

40.1 What is the nature of the upkeep for the hydraulic models used by FEI in its resource planning?

40.1.1 Is this done routinely in-house, or does FEI periodically acquire new modelling capabilities?

Response:

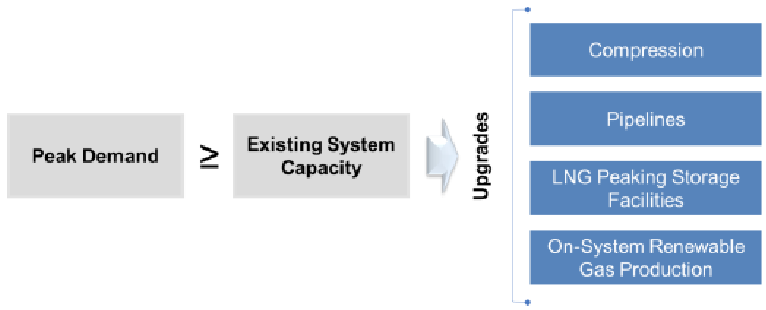
FEI analyzes customer demand information annually and updates this information in the hydraulic models it maintains for FEI's transmission and distribution systems. On an annual basis, FEI imports all new pipeline and customer meter additions installed each calendar year. In between annual updates, hydraulic models are updated manually if pipeline additions, alterations or load additions of a significant nature occur. The updates to the models occur at the time such changes are put into service in the field. FEI uses the same hydraulic models to support operational work and emergency response activities, in addition to resource planning. FEI requires accurate and up-to-date system information to provide reliable support to FEI Operations personnel in these activities.

FEI uses state-of-the-art hydraulic modelling software provided by a third-party vendor and the software is periodically updated with enhancements to improve performance. FEI will periodically expand modelling capabilities and, for example, recently acquired a gas component module for the hydraulic software to allow enhanced modelling capability for hydrogen and hydrogen natural gas blends.

41. Reference: Exhibit B-1, Pages 7-4; and 7-5, Figure 7-1

> to a decrease in available pipeline capacity. As FEI incorporates renewable and low-carbon gases into the gas distribution and transmission systems, the physical properties of these gases, such as density and energy content per standard volume, and the ability to generate supply located on-system can have an impact on capacity. These changes in physical properties and supply options must be considered. Section 7.4 discusses the potential impacts of renewable and low-carbon gases on FEI transmission system capacity at a high level.

Figure 7-1: Options for Gas System Reinforcements



41.1 With the advent of the increased incorporation of LC fuels overtime, which LC fuel would bring the most complexity to FEI's system planning activities?

Response:

None of the low-carbon fuels present a high level of complexity to system planning activities and hydraulic modelling used to determine system capacity, once the supply of each is characterized (volume and source location) and the location of demand centres of each fuel relative to the supplies are determined. The complexity lies not in the system planning activities, but in the development of these low-carbon fuel producers and markets as well as providing the definition to the specific capability and requirements for each that can then be modelled.

FEI expects over time the increasing share of renewable and low-carbon gas will involve various complexities irrespective of fuel type. Developing on-system supply will involve system planning and FEI already has over a decade of experience integrating on-system RNG (biomethane) supply projects. RNG is a "drop-in" fuel that can directly displace conventional methane. However, the distributed nature of the resources to produce RNG has required an innovative approach by FEI to ensure that the existing gas network has the capacity to interconnect the production volumes. For example, FEI will need to upgrade unidirectional networks to bi-directional capabilities to allow RNG production facilities to "reverse-flow" from low-pressure to higher-pressure networks. This is not dissimilar to how power networks have needed to evolve over the last number of decades to facilitate interconnection of distributed power generation both in British Columbia and world-wide.

FEI is also considering opportunities for new forms of on-system renewable fuels such as syngas, lignin, and renewable and low-carbon hydrogen supply to supplement RNG to further decarbonize the gas system. Syngas and lignin would displace natural gas use at existing industrial facilities and would therefore present low system planning complexities.

Hydrogen has the potential to be produced in very large volumes given the available resources in BC. Given the physical and chemical differences between methane and hydrogen, there are different system planning complexities compared to RNG. Hydrogen is compatible with the existing gas system when blended in low-concentrations and FEI plans to initially take this approach to introduce hydrogen to further decarbonize the gas supply and minimize on-system system planning complexity. FEI also plans to acquire off-system hydrogen supply to increase supply volumes without increasing system planning complexity in the near-term. Over time, as the gas industry evolves, regulatory codes, standards, procedures, and practices to increase the share of hydrogen in the gas system to higher shares of hydrogen and towards 100 percent hydrogen service, FEI expects that system planning activities will also evolve.

41.2 Of the four segments of FEI's Gas System infrastructure provided in Figure 7-1, which segment(s) would be most vulnerable to increased complexities (associated with the increased incorporation of LC fuels overtime) from a system planning perspective?

