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May 3, 2023

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

Attention: Patrick Wruck, Commission Secretary

Dear Patrick Wruck:

Re: FortisBC Energy Inc. (FEI)

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

Response to the British Columbia Utilities Commission (BCUC) Information Request (IR) No. 2

On May 9, 2022, FEI filed the LTGRP referenced above. In accordance with the amended regulatory timetable established in BCUC Order G-99-23 for the review of the LTGRP, FEI respectfully submits the attached response to BCUC IR No. 2.

In its responses, FEI has identified responses which were provided by, contributed to, or developed with its consultants, the Posterity Group, Guidehouse and ICF Consulting Canada Inc. (ICF Consulting).

FEI requests that a portion of the response to BCUC IR2 95.4, which is redacted in the public version, be filed on a confidential basis in perpetuity, pursuant to section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-72-23, related to the details of its storage contracts with Aitken Creek. U nder its storage contracts with Aitken Creek, FEI is contractually obligated to keep this information confidential and may only provide it to the BCUC. Given FEI's contractual obligations, FEI is filing the unredacted version of this response confidentially to the BCUC only for the purposes of this proceeding, and requests that it not be provided to other parties in this proceeding.

For convenience and efficiency, if FEI has occasionally provided an internet address for referenced reports instead of attaching lengthy 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:

Sarah Walsh

Attachments

cc (email only): Registered Parties

Table of Contents **Page No.**

A. PLANNING ENVIRONMENT

79.0 Reference: PLANNING ENVIRONMENT
Exhibit B-6, BCUC IR 1.1, 1.1.2
Resource Portfolios

In response to British Columbia Utilities Commission (BCUC) Information Request (IR) 1.1, FortisBC Energy Inc. (FEI) states:

> A comparison of renewable and low-carbon gas portfolios is a potential future matter rather than a matter for the Application because the marketplace for these resources is still new and there are currently not enough supply resource alternatives from which to develop and assess a robust set of alternative portfolios.

In response to BCUC IR 1.1.2, FEI states:

> due to the rapid transition to renewable and low-carbon gas required to meet the forthcoming Greenhouse Gas Reduction Standard (GHGRS) announced by the BC Government, FEI estimates that the opportunity to develop a broad range of renewable and low-carbon gas supply resource alternatives for examination in an LTGRP [Long Term Gas Resource Plan] may not be practical until near or perhaps after 2030… Until that time, the anticipated legal requirement to rapidly decarbonize the energy supply to buildings and industry in BC as a result of the cap means that FEI's Clean Growth Plan will involve purchasing most of the

reasonably priced renewable and low-carbon gas available to it, thereby supplanting the opportunity to develop alternative portfolio options.

79.1 Please discuss whether, prior to 2030, FEI considers it will need to make any trade-offs between available renewable and low carbon gases. If yes, please discuss the potential factors that FEI will need to take into account.

Response:

As stated in the response to BCUC IR1 1.1, there are currently not enough supply resource alternatives from which to develop and assess a robust set of alternative renewable and low-carbon gas portfolios. Therefore, FEI does not consider it will need to make any trade-offs between available renewable and low-carbon gas supplies prior to 2030. That said, FEI will continue to seek the most cost-effective supply sources available and negotiate acceptable contract terms.

79.2 Based on FEI's understanding of the supply potential, please further explain the statement "FEI's Clean Growth Plan will involve purchasing most of the reasonably priced renewable and low-carbon gas available to it".

Response:

To enable FEI to meet the proposed cap on GHG emissions attributable to gas use in buildings and industry in the CleanBC Roadmap, FEI's strategy will involve acquiring all cost-effective renewable and low-carbon gas resources available to it. FEI expects that the proposed GHG emissions cap would be met, in large part, through the delivery of renewable and low carbon gas. Since there is a requirement to ramp up its purchases quickly, and the marketplace for renewable and low carbon gas will be developing over the same period, FEI anticipates that, rather than having access to the wide range of supply options that are currently available in the mature conventional natural gas market, FEI will likely need to purchase most or all of the reasonably priced resources available to it. The ability to "shop around" for a range of price and purchase condition options may not be available to FEI for developing alternative supply portfolios for evaluating in either the LTGRP or Annual Contracting Plan (ACP) until later in the planning horizon of the 2022 LTGRP. Also, as outlined in Section 2 of the LTGRP, FEI anticipates increasing competition to acquire RNG based on evolving energy and climate policy mandates in other jurisdictions; therefore, FEI anticipates a more competitive and potentially higher-cost RNG market environment as other entities also seek to purchase RNG. Potential mitigating factors would be the extent to which government incentives are put in place to subsidize projects, as well as technology advances in the sector.

79.3 Please explain whether in the next LTGRP, FEI considers it would be feasible to develop and compare resource portfolios from 2030 to the end of the planning horizon.

Response:

The extent to which FEI will be able to develop and compare renewable and low carbon gas portfolios in the next LTGRP or future LTGRPs depends on the extent to which the market for these gases has developed. FEI expects the market to develop quickly, but cannot predict whether it will be sufficiently advanced for this type of analysis in the next LTGRP or the one following.

80.0 Reference: PLANNING ENVIRONMENT
Exhibit B-6, BCUC IR 2.1
Sectoral Emissions

BCUC IR 2.1 states:

> Please outline the proportion of BC's total GHG [greenhouse gas] emissions resulting from energy supplied by FEI in the following sectors: (i) Industry, and (ii) Buildings and Communities.
>
> [FEI] Response: For 2019, FEI estimates that its customer-related emissions (life cycle) as a proportion of BC's total GHG emissions inventory are as follows: • Industry – percent; and • Buildings and communities – 12 percent.

80.1 Please provide the percentage of (i) total Industry sector GHG emissions resulting from energy supplied by FEI, and (ii) total Buildings and Communities sector GHG emissions resulting from energy supplied by FEI.

<u>Response:</u>

The specific methodology and data used by the Province to calculate and categorize sectoral GHG emissions is not fully known to FEI. Therefore, FEI's data on gas delivery and consumption and approach to quantify and attribute emissions may differ slightly from the provincial approach. Furthermore, the information discussed in the response to BCUC IR1 2.1 tabulated FEI's GHG emissions using a lifecycle GHG approach.

The BC GHG inventory and resulting sector categorizations do not use a lifecycle approach but are rather a point-source or a combustion-related approach. For consistency, in this response FEI is presenting emission data as combustion-related to align with the provincial government's sectoral GHG accounting approach. A combustion-related approach does not include the associated GHG emissions from the upstream extraction and processing of natural gas and the mid-stream transport and delivery of natural gas to end-users. This serves from a GHG accounting perspective to lower the overall emissions attributed to end-use sectors like buildings and industry.

In response to BCUC IR1 2.1, FEI used a lifecycle approach to estimating customer-related emissions. When using a combustion-related approach, FEI estimates that its customer-related emissions (combustion) as a proportion of <u>BC's total GHG emissions inventory</u> are as follows:

- Industry – 5 percent; and
- Buildings and communities – 10 percent.

For 2019, FEI estimates that its combustion-related emissions as a proportion of BC's sectoral GHG emissions[1] are as follows:

- Industry – 26 percent; and
- Buildings and communities – 49 percent.

[1] FEI added the total end-use emissions of its residential and commercial customers in order to estimate the proportion of buildings and communities' sectoral emissions.

81.0 Reference: PLANNING ENVIRONMENT
Exhibit B-6, BCUC IR 4.1, 4.2, 4.3
Municipal Regulations and Policies

In response to BCUC IR 4.1, FEI states:

> According to the BC Energy Step Code website, 85 local governments have submitted their initial notification, indicating they have started to consult on the Step Code. In addition, UBC has its green building rating system and the City of Vancouver has its own zero emissions building plan. Along with adopting the Step Code, a growing number of local governments are implementing changes to their building codes, planning guidelines, or zoning bylaws in order to reduce GHG emissions in new building construction projects and, in some cases, existing building retrofits and improvements. These measures prevent new natural gas connections, as natural gas does not meet their requirements.

In response to BCUC IR 4.2, FEI states:

> To the best of FEI's knowledge, the local governments that have adopted GHGi [greenhouse gas intensity] targets are: • City of Vancouver; • City of Surrey; • City of Burnaby; • District of North Vancouver; • City of Richmond; and • District of West Vancouver.

In response to BCUC IR 4.3, FEI states:

> FEI's modelling of future gas load under different future scenarios accounts for the impacts of potential future limitations, although specific municipal actions or bylaws were not defined other than for the City of Vancouver. The New Construction Code Critical Uncertainty used to create the load forecast scenarios has an "Accelerated" setting that reflects earlier adoption of steps in the BC Energy Step Code, which includes energy performance requirements. FEI applied the "Accelerated" setting to the Deep Electrification and Lower Bound scenarios. This setting did not impact the forecast of customer additions, but rather the amount of gas used by each customer as described in Section 4.4.1.2 of the Application. This modelling characteristic is employed to avoid potential double counting of energy reductions that might occur if both the customer additions and the energy use per end-use were both being adjusted at the same time. While the BC Energy Step Code does restrict the use of conventional natural gas, FEI's modelling did not assume that municipal gas connection policies would prevent the use of low-carbon and renewable sources of gas.
>
> FEI defined specific municipal actions for the City of Vancouver because it is regulated under the Vancouver Charter, a provincial statute which enables the City with broader authority than other municipalities in BC to pass bylaws that regulate activities within the City. One such bylaw, the Vancouver Building Bylaw, has more

stringent energy performance requirements than what is applicable in other regions of the Province.

81.1 Please explain whether, in future, FEI intends to model the effect of specific municipal policies or bylaws for municipalities other than the City of Vancouver. Please explain the degree of complexity associated with modelling specific municipal policies or bylaws.

Response:

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

Confirmed. FEI intends to make reasonable efforts to model the effect of specific municipal policies and bylaws in the development of the next LTGRP, to the extent they are material to the analysis, just as it has taken into consideration the specific requirements of the City of Vancouver for both the 2017 and 2022 LTGRP applications.

In terms of complexity, there are two main options for modeling municipal policies or bylaws:

- Separate those municipalities into distinct regions with their own assumptions about unit energy consumption and/or fuel shares, or
- Group municipalities into larger regions and develop weighted average unit energy consumption and/or fuel shares based on the location of each municipality in the region.

For example, the 2022 LTGRP separated the City of Vancouver into its own region with its own unit energy consumption and fuel shares whereas the 2017 LTGRP included the City of Vancouver in the Lower Mainland region and used weighted averages.

There are trade-offs with each approach. Modeling multiple distinct regions makes the model larger, requiring a larger, more complex dataset and more processing time. The requirement for weighted averages makes the process of developing model inputs somewhat more complex but limits the overall size of the model.

In the next LTGRP, FEI will adopt the approach that most efficiently provides the flexibility to produce the information needed for the Application.

81.2 Please discuss whether the current status of municipal policies and bylaws (for example but not limited to: municipalities consulting on the Step Code; local governments that have adopted GHGi targets) is more aligned with the Accelerated New Construction Code setting than the Reference setting.

Response:

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

The current status of municipal policies and bylaws for new construction have progressed since the development of the LTGRP scenarios, and now a greater number of municipalities are more closely aligned with the Accelerated Setting rather than the Reference Setting with respect to new construction codes.

81.2.1 Please illustrate the impact of applying the "Accelerated" New Construction Code Critical Uncertainty setting to the Diversified Energy Planning (DEP) scenario.

Response:

FEI and Posterity Group have collaborated on the following response.

In this response, FEI provides background on the challenges faced in developing the 2022 LTGRP in the rapidly changing planning environment and how this impacted critical uncertainties. FEI then discusses factors influencing the magnitude of impact on demand for critical uncertainties, first for codes and standards and then fuel switching. FEI then provides an illustrative example of the impact on the Reference Case demand when applying the Accelerated setting for codes and standards and how these learnings can be applied to the DEP Scenario. Finally, FEI discusses how critical uncertainties will need to be adjusted in the next LTGRP.

For these discussions, it is important to note a few key points:

- As discussed in the response to BCUC IR1 4.3, the BC Energy Step Code does restrict the use of natural gas, especially at the highest steps. This would also apply to the more stringent steps of the new opt-in Zero Carbon Step Code, discussed further in the responses to BCUC IR2 98.1 and 112.1.1. However, FEI's modeling did not assume that municipal policies would prevent new additions, but rather reflects FEI's expectation that a role for renewable and low carbon gas in the decarbonization of new construction would be preserved;

- The response to BCUC IR1 4.3 also notes that New Construction Code settings do not impact the forecast of customer additions, but rather the amount of gas used by each customer, in order to avoid double counting of energy reduction; and

- More importantly, at the time of modelling for the 2022 LTGRP, the codes and standards critical uncertainties were designed to reflect energy performance policies at the building and appliance level. They were considered to be fuel-agnostic.

However, over the development of the LTGRP, due to the profound shift in climate policy, policies have emerged that may be more appropriately modelled using the fuel switching critical uncertainty. As such, these two distinct critical uncertainties (codes and standards, and fuel switching) have evolved into an inter-related impact on demand.

The Impact of Codes and Standards Critical Uncertainties and their Settings is Limited

In the response to BCUC IR1 27.3, FEI provided Table 1 (reproduced below) illustrating the order of the impact of critical uncertainties[2] on gas demand in 2042, from largest to smallest impact.[3] In both the 2017 and 2022 LTGRPs, codes and standards have had the smallest impact relative to other critical uncertainties. This is largely because their impact is limited by the rate at which they can be applied. The impact of new construction codes, including the Step Code energy efficiency requirements considered in the new construction code settings, is limited by the rate of new construction. The impact of appliance standards is limited by the rate of appliance replacement. Retrofit codes are usually assumed to apply only when an existing building undergoes a major renovation. Most buildings do not frequently undergo major renovations, so the impact of even more stringent retrofit codes is gradual.

Table 1: Order of Impact of Critical Uncertainties on Gas Demand

Order of Impact	Critical Uncertainty
1	Non-Price Driven Fuel Switching
2	Global LNG Demand
3	New Large Industrial Demand Growth
4	Low-Carbon Transportation Demand
5	Carbon Price
6	Natural Gas Price
7	Customer Growth
8	Codes & Standards

Non-Price Driven Fuel Switching is Greatest Driver of Declining Demand

In contrast to the modest effect of codes and standards, as illustrated in Table 1, the main driver of declining annual gas demand in the Deep Electrification Scenario relative to the DEP Scenario is non-price driven fuel switching (electrification) set at the accelerated input setting. In the residential sector, the electrification of space heating and water heating by 2042 was assumed to approach 75 percent, driven by policy. In the commercial sector, electrification of space heating and water heating was assumed to approach 85 percent, again driven by policy.

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2 List of Critical Uncertainties were presented in Table 4-1 of the Application.

3 Note that the impact on the load forecast is a product of the modelling approach for estimating the effect of each critical uncertainty and the input values for the settings established.

Accelerated Codes and Standards Setting Applied to the Reference Case

FEI cannot directly illustrate the impact of applying the Accelerated New Construction Code Critical Uncertainty setting to the DEP Scenario, as this exercise was not undertaken when FEI conducted its modelling, and it would be onerous to do so now.[4] However, the accelerated settings for the codes and standards critical uncertainties were applied to the Reference Case in isolation, and can be used as an illustrative example of directional impact on reducing annual demand as follows:

- Residential annual demand was reduced by 2.7 percent in 2030 and by 13.2 percent in 2042;
- Commercial annual demand was reduced by 1.2 percent in 2030 and by 4.3 percent in 2042;
- Industrial annual demand and natural gas transportation sectors were not impacted; and
- The overall annual demand relative to the Reference Case would be reduced by 1.3 percent in 2030 and 5.4 percent in 2042, all other settings remaining equal.

Since the New Construction Code represents a subset of the total Codes and Standards settings, the DEP Scenario would result in even lower emission reductions than the level stated in the example. Furthermore, in the DEP Scenario, the codes and standards settings would be further muted as critical uncertainty settings would be applied to a decreasing share of the overall gas demand than the Reference Case.

Therefore, holding all else equal and under current modeling assumptions, FEI's estimate of the impact of the potential changes in the BC Building Code and adoption of the Step Code is in the range of 5 to 10 percent reduction in annual demand by 2042.

Assumptions & Model Levers are Reassessed on an Iterative Basis

For the next LTGRP, it is possible that FEI will adapt its approach to modelling the impacts of codes and standards, given that, at the time of modelling for the 2022 LTGRP, the codes and standards Critical Uncertainties were designed to reflect energy performance policies at the building and appliance level, not policies targeted at fuel switching and reducing new gas connections. FEI would first evaluate the planning environment and then update the assumptions, inputs and model levers for the critical uncertainties and settings based on feedback from stakeholders. FEI will develop input settings and an approach that most efficiently provides the ability and flexibility to produce the best information needed for the Application, and is calibrated to the context of the planning environment in the reference year.

With increasingly stringent codes and standards, which over time have incorporated policies targeted at fuel switching and reducing new gas connections, the order of impact of the critical uncertainties may change in the next LTGRP. FEI notes that much of the announced CleanBC Roadmap has not yet been implemented through legislation and the nature of any such legislation

[4] Posterity has estimated that this exercise would require 125 person-hours to execute.

remains somewhat uncertain. Therefore, it is possible that new regulations could cause a greater shift in the order of impact of the critical uncertainties than can be anticipated at this time.

81.3 For municipal policies that prevent gas connections for new construction, please discuss whether FEI considers that it would be feasible for gas connections to be retrofitted.

Response:

For municipal policies that prevent gas connections for new construction, FEI does not expect it to be feasible for gas connections to be retrofitted as there are both financial and practical implications beyond the cost of the gas equipment.

For example, retrofitting a multi-family building to include gas piping would require major renovation and construction activities to tear down walls, flooring, ceilings and building envelope. In addition, it is unlikely that a customer would retrofit a new residential home if brand new (albeit electrical) equipment was already installed, essentially paying twice for the same functionality.

The problem is even more challenging in new all-electric subdivisions where there would be no gas main in the street. In this situation, new customers would be faced with the financial and operational challenges of digging up a newly finished paved road to install a main. This is very expensive and likely unfeasible for a limited number of customers who may choose to bear the costs for gas services. The challenges become compounded as homes are built further and further from gas infrastructure. Further, the policy impacts of all-electric residential subdivisions are largely irreversible, limiting British Columbians' access to renewable and low-carbon gas that will become more readily available in the future.

82.0 Reference: PLANNING CONTEXT

Exhibit B-6, BCUC IR 9.2

Hybrid Heating Systems

In response to BCUC IR 9.2, FEI states:

> The biggest challenge resulting from hybrid systems is quantifying the value of the peaking service and mitigating the potential increase in gas rates resulting from decreased gas load. FEI's approach to hybrid heating systems is still at an exploratory stage. Hybrid heating systems are one of three emerging energy efficiency technologies, referred to as Advanced DSM [demand-side management] Programming in the 2023 DSM Plan Application. They are expected to have a higher potential impact on gas demand than was modelled in the 2021 CPR or in the 2022 LTGRP. If the benefits are proven through FEI's pilots and studies, it is anticipated that hybrid systems will take a larger role in upcoming DSM Plans and the next CPR and LTGRP.

In response to BCUC IR 9.3, FEI states:

> The extent to which the natural gas system and technologies such as dual fuel systems can play a role in meeting both future annual and peak energy demand, in combination with the electricity system in BC, requires further study and offers an important opportunity for collaboration between gas and electric utilities, as well as municipal and provincial governments. Such initiatives are viewed by FEI to be more in line with its DEP Scenario and Clean Growth Pathway, than a separate and distinct scenario from those modelled for the 2022 LTGRP… FEI considers, however, this opportunity is more appropriately examined for its potential to benefit the electric system. Some customers choosing to electrify their space heating equipment, and retaining their existing gas system to deliver energy during peak periods, can help to defer investment in electric generation, transmission and distribution resources, potentially benefitting the customer through lower bills, as well as indirectly benefitting all other electric customers.

82.1 Please discuss the timelines and anticipated learnings associated with FEI's pilots and studies related to hybrid heating systems.

<u>Response:</u>

FEI began evaluating performance of existing dual fuel furnace and heat pump systems in Q4 2022. FEI plans to launch an early-adopter offer for residential hybrid heating systems in mid-2023. The early adopter offer will provide incentives for customers to retrofit their existing furnace with a new dual fuel heat pump and furnace system. Customers will be required to participate in measurement and verification and acceptance surveys.

The key learnings FEI intends to achieve are:

- Understanding various control strategies to optimize greenhouse gas reduction, efficiency, customer economics and comfort;
- Evaluating costs and performance for installing the system on differing building archetypes;
- Understanding the system implementation barriers for customers, contractors, distributors and developers;
- Understanding what training and support contractors and developers need to promote and install the system;
- Understanding the motivation for why customers would want the system;
- Developing various potential program designs to encourage market adoption of the system;
- Developing greater understanding of the energy system impacts of hybrid system adoption;
- Developing greater understanding of the value of hybrid systems as a potential electricity system capacity resource; and
- Developing greater understanding of potential rates and transfer pricing mechanisms that incorporate the potential systemic value of hybrid systems.

82.2 Please confirm, or explain otherwise, that hybrid heating systems would result in a lower gas load factor, compared to gas only heating systems.

Response:

Confirmed.

Load factor is essentially a measure of how efficiently the energy delivery system (gas or electricity) is being utilized, either by the individual customer or in aggregate for a customer group or for the entire system as a whole. It is calculated based on the average demand per day divided by the peak demand.

Hybrid systems would not be expected to increase peak demand as the requirement during the winter months would be similar whether it is using gas for heating with a hybrid system or with a gas-only system. As such, FEI is not expecting hybrid systems to materially impact the capacity requirements of the gas system.

However, a hybrid system will likely reduce gas use during warmer weather, which, if all else is equal, would lower the load factor. A reduced load factor on a system level or within specific customer groups, potentially due to increased adoption of residential hybrid systems or due to other factors, may have implications for the rates of those customers.[5] The extent of the impact will depend on the extent to which hybrid systems are deployed as well as their design and operation.

The hybrid heating system discussed in the response to BCUC IR1 9.3 will offer customers the option to use both electricity and gas for heating. In turn, this will enable continued use of the gas system while providing added benefits to the electric system such as deferring otherwise necessary investments in electric generation, transmission and distribution capacity resources.

82.2.1 If confirmed, please further explain why FEI considers a scenario in which the natural gas system is used primarily to serve peak heating requirements is more in line with the DEP Scenario than a separate and distinct scenario.

<u>Response:</u>

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

FEI's consideration that greater implementation of hybrid systems is more aligned with the DEP Scenario is based on the following:

- FEI considers it unlikely in the time frame of the LTGRP planning period that FEI's entire service area would be changed to hybrid systems. Rather, there is more likely to be some combination of dual fuel heating systems, all electric heating systems and all gas systems that use increasing supplies of renewable and low carbon gas. FEI has already included electrification and renewable and low carbon gas in its DEP Scenario, so that adding higher adoption of hybrid heating systems would not be a major departure from the DEP Scenario.
- Utilizing dual fuel systems still maintains an important role for the gas infrastructure and allows deeper integration of the gas and electric systems which is a key aspect of the DEP Scenario.
- FEI's system is already oriented towards meeting peak requirements and the inclusion of higher levels of adoption of hybrid heating systems would maintain this characteristic as in the DEP Scenario.

As discussed in the responses to BCUC IR1 9.2 and 9.3, FEI is in an exploratory stage of understanding the impacts of dual-fuel/hybrid systems; therefore, FEI considers that it is too early to determine with any precision the impact on gas demand if the gas system is used primarily to

[5] For instance, load factor is relevant to the allocation of system costs between customer groups and is a consideration in rate design proceedings.

serve peak heating requirements. Although FEI considers such a scenario to be more aligned with the DEP Scenario than a separate and distinct scenario, FEI provides the following discussion on the information requirements that will be necessary to support FEI's ongoing research into dual-fuel/hybrid systems and implications to resource planning.

FEI's ongoing research will assist FEI in a number of ways. In the shorter term, at the program level, this work will provide FEI with further information to support the ongoing development of DSM pilots and programs that will provide energy and emissions savings opportunities for FEI's future DSM expenditure plans. This program-level information will also support the analysis required for a longer-term vision, at a system level, to evaluate the impacts of broader commercialization of dual-fuel heating systems in BC. FEI's system-level analysis involves quantifying the value of the peaking service and mitigating the potential increase in gas rates resulting from reduced overall throughput of the system. As such, FEI is examining the potential for hybrid systems to benefit the electric system and considering recommendations that would provide FEI customers with a benefit-sharing mechanism.

FEI expects supplemental ongoing research to inform impacts related to customers, customer types, rate impacts and both annual and peak demand implications for the gas and electric systems. Furthermore, FEI plans for this research to provide information on the performance of dual-fuel systems in a range of operating conditions including:

- Existing buildings and new construction;
- Different climate zones across FEI's service territory; and
- Different building types in residential, commercial and industrial settings.

FortisBC is uniquely positioned to provide insight into capacity modeling needed to understand the impact of hybrid systems on both the gas and electricity systems in the southern Interior. This research and analysis will assist FortisBC in understanding the value of avoided capacity upgrades in comparison to other resource options and impacts to the gas system. Based on actual customer data, this study could facilitate a more accurate quantification of the value of the gas peaking service and mechanisms that could be implemented to mitigate the potential increase in gas rates resulting from decreased gas load. Further research would be required to extrapolate these findings across the Province.

FortisBC's ongoing research will be critical to understand the impacts of dual-fuel systems on customers, supply chains, and both energy systems as discussed further below.

Research to Support Scenario Modeling and Energy System Impacts

In the following discussion, FEI provides an overview of critical assumptions and inputs that would be required to develop scenario modeling to facilitate an understanding of the impacts of increasing the proportion of dual-fuel systems, including a view in which the gas system is used to primarily provide peak heating requirements.

These would include:

- Load shape of both gas and electricity demand resulting from the dual fuel systems in terms of both annual demand and peak demand impacts. FEI has coordinated with FBC to share data in its shared service territory to better understand the impact of these systems. At the provincial scale, further utility collaboration between FEI and BC Hydro would be beneficial for more robust analysis.
- Customer adoption curves for both existing buildings and new construction will be required in long-term scenario development.
- Rate impact implications on both energy systems, including benefits to the electricity system as a capacity resource and the negative impacts of increasing rates on FEI's customers through declining system throughput.
- Research into options and recommendations for transfer pricing mechanisms that reflect the value of hybrid systems to the overall BC energy system and which could mitigate rate impacts to gas system customers.
- Modeling of building and heating system turnover under different building energy and emissions policy and techno-economic assumptions to develop a range of reasonable outcomes on the adoption of hybrid heating systems and the system-level impacts.

Since understanding the system level impacts is currently in an early stage, the time and effort required to develop a scenario based on dual fuel systems is significant. A lack of accurate inputs may limit the usefulness of the results. For these reasons, both FEI and Posterity Group consider that this analysis will be more timely as part of a future filing with the BCUC.

Nevertheless, if asked to do so, Posterity Group estimates that it would take approximately 175 person-hours of consulting time to produce a typical complete scenario, although the level of effort varies based on complexity and research requirements. This estimate includes typical effort for modeling, stakeholder engagement, client review, and documentation. This estimate does not include FEI staff time or resources. FEI estimates that the elapsed time for such a scenario is six to ten weeks or longer, depending on other projects and priorities underway for both Posterity Group and FEI at the time the scenario work is undertaken. Since this scenario would be just as relevant to electric system planning, FEI will consider opportunities for collaboration and co-funding with BC Hydro and FortisBC.

82.3 Please discuss the extent to which modelling a scenario where the natural gas system is used primarily to serve peak heating requirements, could facilitate a better understanding of (i) quantifying the value of the gas peaking service, and (ii) mitigating the potential increase in gas rates resulting from decreased gas load.

Response:

Examining the gas system being used primarily to serve peak heating requirements is under consideration for the next LTGRP, though this may not require a separate scenario for the reasons discussed in the response to BCUC IR2 82.2. Further, as discussed in the responses to BCUC IR1 9.2 and 9.3, FEI is continuing to explore these types of systems and expects to bring more information to bear in this regard in the next LTGRP.

FEI is also evaluating these concepts through further activity related to the Kelowna Electrification Case Study filed as part of this LTRGRP proceeding (Exhibit B-20). Further capacity modeling and analysis is needed to understand the impact of hybrid systems on both the gas and electricity systems and the value of avoided capacity compared to other resource options. This could facilitate a better understanding of quantifying the value of the gas peaking service and mitigating the potential increase in gas rates resulting from decreased gas load.

82.4 Please discuss whether FEI considers a scenario in which the natural gas system is used primarily to serve peak heating requirements: (i) is more, the same or less plausible than the Deep Electrification scenario, and (ii) provides benefits to FEI compared to the Deep Electrification scenario.

Response:

In comparison to the Deep Electrification Scenario, FEI considers a scenario in which the gas system is used to serve peak heating requirements to be more plausible and would provide more benefits to FEI and its customers, as it would be more in line with the DEP Scenario and the Clean Growth Pathway. This scenario would mitigate the risks and costs associated with the infrastructure challenges required for gas demand to be shifted to the electric system, as well as rate impacts for both the gas and electric systems.

Dual-fuel systems are also expected to provide benefits to the electric system, including helping to defer investment in electric generation, transmission and distribution resources, and lowering customer bills. However, the gas system could see reduced overall throughput and increasing customer rates. The impact on customer rates and, if needed, mechanisms to address such impact requires further study.

As discussed in the response to BCUC IR1 9.3, further study beyond the shared FEI/FBC service territory will require information sharing between the gas and electric utilities.

B. CLEAN GROWTH PATHWAY

83.0 Reference: CLEAN GROWTH PATHWAY

Exhibit B-6, BCUC IR 10.3, 10.4, 10.4.1, 10.5, 10.11.1, 10.18, 10.22

Pathways Report

In response to BCUC IR 10.3, FEI states:

> In the Electrification Pathway, it was assumed that 10 percent of commercial vehicles are not electrified and consume a mix of natural gas, renewable natural gas or biodiesel. For the industrial sector, it was assumed that 20 percent of current fossil fuel use is converted to electricity. For the agriculture sector, it was assumed that 50 percent of end use demand is satisfied by electricity.

83.1 Please further explain the basis for the assumptions for industrial and agricultural electrification percentages. Please describe how these assumptions compare to FEI's current understanding of end-uses that may be electrified.

Response:

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

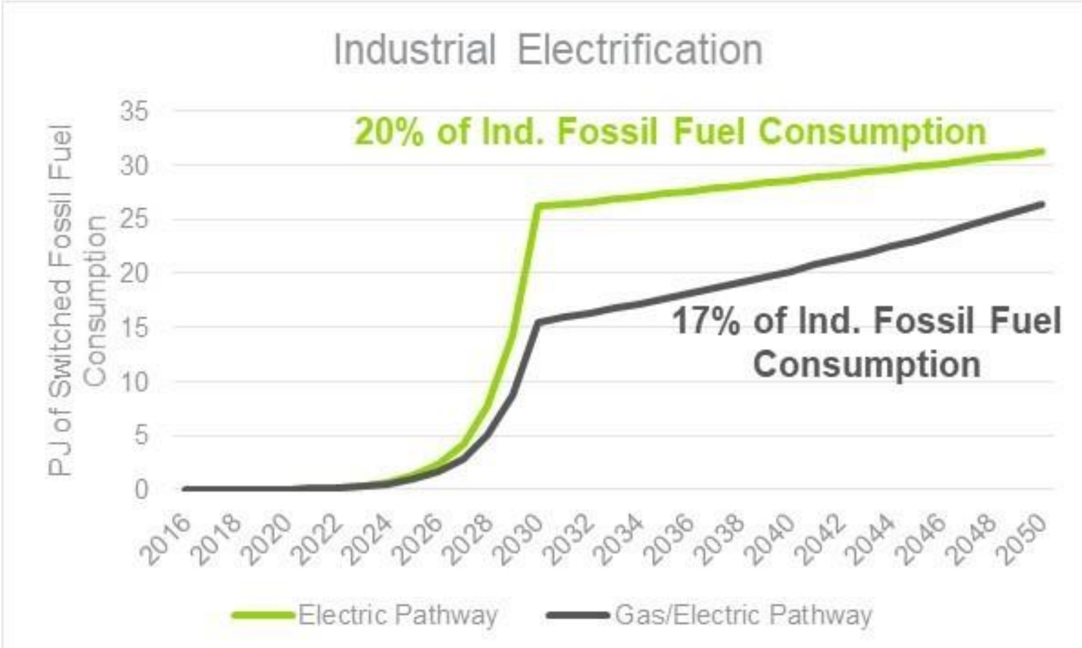
FEI provides the following additional description of the basis for the assumptions for industrial and agricultural electrification.

The CleanBC Plan, at the time of the study, set the following targets for industrial electrification by 2030:

- 2.2 Mt of GHG reductions from providing electricity to planned natural gas production in the Peace region; and
- 1.3 Mt of GHG reductions by increasing access to clean electricity for large industrial operations.

The Diversified Pathway is characterized by a 10 percent reduction of fossil fuel consumption by 2030. This was informed by Ontario-based assumptions about industrial electrification potential assessed through a Fuels Technical Report developed by the Ministry of Energy. The remainder of the target outlined in the CleanBC Plan is expected to come from other industrial efficiency improvements rather than electrification.

The two scenarios within industrial electrification are illustrated in the following figure:



As illustrated above, Guidehouse assumed that total industrial electrification in the Diversified Pathway would grow to 17 percent by 2050, equivalent to approximately 26 PJ. In comparison, the Electrification Pathway reaches a similar level of 26 PJ of fuel switching by 2030 (sooner than the Diversified Pathway).

Agricultural electrification levels were chosen as an indicative value reflecting a proximate stringency of overall abatement for the sector.

In response to BCUC IR 10.4, Guidehouse states:

> The types of costs that are captured in each of the noted components of Figure 9 are as follows. • **Consumer equipment investment**: This component captures the incremental cost of low-carbon equipment over business-as-usual equipment. For example, the incremental cost of an electric vehicle over an internal combustion engine vehicle.
>
> …
>
> **Underutilized Capacity Costs**: This component captures the estimated excess costs of maintaining and sustaining FEI's existing gas system which would be oversized based on declines in load in the Electrification Pathway. FEI worked with Guidehouse to estimate the additional costs to 2050 of maintenance and sustainment using historical cost trends compared to a system that was scaled to meet load levels that were approximately two thirds lower in 2050. In this exercise,

> Guidehouse simulated the assumption that the full gas system would need to be sustained to 2050, accounting for the fact that individual customer defections from the system would not follow a reliable pattern that would enable a planned shut down of elements of the system. Guidehouse then estimated the sustainment costs if a gas system were ideally-sized and built to meet 2050 loads. The analysis did not estimate decommissioning costs of the gas system.

The response to BCUC IR 10.4.1 includes the following table:

Table 1: Cumulative incremental costs to 2050 for Electrification and Diversified Pathways

	Electrification Pathway ($ billions)	Diversified Pathway ($ billions)
Consumer Equipment Investment	$29.4	$37.0
Retrofit Cost	$29.7	$22.4
Underutilized Capacity Costs	$17.0	n/a

83.2 Please discuss whether the Diversified Pathway includes costs associated with maintaining and sustaining FEI's existing gas system.

83.2.1 If yes, please outline the assumed costs and where the costs are factored into the analysis.

83.2.2 If no, please explain why such costs have been excluded for the Diversified Pathway but included in the Electrification Pathway. Please discuss whether this distorts the analysis.

<u>Response:</u>

FEI confirms that the Diversified Pathway includes the costs associated with maintaining and sustaining the existing gas system as of 2018, the year in which the Clean Growth Pathway was developed. Based on the initiatives in the Diversified Pathway, gas demand is assumed to only marginally increase. Accordingly, the gas system is assumed to be in sustainment, and sustaining capital was assumed to equal annual depreciation of approximately $200 million per year, increasing to $280 million per year by 2050.[6]

83.3 Please explain whether the overall costs of maintaining and sustaining FEI's oversized gas system in the Electrification Scenario are expected to be greater, similar, or lower than the overall costs of maintaining and sustaining FEI's gas system in the Diversified Pathway.

[6] Operating and maintenance costs were inflated annually based on BC's consumer price index (CPI).

Response:

The terms "underutilized capacity costs" or "excess" costs of maintaining and sustaining FEI's existing gas system as referenced in the preamble above do not mean there is an incremental cost of $17 billion to maintain the system under the Electrification Pathway over and above the costs under the Diversified Pathway. The costs to maintain or sustain the gas system under an Electrification Pathway or a Diversified Pathway would be the same or similar; however, under the Electrification Pathway, the costs to maintain an underutilized system would be considered "excess" beyond what is required if the system is originally designed to serve much fewer customers.

For example, if the cost to maintain or sustain a 5 km pipeline that is originally designed to serve 100 customers is $1 million, then the cost to maintain or sustain this same pipeline would be similar if there are only 10 customers remaining on this pipeline, consistent with the Electrification Pathway. Gas is passing through the entire pipeline even if there are just 10 customers (most likely scattered along the entire pipeline); therefore, maintenance or sustainment work will have to be performed on the entire pipeline, not just the individual section(s) where the last 10 remaining customers are located.

Using this example, FEI would have to spend a similar amount (i.e., $1 million) to maintain or sustain a significantly underutilized pipeline under an Electrification Pathway or a fully utilized pipeline under a Diversified Pathway. In other words, when comparing to a pipeline that is designed to serve just 10 customers to begin with, FEI is spending an "excess" $1 million to serve just 10 customers for maintaining or sustaining a pipeline that is originally designed to serve 100 customers.

FEI's entire system will have to be maintained whether it is being fully utilized under the Diversified Pathway or if it is underutilized (regardless of the level of underutilization) under the Electrification Pathway. The only possible situation that FEI envisions could reduce the overall costs of maintenance and sustainment on FEI's system would be if electrification happens in a systematic, staged and regionalized manner across the entire Province, such that it begins from the most downstream point of FEI's existing system. In this case, it might be possible that FEI could consider a planned and regionalized shut-down of specific elements of its system which, in theory, could result in lower overall costs than the underutilized capacity costs assumed in the Pathways Report. However, FEI does not believe this is possible in reality and the likelihood of such an approach is subject to significant uncertainty, such as fairness of forced conversion (i.e., remaining customers will see higher rates due to reduced demand), and practical coordination, technical, political, as well as other challenges that would undermine a highly planned systematic approach.

As highlighted in the Pathways Report and referenced in the preamble, the fact that individual customer defections from FEI's system would not follow a reliable pattern would prevent FEI from executing a planned shut-down of its system. Those customers that remain on the FEI system or those that are slower to convert to electricity will likely to be scattered throughout FEI's service areas.

In fact, it is possible that under a Deep Electrification Scenario, FEI's overall costs to maintain and sustain the existing system could be higher than the Diversified Pathway for a variety of reasons. For example, higher costs would result from the inefficiencies associated with FEI staff travelling longer distances between sites or customers since FEI's customers will be much more scattered under the Electrification Pathway. Additionally, as shown in the response to BCUC IR1 75.5, one of the biggest drivers of FEI's estimated rate increases over the 20-year planning period is the forecast decline in demand which will be worse under the Electrification Pathway than under the Diversified Pathway. Therefore, in the likely scenario that customers will remain scattered throughout FEI's system, FEI does not believe any potential cost reductions (if possible) in maintaining and sustaining its system will be able to offset the rate impacts resulting from the decline in demand, especially under the Electrification Pathway.

83.4 Please discuss whether FEI considers planned shut downs of elements of the system would result in greater, similar, or lower overall costs than the underutilized capacity costs assumed in the Pathways Report.

Response:

Please refer to the response to BCUC IR2 83.3.

On page 16 of the Pathways Report (Appendix A-2), Table 1 outlines Initiatives by Pathway. The Electrification Pathway assumes Transition to 100% zero-emissions light duty Vehicles; and significant role for medium and heavy duty (MHD) electric vehicles (EVs) (60% EV, 40% CNG/LNG and internal combustion).

The Diversified Pathway assumes transition to 100% zero-emissions light duty vehicles; and significant role for gases in MHD vehicles (75% CNG, 20% EV, 5% fuel cell vehicles).

In response to BCUC IR 10.5, Guidehouse states:

> The contribution of peak load increases due to fuel switching and transportation vary by year and pathway. In 2050, the incremental electric peak loads are as follows:

	Electrification Pathway	Diversified Pathway
Fuel Switching	4,578 MW	1,467 MW
Transportation	4,250 MW	2,731 MW

83.5 Please confirm, or explain otherwise, that the only difference in electric load resulting from transportation between the two pathways is the percentage of MHD vehicles that are electrified.

83.5.1 If confirmed, please further explain why the higher percentage of MHD vehicles in the Electrification Pathway is assumed to result in 1519 MW additional peak load compared to the Diversified Pathway.

83.5.2 If not confirmed, please provide a breakdown and explanation of the 1519 MW additional peak load in the Electrification Pathway compared to the Diversified Pathway.

<u>Response:</u>

Not confirmed. The difference in electric peak load resulting from transportation between the two pathways is based on differences in the percentage of light duty (LD) as well as medium and heavy duty (MHD) vehicles that are electrified.

The differences in the percentages of electrified MHD vehicles between the two pathways is provided in the preamble.

The percentage of LD vehicles electrified is different between pathways, contributing to the difference in electric peak load. By 2050, 99.5 percent of light duty vehicles are electrified in the Electrification Pathway, while 95 percent are electrified in the Diversified Pathway. The BC government announced that by 2040, every LD vehicle sold in BC will be a zero-emission vehicle (ZEV). Guidehouse has interpreted this as every LD vehicle sold in BC in 2040 will either be a Battery Electric Vehicle (BEV) or hydrogen fuel cell vehicle (FCV). The split of the ZEV population between BEVs and FCVs was based on the forecasted values from the BC Conservation Potential Review (CPR) for BEVs and Guidehouse Research for FCVs.

The difference of 1,519 MW in peak load between the pathways, broken down by vehicle type during the peak hour, is provided in the following table.

Table 1: Effect of Vehicle Conversions on Peak Electric Load in 2050 (MW)

Vehicle type	Electrified Pathway	Diversified Pathway
Light Duty Personal Vehicles	1,596	1,461
Commercial Vehicles	1,863	1,140
Combination Tractor Trailers	505	130
Buses	287	0
Total	**4,250**	**2,731**

83.6 Please estimate the incremental electricity system costs associated with the 1519 MW additional peak load in the Electrification Pathway compared to the Diversified Pathway.

Response:

The incremental electricity system costs associated with the 1,519 MW difference in peak load between scenarios is $45,663 million (i.e., $111,441 million less $65,778 million). The calculations presented in the tables below were used to estimate the total cost attributed to the transportation peak load in each scenario as a direct proportion of total electricity system costs.

Table 1: Percentage of Transportation Peak Load of Total Scenario Peak Load

	Unit	Electrification	Diversified
Total Peak Load	MW	21,594	17,707
Transportation Peak Load	MW	4,250	2,731
Calculation	Transportation Peak Load % = Transportation Peak Load / Total Peak Load		
Transport Peak Load Percentage	**%**	**19.7%**	**15.4%**

Table 2: Cost of Transportation Peak Load as a Direct Proportion of Total Electric System Cost by Scenario

	Unit	Electrification	Diversified
Total Electric System Cost	$million	$566,226	$426,487
Calculation	Transportation Peak Load Cost = Transportation Peak Load % x Total Electric System Cost		
Transportation Peak Load Cost	**$million**	**$111,441**	**$65,778**

83.7 Please further discuss the assumptions regarding the contribution of electric vehicles to peak load. Specifically, please explain whether Guidehouse made any assumptions regarding the shifting of electric vehicle charging outside of peak hours.

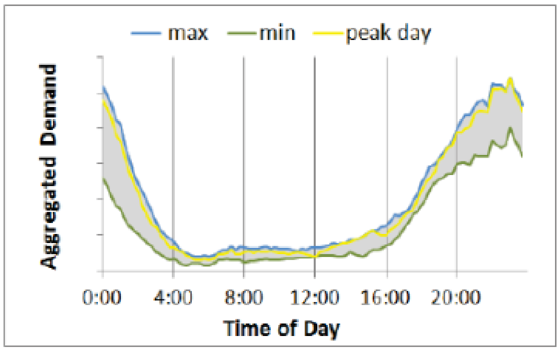
Response:

The contribution of electric vehicles to peak load was measured based on vehicle charging load shapes for each class of vehicle using public data. The shapes and resulting impact on peak loads are based on data that includes the shifting of vehicle charging outside of peak hours, which are the same between scenarios. Sources for this data by vehicle class include:

- **Commercial Vehicles, CT Vehicles, Buses**: Hourly charging load data from Navistar eStar and Smith Newton.

- **Light Duty Personal Vehicles:** Data collected from 5,000+ electric vehicles (Nissan LEAFs and Chevrolet Volts) and 10,000+ charging systems in 18 regions across the US, producing a charging load curve for residential EVs.[7] On average, the peaks along this curve are caused as people return to their residences and plug in their vehicles in the evening. The troughs are caused as people unplug their vehicles and (presumably) leave their residences.

Figure 1: Time-of-Day Demand Plot with Peak Day Curve[8]



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[7] Stephen Schey et al., "A First Look at the Impact of Electric Vehicle Charging on the Electric Grid in The EV Project" (September 2012) *World Electric Vehicle Journal*, Vol. 5, online at: https://www.researchgate.net/publication/255000937_A_First_Look_at_the_Impact_of_Electric_Vehicle_Charging_on_the_Electric_Grid_in_The_EV_Project.

[8] Ibid, Figure 9.

In response to BCUC IR 10.11.1, Guidehouse provides the following table outlining the differences in costs for the initiatives included in the Pathways Report.

Initiative	Electrification ($millions)	Diversified ($millions)
Total initiative costs	**$132,360**	**$147,395**
Fuel Switching – Total	**$29,357**	**$36,961**
Residential Electric Heat Pumps	$23,524	$7,129
Residential Gas Heat Pumps	$0	$857
Commercial Electric Heat Pumps	$1,879	$0
Commercial Gas Heat Pumps	$0	$1,940
Flex Fuels	$3,954	$27,036
Built Environment Initiatives - Total	**$29,683**	**$22,415**
Residential Building Envelope	$16,805	$17,769
Commercial Building Envelope	$12,796	$4,552
Automated Building Controls	$82,979	$95
Transportation Initiatives – Total	**$73,140**	**$87,880**
Vehicles (EVs, LDV, MHD, CNG, bus, marine)	$21,362	$39,938
Vehicle charging and refueling **stations**	$51,778	$47,942
Industrial processes Improvements	**$179**	**$138**

83.8 Please confirm, or explain otherwise, that the line item for Automated Building Codes in the Electrification Pathway is a typographical error.

If yes, please provide the correct line item for Automated Building Codes in the Electrification Pathway

Response:

Confirmed. In reviewing the table above, Guidehouse has identified that there is an error in the total residential gas heat pump cost which was carried through to the total initiative costs. An error was also identified for the Automated Building Controls in the Electrification Pathway. The corrected table is included below. This heat pump cost correction increases the investment in residential gas heat pumps in the Diversified Pathway.

Based on the corrected table provided below, which accurately reflects the higher costs of gas heat pumps, the total difference in initiative costs (first row below the column headings) between the two pathways is now $28 billion rather than $15 billion. When carried through to the total cost difference between pathways, this leads to a cost differential of $91 billion between the pathways with the Diversified Pathway being the lower cost pathway.

This correction does not fundamentally impact any of the results from the Pathways Study. The Pathways Study is intended to compare potential future scenarios, but not to predict a specific future. Many inputs across the scenarios are varied to model distinct and different potential futures. The scenario definitions of this analysis represent two different perspectives of what the future state of the energy system could look like, and are not predictive or exhaustive of all possible scenarios.

Related to the LTGRP, the Pathways Study provided a framework by which to develop scenarios. However, the LTGRP did not use the cost differential between the pathways or heat pump cost data from the Pathways Study as an evaluation criteria for assessing the scenarios.

INITIATIVE	ELECTRIFIED	DIVERSIFIED
TOTAL INITIATIVE COSTS	**$132,359,947,560**	**$147,394,756,791**
FUEL SWITCHING – TOTAL	**$29,357,122,604**	**$36,960,957,339**
Residential Electric Heat Pumps	$23,524,159,969	$7,128,515,904
Residential Gas Heat Pumps	$0	$856,900,304
Commercial Electric Heat Pumps	$1,878,552,902	$0
Commercial Gas Heat Pumps	$0	$1,939,495,130
Flex Fuels	$3,954,409,738	$27,036,046,001
BUILT ENVIRONMENT INITIATIVES - TOTAL	**$29,683,399,512**	**$22,415,067,910**
Residential Building Envelope	$16,804,945,729	$17,768,701,425
Commercial Building Envelope	$12,795,474,706	$4,551,488,160
Automated Building Controls	$82,979,076	$94,878,325
TRANSPORTATION INITIATIVES – TOTAL	**$73,140,092,136**	**$87,880,354,851**
VEHICLES (EVS, LDV, MHD, CNG, BUS, MARINE)	$21,362,234,619	$39,938,203,229
VEHICLE CHARGING and refueling **STATIONS**	$51,777,857,517	$47,942,151,622
INDUSTRIAL PROCESSES IMPROVEMENTS	**$179,117,387**	**$138,376,691**

83.9 Please explain the relatively low total investment in residential gas heat pumps in the Diversified Pathway, compared to residential electric heat pumps in both Pathways.

Response:

Please refer to the response to BCUC IR2 83.8.

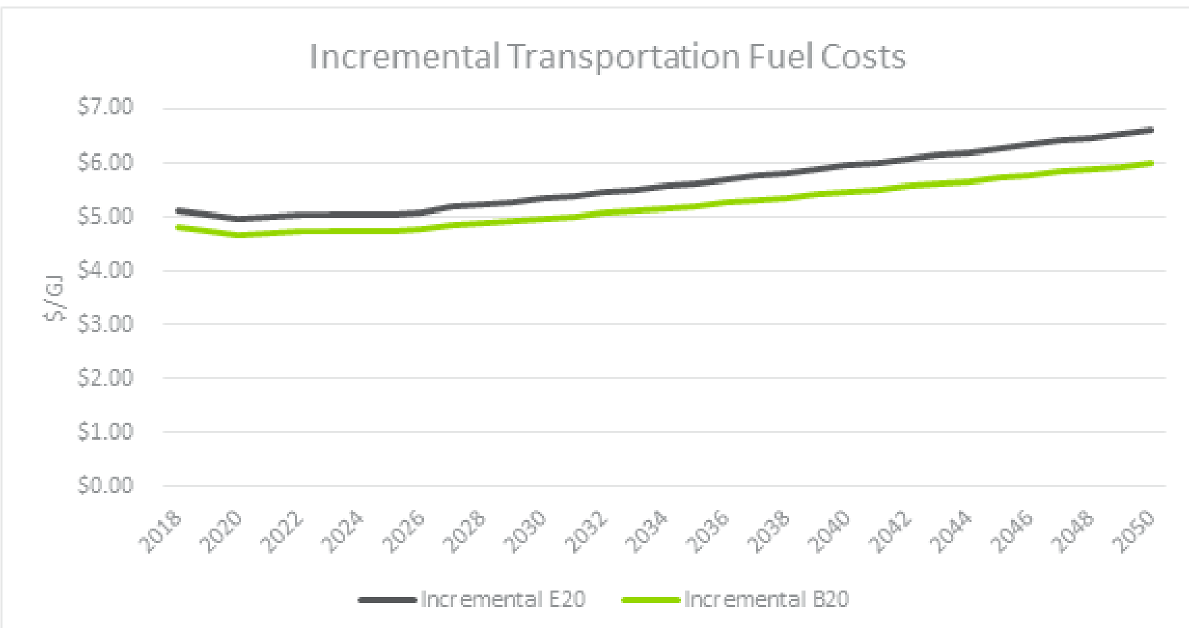
83.10 Please clarify the meaning of "Flex Fuels".

Response:

Flex Fuels refer to ethanol and biodiesel used in the transportation sector. Guidehouse assumes that ethanol will make up 12 to 20 percent of the transportation fuel mix in 2050, while biodiesel will make up 5 to 20 percent. E85 and B20 were chosen as the representative fuel mixes for ethanol and biodiesel, respectively, given the availability of cost forecasts for each.

The method to determine the incremental costs for these Flex Fuels is as follows:

- Forecasts of each of E85 and B20 costs were taken from a California Energy Commission analysis, which set upper and lower bounds for each fuel type. Guidehouse calculated an average value from these forecasts.
- Guidehouse assumed that the gasoline mix will consist of up to 20 percent ethanol and the diesel mix will consist of up to 20 percent biodiesel in the future pathways.
- Guidehouse weighted the conventional gasoline price (76 percent) and the E85 price (24 percent) to approximate the cost of a 20 percent ethanol gasoline mix. This was compared against the price of conventional gasoline to determine the incremental costs in the figure below.
- Similarly, Guidehouse weighted the conventional diesel price (80 percent) and the B20 price (20 percent) to determine the cost of a 20 percent biodiesel diesel mix. This was compared against the price of conventional diesel to determine the incremental costs in the figure below.



In response to BCUC 10.18.1, Guidehouse states:

> Guidehouse reviewed transmission and distribution costs from BC Hydro's Fiscal 2020 to Fiscal 2021 Revenue Requirements Application and assumed the growth capital was linked to the capacity growth and determined a $1 million per GWh construction cost. Guidehouse used this cost per GWh assumption for incremental capital for capacity growth for the forecasted years.

83.11 Please further explain why transmission and distribution costs were calculated on a per GWh basis rather than a per GW basis.

Response:

Guidehouse used a cost approach for transmission and distribution normalized to volumetric energy load to be consistent with the outputs from other portions of the cost model. Costs associated with capacity expansion were calculated based on the GWh growth in annual electricity demand which was an output of the underlying modeling framework. This modeling approach was used to estimate the required infrastructure buildout over time based on increases in electrification. In order to convert capacity needs of the transmission and distribution system to an annualized GWh metric, Guidehouse used a cost factor for new delivery capacity for incremental load over and above an estimated annual system delivery capacity based on the peak hour of the provincial electricity system. This is a common approach in high-level system costs analyses like what was conducted in the Pathways to Report.

In response to BCUC IR 10.22, with respect to the sensitivity analysis, Guidehouse states:

> The sensitivities evaluated include the following: • The production cost of low-carbon gas either increasing by 25 percent or reducing by 10 percent; • Financing costs increasing or decreasing by 1 percent; • Capital expenditure (capex) costs for infrastructure increasing or decreasing by 10 percent; • Debt capitalization increasing or decreasing by 10 percent; • New firm electric capacity costs increasing or decreasing by 25 percent; and • The cost of gas heat pumps increasing by 25 percent.

83.12 Please further explain the reasonableness of the uncertainty ranges for low carbon gas and the cost of gas heat pumps, in consideration of the level of market maturity.

Response:

Sensitivity analysis in the Pathways Report was not conducted to explain reasonableness or to provide a range of uncertainty for low carbon gas and the cost of gas heat pumps. Rather, it was conducted to demonstrate the proximate magnitudes of the impacts of different cost drivers between the scenarios, including those listed in the response to BCUC IR1 10.22. The sensitivity analysis aimed to address uncertainties such as "*if the costs of low carbon were underestimated by 25 percent – how would that narrow the approximate $100 billion cost difference between the Diversified and Electrification pathways?*" Similarly, a sensitivity was chosen to determine "*what if the cost declines of gas heat pumps were overestimated and if they were 25 percent more expensive, how much would the cost differential change?*"

The purpose of this sensitivity analysis was to understand what the key factors driving the cost divergence between the Electrification and Diversified Pathways were. When considering the different sensitivities around the cost of low carbon gas or the cost of gas heat pumps, the Diversified Pathway is still less costly than the Electrified Pathway. For example, if the cost of low carbon gas is 25 percent more expensive in the future, the Diversified Pathway would still be less costly. If the cost of gas heat pumps are 25 percent more expensive in the future, the Diversified Pathway would still be less costly. The sensitivities show that using conservative assumptions around the future costs of those two variables lead to small differences, overall, in the approximate $100 billion cost differential between the two pathways. This means that other factors outside of the cost of low carbon gas or the cost of heat pumps had more meaningful impacts on the cost differential between the two pathways.

83.13 Please explain why a sensitivity was not modelled for (i) the cost of electric heat pumps, and (ii) the efficiency of electric and gas heat pumps.

Response:

A cost sensitivity for electric heat pumps was not modeled as electric heat pumps are a proven commercial technology and have more predictable price forecasts than gas heat pumps, which are further behind the commercialization learning curve.

The efficiency assumptions of gas and electric heat pumps meet the minimum standards set out by the Province's Clean Energy Plan for buildings, so no sensitivity was deemed to be warranted.

C. ANNUAL ENERGY DEMAND FORECASTING

84.0 Reference: LONG-TERM CUSTOMER FORECAST METHOD AND RESULTS

Exhibit B-6, BCUC IR 11.8

Residential Customer Forecast

In response to BCUC IR 11.8, FEI states:

> The residential customer forecast method is based on net customer additions. Net customer additions are defined as gross customer additions less customer losses.
>
> … The customer forecast method does not include a separate customer losses forecast. The forecast is refreshed regularly, so that, if any customer losses trends were to develop, they would be identified and included in subsequent forecasts.

84.1 Please further explain how customer losses trends would be identified and included in subsequent forecasts.

<u>Response:</u>

Customer losses, and therefore trends, are embedded in the net customer additions data used to develop the forecast. As a result, losses and trends are already intrinsically included in the forecast. However, at a high level, customer losses trends could be identified as follows:

Gross Additions Trend	Net Additions Trend	Implication
Increasing	Increasing	Losses are stable
Increasing	Decreasing	Losses are increasing
Decreasing	Increasing	Losses are decreasing
Decreasing	Decreasing	Losses are stable

84.2 Please discuss whether FEI produces a customer losses forecast, independent from the LTGRP annual demand forecast.

84.2.1 If yes, please discuss the feasibility of including a customer losses forecast as part of the LTGRP annual demand forecast methodology.

Response:

FEI does not produce a specific customer losses forecast independent from the LTGRP annual demand forecast.

The basic customer additions relationship is:

$$Net\ Customer\ Additions\ Forecast = Gross\ Customer\ Additions\ Forecast - Customer\ Losses\ Forecast$$

This relationship can be manipulated to isolate the Customer Losses Forecast:

$$Customer\ Losses\ Forecast = Gross\ Customer\ Additions\ Forecast - Net\ Customer\ Additions\ Forecast$$

FEI notes that only two of the three quantities can be independently forecast. As FEI already creates forecasts for Gross Customer Additions and Net Customer Additions, inherently the forecast for Customer Losses is also developed.

85.0 Reference: LONG-TERM CUSTOMER FORECAST METHOD AND RESULTS

Exhibit B-6, BCUC IR 11.3, 11.4; Exhibit B-12 CEC IRs 2.1, 27.1

Capture Rates

In response to BCUC IR 11.3, FEI states:

> FEI has residential capture rate data available for the six years prior to 2021 (note that the capture rate is based upon the percentage of housing completions that become FEI customers, not housing starts). Table 1 below shows how FEI's overall market capture rate reached a high of 85 percent in 2017 and has since declined.

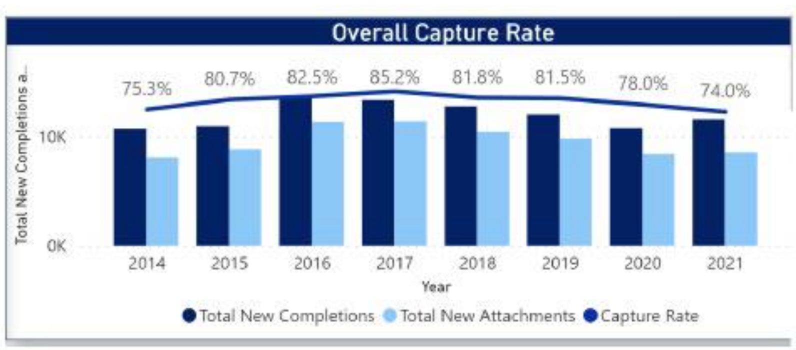
Table 1: FEI's Overall Capture Rate Trend

	2015	2016	2017	2018	2019	2020
Market Capture	81%	83%	85%	82%	81%	78%

In response to BCUC IR 11.4, FEI states:

> As discussed in the current GCOC proceeding referenced in the question preamble, based on the shift in its net customer additions, FEI expects this downward trend in capture rates to continue. FEI does not prepare a capture rate forecast and the historical capture rate is not an input into the residential customer forecast method. FEI's demand forecast method accounts for demand reductions (from electrification, for example) through its end-use forecast rather than its customer forecast, as discussed in the response to BCUC IR 1 14.3.

On page 4 of FEI's response to CEC IRs 2.1, FEI provides a bar chart of the overall capture rate and states:



> 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.

On page 71 of FEI's response to CEC IRs 27.1, FEI provides a table of the CBOC forecast data for BC population, single and multi-family housing starts, and GDP projections:

	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	350,253	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	4,526	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	16,256	15,808	15,378	14,971	14,594

85.1 Please discuss the reasons behind the decline of FEI's overall capture rate since 2017.

Response:

The decline in FEI's capture rate is driven primarily by government policies which promote electric solutions and discourage the use of gas in the building sector. For example, greenhouse gas emissions targets which are embedded in building codes serve to limit or exclude the use of gas and send a signal to the marketplace that buildings should not use gas, resulting in a drop off in market share.

Further, an increase in multi-family developments has impacted FEI's capture rate, as gas has a lower penetration rate in this customer segment.

85.2 Please confirm, or explain otherwise, that the declining capture rates are not reflected in net customer additions. If confirmed, please discuss whether FEI considers it feasible for capture rates to be used as input into the customer forecast method.

85.2.1 If not confirmed, please explain how net customer additions account for the declining capture rate trend observed by FEI.

Response:

Not confirmed.

The capture rate is one of many factors that impact the annual net customer additions. For instance, if the capture rate decreases or increases in any given year, it affects the number of gross additions, which is used to calculate the net additions for the year. The capture rate and other factors, such as electrification policy, advertising and heat pump incentives, densification, affordability, inflation, and climate change, are fully and intrinsically captured in the year-end actual net customer additions.

Capture rate is a backward-looking metric that requires data to be provided by provincial entities that has a one-year lag. The capture rate compares the number of residential gross additions to the actual residential building completions. Therefore, the total number of gross additions is highly dependent upon the number of units constructed. Moreover, the number of units constructed has a larger impact on gross additions than does the capture rate.

85.3 Please confirm that the capture rate does not directly impact the end-use forecast despite a declining trend since 2017.

85.3.1 If confirmed, please explain why the capture rate would not impact the end-use forecast. Please discuss what impact not incorporating capture rates would have on the overall demand forecast.

85.3.2 If not confirmed, please explain how declining capture rates can be reflected in the demand forecast.

Response:

Not confirmed. The capture rate does affect the end-use forecast because it is one of the intrinsic factors in the actual net customer additions recorded each year. In any year, if the capture rate declines then, all else equal, the net customer additions for that year will also go down, and vice versa. The net customer additions are used to prepare the end-use forecast, so any influence from the capture rate will be reflected in that forecast.

85.4 Please discuss why FEI does not prepare a capture rate forecast, and whether FEI considers it would be feasible in future.

Response:

FEI does not incorporate capture rates or housing starts data into the residential forecast method because the data does not chronologically align with the actual net additions from the billing system. Housing starts and capture rates typically measure market conditions from 1 ½ to 2 years ago. Timely data is not available when the forecast is prepared, when billing system data that is only 1 to 2 months old is used. For example, capture rates and housing starts were very robust in 2020. FEI does not believe a useful or reliable forecast could be developed by combining those outdated trends with the very different market conditions experienced in 2022.

86.0 Reference: LONG-TERM CUSTOMER FORECAST METHOD AND RESULTS

Exhibit B-6, BCUC IR 14.3, 14.3.1

Residential, Commercial, and Industrial Customer Forecast

In response to BCUC IR 14.3 about why future uncertainties around end-use energy are addressed as part of demand forecast and not customer forecast, FEI states:

> FEI has addressed these future uncertainties through its end use demand forecast modelling and not through its customer forecast because changing both customer additions and end-use assumptions to address the same critical uncertainties in the scenarios would increase modelling complexity and the number of output permutations, while not increasing the value of the information provided by the overall demand forecast results.
>
> FEI and Posterity Group prefer separating whether someone is a customer from what they use energy for […] If energy use and customer numbers are all blended together into one parameter, understanding and testing the effects of specific changes is more difficult. As well, addressing a critical uncertainty such as fuel switching, for example, partially using assumptions about customer additions and partially through changes in energy end-use patterns, would require additional checks and balances within the modelling to ensure that the impact of fuel switching on demand is not being double counted for any individual or group of customers.

Further, in response to BCUC IR 14.3.1, FEI states:

> While it is possible for changes to be made to the customer forecast, this approach is not recommended at this time for the reasons discussed in the response to BCUC IR1 14.3.

86.1 Please discuss whether the customer forecast is used to inform other aspects of the LTGRP, for example but not limited to: analysis of potential DSM savings in section 5 and the peak demand forecasts in section 7 of the LTGRP, and the rate impact analysis in section 9.4 of the LTGRP.

<u>Response:</u>

The customer forecast informs many aspects of the LTGRP, including, but not limited to, the following examples:

- DSM savings potential in the following ways:
    - Greater customer growth implies more new construction. The potential for all new construction DSM measures increases if there is more new construction. Lower customer growth implies less new construction and lower potential for new construction DSM measures.

- Some scenarios include assumptions for declining customer numbers in certain rate classes. The potential for DSM measures in existing buildings declines in these scenarios, as customers drop off the gas grid.

- Peak demand:
  - The peak demand estimates are based on the combination of customer numbers and peak usage per customer (UPC_{peak}). Section 7.2.3 of the Application describes the development of UPC_{peak} for each rate schedule and region. These values are multiplied by the numbers of customers in each rate schedule, region, and year, which are derived from the customer forecast.
- GHG emissions:
  - GHG emissions are based on annual demand for each fuel multiplied by the appropriate emission factors. Annual demand is driven by annual consumption per customer and the number of customers in each region, rate class, customer segment, and year. The number of customers comes from the customer forecast. Annual consumption per customer is a function of all the other critical drivers and assumptions in the model.
- Rate impact analysis:
  - The number of customers is an input into the rate impact analysis.

86.1.1 If the customer forecast is used to inform other aspects of the LTGRP, please further explain why FEI considers addressing future uncertainties in the customer forecast would not increase the value of information provided.

Response:

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

As described in the response to BCUC IR2 86.1, the different aspects of the LTGRP are often a product of the number of customers and other factors controlled by other assumptions and critical uncertainties. The other factors may include end use unit energy consumption, fuel shares, UPC_{peak}, emission factors, and so on, depending on the specific values being calculated. Controlling each of these inputs with their own sets of assumptions and, in some cases, with dedicated critical uncertainties provides greater visibility into their distinct effects on the outcome and adds value to the results.

FEI's and Posterity Group's objective is to have clear, well defined and understandable assumptions underlying the LTGRP. Using one model lever - the number of customers - to reflect many different critical uncertainties would “bury” their separate influence rather than reveal it, and doing so would not increase the value of the information provided.

86.2 If the future uncertainties around end-use were to be modelled as part of the customer forecast, please discuss in detail the changes to FEI’s demand forecast methodology and models that would be required. Please include in your answer a discussion of potential resource requirements, and any modelling limitations that would not be resolvable.

Response:

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

The full extent of the changes to the forecast modelling under the conditions cited in the question cannot be completely known until such a modelling exercise is undertaken. However, making this change to the methodology would require research to establish methods to tease apart the influence of energy pricing and policies on customer numbers versus usage per customer. It is uncertain if such methods currently exist in the energy industry. The customer growth model would also have to be changed to include both the effects of historical variation in customer growth and the effects of energy price and policy change. The fuel switching model would have to be changed to include only the effects of energy price and policy changes on usage per customer. If this exercise were to be undertaken at this point in the resource planning process, it would require two to three months, or perhaps longer, of effort. Then all scenarios would need to be rerun and all the reporting redone.

FEI and Posterity Group believe that at the end of this work, the estimated PJ of demand would be close to the same as in the current set of scenarios. In a scenario with decreasing demand, there would be fewer customers but the same amount of gas demand would be distributed among this smaller number. In a scenario with increasing demand, there would be more customers but each of them would use somewhat less gas.

As stated in the response to BCUC IR2 86.1, careful quality control would be required (which is not included in the above estimate of resources and timing) to avoid double-counting demand reductions by reducing usage per customer for customer groups whose demand has already been sufficiently reduced by changes in customer growth. It would also be more difficult to interpret the results. Instead of this critical uncertainty being attached to one lever in the model, it would be spread between two.

For the above reasons, FEI and Posterity Group do not consider that embedding the impact of critical uncertainties into the customer forecast will provide more useful (nor as useful) information as the current method and would take a substantial amount of additional effort and cost.

86.3 Please show a worked example to illustrate how modelling uncertainties around end-use in the customer forecast would result in double counting with the demand forecast.

Response:

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

The following example illustrates how modelling uncertainties around end-use in the customer forecast would result in double counting with the demand forecast.

Consider a simple model with 1,000 houses that consume 70 GJ each for space heating. Absent improvements from energy retrofits or natural equipment replacement, it is assumed they would continue to consume 70,000 GJ per year for space heating for the next twenty years.

Now a price signal strong enough that the long-term elasticity would predict a 50 percent reduction in space heating energy demand is imposed. Therefore, expected heating demand is 35,000 GJ after twenty years.

Conversely, if the number of customers is reduced by 25 percent to 750 and heating demand per customer is reduced by 25 percent to 52.5 GJ, the resulting heating demand is 39,375 GJ, which is higher that the above calculation by 12.5 percent.

This type of error would potentially be repeated millions of times in a model this size. It is possible, of course, to use a formula to force the results to agree with the predicted 50 percent reduction (for example, reducing customers by 29.3 percent and demand per customer by 29.3 percent), but then there is no change to the results the existing model gives and no new information results.

The literature on customer response to energy pricing signals is relatively limited. Studies that focus on either customer attachment (or detachment) behavior in response to pricing signals may not include the fuel choice behavior of customers that choose to continue. Conversely, studies focusing on fuel choice behavior may not consider the effects of customer attachment and detachment. Posterity Group and FEI are not aware of research that considers both effects together and that tease apart the response to pricing signals into the two effects. As discussed in the response to BCUC IR2 86.2, it is likely that the exercise would be introducing an artificial distinction between them in the model, with no firm foundation in the literature.

86.4 Please provide a list of examples of different drivers of demand that, in practice, would be expected to affect the number of customers only, use per customer only, and both the number of customers and use per customer.

Response:

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

Neither FEI nor Posterity Group is aware of drivers that can be easily categorized in this way. Each of the demand drivers that are considered in the 2022 LTGRP to have a substantial impact on FEI's future demand, which are modelled as critical uncertainties as described and listed in Section 4.5.2 of the Application, could be said to manifest through both number of customers and use per customer, which is why it is challenging to try to model both at the same time as discussed in response to BCUC IR1 14.3 and 14.3.1. FEI considers that these critical uncertainties could be broken down further into a potential list of "sub-drivers" of demand, such as (for example) marketing and media influences, availability of rebates for certain equipment over others, housing prices, weather factors, standard of living, household and housing characteristics and more. The majority of these 'sub-drivers' of demand could also be said to manifest to some degree in both use per customer and customer numbers. However, identifying, understanding and modelling these 'sub-drivers' is problematic for the following reasons:

- There are no available tools with which to measure the degree of impact these sub-drivers could have on customers and demand and so no data on which to model them;
- The degree to which these 'sub-drivers' might influence use per customer versus number of customers could change under varying planning environments;
- Most or all of these 'sub-drivers' will have interactive affects among one another that cannot be separated; and
- Deciding which 'sub-drivers' to include and not include at a deeper level of granularity than the critical uncertainties that FEI has modelled is liable to introduce false biases into the forecast.

To explain by way of example, FEI and Posterity Group, in practice, consider that energy pricing and policy drivers tend to affect customer fuel choice (and also, to some extent, efficiency choices) for individual end uses. In existing buildings, this would typically occur at the point of equipment replacement at the natural end of life for the existing equipment. This timing would generally be different for each end use. There is then likely a critical number of end uses (or level of remaining gas demand) below which the customer may decide it is no longer worthwhile to remain a gas customer. This would vary. For example, some customers may be sufficiently attached to using gas for cooking such that they would be willing to pay the monthly charges to remain connected to the gas system even if they use gas for no other end use. Others would be less particular.

In new construction, it may be the developer who makes a similar determination of whether it is worth bringing gas lines to the development, depending on how many end uses in the buildings will use gas. Alternatively, for custom homes and commercial buildings, the prospective owner may make these choices.

There is an interaction between these two impacts that is likely to evolve over time and vary by customer type and sometimes by individual customer. Without access to studies that identify correlations for this behavior in the literature, modeling such relationships would be based on speculation.

87.0 Reference: LONG-TERM CUSTOMER FORECAST METHOD AND RESULTS

Exhibit B-6, BCUC IR 17.1, 17.2

End Use Annual Method of Demand Forecasting for the Residential, Commercial and Industrial Demand

In response to BCUC IR 17.1, FEI states:

> As explained in Section 4.4.1.3 of the Application, the Reference Case incorporates laws and policies that affect energy use. Because the Reference Case was developed in 2019, it reflects what was enshrined, and was likely to become enshrined, in law at the time.

In response to BCUC IR 17.2, FEI states:

> The Reference Case includes those trends, regulations and policies that are known at the time the analysis is undertaken, or are very certain to come to pass. These considerations are then held static through the planning horizon. This condition of the Reference Case therefore provides a reference point from which to model and compare other scenarios, with other Critical Uncertainty settings.

87.1 Please further discuss why the Reference Case was developed in 2019.

Response:

The Reference Case demand is a key input into other aspects of the LTGRP that are on a critical timeline for completing and submitting the LTGRP. In particular, the Reference Case demand forecast was a key input into the CPR. The CPR is a study that takes months to complete. In turn, the data developed through the CPR process, such as the existing gas equipment inventory in BC and equipment stock turnover rates, becomes a key input into the development of the demand forecasts for the other future scenarios, another task that takes months to complete. Therefore, the Reference Case must be developed that far in advance of filing the LTGRP (which was at that time scheduled for Q1 2022) in order to allow enough time to complete all of the subsequent LTGRP analyses and tasks for input into the Plan, such as the annual demand forecast, peak demand forecasts, estimated energy savings from demand-side management activities, gas supply planning activities, system planning analysis, rate impact analysis, garnering input from stakeholders and communities on draft outcomes of the plan and more.

87.2 Please discuss the potential limitations associated with developing the Reference Case in 2019, including any limitations with the development of the other scenarios.

87.2.1 Please discuss whether FEI considers these limitations can be addressed in future LTGRPs.

Response:

There is a limitation associated with developing the Reference Case in advance in developing alternative future scenarios for any LTGRP, and, in fact, for any planning activity, given the degree to which the planning environment might shift after the need to finalize inputs in time to undertake the subsequent analyses that must be completed to prepare a useful plan. Every LTGRP will have these limitations to a greater or lesser extent depending on the speed at which the planning environment is changing. No LTGRP will have access to “perfect information”. However, FEI considers that its scenario analysis, Clean Growth Pathway and LTGRP Action Plan are robust enough to encompass the changes in the planning environment that have occurred during the interim and thus receive acceptance from the BCUC, and allow FEI to begin work on its next LTGRP.

87.3 In the development of future LTGRP’s, please discuss FEI’s ability to use a base year and Reference Case forecast that is more current.

Response:

Given the requirements of the LTGRP development process, stakeholder engagement requirements, and regulatory process around the LTGRP as it exists today, opportunities to use a more current base year than that used to prepare the 2022 LTGRP, while still ensuring the subsequent analysis is sufficiently robust to meet expectations, would be modest at best (perhaps a matter of a few months).

88.0 Reference: LONG-TERM CUSTOMER FORECAST METHOD AND RESULTS

Exhibit B-6, BCUC IR 19.2, 19.2.2

Customer Forecast and End-Use Annual Method of Demand Forecasting for the New Large Industrial Demand Category

In response to BCUC IR 19.2, FEI states:

> FEI has not assessed the likelihood of a second large industrial load of similar demand to that of the Woodfibre LNG project. The purpose of modelling this demand was not to determine the probability of such an occurrence, but rather to understand the implications of such a step change in demand on the need for future resources. FEI does periodically receive inquiries regarding industrial customers looking for natural gas service; however, FEI is not currently advancing projects to serve any such load addition inquiries of the magnitude shown and therefore cannot comment on the likelihood of such a load materializing. … As the specific customer location and demand requirements can determine the scope of upgrades that may be required, the lead time would vary but would likely be several years in development.

In response to BCUC IR 19.2.2, FEI states:

> Since this additional load remains hypothetical at this time (please refer to the response to BCUC IR1 19.2), the precise timing of the load addition modelled is less important than is understanding the system implications for meeting such potential new load.

88.1 Please discuss whether FEI considered only modelling the load impacts of potential large industrial projects where FEI has received load addition inquiries.

<u>Response:</u>

FEI did model the impacts of only those large potential load additions where FEI has received load addition inquiries. The results of these modelling considerations are provided in the DEP Scenario demand outputs.

For those hypothetical potential additional loads in an Upper Bound Scenario, there are two key perspectives on potential large industrial load additions that FEI considers in its LTGRP.

- The first is the annual demand impact perspective where FEI can examine the supply resource and revenue implications of such potential additions. There is some value in examining those aspects of these hypothetical load additions from an annual perspective on a more speculative basis without requiring a specific inquiry from a potential customer. In the absence of a specific inquiry, such an examination remains at a high level and is conducted simply to test the upper limits of possible demand growth – something the BCUC has indicated interest in during past LTGRP proceedings.

- The other perspective is the peak day demand impact perspective where the system capacity impacts and scope of facility upgrades required for potential load additions would be considered. When considering these latter aspects, because the effect on system capacity and upgrades required are directly related to the magnitude and location of the new load addition within the system, there is limited real value to be derived from speculating on these hypothetical loads.

Accordingly, while FEI examines some aspects of the annual demand implications of such hypothetical loads, FEI does not examine the detailed peak demand and related infrastructure aspects of such additions without a specific load addition inquiry. In line with this approach, Section 7.3 of the Application did not include any system assessment of the hypothetical second large load addition, but rather focused on the more tangible large industrial load additions of Woodfibre LNG and the more defined future phases at the Tilbury site, where the location, magnitude and timing of the load potential is more developed.

88.1.1 Given the potential lead times of such projects, please discuss whether such an approach in future LTGRPs would still allow FEI sufficient time to understand the system implications for meeting such potential new load.

<u>Response:</u>

FEI does not expect the approach used in the 2022 LTGRP would impact the time required to understand the system implications of such potential new load additions. As discussed in the response to BCUC IR2 88.1, FEI can consider some of the annual demand implications of hypothetical large industrial load additions and can speculate on the timing of such loads with less rigor.

When specific load inquiries are received by FEI for large load additions, FEI works with the proponents to develop achievable schedules to ensure sufficient time is available to fully understand and address the system implications. FEI considers that modelling such a hypothetical load addition and testing the upper bound of potential future demand at a high level in this way makes the LTGRP more complete.

89.0 Reference: ALTERNATE FUTURE SCENARIOS AND CRITICAL UNCERTAINTY SETTINGS

Exhibit B-6, BCUC IR 21.1, 21.1.1

Traditional Annual Method and End Use Annual Method of Demand Forecasting for the Residential, Commercial and Industrial Demand

In response to BCUC IR 21.1, FEI stated:

> FEI expects the Traditional Annual Method to result in a forecast that is slightly higher than the Reference Case Forecast, especially over the long-term, for the reasons noted in the preamble. However, as shown in Figure 4-7 of the Application, the differences are only approximately 5 percent at the end of the planning period. If a future draft Reference Case Forecast was found to be significantly different to the Traditional Annual Method result, it would signify the need for additional research or data validation.

In response to BCUC IR 21.1.1, FEI stated:

> If the changes expected in the planning environment occur rapidly in the short term and are captured in the End Use Annual Method, then FEI expects that the divergence between the Traditional Annual Method and the End Use Annual Method could increase.

89.1 In a future scenario where there was an increased divergence between the Traditional Annual Method and the End Use Annual Method, please discuss whether FEI would consider the Traditional Annual Method to provide value for data validation purposes.

89.1.1 Please discuss whether FEI considers there is a percentage divergence where the Traditional Annual Method would no longer add value for data validation purposes.

<u>Response:</u>

FEI believes that, due to the ease with which the Traditional Annual Method forecast can be prepared, it will always be a useful tool during the development of the End Use Annual Method forecast. If the two forecasts do significantly diverge, then FEI expects to be aware of the factors causing the divergence. If the forecasts diverge significantly more than anticipated, it would signify the need for additional research or data validation.

FEI does not have or expect to have a specific cut-off point at which the checks would cease to be performed.

90.0 Reference: ALTERNATE FUTURE SCENARIOS AND CRITICAL UNCERTAINTY SETTINGS

Exhibit B-6, BCUC IR 25.1, 26.1, 26.4 29.1; Exhibit B-1, Section 2.2.2.1, 2.2.2.2, pp. 2-7, 2-8; Exhibit B-1, Appendix B-3, Section 1.1.1.1.4, pp. 10-11

Diversified Energy Planning (DEP) Scenario

In response to BCUC IR 25.1, FEI explains:

1. <u>FEI calculated the 2050 fuel share target</u>: For residential and commercial sectors, this meant subtracting 25 percent from the base year fuel share of space and water heating end uses, respectively. For the industrial sector, 10 percent was subtracted from end-uses that were assumed to be able to switch to electricity.
2. <u>FEI Calculated the 2042 fuel share target</u>: a linear interpolation from 2020 (first year of the forecast period) to 2042 (last year of the forecast period) was used.
3. <u>FEI modelled reductions to gas fuel shares for applicable end uses</u>: the model switches fuel shares using an equipment turnover rate. It is assumed equipment is replaced when it reaches end of life (i.e., no early replacement). When gas-using equipment reaches end of life, it is assumed to be replaced with an electric option.

90.1 Please explain how the gas fuel share target is calculated from the electrification target (e.g., show a formula that translates 25% electrification into a reduction in gas fuel share).

<u>Response:</u>

The following response is provided by Posterity Group.

The base year of the study is 2019. If the target electrification percentage is 25 percent, then the fuel share reduction target is given by the following equation:

$$\text{FuelShareReduction} = \frac{(2042-2019)}{(2050-2019)} x 25\% = 18.55\%$$

Therefore, the target gas share reduction by 2042 is 18.55 percent. That is the target that was used in the modeling.

On page 2-7 of the Application, FEI states:

> The CCAA required the Minister of Environment and Climate Change to establish sector-specific targets for GHG reductions by March 31, 2021, and to then review these targets by the end of 2025 (and at least once every five years thereafter). In March 2021, sectoral targets for 2030 were established as follows, expressed as a percentage reduction from 2007 sector emissions:
>
> - Transportation – 27 to 32 percent
> - <u>Industry – 38 to 43 percent</u>
> - Oil and Gas – 33 to 38 percent
> - <u>Buildings and Communities – 59 to 64 percent</u>
>
> [Emphasis added]

90.2 Please discuss how the assumptions of 25% electrification in the residential and commercial sector and 10% electrification in the industrial sector align with the sectoral target for GHG reductions by 2030 specifically in industry and buildings and communities.

<u>Response:</u>

FEI and Posterity Group have collaborated on this response.

FEI notes that there are no Provincial electrification targets overall or for specific sectors, rather electrification is used as a strategy by which to achieve the Province's GHG reduction targets. FEI used various strategies such as electrification to achieve emission reductions in the different scenarios as discussed in the preamble. Furthermore, the DEP Scenario is designed to achieve the overarching GHG reduction goals of the Province of 40 percent by 2030 and 60 percent by 2040, rather than achieving the specified sectoral targets. This was to align with the Pathways Report that provided the guiding inputs for developing two of the scenarios. The Pathways Report was developed before the announcement of the sectoral targets.

After the release of the CleanBC Roadmap, FEI modelled key policies of the Roadmap at a high level, where reasonable to do so, like the proposed GHGRS, as part of the LTGRP process by updating the DEP Scenario with greater ambition. For example, FEI selected the High DSM setting and maximized the amount of renewable and low-carbon gas it believed it could reasonably acquire to reach the proposed cap.

More specifically, in developing the DEP Scenario, FEI's approach to emission reduction was to meet the proposed GHGRS emissions cap of 5.7 MtCO_2e in 2030 and to meet the overall BC legislated GHG emissions reduction target (60 percent reduction of FEI's 2007 customer emissions) of 4.3 MtCO_2e by 2040. In doing so, FEI's goal was to meet the overall emission reduction target rather than focusing on meeting the individual sectoral targets.

For further context, in the BCUC Energy Scenarios Project,[9] BC Hydro's GHG emissions modelling found that the DEP Scenario and both electrification scenarios (FEI's Deep Electrification and BC Hydro's Accelerated Electrification) resulted in the same impacts on provincial GHG emissions in 2040. All three scenarios achieved the Provincial emissions target of 25 $MtCO_2e$ by 2040, 61 percent below 2007 base level emissions.

On page 2-8 of the Application, FEI states:

> **2.2.2.2 CleanBC Roadmap to 2030 (Roadmap)**
>
> On October 25, 2021, the provincial government released the CleanBC Roadmap to 2030 (Roadmap)49 as an update to the 2018 CleanBC plan and part of its commitment to achieve BC's legislated GHG reduction target of 40 per cent below 2007 levels by 2030. The Roadmap articulates a plan to fully achieve this target and sets the course to reach net-zero by 2050. The Roadmap, includes ambitious measures that place FEI at the forefront of the global energy transition. It is also anticipated to have a significant impact on FEI's customer rates, competitiveness and throughput.
>
> Key measures in the Roadmap that directly impact FEI include:
>
> - An increased carbon tax which will rise to $170 per tonne by 2030;
> - A GHG cap for natural gas utilities;
> - A zero-carbon requirement for new buildings and highest efficiency standards for space and water heating equipment by 2030;50
> - Amendments to the *Greenhouse Gas Reduction (Renewable & Low-carbon Fuel Requirements) Act* and the *Renewable & Low-carbon Fuel Requirements Regulation*, known collectively as British Columbia's Low-carbon Fuel Standard (BC-LCFS), 51 to decrease the carbon intensity benchmark while including marine and aviation fuels in the amendment; and
> - A 75 percent reduction in oil and gas methane emissions by 2030.

[9] BC Hydro's Stage Two Submission, Summary Table 5-1 found within the BC Energy Scenarios Project Stage One and Stage Two can be found online at the following links:

- FEI 2022 Long-Term Gas Resource Plan Exhibits B-2 and B-4 at: https://www.bcuc.com/OurWork/ViewProceeding?applicationid=1000.
- BC Hydro 2021 Integrated Resource Plan Exhibits B-8, B-14, and B-19 at: https://www.bcuc.com/OurWork/ViewProceeding?applicationid=965.

90.3 Please discuss which elements of the Clean BC Roadmap relevant to FEI are modelled in the DEP scenario, and which relevant elements are not, with rationale explaining why they are not modelled.

Response:

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

The CleanBC Roadmap to 2030 (Roadmap)[10] announcement on October 25, 2021, was late in the process of developing the 2022 LTGRP. While technical challenges and time constraints led to some limitations regarding the incorporation of this ambitious emissions reduction policy, the greatest limitation continues to be uncertainties associated with the planning environment. In some respects, details on key policies in the Roadmap have not yet been provided, making it difficult to accurately characterize the policy in the modeling analysis and evaluate its impact on FEI's long-term resource planning. Please refer to Section 2.2.2.2 of the Application for a comprehensive discussion on the Roadmap and its impact on FEI's planning environment.

An overview of Roadmap initiatives that impacted FEI's planning environment and those that were taken into consideration in the development of the 2022 LTGRP are discussed in Table 1.

Table 1: Overview of CleanBC Roadmap Policy Initiatives, if Modeled in 2022 LTGRP, and Impacts on FEI Resource Plan Development

CleanBC Roadmap Initiative	Modeled in LTGRP [11] (Y / N / NC)	Impacts to FEI Resource Planning
Economy-Wide Initiatives		
Increasing the Price of Carbon	Y	• DEP Scenario is consistent with CleanBC carbon price trajectory, as it is consistent with the federal carbon pricing benchmark in place when modelling was conducted. • Response to BCUC IR2 90.4 provides further discussion.
Low Carbon Energy Initiatives		
Expanding the Low Carbon Fuel Standard or "BC-LCFS"	NC	• Reducing environmental impacts of transportation fuels. • LCT sector may be impacted in next LTGRP.
Greenhouse Gas Reduction Standard: Emissions Cap for Natural Gas Utilities or "GHGRS"	Y / NC	• The GHGRS would require a GHG reduction of approximately 5.5 Mt of CO_2e, which is equivalent to displacing approximately half of the natural gas delivered by FEI. • FEI anticipates the reduction will be calculated based on end-use emissions in the residential, commercial and industrial sectors. • The DEP Scenario is designed to meet the cap by undertaking all available and reasonable GHG emission reduction activities. • The compliance pathways to meet the cap have not yet been released by the Province.

[10] Exhibit B-1, Appendix A5. CleanBC Roadmap to 2030.
[11] "Y" = Yes, "N"= No, "NC"= Details Not Certain in Time for 2022 LTGRP Application May, 2022 Filing Deadline.

CleanBC Roadmap Initiative	Modeled in LTGRP [11] (Y / N / NC)	Impacts to FEI Resource Planning
Phase out gas fired electricity facilities	N	• Co-generation plant on Vancouver Island has been included in total demand including GHGRS emission reduction requirements although its future utilization is uncertain.
Advancing BC Hydro's Electrification Plan	Y / NC	• DEP Scenario poses moderate electrification setting and LTGRP provides comprehensive comparison to the Deep Electrification scenario. • BC Hydro modeling suggests that DEP and Electrification Scenarios resultant provincial emissions at 2040 would be equivalent. • BC Hydro has not released comprehensive plan as to infrastructure requirements, costs and rate impacts for this plan. • Responses to BCUC IR1 25 series provides further discussion.
Implementing the BC Hydrogen Strategy	Y	• DEP Scenario is focused on accelerating higher levels of supply availability of renewable and low-carbon gas, including hydrogen. • FEI will be key player in economic development of BC's Hydrogen Economy. • Responses to BCUC IR1 52.4, 52.5, 52.6 and 61.3 provide further discussion.
Buildings		
Zero carbon new construction by 2030	NC	• Role of renewable and low-carbon gas in zero carbon new construction is not yet legislated. • Will be modeled in next LTGRP.
Energy efficiency standards for existing buildings	NC	• BC Building Code for existing buildings is not yet announced but expected for 2024. • Will be modeled in next LTGRP.
Highest efficiency standards for new space and water heating equipment	NC	• Role of renewable and low-carbon gas in appliance standards not yet legislated. • Will be modeled in next LTGRP.
Update DSM regulations	NC	• DSM Regulations announcement in 2023 will impact cost-effectiveness tests. • Will be modeled in next LTGRP.
Phase out utility gas equipment incentives	NC	• DSM Regulations announcement in 2023. • Role of renewable and low-carbon gas not yet legislated. • Will be modeled in next LTGRP.
Retrofit incentives (ie. PACE funding)	NC	• Still under development by the Province. • Will be considered within DSM program development.
Industrial (including oil and gas) Initiatives		
Net-zero plans for new large industrial facilities	Y	• The DEP Scenario incorporates increased use of renewable and low-carbon gas for industrial applications, specifically the potential for on-system hydrogen.

CleanBC Roadmap Initiative	Modeled in LTGRP [11] (Y / N / NC)	Impacts to FEI Resource Planning
Reducing emissions from the oil and gas sector	N	• Few details on the cap for oil and gas emissions. • Reduced emissions reduction in upstream gas production will reduce the carbon intensity of natural gas. • Could potentially increase the commodity cost of gas in the Province, impacting FEI customer rates and decreasing FEI's competitiveness. • If carbon intensity life cycle emission factors are reduced, FEI will incorporate into next LTGRP by updating Table 1-2 in the Application.
Approach to CCUS and negative emissions technologies	Y / NC	• Role of negative emissions technologies on GHGRS not yet clarified as to legislation by government.
	Agriculture Initiatives	
Supporting local biogas production	Y	• Incorporated higher levels of BC-based supply availability of renewable and low-carbon gas, including locally-produced biogas. • FEI will be key player in economic development of BC's renewable and low-carbon gas market. • Refer to responses to BCUC IR1 52.4, 52.5 and 52.6 for further discussion.
	Negative Emissions Technologies Initiatives	
NETs as compliance pathway for the LCFS	Y / NC	• Role of negative emissions technologies on GHGRS not yet clarified within legislation from government. • Refer to responses to BCUC IR1 64 series, 9 series and MS2S IR1 9 series for further discussion.
Changes to GHG accounting framework	NC	• GHG accounting framework not yet released by government.
Support and incentives for CCUS & other NETs	NC	• Support and incentive information not yet released by government.

<u>Notes to Table:</u>

[1] *See: Exhibit B-1, Application, p. 4-17.; BCUC IR1 71.7, 72.2, 74.1, 74.2.*

In response to BCUC IR 29.2 about the Reference setting used for the carbon tax, FEI states:

> FEI acknowledges an error in Table 4-1 of the Application. The actual setting used for the carbon tax in the DEP Scenario was the Planning setting (increasing to $170 per tonne in 2030) and not the Reference setting as shown in Table 4-1. The

> Planning setting was used to model future changes to the carbon price in the DEP Scenario.

In response to BCUC IR 29.1, FEI explains that it used the Reference setting, which includes what was in place and known to be changing at the time in critical uncertainties such as Appliance Standards, New Construction Code, and Retrofit Code, because it is the most reasonable assumption for the DEP scenario, so no separate Planning setting was developed.

Further, in response to BCUC IR 26.1, FEI states:

> The 2022 LTGRP was developed at the time of unprecedented change in policy and market forces. The Critical Uncertainty settings could not explicitly incorporate the requirements of the CleanBC Roadmap to 2030 because the November 2021 announcement occurred too late in the development cycle to make such a significant change to the modelling of both the Conservation Potential Review and LTGRP. However, although not explicitly incorporated, both the DEP and Deep Electrification Scenarios produce outcomes that are in close alignment to the CleanBC Roadmap requirements with respect to new construction code in the sense that these scenarios do anticipate increasingly stringent, carbon emission reduction related policy. However, only the DEP achieves the target.

90.4 Please discuss why the carbon tax rise to $170/tonne by 2030 is incorporated in the DEP scenario, considering FEI's response to BCUC IR 26.1 which states that the critical uncertainty settings could not explicitly incorporate the requirements of the Clean BC Roadmap to 2030.

Response:

FEI did not consider the carbon tax to be a CleanBC Roadmap requirement for the purposes of its response to BCUC IR1 26.1. Rather, FEI included the carbon tax price of $170 per tonne by 2030 as this was announced by the federal government in 2020 as a requirement across Canada. While mentioned in the CleanBC Roadmap to 2030 in late 2021, the Province's adoption of the carbon tax at this level was expected and FEI and Posterity Group had already applied it in the carbon price setting applied to the DEP Scenario.

With reference to the Appliance Standards on pages 10-11 of Appendix B-3 of the Application, FEI states:

> The Reference Case assumes that the 2019 in-market mandatory or legally enshrined appliance standards continue across the entire forecast period.

Accelerated outcome assume the introduction of the following additional performance requirements for appliances.

- Gas Storage Water Heater: No change (BC MEPS are already slightly more stringent than Federal MEPS)
    - BC = energy factor must be ≥ 0.70 − (0.0005 × V), and
    - Federal = energy factor must be ≥ 0.675 – 0.00039 Vr.
- HRV: estimated new minimum performance of 50 percent (residential only); likely minimal impact, since there are few homes with HRVs.
- Gas Dryer: likely new testing requirements, but no expected efficiency requirements.
- Gas Range: estimated 10 percent improvement in minimum efficiency level (residential only)
    - Assuming 20 percent of existing ranges are non-conforming, and will be upgraded when they are replaced. Replacement rate is assumed at 1/lifespan or 1/15th per year.
- Windows: new minimum performance of USI 1.61 or ER 25 (residential only)
    - Assuming 20 percent of existing windows are non-conforming, and will be upgraded when they are replaced. Replacement rate is assumed at 1/lifespan or 1/20th per year, and
    - Previous work by Posterity Group found this upgrade has on average a 2.7 percent heating energy savings.
- Commercial Warm Air Furnace: estimated improvement to 85 percent efficiency from 80 percent efficiency
    - Assuming 20 percent of existing commercial furnaces are non-conforming, and will be upgraded when they are replaced. Replacement rate is assumed at 1/lifespan or 1/15th per year, and
    - Commercial furnaces are estimated to make up 37 percent of the gas heating mix in BC.

90.5 Please summarize the 2019 in-market mandatory or legally enshrined appliance standards used in the Reference setting, applicable to the appliances noted in the preamble (Gas Storage Water Heater, HRV, Gas Range etc).

Response:

The following response has been provided by Posterity Group.

The 2019 in-market mandatory or legally enshrined appliance standards used in the Reference setting are as follows:

Gas Storage Water Heater:

- Residential:
  - 0.62 Energy Factor, based on *British Columbia Energy Efficiency Standards Regulation*: (EF) ≥ 0.70 – 0.0005V, where "V" is storage tank volume in litres (≥ 0.62 EF for 151 liters or US 40 gallon)
  - For City of Vancouver: EF ≥ 0.78, based on *Vancouver Building Bylaw*.
- Commercial:
  - Thermal Efficiency 80%, based on British Columbia Energy Efficiency Standards.

HRV:

- No Minimum Energy Performance Standard (MEPS).
- For City of Vancouver: Mandatory (65% Minimum SRE at 0 degC) based on *Vancouver Building Bylaw*.

Gas Dryer:

- No MEPS

Gas Range:

- No MEPS

Windows:

- Residential:
  - Maximum U-value of 1.80 W/m^2K based on *British Columbia Energy Efficiency Standards Regulation*
- Commercial:
  - No MEPS

Commercial Warm Air Furnace:

- No MEPS

90.6 Please explain whether the appliance standards in the DEP scenario anticipate an increasingly stringent carbon emission reduction policy in a manner similar to the new construction code, referenced in the FEI response to BCUC IR 26.1.

Response:

The following response has been provided by Posterity Group.