Response:

From a system planning perspective, FEI would not consider any of the options as highly vulnerable to adopting renewable and low-carbon gases. On-system renewable and low-carbon gas production is a new resource that can alleviate capacity constraints and will be more available and have more impact once more renewable and low-carbon fuel production is developed and becomes a reliable option. Pipeline and compression will continue to be options and are compatible with all forms of renewable and low-carbon gases. LNG peak shaving can continue to be considered to support portions of the system where renewable and low-carbon gas blends that include methane continue to be delivered.

42. Reference: Exhibit B-1, Page 7-7

> For large industrial demand, the Traditional Peak Method forecast does not apply any forecast growth or decline in the demand associated with these customers. This is because the ability to forecast both the future load and location of these customers is subject to a great deal of uncertainty. UPC_{peak} for large industrial customers varies widely and can significantly impact local system capacity. Speculating on infrastructure requirements for loads of unknown magnitude and location has little value in long-term planning of facilities whose design can be greatly influenced by their location within the transmission or distribution system. However, to explore impacts to peak demand because of potential changes in industrial account forecasts, FEI has produced both high and low account forecasts that show increasing or decreasing numbers of accounts,

42.1 In producing high and low industrial account forecasts for purposes of developing end use regional peak demand forecasts, what factors does FEI consider in developing the increasing or decreasing number of industrial accounts?

<u>Response:</u>

The high and low regional industrial account forecasts used to develop the end use regional peak demand forecasts were developed using a statistical approach using 95 percent confidence intervals to model customer forecast uncertainty.

Please see Section 1.1.1.3 of Appendix B-1, and Section 1.3.2.1.1 of Appendix B-3 of the Application.

42.2 What drives the estimate of the number of industrial accounts for developing the end use regional peak forecasts? Is it region-specific considerations or provincial economic growth scenarios? Please elaborate.

<u>Response:</u>

Please refer to the response to BCUC IR1 13.3.

STAKEHOLDERS, INDIGENOUS AND COMMUNITY ENGAGEMENT

43. Reference: Exhibit B-1, Page 8-8

> **8.2.3 Stakeholder Expert (Crowd) Opinion Forecast**
>
> At the June 21, 2021 RPAG meeting, FEI introduced the Expert (Crowd) Opinion Forecast and "Slider" forecasting tool (Expert Opinion Tool). Stakeholders were given an introduction to the exercise and a website link via email after the session. Stakeholders were invited to use the tool to develop their own forecast scenario and to then submit the results to FEI. The exercise was anonymous, but an option was made available for participants to identify their affiliation. The invitation was sent to 31 stakeholders. FEI received responses from 14 RPAG members.

43.1 To what extent does FEI consider the variability in community and customer preferences, depending on which areas or regions they are located?

Response:

FEI considers the variability in community and customer preferences to some degree through its community engagement sessions and where RPAG feedback specifically cites geographic or regional consideration in BC. FEI invites representatives from the FEI Community Relations or Energy Solutions teams to planning meetings prior to each session to understand if there is some key information that could be highlighted that would serve the unique needs of the community. In addition, there may be internal knowledge about upcoming regional clean energy projects, for example that would be of particular interest to attendees. Though it varies to some degree, Lower Mainland attendees tend to raise issues and comments on climate action related activities, whereas southern and northern communities tend to raise issues in affordability, opportunities for clean energy projects and system resiliency. Vancouver Island attendees tend to raise more issues on access to gas for new developments, system resiliency and the ability for local energy sources, and climate action initiatives.

43.2 In addition to tools such as the Expert Opinion Forecast and Slider, which are designed to canvass and incorporate broader opinion considerations, does FEI solicit and/or use more focused opinions as it concerns planning for future community solutions?

Response:

During the LTGRP development, FEI solicited feedback and input from stakeholders, rights holders and customer groups through regional engagement sessions. While the focus of these sessions was on high-level energy themes and planning scenarios, this created additional opportunity to solicit input from communities and organizations on energy solutions to meet their planning requirements. During engagement workshops, community representatives raised interest in FEI energy extension projects, provided information on community growth plans and during one session, inquired about proposed district energy projects within their jurisdiction. FEI held follow up discussions to explore the feasibility of energy project opportunities and to better understand community energy plans, including district energy. FEI will continue to hold community engagement sessions in the various regions of BC it serves as a general forum to solicit input from communities and customers on their energy plans. This creates the opportunity to have follow up discussions on how FEI can best meet customer needs, and it allows FEI's resource planning team to integrate significant energy plans or projects into the LTGRP demand scenarios. FEI also remains open to feedback and new ideas on its engagement activities related to the LTGRP.