Appliance standards in the DEP scenario are set at the “reference” setting, which assumes that the 2019 in-market mandatory or legally enshrined appliance standards continue across the entire forecast period.

Some of the legally enshrined appliance standards in the reference setting are constant over time, while others are scheduled to become more stringent in the future. For example, the MEPS for residential boilers was modelled at 82% Annual Fuel utilization Efficiency (AFUE) beginning in the 2019 base year, increasing to 90% AFUE in 2024, based on Amendment 15 of Canada’s *Energy Efficiency Regulations,* which was passed in 2019.

The reference appliance standards setting used in the DEP scenario includes similar future MEPS improvements for other equipment categories including residential furnaces (2020), commercial boilers (2025) and commercial tankless water heaters (2024).

Please also refer to the response to BCUC IR2 81.2.1 which discusses the modest impact on gas demand of applying the “accelerated” setting to the codes and standards critical uncertainty.

In response to BCUC IR 26.4, FEI states:

> In the 2022 LTGRP, the Accelerated setting for appliance standards was not yet updated to incorporate the policy direction in the CleanBC Roadmap to 2030. As discussed in the response to BCUC IR1 26.2, the announcement of the CleanBC Roadmap was too late in the development cycle to make such a significant change to the modelling of both the CPR and LTGRP. The Reference Case assumes that the 2019 in-market mandatory or legally enshrined appliance standards continue across the entire forecast period. The Accelerated setting provided additional performance requirements for appliances based on 2019 knowledge of upcoming codes and standards and these are outlined in Appendix B-3, pages 10-11. The next LTGRP will incorporate the CleanBC Roadmap and all other policy updates that will be clarified in the short term.

90.7 Please discuss whether the accelerated setting for appliance standards is more or less stringent than anticipated standards arising from the Clean BC Roadmap 2030.

Response:

FEI notes that many of the standards announced in the CleanBC Roadmap have not yet been implemented through legislation and the nature of any such legislation remains somewhat uncertain. The Province has not yet announced compliance pathways for gas equipment nor has there been a decision regarding the impact of renewable and low-carbon gas supply on conventional gas combustion appliances. Although there is more policy direction regarding building code impacts for new construction, appliance standards impacting both retrofit and new construction, as well as the timing of their implementation, remains uncertain.

Therefore, due to policy uncertainty, FEI cannot comment on whether the appliance standards critical uncertainty is more or less stringent. Please refer to the response to BCUC IR2 81.2.1 for discussion of the impact of the codes and standards critical uncertainties on demand.

90.8 Please discuss the circumstances that would lead FEI to use the accelerated setting for its Diversified Energy Planning Scenario.

Response:

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

FEI would not automatically apply the accelerated setting for any critical uncertainty in the DEP Scenario. As described in the response to BCUC IR2 81.2.1, in the next LTGRP, FEI will develop input settings and an approach that most efficiently provides the ability and flexibility to produce the best information needed for the Application. In terms of codes and standards, the reference settings will likely be established in a similar manner to the 2022 LTGRP: to include minimum performance standards that are already adopted, those whose adoption is extremely likely and those whose year of adoption is known with high confidence.

For further context regarding the impact of accelerated codes and standards settings in the LTGRP, please refer to the response to BCUC IR1 81.2.1 which explains that, in the context of overall demand, accelerated codes and standards settings have a modest impact on annual demand as illustrated by the Reference Case example.

91.0 Reference: CRITICAL UNCERTAINTIES AND THEIR FORECAST MODELLING INPUT SETTINGS FOR THE END-USE METHOD DEMAND FORECAST SCENARIOS

Exhibit B-6, BCUC IR 27.3, 27.4 27.5, 27.7, 71.8.1; FEI Biomethane Energy Recovery Charge Rate Proceeding, Exhibit A4-2-1, Section III.B pp. 48 – 50

Critical Uncertainty Impacts on the Forecast Model – Residential, Commercial and Industrial Demand Category

In response to BCUC IR 27.3, FEI provides a table:

The following table shows the order of the critical uncertainties, as presented in Table 4-1 of the Application, from largest to smallest impact on the gas demand in 2042.

Order of Impact	Critical Uncertainty
1	Non-Price Driven Fuel Switching
2	Global LNG Demand
3	New Large Industrial Demand Growth
4	Low-Carbon Transportation Demand
5	Carbon Price
6	Natural Gas Price
7	Customer Growth
8	Codes & Standards

91.1 Please explain at a high level how FEI anticipates that the order of impact would change in the next LTGRP when CleanBC Roadmap is incorporated in the load forecasting method, for example, due to more stringent policies in codes and standards.

<u>Response:</u>

Please refer to the response to BCUC IR2 81.2.1.

In response to BCUC IR 27.4, Posterity Group states:

> The following table shows the approximate percentage change in fuel share that would be expected by 2042 for the applicable end uses, for the high, planning and low settings for the carbon price and natural gas price critical uncertainties… In each case, the expected percentage change is based on the long-run price elasticity of demand for the sector. The elasticity values obtained from a search of the literature were -0.38 for residential, -0.35 for commercial and -0.7 for industrial. FEI used the same elasticity whether the change in gas price was caused by changes in carbon price or commodity price or a combination of the two.

In response to BCUC IR 27.5, FEI states:

> FEI confirms that the cost of RNG, hydrogen, syngas and lignin is not itself a modelled critical uncertainty. The drivers for these fuels were modeled by providing the model with specific amounts of energy supplied by each fuel in each year. <u>The model replaced conventional natural gas with these amounts mechanically</u>, without regard for the cost of any of the fuels or the elasticity of demand.
>
> The reason that these costs are not a critical uncertainty is that the production, technologies and market for these fuels is still emerging and market data for these fuels is not available in the same way that it is for conventional natural gas. In addition, an independent variable is required to model alternative gas supplies. <u>If cost and supply for these fuels were both modelled as uncertainties, it would create a circular loop in the model, as costs and supply affect one another</u> […] While it is assumed that as the price of natural gas or carbon increases, demand for natural gas declines, that same assumption may not hold in the future with respect to low-carbon fuel. For example, a higher carbon price may increase demand and thus supply for these lower carbon fuels. However, the model lever used to model the change in demand for these fuels would likely be the same (adjusting fuel shares). [Emphasis added]

In response to BCUC IR 71.8.1, FEI provides a forecast of renewable and low-carbon gas supply and costs.

91.2 Please elaborate on the mechanical process of replacing natural gas with alternative fuels and provide a table showing how much natural gas is replaced by alternative fuels in scenarios where this replacement is applicable.

<u>Response:</u>

Posterity Group has provided the following response.

The Navigator software has a module designed to calculate the fuel shares that will result in the target amount of an alternative fuel for each year. For example, if the scenario includes 10 PJ of RNG and the consumption of natural gas in that year of the scenario is 200 PJ, 5 percent of the natural gas must be replaced by RNG in that year. For a fuel that is assumed to flow equally to all customers, Navigator must calculate RNG fuel shares for every building type and end use that are 5 percent of what the fuel shares for natural gas were before the change. Navigator iterates, trying larger and smaller fuel share changes, until it finds the fuel share changes that produce the desired 10 PJ of RNG. The new RNG fuel shares are then subtracted from the natural gas fuel shares, reducing the amount of natural gas to 190 PJ.

Some alternative fuels (for example, syngas and lignin) are not expected to flow equally to all customers. In these cases, Navigator is configured so that the target is applicable to only a subset of the model, such as certain specific end uses in the industrial sector. Then, the same iterative process is used to calculate new fuel shares for just those end uses and industrial segments.

The table below shows the amount of alternative renewable and low carbon fuels included in each scenario, in PJ per year. The amounts shown displace natural gas.

Year	Reference Case and Alternate Scenarios					
	Reference Case	DEP	Deep Electrification	Price-Based Regulation	Economic Stagnation	Upper Bound
	(PJ/Yr)					
2019	0.0	0.0	0.0	0.0	0.0	0.0
2020	0.3	0.3	0.3	0.3	0.3	0.3
2021	0.9	0.7	0.8	4.8	0.9	4.8
2022	3.4	5.8	3.3	9.5	3.4	9.6
2023	6.1	11.0	5.5	13.7	6.1	13.9
2024	8.0	16.3	5.9	21.3	8.0	21.7
2025	8.9	22.7	6.4	28.3	8.9	29.1
2026	9.8	29.5	6.6	35.7	9.9	37.1
2027	10.9	37.0	6.9	43.7	11.0	45.7
2028	11.1	44.6	7.1	50.8	11.2	53.5
2029	11.1	52.2	7.3	58.7	11.2	62.2
2030	11.2	60.2	7.5	66.4	11.3	70.7
2031	11.3	64.1	8.2	75.0	11.4	80.0
2032	11.4	68.0	8.8	83.4	11.6	89.3
2033	11.6	71.8	8.9	91.9	11.7	98.7
2034	11.7	75.7	7.9	100.4	11.8	108.3
2035	11.8	79.6	7.9	108.8	11.9	117.7
2036	11.9	83.5	7.9	117.1	12.0	127.1
2037	12.0	87.3	8.0	124.8	12.2	136.6
2038	12.2	91.2	8.0	132.5	12.3	146.0
2039	12.3	95.1	8.0	140.1	12.4	155.5
2040	12.4	99.0	8.0	147.6	12.5	165.1
2041	12.5	102.8	7.0	155.1	12.7	174.7
2042	12.6	106.7	7.1	162.7	12.8	184.3

91.3 Please explain why modelling both supply and cost of alternative fuels would create a circular loop.

91.3.1 Please discuss whether there are ways that this limitation could be overcome, for example, selecting a point estimate for both cost and supply of alternative fuels, and calculating a blended cost for conventional gas and alternative fuels.

91.3.2 If FEI were to model both supply and cost of alternative fuels, please discuss in detail the changes to FEI's demand forecast methodology and models that would be required. Please include in your answer a discussion of potential resource requirements, and any modelling limitations that would not be solvable.

Response:

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

Modelling two variables that interact with one another will cause a circular loop when a change in one of the variables (the first variable) causes a change in the other variable (the second variable), which then causes a further change in the first variable that results in further change to the second variable and so on. This modelling limitation can be overcome; however, if there is limited information for one of the variables, as is the case for renewable and low carbon gases for which the market is still emerging, the value of the results does not typically warrant the additional time and budget for doing so. If considered worthwhile, Posterity Group would recommend the following steps for overcoming the limitation of modelling these two variables that interact with one another.

The demand modeling includes the elastic response of energy demand to the price of fuel. If the amount of each alternative fuel is known in the scenario, it is relatively straightforward to calculate the weighted average avoided cost of the gaseous fuels. It is less straightforward to estimate how the retail rates would change in response but, as a simplification, they could be assumed to track the change in the weighted average avoided cost over the long term. The elastic response to the change in energy rates could then be calculated and implemented in the Navigator model.

Outside the Navigator model, a second model for the relationship between energy supply and the prices of the different alternative fuels would be needed. Then, for each year, a set of prices for the alternative fuels that cause the Navigator model to demand an amount of fuel that is equal to the amount of supply triggered by those prices would be needed.

If the price of fuel is too high, the amount of supply predicted by the supply model would be higher than the amount of demand predicted by the Navigator model. If the price of fuel is too low, the amount predicted by the supply model would be lower than the demand predicted by the Navigator model. The modeling process would have to iterate between the models until the set of prices caused them to align.

This procedure is a possible modeling solution to the noted limitation but would be challenging. The market for supply of alternative fuels is not a mature one, and any model of the relationship of supply and fuel price would be somewhat speculative. The relationship between avoided costs and rates is very complex and would likely need to be highly simplified in the model. At this time and without actually implementing this modeling change, Posterity Group and FEI have not identified other modelling limitations that would not be solvable, but do not consider that the results of such an exercise would have much utility given the current early stages of the renewable and low carbon gas market.

Finally, at this time, the time per iteration would be measured in hours, particularly if DSM is included in the modeling. Possibly, DSM could be turned off until the last few iterations, but it is still likely to be an expensive and time-consuming process. It is difficult to estimate the total time to implement this approach without having worked with the supply-side model. As a rough estimate, it is likely to take at least one person-week per scenario. In contrast, the current process takes a few hours of set-up time per scenario and then runs in a matter of seconds.

91.4 Please discuss whether the increased supply of alternative fuels would be reasonably expected to increase the combined cost of gas delivered to customers. Please include a discussion of the extent to which the cost is expected to change in each of FEI's load scenarios.

Response:

FEI agrees that an increased supply of alternative fuels, which would be on average at a higher price than conventional natural gas, would reasonably be expected to increase the combined cost of gas delivered to customers. This was considered in the modelling for the LTGRP. Please refer to Attachment 75.4.1 in the response BCUC IR1 75.4 for the 20-year cost of energy modelled for each scenario and the extent to which the costs might change between the scenarios.

As discussed in the response to MetroVan IR1 2.1.1, the rate impact analyses shown in Section 9.4 of the Application used the weighted-average cost of energy ($ per GJ), which is based on the different mixes of conventional natural gas and renewable and low-carbon gas depending on the different load scenarios. Therefore, the weighted-average cost of energy ($ per GJ) will be different (and expected to change) in each of FEI's load scenarios to the extent that the different amounts of renewable and low carbon gas change in each scenario.

91.4.1 Given the price elasticity of demand, please explain whether FEI's treatment of alternative fuels in the demand forecast methodology may result in an overestimate of annual demand. Please include a discussion for each of FEI's load scenarios.

Response:

FEI considers that there is equal likelihood that its treatment of alternative fuels in the demand forecast methodology has resulted in an overestimate or an underestimate of annual demand, and that as such, its forecast method in this regard is appropriate. As explained in the response to BCUC IR1 27.5 and referenced in the preamble above, the market data for these emerging alternative fuels is not yet available in the same way that it is for conventional natural gas. Therefore, the price elasticity discussed in the response to BCUC IR1 27.4 and also referenced in the preamble above, might not be applicable for the alternative low-carbon fuels. As noted in the response to BCUC IR1 27.5, the same assumption that increasing the price of natural gas will lead to a decline in the use of natural gas may not hold in the future with respect to low-carbon fuel. For example, the price of carbon, which could be in the form of tax or other societal costs, may increase demand for the alternative low-carbon fuel regardless of the price.

If the assumption is that the same price elasticity for natural gas is applicable to alternative low-carbon fuel in the future, then yes, the demand forecast methodology used in this Application might result in a certain degree of overestimation. However, as shown in the tables provided in the response to BCUC IR1 71.8.1, all of FEI's load scenarios involve certain levels of alternative fuels such as RNG, hydrogen, syngas, and lignin; therefore, to a certain extent, the overestimation or underestimation of annual demand would apply to all load scenarios, including the DEP, Deep Electrification, Reference, and Upper Bound scenarios. As such, FEI does not expect this possibility would substantially change other outcomes of the LTGRP.

91.4.2 Please discuss whether FEI has undertaken any analysis to model the elasticity of demand associated with the increased supply of alternative fuels.

Response:

No, FEI has not undertaken any further analysis to model elasticity of demand associated with increased supply of alternative fuels, nor does FEI consider such analysis to be appropriate at this time. As explained in the response to BCUC IR1 27.5, the market data for the alternative (low carbon) fuels is not yet available in the same way that it is for conventional natural gas. As such, FEI does not consider that such an undertaking would provide any degree of certainty or accuracy. Please also refer to the response to BCUC IR2 91.4.1 for further discussion about overestimation of annual demand related to price elasticity.

FEI also considers that an important indicator of customer reaction to higher cost renewable and low carbon gas is the cost of the next available substitute, which is clean and renewable electricity rather than conventional natural gas. This involves the concept of cross-price elasticity of demand for which there is very little research available in the energy industry. Even if cross-price elasticity values existed between the cost of renewable and low carbon gas and the cost of clean and renewable electricity, FEI does not have fully and transparently developed costs for meeting future clean and renewable electricity demand across BC and so could not conduct such an analysis.

91.5 Using the price elasticity values outlined in BCUC IR 27.4, please provide an illustrative analysis which shows the demand impact associated with applying the weighted average cost of FEI's forecast of renewable and low-carbon gas supply and costs, as outlined in BCUC IR 71.8.1. Please provide analysis for all scenarios in 2030 and 2042, and explain any assumptions made.

91.5.1 Please provide a discussion of the results.

Response:

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

FEI and Posterity Group do not consider that applying price elasticities in the manner suggested in this IR is an appropriate method for estimating the load change driven by changes in the price of renewable and low carbon gas for the following reasons:

- As explained in FEI's BERC Rate Methodology and Comprehensive Review of a Revised Renewable Gas Program (RG Program Application) proceeding,[12] the supply and demand for RNG are matched by design, irrespective of the price elasticity estimates for RNG. Further, FEI agreed with the Brattle Group that price is not the only determinant for renewable gas demand. Renewable gas demand stems from its environmental attributes and customers' desire to reduce their GHG emissions. Demand for low carbon fuels is also heavily influenced by government policy and its strategy to reach the legislated GHG reduction targets. Therefore, only relying on price elasticity numbers to forecast a decrease in demand would lead to erroneous conclusions.
- FEI and Posterity Group expect that at some unknown point or points, the price elasticities will change as prices continue to increase. Some factors that come into play are:
    - At some unknown inflection point, customers will begin to examine alternatives and energy purchase decisions which begin to be based on cross-price elasticities between energy substitutes (namely, renewable and low carbon gas versus clean and renewable electricity).
    - Very little is known about cross-price elasticities, the effect of switching costs, and the influence of market interference by government and utilities, making it difficult to model these effects.
    - After overcoming the above issues, both future clean electricity costs and future renewable and low carbon gas costs would need to be examined on an equal footing in order to obtain useful results from such an analysis.

To fully undertake the requested analysis would require weeks of work and would not provide reliable results for the reasons listed above.

[12] Exhibit B-66, FEI's BERC Rate Methodology and Comprehensive Review of a Revised Renewable Gas Program, FEI Rebuttal Evidence to the My Sea to Sky and the Brattle Group Evidence Regarding Elasticity of Demand, pp. 2-3, 6-7.

Illustratively (and logically), applying higher cost gas (regardless of the type of gas) within the current demand forecast method using the same price elasticity values as those used in the 2022 LTGRP will result in lower demand outcomes than those presented in the 2022 LTGRP. As described above, prescribing any weight to such an outcome in the absence of more information about the renewable and low carbon gas market, complete and transparent costs for future clean and renewable electricity and reliable cross price elasticity values between the two alternatives would be inappropriate.

In response to BCUC IR 27.7, FEI states:

> The prices of renewable or low-carbon fuels did not factor into price-driven fuel switching, because their introduction was handled in other, dedicated critical uncertainties. The interaction between prices of multiple fuels would have been a very complex, iterative modeling problem and would have involved estimating elasticities that are not available in the literature. Instead, the supply amounts of these gases were modelled as critical uncertainties and their prices were not.

91.6 Please explain which dedicated critical uncertainties, if any, were used to introduce the prices of renewable or low-carbon fuels.

Response:

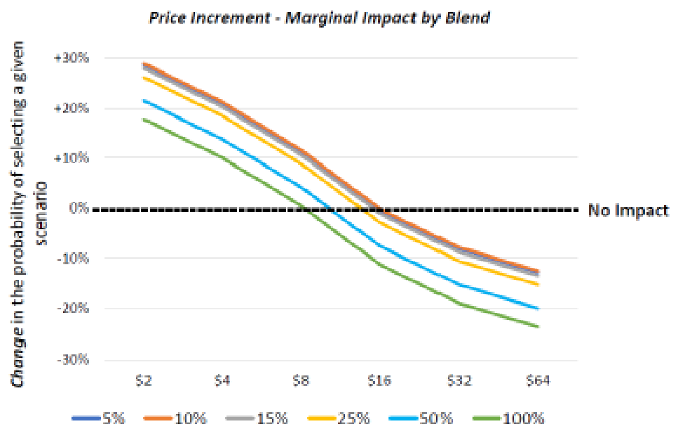
The following response was provided by Posterity Group.

No dedicated critical uncertainties were used to introduce the prices of renewable or low-carbon fuels. The introduction of the *fuels* was handled in dedicated critical uncertainties. In the response to BCUC IR1 27.7, the word “their” in the first sentence above refers back to the word “fuels” not to the word “prices.”

On pages 48-49 of the Brattle Independent Expert Report, Brattle stated:

> Only in recent years has RNG played a role in fully or partially displacing customer’s natural gas supplies. As such, we are not aware of peer-reviewed academic studies that estimate the price elasticity of RNG. The current body of evidence primarily comes from utilities with RNG programs. For example, FEI conducted a survey of current and potential FEI Renewable Gas Program customers, where the company evaluated the willingness of potential Voluntary Renewable Gas Customers to choose various blending percentages, based on a given price increment above the cost of natural gas. The results of the study are replicated graphically in Figure 19 below.

FIGURE 19: PRICE INCREMENT – MARGINAL IMPACT BY BLEND
(Replication of FEI Figure in Appendix B-1)



Further, on page 50 of the Brattle Independent Expert Report, Brattle stated:

> FEI and Innovative Research Group conducted a second survey to evaluate FEI's Renewable Connections Program. The survey asked participants their level of support for requiring 100% RNG purchase for new buildings based on different RNG prices ($4/GJ, $8/GJ, $16/GJ, or $32/GJ which equates to $24, $48, $96, and $192 per month, respectively). The survey results are replicated in Figure 20 below. The study found that the level of support for a 100% RNG requirement in new buildings declines after $4/GJ. This finding broadly supports the findings from the Voluntary Renewable Gas Program—that beyond a certain premium (in this case $48 per month), the willingness to enroll in a 100% RNG blend turns negative.

FIGURE 20: PRICE SENSITIVITY FOR REQUIRING RNG IN NEW BUILDINGS[220]
(Replication of FEI Figure in Appendix B-1, p. 14)

BC Adults

Price Shown	Pre-post change in net support
Additional $24 per month [n=389]	+11%
Additional $48 per month [n=362]	-11%
Additional $96 per month [n=367]	-14%
Additional $192 per month [n=382]	-29%

RNG Customers

Price Shown	Pre-post change in net support
Additional $24 per month [n=121]	+4%
Additional $48 per month [n=134]	0%
Additional $96 per month [n=127]	-15%
Additional $192 per month [n=119]	-53%

Small Business Customers

Price Shown	Pre-post change in net support
Additional $113 per month [n=44]	+17%
Additional $227 per month [n=42]	-14%
Additional $453 per month [n=41]	-19%
Additional $907 per month [n=48]	-30%

*Note: Results in blue/red significant at 95% confidence

91.7 Please explain to what extent FEI would be able to consider the price sensitivity for requiring RNG in new buildings, to inform the demand forecast. In the response, please also describe the high-level impact of the price sensitivity of RNG on the demand forecast.

91.7.1 In the development of any future LTGRP, please discuss how FEI could consider the price sensitivity of RNG in its forecasting method.

Response:

Given the limitations described in the responses to BCUC IR2 91.3 and 91.5, FEI does not consider that it should change the way it applies price sensitivity to RNG in its long-term demand forecast and cannot provide further insights regarding a high-level impact of such price sensitivity at this time.

The price sensitivity of RNG demand to the premium paid over the conventional natural gas discussed in the preamble is aligned with FEI's position that RNG and conventional natural gas are substitutes and, therefore, have a relatively high cross-elasticity of demand. This means that if the price differential between RNG and conventional natural gas is more than a certain threshold, RNG voluntary demand would decrease. Nevertheless, as discussed in the response to BCUC IR2 91.5, under FEI's rate proposal, the supply and demand for RNG are matched by design irrespective of the price elasticity estimates for RNG. This is because if RNG supply does not flow to the Renewable Gas Connections or Voluntary Renewable Gas service customers, FEI has proposed to increase the percentage of RNG for the Renewable Gas Blend service charged to all customers.

92.0 Reference: LONG TERM ANNUAL GAS DEMAND FORECAST METHODS

Generic Cost of Capital Proceeding, FortisBC Reply Argument; Exhibit B-1, Section 4.1, Section 4.8

Reference Scenario and Upper Bound Scenario

On page 23 of FEI's Reply Argument for the Generic Cost of Capital (GCOC) proceeding, FEI states:

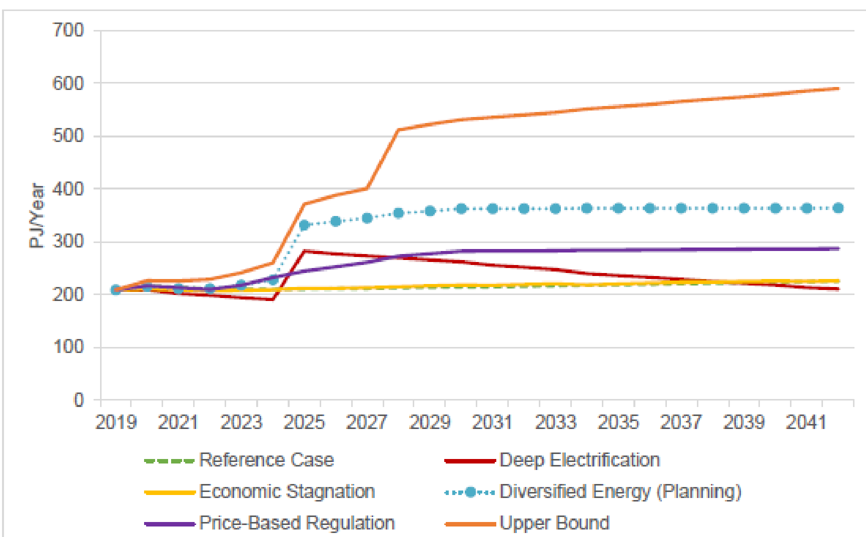
> CEC says the BCUC should find FEI has similar demand/market risk as 2016 based on […]The Diversified Energy (Planning) Scenario is FEI's planning scenario and is reflected in FEI's GCOC evidence. The <u>Reference Case and Upper Bound Scenarios are implausible</u>. The Reference Case Scenario assumed that "critical uncertainties", such as political policy and economic conditions, remain as they were in 2019, throughout the 20-year planning horizon. […] [emphasis added]

On page 4-40 of the Application, FEI states:

> <u>The End Use Annual Method forecast process starts with developing a Reference Case forecast</u>. The Reference Case is based on end use patterns observed, as well as any new changes in law or policy that will affect future demand and have been, or are quite certain of becoming, enshrined in legislation, codes, standards or bylaws in and as of the base year. [Emphasis added]

On page 4-40 of the Application, FEI shows the total annual demand graph and states:

Figure 4-20: Total Annual Demand Including LCT – All Categories, All Scenarios



> FEI's Upper Bound scenario models all critical uncertainties set to increasing gas demand, including the highest setting for potential CNG and LNG demand growth as well as both the Woodfibre LNG project and a second generic industrial facility of similar annual demand to that of Woodfibre LNG project. These two industrial

> load additions cause the large step-change demand increases that can be seen in Figures 4-18 and 4-20. FEI has not assumed that it would need to acquire gas supplies to serve these industries, but uses the results of Upper Bound scenario to understand the implications of these types of demand increases and thus to monitor for indications that these types of demand increases might be unfolding. In this way, the Upper Bound scenario provides important information for consideration in planning FEI's infrastructure. [Emphasis added]

Further, on page 4-2 of the Application, FEI writes:

> Section 4.6 presents the demand forecast results for each of the demand categories described above. This section also explains that the amount of electrification that has been modelled in the Deep Electrification and Lower Bound scenarios is determined to be not plausible and presents the context for limiting their further consideration within the 2022 LTGRP. [Emphasis added]

92.1 Please clarify whether FEI considers the Reference case and Upper Bound Scenario implausible.

92.1.1 If not, please reconcile the statements in FortisBC Reply Argument in the GCOC Proceeding and the 2022 LTGRP as noted in the preamble.

Response:

FEI's argument in the GCOC Proceeding needs to be understood in the context of FEI's response to the CEC's argument that the BCUC should find that FEI has similar demand/market risk as 2016 based on the 2022 LTGRP Reference Case and Upper Bound Scenarios. For reference, below is the full paragraph from FEI's reply argument:

> CEC says the BCUC should find FEI has similar demand/market risk as 2016 based on the Reference Case and Upper Bound scenarios in the FEI's 2022 Long Term Gas Resource Plan ("LTGRP") proceeding. However, these two scenarios are not the basis for FEI's system planning. FEI developed a range of six alternate future scenarios to model different ways the future could potentially impact the amount of demand. The Diversified Energy (Planning) Scenario is FEI's planning scenario and is reflected in FEI's GCOC evidence. The Reference Case and Upper Bound Scenarios are implausible. The Reference Case Scenario assumed that "critical uncertainties", such as political policy and economic conditions, remain as they were in 2019, throughout the 20-year planning horizon. The Upper Bound Scenario assumes that the BC economy experiences higher-than-average growth, with the government moving away from its focus on climate policy and towards continued extraction infrastructure development in BC. FEI's evidence in this proceeding on demand/market risk is consistent with the LGTRP. [Emphasis added. Footnotes omitted]

In the context of the GCOC Proceeding, business risk (which includes demand/market risk) is evaluated from the perspective of a reasonable and well-informed investor, based on what they expect will happen in the future. In contrast, the alternate future scenarios in the LTGRP model different ways the future could potentially impact the amount of demand.

The Reference Case essentially represents the continuation of the status quo as of 2019. As many of these conditions have in fact already changed and are unlikely to revert to pre-2019 conditions, the Reference Case is not a plausible forecast of the political and economic conditions over the 20-year planning horizon upon which a reasonable investor would base an assessment of business risk. Therefore, the Reference Case demand forecast is an important reference point for the scenario analysis in the LTGRP, but it does not support CEC's notion that FEI's demand/market risk has not changed since 2016.

Similarly, the Upper Bound Scenario represents the theoretical maximum annual demand and is used to create the upper boundary that frames the scenario analysis. FEI does not plan for the Upper Bound Scenario but uses it to understand the implications of various types of demand increases and to monitor for indications that these types of demand increases might be unfolding. As FEI states in its reply argument in the GCOC Proceeding, the Upper Bound "assumes that the BC economy experiences higher-than-average growth, with the government moving away from its focus on climate policy and towards continued extraction infrastructure development in BC." The Upper Bound Scenario is an important reference point from a resource planning perspective, but it is not a plausible scenario from the perspective of an investor.

Furthermore, from a resource planning perspective, FEI does not consider the level of demand resulting from either the Reference Case or the Upper Bound Scenario to be implausible in the same way that the Lower Bound and Deep Electrification levels of demand are implausible, as described in Section 4.6.1.1 of the Application. In this regard, please refer to the responses to BCUC IR1 30.2.1 and 30.3.

93.0 Reference: LONG TERM ANNUAL GAS DEMAND FORECAST METHODS

Exhibit B-6, BCUC IRs 28.1; Exhibit B-17, BCUC IR 12.2.1, 12.2.2; FEI Natural Gas Rates; Exhibit B-1, Appendix B-5 (Annual Demand Forecast Results, Excel Spreadsheet); FEI BERC Rate Proceeding, Exhibit A4-2-1, Section III.B

Biomethane Energy Recovery Charge Rate

In response to BCUC IR 28.1 regarding the assumption of Renewable Gas Connections service, FEI explains:

> The approval or not of FEI's Renewable Gas Connections service was not a modelled critical uncertainty in the 20-year demand forecasts for the 2022 LTGRP. Rather, the extent to which electrification might occur over the next 20 years (which could be partly determined by the final decision on the Renewable Gas Connections service) was modelled as a critical uncertainty. <u>FEI considers that the DEP Scenario is more akin to a scenario where the service is approved, whereas the Deep Electrification Scenario is more akin to a future where the service is not approved</u>. [Emphasis added]

In response to BCUC IR 12.2.1 in the FEI BERC Rate proceeding (Exhibit B-17), FEI states:

> In a scenario which assumes that provincial building stock turnover is approximately 2 percent per year and none of those new buildings connect to the gas system, resulting in FEI losing 2 percent of its residential and commercial customers per year, FEI could expect the total volume of gas sold to residential and commercial customers to be 20 PJ or 18 percent lower than it would be if the Renewable Gas Connections service were approved.

93.1 If the Renewable Gas Connections service were not approved, please clarify whether FEI considers that FEI's future demand is likely to be aligned with the Deep Electrification scenario.

93.1.1 If yes, please explain in more detail.

93.1.2 If no, please further explain the anticipated directional and order of magnitude impact upon load compared to the DEP scenario.

<u>Response:</u>

It is not possible to predict with certainty the resulting changes in customer additions, losses or demand if the Renewable Gas Connections service were not approved. However, if this were to occur, FEI's future demand would not be aligned with the Deep Electrification Scenario.

If the Renewable Gas Connections service is not approved, then FEI would likely be precluded from offering gas service to new residential and commercial customers in municipalities where

GHG intensity metrics have been adopted, such as through the opt-in Zero Carbon Step Code. However, FEI would continue to be able to serve some new customers with conventional natural gas in municipalities that do not adopt GHG intensity requirements.

Since the approval or not of FEI's Renewable Gas Connections service was not a modelled critical uncertainty in the 20-year demand forecasts for the 2022 LTGRP, FEI draws on the following analysis provided by FEI in the RG Program Application proceeding.[13] In that analysis, a "worst-case scenario" for the potential loss in load that might result from a denial of that application was assessed to be a 2 percent loss in residential and commercial load per year, based on an estimated provincial building stock turnover of approximately 2 percent per year and none of those new buildings being connected to the gas system. This analysis does not represent the DEP Scenario modelled in the LTGRP, but is based on the demand forecast for the DEP Scenario.

Table 1 below shows the 10-year load forecast based on the DEP Scenario, while Table 2 below shows the same load forecast with a 2 percent loss of residential and commercial customer count per year reflecting the inability of FEI to add new customers. FEI has omitted Rate Schedule 23, which serves large commercial transport service customers, from the table below, because these customers are not affected by the RG Program Application.

Table 1: 10-Year Load Forecast based on Diversified Energy (Planning) Scenario for Residential and Commercial Customers (Post-DSM)

Rate Schedule	Category	Unit	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
RS 1	Residential	TJ	69,752	68,319	67,077	65,896	64,762	63,675	62,673	61,746	60,769	59,831
RS 2	Small Commercial	TJ	30,163	30,112	30,034	29,968	29,853	29,708	29,626	29,615	29,430	29,269
RS 3	Large Commercial	TJ	27,314	27,267	27,197	27,138	27,033	26,902	26,828	26,818	26,650	26,504
	Total	**TJ**	**127,229**	**125,698**	**124,308**	**123,003**	**121,649**	**120,285**	**119,128**	**118,179**	**116,848**	**115,604**

Table 2: 10-Year Load Forecast based on Diversified Energy (Planning) Scenario Demand Forecast with Two Percent loss of Residential and Commercial Customer Counts per Year (Post-DSM)[14]

Rate Schedule	Category	Unit	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
RS 1	Residential	TJ	65,503	62,441	59,702	57,133	54,711	52,429	50,307	48,328	46,388	44,551
RS 2	Small Commercia	TJ	28,939	27,982	27,036	26,136	25,228	24,329	23,510	22,773	21,934	21,140
RS 3	Large Commercia	TJ	26,205	25,339	24,482	23,668	22,845	22,031	21,289	20,622	19,862	19,144
	Total	**TJ**	**120,647**	**115,761**	**111,220**	**106,936**	**102,784**	**98,788**	**95,107**	**91,723**	**88,183**	**84,835**

The difference between Table 1 and Table 2 is an annual load reduction of approximately 31,000 TJ by 2032 which represents the "worst-case scenario" outcome if the RG Program Application is not approved. Based on Post-DSM analysis, the Deep Electrification Scenario represents an

[13] FortisBC Energy Inc. (gas) Biomethane Energy Recovery Charge Rate Methodology and Comprehensive Review of a Revised Renewable Gas Program**,** Exhibit B-17, BCUC IR1 12.2.2 and Exhibit B-42, BCUC IR2 53 and 54 series.

[14] FortisBC Energy Inc. (gas) Biomethane Energy Recovery Charge Rate Methodology and Comprehensive Review of a Revised Renewable Gas Program**,** Exhibit B-42, BCUC IR2 53.3.

even greater annual load reduction for all residential and commercial demand of approximately 41,000 TJ by 2032 over the DEP Scenario as modelled in the LTGRP[15]. Note that the DEP Scenario modelled in the LTGRP includes a portion of electrification of existing load beyond electrifying new construction and demolition rebuilds.

93.2 If the Renewable Gas Connections service were not approved, please outline the demand impact of applying 2% yearly customer losses and 18% decline in gas sold to residential and commercial customers are to the Diversified Energy Planning scenario.

Response:

FEI used two methodologies to illustrate a range of "worst-case scenario" demand impacts of applying a 2 percent residential and commercial customer loss, if the RG Program Application is not approved, using the assumptions described below:

- The 20 PJ estimated annual demand reduction by 2032 illustrated in the response to BCUC IR1 12.2.1 in the RG Program Application proceeding, as described in the preamble, was a high-level calculation based on using FEI's 2022 annual demand from the 2022 Annual Review (for residential and commercial customers). A two percent customer loss was applied, while all other factors remained constant.
- The 31 PJ estimated annual demand reduction by 2032 illustrated in the response to BCUC IR2 93.1 was based on the DEP Scenario where UPC declines over time based on changes in equipment efficiencies, the incorporation of DSM, some electrification and all other related factors in LTGRP modeling.

93.2.1 Please discuss whether FEI considers this a reasonable approximation of the demand impact of a scenario where the Renewable Gas Connections service is not approved.

Response:

FEI considers this to be an estimate of the worst-case scenario if the Renewable Gas Connections service were not approved. Please also refer to the response to BCUC IR2 81.2 for an estimate of the impact of applying the accelerated setting to the codes and standards critical uncertainties.

[15] Data derived from Post-DSM demand analysis was discussed in Section 5 of the Application.

This provides another reference point for the potential impact of not approving the Renewable Gas Connections service.

93.3 Please discuss the main drivers of declined annual gas demand in the Deep Electrification scenario relative to the Diversified Energy Planning scenario.

Response:

The main driver of declining annual gas demand in the Deep Electrification Scenario relative to the DEP Scenario is non-price driven fuel switching. Please refer to the response to BCUC IR2 81.2.1 for further discussion.

94.0 Reference: DEMAND FORECASTING

Exhibit B-1, p. 3-24, 4-16; Exhibit B-6, BCUC IR 33.1, 33.3, 33.7, 33.8, 33.9; Exhibit B-9, BCOAPO IR 3.1

Low-Carbon Transportation and Global LNG Demand Category

In response to BCUC IR 33.1, FEI states:

> Please see the below table showing the total CNG committed volumes up to the period of 2031. All current CNG contracts range from 3 to 8 years and currently there are no current contracts that extend past 2031. These committed volumes represent the minimum annual load a customer is required to purchase; however, customers often consume significantly more than their minimum. For example, in 2021, the total committed load was approximately 0.3 PJs, and actual consumption from the same customers was approximately 1.4 PJs.

Year	CNG Committed Load Volume (PJ)
2022	0.3104
2023	0.2309
2024	0.1819
2025	0.1534
2026	0.1059
2027	0.0821
2028	0.0757
2029	0.0635
2030	0.0295
2031	0.0155

94.1 Please provide a table showing the total CNG committed volume, total actual CNG demand and number of CNG customers by year for the past 5 years.

Response:

The following table shows the total CNG committed volume, total actual demand volume and number of CNG customers for the past five years.

Historical CNG Data (2017-2021)			
Year	Committed Volume (GJ)	Total CNG Demand (GJ)	No. of CNG Customers
2021	349,856	1,432,356	61
2020	278,231	943,984	42
2019	269,628	909,120	33
2018	247,328	869,813	31
2017	227,822	795,116	27

FEI notes that the committed volume data is estimated based on historical billing data.

94.1.1 Please discuss the trends to date in CNG committed volume, total actual CNG demand and number of CNG customers and FEI's views as to the reasons for the trends.

Response:

Please refer to the table provided in the response to BCUC IR2 94.1, which shows that the total CNG demand and number of CNG customers continue to grow year over year, highlighting the success of FEI's CNG service. Committed volumes as a percentage of total CNG demand have also increased but remain about 40 percent of total CNG demand. The table also highlights the importance that CNG has played in helping to decarbonize BC's transportation sector by displacing diesel fuel in on-road transportation uses, with total demand of over 1.4 PJ in 2021.

In response to BCUC IR 33.3, states:

Please see the below table summarizing all LNG committed volumes. FEI interprets "commitment" in this IR to mean "contracted". The majority of LNG customers are currently on contracts that automatically renew each year pursuant to section 16.2 of FEI's Rate Schedule 46 (RS 46), and the customer may terminate their contract with two months' notice prior to the end of the contract year. These LNG customers have made significant investments in LNG vessels, and FEI expects this load to continue for many years, even though their contractual commitments do not extend beyond the standard annual renewal requirements of RS 46. Given the short-term contractual commitment of these contracts, there are minimal risk factors that will impact the customers' ability to satisfy their commitments.

Year	LNG Commitment (PJ)
2022	1.3104
2023	1.2751
2024	0.035
2025	0.035

94.2 Please provide a table showing the total LNG contracted volume, total actual LNG demand and number of LNG customers by year for the past 5 years.

Response:

Please see the historical LNG data table below.

Historical LNG Data (2017-2021)			
Year	Committed Volume (GJ)	Total LNG Demand (GJ)	No. of LNG Customers
2021	1,410,676	1,514,540	13
2020	1,401,129	1,692,018	12
2019	1,130,730	1,640,376	15
2018	790,061	1,264,398	26
2017	697,008	980,977	22

FEI notes the committed volume data is estimated based on historical billing data.

94.2.1 Please discuss the trends to date in LNG contracted volume, total actual LNG demand and number of LNG customers and FEI's views as to the reasons for the trends.

Response:

Please refer to the table provided in the response to BCUC IR2 94.2, which shows that the total LNG demand has increased significantly overall, but was slightly reduced in 2021, and the number of customers has been decreasing from a peak of 26 in 2018 to 13 in 2021. FEI attributes these trends to increased LNG demand for two customers in the short sea marine sector, which is a large portion of the load, and the lack of available on-road high horsepower engines, which has reduced the number of on-road customers and has reduced the LNG demand slightly. On-road customers are typically lower volume customers, and so the impact on LNG demand is not as pronounced as the impact on customer numbers. The table also highlights the importance that LNG has played in helping to decarbonize BC's transportation sector by displacing diesel fuel in on-road transportation uses by upwards of 1.5 PJ over the last three years.

In response to BCUC IR 33.7, FEI provided a table showing the assumptions made for each of FEI's LNG Demand Forecast Settings and the approximate annual load impact between the Forecast Settings in the year 2040 as follows:

Parameter		LNG Demand Forecast Setting			
		Reference	Low	Planning	High
On Road: Customer Demand		Current contracted customer demand only	Current contracted customer demand only	Current contracted customer demand only	Current contracted customer demand contract renewal and new customers
On Road: GGRR Provision Extensions		GGRR provisions extended beyond 2030	GGRR provisions not extended beyond 2022	GGRR provisions extended beyond 2030	GGRR provisions extended beyond 2030
On Road: Technology Advancements		No significant technology advancements	No significant technology advancements	No significant technology advancements	Technological advancement of the high horsepower (400HP) and engine is available to the on-road market
	On Road: Load Impact in 2040 (PJ)	0	0	0	0.1
Short Sea Marine Market Growth		Increased LNG vessel adoption by short sea customers	Limited LNG vessel adoption by short sea customers	Increased LNG vessel adoption by short sea customers	Increased LNG vessel adoption by short sea customers
	Load Impact in 2040 (PJ)	3	2	3	3
Marine Bunkering Jetty (Transpacific Shipping)		No adoption of LNG for Marine Bunkering Jetty	No adoption of LNG for Marine Bunkering Jetty	Adoption of LNG for Marine Bunkering Jetty - Jetty is built and transpacific vessels utilize LNG	Adoption of LNG for Marine Bunkering Jetty - Jetty is built and transpacific vessels utilize LNG with slightly increased demand
	Load Impact in 2040 (PJ)	0	0	53	70
Remote Power and Mining Industry Growth		Limited to no growth	Limited to no growth	Forecasted Mine and Remote Power industry growth	Slightly higher Forecasted Mine and Remote Power industry growth
	Load Impact in 2040 (PJ)	0	0	4	7

Parameter		LNG Demand Forecast Setting			
		Reference	Low	Planning	High
EGP Project Completion		Not completed	Not completed	EGP completed resulting in increased load	EGP completed resulting in increased load
	Load Impact in 2040 (PJ)	0	0	95	95
Other Large Industrial Load (LNG Facility)		Not completed	Not completed	Not completed	Other Large Industrial Load (LNG Facility) of 95PJ
	Load Impact in 2040 (PJ)	0	0	0	95
ISO Export Market Growth		Limited to no Growth	Limited to no Growth	Steady ISO Export Market Growth	Increased ISO Export Market Growth
	Load Impact in 2040 (PJ)	0	0	6	16
Total LNG Load Forecast (PJ)		3	2	161	286

In response to BCUC IR 33.8, FEI discussed the basis for the LNG forecast assumptions. As part of this response, FEI states:

> All of these parameters were assessed based on FEI's understanding of the LNG market, discussions with LCT customers and prospects, and historical experience in the market when developing the demand forecast settings.

94.3 Please describe in detail the basis for FEI's assumptions for LNG demand in the marine bunkering sector, and how the load impact of 53 PJ for the planning setting and 70 PJ for the high setting in 2040 was determined. In your response, please include how discussions with customers or prospective customers and FEI's experience in the market has informed this forecast.

Response:

FEI's marine bunkering forecast is based primarily on the Port of Vancouver (PoV) Study, filed confidentially with the BCUC on February 24, 2023.[16]

- The Planning Setting relies on the PoV Study Base Case forecast and assumes that the Tilbury Marine Jetty will be built and will be utilized by the trans-pacific customer segment. As trans-pacific customers utilize the Tilbury Marine Jetty, FEI expects that there will be an increase in consumption volumes for this segment.
- The High Setting relies on the PoV Study High Case forecast where FEI expects that the utilization rate and adoption rate is higher that the Planning Setting, further increasing consumption volumes.

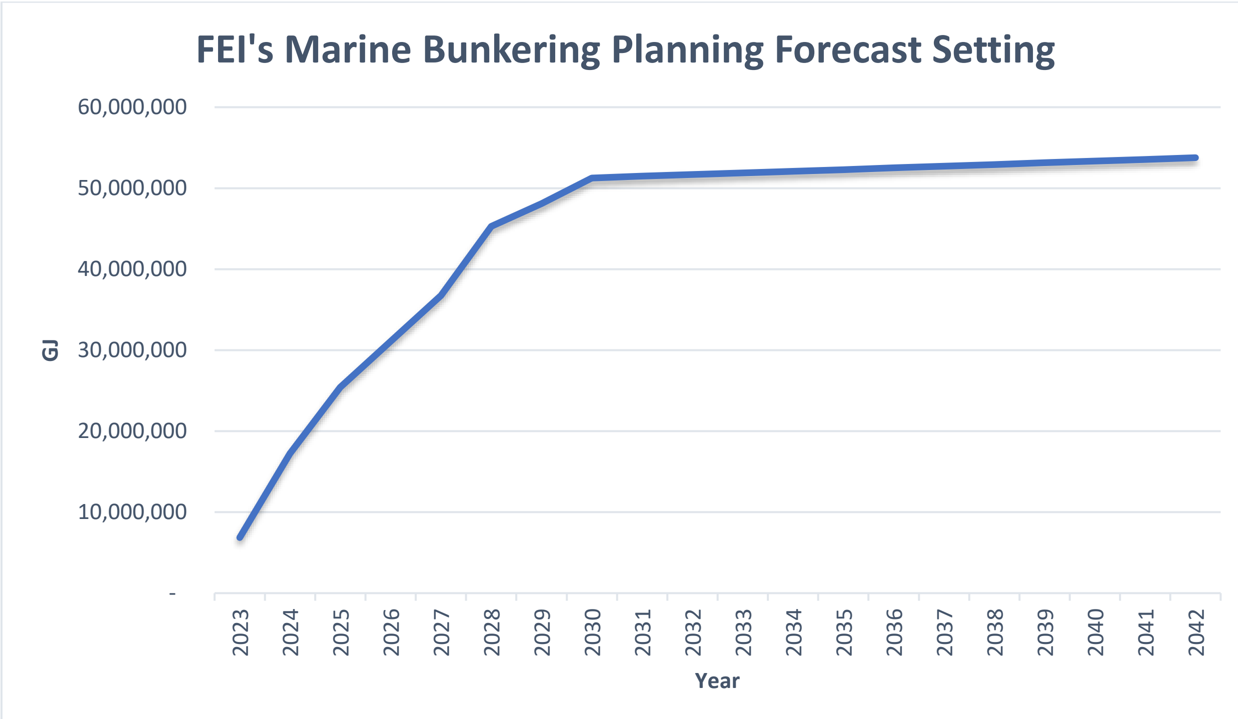
In both cases, FEI extrapolates the data to create an annual forecast, as the PoV Study only includes annual forecast data for 2023, 2025 and 2030. The data in the PoV Study aligns with FEI's discussions with customers and prospective customers on the potential for the Port of Vancouver's opportunity to provide LNG bunkering services. FEI considers that the PoV Study represents a reasonable forecast range for the LNG marine bunkering potential in the Port of Vancouver.

94.3.1 If possible, please provide FEI's forecast of LNG demand for the planning horizon of the LTGRP in graphical form solely from the marine bunkering sector.

Response:

The following figure illustrates the marine bunkering forecast in the Planning Setting.

[16] Exhibit B-21.



94.4 Please describe in detail the basis for FEI's assumptions for LNG demand in the remote mining and industry load sector and how the load impact of 4 PJ for the planning setting and 7 PJ for the high setting in 2040 was determined. In your response, please include how discussions with customers or prospective customers and FEI's experience in the market has informed this forecast.

Response:

In the planning forecast setting, FEI estimates that there will be growth starting in 2024 which will steadily increase until the end of the forecast period, reaching 4 PJ in 2040. Similarly, for the high forecast setting, FEI expects that there will also be growth in the industry starting in 2024, but annual growth will be higher until the end of the forecast period, reaching 7 PJ in 2040. FEI considers the LNG demand forecast for the remote power and mining industry represents a reasonable range of outcomes for the sector.

FEI's forecasts are based on its understanding of customer demand requests and an estimate of the potential opportunity. FEI has had numerous discussions with customers and the industry stakeholders on the future of the remote mining and power industry sector, which have informed its forecast assumptions. Based on these discussions, the main factors considered in the forecast are dependent on technology, pricing, and infrastructure. Technology advancements for LNG fueled mining vehicles are important for demand to be possible in this industry. With increased availability and advancement of LNG powered mining vehicles, there will be an increased demand in the industry. Similarly, pricing is an important factor as these vehicles and projects need to be reasonably economic in order to compete with diesel. Lastly, infrastructure is needed to support the provision of LNG fuel for remote regions.

94.5 Please describe in detail the basis for FEI's assumptions for LNG demand in the ISO Export Market sector and how the load impact of 6 PJ for the planning setting and 16 PJ for the high setting in 2040 was determined. In your response, please include how discussions with customers or prospective customers and FEI's experience in the market has informed this forecast.

Response:

The ISO Export Market forecast demand is impacted by global LNG demand and price fluctuations, geo-political conditions, international shipping costs and accessibility. FEI is currently in discussions with a number of current and prospective customers that have future plans for LNG export, which have informed the forecast. However, FEI has tempered the impact of customer plans on forecasted demand. In FEI's experience with this market, not all of these plans will materialize into actual demand. In the Planning Scenario, the ISO Export Market forecast load increases to 6 PJ in 2040. This is equivalent to approximately 6,000 ISO containers of LNG per year, or roughly 16 ISO per day, representing about 25 percent of the total loading capacity at the Tilbury plant. In the High Scenario, the ISO Export Market forecast load increases to 16 PJ of demand in 2040, representing about 90 percent of the loading capacity at Tilbury.

In response to BCUC IR 33.9, FEI provided risk factors that may affect the certainty of acquiring and retaining LNG customers. One of the risk factors identified is the marine bunkering jetty. FEI states:

> Marine bunkering jetty: FEI requires a jetty to enable ship-to-ship bunkering and serve transpacific vessels, one of the most significant opportunities for LNG growth.

On page 3-24 of the Application, FEI states:

> Leveraging FEI's success in marine bunkering, an FEI Affiliate is exploring a potential marine jetty next to the Tilbury LNG storage facility that would allow for ship-to-ship LNG bunkering using LNG from FEI's Tilbury LNG facility for Trans-Pacific customers and for bulk delivery to overseas markets. It is important to note

> that the jetty will be owned by a non-regulated entity with services provided to it by FEI. This is not part of FEI's initiatives included in the LTGRP, however this initiative needs to be considered in terms of gas supply and any system contracting requirements, as it is expected the marine jetty will enable significant sales under Rate Schedule 46. The marine jetty is currently completing an environmental assessment under the direction of the BC Environmental Assessment Office. The environmental assessment is expected to conclude in 2022. If approved, the jetty could provide service for LNG marine fueling by 2024 or 2025.

On page 4-16 of the Application, FEI states:

> The jetty project is currently under development by an FEI affiliate. Final approvals for the marine jetty project are expected in 2023 with the marine jetty to be in service by the middle of 2024.

94.6 Please provide a high-level update on the marine jetty project, including the status of necessary permits and current expected in-service date.

Response:

The assessment of the application for an Environmental Assessment Certificate for the proposed Tilbury Marine Jetty is complete. The project was referred to provincial decision-makers and provided to the Impact Assessment Agency of Canada to inform the federal decision in October 2022. FEI understands that an Environmental Assessment Certificate could be issued for the Tilbury Marine Jetty this year.

If an environmental assessment certificate is received, the FEI affiliate proposing the Tilbury Marine Jetty expects to obtain necessary permits from the BC Energy Regulator, Fisheries and Oceans Canada, the City of Delta, and other relevant agencies prior to initiating construction. Depending on when the environmental assessment certificate is received, the expectation is that permitting could be completed to allow construction to start as early as 2024, and limited bunkering service could begin as early as 2025.

94.6.1 Please discuss the risk factors associated with the marine jetty project that may cause delays, deferral or cancellation of the project.

Response:

As mentioned in the preamble, the jetty project is currently under development by an FEI affiliate, rather than FEI. However, there are a number of risks and uncertainties that are commonplace for projects of this scale, which could cause the delay, deferral or cancellation of the project. These risks include regulatory (e.g., rejection of the Environmental Assessment

Certificate application, or a key permit being withheld), commercial (e.g., competition and market development), or technical (cost escalation rendering the development non-viable).

94.7 Other than the marine jetty, please discuss whether FEI makes any other assumptions regarding the building of key infrastructure necessary to support the LNG demand forecast, such as infrastructure owned by FEI, FEI's affiliates, the Port of Vancouver, or any other party. Please describe all assumptions made, with rationale.

Response:

For both the Planning and the High Demand Settings, FEI will require the construction of the Tilbury 1B Expansion facilities to meet the expected demand, which is expected to provide an additional 0.25 to 0.65 MTPA of liquefaction capacity at the Tilbury facility. Please refer to the response to BCUC IR2 109.3.

In Exhibit B-9, in response to BCOAPO IR 3.1, FEI provides a table of Critical Uncertainties and Settings for the DEP Scenario. Two excerpts from the table for the Low-Carbon Transportation and Global LNG Demand Category are provided below:

Low-Carbon Transportation and Global LNG Demand Category					
LCT demand	Planning	In the Planning setting, incentives supporting CNG and LNG infrastructure under Greenhouse Gas Reduction Regulation (GGRR) will be extended beyond 2030 and the BC-Low Carbon Fuel Standard continues. This setting includes no solution to the discontinued 15L road engine for truck fleet customers and consumption by these customers will halt by 2026, however, the mining and remote power market segments will grow by an average of 2.9 PJ annually from 2024 to 2042. Demand from CNG customers is assumed to grow at 3 percent per year. The growth of CNG demand is forecast to capture about 2.9 percent of the eligible market by the end of the forecast period of 2042. This level of market capture constitutes a growth rate of approximately 3 percent per year with average demand increase of 0.015 PJ per year from 2031 to 2042.		Demand (PJ)	
			Year	CNG	LNG
			2020	0.96	1.46
			2021	1.00	1.40
			2022	1.03	1.41
			2023	1.06	8.40
			2024	1.10	19.18
			2025	1.13	28.12
			2026	1.18	34.48
			2027	1.21	40.85
			2028	1.24	49.93
			2029	1.27	53.49
			2030	1.30	57.23
			2031	1.31	57.47
			2032	1.33	57.78

…

Critical Uncertainty	Setting applied	Description	Values/Mechanism
Global LNG Demand	Planning	The Planning setting assumes there is continued LNG adoption in the short sea market segment. The marine bunkering jetty at Tilbury is constructed, accelerating the adoption of LNG by trans-Pacific marine vessels. The ISO exports market segment is assumed to increase by 0.33 PJ per year from 2021-2030 and remain constant thereafter.	Year Annual Demand (PJ) 2020 3.00 2021 3.00 2022 3.33 2023 3.66 2024 3.99 2025 4.32 2026 4.65 2027 4.98 2028 5.31 2029 5.64 2030 - 2042 6.30

94.8 Please reconcile the above table, which states that "the mining and remote power market segments will grow by an average of 2.9 PJ annually from 2024 to 2042," with the information provided in response to BCUC IR 33.7, which indicates that the load impact for the remote mining and industry load sector is 4 PJ by 2040. Please clarify the forecast for the mining and remote power market sector.

Response:

FEI clarifies that, in the Planning Setting, the mining and remote power market segment's load is projected to be an average of 2.9 PJ annually between 2024 and 2042, reaching a maximum of approximately 4 PJ in 2040, as shown in the table in the response to BCUC IR1 33.7. The growth rate averages approximately 0.2 PJ per year over the forecast period from 2024 to 2042.

94.9 With reference to the LNG sectors identified in response to BCUC IR 33.7 (i.e.: short sea marine market, mining and remote power market, marine bunkering etc.), please clarify which sectors are considered within the LCT demand category and which sectors are considered within the global LNG demand category in the above tables provided in BCOAPO IR 3.1.

Response:

The LCT demand category consists of the on-road, short sea marine market, mining and remote power market, and marine bunkering market. The Global LNG demand category consists of solely the LNG ISO Export Market sector. The EGP project and Other Large Industrial load are not included in the LNG demand forecast as they are not expected to purchase gas from FEI. Please also refer to the response to BCUC IR1 33.15 regarding the Woodfibre LNG demand.

94.10 Please explain, with rationale, to which sectors the forecast growth in LNG demand shown in the above table in years 2023, 2024 and 2025 is attributed (i.e.: short sea marine market, mining and remote power market, marine bunkering etc.).

Response:

The main driver of growth in LNG demand in 2023, 2024 and 2025 is the introduction of marine bunkering to the forecast starting in 2023. However, FEI notes that there have been changes to the expected timing of this demand since the development of the load forecast for the Application and since the responses to the first round of information requests were filed. As discussed in the response to BCUC IR2 94.6, the Tilbury Marine Jetty is now expected to be delayed until 2025, and the marine bunkering load will not commence until at least 2025. Please also refer to the response to BCUC IR2 94.3.1.

D. GAS SUPPLY PORTFOLIO PLANNING

95.0 Reference: Gas Supply Portfolio Planning

Exhibit B-1, pp. 6-8 – 6-9; Exhibit B-6, BCUC IR 52.11, 52.16, 52.20; Exhibit B-12, CEC IR 5.2, Exhibit B-17 RCIA IR 22.3, 23.2

Gas Supply Portfolio Planning

In response to BCUC IR 52.11, FEI states:

> The difference in firmness between contracts is as discussed in the preamble. FEI's RNG contracts can have an annual or monthly supply requirement or a minimum daily firm amount, whereas FEI's firm conventional natural gas purchases are for a fixed GJ/day delivery for each day of the term of the transaction. Due to the potential variability in renewable gas supply, FEI monitors any fluctuations in nominated supply to ensure that it is supplying secure and reliable firm supply service for its customers. FEI is also actively working to minimize the difference between the minimum and maximum volumes in future RNG contracts.

95.1 Please describe more specifically the active steps FEI is taking to minimize the difference between the minimum and maximum volumes in future RNG contracts.

Response:

FEI is undertaking several strategies to minimize differences between minimum and maximum volumes in RNG contracts, including:

- FEI is requiring suppliers to contractually commit to higher minimum volumes. This can be achieved by taking additional time during negotiation of the contract and requiring more diligence on the part of suppliers when estimating plant output volumes.
- FEI is contracting for non-exclusive supply, with FEI as the off-taker for only the first portion of supply. That is, FEI is committing to purchase amounts below the total expected output of supplier facilities and allowing the suppliers to sell the excess RNG to other purchasers. As the receiver of the base amount of produced RNG, FEI is able to negotiate tighter windows between minimum and maximum volumes.
- FEI has entered into contracts and will look at future contracts that represent a portfolio of projects. In these contracts, suppliers may have multiple facilities and one agreement with FEI. This provides confidence that suppliers can more consistently deliver specific volumes because the RNG supply can come from multiple facilities. With increased confidence due to a portfolio approach, suppliers are willing to commit to a higher minimum volume as compared to the maximum volume, thereby decreasing the difference between the minimum and maximum volumes.

In response to BCUC IR 52.16, FEI states:

> FEI has maintained long-term supply ranging between 40 percent and 65 percent of its Station 2 Baseload supply requirements. Maintaining this range will avoid undue exposure and reliance on purchasing large quantities of Station 2 supply on the spot market and on a seasonal or annual term basis. This range also offers FEI enough flexibility to manage various changes that may occur to the portfolio over the long term, including evolving market conditions and updated load forecasts. FEI may target the lower range (i.e., 40 percent) or choose to reduce this range over the planning horizon of the LTGRP, as more renewable gas is incorporated into FEI's gas supply portfolio over the long term.

95.2 Please discuss what factors typically inform where the percentage of long-term supply contracts falls within the 40 percent to 65 percent range noted above.

Response:

Some factors that have typically informed the percentage of long-term supply contracts include:

- The ability and willingness of counterparties to enter into long-term commercial arrangements. For example, if market conditions result in a low forward commodity market price, producers may be hesitant or reluctant to enter into a long-term contract.
- The market factor (premium or discount) negotiated at Station 2 for long-term supply in comparison to what FEI is offered for seasonal and annual agreements. For example, if long-term market factors become disconnected from the annual market factors, FEI may choose to target the lower end of the range.
- Any significant change to the annual normal load forecast for FEI's Core customers could impact where FEI will fall within the 40 percent to 65 percent range.[17] For example, after 42 percent of the Transportation Service customers returned to FEI's bundled service effective November 1, 2019,[18] the annual normal load forecast for FEI's Core customers increased year-over-year by 35 TJ/day. This played a major role in the year-over-year drop in FEI's portfolio commitment to long-term supply from 65 percent during the 2018/19 gas year to approximately 50 percent for the 2019/20 gas year.

Entering into long-term supply contracts, as well as providing flexibility in pricing arrangements, has proven to be vital for FEI to maintain and establish relationships with the producers who continue to develop supply in BC. However, FEI does not want to target having long-term contracts for above 65 percent or closer to 100 percent of supply, as it would limit the number of

[17] As referenced in Table 6-2 of the 2022 LTRGP Application, the Station 2 Baseload supply requirements are tied to the forecast annual normal load for FEI's Core customers.

[18] Section 1.2.4.2 of the 2022 LTGRP Application.

counterparties with whom FEI transacts. Several counterparties that FEI has long standing relationships with are only interested in transactions of one year or less.

Additionally, as noted in the preamble, as more renewable and low-carbon gas is incorporated into FEI's supply portfolio over the long term, FEI may target the lower end of the 40 percent to 65 percent range or choose to reduce this range. Finally, new infrastructure developments in the region, specifically a new pipeline that would provide FEI with greater access to AECO/NIT (one of the largest natural gas trading hubs in North America), would also allow FEI to target a lower range of long-term supply commitments.

95.3 What are the risk factors associated with reducing the percentage of long-term supply contracts below 40%. Please discuss how FEI intends to mitigate these risks.

Response:

Over the past couple of years, FEI has been near the lower end of the long-term supply range (i.e., 40 percent), and it is possible that FEI may not be able to attain the targeted range in the near future. The main reasons for this include fewer counterparties at Station 2 compared to five years ago, and a high turnover rate of producers in the region due in large part to the challenging market environment at Station 2 (i.e., low commodity prices compared to other North American natural gas trading hubs).

The primary risk factor with not attaining or reducing the percentage of long-term supply contracts below 40 percent is that FEI would then have a higher exposure to term supply transactions during its typical negotiation period, which is one to six months prior to the gas delivery date. Given the small market size at Station 2, this exposure could affect pricing and security of supply under certain market conditions, especially in the winter.

Given this development, FEI has been evaluating additional options to mitigate this risk through the ACP. For example, FEI has recently implemented a strategy to extend the negotiation period for its winter term supply requirements over a 10-month period. This has allowed FEI to transact winter term supply over a longer period of time, which provides additional pricing diversification within the portfolio, and helps to prevent the impact of adverse market prices.

It is still in FEI's interest to maintain a range of 40 percent to 65 percent of long-term supply contracts at the Station 2 market in order to promote the long-term viability of gas supply delivered to Station 2. This will become increasingly more important as producers in the region begin to have additional outlets for their supply (i.e., LNG export markets). Therefore, FEI will continue to try and renew existing long-term supply contracts within the supply portfolio and explore additional mutually beneficial deals with regional counterparties.

On pages 6-8 to 6-9 of the application, FEI states:

> Seasonal gas storage is an integral part of FEI's gas supply portfolio as it provides flexibility to meet load variations during the winter and summer months. FEI contracts the majority of seasonal storage with Aitken Creek in NEBC and a currently small portion with Rockpoint Gas Storage in Alberta. These seasonal storage assets are available to be utilized throughout the winter season as needed. FEI also contracts for shorter duration market area storage resources, which are needed when colder-than-normal winter loads are greater than the supply available from termed gas supply and seasonal storage. FEI contracts these shorter duration assets at Jackson Prairie Storage (JPS) in Washington and Mist Storage in Oregon.

In response to BCUC IR 52.20, BCUC states:

> FEI has a variety of storage contracts at the Mist storage facility, each with different capacities and expiry dates. As these contracts have no renewal rights, once they expire, NW Natural has the right to take back a portion, if not all, of the storage capacity for their customer load requirements.

95.4 Please provide a list of FEI's storage contracts, including capacities, and corresponding expiry dates.

Response:

FEI is filing a portion of this response confidentially, in perpetuity, pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-72-23, related to the details of its storage contracts with Aitken Creek. Under its storage contracts with Aitken Creek, FEI is contractually obligated to keep this information confidential and may only provide it to the BCUC. Given FEI's contractual obligations, FEI is filing the unredacted version of this response confidentially to the BCUC only for the purposes of this proceeding, and requests that it not be provided to other parties in this proceeding.

Table 1: Third Party Contracted Storage Portfolio Summary

	Contract	Capacity	Expiry Date
1	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]
5	Rockpoint (AECO Gas Storage)– 3 Year Contract	2,000,000 GJ	March 31, 2026

	Contract	Capacity	Expiry Date
6	JPS - NW Pipeline	421,863 Dekatherms (Dth)	April 30, 2032
7	JPS - NW Pipeline	632,717 Dth	April 30, 2032
8	Third Party Storage Agreement (JPS)	1,500,000 Dth	April 15, 2025
9	Mist Contract D	1,430,000 Dth	May 31, 2024
10	Mist Contract E	1,040,000 Dth	May 31, 2026
11	Mist Contract H	260,000 Dth	April 30, 2025

Further in response to BCUC IR 52.20, FEI states:

> NW Natural's 2022 IRP discussed customer exposure to the Sumas/Huntingdon market, and how this exposure will be "further exacerbated in 2027 when the Woodfibre LNG facility is expected to come online."62 Their strategy to reduce this Huntingdon/Sumas supply exposure is to recall interstate/intrastate Mist storage capacity for the purposes of NW Natural's own use. Although the exact amount and timing is yet to be determined, FEI expects the recalls to cut into its existing Mist storage contracts starting in 2027 and that the cuts will be material.

95.5 Please quantify the approximate materiality of the expected cuts into FEI's existing Mist storage contracts.

Response:

FEI has ongoing discussions with NW Natural to understand the materiality of the expected capacity being recalled in the near future. Based on the most recent discussion, FEI expects that as much as 70 percent of its currently contracted capacity could be recalled by winter 2027/2028. The exact amount is subject to change based on updates to NW Natural's integrated resource plan and/or if there is a change to the expected in-service date of the Woodfibre LNG project.

95.6 Please describe any cuts expected for any other of FEI's storage contracts (amount and timing, if known).

Response:

At this time, there has been no indication to FEI that any of its other storage contracts are at risk of being cut. However, there is one short-term contract with a regional counterparty that FEI has been monitoring over the years, which is associated with storage capacity at the Jackson Prairie storage facility. FEI believes that the risk associated with this contract is similar to FEI's contracts at Mist, as the counterparty may take this capacity back to avoid purchasing supply at the Huntingdon/Sumas market. The amount of storage capacity at risk is up to 1.5 PJ annually and could be cut as soon as 2025.

95.7 Please discuss the overall expected impacts to FEI's supply portfolio due to the expected cuts into FEI's storage contracts, including supply and pricing impacts.

Response:

As discussed in the response to BCUC IR2 95.5, FEI expects that as much as 70 percent of its currently contracted capacity at Mist could be recalled. This would result in up to an 80 TJ shortfall to FEI's peak day portfolio (Table 6-2 of the Application).

FEI's market area storage resources serve a unique purpose to FEI's gas supply portfolio, as they provide short- to medium-duration seasonal supply for periods of colder than normal weather. Given that the resources in the region are fully contracted and can be constrained in the winter, any substantial cut into FEI's market area storage will have a significant impact to FEI's supply portfolio from a security of supply and pricing risk standpoint.

For example, absent any new infrastructure, FEI would either have to secure supply at the Huntingdon/Sumas market or try to secure additional pipeline capacity on the T-South system. FEI has updated Figures 6-4 and 6-5 of the Application given the recent pricing volatility at the Sumas/Huntingdon market during the 2022/23 winter. Figure 1 below illustrates the pricing risks to FEI's portfolio should FEI replace its expected supply cuts at Mist with Sumas/Huntingdon supply. Figure 2 below illustrates the extremely high premium that FEI would likely have to pay an existing T-South shipper should FEI decide to contract additional T-South capacity to replace the expected supply cuts at Mist.

As such, it is imperative for FEI to continue evaluating the potential to contract for long-term capacity with NW Natural, through an expansion of the Mist facility. If the expansion has merit and FEI can reach an acceptable commercial arrangement with NW Natural, FEI will file an application with the BCUC for approval of a Mist storage contract, which FEI expects will be in Q4 2023.

Figure 1: Historical Daily Market Spot Prices

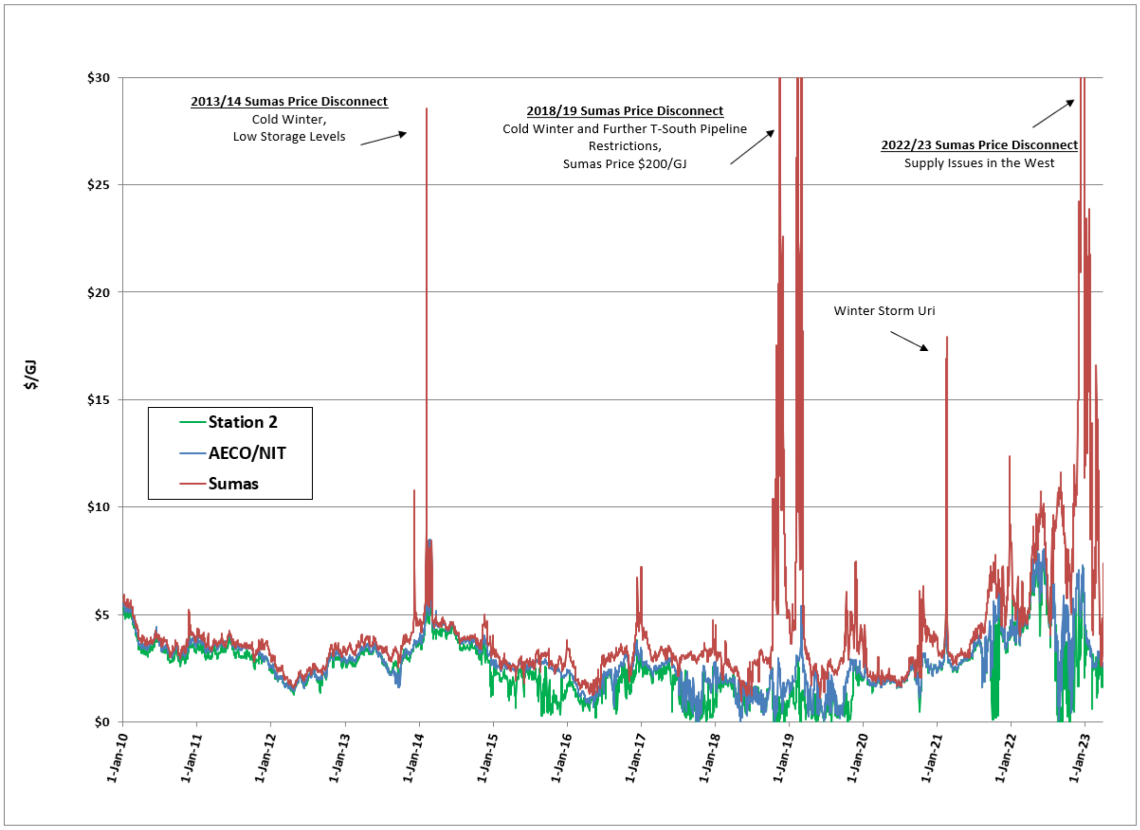
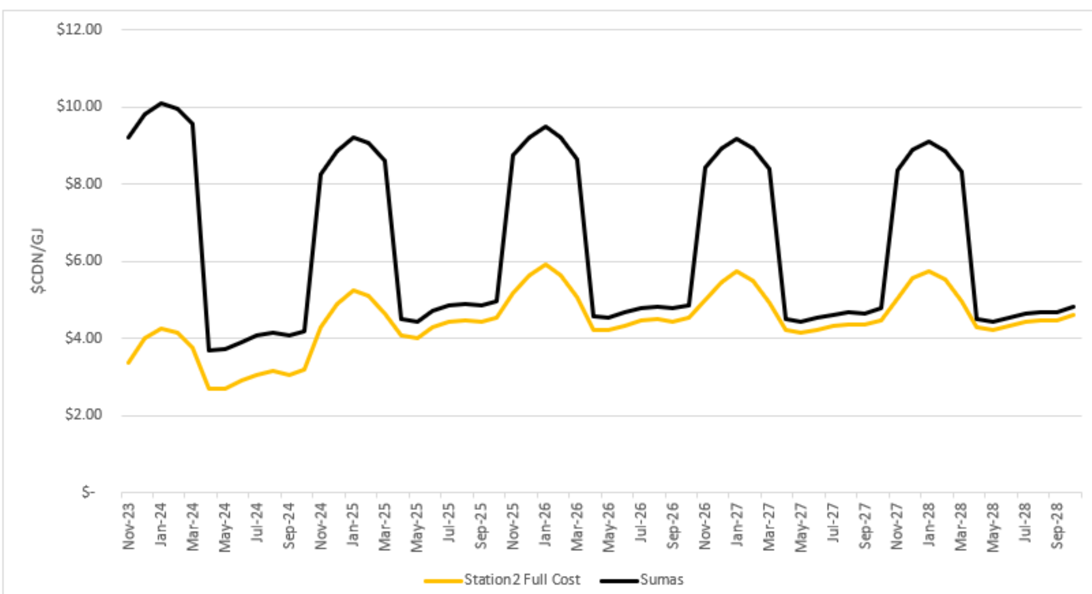


Figure 2: Station 2 Full Cost and Sumas Forward Price Comparison[19]



19 Graph is based off indicative forward pricing provided by Amerex on April 3, 2023. Station 2 Full Cost includes Station 2 forward monthly price, T-South fuel, Westcoast 2023 Interim Tolls, Motor Fuel Tax and Carbon Tax.

In Exhibit B-17, FEI responds to RCIA IR 22.3, which asked what FEI's contingency plans are if some or all of its Mist storage capacity or U.S. pipeline displacement capacity are recalled:

> As discussed in the responses to BCUC IR1 52.20 and 52.21, FEI has had preliminary discussions with NW Natural regarding the potential for NW Natural to further expand its Mist storage facility. This expansion would also require FEI to contract long-term capacity on Northwest Pipeline. The best-case scenario would be to have this Mist expansion in-service by the time that NW Natural recalls a significant volume of FEI's Mist capacity. If the Mist facility were not expanded, or terms and conditions were not agreed to by the parties, FEI would need to secure other resources to replace the supply lost from this asset and apply to the BCUC for approval of the resource.

95.8 If the Mist facility were not expanded, or terms and conditions were not agreed to by the parties, please discuss what other resources may be available to replace the supply lost from this asset, in what quantities, and in what timeframes these may be available.

Response:

The best option for FEI to replace this asset with another market area storage resource in the region would be if Jackson Prairie Storage (JPS) expanded. However, it is FEI's understanding that there are risks to future reservoir expansions at JPS, and therefore the owners of JPS (Puget Sound, Northwest Pipeline, and Avista) have no plans for future development at this time.

Pipeline capacity through an expansion on either T-South or Southern Crossing (Regional Gas Supply Diversity Project (RGSD)), or commercial deals in the secondary market could be available to replace the capacity lost from the Mist facility. The timeline for these resources to be available would be no earlier than 2028. All of these new resources including a Mist expansion will come at a greater cost than the existing cost of resources.

Replacing the Mist resource with pipeline capacity (T-South and/or RGSD) or with on-system storage (Tilbury LNG Storage Expansion Project (TLSE)), would be less efficient from a gas supply portfolio planning perspective than the existing use of market area storage. As detailed in Section 6.2.1 of the Application, it is generally more efficient in designing a gas supply portfolio to, for instance:

- Purchase firm natural gas commodity volumes and contract third-party pipeline capacity to address seasonal and base load requirements (i.e., consistent demand for the 151-day winter season and annual demand);
- Use shorter duration market area storage to provide short- to medium-duration seasonal supply; and

- Use on-system storage resources for short-duration supply to cover events such as winter demand peaks.

For example, while FEI would be able to replace all of its Mist supply with pipeline capacity, it would not be a cost-effective approach given that FEI would need to pay a 365-day pipeline toll for supply that is only required for 10 to 60 days during the winter season.

FEI's existing on-system storage assets at the Tilbury Base Plant and Mt. Hayes would provide negligible ability to absorb the loss of Mist storage; they are designed specifically to help meet peaking weather conditions (1 to 10 days) and other operational emergencies, whereas FEI's contracted capacity at Mist helps with 10 to 60 days of cold weather as well as daily load balancing. The Tilbury 1A tank is designated to support transportation sector customers so stored volumes may not be available in the event of peak weather conditions, and it too is similarly limited in comparison to Mist storage.

FEI could replace a portion of supply lost from Mist with the proposed TLSE Project (the portion not set aside as a resiliency reserve). The amount of replacement supply the TLSE Project would provide is limited due to the smaller volumes stored relative to the market area storage size provided by Mist and liquefaction capability at Tilbury that limits how quickly it can be replenished. As such, in the event Mist storage needed to be replaced, the sizing of the TLSE Project as proposed in the TLSE Project CPCN Application (i.e., having the "third Bcf" available) would provide benefits, but would not fully replace the loss of Mist capacity.

In Exhibit B-12, in response to CEC IR 5.2, FEI states:

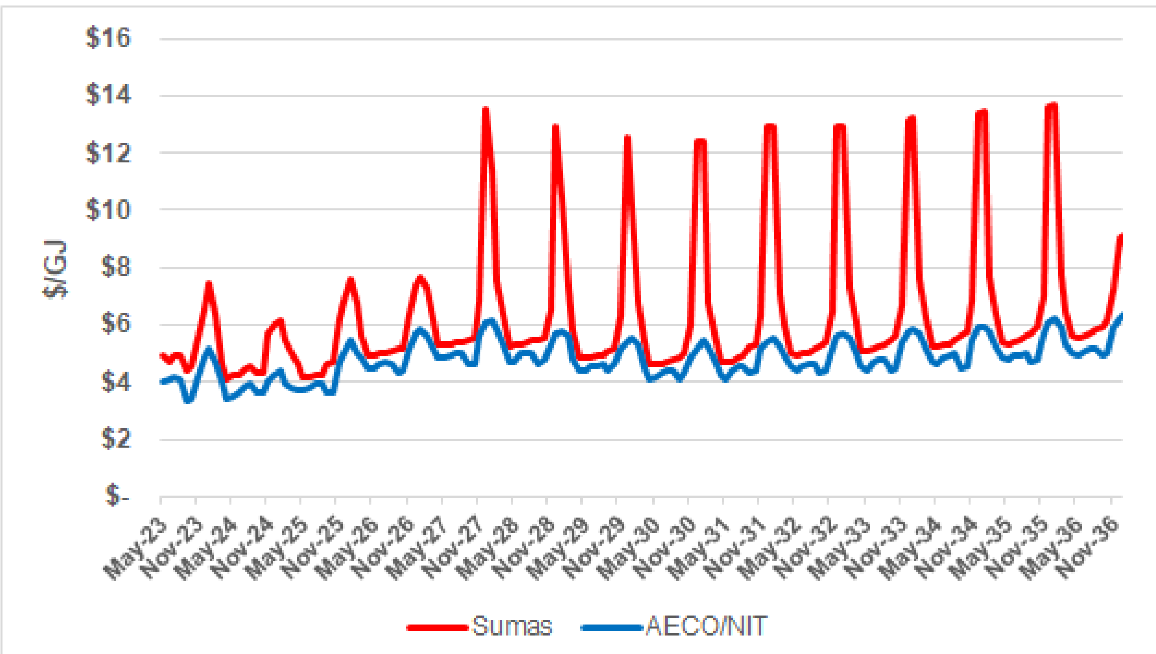
> The steps that FEI has already undertaken to mitigate supply and pricing risks for its Core customers in the region are described in Sections 6.2.4 and 6.2.5 of the Application. Going forward, the "best-case scenario" for FEI is that the RGSD, TLSE and a Mist Expansion are built in the region as soon 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.

95.9 Please discuss how the demand associated with Woodfibre LNG, once operational and in-service, is expected to impact gas commodity prices, and the commodity rates charged to FEI customers. Please provide a forecast demonstrating the impacts discussed.

Response:

The demand associated with Woodfibre LNG will likely lead to higher regional commodity prices at the Huntingdon/Sumas market hub, if there is no additional capacity added to the region. As illustrated in Figure 1 of the response to BCUC IR2 95.7, prices at the Huntingdon/Sumas market hub are already high, even before the additional demand from Woodfibre LNG is considered. S&P Global's price forecast released in August 2022 provides a good indication of what the impact could be on commodity rates. This forecast assumes that Woodfibre LNG would begin operations in Winter 2027/2028. The following figure demonstrates the increase in the forecasted Huntingdon/Sumas price compared to the AECO/NIT price after Woodfibre LNG comes online, assuming there is no additional capacity added to the region.

Figure 1: Sumas and AECO/NIT Price Forecast[20]



FEI's gas contracting strategy for its Core customers in today's market features limited supply exposure to the Huntingdon/Sumas market. This is because FEI's gas supply strategy, as accepted by the BCUC in past ACPs, has been to secure firm resources to handle the load requirements of its customers. This includes contracting a significant amount of pipeline capacity in order to acquire supply at Station 2 and at AECO/NIT. Therefore, FEI's commodity rate exposure would be closely tied to the AECO/NIT forecast illustrated in the figure above, which shows that it will not be materially impacted once Woodfibre LNG comes online.

[20] Source: ©2023 S&P Global Commodity Insights. 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 Commodity Insights.

95.10 Please discuss whether the demand associated with Woodfibre LNG, once operational and in-service, is expected to impact supply availability.

Response:

As discussed in the responses to CEC IR1 5.1 and 5.2, if Woodfibre LNG comes online and in-service before any major regional expansion occurs (such as the latest T-South open season, or the RGSD project), the Huntingdon/Sumas market will continue to have significant supply risks and pricing volatility going forward. The increase in Woodfibre LNG demand is expected to reduce the amount of supply available for remaining BC and Western US demand.

From an upstream perspective, as discussed in the response to CEC IR1 16.4, IHS Markit expects that there will be a minimal price increase at AECO/NIT and Station 2 from LNG exports based on the assumption of increasing natural gas production. However, if actual natural gas production does not increase to meet the marginal LNG demand, prices may increase more than expected. For more detail on this point, please refer to the response to CEC IR2 65.1.

For Woodfibre LNG specifically, given that this LNG export terminal is owned by Pacific Energy, whose subsidiary is Pacific Canbriam Energy, it is expected that the supply for export will be made available through production from the same company.[21] However, any supply from Pacific Canbriam Energy that was previously sold to FEI, the Huntingdon/Sumas market, or downstream utilities and end-users would need to be replaced by increased supply from other gas producers to maintain the equivalent overall supply availability in the region.

In Exhibit B-17, FEI responds to RCIA IR 23.2, when asked to summarize the principles of the currently approved Price Risk Management Plan and the activities that FEI takes in support of these principles: “Please refer to the response to CEC IR1 23.1.”

BCUC staff note CEC IR 23.1 refers to gas heat pumps.

95.11 Please clarify the reference to CEC IR1 23.1 in this response.

Response:

FEI clarifies that the response to RCIA IR1 23.2 intended to refer to RCIA IR1 23.1. The objective of FEI’s price risk management, which includes hedging, has always been to mitigate market price volatility and support rate stability. Further, the principles of the currently approved Price Risk Management Plan (PRMP) include mitigating market price volatility and increasing the price

[21] Pacific Canbriam Energy, “Pacific Canbriam Acquires Additional Montney Lands in British Columbia” (August 18, 2022) online at: https://www.pacific-canbriam.ca/pacific-canbriam-acquires-additional-montney-lands-in-british-columbia.

diversity in the commodity portfolio. The approved PRMP includes hedging at AECO/NIT to support these objectives.

E. DEMAND-SIDE RESOURCES

96.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-6, BCUC 34.2

Cost-Effectiveness

In response to BCUC IR 34.2, FEI provided an updated Table C2-1 using a ZEEA value of $65/MWh, rather than the original ZEEA of $106/MWh.

The revised C2-1 shows a Portfolio Aggregate TRC of 4.7:

Year	TRC	MTRC	UCT	CCE ($/GJ)
Portfolio Aggregate	4.7	10.1	4.5	9.4
Residential Aggregate	2.0	3.9	1.8	12.3

The original Table C2-1, App C-2, p. 4 shows a Portfolio Aggregate TRC of 4.1:

Year	TRC	MTRC	UCT	CCE ($/GJ)
Portfolio Aggregate	4.1	14.2	4.0	11.3
Residential Aggregate	1.5	4.8	1.4	17.2

96.1 Please explain why the Residential and Portfolio Aggregate TRC values are higher in Revised C2-1 than the original C2-1, including why the use of a lower ZEEA of $65 has a different directional impact on TRC as opposed to the MTRC.

<u>Response:</u>

FEI and Posterity Group have collaborated on the following response.

The Residential and Portfolio Aggregate TRC values are higher while MTRC values are lower in the Revised C2-1 with a ZEEA of $65 per MWh, than the values in the original C2-1 with a ZEEA of $106 per MWh, for the following reasons.

For a given measure, a higher ZEEA value results in a higher MTRC value but leaves the TRC value unchanged. Put another way, a higher ZEEA value means that there will be measures with lower TRC ratios that will have MTRC ratios greater than 1. Conversely, decreasing the ZEEA value means that some measures with low TRC values that were formerly included in the scenario because of their passing MTRC ratio will now be excluded.

Decreasing the ZEEA value and making the MTRC more difficult to pass had the effect of removing some marginal measures with very low TRC values from the DSM potential. The average TRC ratio for the remaining set of measures was therefore higher than before.

97.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-6, BCUC 39.3; Exhibit B-1, Appendix C-1, Exhibit 21, pp. 34-35; 69-70; Exhibit B-1, Appendix D-2, p. 113

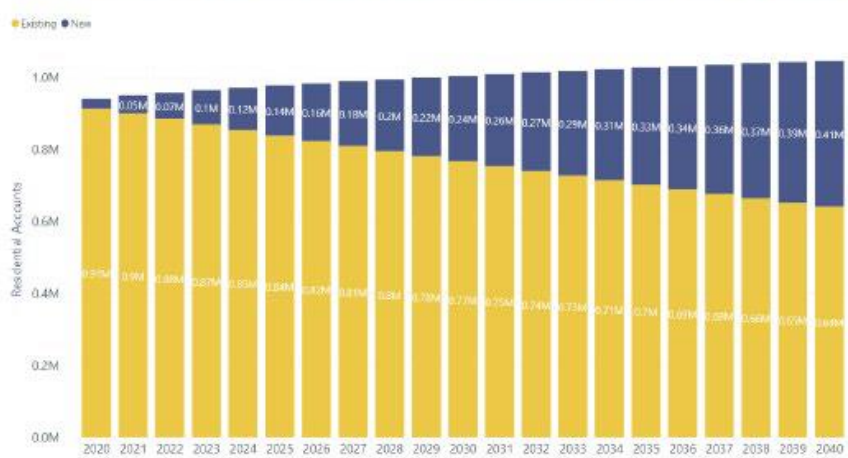
Load Forecast Scenarios and New Customer Counts

On page 34 of Appendix C-1, Posterity states:

> Despite the reference case showing a 5% decrease in residential sector gas use from 2020 to 2040, residential accounts are expected to grow by approximately 11% from 2020 to 2040, from 932,000 to 1,047,000. The portion of FEI accounts from new residential dwellings is forecasted to increase over the reference case from 3% in 2020 to almost 40% in 2040, with new construction contributing approximately 400,000 new accounts, and approximately 290,000 existing dwellings being demolished over the reference case period.

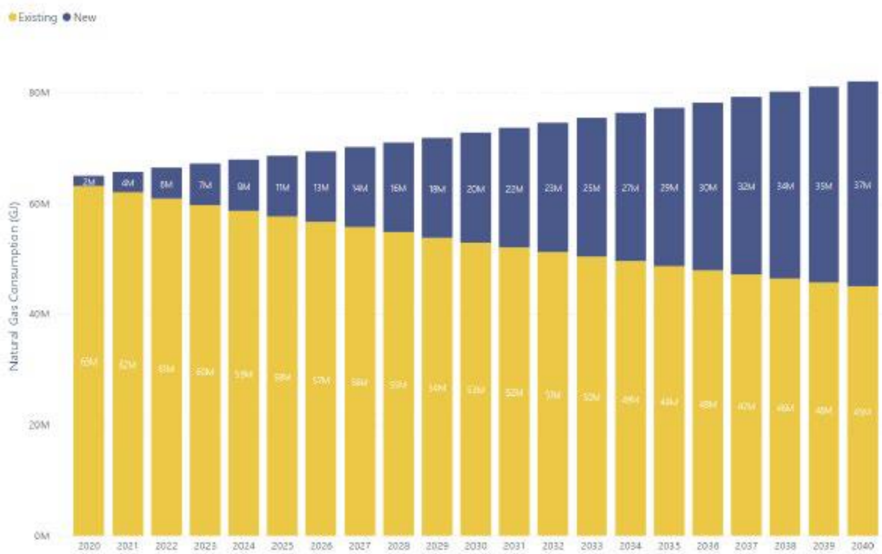
Exhibit 22 of Appendix C-1 shows the reference case assumptions for residential gas accounts by existing and new residential customer segments:

Exhibit 22 – 2020 vs 2040 Residential Gas Accounts Forecast by Existing and New Vintage



Posterity states on page 69 that "(i)n 2020, natural gas consumption from new [commercial] buildings was roughly two million GJ, or 3% of the total commercial sector consumption. By 2040, new buildings are forecasted to use 37 million GJ (45% of total sector), as shown in Exhibit 71."

Exhibit 71 – 2020 vs 2040 Commercial Gas Consumption Forecast (GJ) by Existing and New Vintage



In response to BCUC IR 39.3, FEI states

> The load forecast scenarios exhibit differing levels of estimated energy savings potential because of the Critical Uncertainty settings that are used to create the load forecast scenarios before DSM is applied, and the DSM setting used for post-DSM scenario demand. The Critical Uncertainty impacts are grouped into four categories: pre-DSM scenario demand, energy costs, codes and standards, and DSM settings.
>
> ***Pre-DSM Scenario Demand***
>
> The amount of demand and the gas portfolio chosen for a scenario affect the amount of DSM savings potential. Specifically, this “pre-DSM” demand in each scenario is influenced by the following Critical Uncertainties:
>
> • *Customer Forecast*: More growth in gas customers increases measure potential and less growth decreases it.
>
> …

In response to BCUC IR 14.3 about why future uncertainties around end-use energy are addressed as part of demand forecast and not customer forecast, FEI states:

> FEI has addressed these future uncertainties through its end use demand forecast modelling and not through its customer forecast because changing both customer additions and end-use assumptions to address the same critical uncertainties in the scenarios would increase modelling complexity and the number of output permutations, while not increasing the value of the information provided by the overall demand forecast results.

97.1 Please provide and compare the customer growth assumptions underpinning the different load scenarios, including the Reference case, DEP and Deep Electrification scenarios.

Response:

FEI and Posterity Group have collaborated on the following response.

FEI's customer growth assumptions provide an input into the annual demand forecast for Residential, Commercial and Industrial demand by establishing a base customer forecast for these customer segments as a reference setting. FEI uses a well-established method that remains consistent with previous LTGRP filings. The customer growth to 2042 is based on assumptions underpinning customer account numbers for the Reference Case, DEP and Deep Electrification scenarios shown in Table 1 below. Customer type is classified based on rate class,[22] which reflects the amount of energy consumed by these customer types.

Table 1: Overview of Customer Growth Setting Assumptions Based on Number of Accounts for Reference Case, DEP and Deep Electrification Scenarios

Customer Counts		Reference Case	DEP	Deep Electrification
Setting		Reference	Reference	Low
	2019 (Base Year)	2042 (End of Planning Period)		
Residential[23]	942,769	1,064,902	1,064,902	1,028,963
Commercial[24]	96,880	123,978	123,978	111,264
Industrial[25]	1,325	1,337	1,337	878
Total	1,040,974	1,190,217	1,190,217	1,141,106

As illustrated in Table 1, the DEP Scenario uses the Reference setting and, therefore, the number of customer accounts remains the same as the Reference Case for each customer type. The Deep Electrification Scenario uses the Low setting, although, as illustrated in Table 1, there is still growth in customer accounts over the planning period.

Customer growth rates for each rate class and region were based on three trajectories (High, Reference and Low) developed by FEI's load forecasting group, as described in Section 4.3 of the Application. The Reference customer growth setting assumptions are discussed below for each customer type as follows:

[22] Customer numbers in the preamble are based on the Conservation Potential Review (Appendix C-1) in which customers are categorized by sectors based on end-use. This sector breakdown supports DSM analysis and the analysis of energy savings assessments for DSM program development.

[23] RS 1.

[24] RS 2, 3 and 23.

[25] RS 4, 5, 6, 25, 7, 27 and 22.

- For residential customers, it is based on Conference Board of Canada projections. The FEI aggregate forecast predicts a compound annual growth rate of 0.48 percent across the 20-year planning period with regional distribution relatively unchanged.
- For commercial customers, it is based on the most recent three-year average additions. The FEI aggregate forecast predicts a compound annual growth rate of 1.06 percent across the 20-year planning period with regional distribution relatively unchanged.
- For industrial customers, it is based on including existing customers in the base year, along with known commitments by customers planning to join or leave the system.

The High and Low trajectories are based on a 95 percent confidence interval developed from the variability in growth seen in the previous years. In some cases, the variability was sufficiently modest that even the lowest trajectory represented an increase in customer numbers. In other cases, the variability was large enough that the lowest trajectory included a decline in customer numbers. Within a given rate class and region, growth rates were assumed to be equal for different segments. For example, in a given scenario, the same growth rate would be applied across a range of different customer segments such as grocery stores and schools.

It is important to reiterate that in LTGRP modeling, future uncertainties around end-use energy are addressed as part of the demand forecast and not customer account forecast. In the model, the customer growth assumptions discussed above do not impact demand as much as other critical uncertainties. Please refer to the response to BCUC IR2 81.2.1, Table 1, for further discussion on the impact of critical uncertainty settings on annual demand.

97.2 Please provide FEI's assumptions regarding the capture rate for new construction between the Reference case, the DEP High Scenario, and Deep Electrification scenarios.

Response:

FEI and Posterity Group have collaborated on the following response.

Capture rate is not an explicit input into any critical uncertainties in any of the scenarios. Individual scenarios include assumptions about the number of accounts added to the FEI system. As discussed in the response to BCUC IR 2 85.2, the capture rate is one of many factors that impact the annual net customer additions. However, there are no assumptions made in the model regarding the proportion of new construction (residential and commercial) that does or does not become FEI accounts.

97.3 Please explain and show how the different customer growth assumptions between load scenarios have informed the estimates of DSM savings, in particular the DEP Medium and High DSM scenarios, for all customer segments.

Response:

FEI and Posterity Group have collaborated on the following response.

FEI interprets the question to be asking about customer types (residential, commercial and industrial) rather than customer segments.

The DEP Medium DSM Setting and the DEP High DSM Setting use the same customer growth assumptions, so customer growth has no effect on the difference between them.

As the years progress and more new buildings are assumed to be constructed, measures applied to new construction account for an increasing proportion of the overall DSM savings. By 2042, new construction measures account for the following proportion of savings:

- DEP High DSM Setting – 1.8 percent of total residential savings and 21.4 percent of total commercial savings;
- DEP Medium DSM Setting – 1.9 percent of total residential savings and 15.8 percent of total commercial savings; and
- In the industrial sector, the model does not distinguish between measures applied to new and existing buildings.

Page 113 of the B.C. Renewable and Low-Carbon Gas Supply Potential Study states:

Demand-side management and fuel switching:

The 15% renewable gas target for 2030 can be achieved easier and likely at a lower cost by reducing the demand for fossil natural gas. In the moderate climate of southern and coastal B.C., electric heat pumps can achieve GHG reductions more effectively than renewable and low-carbon gases. Similarly, pellet production and heating with pellets has a higher overall efficiency than the biomass-syngas-hydrogen-methane pathway. Switching natural gas use for low-temperature applications, such as building heat, to other fuels will reduce costs for achieving CleanBC targets. This applies especially to new construction. Vancouver City Council has approved a bylaw that bans fossil fuel appliances for low-rise buildings as of 2022.Fossil natural gas will be phased out completely by 2050. This approach could be extended to all of B.C.