43.3 How does FEI canvass the opinion of those BC communities that are not presently served by FEI?

Response:

Please refer to the response to CEC IR1 8.1.

OUTCOMES OF THE CLEAN GROWTH PATHWAY

44. Reference: Exhibit B-1, Page 9-6

> **9.2.2 Low-Carbon Transportation and Global LNG**
>
> Figure 9-3 presents the emissions reductions that result from growth in FEI serving low-carbon transportation fuels and global LNG exports in the Diversified Energy (Planning) Scenario. These emission reductions are separated into those that would occur within BC, and so would contribute to reductions in BC's GHG emissions inventory, and those that are either in other inventories other than BC or, though occurring, are not captured in any inventory. FEI is not inferring ownership of any carbon credits with regard to Figure 9-3, but simply stating the emission reductions that will occur when natural gas displaces higher-carbon fuels for these uses. The total potential for carbon reductions as a result of serving this demand is much greater than FEI has modelled in the Diversified Energy (Planning) Scenario and shown in Figure 9-3.

44.1 As part of the Stakeholder, Indigenous and Community Engagement process for the development of its 2022 LTGRP, did FEI receive any questions or opinions about potential use of BC-produced LNG for niche applications in BC?

Response:

FEI does not recall any questions or opinions related to BC-produced LNG for niche applications in BC.

44.2 Would potential carbon credits associated with such niche applications (in theory) be captured in Figure 9-3?

Response:

Figure 9-3 represents the potential GHG emissions reduction associated with fuel switching in the transportation and Global LNG markets. If further niche applications for LNG in BC represented an opportunity to fuel switch from a higher carbon fuel to LNG in these markets, then the related carbon reductions could potentially be represented in a future version of this figure. However, as indicated in Section 9.2.2, FEI is not inferring ownership associated with any carbon credits but instead presenting the overall societal benefit associated with fuel switching. The ability to monetize this GHG emissions reduction in the form of carbon credits would not change this overall societal benefit of fuel switching.

45. Reference: Exhibit B-1, Page 9-12

- The effective rate impacts are based on the average use per customer (UPC) between 2022 and 2042 under the Diversified Energy (Planning) Scenario:
  - Residential (RS 1): 60 GJ per year
  - Small Commercial (RS 2): 293 GJ per year
  - Large Commercial (RS 3): 3,253 GJ per year
  - Industrial General Firm Service (RS 5): 18,542 GJ per year

45.1 Please provide a table comparison between average UPC's used in the 2022 LTGRP (as per the above reference) and average UPC's in FEI's previous LTGRP.

<u>Response:</u>

FEI only used the average UPCs listed on page 9-12 of the Application, as referenced in the preamble above, to demonstrate the directional bill impact for the average customers in each of those rate classes under the four demand scenarios (i.e., Reference, DEP, Deep Electrification, and Upper Bound). FEI used the same average UPCs across all scenarios in order to provide a comparative bill impact analysis with fixed customer consumption.

To be clear, the UPCs listed on page 9-12 of the Application are simply the averages of forecast annual demand divided by the forecast annual customer count from 2022 to 2024 under the DEP scenario. These UPCs listed on page 9-12 of the Application are not used to forecast the demand or the delivery margin for any of the scenarios over the 20-year period of the 2022 LTGRP. Please refer to Section 4 of the Application for an explanation of the demand forecasting methodology used in the 2022 LTGRP.

A similar directional bill impact analysis was not provided in the 2017 LTGRP. However, please refer to Table 1 below for the average UPCs from the 2017 LTGRP. The UPCs in the table were calculated using the same approach as those UPCs listed on page 9-12 of the 2022 LTGRP (i.e., 20-year average of annual demand divided by annual customer forecasts). FEI also clarifies that the industrial (RS 5) UPC that was listed on page 9-12 of the Application in the 2022 LTGRP was based on the average of total industrial demand divided by the total industrial customer count (i.e., not just industrial RS 5 customers) and used to demonstrate the directional impact at a certain consumption level for customers under RS 5. This is the reason why the UPCs shown for RS 5 in the table below are higher for the 2022 LTGRP than the 2017 LTGRP.

1 **Table 1: Comparison of Average UPCs between 2022 LTGRP and 2017 LTGRP**

Rate Schedule	2022 LTGRP Average 2042 UPC (GJ/Year)	2017 LTGRP Average 2036 UPC (GJ/Year)
Residential (RS 1)	60 GJ per year	72 GJ per year
Small Commercial (RS 2)	293 GJ per year	300 GJ per year
Large Commercial (RS 3)	3,253 GJ per year	3,307 GJ per year
Industrial General Firm Service (RS 5)	18,542 GJ per year	8,153 GJ per year

2

ACTION PLAN

46. Reference: Exhibit B-1, Page 10-1

> - Support the development of BC's hydrogen economy through implementing hydrogen blending and hydrogen hubs, and plan for transitioning to hydrogen compatible infrastructure;

46.1 As per FEI's current understanding of the policy requirements of the CleanBC Roadmap, does FEI plant to own and operate hydrogen hubs?