FEI is currently seeking BCUC approval for revisions to its Renewable Natural Gas Program in the ongoing Biomethane Energy Recovery Charge (BERC) Rate Methodology and Comprehensive Review of a Revised Renewable Gas Program.[26]

97.4 Please discuss to what extent the assumptions regarding new construction customers depend on the availability of renewable and low-carbon gases over the planning period.

Response:

FEI and Posterity Group have collaborated on the following response.

The availability of renewable and low-carbon gases over the planning period did not directly impact gas demand associated with new construction customers in that the model did not consider this assumption within the critical uncertainties.

97.5 Please discuss to what extent the assumptions regarding new construction customers depend on the approval by the BCUC of FEI's BERC Rate Methodology.

Response:

FEI and Posterity Group have collaborated on the following response.

In the RG Program Application proceeding, FEI is seeking approval of a Renewable Gas Connections service to serve 100 percent RNG to new residential construction. At the time the forecast modelling was undertaken for the LTGRP (prior to the RG Program Application), FEI did not assume that approval or not of the Renewable Gas Connections service (or any other aspect of FEI's approvals sought in that proceeding) would be a critical uncertainty impacting FEI's ability to add new construction customers. FEI will assess the outcome of the BCUC's decision in the RG Program Application proceeding on future customer demand, along with other factors that may unfold following the submission of the 2022 LTGRP, in its next LTGRP.

[26] https://www.bcuc.com/OurWork/ViewProceeding?ApplicationId=807.

98.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-6, BCUC 40.1; Exhibit B-1, Appendix C-1, p. 145; Appendix B-3, pp. 3, 9;

High DSM Scenario – New Construction Savings

In response to BCUC 40.1, FEI states:

> The greater increase in DSM expenditures in the commercial sector compared to the other sectors is largely driven by the trajectory of gas heat pump (GHP) adoption, followed by New Construction Step Code measures and energy recovery ventilators.

On page 145 of Appendix C-1, Posterity states:

> Commercial sector savings show the most variance between the high and medium market potential scenarios. Using the MTRC screen, by 2040 the difference in potential between the medium and high market scenarios is 11.6 PJ. Gas heat pumps (GHPs) and efficient new construction are major contributing factors to this difference. These measures have high technical and economic potential, but future uptake is uncertain.

On page 3 of Appendix B-3, FEI provides a Summary of Modelled Critical Uncertainty Trajectories for the Residential, Commercial and Industrial Demand Category. One of these includes the New Construction Code, where modelled trajectories include: Reference; Accelerated; Delayed.

On page 9 of Appendix B-3, FEI states:

> The Reference Case assumptions are based on what was known and enforceable in the market as of 2019. BC has enacted the BC Energy Step Code, and the provincial Climate Leadership Plan (CLP) declares a goal of net-zero-ready new construction for 2032. The 2022 LTGRP progressively applies two settings in the parametric analysis: accelerated and delayed. These settings are relative to the Reference Case where the accelerated setting contemplates earlier adoption/compliance and the delayed setting contemplates later adoption/compliance.

In Table 4-1, p. 4-21 of the Application, FEI specifies the new construction code trajectories used in each of the scenarios:

- Upper Bound: new construction code - Delayed
- Diversified: new construction code: Reference
- Deep Electrification & Lower bound: new construction code: Accelerated

98.1 Please compare the Reference assumptions used for the new construction code trajectory in the Diversified scenario, with the current new construction code trajectory contained in the latest BC Building Code update.

Response:

FEI and Posterity Group have collaborated on the following response.

FEI understands that the most recent amendments to the BC Building Code[27] require Step 3 and Step 2 BC Energy Step Code performance for all residential and commercial new construction, respectively, to achieve a 20 percent improvement in energy efficiency above the 2018 BC Building Code performance.[28] These amendments are consistent with the "Reference" new construction code setting applied to the DEP Scenario, as this setting applies Step 3 to residential new construction and Step 2 to commercial new construction.[29]

The amendments to the BC Building Code also introduce the Zero Carbon Step Code, which is a new framework that is optional for BC local governments to reference in their building bylaws and policies as of May 1, 2023. Rather than targeting the efficiency performance of new construction, it targets their operational emissions. The details of the Zero Carbon Step Code were not known or proposed at the time of modelling. Accordingly, the Zero Carbon Step Code measures are not reflected in the Reference setting applied to the DEP Scenario, which incorporates measures that are known or expected as of the reference year (2019). FEI intends to update its modelling assumptions with the new Zero Carbon Step Code in the next LTGRP.

On pages 37-79 of Exhibit 24 to Appendix C-1 , Posterity includes the cost-effectiveness results for the following residential New Construction DSM measures:

New Construction - Step 3 Homes – Electric DHW
New Construction - Step 4 Homes – Electric DHW
New Construction - Step 4 Homes
New Construction - Step 5 Homes – Mature Market Costs
New Construction - Step 5 Homes – Electric DHW
New Construction - Step 5 Homes

On pages 73 to 75 of Exhibit 73 to Appendix C-1 , Posterity includes the cost-effectiveness results for the following commercial New Construction (NC) DSM measures:

NC Step 2 – Res

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27 BCBC 2018 Revision 5 (effective May 1, 2023).
28 https://energystepcode.ca/requirements/.
29 See Exhibit B-1, Appendix B-3, Table B3-2, for New Construction Code Settings Assumptions.

NC Step 2 – Comm
NC Step 2 - Non-Step
NC Step 3 - Non-Step
NC Step 3 – Res
NC Step 3 – Comm
NC Step 4 - Non-Step
NC Step 4 – Res

98.2 Please explain what activities are involved in each of the above residential and commercial new construction measures, and how the savings are realized for each measure. For example, please clarify if the measures are solely related to building envelope efficiency improvements relative to the BC Building Code, and what assumptions are made with respect to the fuel source being used for space and water heating in each measure.

Response:

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

All of the measures mentioned in the preamble were characterized in 2020. At the time, the baseline condition for all Step Code measures was defined as follows:

> Though the BC Step Code is a compliance path in the current BCBC, DSM Regulation 326/2008 (with amendments as of March 24, 2017) indicates that "the benefit of the demand-side measure is what it would have been had no step code been adopted in the Province." For this reason, all savings calculated here assume "Step 1" performance (i.e. compliance with Part 8 of NECB 2015) to represent the baseline performance.

As the Step Code is performance-based and not prescriptive, the activities involved in achieving the energy savings can vary from building to building and likely include a combination of building envelope and equipment measures. Figure 1 illustrates that there are over 53 million possible combinations of various energy conservation measures that can be used when modelling Part 9 (residential) buildings to achieve Step Code compliance targets.

Figure 1: Energy Conservation Measures Options Used in Part 9 Energy Modelling[30]

Component	Options	# of choices
Airtightness ACH	3.5 ACH, 2.5 ACH, 1.5 ACH, 1.0 ACH, 0.6 ACH	5
Wall R-Value	R16, R18, R22, R24, R30, R40, R50, R60	8
Under-slab R-Value	R0, R11, R15, R20	4
Foundation Wall R-Value	R11, R17, R20, R25	4
Exposed Floor R-Value	R27, R29, R35, R40	4
Ceiling/Roof R-Value	R40, R50, R60, R70, R80, R100	6
Window Option & U-Value	Double (1.8), double (1.6), double (1.4), high gain triple (1.2), low gain triple (1.2), triple (1.0), high performance triple (0.8)	7
Domestic Hot Water (DHW) System	Electric tank, gas tank, 2 x gas tankless, heat pump (electric)	5
Drain Water Heat Recovery	None, 30%, 42%, 55% (recovery efficiencies)	4
Space Heating	Gas 92% & 95% AFUE, gas combo, Cold Climate ASHP (electric), Baseboard (electric)	5
Ventilation Heat Recovery	None, 60%, 70%, 75% & 84% SRE	5
Total Number of Possible Combinations		**53,760,000**

Posterity Group modelled the energy savings in the CPR by applying savings percentage assumptions to space heating and water heating end-uses and energy use intensities (EUIs). The LTGRP assumed an even more stringent Step Code requirement than the CPR. These assumptions were sourced from the most recent data sources and literature at the time. Space heating and water heating savings assumptions for residential Step Code measures were based on FEI's New Home Program participant data. Savings assumptions for commercial Step Code measures were based on engineering calculations using the Step Code targets, billing data, and modelling studies.

Figure 2 shows the fuel source used for space and water heating in each of the above-mentioned measures.

Figure 2: Fuel Source Used for Space and Water Heating

Measure	Space Heating	Domestic Hot Water
Residential		
Step 3 Homes	Gas	Gas
Step 3 Homes - Electric DHW	Gas	Electric
Step 4 Homes	Gas	Gas
Step 4 Homes - Electric DHW	Gas	Electric
Step 5 Homes	Gas	Gas
Step 5 Homes - Electric DHW	Gas	Electric
Step 5 Homes - Mature Market Costs	Gas	Gas

30 BC Housing and the Energy Step Code Council, 2018 Metrics Research Full Report Update, (September 18, 2018) Table 14, p. 20, online at: http://energystepcode.ca/app/uploads/sites/257/2018/09/2018-Metrics_Research_Report_Update_2018-09-18.pdf.

Measure	Space Heating	Domestic Hot Water
Commercial		
Step 2 - Residential Occupancies	Gas	Gas
Step 2 - Commercial Occupancies	Gas	Gas
Step 2 Equivalent Performance - Non-Step Code buildings	Gas	Gas
Step 3 - Residential Occupancies	Gas	Gas
Step 3 - Commercial Occupancies	Gas	Gas
Step 3 Equivalent Performance - Non-Step Code buildings	Gas	Gas
Step 4 - Residential Occupancies	Gas	Gas
Step 4 Equivalent Performance - Non-Step Code buildings	Gas	Gas

99.0 Reference: DEMAND-SIDE RESOURCES

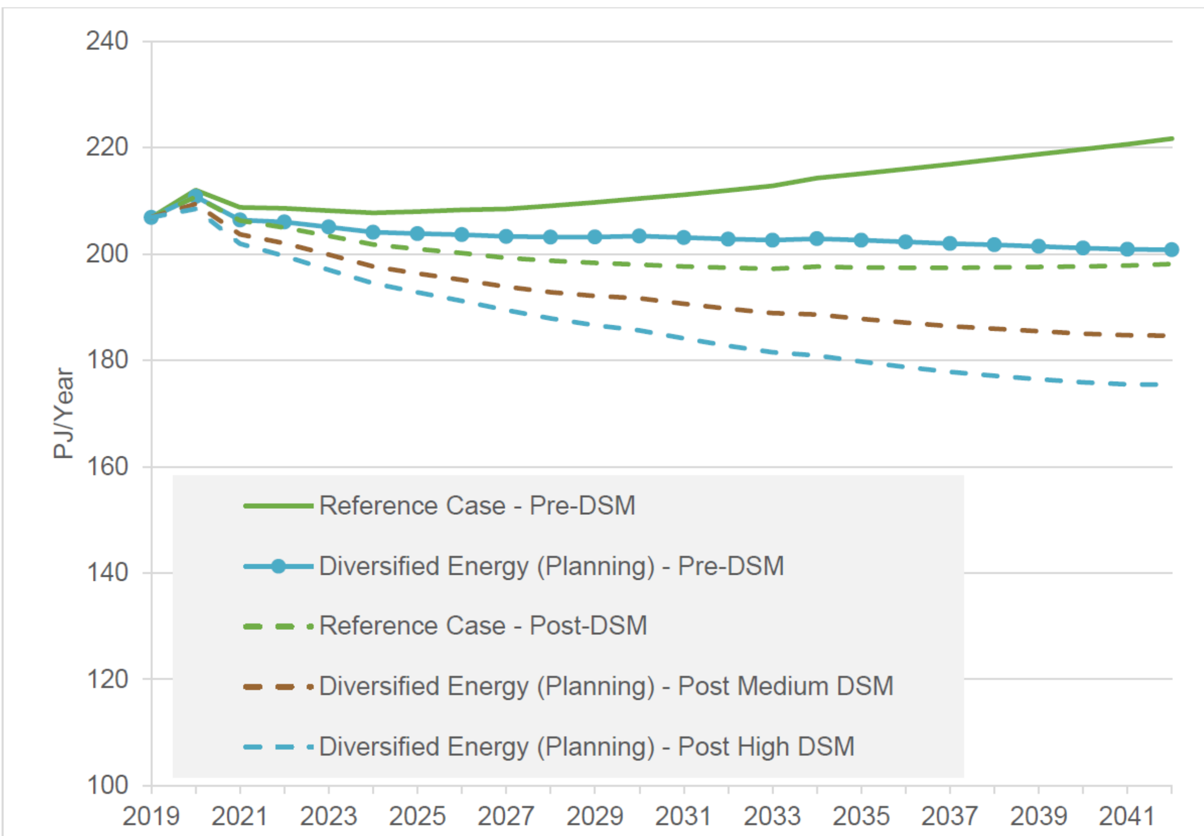
Exhibit B-1, Appendix C-1, p. 133; Appendix C-2, p. 2-3; Appendix A-5, p. 68

Impact of New Carbon Pollution Standard on Potential DSM Potential Savings

On page 133 of Appendix C-1, FEI states that the reference consumption is forecasted to increase to 241 PJ by 2040 – it is 222 PJ today.

On pages 2 to 3 of the Supplemental DSM Analysis provided in Appendix C-2, FEI provides Figure C2-1 illustrating annual energy demand, excluding Low Carbon Transportation, before and after estimated DSM energy savings for all sectors combined. Reference consumption in 2040 appears to total approximately 222PJ.

Figure C2-1: Annual Demand Before and After Estimated DSM Savings (Excluding LCT) - All Sectors Combined



99.1 Please compare the reference case shown in Appendix C-1, with the reference case shown in Appendix C-2, and provide an explanation for any adjustments made between the two reference cases.

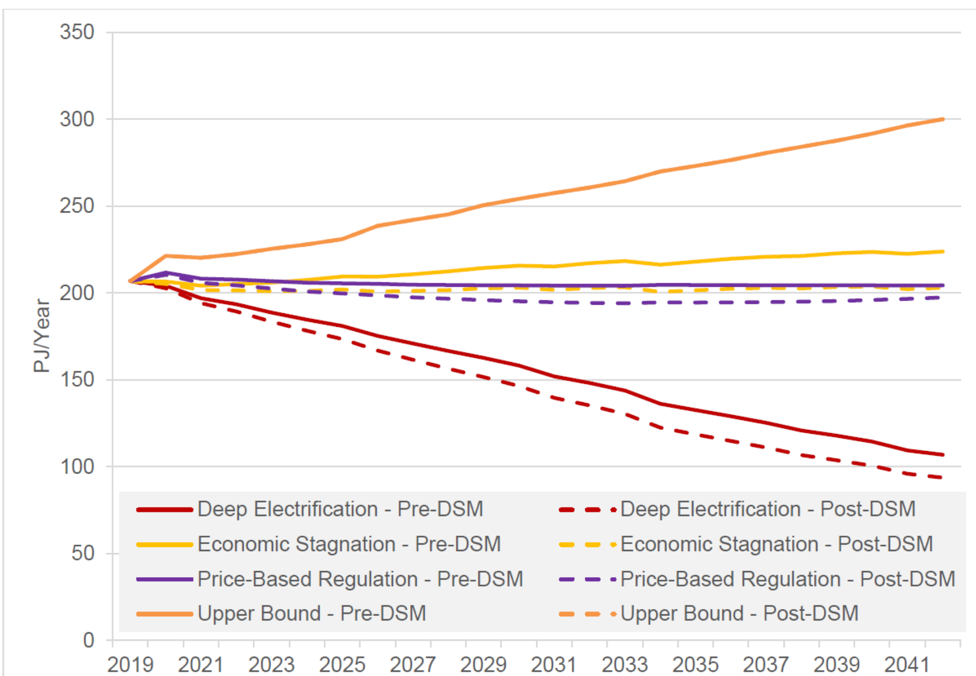
Response:

The difference between the higher Reference Case demand illustrated in Appendix C-1 (2021 Conservation Potential Review Report) versus Appendix C-2 (Supplemental Information for Demand Side Resources - DSM Analysis) is related to the co-generation plant on Vancouver Island as follows:

- Appendix C-1 – the higher demand includes the co-generation plant on Vancouver Island; and
- Appendix C-2 – does not include the co-generation plant on Vancouver Island and aligns with the DSM analysis discussion in Section 5 of the Application.

FEI provides Figure C2-2 showing the forecast annual demand before and after estimated DSM savings, across the various annual energy demand forecasts:

Figure C2-2: Annual Demand Before and After Estimated DSM Savings (Excluding LCT) - All Sectors Combined



The Clean BC Roadmap states on pages 39-40:

> The decarbonization of buildings is at an early deployment phase. Households and businesses can choose from a range of low carbon solutions and B.C. is already a leader in this space. New construction is steadily moving towards the highest efficiency levels and builders are growing their capacity to make new buildings

cleaner, supported by increasing adoption of the Energy Step Code, which sets higher energy-efficiency standards than the base BC Building Code. However, we still rely on fossil fuels to meet more than half our energy needs in buildings. …That's why we're adding a new carbon pollution standard to the BC Building Code, supporting a transition to zero-carbon new buildings by 2030.…The standard will be performance-based, allowing for a variety of options including electrification, low carbon fuels like renewable natural gas, and low carbon district energy.

99.2 Please discuss which of the above demand forecasts most closely aligns with the proposed transition to zero-carbon new buildings by 2030, for all customer segments.

Response:

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

FEI considers that it is too early to determine with any precision the demand impacts of the proposed transition to zero-carbon new buildings by 2030 until there is more certainty with regard to the role of renewable and low-carbon gas and other policy decisions affecting FEI, as discussed in the response to BCUC IR2 81.2.1. At the time the forecast modelling was undertaken for the LTGRP (prior to the RG Program Application), FEI did not assume that approval or not of the Renewable Gas Connections service (or any other aspect of FEI's approvals sought in that proceeding) would be a critical uncertainty impacting FEI's ability to add new construction customers or comply with the proposed transition to zero-carbon new buildings by 2030, as suggested in the preamble.[31]

One measure to evaluate how aligned scenarios are with a zero-carbon buildings transition by 2030 is to evaluate the GHG reductions in new buildings relative to the Reference Case from the existing scenarios. The emissions reductions from the scenarios listed in Figure C2-2 are illustrated in Table 1 below.

Table 1: New Construction Measures: Percentage Emission Reductions Over Reference Case for Select Scenarios[32] 2019 to 2030

Customer Type	DEP	Deep Electri-fication	Price-Based Regulation	Economic Stagnation	Upper Bound
Residential	-21%	-49%	-24%	32%	19%
Commercial	-18%	-52%	-19%	-15%	50%
Industrial	-17%	-34%	-26%	-35%	128%
Total	**-19%**	**-47%**	**-22%**	**-5%**	**57%**

[31] Please refer to the response to BCUC IR2 97.5 for further discussion.

[32] The analysis includes emission reductions through distribution of conventional natural gas, renewable and low-carbon gases. FEI recognizes there would be some increase in emissions from the increased electricity required due to electrification, but that increase is not included in the table.

Based on emissions reduction for new construction measures from 2019 to 2030, the Deep Electrification Scenario achieves the most GHG reductions for all customer segments. This is due to the possibility that fuel switching, with its inherent uncertainty, has the largest impact on demand, as discussed in the response to BCUC IR2 81.2.1. However, as discussed above, the LTGRP did not fully model the impact of measures proposed in the RG Program Application. Were they to be approved, then the DEP Scenario would likely show greater GHG reductions in line with the Deep Electrification Scenario.

100.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-6, BCUC IR 43.1; 43.6; Exhibit B-1, Table 5-4, p. 5-27

DSM Expenditures

Table 5-4 of the Application shows the estimated Diversified Energy (Planning) - High DSM Setting Expenditures – All Sectors Combined.

In response to BCUC IR 43.1, FEI states:

> program area non-incentive expenditures were included in each of the DSM Setting scenarios. Non-incentive program costs were assumed to be 15 percent of the corresponding incentive costs. The most recent DSM Annual Report year would act as a good annual proxy for these expenditures. In the FEI 2021 DSM Annual Report, non-incentive expenditures were close to 10 percent of incentive expenditures for the energy savings programs included in the LTGRP.

In response to BCUC 43.1, FEI states:

> Other expenditures not included in Table 5-4 were those that support or enable DSM programs at the portfolio level, such as Enabling Activities and Conservation, Education, and Outreach expenditures. As discussed in the response to BCUC IR1 36.6, FEI does not anticipate that these additional expenditures will significantly impact portfolio cost effectiveness, however this analysis will be completed as a part of DSM Plan development.

In response to BCUC IR 43.6 about the costs included in the directional bill impacts shown in section 5.4.2, FEI states:

> Please refer to the response to BCUC IR1 43.1 for the DSM expenditures that were incorporated into the DSM setting scenario analysis. These expenditures were then included in the directional bill impacts shown in Section 5.4.2.

100.1 Please confirm that portfolio level expenditures such as Enabling Activities and Conservation, Education, and Outreach expenditures, were not included in the directional bill impacts.

100.1.1 If not confirmed, please provide the amount and proportion of DSM expenditures allocated to the portfolio level expenditures for F2021, relative to total DSM expenditures (i.e. including both portfolio and program costs.) Please also provide the estimated impact on directional bill impacts, if all DSM expenditures are included, in dollars and as a proportion of the impacts shown in Section 5.4.2.

Response:

Confirmed. As discussed in the response to BCUC IR1 43.6, the directional bill impacts shown in Section 5.4.2 of the Application are in accordance with the discussion in the response to BCUC IR1 43.1, and as referenced in the preamble. In other words, the directional bill impacts analysis shown in Section 5.4.2 of the Application includes all DSM expenditures that are intended to be included under the DSM Setting scenarios in the Application, and as noted in the response to BCUC IR1 43.1, the DSM Settings in the Application are intended to provide a theoretical model of long-term DSM programming and are not intended for setting the development of ongoing or future DSM plans.

Enabling Activities and Conservation, Education, and Outreach expenditures will be analyzed in the development of future DSM plans. FEI expects there will be differences in expenditures and savings between the DSM Settings in this Application and in the development of ongoing or future DSM Plans.

101.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Appendix C-3, pp. 11; 43-44; Exhibit B-6, BCUC IR 47.1; Anderson, M., LeBel, M., and Dupuy, M. (2021). Under pressure: *Gas utility regulation for a time of transition*, p. 36

Non-Pipe Solutions: Targeted Electrification/Energy Transition

In Exhibit 2 of Appendix C-3, page 11, ICF Consulting Canada Inc. (ICF) summarizes the different types of non-pipe solutions, including:

- **Distributed Infrastructure (supply-side) options** such as LNG, CNG, RNG and Power to Grid; and
- **No-infrastructure (Demand-side) Options** including Enhanced Targeted Energy Efficiency (EETE); Natural Gas Demand Response; and Electrification.

Also on page 11, ICF states:

> most of resources listed in Exhibit 2 can be deployed to seek benefits on a franchise-wise basis; however, they are considered as NPS when they are geo-targeted and considered as alternatives to distribution system infrastructure…. Distributed infrastructure NPS options have a different risk profile than traditional distribution infrastructure because they can be generally be added in smaller and shorter-term capacity increments, reducing their risk of becoming stranded assets if the demand growth does not materialize as forecasted. However, distributed infrastructure NPS options are also typically more expensive than regular distribution infrastructure on a per unit capacity basis.

In response to BCUC IR 48.2, FEI states:

> The disadvantages of formally requiring that NPS be considered in all CPCN applications are primarily that it will in many cases create additional and unnecessary delays and costs to the project approval process. This is particularly the case where a CPCN application, such as the FEI's Advanced Metering Infrastructure (AMI) application, is not related to system capacity requirements. Further, except for considering distributed infrastructure options like CNG or LNG peak shaving solutions, NPS alternatives can present a risk of large system outages if they underperform expectations that are very difficult to quantify. It is therefore difficult to rank and assess such alternatives against the more verifiable increases in capacity to meet peak demand inherent in hard infrastructure assets.

101.1 Please provide FEI's views on the potential role of Non-Pipe Solutions, including geo-targeted ETEE and electrification, in areas where FEI is experiencing system constraints.

Response:

The following response has been provided by ICF Consulting in consultation with FEI.

Geo-targeted ETEE could be an intervention to mitigate future system constraints. However, as FEI's DSM portfolio is currently aligned with the High DSM Setting for the DEP Scenario, it would be challenging to identify what additional geo-targeted DSM offers could reduce load impacts in system constrained areas that is not already offered.

A demand response (DR) program (non-behavioural) that does not allow participants to override the settings could be more effective and reliable, although data would need to be gathered to verify. Most demand response programs focus on residential and commercial space and water heating through connected thermostats and water heater controllers. Similar to electric DR programs, the maximum expected period to shift load would likely not exceed two to four hours, which may or may not align with the temporal nature of the system constraints. FEI plans to evaluate and pilot gas demand response later in 2023.

Geotargeted electrification may be effective in some specific circumstances. The temporal period of FEI system constraints aligns primarily during the coldest periods of the year when demand for space heating is the highest. Electrifying space heating and hot water during those peak periods will add significant peak to the electrical system during the same time as BC Hydro and FortisBC's electrical systems also experience their peak period. This period of time is also when electric space heating is at its least efficient. There could be some specific areas where the gas system has constraints but the electric system has excess capacity, and those would need to be identified through cross-utility system planning.

FEI has had some experience utilizing small scale CNG and LNG to manage short term capacity deficits pending the eventual pipeline solution being installed. However, to avoid an eventual pipeline solution there would need to be substantial evidence that the demand growth was leveling off or beginning to reduce, otherwise the scale of the LNG/CNG supply required grows quickly.

Of note, it is more likely in a particular geographical area that the electric system would experience greater long-term constraints compared to the gas system. In these areas, the gas system can also play a role for peaking support. This peaking support could include the gas system providing back-up to the electric system for heating applications during peak periods (ex. dual-fuel hybrid heating systems) or operating small-scale gas peaker plants to supply peak power in grid-constrained areas.

On pages 43 to 44 of Appendix C-3 to the Application, ICF states:

> To help advance the consideration of NPS in BC, FEI may be interested in submitting an application to BCUC to formalize a framework for the consideration

> and deployment of NPS projects. Following the model of frameworks that have been developed in New York State and Ontario, this would provide guidance and direction regarding important aspects such as the assessment process for NPS projects, the approach for cost-effectiveness analysis, the allocation of risk, monitoring and reporting requirements, timeline, sourcing, and cost recovery.

In response to BCUC IR 49.1, FEI states:

> FEI plans on exploring demand response natural gas solutions as part of its Innovative Technologies portfolio in the 2023 DSM Expenditures Plan. Although design work has not commenced, a prefeasibility study is underway to identify information gaps such as technology options, market potential, costing inputs and energy savings. FEI expects to complete this analysis by Q1 2023.

101.2 In addition to exploring demand response solutions noted in the 2023 DSM Expenditures Plan, please provide FEI's views on preparing a framework for the consideration and deployment of other types of NPS projects.

Response:

As noted in the ICF Report, the development of a BC-specific NPS framework would provide guidance and direction regarding several important aspects related to the development and deployment of NPS projects in BC. The development of NPS frameworks in other jurisdictions such as New York State and Ontario has facilitated the evaluation and deployment of NPS projects in these jurisdictions. FEI is supportive of the development of a BC-specific NPS framework that leverages best practices in other jurisdictions, while reflecting the realities of the BC market.

At the time of writing, gas demand response pilot activities have not commenced. Therefore, it is too early to speculate on the views or timelines for preparing the framework until further information is gathered on the efficacy and applicability of NPS projects.

A paper released by the Regulatory Assistance Project in 2021 entitled *Under pressure: Gas utility regulation for a time of transition* states[33] on page 36:

> …at least in principle, managing the transition carefully by targeting electrification efforts can lower the costs associated with the gas distribution system that remains in place during and after the transition. A smaller network should have lower O&M

[33] Anderson, M., LeBel, M., & Dupuy, M. (2021, May). Under pressure: Gas utility regulation for a time of transition. Regulatory Assistance Project. https://www.raponline.org/wp-content/uploads/2021/05/rap-anderson-lebel-dupuy-under-pressure-gas-utility-regulation-time-transition-2021-may.pdf.

costs. The main idea behind targeted electrification is to retire geographic areas of the distribution grid, area by area. First, an area of the distribution network is selected or targeted for retirement, and then an electrification program is implemented, with the goal of rapidly electrifying all gas usage in that particular area (see Figure 1188), before moving on to the next area. Such an approach should allow a part of the distribution network to be retired, obviating the need for continued O&M spending in that area. In contrast, electrification efforts that proceed in a nontargeted, scattershot fashion — with, say, neighboring buildings undergoing electrification in different years — will leave the distribution network in place at its current size for longer, with little reduction in O&M costs, despite the reduced gas throughput. This would leave fewer gas-using customers paying a greater share of system costs, creating upward pressure on rates. The California report suggests that a targeted approach could lead to substantial O&M savings and help manage the costs of a gas transition, although the authors caution that the cost savings will depend on careful study of suitable footprints for targeting. For that reason, states committed to gas transition should consider implementing targeted electrification and gas distribution retirement pilots early in the process.

101.3 Please provide FEI's views on the potential role of Non-Pipe Solutions, including geo-targeted ETEE and electrification, as a means of managing the potential impact of the energy transition on FEI and its ratepayers.

Response:

Please refer to the response to BCUC IR2 101.1. NPS may play a role in managing the potential impact of the energy transition on FEI and its customers.

101.4 Please discuss the ability of FEI to provide a system view of network segments which are experiencing system constraints, as part of the next and future long-term resource plans.

Response:

FEI assumes the term "network segments" refers to FEI's gas distribution infrastructure, and not its transmission infrastructure. While FEI has the ability to provide various views of its system network segments, it does not, at this time, have sufficient understanding of the parameters of information the BCUC would require to be provided within the context of a long-term resource plan. For instance, it is likely that a broader program would be required to coordinate the transition between electric and gas utilities, as well as regulatory approvals. For this reason, FEI cannot provide a complete estimate of the additional time and resources it would take to develop an approach but anticipates that they would be substantial given both the detailed and site-specific information that would be required, and the complexity of coordinating the exercise.

The 2022 LTGRP has identified the need to maintain the gas system in order to support the resiliency and decarbonization of BC's overall energy system. As such, FEI does not consider that a review of network segments is needed or would serve the public interest. Given that no decision or program has been implemented to electrify portions of the gas distribution system, such a review would be premature at best.

Further, as discussed in Section 7.3.5 of the Application, distribution system projects are routinely identified as part of FEI's capital planning process and are not discussed in long-term resource plans, other than to provide updates on more significant work proposed or underway. FEI therefore considers that the LTGRP is not the appropriate proceeding in which to provide a system view of network segments. However, in the future, if a decision or program to electrify certain segments of the gas distribution grid were to be implemented, FEI expects that this would form part of the planning environment that would be considered by future LTGRPs, and FEI expects impacts of the activity would be reflected in FEI's demand scenarios and other long-term planning considerations.

F. SYSTEM RESOURCE NEEDS AND ALTERNATIVES

102.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-6, BCUC IR 54.5.1; Exhibit B-1, Appendix B-2, pp. 29, 35, 57, 59, Section 7.2.3.2, p. 7-9

End Use Methodology for Capacity Planning

In response to BCUC IR 54.5.1, FEI states:

> FEI is not aware of any natural gas utilities using an end use methodology in capacity planning. Appendix B-2 of the Application contains a demand forecasting methods benchmarking study in which 18 utilities were examined across multiple jurisdictions. The study includes information on how annual and peak demand forecasts are related for the utilities examined. The study identified a few cases of electric utilities utilizing an end use or hybrid end use method for peak demand forecasting, but no cases of gas utilities using an end use methodology for peak demand forecasting.

On page 29 of Appendix B-2 to the Application, with respect to “Organization D” of the benchmarking study, Energitix states:

> The organization forecasts natural gas demand in the state as part of each [Integrated Energy Policy Report] (IEPR)cycle. The organization uses end-use and econometric models structured along utility planning areas for the residential, industrial, commercial, agricultural, transportation, communications, and utilities sectors.
>
> End-use modelling is used for forecasting residential and commercial demand, while econometric/trend modeling is used for forecasting industrial and agricultural demand.

On page 35 of Appendix B-2 to the Application, further with respect to “Organization D” of the benchmarking study, Energitix states:

> The organization uses hourly load shapes for each end-use and applies the load shapes to the annual demand forecast from the end-use model to determine the hourly demand for each end-use. It then aggregates all the hourly demand for all end-uses to forecast the peak-day demand.

On page 57 of Appendix B-2 to the Application, with respect to “Organization K” of the benchmarking study, Energitix states:

> The company provides gas service to approximately 42,000 residential, commercial and industrial customers in more than 16 communities.

> The company used an end-use model in its annual demand forecast for the residential sector in its most recent long-term forecast, which was part of its 2019 consolidated resource plan.

On page 59 of Appendix B-2 to the Application, further with respect to "Organization K" of the benchmarking study, Energitix states:

> The company determines the design day demand for each of its customer segments based on a mathematical relationship between ambient air temperature and gas consumption that has been determined empirically from historical weather and billed consumption data. The design day demand of residential customers is calculated using the residential end-use model and multiplied by the number of customers forecasted. The design day demand for small and large commercial, and small industrial customers is determined from third- and first-order linear regressions, respectively, of their historical billing and weather data.
>
> As a final step in forecasting peak-day demand, the company sums up the peak-day demand for each customer class to forecast the peak-day demand for the system.

102.1 Please confirm, or explain otherwise, that Organization D and Organization K from the benchmarking study are utilizing the end-use methodology for natural gas peak demand forecasting.

102.1.1 If confirmed, please reconcile FEI's statement that it is "not aware of any natural gas utilities using an end use methodology in capacity planning."

<u>Response:</u>

Organization D is the California Energy Commission and not a utility; therefore, their demand forecast is not used for directly planning utility infrastructure. Organization K is Pacific Northern Gas (PNG). Although the benchmarking study describes incorporation of an end-use methodology by PNG, FEI understands the following considerations:

- The end-use information employed by PNG applies to only a limited portion of PNG's customer demand, namely residential demand, as presented in the benchmarking study.
- Although the end-use trends help to inform PNG's demand forecast, FEI understands that the PNG forecasting model does not yet employ future changes to those trends that are not intrinsically captured in the historic energy use data of PNG's customers. In this aspect, PNG's peak demand forecasting method is similar to FEI's.
- PNG's system design and its customer demand characteristics are not comparable to those of FEI's, making it important that each utility develop and utilize peak demand forecasting methods to provide the best information with which to design and manage its own system.

In summary, FEI remains unaware of any gas utility that fully utilizes an end-use methodology for peak demand forecasting but continues to believe that the information gained from the end-use methodology can be insightful.

102.2 Please identify Organization D and K, and the relevant jurisdictions.

Response:

Please refer to the response to BCUC IR2 102.1.

FEI notes that it had requested that Energitix keep the identities of the organizations surveyed anonymous to facilitate a broader cross-section of input, including those responders who might not be comfortable responding if they know their identities and responses will be included on the public record in a regulatory proceeding. Going forward, FEI and its consultants will clearly state that such responses are likely to be placed on the public record. It may be that participation in such surveys and the value of survey outcomes are reduced as a result.

102.3 Please discuss whether FEI has engaged, or has plans to engage, in discussions Organization D and K to better understand their peak demand methodologies.

Response:

Other than through the benchmarking study, FEI has not engaged and, at present, does not have specific plans to engage further with either organization on the topic of peak demand forecasting methodologies. FEI will continue to monitor developments in peak demand methods in future studies and engage with those organizations it believes can better FEI's understanding.

102.4 Please confirm, or explain otherwise, that Organization K refers to Pacific Northern Gas.

102.4.1 If confirmed, please discuss whether FEI has engaged, or has plans to engage, in discussions with PNG to better understand PNG's peak demand methodology.

Response:

Confirmed. Please refer to the responses to BCUC IR2 102.2 and 102.3.

102.5 Please explain how FEI intends to utilize the results of the Energitix benchmarking study to develop and implement end-use methodology for peak demand forecasting.

Response:

To clarify, while the benchmarking study can help inform FEI about potential paths of development to explore as data technologies and forecasting methods advance, it was not designed or undertaken for the purpose of developing and implementing an end-use methodology for peak demand forecasting and is therefore of little use in doing so.

The Energitix benchmarking study was prepared in response to the BCUC's direction in the 2017 LTGRP Decision to "provide an analysis of FEI's End-use Method as compared to other end-use methods" in the 2022 LTGRP.[34] This direction in turn arose out of the analysis FEI filed for the 2017 LTGRP to comply with the BCUC's direction in the 2014 LTRP Decision, to "provide a detailed analysis of the relative benefits/shortcomings of their particular end-use method as compared to other end-use methods".[35] As such, the study surveys utilities on what method they use, not on the detailed methodology involved. The survey was focused more on annual demand than peak demand methods. Further, the study did not reveal any utilities that truly use an end-use method for forecasting peak demand, so there is no follow up that can be done with any of the utilities surveyed to glean these additional details. FEI considers that it has utilized the benchmarking study for its intended purpose and will continue to monitor and explore forecasting methods and tools for potential improvements that could be implemented by FEI with or without a benchmarking study.

On page 7-9 of the Application, FEI states:

> Since the exploratory end use method is not based on metered FEI customer data, and the effectiveness of DSM programs on peak demand cannot be directly measured until hourly metering is deployed, the Traditional Peak Method forecast, which intrinsically reflects the current effects of DSM programs, remains FEI's base forecast for determining infrastructure requirements and timing for addressing

[34] 2017 LTGRP Decision and Order G-39-19, p. 8.
[35] 2014 LTRP Decision and Order G-189-14, p. 15.

capacity constraints. However, FEI's current application before the BCUC for its AMI project will support FEI's ability to field-validate the projections of the exploratory end use peak demand forecast method and will enable FEI to improve this method in future LTGRPs.

102.6 Please explain whether the AMI project is critical for FEI to implement the end use methodology in capacity planning.

102.6.1 If so, should the AMI project be approved by the BCUC, please explain how FEI intends to improve the end use peak demand forecast method and when FEI intends to implement the end use methodology in capacity planning.

102.6.2 If not, please discuss other methods of gathering the required data to implement the end use methodology in capacity planning.

<u>Response:</u>

FEI views AMI as a critical component, but not the sole component, in developing FEI's understanding and ability to implement an end-use method in peak demand forecasting used in capacity planning. FEI also views the need to employ more extensive residential and commercial end-use studies and surveys that can form the basis of understanding energy use beyond the meter as critical. These studies and surveys could be used to develop sample populations of similar customers reflecting various end-use characteristics. The surveys could also be used to develop sample populations for peak demand response before and after implementation of general DSM or Demand Response (DR) programs, or more targeted ETEE and DR programs. From these sample populations, advanced meter data could be used to study various peak demand impacts to develop end-use forecasts that could be extrapolated to the wider system with greater confidence. It may also be necessary to some extent for FEI to examine actual end-use consumption beyond the customer meter more closely.

FEI would be able to begin examining the initial streams of data the first winter after the beginning of AMI meter deployment. If approval were received in the first half of 2023, deployment would be expected to begin by 2024. However, information sufficient to understand, verify, and fully apply meaningful changes to system planning processes, supported by data, and to apply those changes to the system at a larger scale will require data collection and assessment through multiple winter periods in all FEI operating regions. FEI expects this to take a few years beyond completion of AMI deployment in all regions. Regardless of employing AMI to study end-use effects on peak demand forecast throughout the AMI deployment period, FEI is expecting to achieve results that will improve the precision of FEI's traditional peak demand method.

103.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-6, BCUC IRs 54.6, 54.7.2,

Traditional Peak Demand Forecast

In response to BCUC IR 54.6, FEI states:

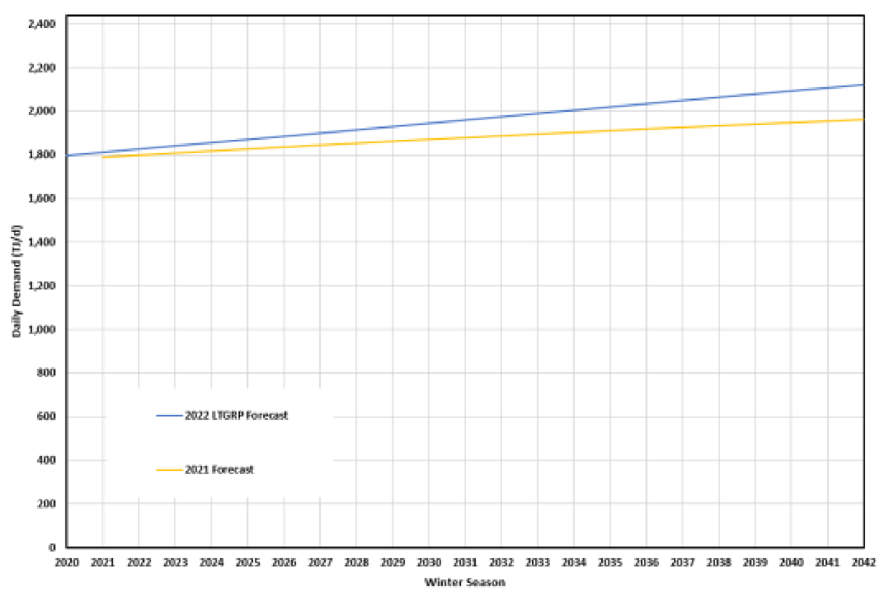
> The base year for the peak demand forecast was 2019 (referred to as the 202 peak demand forecast). Customers attached on or before December 31, 2019 were accounted for in base demand and values for 2020, and future years included the peak demand of forecasted account additions.

In response to BCUC IR 54.7.2, FEI states:

> FEI produces a peak demand forecast each year for each transmission system. FEI's most recent completed forecast for each system is the 2021 forecast (based on 2020 year-end customer attachments in all areas). FEI expects that the 2022 forecast (based on 2021 year-end customer attachments) will be completed by mid-December 2022.

Further in response to BCUC IR 54.7.2, FEI provided the following figure for each transmission system:

Figure 2: CTS Traditional Peak Demand Comparison63

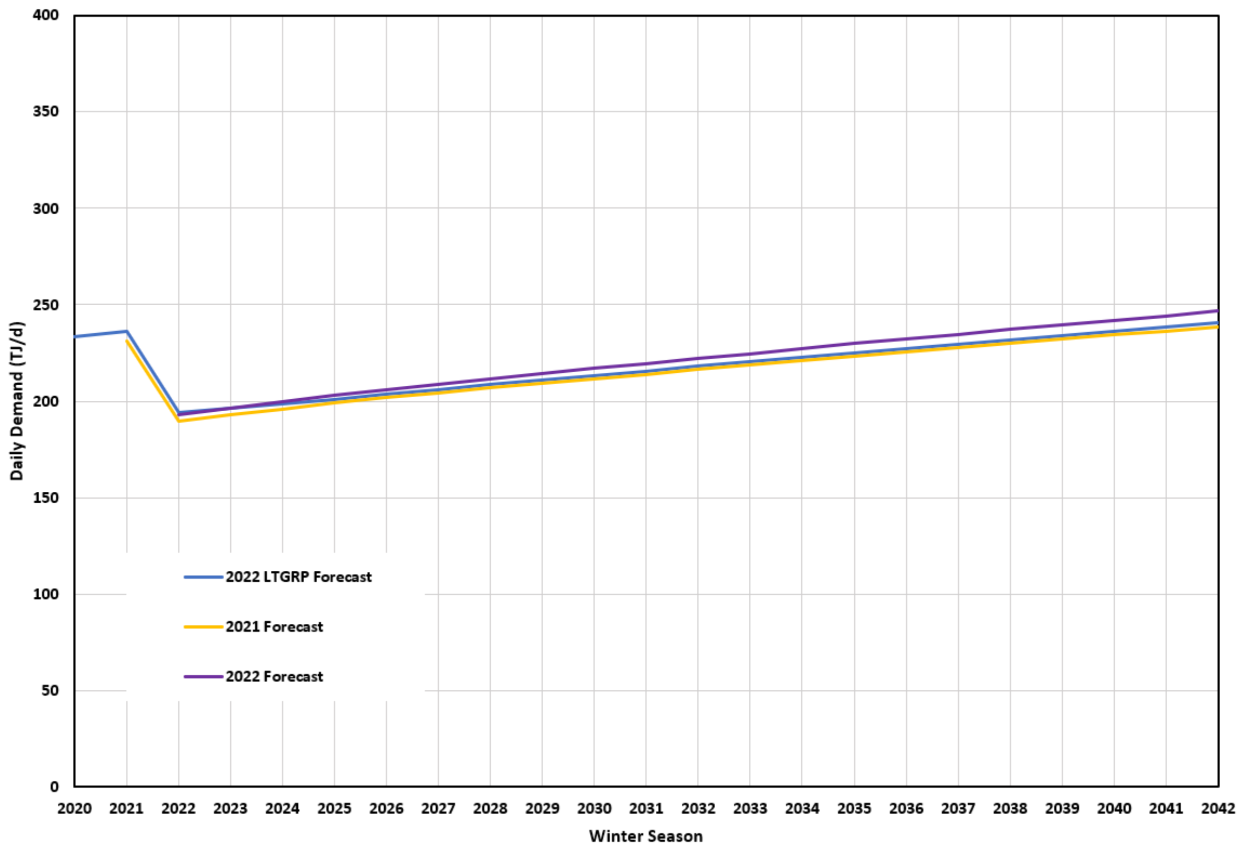


103.1 Please reproduce the preceding figure for each transmission system including results of the 2022 peak demand forecast.

Response:

The requested figures modified to add the 2022 peak demand forecast are reproduced below.

1 **Figure 1: VITS Traditional Peak Demand Comparison**



2

Figure 2: CTS Traditional Peak Demand Comparison

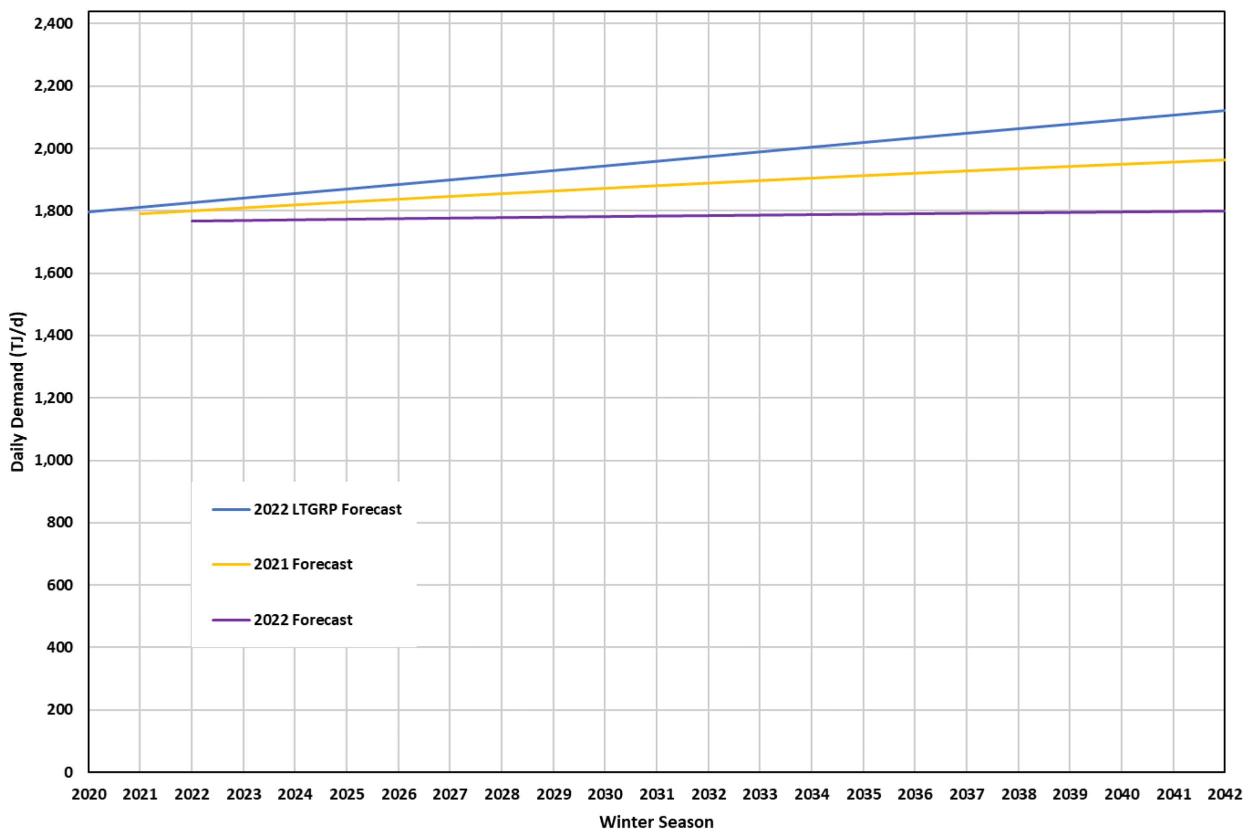
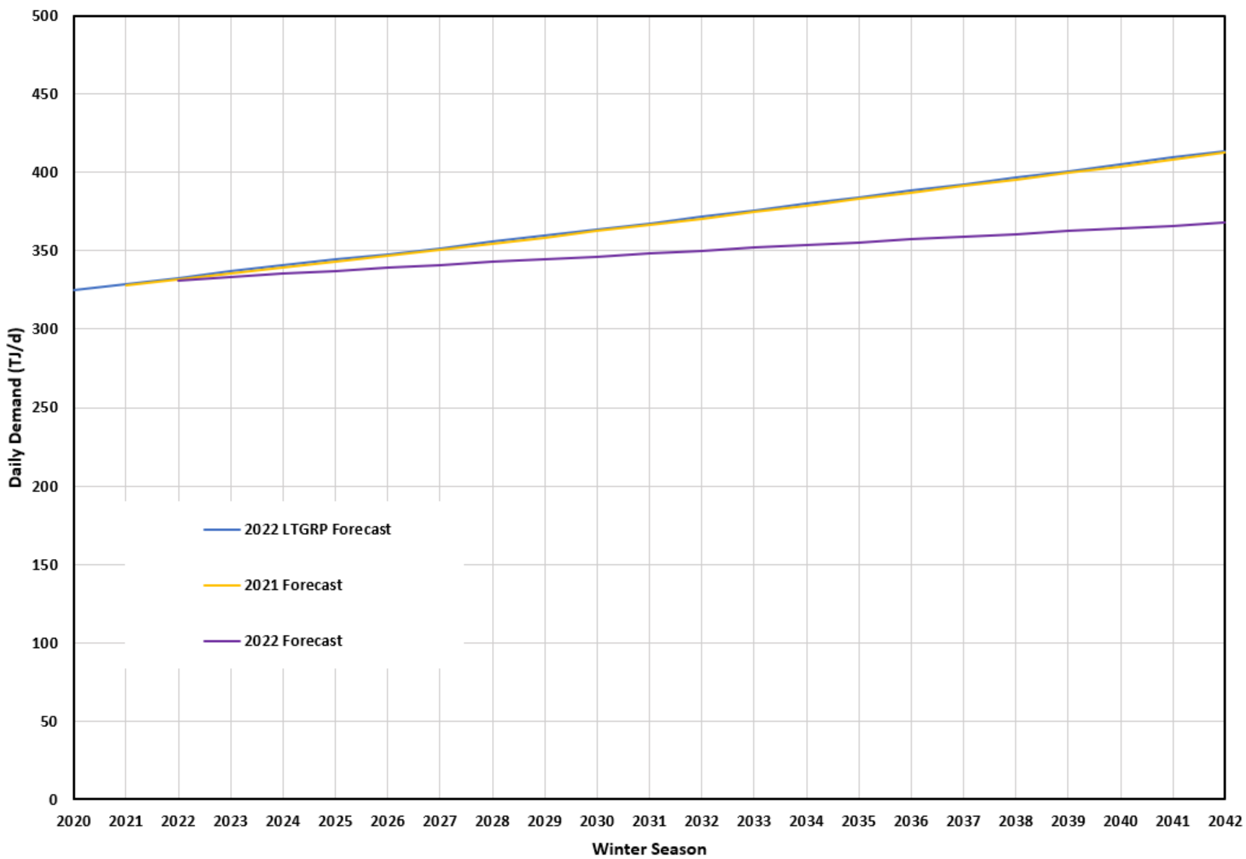


Figure 3: ITS Traditional Peak Demand Comparison



103.1.1 Please provide a detailed explanation for any differences between the forecasts over the 20-year planning horizon. In the response, please discuss any implications to capacity planning as a result of these differences.

Response:

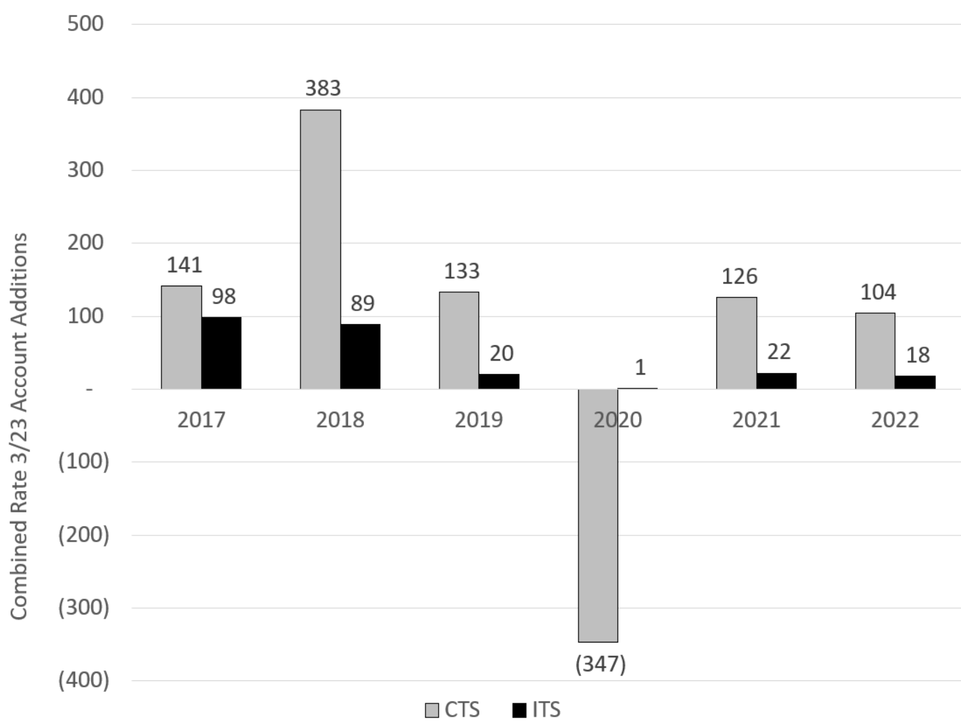
FEI updates the traditional load forecast for each system annually and each year's changes in the long-term forecast, either upwards or downwards, are observed. The changes in the forecast are primarily the result of changes in two parameters:

1. UPC_{peak}, or peak use per customer values that are refreshed each year based on FEI customers' most recent consumption data; and
2. New customer account forecasts that revise the estimates of residential, small commercial and large commercial additions over the next 20 years.

A key input to the commercial account forecast is the average of the most recent three years of net account additions (or subtractions) which can vary significantly year to year; and so, while the yearly variations to customer UPC_{peak} are generally small, account forecasts can swing more dramatically. This effect is apparent in the graphs for the CTS and ITS provided in the response to BCUC IR2 103.1, where the 2022 forecast is seen to be lower than the original 2022 LTGRP forecast. The 2020 net account additions for Rate Schedule 3 and 23 customers in the ITS and CTS were unusually low values, which has resulted in a low account forecast for 2022, and a correspondingly lower load forecast as well.

Figure 1 shows the annual account additions/subtractions for the five years preceding the 2022 forecast. Data for 2022 year-end is now available and shown for reference, though it was not used in the development of the 2022 forecast which was produced last year.

Figure 1: CTS and ITS Rate 3 & 23 Account Additions



In the CTS, in 2018 a large number of additions were noted which may have been related to the rupture incident on the Enbridge T-South pipeline in late 2018, prompting interruptible customers to take up firm contracts. The correspondingly low value in 2020 may in part be a correction of that 2018 spike. For both the CTS and ITS, FEI further speculates that the emergence of the COVID-19 pandemic could have been a factor in the low account addition totals for that year.

Since system improvements are sized to meet long-term requirements, their ultimate need is seldom affected by these changes in peak demand forecasts. The near-term changes are used to refine timing of projects (i.e., advancement or deferral opportunities) and potentially larger, long-term forecast changes can be used to confirm or refine the ultimate scope of projects.

Therefore, FEI does not consider the changes in the 2022 forecast to have immediate implications to capacity planning.

103.2 Please discuss the magnitude of deviation between consecutive annual peak demand forecasts that FEI expects and considers acceptable.

Response:

FEI does not have an acceptability threshold for changes in peak demand forecasts. FEI studies any differences to understand and explain the reasons for the year-over-year changes in forecast. In response to changes, on the rare occasion it is required in the short term, FEI takes action on any adjustments or mitigation required to accommodate execution of existing project work. For changes in the later forecast period, FEI monitors the forecasts for potential adjustments to project timing for any capacity constraints identified.

103.3 Please discuss the magnitude of deviation between consecutive annual peak demand forecasts that FEI would consider concerning.

103.3.1 Please discuss any actions as a result of this magnitude of deviation.

Response:

Please refer to the response to BCUC IR2 103.2.

104.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES
Exhibit B-6, BCUC IRs 56.3.1, 56.3.2.1, 22.1.1
Annual Demand and Peak Demand Relationship

In response to BCUC IR 56.3.1, FEI states:

> In the Reference Case Annual Demand Forecast over the forecast period, some end use patterns and policies in place in the base year are applied to the Reference Case forecast. The policies that provide reductions to future annual demand are not applied in the traditional peak demand forecast. The relationship between Annual Demand forecast and the Peak Demand forecast is influenced by how these factors are applied to annual demand, but not the Traditional Peak Demand. Traditional Peak Demand forecast does not apply future demand reduction for various customer classes as seen in the Reference Case Annual Demand forecast, and therefore peak demand will typically increase by a greater percentage, or will increase when annual demand is declining.
>
> On an annual basis, FEI is now planning to the DEP Scenario forecast. When considering the DEP Scenario forecast, annual demand is the result of a wider range of end use influences being applied including, among others, electrification, substantial adoption of renewable gases, high levels of DSM, government policy and program, etc. The relationship diverges to a greater degree as is documented in the response to BCUC IR1 56.3.2. The ramping up of various end-use factors in the forecast period is the driver for the change in the relationship between annual demand and peak demand over the forecast period. FEI purposefully does not apply these moderating factors to peak demand forecasts because of the uncertainty in the ability to measure the effect on peak demand and the resulting potential for suppressing the identification of need for infrastructure or forecasting sufficient lead time to implement if the peak reduction potential is over-represented.

104.1 Please explain what is meant by:

i) End use patterns and policies

ii) End use influences

iii) End-use factors

iv) Moderating factors

Response:

FEI acknowledges the use of these informal terms in the response to BCUC IR1 56.3.1 but confirms that they are not referring to any data or analysis that FEI has access to or has conducted that is not already included in the LTGRP. FEI provides additional context below to explain how these terms relate to the analysis undertaken in the LTGRP to model future annual demand.

- The term “end use patterns and policy” generally describes those customer behaviors and government policies (at any level) that can affect the amount of energy used and the times that it is used.
- “End use influences” is a somewhat broader term intended to include those things that can impact customer energy use behavior. Examples of influences include price of energy, energy policies (including the setting of a price on carbon), societal values and programs such as incentive or marketing programs designed to affect customer energy decisions and energy use behavior.
- In the context of the response to BCUC IR1 56.3.1, the term “end use factor” is a broad term used to encompass the concept of end use patterns, policy and influences as described in the preceding sentences.
- The term “moderating factor” is intended to refer to those end use factors that cause a moderating effect on demand growth (i.e., cause demand growth to be less than it would be in their absence).

Practically speaking, in many cases, the impact of each end use pattern, policy or influence that can potentially impact energy use cannot readily be individually measured, monitored or modelled. Rather, FEI went through an extensive process of identifying “Critical Uncertainties” that capture the most important and influential of these “factors”. These Critical Uncertainties are listed in Tables B3-1 and B3-4 of Appendix B3 and are discussed in full in Section 4.5 and Appendix B3 of the Application, with one exception: the estimated impact of energy efficiency activities is examined separately from other “factors” in Section 5 of the LTGRP.

104.2 Please identify the end use patterns and policies in place in the base year that are applied to the Reference Case forecast but not the peak demand forecast.

<u>Response:</u>

Please refer to the response to BCUC IR2 104.1. The Critical Uncertainties are described in Appendix B3 of the Application.

Each of the Critical Uncertainties described in Appendix B3 cause changes in the Annual Demand forecast that are not included in the determination of the Traditional Peak Demand forecast. As discussed in Section 7.2.3.1 and in the response to BCUC IR1 56.3.1 quoted in the preamble, FEI’s traditional peak demand forecast reflects and carries forward, unchanged, the end-use factors currently present in customers’ measured consumption, but does not reflect any projected future changes to existing end use factors or those that are expected to be implemented later in the forecast period.

104.2.1 For each end use pattern and policy, please discuss its expected impact to peak demand over the 20-year planning horizon.

Response:

In Section 7.3 of the Application, several figures were provided comparing the FEI Traditional Peak Demand Forecast and the theoretical end use peak demand forecasts. As discussed in the response to BCUC IR2 104.1, in many cases, the impact of each end use pattern, policy or influence that can potentially impact energy use cannot readily be individually measured, monitored or modelled, so the individual contributions of specific patterns, policies and influences are not practically identifiable beyond what is broken out below related to DSM programs. With FEI's response to BCUC IR2 104.1 as background, FEI and Posterity Group provide the following discussion about the impact of the Critical Uncertainty analysis on peak demand over the 20-year planning horizon.

In Figures 7-4 and 7-5, examples of the traditional and end use peak demand forecasts, pre-DSM and post-DSM, for the VITS are presented. At the end of the forecast period (2042), the Traditional Peak demand was approximately 38 TJ per day (15.7 percent) higher than the Reference Case peak demand without DSM. At the end of the forecast period, the Traditional Peak demand was approximately 54 TJ per day (22.4 percent) higher if DSM were applied to the Reference Case forecast. If the impacts of DSM could be applied to peak demand as hypothesized in the Reference Case Peak Demand forecast, the impact of DSM programs specifically would amount to a reduction of 16 TJ per day (6.6 percent) by 2042 in the VITS.

In Figures 7-9 and 7-10, examples of the traditional and end use peak demand forecasts, pre-DSM and post-DSM, for the CTS are presented. At the end of the forecast period, the Traditional Peak demand was approximately 265 TJ per day (12.5 percent) higher than the Reference Case peak demand without DSM. At the end of the forecast period, the Traditional Peak demand was approximately 411 TJ per day (19.4 percent) higher if DSM were applied to the Reference Case forecast. If the impacts of DSM could be applied to peak demand as hypothesized in the Reference Case Peak Demand forecast, the impact of DSM programs specifically would amount to a reduction of 146 TJ per day (6.9 percent) by 2042 in the CTS.

In Figures 7-15 and 7-16, examples of the traditional and end use peak demand forecasts, pre-DSM and post-DSM, for the ITS are presented. At the end of the forecast period, the Traditional Peak demand was approximately 49 TJ per day (11.8 percent) higher than the Reference Case peak demand without DSM. At the end of the forecast period, the Traditional Peak demand was approximately 82 TJ per day (19.8 percent) higher if DSM were applied to the Reference Case forecast. If the impacts of DSM could be applied to peak demand as hypothesized in the Reference Case Peak Demand forecast, the impact of DSM programs specifically would amount to a reduction of 33 TJ per day (8.0 percent) by 2042 in the ITS.

104.3 Please discuss whether there are gas utilities that account for similar end use patterns and policies in peak demand forecasting in other jurisdictions.

Response:

FEI is not aware of other utilities that account for similar end use patterns as those examined by FEI for its annual demand, in their peak demand forecasting.

104.4 Please provide a description of each end-use factor in the forecast period that is the driver for the change in relationship between annual demand and peak demand over the 20-year planning horizon.

Response:

Please refer to the responses to BCUC IR2 104.1 and 104.2. Given FEI's response to BCUC IR2 104.1 indicates that it considers "end-use patterns and policies" and "end-use factor" in FEI's response to BCUC IR1 56.3.1 to have similar meaning, FEI's response to BCUC IR2 104.2 also addresses this IR.

104.4.1 For each end-use factor, please explain how it impacts the relationship between annual demand and peak demand over the 20-year planning horizon.

Response:

Please refer to the responses to BCUC IR2 104.1, 104.2 and 104.2.1.

104.4.2 For each end-use factor, please discuss its expected impact to peak demand over the 20-year planning horizon.

Response:

Please refer to the responses to BCUC IR2 104.1, 104.2 and 104.2.1.

104.5 Please describe what is needed for FEI to accurately represent the peak reduction potential of the end-use factors discussed in the preamble.

104.5.1 Please explain how, if at all, FEI intends to achieve this for future peak demand forecasts.

Response:

Please refer to the response to BCUC IR2 102.6 for more detail. As discussed in that response, FEI needs more detailed metering data at the customer or even end-use application level to validate the peak demand reduction potential for end use forecasting. AMI data will provide a substantial improvement to existing peak demand characteristics. In addition, FEI also views as critical the need to employ more extensive residential and commercial end-use studies and surveys that can form the basis of understanding energy use beyond the meter, and that can complement the AMI data and the influence end-use factors have on peak demand.

104.5.2 Please explain whether FEI is aware of other utilities accounting for similar end-use factors in peak demand forecasting in other jurisdictions.

Response:

Please refer to the response to BCUC IR2 102.1.

104.6 Please discuss any risks to capacity planning by not accounting for the end-use factors in peak demand forecasting.

Response:

With the FEI Traditional Peak Demand forecast currently not accounting for future end-use factors, there could be a risk that some capacity upgrades could be installed unnecessarily that might otherwise have been deferred, reduced in scope, or eliminated as demand patterns and end-uses change.

Also, as discussed in the response to BCUC IR1 56.3.1 referenced above, FEI considers the greatest risk to capacity planning is in not anticipating the capacity shortfalls that might occur because of the inability to directly measure the impact of various end-use factors on peak demand. This could result in FEI being unable to anticipate and install needed infrastructure in time to support future peak demand.

However, FEI addresses these potential risks through the annual process of refreshing and keeping the assessment of peak demand and the peak demand forecasts current. FEI uses these refreshed forecasts to validate the short- to medium-term need for capacity upgrades as well as to identify new requirements or monitor the need for previously identified requirements later in the forecast period. As a result, there is low risk that capacity upgrades are initiated when they are not required. As the time for initiating detailed planning and then execution on these major projects nears, FEI uses updates to peak demand forecasts in the years since the projects were first identified to refine the timing and scope of the projects to reflect the more current peak demand needs. These more recent peak demand assessments and forecasts will incorporate the effects of end-use factors present in current customer consumption that materialize in the intervening years.

In response to BCUC IR 56.3.2.1, FEI provides the following tables outlining the change in DEP annual forecast and traditional peak demand forecast over the 20-year planning horizon:

Region / Transmission System	Customer Class	DEP Annual Forecast	Traditional Peak Demand Forecast
VITS	Residential	14 percent decrease	35 percent increase
	Small Commercial	6.5 percent decrease	48 percent increase
	Large Commercial	30 percent decrease	10 percent increase
	Industrial	16 percent decrease	No change
	Combined	16 percent decrease	27.5 percent increase
CTS	Residential	33 percent decrease	6 percent increase
	Small Commercial	17 percent decrease	17 percent increase
	Large Commercial	40 percent increase	96 percent increase
	Industrial	28.5 percent decrease	No change
	Combined	13 percent decrease	18 percent increase

Region / Transmission System	Customer Class	DEP Annual Forecast	Traditional Peak Demand Forecast
ITS	Residential	30 percent decrease	14 percent increase
	Small Commercial	20 percent decrease	20.5 percent increase
	Large Commercial	82.5 percent increase	250 percent increase
	Industrial	14 percent decrease	No change
	Combined	13.5 percent decrease	32 percent increase

104.7 Given the directional divergence between FEI's planning scenarios for annual demand and peak demand, please discuss how the peak demand forecast can be relied on for the purposes of evaluating the need for future capacity upgrades.

Response:

A key difference in applying the end-use method to the annual forecasting process and applying the same approach to the peak forecasting process is that annual impacts can be measured and verified in sufficient resolution with FEI's existing metering capabilities. Peak-hour and peak-day impacts cannot be sufficiently measured and verified with existing metering capabilities. Therefore, FEI treats end-use peak demand forecasting as a theoretical exercise that can present some possibilities of how peak demand might be influenced through the forecast period but does not consider these forecasts as a reliable planning tool and capable of replacing FEI's traditional method of determining future infrastructure requirements.

FEI uses the Traditional Peak demand forecast to conceive of and determine the preliminary scope of projects to address future capacity needs. Post-conception, FEI continually verifies the project scope and timing based on the most current assessments of peak demand requirements.

104.8 Please discuss the risk(s) that relying on FEI's peak demand forecast would over-represent the need for capacity upgrades..

Response:

Please refer to the responses to BCUC IR2 104.6 and 104.7.

104.9 For each customer class on each transmission system, please provide a detailed explanation of the following:

i) The magnitude and direction of the DEP annual forecast over the 20-year planning horizon.

ii) The magnitude and direction of the Traditional Peak demand forecast over the 20-year planning horizon.

iii) The difference in direction and/or magnitude of the DEP annual forecast and the Traditional Peak demand forecast over the 20-year planning horizon.

Response:

The following table provides the detail of the magnitude and direction of the DEP Annual Forecast and the Traditional Peak Demand for FEI's three major transmission systems over the 20-year planning horizon. This information formed the basis of the table presented in the preamble.

Region / Transmission System	Customer Class	DEP Annual Forecast	Traditional Peak Demand Forecast
VITS	Residential	0.89 PJ decrease	29.0 TJ/day increase
	Small Commercial	0.22 PJ decrease	20.5 TJ/day increase
	Large Commercial	0.96 PJ decrease	2.5 TJ/day increase
	Industrial	1.33 PJ decrease	no change
	Combined[36]	3.40 PJ decrease	52 TJ/day increase
CTS	Residential	17.08 PJ decrease	45.1 TJ/day increase
	Small Commercial	3.06 PJ decrease	53.7 TJ/day increase
	Large Commercial	8.70 PJ increase	226.3 TJ/day increase
	Industrial	5.16 PJ decrease	no change
	Combined[1]	16.60 PJ decrease	325.1 TJ/day increase
ITS	Residential	4.49 PJ decrease	22.5 TJ/day increase
	Small Commercial	1.09 PJ decrease	13.6 TJ/day increase
	Large Commercial	3.20 PJ increase	68.1 TJ/day increase
	Industrial	4.28 PJ decrease	no change
	Combined[1]	6.66 PJ decrease	104.2 TJ/day increase

FEI's planning process applies a series of Critical Uncertainties to the annual demand forecasts but not the peak demand forecasts, resulting in the overall forecasts for each system diverging, with the DEP Annual Demand Forecast decreasing over time and the Traditional Peak Demand Forecast increasing over time. This difference in direction between the two forecasts persists when considering the individual customer classes as well, except for the large commercial customer class in the CTS and ITS. In these systems, both the annual and peak demand forecasts in this customer class increase over time. This is the result of a relatively high rate of large commercial customer additions in both the CTS and ITS in 2017, 2018, and 2019 that resulted in a larger than typical account forecast for this customer class in those systems. The increase in annual demand associated with the forecasted increase in large commercial accounts in those systems outweighed the overall declining influence in DEP annual demand caused by the various

[36] As discussed in the response to BCUC IR1 56.3, while peak demand forecasts are grouped by transmission system "…Annual Demand forecasts are not grouped by the transmission systems but by region. It is reasonable for the regions used in the annual demand scenarios to be grouped to approximately represent (with minor variation) the customers on each system. The Vancouver Island and Whistler region correspond generally to the VITS. The City of Vancouver and Lower Mainland regions correspond to the CTS. The Southern region corresponds to the ITS, although some east Kootenay communities outside of 12 the ITS served by transmission laterals are included."

end-use factors compared to the other rate classes. This forecasted uptick in large commercial accounts did not occur in the VITS.

104.10 Please explain whether there are any other possible drivers, besides a difference in methodology, that could result in a directional divergence between the annual forecast and the peak demand forecast.

Response:

The nature of the end-use equipment being installed over time could also drive a divergence in the changes to annual demand versus the changes to peak demand. In the 2017 LTGRP proceeding, FEI identified smart learning thermostats and on-demand hot water appliances as examples of equipment that could reduce annual demand while increasing (or concentrating) peak demand.[37] The relationship between annual and peak gas demand for hybrid or dual-fuel heating systems that rely entirely or primarily on gas use during peak cold periods is also expected to change the relationship between overall annual demand and peak demand. These examples and the diverging trajectories cited in the preamble highlight that the changing nature of the relationship between annual gas demand trends and peak gas demand trends remains unclear.

104.11 For each customer class, please provide a detailed description of the expected impact of fuel switching on the load factor.

Response:

The impact of fuel switching is difficult to isolate from the other factors causing changes in the DEP Scenario. For example, we are unable to separate out the effects of improvements in codes and standards from the effects of electrification without doing additional modelling. To arrive at an approximation, the following table presents the change in load factor in the DEP Scenario over the planning horizon resulting from all drivers. For the purpose of this response, the change in load factor is based on the change in the ratio of average hourly demand to peak hourly demand.

VITS includes the Vancouver Island and Whistler regions, CTS includes the Lower Mainland and the City of Vancouver, and ITS includes the Southern Interior and Northern BC. The residential rows in the table are based on RS 1 averages, the small commercial rows are based on RS 2, the large commercial rows are based on RS 3 and RS 23, and the industrial rows are based on RS 5 and RS 25.

[37] FEI 2017 LTGRP Proceeding, Exhibit B-5, BCUC IR2 64.2, p. 75.

Region / Transmission System	Customer Class	Change in Load Factor
VITS	Residential	-2%
	Small Commercial	12%
	Large Commercial	4%
	Industrial	-14%
CTS	Residential	2%
	Small Commercial	1%
	Large Commercial	4%
	Industrial	3%
ITS	Residential	-1%
	Small Commercial	2%
	Large Commercial	-1%
	Industrial	2%

In response to BCUC IR 22.1.1, with respect to the pros and cons of having both the annual and peak demands being informed by the end use model, FEI states in part:

Pros:

- The variation in annual and peak demand are related, because the relationship between annual and peak demand at the level of individual end uses in different building types is expected to be relatively consistent. Once you have calibrated these end use factors and have confidence in them, you can explore changes to end use assumptions and the same model will produce estimates of changes to both annual and peak UPC.

…

Cons:

…

- The hydraulic models used to estimate peak demand for system planning are highly sophisticated. The end use model does not have the geographic granularity to show how demand is distributed along the FEI systems, nor the sophisticated handling of the interaction between pressure, volumes, and energy flow of the hydraulic model currently used for peak demand forecasting.

104.12 Please explain whether FEI expects the annual demand forecast and the peak demand forecast to be directionally aligned for each customer class if both annual and peak demands are informed by the end use model.

Response:

Section 7.3 of the LTGRP includes several figures that present theoretical end-use peak demand forecasts for the major transmission systems, including a DEP Peak Demand Forecast. The DEP Peak Demand Forecasts presented are largely directionally aligned with the DEP Annual Demand Forecasts. Were FEI to implement AMI and study the data along with other end-use studies and surveys (as described in more detail in the response to BCUC IR2 102.6) to obviate the risk associated with projecting unverifiable peak demand reductions in the forecast, it is possible that the annual and peak demand forecast may directionally align at some point. Alignment between traditional and end-use demand forecasting methods is likely to advance sooner in residential and commercial sectors than in the industrial sector as industrial customer operations are much more heterogeneous and their end-use load shapes are more difficult to obtain. A future LTGRP may use end-use forecasting for residential and commercial customers, with the traditional peak forecast as a check, and the traditional method for industrial customers.

104.13 Please explain why the end use model does not have the geographic granularity to show how demand is distributed along the FEI systems.

Response:

FEI and Posterity Group have collaborated in providing this response.

Given the volume of data already managed by the end-use model, it is computationally prohibitive to increase the geographic granularity to a level that would illustrate how demand is distributed along the FEI systems. The use of FEI's hydraulic model in concert with the end-use model provides a suitable balance of geographic granularity and efficient analysis of end-use scenarios.

The end-use model incorporates and analyzes scenarios across nine fuels, four sectors, 47 building segments, 24 energy end-uses, hundreds of DSM measures, across all FEI rate classes and does so over a 20-year timeframe. Increasing the complexity of the Navigator end-use model to function with the same level of geographic granularity as the peak demand hydraulic model will increase the digital storage requirements for the model from a few hundred GB of data to close to 350 TB of data, along with commensurate increases in computer processing requirements and significant additional consulting resources to set up, manage and maintain the data.

FEI considers there to be relatively low benefit beyond the information provided by the hydraulic model when considering the amount of development and analysis involved in increasing the end-use model's granularity. As noted above, with the models used in concert, FEI is able to use outputs generated from the end-use models as inputs to the hydraulic models to understand the hypothetical capacity and infrastructure impacts. FEI's current knowledge of the geographic distribution of its customer base provides the granularity the hydraulic model needs to assess the capacity impacts.

104.13.1 Please discuss any associated risks should FEI rely on the end use approach for future peak forecasts.

Response:

As discussed in the responses to BCUC IR1 56.3.1 and BCUC IR2 104.6, FEI does not plan infrastructure based on an end-use peak demand forecast because of the risk associated with suppressing and under-representing the need for infrastructure. This could result in insufficient lead time for FEI to recognize the impending need and then implement the necessary infrastructure projects in the time available if the peak reduction potential does not materialize. As also noted in the response to BCUC IR2 104.6, however, FEI's process of continually refreshing its forecasted demand for the near and medium term helps ensure that capacity upgrades are not initiated when they are not required.

104.13.2 Please discuss how FEI could account for the lack of geographic granularity in future.

Response:

As discussed in the response to BCUC IR2 104.13, the introduction of end-use modelling at the customer level is currently computationally prohibitive. FEI acknowledges a need to find some way to incorporate more geographic granularity if the capacity impacts on the pipeline systems of end-use peak demand forecasts are to be presented in future. This is an issue to be addressed in the hydraulic model and is not something the end-use model is designed for or appropriate for. To achieve this may require an account forecast that may be unique to each end-use forecast scenario and provide insight at some local level into the accounts using the various blends of renewable and low carbon gases. Also important within the hydraulic model, is making some assumption in each scenario where future "on-system" RNG or hydrogen supplies will materialize that change the pipeline capacity needs. That also is not something that the end-use model is suited for.

At present, FEI is developing pilot programs and engaging in studies on the feasible means of deploying renewable gases throughout FEI's distribution and transmission systems that could allow FEI to enhance the forecasting processes in the future. However, presently the work, while actively being pursued, is very new and has not yet progressed to the point where it can be incorporated into the end-use peak demand forecasts used with the hydraulic models to determine the capacity impacts.

104.14 Please explain why the end use model does not have the sophisticated handling of the interaction between pressure, volumes, and energy flow of the hydraulic model currently used for peak demand forecasting.

Response:

The hydraulic model and the end-use model are separate models that are satisfying separate needs, as discussed in the responses to BCUC IR2 104.13 and 104.13.2. The end-use model is not intended for and does not need to consider how energy flows within the pipeline system. As the deployment of renewable and low carbon gases advances across FEI's system, the unique flow characteristics and modes of delivery (be that through local hubs or more broadly delivered with various renewable gas blends in local areas), the volumes and energy flow and resulting pressure losses need to be considered in more granularity. These impacts will need to be captured in FEI's hydraulic models rather than the end-use models to enable an assessment of the capacity implications.

104.14.1 Please discuss any associated risks should FEI rely on the end use approach for future peak forecasts.

Response:

Please refer to the response to BCUC IR2 104.13.1.

104.14.2 Please explain whether a separate hydraulic model could be built to support the end use methodology for peak demand forecasting.

Response:

As discussed in the response to BCUC IR2 104.14, FEI has a separate hydraulic model. It is not the same or incorporated directly within the end-use model presently or intended to be in the future. It is computationally prohibitive to provide the granularity required within the end-use model that is needed to input into the hydraulic model when blends of renewable gases are delivered with different flow characteristics with various points of supply. If forecasting adjustments are developed, as described in the responses to BCUC IR2 104.13 and 104.13.2 (most likely considered separately from the end-use model), to add an enhanced level of granular detail, FEI's hydraulic modelling software is currently capable of being used to model the capacity implications and infrastructure requirements on the transmission systems.

105.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-6, BCUC IRs 57.2, 57.6

Portfolio Approach to Resiliency

In response to BCUC IR 57.2, FEI states:

> The TLSE project will significantly improve FEI's ability to maintain <u>short-term</u> continuity of service to the Lower Mainland in the event of a disruption in the supply of natural gas to FEI's system, following a major incident on the T-South pipeline.
>
> […]
>
> Short-term continuity of this kind cannot be provided in a cost-effective manner by a pipeline solution such as the RGSD project. In particular, without the TLSE Project, FEI would have to increase the size of the RGSD pipeline to enable it to serve as a full replacement for the T-South pipeline and contract significantly more pipeline capacity in order to replicate the resiliency benefits of on-system storage. FEI is not proposing such a solution, as increasing pipeline capacity on the RGSD project beyond an optimal amount would leave a significant portion of pipeline capacity reserved for resiliency with FEI's customers paying higher annual costs due to the additional pipeline demand charges.

105.1 Please describe the extent to which FEI would have to increase the size and capacity of the RGSD pipeline to account for the resiliency benefits of the proposed TLSE project.

<u>Response:</u>

As described in FEI's RGSD Development Account Application, market conditions in the region are driving the need to expand regional infrastructure, irrespective of demand on FEI's system. As a result, FEI and its customers are facing significant cost implications associated with the expansion of the T-South system, with little or no other long-term benefits, such as resiliency, associated with the project. FEI is developing the RGSD project to address these risks. It is important to recognize that while resiliency benefits are a reason in support of the RGSD project over contributing to the cost of a T-South expansion, the RGSD project is best viewed first and foremost as a supply portfolio-related investment that, when optimized, comes with resiliency benefits. The TLSE project is, by contrast, best characterized as a resiliency investment that comes with increasingly valuable supply portfolio benefits.

The current sizing of the RGSD pipeline being evaluated for development is estimated to deliver approximately 450 MMcf/day to the Lower Mainland. The RGSD project's sizing would need to increase to 800 MMcf/day to provide full replacement capacity for T-South if that system was not available for any reason.

The scope of increasing the capacity to 800 MMcf/day delivered to the Lower Mainland would be much more cost intensive, as FEI's initial preliminary assessments indicate that more pipeline looping upstream of the RGSD pipeline and additional compression would be required to facilitate flowing 800 MMcf/day to the Lower Mainland. As explained in Section 4.3.4.5.2 of the TLSE Project CPCN Application, doubling the amount of pipeline capacity between T-South and an RGSD pipeline to Huntingdon is not economic and has not been considered beyond a conceptual stage as an option, versus a balanced portfolio approach of developing new pipeline and storage to tackle the various scenarios and phases of outages and supply curtailments as experienced by FEI. Further, the TLSE project will provide back-up to the RGSD pipeline, along with other supply resources, should they be impacted by future outages.

105.2 Please explain what portion of the RGSD pipeline capacity would be reserved for resiliency, should the pipeline account for the resiliency benefits of the proposed TLSE project.

<u>Response:</u>

To replace the resiliency benefits of the proposed TLSE project, FEI would need to have available the same level of total pipeline capacity on the RGSD pipeline immediately following an event that curtails gas supply of any magnitude, including a no-flow situation. In this scenario, FEI would have to over-contract (i.e., contract a higher than necessary amount of pipeline capacity) on the RGSD pipeline, thus leaving a significant portion on standby until a no-flow event occurs. As discussed in the response to BCUC IR2 105.1, FEI would need to have approximately 800 MMcf/day of available capacity on the RGSD pipeline.

This is why, from a resiliency standpoint, the TLSE and RGSD projects need to be viewed as complementary assets; the former best addresses short-duration supply issues and the latter addresses long-duration supply issues, in a cost-effective manner. Neither project is a substitute for the other.

105.3 Please discuss the cost implications to FEI's customers due to the additional pipeline demand charges should the RGSD project be developed to account for the resiliency benefits of the proposed TLSE project.

<u>Response:</u>

In 2020, FEI assessed the cost of holding pipeline capacity on the RGSD pipeline at much higher levels under a scenario in which additional on-system storage is not built. The results were filed in a confidential report to the BCUC[38]. Although the TLSE Project CPCN Application was not filed at the time this assessment was undertaken and the vaporization figure of 800 MMcf/day was not fully determined, the level of pipeline capacity assessed by FEI under the RGSD project at that time was comparable to FEI's current T-South holdings for the Lower Mainland which would have provided the utility with nearly full pipeline redundancy to mitigate a "no-flow" event on one pipeline.

Table 1 below shows the annual cost of service of holding full resiliency on two pipelines with the RGSD project at 650 TJ per day (approximately 600 MMcf/day) versus the annual cost of service of an optimized portfolio of pipeline capacity and storage (i.e., the TLSE project).

Table 1: Pipeline-only versus Optimized Portfolio Approach (as assessed in 2020 by FEI)[39]

Costs For Full Resiliency (Pipeline Only Approach)				
Toll Forecast Range SCP Expansion to Huntingdon	**$0.65**	**$0.80**	**$0.95**	**$1.10**
SCP Expansion to Huntingdon - New Capacity @ 650 TJ/d	$ 154	$ 190	$ 225	$ 261
Cost of Existing NGTL/FHBC Capacity	$ 42	$ 52	$ 62	$ 71
T-South Capacity using Estimated 2021 Tolls	$ 129	$ 129	$ 129	$ 129
Total Portfolio Costs Under SCP Expansion to Huntingdon	**$ 325**	**$ 371**	**$ 416**	**$ 461**
Optimal Portfolio - (Pipeline and Tilbury Expansion)				
Toll Forecast Range for SCP Expansion to Huntingdon	**$0.65**	**$0.80**	**$0.95**	**$1.10**
New Pipeline - Contracted Capacity @ 350 TJ/d ($Million)	$ 83	$ 102	$ 121	$ 141
Cost of Existing NGTL/FHBC Capacity ($Million)	$ 42	$ 52	$ 62	$ 71
T-South Capacity using Estimated 2021 Tolls ($Million)	$ 82	$ 82	$ 82	$ 82
Tilbury Expansion -Indicative Cost of Service ($Million)	$ 95	$ 95	$ 95	$ 95
Total Portfolio Costs (Pipeline and Tilbury Expansion ($Million)	**$ 303**	**$ 331**	**$ 360**	**$ 389**
Difference ($Million)	**$ 23**	**$ 39**	**$ 56**	**$ 72**

The results above clearly demonstrate that the optimized portfolio that includes the RGSD project and the TLSE project is more cost effective compared to the full pipeline resiliency portfolio for FEI's customers. FEI notes that the deliverability of the TLSE project as presented in the CPCN application was 800 MMcf/day; however, this level of deliverability has not been scoped by FEI.

A portfolio approach (that is based on the objectives of FEI's ACP filed with the BCUC each year) which incorporates holding an optimized level of pipe on diverse systems such as the RGSD project and T-South, combined with on-system TLSE storage would be a more cost effective and operationally efficient solution to protect FEI's customers from major outages and effectively manage the various phases of supply curtailments as experienced by FEI after the October 9, 2018 T-South incident.

105.4 Please outline the range of daily gas delivery volumes to the Lower Mainland that RGSD is expected to be able to provide.

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[38] 2020/2021 ACP BCUC Letter L-31-20 Compliance Report, dated August 31, 2020.

[39] Toll values are expressed in dollars per GJ.

Response:

The current RGSD project scope would deliver around 450 MMcf/day of gas volume to the Lower Mainland. This capacity would be supported by the installation of four compressor stations. FEI estimates that deliveries to the Lower Mainland could be increased by approximately another 200 MMcf/day by adding three additional compressor stations along the RGSD project's route. Further capacity increases beyond these levels (such as 800 MMcf/day delivered to the Lower Mainland) would require significant piping upgrades. Please also refer to the response to BCUC IR2 105.1 for further discussion.

105.5 Please further explain why FEI would need to contract significantly more pipeline capacity in order to replicate the resiliency benefits of on-system storage.

Response:

FEI manages pipeline resources by matching gas supply resources to load, which is conducted 24 hours prior to each gas day. Based on weather forecasts for the following day, FEI sets up the next day's pool of resources, and any excess capacity not required to meet the forecast load would be offered in the marketplace (i.e., reselling any excess gas supply or transportation). Therefore, depending on the load forecast, the RGSD project capacity available to FEI could be lower during the first two days of a no-flow event. In order to have the capacity available immediately after the no-flow event, FEI would have to over-contract (i.e., contract higher than the necessary amount) pipeline capacity on the RGSD, thus leaving a significant portion on standby until a no-flow event occurs. This is the only way for pipeline capacity to replicate the resiliency benefits of on-system storage, which is not optimal nor cost-effective when designing a resilient gas supply portfolio.

FEI notes that in a scenario where RGSD was constructed to interconnect with T-South north of Huntingdon, an event that affects the segment of T-South to the south of that point of interconnection would preclude accessing any supply from RGSD. The TLSE project would, by contrast, provide supply to the Lower Mainland in that circumstance.

105.5.1 Please discuss whether, in a supply emergency, FEI could utilize uncontracted capacity on RGSD by displacement and mutual aid.

Response:

FEI does not know at this time whether there would be uncontracted capacity on the RGSD pipeline to use in a supply emergency. However, FEI would explore all options that would optimize the economics of the RGSD pipeline for sub-leasing any capacity to third parties not required by its core market for daily operational needs. FEI would also explore all options that enable the utility to access sub-leased capacity for its own needs during an emergency or to manage capacity constraint conditions.

In response to BCUC IR 57.6, FEI states:

> …expansions to on-system LNG storage is the most effective way to immediately respond to a critical emergency to ensure the integrity of FEI's system, and aligns well with FEI's efficient supply portfolio and load profile. The addition of new regional pipeline infrastructure, constructed in a corridor different from the T-South system, would help ensure that some supply is available during an event that involves a sustained loss of pipeline capacity. Figure E-8 of the Application illustrates how diverse pipeline capacity can be used efficiently in combination with expanded peaking resources like on-system LNG storage, to build resiliency.
>
> FEI evaluated whether it makes sense to pursue either a pipeline or on-system LNG solution exclusively; however, the analysis indicated that employing only one measure to address all resiliency needs was either too costly or not feasible. Therefore, FEI evaluated multiple solutions and identified a portfolio of investments as the most cost-effective and optimal solution to address its resiliency needs. FEI is unable to specifically prioritize the individual components of these investment decisions because they are complementary and may involve different design and approval timelines impacting in-service time frames.

105.6 Please discuss, at a high level, all potential solutions FEI considered to effectively respond to a critical emergency to ensure the integrity of FEI's system.

Response:

FEI emphasizes that there is no single solution to effectively respond to a critical emergency to ensure the integrity of FEI's system, as each of FEI's service regions have their own unique needs depending on the accessibility to the three key elements that make up a resilient system (as discussed in Appendix E - Diverse Pipelines & Supply, Ample Storage, and Load Management). The optimal solution(s) to respond to a critical emergency reflects the characteristics of FEI's supply portfolio, as illustrated in Figure E-2 of Appendix E.

In the TLSE Project CPCN Application, FEI identified the Lower Mainland service area, which makes up the largest share (approximately 60 percent) of the demand on FEI's system, as having the least amount of resiliency, and thus greatest amount of risk, to upstream supply disruptions. To provide the necessary resiliency for the Lower Mainland, FEI developed a Minimum Resiliency Planning Objective (MRPO)[40] which was a way of articulating the identified risk to the Lower Mainland service area associated with a no flow event on the T-South system. FEI considered whether it would be feasible to meet the MRPO by focusing exclusively on improving FEI's load management capabilities or increasing pipeline diversity in the region. FEI also examined the feasibility of various storage options. With respect to the Lower Mainland service area, the following table (extracted from the TLSE Application) summarized all of the potential solutions FEI considered and the reasons they were not selected as an effective way to respond to a critical emergency such as a "no flow event."

Table 4-1 of the TLSE CPCN Application: Summary of Alternatives Considered to Meet Minimum Resiliency Planning Objective

Resiliency Elements	Alternatives	Reason Why Not an Alternative to On-System Storage at Tilbury
Load Management	Automated Metering Infrastructure (AMI)	AMI remote shut-off capability will add resiliency by reducing the potential for an uncontrolled shutdown, but is best viewed as complementing supply-side solutions. Without additional supply in event of a "no-flow" event, large scale load shedding would be required, leaving many non-interruptible customers without service.
Diversified Pipeline Supply	T-South Expansion	Expansion in the same corridor would still leave FEI subject to single point of failure risk, such that new storage would still be required to meet FEI's Minimum Resiliency Planning Objective even if the pipeline was constructed.
	Expansion to Northwest Pipeline's (NWP) Gorge Capacity	Expansion would add little resiliency for FEI. FEI must rely on displacement to access Gorge capacity, such that T-South gas must be physically flowing. Even if Gorge expansion was constructed, new storage would still be required to meet FEI's Minimum Resiliency Planning Objective.
	SCP Expansion to Kingsvale (i.e., interconnecting with the T-South system 172 km north of FEI's Lower Mainland system)	New regional pipeline would add resiliency by reducing single point of failure risk north of Kingsvale on the T-South system. Even if constructed, new storage would still be required to address single point of failure risk for the 172 km south of Kingsvale on the T-South system.
	SCP Expansion to Huntingdon	New regional pipeline adds resiliency by diversifying supply into the Lower Mainland. Some gas will still be available if there is a failure on one pipeline system (T-South or expanded SCP). However, even if constructed, new storage would still be required to supplement remaining pipeline flows and avoid significant load shedding. Cost savings from reducing the size of on-system LNG are limited due to inherent economies of scale.

[40] Having the ability to withstand, and recover from, a 3-day "no-flow" event on the T-South system without having to shut down portions of FEI's distribution system or otherwise lose significant firm load.

Resiliency Elements	Alternatives	Reason Why Not an Alternative to On-System Storage at Tilbury
Storage	Contract Additional Off-System Storage	Contracting additional off-system storage would still leave FEI subject to single point of failure risk, since FEI would remain dependent on the T-South system to access the storage resource. (Access to JPS and Mist is only by displacement and the displacement commercial transactions require physical flows on the T-South system.)
	On-System Underground Storage	Not feasible within the FEI service territory.
	On-System Storage at a New Site	Would provide resiliency but is more costly than expansion at an existing brownfield site, and would require construction of liquefaction in addition to storage and regasification.
	Use the Existing Base Plant Storage (including regasification) and Add Additional Storage	This option would not leverage the economies of scale of a single, larger tank. It would be more costly over time because the existing Base Plant facilities would still require replacement at some point.
	On-System Storage at Tilbury (< 2 Bcf)	Does not meet the Minimum Resiliency Planning Objective described in Section 3.
	On-System Storage at Tilbury (> 3 Bcf)	Diminishing economies of scale beyond 3 Bcf due to constructability challenges.

After careful and thorough evaluation, FEI concluded that the TLSE project was the most cost-effective and feasible way for FEI to handle a short-duration high-deliverability event in the Lower Mainland. However, the TLSE project has limitations in addressing longer-term capacity shortfalls. As discussed in Section 6.3.2 of the TLSE CPCN Application, following a critical emergency such as a no-flow event, it is typical for the outage to be followed by a ramp-up to normal supply conditions. For example, after the "no-flow period" during the T-South incident, supply to FEI's system remained constrained for approximately 14 months. The period of time that the TLSE project can help following a ramp-up back to normal supply conditions is limited by the LNG volume contained in the storage tank. The only effective way to manage an event that involves a sustained loss of pipeline capacity is additional pipeline infrastructure in the region. Potential solutions to handle this type of event are discussed further in the response to BCUC IR2 105.7.

105.7 Please discuss, at a high level, all potential solutions FEI considered to effectively respond to an event that involves a sustained loss of pipeline capacity.

Response:

The ability to effectively respond to an event that involves a sustained loss of pipeline capacity depends on the utility's access to multiple regional pipelines, preferably separated geographically, to serve the distribution system. As discussed in Appendix E, the T-South pipeline is the primary supply for gas delivery into the Lower Mainland, and also a portion of FEI's Interior customers. As discussed in the response to BCUC IR2 105.1, market conditions in the region are driving the need to expand regional infrastructure, irrespective of demand on FEI's system. As a result, FEI and its customers are facing significant gas supply portfolio cost implications associated with the expansion of regional pipeline infrastructure. Rather than simply accepting the additional cost of expanding T-South, FEI is exploring whether there are other options constructed in different corridors from the T-South system that are better from the perspective of FEI and its customers from a resiliency or other standpoint. The potential solutions under consideration have included the following:

1. Northwest Pipeline Gorge Expansion - An expansion of 450 MMcf/day on Northwest Pipeline (NWP) Gorge section, expanding capacity between Stanfield, Oregon and Seattle, Washington. This would increase the physical capacity to bring supply westbound from Stanfield or the Rockies into the I-5 corridor. Expanding the NWP Gorge capacity would allow gas to flow west into the Seattle and Portland region that would potentially decrease demand at Huntingdon. While an expansion of this size would greatly increase the capacity of the Gorge section of NWP, gas would only physically move as far north as Seattle based on the system's current configuration. For gas to flow physically north beyond Seattle up to Huntingdon, the pipeline would require further major facilities, such as dedicated compressors to flow gas in the opposite direction from the system's current design. Building dedicated compressors to flow north would arguably be redundant for use on a day-to-day basis and would only be used under extreme capacity curtailment or no-flow situations on T-South to Huntingdon.

2. Southern Crossing Extension to Huntingdon or Alternate Delivery Points (RGSD Project) - The RGSD Project would extend FEI's existing Southern Crossing Pipeline system from Oliver to Huntingdon and would deliver approximately 450 MMcf/day. The main focus is the Oliver to Huntingdon routing, however potential variants are possible as the project is further developed. FEI will also consider other delivery points such as interconnecting with the T-South system either at Kingsvale or Hope in the event that a direct connection to Huntingdon is not considered feasible during the development phase of the Project.