Response:

Confirmed. FEI envisions that it will be collaborating with all parties in hydrogen hubs development which may include building, owning, and operating hydrogen production facilities and supplying hydrogen through its infrastructure system to end users.

46.2 As per FEI's current understanding of the policy requirements of the CleanBC Roadmap, would FEI fund the costs of transitioning its own system to hydrogen compatible infrastructure?

Response:

Absent provincial or federal funding or grants, FEI expects that it will apply to the BCUC for recovery of system expenditures related to enabling hydrogen as an energy source.

47. Reference: Exhibit B-1, Page 10-5

> - Continue its ongoing system resiliency review and monitoring across all regions of its service network;
> - Further define resiliency criteria for application when identifying and selecting preferred project alternatives to meet system growth and/or sustainment on the gas grid; and
> - Continue to monitor regional issues in the PNW for developments that could impact the resiliency of gas supplies for FEI's customers.

47.1 When did FEI first introduce the resiliency criteria in its project planning activities?

Response:

To FEI's knowledge, the North American natural gas industry does not have any industry-adopted reliability or resiliency standards, equivalent to the Mandatory Reliability Standards for electric utilities. However, the examination of gas system resiliency is becoming increasingly relevant for natural gas utilities. Given that there are no established industry standards for addressing resiliency, resiliency objectives and any related investment decisions are based on each utility's own system configuration, unique characteristics, and operational challenges.

FEI first introduced its resiliency criteria shortly after the T-South Incident, as FEI initiated an internal working group to study and identify strategies to improve resiliency in its service regions. Through this working group and in conjunction with external experts, FEI concluded that there is no single approach for building resiliency as it depends on each service region's accessibility to the three key elements that make up a resilient system: ample storage, diverse pipelines and supply, and load management capabilities (as discussed in Appendix E of the Application).

47.2 How does FEI apply the resiliency criteria to identify and select a preferred project alternative?

Response:

FEI applies specific resiliency criteria to each of its service regions based on their own unique system requirements. For instance, the resiliency considerations for the Lower Mainland do not necessarily apply to the Vancouver Island and the Interior Service areas. The Lower Mainland customer load, which makes up the largest share (approximately 60 percent) of the demand on FEI's system, is subject to the most impactful consequences resulting from upstream supply disruptions. The T-South Incident brought into focus the extent to which FEI's dependency on the T-South system represents a significant risk to FEI and its customers in the Lower Mainland. Given the potentially significant consequences that would impact a large number of customers resulting from a no-flow event on the T-South system, FEI considered it necessary to develop a portfolio of projects, including the Tilbury LNG Storage Expansion Project, to improve resiliency in the Lower Mainland. This project is a resiliency investment that would allow the Lower Mainland to withstand a supply disruption on T-South for at least three days.

47.3 Does the resiliency criteria contribute (a score) to the ranking of project alternatives; or does the resiliency criteria 'check' result in additional project scope where a resiliency deficiency is identified?

Response:

Each of FEI's major capital projects are necessary and have their own unique drivers which contribute to the need and timing for these projects. Although resiliency may not be the primary driver for some projects, many of the capital projects that FEI is currently developing or assessing will improve and strengthen system resiliency. In the ranking of alternatives, FEI considers resiliency, but the score or contribution to alternative project ranking may vary depending on the underlying need for the project. The TLSE Project, for example, has resiliency as a primary driver. Other projects have different primary drivers (capacity or integrity, as examples) which would then lead FEI to include resiliency in the scoring to rank and select the preferred alternative. In some cases, this may include FEI recognizing opportunities and adjusting the project scope to enhance resiliency.

47.4 When does FEI plan to finalize the resiliency criteria for use in identifying and selecting a preferred project alternative?

Response:

As discussed in the response to CEC IR1 47.1, there is no established industry standard criteria for addressing resiliency. FEI's approach to enhancing resiliency will be an ongoing process and applied differently based on each service region's needs. Therefore, FEI's resiliency criteria for use in identifying and selecting a preferred project alternative will not result in a finalized criteria for all large-scale projects. For enhancing resiliency in the distribution and transmission pipeline lateral systems, as discussed in Appendix E, Section 3.1.1, FEI is working to establish criteria for assessing and ranking these types of projects, at least initially, over the coming year.

48. Reference: Exhibit B-1, Page 10-8

- Refine criteria to identify and prioritize projects to address system resiliency in all FEI systems;

48.1 When does FEI plan to complete the task of refining the criteria for identifying and prioritizing projects to address system resiliency in all FEI systems?

Response:

Please refer to the response to CEC IR1 47.4.