   In the RGSD Development Cost Deferral Account Application, which was filed with the BCUC in May 2022, FEI demonstrated a clear need for new pipeline infrastructure in the region.

105.8 Please summarize FEI's evaluation and decision-making process when determining which solutions to pursue in the portfolio approach to resiliency.

<u>Response:</u>

The T-South incident in October 2018 and the subsequent challenges with maintaining service to FEI's customers during the event, underscored the importance of investing further in system resiliency. Based on FEI's system configurations, unique characteristics, and operational challenges, all three key elements that make up a resilient system (Diverse Pipelines and Supply, Ample Storage and Load Management Capabilities) require enhancing.

FEI's evaluation and decision-making process when determining which solutions to pursue follow the same principles that FEI applies to its gas supply portfolio through its ACP. Section 6.2.1 of the Application details the fundamental principle for constructing a gas supply portfolio, which is to match the resource characteristics to the characteristics of demand (i.e., peak day, winter seasonal or year-round). In broad terms, that efficient supply portfolio consists of:

- Holding pipeline capacity to address long duration supply or base load (i.e., consistent demand throughout the year);
- Off-system regional storage to provide short to medium duration seasonal supply; and
- On-system storage resources for short duration supply to cover events such as winter peak demand which occur for short periods driven by weather conditions.

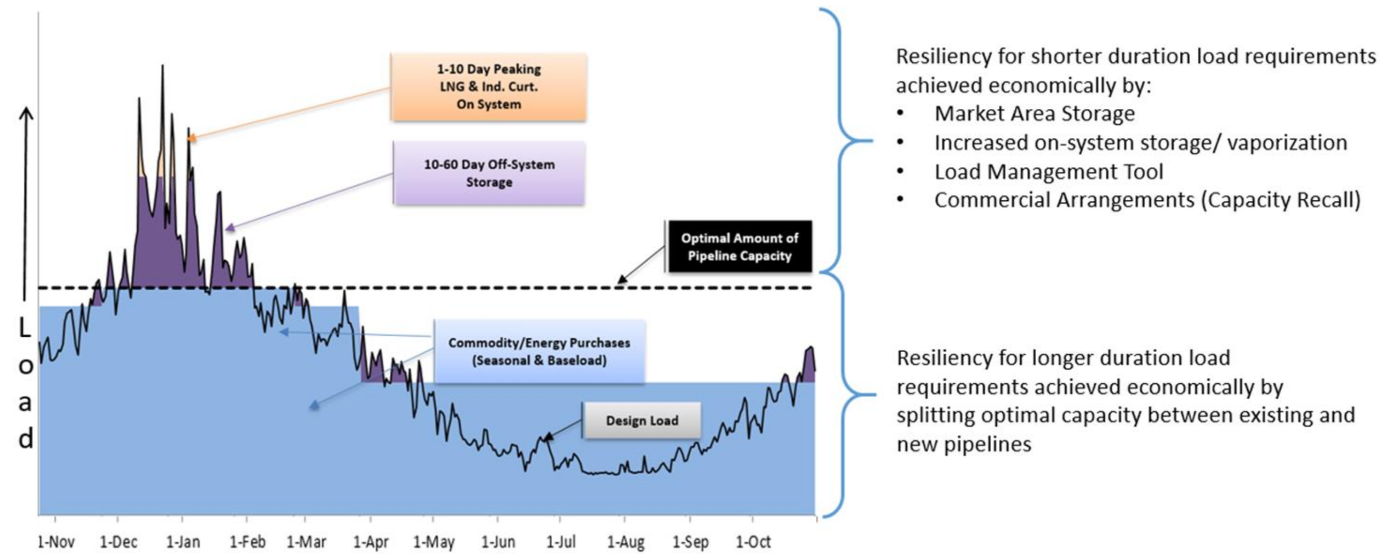
Just as FEI's ACP combines assets with distinct attributes to meet the shape of FEI's load profile, a portfolio approach to resiliency incorporates enhancements with distinct attributes that, together, provide a cost-effective approach to resiliency. This was also detailed in Appendix E (Section 5.4) of the Application.

For example, the value of on-system LNG storage is its ability to respond quickly to a critical emergency, enhancing the system's ability to avoid service disruptions as borne out during Phase 1 of the T-South incident. FEI's ability to rely on on-system resources in the event of a supply disruption does not depend on the physical or contractual availability of alternate pipeline capacity upstream of FEI's system. FEI identified the TLSE project as the most viable option, given its close proximity to the area that has the least amount of resiliency (Lower Mainland). Further, the TLSE project will replace the aging Tilbury Base Plant, which is a critical asset for FEI's peak day portfolio, as shown in Table 6-2 of the Application. Contracting for the 163 TJ/day peaking asset in the open market would be both challenging and costly, given that the resources in the region are fully contracted (as shown in Table 6-3).

Apart from a supply disruption occurring in cold periods, the TLSE project would have some supply in the tank after an initial three-day no flow period to manage subsequent supply challenges; however, in a prolonged period of constraint the potential exists for the supply in the tank to be insufficient. This shows the value of having additional pipeline capacity (preferably in a different corridor from the T-South system), as it would further mitigate the risk of a prolonged reduction in gas supply.

As described in FEI's RGSD Development Account Application, market conditions in the region are driving the need to expand regional infrastructure, irrespective of demand on FEI's system. As a result, FEI and its customers are facing significant cost implications associated with the expansion of the T-South system, with little or no other long-term benefits, such as resiliency, associated with the project. The RGSD project offers the potential to also enhance gas supply resiliency by providing needed pipeline diversity in the region as well as assisting with the transition to a lower carbon energy future. Further, it would allow FEI to split the optimal amount of pipeline capacity required to serve its Core customers between T-South and the new pipeline (Figure E-8 of the Application recreated below).

Figure E-8: Resiliency Measures Should Reflect Optimal ACP Supply Portfolio



FEI did evaluate whether it makes sense to pursue either a pipeline or on-system LNG solution exclusively. However, the analysis that was conducted during the TLSE Project CPCN Application development made it clear that relying on only one measure to address all resiliency needs was either too costly or not feasible. Therefore, FEI evaluated multiple solutions and identified a mix of investments as the most cost effective and optimal solution to address its resiliency needs.

106.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-6, BCUC IRs 61.1, 61.3, 61.8, 61.9, 61.12, 62.11; Exhibit B-1, Section 7.4.1.1, p. 7-38, Table 7-2; CSA Group: *Use of hydrogen and natural gas mixtures in products certified for natural gas in Canada and the US*[41]

Hydrogen Blending

In response to BCUC IR 61.1, FEI states:

> FEI is not currently considering hydrogen blends into the VITS at Eagle Mountain, due to the impact of hydrogen blends on pipeline capacity and consequent LNG production at Woodfibre. This does not preclude hydrogen from being introduced downstream of the Woodfibre site. The compatibility and tolerable blend percentages for existing downstream infrastructure has yet to be fully determined.

106.1 Please explain how FEI is planning to deliver hydrogen to its VITS customers, if it is not currently considering hydrogen blends into the VITS at Eagle Mountain.

106.1.1 Please clarify whether, based on FEI's current planning, any hydrogen distributed to VITS customers will need to be produced locally, on-system.

Response:

FEI would acquire hydrogen that could be procured or produced locally and connected to the VITS downstream of the Woodfibre site for supply to VITS customers.

In response to BCUC IR 61.3, FEI states:

> FEI has developed a preliminary hydrogen development roadmap that integrates our ongoing and planned activities to verify that hydrogen is safe to transport in the existing CTS gas system and confirm any changes that would be required to FEI's system to integrate hydrogen at higher blend levels in the future. FEI also continues to utilize available resources including our Clean Growth Innovation Fund (CGIF) to build our knowledge base and business innovation portfolio by supporting hydrogen technology development and other research initiatives in BC and Canada.

106.2 Please elaborate on how FEI utilizes resources such as its Clean Growth Innovation Fund to support hydrogen technology development.

[41] https://www.csagroup.org/article/use-of-hydrogen-and-natural-gas-mixtures-in-products-certified-for-natural-gas-in-canada-and-the-us/.

Response:

FEI utilizes resources such as its Clean Growth Innovation Fund (CGIF) in several ways. The CGIF supports the development of hydrogen technology solutions as outlined below. Grants from the CGIF to successful third-party applicants support the development of pre-commercial technologies with potential commercial applications to decarbonize gas supply.

In addition to the hydrogen technology development supported by CGIF grants, FEI is advancing several hydrogen technology initiatives that utilize non-CGIF resources to support the gas system and market transition. For example, in response to BCUC IR1 61.8.1, FEI provided a summary of the key objectives of FEI's hydrogen blending project, and in response to BCUC IR1 61.9, FEI described the next steps required (e.g., continuing research, feasibility studies, codes and standards development, and workforce training) prior to FEI beginning to deliver on-system hydrogen to its customers. In response to BCUC IR1 62.7, FEI identified an example of capital projects that may be required to enable FEI's delivery of on-system hydrogen within the next five years. To support the ongoing early stages of developing these initiatives, FEI has successfully acquired grant funding from the Province of BC, the CleanBC Innovation Accelerator and from the NRCan Federal Clean Fuels Fund (CFF).

In short, FEI is committed to utilizing a variety of resources to support FEI's hydrogen strategy and business goals and successfully execute to completion and commercial operation.

CGIF Supports Technology Innovation Related to Production of Renewable and Low-Carbon Hydrogen

Accelerating the pace of clean hydrogen production innovation, to achieve performance breakthroughs and cost reductions:

- Electrolytic hydrogen production: examples include supporting Simon Fraser University (SFU) to demonstrate a new membrane technology that could significantly reduce the cost to produce hydrogen via electrolysis.
- Pyrolytic hydrogen production: examples include supporting multiple technology developers that are advancing low-to mid-Technology Readiness Level (TRL) pyrolytic hydrogen production technologies including Ekona Power and University of British Columbia – Vancouver Campus.
- Carbon Capture and Storage: examples include supporting a Geoscience BC carbon mineralization project using suitable sub-surface geology (ultramafic rocks) to sequester carbon dioxide at scale in BC which could support the development of low-carbon intensity hydrogen production by reforming methane and capturing the carbon dioxide which would be sequestered and permanently stored in sub-surface formations.

CGIF Supports Technology Innovation Related to Hydrogen Distribution and End-Use Applications

Investigating cost-effective solutions to ensure the distribution use of hydrogen will be safe and reliable:

- Understanding and mitigating risk of hydrogen transport in gas infrastructure: examples include supporting UBC H2Lab analytical modelling of hydrogen injection, transmission, and flammability risk, and investigating hydrogen leakage sensing technologies.
- Hydrogen deblending technologies: examples include supporting UBC H2Lab work to investigate technology solutions to remove and separate a blended natural gas-hydrogen stream into separate streams to facilitate long distance hydrogen transport in the gas system to supply hydrogen refuelling stations.
- Hydrogen embrittlement of materials and welded joints: examples include supporting UBC H2Lab to establish the suitability of metal alloys and welded joints for a long-term operation in hydrogen-rich elevated pressure gas environments.
- Supporting various proposals to develop customer end use systems and appliances capable of operating on hydrogen (both hydrogen-enriched natural gas and 100 percent hydrogen).

CGIF Supports Technology Innovation Related to Using Hydrogen to Displace Natural Gas in Industrial Fuel Systems

Working directly with industrial gas users in BC to pilot and demonstration the use of hydrogen to displace natural gas in industrial fuel systems. For example, FEI is supporting the demonstration of hydrogen in lime kilns at Nanaimo Forest Products – Harmac Pulp and Paper operations.

106.2.1 Please provide the amount of funds from the Clean Growth Innovation Fund used to support hydrogen technology development over the past three years.

Response:

FEI has approved CGIF expenditures of approximately $3.05 million to support hydrogen technology development over the past three years.

106.2.2 Please explain whether FEI is considering expanding its use of the Clean Growth Innovation Fund in the future to support hydrogen technology development and whether FEI anticipates making any requests to the BCUC to increase this fund over the next five years.

Response:

FEI is already supporting decarbonization of its gas operations though the CGIF, including the introduction of low-carbon intensity hydrogen into the distribution system and related customer end-uses Clean Growth Innovation. FEI is also considering expanding its use of the CGIF to further accelerate these technologies. When applying for changes to the fund, FEI will consider historical approvals and expenditures, as well as any changes in the mandate of the CGIF which it considers important to the overarching goals of gas operations decarbonization.

FEI's original application for the CGIF in its Application for Approval of a Multi-Year Rate Plan (MRP) for the Years 2020 through 2024[42] was designed to address gaps in industry funding related to development of low-carbon intensity gas technologies. Low-carbon intensity hydrogen and other gases would be high priorities for funding given the ambitious emissions reductions sought in the CleanBC Plan by 2030. Since FEI filed the last MRP:

- The Province issued the CleanBC Roadmap to 2030 which sets more aggressive decarbonization targets;
- The Province issued the BC Hydrogen Strategy, which further supports blending low-carbon intensity hydrogen in the gas system, including full conversion of segments of the gas system to 100 percent hydrogen service; and
- In March 2023, the British Columbia Center for Innovation and Clean Energy (BC CICE) issued the Carbon Intensity for Hydrogen Methods Production Methods Report, which further details the beneficial role blending in the gas system will play in aggregating demand for hydrogen to underpin hydrogen production in BC and drive market adoption.

Given these developments, FEI will consider making a request to the BCUC to extend and perhaps increase this fund beyond the current MRP term.

In response to BCUC IR 61.3, FEI states:

> FEI's 10 year supply outlook includes…Off-system low-carbon intensity hydrogen delivered by displacement – significant supply potential, however, <u>regulatory approval requirements are currently uncertain</u>. [Emphasis added]

[42] See: BCUC Decision and Orders G-165-20 and G-166-20, FEI and FBC Application for Approval of a Multi-Year Rate Plan for the Years 2020 through 2024 (June 22, 2020) online at: https://www.ordersdecisions.bcuc.com/bcuc/decisions/en/481438/1/document.do.

106.3 Please explain why regulatory approval requirements for off-system low-carbon intensity hydrogen are currently uncertain. Based on FEI's assessment, please explain what regulatory approvals are required from the BCUC prior to procuring off-system low-carbon intensity hydrogen.

Response:

FEI noted that the regulatory approval requirements for off-system low-carbon intensity hydrogen are currently uncertain because the GGRR only enables FEI to acquire hydrogen derived from water using electricity that is generated primarily from clean or renewable resources, or waste hydrogen.

As hydrogen is not included in the definition of "energy" for the purposes of section 71 of the UCA (Energy Supply Contracts), FEI would expect to seek acceptance from the BCUC under 44.2 (1)(c) of the UCA for the expenditures to procure off-system low-carbon intensity hydrogen.

In response to BCUC IR 61.3, FEI states:

> As our understanding on hydrogen production, distribution, and end-use applications develops, FEI is also currently planning pilot demonstration projects that will test the use of hydrogen in controlled sections of our gas networks prior to more widespread roll-out of hydrogen. Given the technical research and testing completed to date, FEI has identified a segment of the CTS gas distribution system that in its current form can distribute hydrogen as a blend in the natural gas stream. FEI anticipates that successful blending pilot results will allow FEI to move from the requirement to survey, test, and trial all parts of a network prior to injection, to the ability to inject into an untested CTS network.

106.4 Please explain whether FEI requires any approvals from the BCUC prior to proceeding with its hydrogen blending pilot project on a segment of the CTS gas distribution system.

Response:

Yes. Please refer to the responses to BCUC IR1 61.12 and RCIA IR1 24.1.3 for discussion of regulatory approvals FEI expects to seek prior to blending hydrogen into its transmission and distribution systems. At this early stage of hydrogen development, FEI is still considering the specific BCUC approvals that will be necessary to blend hydrogen into its system or to proceed with the hydrogen blending pilot project.

In a bulletin regarding the use of hydrogen and natural gas mixtures, the CSA Group states the following:

> It has come to our attention that some natural gas utilities in North America have begun to blend, or are planning to blend, hydrogen with natural gas for residential and industrial applications. In the interest of public safety, we are compelled to remind our customers and other stakeholders of the following:
>
> - At present, there are no accepted standards in Canada or the US for fuel burning products using mixtures of natural gas and hydrogen, for either residential or industrial applications
> - In the absence of accepted standards, CSA Group does not currently offer certification programs for products and appliances that burn a mixture of natural gas and hydrogen
> - CSA Group's current certification programs only apply to products that burn natural gas in accordance with existing accepted standards
> - CSA certification of a product is void when it is used outside the parameters of the applicable standards – which would include the use of fuels other than natural gas, such as a mixture of natural gas and hydrogen…
>
> It is our hope that, until appropriate standards and certification programs are in place, <u>gas utilities and other suppliers of natural gas will abstain from blending hydrogen with natural gas for use with products only certified for natural gas</u>. We urge utilities, regulatory authorities, certification bodies, and manufacturers of gas appliances to work together to ensure that <u>the use of any mixture of hydrogen and natural gas in natural gas products take place only after the ongoing research is complete, the standards are amended, and products can be certified to the amended standards.</u> [Emphasis added]

106.5 Please confirm, or explain otherwise, that FEI will proceed with its hydrogen blending pilot project only after relevant CSA standards for products and appliances have been amended to accommodate the use of hydrogen and natural gas mixtures.

<u>Response:</u>

FEI will proceed with its hydrogen blending pilot projects in accordance with all relevant CSA standards and regulatory requirements. With respect to CSA standards for products and appliances, on April 18, 2023, CSA has confirmed that their technical committees agree that existing appliances in service will be considered certified for natural gas containing hydrogen blended up to and including 5 percent by volume with natural gas.[43] FEI expects that the CSA will

[43] CSA Group, Formal Interpretations (April 19, 2023) online at: https://www.csagroup.org/documents/Formal_Interpretations.pdf.

continue to work with industry and stakeholders to further progress standards for products and appliances to allow hydrogen blending projects to increase the level of hydrogen beyond 5 percent.

In response to BCUC IR 61.3, FEI states:

> Over the longer term and as supply and demand for hydrogen grows, FEI expects to transition the CTS higher pressure transmission system pipeline corridors through retrofitting, upgrading and expansion to transport an increasing share of hydrogen and RNG, which will include supply delivered from outside the CTS. This will include import of hydrogen by pipeline into the CTS.

In Table 7-2 on page 7-38 of the Application, FEI states:

- By 2042, hydrogen supplied from upstream of Huntington Control Station and comprises a much larger portion of the fuel mix
- With upstream supply, hydrogen separation facility at Huntingdon anticipated

106.6 Please explain at what level of hydrogen demand would FEI be required to retrofit, upgrade and expand the CTS' high pressure transmission system.

<u>Response:</u>

Overall demand for hydrogen is only one factor that would inform the decision to retrofit, upgrade and expand the CTS high pressure transmission system, as this demand may be met under various approaches to hydrogen delivery and utilization. It is too early to identify with precision a threshold at which FEI would be required to upgrade the CTS as described. As discussed in the response to BCUC IR1 61.3, FEI will undertake a comprehensive technical review and hydrogen readiness assessment to prepare plans to increase the blend concentration of hydrogen in its infrastructure over time. It is expected that through this body of work, FEI will identify a hydrogen blend concentration, or a suite of technical factors, that would trigger the requirement to upgrade the CTS high pressure transmission system. FEI's preferred approach to the delivery of hydrogen to CTS customers is discussed in the response to BCUC IR1 61.3, which describes the technical assessments FEI intends to undertake to evaluate the safe operation of the CTS pipelines under various hydrogen blending scenarios, and the governance and oversight required to increase the hydrogen blend concentrations over time.

106.7 Please clarify at what point in the planning horizon does FEI anticipate the CTS will be supplied hydrogen from the T-South system at the Huntingdon Control Station.

Response:

FEI cannot clarify at what point in the planning horizon the CTS will be supplied hydrogen from the T-South system at the Huntingdon Control Station because FEI has not yet been informed by the T-South system operator. However, the BC Gas System Hydrogen Blending Study and Technical Feasibility project that FEI references in the response to BCUC IR1 61.3 will see FEI collaborating with the T-South system operator to complete a similar project scope on the T-South system. FEI anticipates that this project will need to first be completed to understand when the CTS could be supplied with hydrogen from the T-South system and at what point in the planning horizon this could occur. FEI also expects that the project results will likely inform the amount of hydrogen (% volume) that could be delivered to the Huntingdon Control Station.

106.8 Please provide the amount of hydrogen (% volume) that FEI expects will be delivered to Huntingdon Control Station from the T-South system in 2030 and in 2042.

Response:

Please refer to the response to BCUC IR2 106.7.

106.9 Please provide the maximum amount of hydrogen (% volume) that can be delivered to Huntingdon Control Station from the existing T-South system, as indicated to FEI by T-South system operator, Westcoast Energy Inc.

106.9.1 If FEI has not discussed this with Westcoast Energy Inc., please explain why not.

Response:

FEI has discussed the topic of transporting hydrogen in the BC gas system with Westcoast Energy Inc. (WEI). FEI and WEI recognize the BC gas system will play an important role in reducing greenhouse gases by transitioning to delivering an increasing share of renewable and low-carbon energy over time. FEI, WEI, and PNG have been collaborating since 2020 to complete the BC Gas System Hydrogen Blending Study and Technical Assessment project outlined in FEI's response to BCUC IR1 61.3. In this response, FEI refers only to the component of the project applicable to FEI's gas infrastructure. WEI will complete a similar scope of work focused on their gas infrastructure in BC, including the T-South system, with the intention of determining the amount of hydrogen that could be delivered to the Huntingdon Control Station.

In response to BCUC IR 61.3, FEI states:

> FEI plans to undertake a comprehensive technical review and hydrogen readiness assessment of all gas system assets and customer end-use equipment and systems referred to as the BC Gas System Hydrogen Blending Study and Technical Assessment project. This technical review and assessment will include safety, system integrity, and performance considerations, and will analyze the implications of adding hydrogen to FEI's network operations. This program of work will include asset specific engineering assessments, field testing, and technical verification, with governance and oversight from the Province of BC, the soon-to-be BC Energy Regulator (formally the BC Oil and Gas Commission), and Technical Safety BC, to investigate hydrogen blending targets across the entire gas system.

In response to BCUC IR 61.8, FEI states:

> FEI has issued a Request for Proposal and expects to engage external professional service providers to assist FEI in further developing its hydrogen roadmap plan through the <u>BC Gas System Hydrogen Blending Study and Technical Assessment project</u>. This is part of an integrated program of work to evaluate all of FEI's gas system assets and gas customers' installations, in order to establish the requirements and overall strategy to blend hydrogen throughout FEI's service territories. FEI expects to advance its hydrogen roadmap throughout 2023 and 2024 as part of the broader program of work that will also include developing a hydrogen deployment strategy to guide FEI's roll out of hydrogen in the near-term and also the longer-term.

106.10 Please provide the schedule to complete the BC Gas System Hydrogen Blending Study and Technical Assessment project.

<u>Response:</u>

FEI is currently completing the procurement process to hire a suitably qualified and experienced consultant to assist FEI in executing the BC Gas System Hydrogen Blending Study and Technical Assessment project. The current project schedule requires project kickoff in Q2 2023 and completion by the end of 2025.

106.11 Please discuss whether FEI anticipates filing the outcomes and deliverables from the BC Gas System Hydrogen Blending Study and Technical Assessment project as part of a future LTGRP application, or as part of any other FEI application submitted to the BCUC. If not, why not.

Response:

Yes, FEI anticipates filing the deliverables from the BC Gas System Hydrogen Blending Study and Technical Assessment project (the "Project") with the BCUC as part of a future filing and/or LTGRP given the time expected to complete the study. Note that the Project is currently partially funded by the Province of BC and as such the Province, the BC Energy Regulator and Technical Safety BC will have representation on the Project governance committee.

In response to BCUC IR 61.9, FEI states:

> FEI currently aims to confirm that a 5 percent by volume blend of hydrogen by 2025 and up to a 30 percent volume blend of hydrogen is feasible by 2030. FEI will continue to validate these targets as part of the strategy to efficiently manage the gas portfolio change and hydrogen roll out.

In response to BCUC IR 62.11, FEI states:

> FEI considers that there will be adequate low-carbon and renewable gas supplies, including hydrogen, to support FEI achieving the 2030 GHGRS emissions cap.

106.12 Please provide the hypothetical reduction in GHG emissions, which would result from blending the following volumes of hydrogen into FEI's gas delivery systems in BC:

i) 5 percent by volume

ii) 20 percent by volume

iii) 30 percent by volume

Please provide the annual reduction in GHG emissions as both (annual Mt of CO2e reduction) and (% reduction of FEI's total CO2e emissions). Please provide all assumptions made in determining these GHG emission reduction values, including GHG intensity of hydrogen production.

Response:

For the purposes of this response, FEI assumed a total conventional natural gas demand of 200 PJ and that hydrogen displaces conventional natural gas. The annual reduction in end-use GHG emissions for the various blends of hydrogen requested is presented below. This response is based on end-use emissions because the proposed 2030 GHGRS emissions cap for FEI is based on end-use emissions. This analysis also uses the end-use emission factors for natural gas of 0.0499 tCO_2e per GJ and for Hydrogen of 0 tCO_2e per GJ as provided in Table 2-1, on page 1-6 of the Application.

Hydrogen Blend (by volume)	Emission Reductions (Annual)	Emission Reductions (Percentage)
	$MtCO_2e$	
0%	0	0
5%	0.15	1.5%
20%	0.62	6.2%
30%	0.93	9.3%

The GHG intensity of hydrogen production will vary by project as each project comes online and more information becomes available. This will be examined again in the next LTGRP.

106.13 Please explain what proportion of FEI's anticipated 2030 GHG emission reductions will be achieved by replacing the use of conventional natural gas with hydrogen. Please provide all assumptions made.

Response:

Please refer to the response to BCUC IR2 106.12 for the levels of GHG emission reductions that can be achieved through various levels of hydrogen blending. Overall, the different means of displacing natural gas with hydrogen (i.e., hydrogen blending, hydrogen hubs and dedicated hydrogen infrastructure)[44] are modelled[45] in the DEP Scenario to achieve approximately 19 percent of the total emission reductions in 2030.

[44] Exhibit B-1, Section 3.3.3, pp. 3-13.

[45] Please refer to the response to BCUC IR1 52.6 which discusses that each of the individual components of the renewable and low-carbon forecast is not intended to be in themselves a forecast, but rather a modelled proportion and that actual proportions may vary between the component types within the overall renewable and low-carbon gas supply forecast.

In response to BCUC IR 61.12, FEI states:

> FEI expects that it would also apply for approval of tariff amendments to allow for the sale of the hydrogen, and approval of any related treatment of the costs and revenues that may be required for rate setting purposes.

106.14 Please elaborate on the specific tariff amendments FEI expects will be required to allow for the sale of hydrogen.

Response:

At the present time, FEI expects to account for the cost of hydrogen in its Biomethane Variance Account (BVA), for which FEI has proposed a name change to Low Carbon Gas Account (LCGA), in its ongoing RG Program Application. Additionally, hydrogen will have to be added to the definitions in FEI's General Terms and Conditions (GT&C) and added to the definition of "Gas" within FEI's GT&C for FEI to be able to recover the cost through its existing rate schedules. FEI expects to file an application with the BCUC for approval of both the accounting of hydrogen in the LCGA and inclusion of hydrogen in its GT&C.

107.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Greenhouse Gas Reduction Regulation (GGRR)[46]; Clean or Renewable Resource Regulation[47] ; Exhibit B-6, BCUC IRs 62.8.2 & 62.9

Hydrogen Production

The Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR) states:

> **Prescribed undertaking — hydrogen**
>
> (6) A public utility's undertaking that is in a class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:
>
> (a) the public utility
>
> (i) produces or purchases hydrogen that is distributed through the natural gas distribution system in British Columbia to the customers of that public utility or of another public utility, or
>
> (ii) purchases hydrogen that is provided to a customer of the public utility other than through the natural gas distribution system in British Columbia and that is to be used by that customer to replace, at least in part, natural gas derived from fossil fuels;
>
> (b) the hydrogen referred to in paragraph (a)
>
> (i) is derived from water using electricity that is generated primarily from clean or renewable resources, or
>
> (ii) is waste hydrogen, as defined in the Clean or Renewable Resource Regulation, purchased by the public utility;

The Clean or Renewable Resource Regulation states:

> "**waste hydrogen**" means hydrogen gas produced by a commercial process the primary purpose of which is not the production of hydrogen gas.

In response to BCUC IR 62.8.2, FEI states:

> As FEI considers that blue hydrogen will be required to achieve the Province's GHG reduction goals, FEI expects to seek approval of at least some elements of blue hydrogen development funding over the next five years.

[46] https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/102_2012.
[47] https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/291_2010.

107.1 Please clarify whether FEI considers the production or purchase of blue hydrogen or turquoise hydrogen to currently be included as a prescribed undertaking by regulation.

107.1.1 If not, please explain how FEI anticipates BCUC approval processes for the production or purchase of blue hydrogen or turquoise hydrogen will differ from the BCUC approval processes to produce or procure hydrogen referred to in the GGRR.

Response:

The purchase or production of blue or turquoise hydrogen is not currently included as a prescribed undertaking in the GGRR. If the GGRR is amended to include blue and turquoise hydrogen, FEI may apply for acceptance of the purchase or production of blue or turquoise hydrogen as a prescribed undertaking. In the absence of an amendment to the GGRR, FEI would need to demonstrate that the purchase or production of blue or turquoise hydrogen was in the public interest.

For any kind of hydrogen, and whether prescribed in the GGRR or not, FEI expects to apply for acceptance pursuant to section 44.2(1)(c) of the UCA of “a statement of expenditures the public utility has made or anticipates making during the period addressed by the schedule to acquire energy from other persons.”

In response to BCUC IR 62.9, FEI states:

> FEI does not anticipate a meaningful supply of on-system green hydrogen to be developed over the next five years. In order to be competitive with other sources of renewable and low-carbon gas including RNG and blue and turquoise hydrogen, green hydrogen will need to be developed at large scale with access to low-cost clean electricity.

107.2 Please discuss the advantages and barriers associated with individual customers pursuing small scale green hydrogen production to replace their current demand for natural gas, independent from FEI support.

Response:

An advantage of individual customers pursuing small-scale green hydrogen production to displace their current natural gas demand is that the customer would contribute to meeting the Province’s energy and climate objectives. However, there are significant barriers at this point in time as the design of green hydrogen plants is costly and complex. Furthermore, hydrogen development requires specialized workers who are trained in this field, and in BC, the industry is still in its infancy.

As stated in the preamble, FEI considers that, except in very limited circumstances, high cost and complexity will make it highly unlikely that individual customers will choose to produce their own hydrogen to replace their current demand for natural gas. With current and expected technology, facilities that produce at scale have wide cost advantages to small scale facilities.

107.3 Please discuss the potential role for FEI in supporting the development of small scale green hydrogen production for its larger individual customers, in particular industrial customers.

Response:

Assuming that small-scale green hydrogen production could be acquired under the price cap established in the GGRR, FEI could potentially acquire a portion or the entirety of the hydrogen offtake for its renewable gas portfolio. FEI acquisition of hydrogen from industrial customers may allow some scale up of the facility and help with balancing hydrogen production with demand, both of which could help reduce the cost of production. Acquisition of this hydrogen by FEI would, however, have to be weighed against other sources of low-carbon fuels in terms of cost. As noted in the preamble, FEI expects that hydrogen would need to be developed via large-scale projects as they would likely be lower cost than small-scale projects and therefore more competitive with other low carbon energy. It should also be noted that FEI acquires all environmental attributes associated with the renewable energy that it procures; therefore, the industrial customer would lose the right to claim any environmental attributes upon the sale of energy to FEI, though could still purchase environmental attributes (bundled with renewable gas) through FEI's Renewable Gas program.

108.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-6, BCUC IRs 63.2, 63.3, 77.4; Exhibit B-16, MS2S IR 1.1

Hydrogen Separation

In response to BCUC IR 63.2, FEI states:

> FEI continues to work with the University of British Columbia (Okanagan Campus) (UBCO) team on phase two of the H2Lab that includes the sub-project to advance process feasibility and practical applications of commercial membrane technologies to separate blended hydrogen and natural gas.

In response to BCUC IR 63.3, FEI states:

> FEI is not aware of any natural gas pipeline operators currently separating hydrogen from mixed natural gas and hydrogen streams. FEI is aware of a pilot demonstration project in Germany by Linde and Evonik Industries, to showcase their hydrogen separation technology to extract hydrogen from mixed hydrogen and natural gas streams and a proposed demonstration project by SoCal Gas called "[H2]PureComp" that includes the development, installation, and demonstration of an Electrochemical Hydrogen Purification and Compression (EHPC) skid developed by the Netherlands-based company HyET Hydrogen.

108.1 Please elaborate on the advantages and disadvantages of the hydrogen separation technologies mentioned in the preamble.

Response:

Each of these technologies has advantages, disadvantages, and scenarios in which they perform best. FEI has not yet considered how these different technologies could best be applied in order to facilitate hydrogen deployment and use in the gas system. However, according to the "Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology" report by the National Renewable Energy Laboratory (NREL),[48] the primary types of hydrogen separation technologies include pressure swing adsorption (PSA), cryogenic distillation, membranes, and electrochemical hydrogen separation. At Section 3.5 of the report, the authors summarize the key findings of several previous literature studies that describe hydrogen separation technologies in detail.

[48] Kevin Topolski et al., "Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology" (Golden, CO: National Renewable Energy Laboratory, 2022) online at: https://www.nrel.gov/docs/fy23osti/81704.pdf.

108.1.1 Please explain how much energy is required to separate hydrogen from natural gas using these hydrogen separation technologies. Please list all assumptions made in determining the energy intensity of these hydrogen separation technologies.

Response:

At this time, FEI does not have sufficient equipment vendor data and has not yet studied the application of hydrogen separation equipment in the gas system at different hydrogen blend concentrations to provide the energy intensity of the hydrogen separation technologies. Current hydrogen separation technologies for removing hydrogen from natural gas networks are still undergoing technical and commercial development or are in pilot-stage development and therefore not yet commercially available or in widespread use today and, as such, there is limited published data regarding the energy intensity for these technologies in practical applications.

However, FEI expects that the energy input required for hydrogen separation will vary with the operating pressure of the mixed gas stream, the relative percentage composition of the different gases in the mixed gas stream, and the gas quality requirements of the downstream equipment. In addition, the energy requirement will change with the separation technology selected. In general, membrane separation has emerged as the most efficient method, followed by pressure swing adsorption, with cryogenic distillation being the most energy intensive technology.

108.1.2 Please explain whether FEI has included the energy required to separate hydrogen from natural gas in determining the GHG intensity of various hydrogen production methods. If the energy required to separate hydrogen has not been considered by FEI in its evaluations of the GHG intensity of various hydrogen production methods, please explain why not.

Response:

FEI has not included the energy required to separate hydrogen from natural gas in determining the GHG intensity of various hydrogen production methods because hydrogen separation from natural gas would occur downstream from the hydrogen production facility and therefore would have no bearing on the lifecycle carbon intensity calculation pertaining to the hydrogen production method used in the hydrogen production facility. FEI will consider the energy required to separate hydrogen from natural gas in determining the full life cycle carbon intensity of hydrogen delivered to gas customers that would require hydrogen delivered as a blend in the gas system to be separated from the gas stream.

In response to BCUC IR 77.4, FEI states:

> …identifying the infrastructure needs of a renewable gas system is one of the next steps in FEI's development framework for renewable and low-carbon gases. <u>Based on pre-feasibility work completed over the last number of years, FEI plans to undertake a comprehensive technical review and hydrogen readiness assessment of all gas system assets and customer end-use equipment and systems</u>. The project, referred to as the BC Gas System Hydrogen Blending Study and Technical Assessment project, will provide more information regarding hydrogen considerations, including potential modifications to the system and an assessment of costs. [Emphasis added]

In response to MS2S IR 1.1, FEI states:

> In the event the hydrogen supply is blended into the supply of natural gas feeding the LNG plants, modifications and equipment retrofits, such as hydrogen separation equipment upstream of the liquefaction equipment, would need to be installed to extract hydrogen. This is due to the inability of hydrogen to liquefy at the temperatures at which LNG is produced.

108.2 Please provide any preliminary cost estimates, prepared as part of FEI's feasibility studies to date, to construct and operate hydrogen separation facilities at the scale required by the Tilbury LNG facility.

<u>Response:</u>

FEI has not yet sufficiently advanced feasibility work to sufficiently inform cost estimates related to the construction and operation of hydrogen separation facilities. In response to BCUC IR1 61.9, FEI provided an update regarding the development of the hydrogen deployment roadmap plan which FEI expects will include the requirements and associated costs to construct and operate hydrogen separation facilities (copied below for ease of reference):

> FEI has issued a Request for Proposal and expects to engage external professional service providers to assist FEI in further developing its hydrogen roadmap plan through the BC Gas System Hydrogen Blending Study and Technical Assessment project. This is part of an integrated program of work to evaluate all of FEI's gas system assets and gas customers' installations, in order to establish the requirements and overall strategy to blend hydrogen throughout FEI's service territories. FEI expects to advance its hydrogen roadmap throughout 2023 and 2024 as part of the broader program of work that will also include developing a hydrogen deployment strategy to guide FEI's roll out of hydrogen in the near-term and also the longer-term.

108.3 Please discuss whether there is adequate space at the Tilbury LNG facility to accommodate hydrogen separation equipment. If there is not currently adequate space, how FEI could accommodate hydrogen separation equipment at Tilbury LNG facility.

Response:

Based on preliminary feedback from the technology vendors, it is possible to accommodate hydrogen separation equipment at the Tilbury LNG facility.

109.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-6, BCUC IR 65.1; Government of British Columbia Direction No. 5 to the BCUC [49]

LNG Facility Expansion

In response to BCUC IR 65.1, FEI states:

> LNG marine bunkering benefits will be dependent on the size of facilities required to serve that market and the annual demand of the sector. FEI will serve the LNG marine bunkering market under Rate Schedule 46 (RS 46), which will be used to recover the costs of the infrastructure required to serve that market and also provide benefits to customers when the revenues from RS 46 either utilize existing capacity at Tilbury or exceed the incremental cost of new infrastructure. FEI is currently assessing the market and facilities required and estimates the RS 46 revenue from this market to be approximately $4 billion over the 20-year planning horizon, <u>assuming approximately $1 billion of liquefaction capacity is constructed</u> and that all LNG production capacity is fully sold. [Emphasis added]

109.1 Please explain whether FEI anticipates the need to make any amendments to the RS 46 tariff prior to serve the LNG marine bunkering market.

<u>Response:</u>

Yes, FEI anticipates that amendments may need to be made to the RS 46 tariff to serve the LNG marine bunkering market. FEI will initiate this process allowing adequate time for the BCUC to review and make determinations prior to FEI serving an LNG marine bunkering market.

109.2 Please explain when FEI anticipates constructing the approximately $1 billion of liquefaction capacity.

<u>Response:</u>

The timing of the liquefaction capacity expansion will depend on the timing of the marine jetty approvals and the growth of the marine bunkering market. It is expected that any additional liquefaction capacity would be installed to match market demand (i.e., the capacity could be installed in phases if required). Currently, FEI expects that a liquefaction expansion could be in service as early as 2027.

[49] https://www.bclaws.gov.bc.ca/civix/document/id/lc/statreg/245_2013.

Direction No. 5 to the BCUC states:

> **expansion facilities**" means LNG facilities to be constructed, owned and operated, after this direction comes into force, by a utility at Tilbury Island, Delta, British Columbia; …
>
> **Expansion facilities**
>
> 4 (1) The commission must not exercise its power under section 45 (5) of the Act in respect of
>
> (a) phase 1A facilities, and
>
> (b) phase 1B facilities.
>
> (2) In setting rates under the Act for FortisBC Energy Inc., the commission must do all of the following:
>
> (a) include in the utility's natural gas class of service rate base the sum of the following:
>
> (i) the lesser of
>
> (A) the capital costs of the phase 1A facilities, and
>
> (B) $425 million;
>
> (ii) the construction carrying costs for the phase 1A facilities;
>
> (iii) the feasibility and development costs incurred on or after January 1, 2013;
>
> (b) include in the utility's natural gas class of service rate base the sum of the following:
>
> (i) the lesser of
>
> (A) the capital costs of phase 1B facilities, and
>
> (B) $400 million;
>
> (ii) the construction carrying costs for phase 1B facilities;
>
> (iii) the feasibility and development costs incurred on or after January 1, 2013;

109.3 Please discuss the capacity of liquefaction that would be provided by the $1 billion liquefaction expansion required to serve the LNG marine bunkering market.

109.3.1 Please explain how the $1 billion liquefaction expansion relates to the liquefaction expansion at the Tilbury facility anticipated for the 1B facilities.

Response:

Direction No. 5 currently allows up to $400 million for Phase 1B facilities; however, FEI considers this amount no longer sufficient to meet the required LNG marine bunkering market demand, and to absorb inflationary pressures since Direction No. 5 was first issued in 2013. FEI is currently reviewing potential options for additional funding, either through an amended OIC or a CPCN application and considers that a $1 billion expansion would be appropriate for the site to complete all the required facilities to offer capacity of up to 0.65 MTPA. The required facilities would include liquefaction, onshoring piping to the jetty, electrical infrastructure upgrades, and upgrades to the CTS required to serve the increased gas demand from an LNG marine bunkering market at Tilbury.

G. CONSULTATION

110.0 Reference: CONSULTATION

Exhibit B-6, BCUC IR 66.4

Indigenous Engagement Workshops

BCUC IR 66.4 asked: "Given the timing of the Lower Mainland and Fraser Valley workshops relative to the filing of the LTGRP, please discuss how the input from the participants was incorporated into the development of the LTGRP. [FEI's] Response: Please refer to the responses to BCUC IR1 66.2 and 66.3."

BCUC staff note that the responses to BCUC IR 66.2 and 66.3 appear to refer to the February 4, 2021 and March 3, 2021 workshops in the FBC shared service territory.

110.1 Please provide an updated response to BCUC IR 66.4.

<u>Response:</u>

FEI clarifies that the response to BCUC IR1 66.3 summarizes the key feedback received from all Indigenous community sessions. FEI incorrectly indicated in that response that Table 1 described only "Key areas of feedback from the February 4, 2021, and March 3, 2021, workshop participants", when in fact Table 1 summarized the feedback from all sessions. For example, in the discussion below Table 1, FEI states in reference to UNDRIP: "This was a common theme from the February 4, 2021, and March 3, 2021, workshops sessions, **as well as from engagement sessions in the FEI-only service territory."** [Emphasis added.]

The feedback received from the Lower Mainland and Fraser Valley workshops confirmed the feedback FEI had heard up until that time and helped FEI further understand stakeholder and rights-holder feedback. Given the timing of the sessions, FEI was also able to provide participants with detail on system considerations, demand side management planning, and more refined energy demand scenarios (as these areas of the plan were further refined in Q1 of 2022) relative to the timing of previous engagement sessions.

Input at this stage supported the development of FEI's LTGRP action plan, and reiterated themes from previous engagement sessions, including the importance of effective engagement practices, energy affordability, low carbon project partnership opportunities, and climate action. Feedback during these sessions also emphasized the importance of reconciliation and integrating Indigenous perspectives into long-term utility plans, such as the LTGRP, which was similar to the feedback provided during the February 4, 2021, and March 3, 2021, workshops in the FBC-FEI shared service territory. FEI did not receive any feedback that suggested a need to delay the filing for further considerations.

Finally, feedback received during these sessions will also be considered as FEI prepares its next LTGRP even though a new round of community consultation sessions will also be undertaken. It is FEI's view that gathering feedback from around BC should be an ongoing activity and, except for ceasing such engagement activities for the regulatory proceeding, FEI will continually conduct these types of workshops in various and changing locations. As such, there will always be some workshops that are held as the filing deadline approaches and less time is available for significant changes to be incorporated. This is the nature of the ongoing long-term resource planning process.

111.0 Reference: CONSULTATION

Exhibit B-6, BCUC IR 68.1

Residential Customer Engagement

In response to BCUC IR 68.1, FEI states:

> FEI confirms that it did not appoint specific residential customer designates in community engagement sessions. Rather, FEI considered the participation by representatives from community organizations, municipal governments, non-government organizations, and Indigenous communities can meaningfully represent residential customer interests.

111.1 Please further explain why FEI considers the entities outlined in the preamble can meaningfully represent residential customer interests.

Response:

FEI considers that the entities outlined in the preamble can meaningfully represent residential customer interests as, in many cases, these entity representatives are actively engaged in community energy issues and, as such, have high interest and subject matter expertise in energy planning issues that can influence and shape energy policy for the benefit of residential customers as a whole. Further, many of the organizational representatives are uniquely situated to meaningfully represent customer interests—not only are they often individual residential customers of FEI themselves, their involvement in their own organizations provides them with a high level of awareness surrounding concerns of residential customers and the broader public. In this way, they are able to effectively articulate and situate the independent, but often shared, concerns and perspectives of individual residential customers within the energy planning landscape.

FEI notes that the BCUC recognized these challenges in requesting expressions of interest from organizations who would work to represent residential customers, for which the Residential Consumer Intervener Association (RCIA) was retained. FEI further notes that RCIA was a member of FEI's Resource Planning Advisory Group for the 2022 LTGRP, representing residential customers. For these reasons, FEI considers that the representatives attending community engagement sessions throughout the 2022 LTGRP planning process were able to provide meaningful input to resource planning discussions influencing residential customer long-term interests as outlined in the Section 8.4 of the Application.

The community engagement process outlined in the Application reflects a range of diverse opinions. Attendees were able to provide their perspectives on the challenges associated with balancing affordability with the costs of electrification and decarbonization. Some individuals highlighted the unique requirements needed to serve rural communities and others the economic development potential for clean energy projects in their communities.

111.2 Please discuss whether there are other options for engaging with residential customers in future LTGRP consultations. Please briefly discuss the pros and cons of such options.

Response:

Engaging residential customers in this type of in-depth planning exercise is challenging and FEI appreciates the efforts of the BCUC to seek out the services of RCIA to help represent this customer group. The level of interest in energy planning, the urgency to address climate change, and the future implications of energy-related policy and decision making are more complex than in past LTGRPs. For these reasons, FEI will be seeking increased input from customer groups and the public in the next LTGRP. In response, FEI has developed Action Item 4 in the Action Plan (Section 10 of the Application) to outline the steps it will take to continue to improve community and other engagement activities for future LTGRPs.

FEI serves almost one million residential customers and FEI's Data Analytics and Research department actively surveys customers to gain feedback on customer satisfaction and energy preferences. Resource planning is an extension of these activities. FEI will continue to assess how new communication technologies and outreach approaches could be used to provide greater reach and improved input to the next LTGRP. FEI will consider if activities should be targeted at specific demographics such as students, seniors, rural populations and other segments to gain a broader perspective on the unique needs of these customer groups.

FEI is considering new communications tools, including:

- Working with a market research firm to develop an online engagement survey tool specifically designed to support the resource planning process. The advantage of this option is that FEI can compare the results from a customer sample with the feedback in engagement sessions to ensure that it is representative of the unique needs of FEI's customers. FEI will need to consider and weigh the higher costs of this approach against the benefits it might create.
- FortisBC's MyVoice community enables FEI to conduct in-house market research.[50] FEI is able to focus the research on specific customer segments (defined by demographic groups) enabling FEI to collect relevant information pertaining to its products and services in a timely and meaningful way. After a customer has participated in a survey, they will be able to continue to visit the site to see how their feedback is helping to shape FortisBC's products and services. Advantages of using this approach are that it is affordable and flexible. FEI may be able break down complex resource planning inputs into smaller pieces of information for a more general audience and continue to survey customers over time

[50] https://www.fortisbc.com/in-your-community/our-online-community-myvoice.

throughout the resource planning process. The disadvantages of using this process is that it may be difficult to communicate the relatively complex issues in a manner that facilitates a meaningful two-way dialogue.

- Hosting online public interactive sessions based on providing a high-level view of utilizing the Crowd-Source Expert Opinion Forecast and "Slider" forecasting tool (Expert Opinion Tool). The advantages of using this approach include its wide reach, its low cost, and the relevance of the information that may be gathered. The tool provides visualizations of energy planning scenarios that FEI may be able to make understandable for a broader audience. The disadvantage of using this process is the uncertainty of whether the audience would sufficiently understand the energy planning principles to ensure that results were meaningful such that FEI could translate these results into meaningful inputs into the planning process. As a result of these challenges, this option may be developed later than other approaches.

Other market research activities include:

- FEI's 2022 Residential End-Use Survey (REUS) survey portion was conducted between June 20 and August 7, 2022, with results likely being available in time to inform the development of the Reference Case in the next LTGRP. The REUS collects data regarding natural gas uses including space and water heating and cooking appliances. The survey also collects data on dwelling characteristics which impact energy consumption.
- Ongoing market research activity in support of customer satisfaction and customer preferences will also inform the next LTGRP.

FEI will continue to build upon the community engagement activities in past applications and will work towards improving the integration of LTGRP engagement activities with those of other groups within FEI to ensure the resource planning issues are part of an ongoing consultation process, just as resource planning is an ongoing process.

H. OUTCOMES OF THE CLEAN GROWTH PATHWAY

112.0 Reference: GHG EMISSION REDUCTIONS IN THE DIVERSIFIED ENERGY (PLANNING) SCENARIO

Exhibit B-1, Section 9.2.1.1, p. 9–2; Exhibit B-6, BCUC IR1 69.1

Demand Reduction (pre-DSM)

On page 9-2 of the Application, FEI states:

> The impact of natural efficiency and some electrification of end use demand in the Diversified Energy (Planning) Scenario results in slightly reduced overall demand in these customer groups over the planning horizon as shown in Figure 4-9. This demand reduction corresponds to GHG emission reductions of 0.3 Mt CO2e per year in 2030 and 0.4 Mt CO2e per year in 2040.

In response to BCUC IR1 69.1, regarding the calculation of emissions reductions from natural efficiency in the residential sector, FEI states:

> Further changes to the space heating UEC were estimated based on the evolving efficiency of heating equipment. Furnaces and boilers were assumed to be replaced at the natural rate at which they reach end of life, with whatever equipment will be standard in that year.
>
> The trends in Domestic Hot Water (DHW) tertiary loads were assumed to come from the natural replacement of clothes washers and dishwashers at end of life, with new ones at the current standard. DHW use in showers and other fixtures was not assumed to change in the Reference Case.
>
> Further changes to the UEC of DHW were estimated based on the natural replacement of existing water heating equipment at its end of life with new equipment that meets the equipment standard for that year.
>
> Tertiary loads in new dwellings are based on the current version of the BC Building Code. Step Code regulations that are expected to be adopted in future years were not taken into account.

Regarding the calculation of emission reductions from natural efficiency in the commercial sector, FEI adds:

> Changes to space heating due to improved codes in new commercial construction, are based on the current version of the BC Building Code. Step Code regulations that are expected to be adopted in future years were not taken into account.

In the same IR response, FEI also states, “Natural conservation in industry is assumed to be minimal.”

Furthermore, FEI states:

> The price elasticity of demand reflects how demand for a good changes in response to a change in the price of that good, all else being equal. For the LTGRP modelling, only "own-price" elasticity – how demand changes in response to changes in price of that good only – was used.

112.1 Please elaborate on the rationale of the assumption that, for the calculation of natural efficiency in a long-term plan for the residential and commercial sectors, the current BC Building Code requirements remain stable for the planning horizon.

<u>Response:</u>

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

The Reference Case setting is based on end use patterns observed, as well as any new changes in law or policy that will affect future demand and have been, or are quite certain of, becoming enshrined in legislation, codes, standards or bylaws in and as of the base year. The Reference Case keeps these patterns constant throughout the planning period. Using a reference setting with only the changes that are virtually certain to occur allows for more flexibility in modeling the impact of changes that are somewhat less certain, as well as actions such as DSM activities that usually precede the implementation of new codes and standards. The intent of this LTGRP is to model a range of futures in order to develop a plan that is robust in the face of uncertainty. Some of the scenarios include accelerated improvement in codes and standards and some do not, which helps create a robust range of alternative possible futures.

It is important in long-term resource planning to draw a line (identify a cut-off point) after which changes in the planning environment can no longer be incorporated into the demand forecast and addressed in the future scenarios. Otherwise, the demand forecast, and other aspects of the future scenarios, will be constantly shifting, preventing the remaining analytical activities from being completed and never allowing the LTGRP to be finished. For this reason, each LTGRP submitted can be said to represent somewhat of a snapshot in time. Changes that occur in the planning environment after the completion of one LTGRP and that suggest demand will be higher or lower over the long term are picked up and considered in the next LTGRP. Ensuring that such changes are considered in long-term resource planning is the reason that a new LTGRP is prepared approximately every three to five years.[51]

112.1.1 Please provide FEI's understanding of the potential changes to the BC Building Code in the planning horizon.

[51] Please refer to the responses to BCUC IR1 29.5 and 29.7 and BCSEA IR1 7.2.

Response:

FEI notes that the BC Building Code scheme is highly technical. The following is a high-level summary of the known and potential changes to the BC Building Code.

There are currently two central frameworks in the BC Building Code that target GHG emissions in new construction: the BC Energy Step Code, and the new Zero Carbon Step Code. FEI understands that there is potential for these mechanisms to evolve over the planning horizon to assist with the Province's GHG reduction targets, as discussed further below.

As discussed in the response to BCUC IR2 98.1, FEI understands that the most recent amendments to the BC Building Code[52] require Step 3 and Step 2 BC Energy Step Code performance for all residential and commercial new construction, respectively, to achieve a 20 percent improvement in energy efficiency above the 2018 BC Building Code performance. Most new buildings constructed after May 1, 2023 must meet these energy efficiency requirements.

Generally, the objective of the Step Code is to see progressive improvements in energy efficiency adopted into the BC Building code over time. FEI understands that over the planning horizon, the BC Building Code will move toward the higher steps of the BC Energy Step Code as a minimum requirement for new construction, in order to meet the Province's target of net-zero new construction by 2030.

The most recent amendments to the BC Building Code also enable the new Zero Carbon Step Code (formerly known as the Carbon Pollution Standard), which is an optional compliance path in the BC Building Code that local governments may adopt.[53] Whereas the BC Energy Step Code targets the energy-efficiency performance of new buildings, the Zero Carbon Step Code targets their operational emissions. Local Governments that choose to adopt the Zero Carbon Step Code in their building bylaws can select the level of energy stringency they wish their new buildings to achieve: "Moderate Carbon Performance", "Strong Carbon Performance" and "Zero Carbon Performance".[54] There is also a "measure only" option, which would formalize a requirement for builders to measure and report the amount of carbon pollution that new construction projects will produce.

While the Zero Carbon Step Code is currently optional for local governments, it is FEI's understanding the Province intends to introduce mandatory carbon emission limits into the BC Building Code. While there is currently no further information on these limits, FEI is aware of the Province's target to have zero carbon new construction by 2030, and recognizes the potential for the levels of energy stringency described above to be made mandatory in the future.

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[52] BCBC 2018 Revision 5 (effective May 1, 2023).

[53] Details can be found online at the BC Energy Codes website: Government of BC Building and Safety Standards Branch, "BC Energy Step Code Requirements" (February 16, 2023) online at: https://energystepcode.ca/requirements/#bcbc-2018-rev-4.

[54] It is FEI's understanding that the opt-in Zero Carbon Step Code is applicable to all governments except the City of Vancouver, which has its own building code and plan to reduce emissions from the buildings sector.

Other potential changes to the BC Building Code are expected as building technologies and policy evolve. These changes may involve further performance and prescriptive approaches to the BC Energy Step Code and Zero Carbon Step Code, including further airtightness options, new energy performance improvement compliance calculations, and the introduction of National Building Code provisions.

With respect to BC Building Code requirements for existing buildings, FEI understands that gas appliance standards that require greater than 100 percent efficiency for space and water heating in 2030 may be on the horizon. The Province is currently developing an "Existing Buildings Renewal Strategy"[55] and FEI is aware of a proposed national code approach to existing buildings.[56] These initiatives are ongoing and their details are currently uncertain.

112.1.2 Please provide an estimate (or a range) of natural gas savings and emission reductions associated with potential changes in the BC Building Code and adoption of the Step Code in the planning horizon. If not available, please describe the expected directional impact.

Response:

As described in the response to BCUC IR2 81.2.1, holding all else equal and under current modelling assumptions (including the assumption the DEP portfolio of gas supply remains available to new residential and commercial buildings), FEI's estimate of the impact of the potential changes in the BC Building Code is in the range of a 5 to 10 percent reduction in total annual demand by 2042. Please refer to the discussion in the response to BCUC IR2 81.2.1 of the inherent limitations of new construction codes, appliance standards and retrofit codes in reducing overall gas demand. Under a "worst-case scenario" where FEI is precluded from offering gas service to new residential and commercial customers as discussed in the response to BCUC IR2 93.1, FEI estimates that gas demand from residential and commercial customers could be reduced by 15 to 20 percent by 2032.

The emission reductions would generally mirror the reduction in demand over the planning horizon, except in a scenario where the Renewable Gas Connections service is approved and FEI supplies new residential and commercial customers with 100 percent RNG. FEI would still expect an overall demand reduction between 5 to 10 percent by 2042, but emissions would be lower due to the lower carbon intensity of RNG.

[55] Province of British Columbia, "Existing buildings renewal strategy" (December 13, 2022) online at: https://www2.gov.bc.ca/gov/content/industry/construction-industry/building-codes-standards/existing-buildings.

[56] Government of Canada, "Final report – Alterations to existing buildings" (April 2020) online at: https://nrc.canada.ca/en/certifications-evaluations-standards/codes-canada/codes-canada-publications/final-report-alterations-existing-buildings.

112.2 Please elaborate on the reasons why natural conservation in the industrial sector is assumed to be minimal.

Response:

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

Natural conservation in the industrial sector is assumed to be minimal for several reasons, including:

- Industrial equipment life is long and is often prolonged by on-site repairs instead of replacement due to capital investment requirements. In very large plants, some of the significant equipment is constructed on-site and remains in place for the life of the facility;
- Industry investments in plant upgrades typically require very short payback periods and FEI's experience with industrial DSM programs indicates that without rebates, many industrial energy efficiency projects and programs do not meet investment hurdles;
- Energy conservation is often a relatively low priority in many facilities, compared to other considerations such as material costs, production output, and product quality;
- Rebate programs play a key role in drawing attention from industry to new energy efficiency innovations that become available over time; and
- New equipment may require additional building retrofits, training and maintenance requiring change management thus adding to the complexities of such undertakings.

In terms of modeling, using a reference setting with only minimal industrial natural conservation allows for more flexibility in modeling the impact of increased conservation in other scenarios. The intent of this LTGRP is to model a range of futures, in order to develop a plan that is robust in the face of uncertainty. Some of the scenarios, therefore, include accelerated industrial conservation, induced by government policies motivated by the same objectives that lead to improved building codes, and some do not.

112.3 Please confirm that FEI's modeling, whether in the pre-DSM demand reduction or any other of the Clean Growth Pathways pillars, only considers own-price elasticity.

112.3.1 If not, please indicate if the modeling considers natural gas-electricity cross-elasticity and elaborate on its use in the Application.

Response:

The following response has been provided by Posterity Group.

Confirmed. FEI’s modeling only considers own-price elasticity. Posterity Group did not find usable values for cross-price elasticity in its literature search, so there is no use of cross-price elasticity in the Application.

113.0 Reference: GHG EMISSION REDUCTIONS IN THE DIVERSIFIED ENERGY (PLANNING) SCENARIO

Exhibit B-6, BCUC IR 71.8.1, 71.12, 75.2

Low-Carbon Gas Supply

In response to BCUC IR1 71.8.1, FEI states:

> In the tables below, FEI provides the renewable and low-carbon portfolio supply outlook for the DEP Scenario, Reference Case and all alternate scenarios to serve residential, commercial and industrial customers. This supply outlook represents an example of how components of the scenarios could evolve, including different types of gas supply, their average cost and total annual cost. The origin of supply is discussed below the tables.
>
> It is important to emphasize that FEI has not developed a separate 20-year forecast for each individual component of its renewable and low-carbon gas supplies (i.e. RNG, hydrogen, syngas and lignin) for its 2022 LTGRP. The data for the individual components of the renewable and low- carbon portfolios presented in the tables below is an outlook and not a forecast per se. The individual component volumes could change and new forms of renewable and low-carbon gas or other gas decarbonization pathways could come into play in the future. FEI considers that each of the individual components of the outlook will fall within a range, with the expectation that the actual amount of component acquired will vary from year to year depending on many factors, such as rate of project advancement and cost of supply.

Tables 1 to 6 in BCUC IR1 71.8.1 assume a cost of hydrogen of 30.5$/GJ in the period 2019-2027 and 15$/GJ in the period 2028-2042, for all scenarios.

In response to BCUC IR1 75.2, FEI provided a table with a summary and comparison of rate impacts for different rate schedules and all of FEI's scenarios.

In response to BCUC IR1 71.12, FEI states:

> In terms of the speed to develop individual projects, as discussed above, some types of projects may require longer lead times depending on project requirements such as technology scale up, infrastructure interconnections, regulatory approvals and permits, social acceptance, and investment needs. FEI's experience in BC as an RNG purchaser and project developer indicates that anaerobic digestion RNG projects up to 0.3 PJ per year production, which is currently representative of the largest proposed project capacity of this type in BC, could on average require three to five years of lead time to bring to commercial operation after final investment approval. FEI is also engaging with potential suppliers and completing in-house early-stage technical and economic feasibility assessments for larger scale renewable and low-carbon supply, including green hydrogen projects up to 5 PJ

per year and blue hydrogen projects with significantly greater annual production capacity that would require much longer than five years to achieve commercial operation after establishment of a supply agreement and final investment approval. Off-system projects, depending on the jurisdictional requirements and supporting policy and incentives in place, may require less time to construct similar-sized projects; therefore, FEI's approach of seeking supply from a broader marketplace, including a portfolio of on-system and off-system projects, mitigates some of the risk associated with longer lead time needed to ramp up supply for renewable and low-carbon projects.

113.1 Please explain the difference between a forecast and an outlook.

Response:

In discussing the future portfolio of renewable and low-carbon gas in the Application and its proceeding, FEI intended the following difference in meaning between the term "forecast" and the term "outlook":

- Forecast – refers to a mathematical or data-driven value derived through modeling including inputs that are researched and recorded to the best of FEI's ability at the time.
- Outlook – refers to FEI providing its best estimate of one example of what the 20-year portfolio composition could comprise, knowing that there is a high degree of variability and uncertainty with regard to the components presented, as the industry for renewable and low-carbon gas is at the relatively early stage in contrast to many other components of long-term resource planning that are based on many years of actual data. FEI considers that an outlook in this context is a somewhat more general assessment of a broader range of factors than a forecast and is therefore somewhat more subjective.

113.2 Please confirm, or explain otherwise, that the estimated cost of renewable and low-carbon gas supply and volumes in the outlook were used in the calculation of the scenarios' rate impact analysis.

Response:

Confirmed. Please also refer to the response to BCUC IR2 91.4.

113.3 Please explain the reasons for the significant reduction in the projected cost of hydrogen after the year 2027 and provide all assumptions made.

Response:

Please refer to the responses to the BCSEA IR1 18 series for a comprehensive overview of hydrogen production and cost considerations. In summary, FEI estimated a reduction in the projected cost of hydrogen after the year 2027, based on the announced timing of hydrogen projects coming into service, primarily in Alberta. The assumption is that these large-scale projects will have a positive impact on the price of hydrogen available to FEI from 2027 onwards. A summary of the BCSEA IR1 18 series is as follows:

- BCSEA IR1 18.2 includes tables summarizing the main inputs used to derive the production costs for low-carbon hydrogen produced from natural gas with carbon sequestration in the form of gaseous carbon dioxide (blue hydrogen) and low-carbon hydrogen produced from natural gas with carbon sequestration in the form of solid carbon (turquoise hydrogen). Assumptions were adopted from the British Columbia Renewable and Low-Carbon Gas Supply Potential Study (the Potential Study)[57] and other sources[58]. The research assumes capital and sequestration cost reductions of 9 and 10 percent by 2030, and 20 and 25 percent by 2050, respectively.
- BCSEA IR1 18.3 and 18.4 confirm that the cost calculation includes revenues derived from the potential sale of the captured byproduct, carbon, in the form of carbon black powder or graphite powder to secondary markets. The Potential Study suggests that net cost of turquoise hydrogen after accounting for byproduct carbon sales in the form of carbon black may reduce the production cost below $1 per GJ by 2030.
- BCSEA IR1 18.5 and 18.6 discuss the market maturity of Carbon Capture Utilization and Storage (CCUS) in advancing the availability of blue hydrogen.

Please also refer to the response to MetroVan IR1 2.2.1 which addresses FEI's assumptions associated with a drop in the forecasted commodity cost of renewable and low-carbon gas from 2026 to 2028.

Please also refer to the response to BCUC IR2 113.2 where FEI provides additional information about its estimated cost of renewable and low-carbon gas supply and volumes.

113.4 Please provide an updated version of the table provided in BCUC IR1 75.2, if the hydrogen costs remain constant at 30$/GJ in all the planning horizon, all else remaining equal.

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[57] Appendix D-2 to the Application.

[58] Assumptions in both Table 1 and Table 2 in BCSEA IR1 18.2 were supplied by Envint Consultants outside of the BC Renewable Gas Supply Potential Study.

Response:

Please refer to the table below, illustrating updated rate impact information based on hydrogen costs remaining constant at $30 per GJ across the planning horizon, all else remaining equal, for all scenarios.

	Effective Rate Change (2022 - 2042, %)												
	Average UPC (2022 - 2042)	Reference		Upper Bound		Diversified Energy (Planning)		Deep Electrification		Economic Stagnation		Price Based Regulation	
		Cumulative	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative	Annual
Residential (RS 1)	60	74%	2.8%	100%	3.5%	139%	4.4%	235%	6.2%	21%	1.0%	131%	4.3%
Small Commercial (RS 2)	293	42%	1.8%	94%	3.4%	129%	4.2%	207%	5.8%	2%	0.1%	122%	4.1%
Large Commercial (RS 3)	3,253	41%	1.7%	102%	3.6%	137%	4.4%	206%	5.7%	-2%	-0.1%	131%	4.3%
General Firm Service (RS 5)	18,542	46%	1.9%	119%	4.0%	150%	4.7%	150%	4.7%	11%	0.5%	147%	4.6%

Maintaining hydrogen costs at $30 per GJ has rate impacts on each of the scenarios, relative to their values provided in the table in the response to BCUC IR1 75.2, depending on the proportion of hydrogen in each scenario's portfolio over time. The largest rate impacts are seen in the Upper Bound and DEP Scenarios as they include higher proportions of hydrogen in their portfolios than the other scenarios.

113.5 Please discuss by when FEI would have to secure sufficient volumes of renewable and low-carbon gas contracts or projects, to meet the 2030 targets.

Response:

Since the details surrounding the GHGRS have not been finalized, including the timing and compliance pathways, FEI cannot provide a firm timeline. Generally, FEI's procurement strategy includes acquiring renewable gas supplies via offtakes from third-party project developers in BC and outside BC and developing its own production projects in BC. FEI is also pursuing opportunities to acquire hydrogen, syngas and lignin that will be part of its 2030 portfolio. Given that some renewable and low-carbon gas contracts are for offtake from immediately-available supply and may not require a lead time to secure the energy, and other supply opportunities are from projects not yet in commercial operation, FEI expects that it would need to secure sufficient volumes of renewable and low-carbon gas contracts or projects by 2028 in order to meet 2030 targets in the event that the GHGRS is implemented by the Province.

113.6 Please discuss the feasibility of the 2030 outlook of hydrogen supply, in light of the expected lead times for hydrogen projects.

Response:

The operating environment for hydrogen supply is advancing rapidly – policy, technology and market developments are having important impacts on the outlook for hydrogen supply. For example, the federal Clean Hydrogen tax credit announced in March 2023 can materially aid the business case for hydrogen projects. The US Inflation Reduction Act and its hydrogen production tax credit is also anticipated to have spillover benefits for hydrogen in Canada. It is, therefore, difficult to assess the feasibility of the hydrogen supply outlook within this dynamic context.

Expected lead times for hydrogen projects will vary as outlined in the preamble to the question. As a result, the access to hydrogen supply that FEI has outlined in response to the various IRs referenced in the preamble are likely to result in achieving the 2030 outlook. FEI anticipates that a mix of supply types of hydrogen will be needed, including FEI procuring low-carbon intensity hydrogen supply from outside BC.

114.0 Reference: GHG EMISSION REDUCTIONS IN THE DIVERSIFIED ENERGY (PLANNING) SCENARIO

Exhibit B-6, BCUC IR 62.2; 62.3; 62.5

Off-System Hydrogen

In response to BCUC IR1 62.2, FEI states:

> FEI anticipates the first off-system and on-system hydrogen contracts could be executed in the next 12 to 24 months, and expects the first supply to be delivered in the 2025-2030 timeframe. Since initial off-system hydrogen purchases would most likely be delivered by displacement, the timing would be dependent on the development schedule of off-system projects. With respect to on-system hydrogen, FEI is currently undertaking extensive analysis to advance to final investment decisions for on-system hydrogen production and is engaging with potential third-party hydrogen producers to procure on-system hydrogen supply.

In response to BCUC IR1 62.3, FEI states:

> If low-carbon hydrogen is injected into a distribution network in Canada or the US and delivered by displacement, the off-system hydrogen would contribute to FEI's carbon reductions in the same way that off-system RNG currently contributes to FEI's carbon reductions. Off-system hydrogen can displace natural gas consumption directly at an industrial host site or by injecting hydrogen into a natural gas pipeline that can accept hydrogen… The carbon intensity of hydrogen is expected to vary by project and calculations would be made using government-approved emission factors. As a result, FEI requires clarity from the BC government on emission reduction calculations for hydrogen, in addition to recognition for off-system hydrogen purchases to count toward FEI's GHG emission reduction obligations.

In response to BCUC IR1 62.5, FEI states:

> FEI currently anticipates that on-system delivery of hydrogen by 2025 could be in the range 0.1 to 0.5 petajoules per year. FEI is in discussions to acquire off-system hydrogen supply; however, FEI does not expect any of the large off-system hydrogen projects to come into service before 2025. Therefore, the current estimate for hydrogen supply does not include any off-system hydrogen supply in 2025.

114.1 Please elaborate on how FEI envisions the implementation of an off-system hydrogen supply by displacement. Please provide examples of the types of projects that FEI envisages may facilitate acquisition of off-system hydrogen.

Response:

Before FEI would proceed with any off-system hydrogen supply, FEI would require clarity from the BC government on emission reduction calculations for hydrogen, amendments to the GGRR to facilitate the purchase, and recognition that off-system hydrogen purchases supplied to BC by displacement would count toward FEI's GHG emission reduction obligations.

If FEI had the appropriate support from government for engaging in these activities, off-system renewable or low-carbon intensity hydrogen delivered by displacement would involve FEI negotiating Hydrogen Purchase Agreements (HPA) with counterparties, whereby FEI would purchase the hydrogen molecules produced by the seller's facility. As noted in the response to BCUC IR1 62.3, off-system hydrogen can displace natural gas consumption by injecting hydrogen into a natural gas pipeline that can accept hydrogen, or by directly displacing natural gas used at an industrial host site connected to the gas system:

- **Off-System Hydrogen Used to Replace Natural Gas by Blending in the Gas System:** The supplier would meter and inject certified low-carbon intensity pipeline quality hydrogen into the local gas distribution system and the physical hydrogen-natural gas blended molecules would be consumed by gas customers nearby and who would have their billing tariff adjusted for the different energy content of the gas. FEI would obtain production and injection records to confirm the amount of metered hydrogen FEI would acquire under the HPA and that would displace natural gas in the gas system. This is like how conventional natural gas and RNG are acquired from producers today. FEI also notes that conventional natural gas delivered to customers today is a blend of hydrocarbon gases that is predominantly comprised of methane but also may include other gases such as ethane, butane and propane. Hydrogen would simply become a larger part of the existing mixture of hydrocarbon gases delivered to FEI's customers.
- **Off-System Hydrogen Used to Replace Natural Gas use at Industrial Host Site:** The supplier would meter and inject certified low-carbon intensity hydrogen directly at an industrial facility to replace existing natural gas use. FEI would obtain production and injection records to confirm the amount of metered hydrogen FEI would acquire under the HPA and that would displace natural gas in the gas system. FEI would acquire all environmental attributes of the hydrogen supply, meaning that the industrial host would report greenhouse gas emissions from consuming the hydrogen as if it were still consuming an equivalent volume of conventional natural gas ("methane-equivalent hydrogen"; on an energy basis). FEI would report the reverse; that is, FEI would report the greenhouse gas emissions from consuming the conventional natural gas received as if it were consuming hydrogen ("hydrogen-equivalent methane"; on an energy basis).

In both of these scenarios, the hydrogen supply purchased by FEI would be delivered to FEI when the supplier, or gas marketer working on behalf of the supplier, delivers to FEI the equivalent amount of conventional natural gas (on an energy basis) at a gas trading hub. In this way, FEI "swaps" the purchased volume of hydrogen for an equivalent physical volume of natural gas ("hydrogen-equivalent methane"), which includes all environmental attributes of the hydrogen, plus the physical conventional natural gas-equivalent energy volume. Because FEI would contractually own the environmental attributes associated with the off-system hydrogen, the environmental benefits would accrue to FEI's customers in BC that consume the hydrogen-equivalent methane, rather than to the industrial host. FEI would obtain hydrogen production and consumption records to verify hydrogen displacement at the host site.

114.2 Please explain the commonalities and differences of off-system hydrogen supplies and off-system RNG supplies.

Response:

FEI considers that the acquisition of low-carbon intensity RNG supply and low-carbon intensity hydrogen share common principles in terms of displacing higher carbon intensity conventional methane in the contiguous gaseous energy system, and the ability to be delivered to customers by displacement. Off-system hydrogen and RNG supplies are similar in that both forms of gaseous energy can be used to replace conventional natural gas to reduce the carbon intensity of the delivered energy (discussed in the response to BCUC IR1 62.3).

Off-system hydrogen and off-system RNG are different in that RNG is a drop-in replacement gas for natural gas whereas hydrogen is not. Off-system RNG is more easily understood in terms of displacement of conventional natural gas in the contiguous gas system. Hydrogen presents different fuel properties compared to RNG and, therefore, is not yet a drop-in replacement for natural gas because the gas system has yet to transition to being able to use hydrogen in the gas mix. However, the conventional natural gas delivered to FEI's customers includes not only methane but amounts of other hydrocarbon gases; as such, hydrogen can be seen as another gas that will likely appear as an increasing component in the gas supply delivered to FEI's customers as it becomes available and the market for low-carbon hydrogen scales into the future. Nevertheless, because hydrogen and methane are different gases and long-haul pipelines have yet to accept significant volumes of hydrogen gas, at this time, off-system hydrogen supply must be consumed at or near where it is produced.

114.3 Please discuss if off-system hydrogen supply would require changes to the current legislative and regulatory framework, and characterize such changes.

Response:

To acquire off-system hydrogen supply as a prescribed undertaking, changes to the GGRR would be required because the regulation currently limits hydrogen as a prescribed undertaking to hydrogen that is acquired and distributed through the natural gas distribution system in BC to customers of FEI or another utility in BC. To facilitate the acquisition of off-system hydrogen, the GGRR would need to be amended to allow the acquisition of hydrogen without the requirement that it be distributed through BC's gas distribution system to customers in BC. Also, to enable acquisition of a greater range of hydrogen supply, GGRR changes would be needed to define hydrogen based on a carbon-intensity basis, rather than the current definition of waste hydrogen or hydrogen derived from water using electricity from clean or renewable resources. This approach would open new production pathways for hydrogen acquisition by FEI, such as through auto-thermal reforming and/or pyrolysis of natural gas feedstock.

While not necessary, the definition of "energy" in section 68 of the UCA could be amended to include "hydrogen", so that hydrogen supply contracts are regulated consistently with gas and electricity supply contracts.

115.0 Reference: GHG EMISSION REDUCTIONS IN THE DIVERSIFIED ENERGY (PLANNING) SCENARIO

Exhibit B-6, BCUC IR 71.5

Renewable and Low-Carbon Gas Supply

In response to BCUC IR1 71.5, FEI states:

> The provincial GHG emissions inventory as well as the CleanBC Roadmap accounts for GHG emissions on a sector-by-sector basis using end-use emissions factors. The GHGRS is described in the Roadmap as a tool to reduce emissions in the buildings and industry sectors (net of upstream oil and gas extraction). Emissions in these sectors are accounted for using end-use emissions factors.

115.1 Please discuss how FEI anticipates that upstream GHG emissions associated with FEI's RNG and hydrogen gas supply, where such supply originates in BC, would be accounted for.

115.1.1 Please explain whether those emissions would be included in FEI's end-use emission factors or explain otherwise.

Response:

FEI does not have policy direction or additional clarity from the Provincial government on this issue; as such, FEI's perspective on this question is not informed by direction from the Province.

For the purposes of sectoral targets for the Built Environment, FEI speculates that the upstream GHG emissions associated with FEI's RNG and hydrogen gas supply would be included in RNG or hydrogen end-use emission factors. This is because the approach to address upstream emissions appears to be addressed by the oil and gas sector emissions cap announced in March 2023 in the Energy Action Framework. Inclusion of upstream emissions in sectoral targets for the Built Environment would result in double counting of those emissions and potentially stacking abatement costs. However, these assumptions will need to be determined by relevant policy.

115.2 Please explain, in the case of upstream GHG emissions from renewable and low carbon gas projects located out of the province of BC, how the GHG emissions are accounted for.

Response:

For the purposes of BC sectoral targets, upstream GHG emissions from renewable and low carbon gas projects located out of BC are not accounted for in BC's GHG inventory. FEI recognizes that a rigorous, transparent and standardized GHG accounting framework for renewable and low-carbon gases would be helpful and is taking steps to inform and encourage this approach with the provincial and federal governments and other stakeholders.

115.2.1 Please explain whether those emissions would be included in FEI's end-use emission factors or explain otherwise.

Response:

Upstream emissions from out-of-province supply would not be included in FEI's end-use emission factors. The end-use emission factor applies to the emissions associated with combustion at the appliance and does not include any associated pipeline- or upstream-related emissions. As stated in the response to BCUC IR1 71.5, inclusion of any upstream emissions within sectoral targets would result in double counting of emissions.

115.3 Please discuss the accounting of GHG emissions if production facilities, such as hydrogen, were owned by FEI.

Response:

From a GHG accounting perspective, FEI believes that the emissions from potential low-carbon hydrogen production would be included in either the GHGRS or the upstream emissions cap in order to avoid double counting. However, the approach for accounting of GHGs from hydrogen and the scope of those GHGs in prospective policy regimes like the GHGRS is uncertain. FEI has not received guidance on whether the GHGRS will account for lifecycle or only combustion-related emissions. Furthermore, the scope of the prospective emissions cap for upstream oil and gas and the possibility of hydrogen facilities falling under this regime, will also be an important factor in future policy development.

115.3.1 Please explain if the GHG emissions from these facilities would be considered FEI's emissions.

Response:

GHG emissions from these hypothetical proposed production facilities will be attributed to FEI to the extent that FEI retains operational and/or financial control over the production facilities.

115.3.2 Please explain whether these GHG emissions would or would not be included in the gas supply end-use emission factors

Response:

As discussed in the responses to BCUC IR2 115.1, 115.2, and 115.3, end-use emission factors apply to the GHG emissions associated with the end-use appliance only. Any inclusion of upstream values such as pipeline transportation and production of the fuel will result in double counting of emissions that are covered under other sectoral targets. As such, the GHG emissions from these hypothetical production facilities would not be included in the end-use combustion emission factor.

116.0 Reference: GHG EMISSION REDUCTIONS IN THE DIVERSIFIED ENERGY (PLANNING) SCENARIO

Exhibit B-6, BCUC IR1 64.1

Low-Carbon Conventional Gas

In response to BCUC IR1 64.1, FEI states:

> FEI sees potential for different CCS and CCUS technologies and applications to support FEI's GHG emission reductions goals and contribute to on-system low-carbon gas supply by 2030 and beyond. The BC Renewable and Low-Carbon Gas Supply Potential Study of the Application outlines in detail some of these CCUS technologies that FEI is interested in accelerating to produce low-carbon gas. FEI is in the early stages of investigating and supporting some projects that involve carbon capture through the Clean Growth Innovation Fund. These projects are at a relatively early stage of development and are therefore low on the Technical Readiness Level scale. Some projects are progressing to small-scale pilot demonstrations, after which commercialization planning can proceed based on an established baseline of successful performance.
>
> FEI is also interested in accelerating CCUS technologies in other applications, such as capturing and sequestering post-combustion point source carbon at industrial emitters, capturing carbon emissions from biomethane upgrader facilities to produce deeply negative RNG, and the direct capture of carbon dioxide from air. At present, commercialization timelines, forecasted costs, service offerings, rate design and other relevant considerations are unavailable. FEI also sees a role for CCS in developing low-carbon conventional gas and is in the early stages of investigating an opportunity to invest in CCS with low-carbon gas offtake. However, FEI would require low- carbon conventional gas to be recognized within the regulatory framework in order to execute on this opportunity. These initiatives will be initiated once FEI determines the types of CCUS projects that would support the Company's emissions reduction goals.
>
> With regard to the contribution of CCUS within the overall renewable and low-carbon gas portfolio outlook in the LTGRP, FEI has not forecast specific amounts of each type of renewable and low- carbon gas (including CCUS).

116.1 Please explain the definition of low-carbon conventional gas, including whether CCS and/or CCUS technologies are used.

Response:

There is no standardized definition of low-carbon conventional gas. For the purposes of this discussion, FEI is referring to low-carbon conventional gas as natural gas that has lower lifecycle emissions when compared to existing pipeline natural gas produced using industry standard practices and following existing policies and regulations.

FEI is evaluating projects and supply options where natural gas producers are specifically investing in GHG saving technologies and practices that reduce the GHG emissions associated with any of the extraction, gathering, processing, and transmission activities associated with delivering natural gas to FEI's custody.

There are many potential project types that could lower GHG emissions from these activities which could include investments in CCUS at gas processing facilities, investments in advanced methane controls beyond existing regulations, investments in electrified gas processing and compression, and potentially investments in negative emissions technologies like direct-air capture or nature-based solutions that could couple sequestered CO_2 with natural gas molecules to lower its overall intensity.

117.0 Reference: RATE IMPACT IMPLICATIONS OF THE DIVERSIFIED ENERGY (PLANNING) SCENARIO

Exhibit B-6, BCUC IR 75.2, 75.4, 75.5

Rate Impact Scenarios

In response to BCUC IR1 75.2, FEI provided a table with a summary and comparison of average projected delivery rate changes for FEI's alternate scenarios for the residential, small commercial, large commercial and general firm service rate schedules.

In response to BCUC IR1 75.4, FEI provided a table that compares the assumptions used for the modeling of rate impacts for all FEI's scenarios and BC Hydro's Reference Case and Accelerated Electrification Scenario.

In BCUC IR1 75.5, FEI was requested to elaborate on the variables and assumptions that have the most significant impact on the rates. In its response, FEI provided an example using the residential rate schedule in the DEP Scenario.

117.1 Please, provide an analysis of the variables and assumptions that have the most significant rate impact, similar to that provided for the residential sector in BCUC IR1 75.5, for all scenarios and rate schedules.

Response:

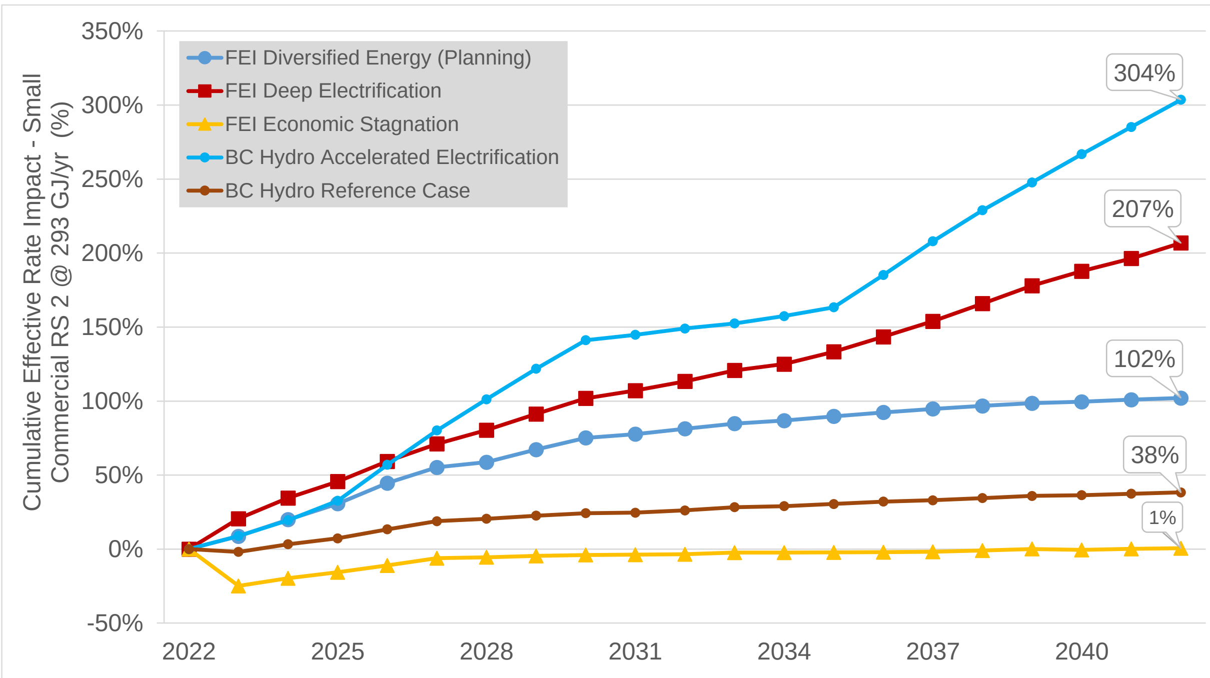
Please refer to Tables 1 to 4 below for a breakdown of the rate impact for all scenarios and for the residential, small commercial, large commercial, and general firm service rate schedules, respectively. The breakdowns are provided in the same format as provided in the response to BCUC IR1 75.5. As discussed in Section 9.4 of the Application, the rate impact analyses were not indicative of a detailed rate forecast; they are simply providing a directional, 20-year view of how rates are influenced by each scenario over time. Furthermore, the rate impact analyses shown in Section 9.4 of the Application were not completed for all individual industrial rate schedules, rather it was completed on the basis of the average general firm service customers which represent the majority of FEI's industrial customer groups (i.e., RS 5 and RS 25 combined). As such, FEI provides the breakdown for the general firm service customers as an example for the industrial rate schedules and is unable to provide a similar breakdown of the rate impact for all industrial rate schedules.

Additionally, while responding to this IR, FEI discovered the rate impacts shown in Figures 7 and 8 of FEI's Stage Two Submission on FEI and BC Hydro Energy Scenarios[59] were incorrect. Specifically, the rate impacts for BC Hydro's Accelerated Electrification scenario for the small commercial and large commercial rate schedules were shown incorrectly due to excel errors. The 2024 cumulative rate impact for the small commercial RS 2 and large commercial RS 3 should have been 304 percent and 310 percent, respectively. FEI confirms the rate impacts shown for other scenarios in Figures 7 and 8 are correct. FEI also confirms the rate impacts shown in

[59] Exhibit B-4 of the FEI 2022 LTGRP Proceeding.

Figures 6 and 9 of the Stage Two Energy Scenarios Submission are correct for the residential and general firm service rate schedules, respectively. FEI provides the revised Figures 7 and 8 below.

Revised Figure 7 of FEI's Stage Two Energy Scenarios Submission – Cumulative Rate Impact (2022 – 2042) – Small Commercial RS 2



Revised Figure 8 of FEI's Stage Two Energy Scenarios Submission – Cumulative Rate Impact (2022 – 2042) – Large Commercial RS 3

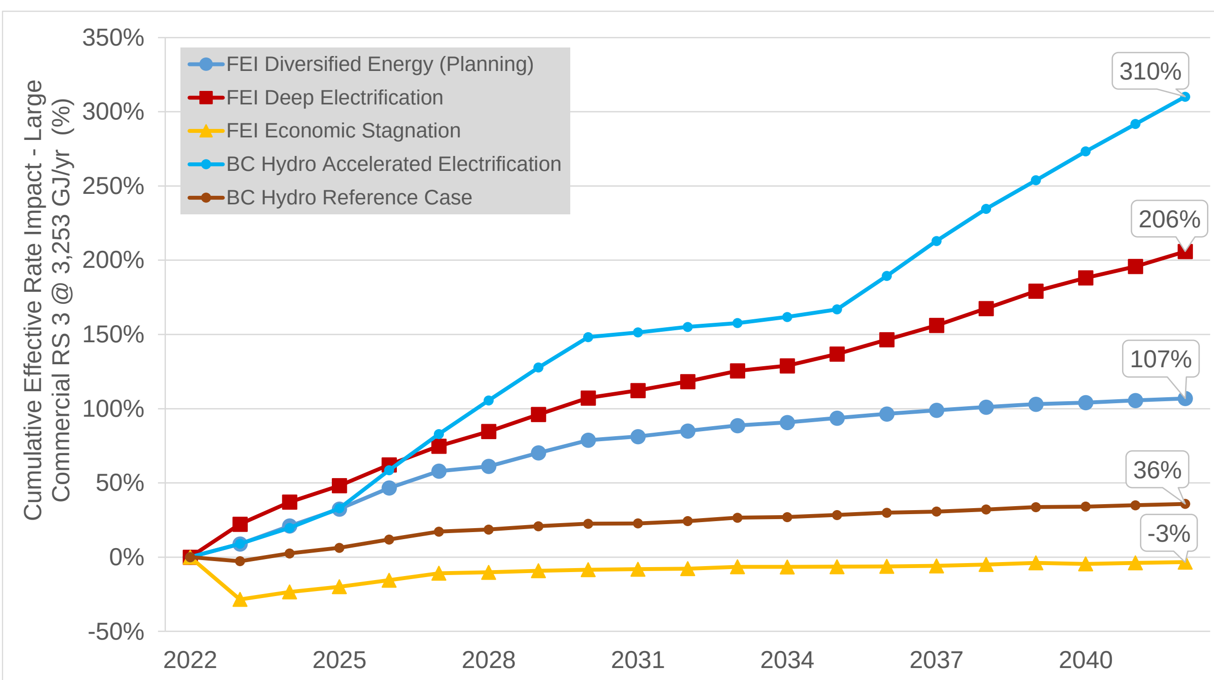


Table 1: Breakdown of Residential RS 1 Cumulative Rate Increase by 2042 for all Scenarios

	Cumulative Rate Impact by 2042 (%)															
	Reference		Upper Bound		Diversified Energy (Planning)		Deep Electrification		Price-Based Regulation		Economic Stagnation		BCH Reference Case		BCH Accelerated Electrification	
Component	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)
Demand Forecast	16%	22%	-1%	-2%	18%	15%	90%	39%	17%	13%	3%	15%	10%	17%	77%	25%
Low Carbon Transportation (LCT)	-10%	-13%	-16%	-21%	-12%	-10%	-37%	-16%	-23%	-18%	-5%	-22%	-13%	-22%	-37%	-12%
CPCNs (Approved/Filed)	7%	10%	11%	14%	12%	11%	16%	7%	16%	12%	5%	26%	14%	22%	16%	5%
Sustainment Capital (VITS, CTS and ITS)	15%	21%	22%	28%	14%	12%	33%	14%	17%	13%	6%	30%	16%	26%	33%	11%
Demand Side Management (DSM)	0%	0%	0%	0%	3%	3%	-4%	-2%	-2%	-2%	-1%	-4%	1%	1%	-5%	-2%
Inflation	29%	40%	17%	22%	25%	21%	65%	28%	25%	19%	20%	100%	24%	39%	58%	19%
Delivery	58%	79%	32%	41%	60%	51%	164%	70%	49%	37%	29%	144%	50%	83%	141%	46%
Commodity Related Charges	16%	21%	59%	77%	48%	41%	46%	20%	32%	25%	5%	24%	17%	27%	129%	42%
Carbon Tax	0%	0%	-14%	-19%	10%	8%	24%	10%	49%	38%	-14%	-68%	-6%	-10%	35%	11%
Total	73%	100%	77%	99%	118%	100%	235%	100%	130%	100%	20%	100%	61%	100%	305%	100%

Table 2: Breakdown of Small Commercial RS 2 Cumulative Rate Increase by 2042 for all Scenarios

	Cumulative Rate Impact by 2042 (%)															
	Reference		Upper Bound		Diversified Energy (Planning)		Deep Electrification		Price-Based Regulation		Economic Stagnation		BCH Reference Case		BCH Accelerated Electrification	
Component	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)
Demand Forecast	8%	18%	-1%	-2%	14%	13%	68%	33%	11%	9%	0%	17%	5%	14%	63%	21%
Low Carbon Transportation (LCT)	-5%	-12%	-9%	-14%	-18%	-17%	-28%	-14%	-15%	-12%	0%	-30%	-8%	-20%	-30%	-10%
CPCNs (Approved/Filed)	4%	9%	6%	9%	10%	10%	12%	6%	10%	8%	0%	35%	8%	20%	13%	4%
Sustainment Capital (VITS, CTS and ITS)	8%	18%	13%	20%	12%	12%	25%	12%	11%	9%	0%	40%	9%	23%	27%	9%
Demand Side Management (DSM)	0%	0%	0%	0%	3%	2%	-3%	-1%	-1%	-1%	0%	-6%	0%	1%	-4%	-1%
Inflation	14%	35%	10%	15%	16%	16%	49%	24%	16%	13%	1%	134%	14%	36%	47%	15%
Delivery	28%	68%	18%	28%	38%	37%	124%	60%	31%	25%	1%	191%	29%	75%	115%	38%
Commodity Related Charges	13%	32%	61%	95%	53%	52%	54%	26%	36%	30%	0%	51%	15%	40%	148%	49%
Carbon Tax	0%	-1%	-15%	-23%	11%	11%	29%	14%	54%	45%	-1%	-142%	-6%	-15%	40%	13%
Total	41%	99%	64%	100%	102%	100%	207%	100%	121%	100%	1%	100%	38%	100%	304%	100%

Table 3: Breakdown of Large Commercial RS 3 Cumulative Rate Increase by 2042 for all Scenarios

	Cumulative Rate Impact by 2042 (%)															
	Reference		Upper Bound		Diversified Energy (Planning)		Deep Electrification		Price-Based Regulation		Economic Stagnation		BCH Reference Case		BCH Accelerated Electrification	
Component	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)
Demand Forecast	7%	17%	-1%	-1%	12%	11%	61%	30%	9%	7%	2%	-56%	5%	14%	55%	18%
Low Carbon Transportation (LCT)	-4%	-11%	-8%	-12%	-16%	-15%	-25%	-12%	-13%	-10%	-3%	97%	-7%	-19%	-26%	-8%
CPCNs (Approved/Filed)	3%	8%	5%	8%	9%	9%	11%	5%	9%	7%	4%	-114%	7%	19%	11%	4%
Sustainment Capital (VITS, CTS and ITS)	7%	17%	11%	16%	11%	10%	23%	11%	9%	7%	4%	-130%	8%	22%	23%	7%
Demand Side Management (DSM)	0%	0%	0%	0%	2%	2%	-3%	-1%	-1%	-1%	-1%	19%	0%	1%	-4%	-1%
Inflation	13%	32%	8%	12%	14%	13%	44%	21%	14%	11%	15%	-435%	12%	34%	41%	13%
Delivery	25%	63%	16%	23%	33%	31%	111%	54%	27%	21%	21%	-619%	25%	71%	100%	32%
Commodity Related Charges	15%	38%	70%	102%	61%	57%	62%	30%	40%	31%	6%	-189%	17%	48%	165%	53%
Carbon Tax	0%	-1%	-17%	-25%	13%	12%	33%	16%	62%	48%	-31%	908%	-7%	-18%	45%	14%
Total	40%	100%	69%	100%	107%	100%	206%	100%	130%	100%	-3%	100%	36%	100%	310%	100%

Table 4: Breakdown of General Firm Service RS 5 Cumulative Rate Increase by 2042 for all Scenarios

	Cumulative Rate Impact by 2042 (%)															
	Reference		Upper Bound		Diversified Energy (Planning)		Deep Electrification		Price-Based Regulation		Economic Stagnation		BCH Reference Case		BCH Accelerated Electrification	
Component	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)	Cumlative (%)	Proportion (%)
Demand Forecast	7%	15%	-1%	-1%	10%	8%	34%	22%	7%	5%	1%	14%	3%	12%	31%	11%
Low Carbon Transportation (LCT)	-4%	-9%	-7%	-8%	-12%	-11%	-14%	-9%	-10%	-7%	-2%	-25%	-4%	-16%	-15%	-5%
CPCNs (Approved/Filed)	3%	7%	4%	5%	7%	6%	6%	4%	7%	5%	3%	29%	5%	17%	7%	2%
Sustainment Capital (VITS, CTS and ITS)	7%	15%	9%	11%	9%	7%	12%	8%	7%	5%	3%	33%	5%	19%	13%	5%
Demand Side Management (DSM)	0%	0%	0%	0%	2%	2%	-1%	-1%	-1%	-1%	0%	-5%	0%	1%	-2%	-1%
Inflation	12%	28%	7%	8%	11%	10%	24%	16%	11%	7%	11%	111%	8%	30%	23%	8%
Delivery	24%	55%	13%	16%	26%	23%	61%	41%	21%	15%	15%	157%	17%	62%	57%	20%
Commodity Related Charges	21%	46%	90%	112%	73%	64%	57%	38%	48%	33%	6%	58%	17%	65%	177%	63%
Carbon Tax	0%	-1%	-22%	-28%	16%	14%	31%	21%	76%	52%	-11%	-115%	-7%	-27%	49%	17%
Total	44%	100%	80%	100%	114%	100%	150%	100%	146%	100%	10%	100%	27%	100%	283%	100%

118.0 Reference: ENERGY SUPPLY PORTFOLIO

Exhibit B-6, BCUC IR 77.3

Renewable and Low-Carbon Gas Supply Potential

In response to BCUC IR1 77.3, FEI states:

> Faster development of renewable and low-carbon gas production in BC could be achieved through updates to the policy and regulatory framework that governs FEI's acquisition and development of renewable and low-carbon gases. Such updates could include...Expanding the definition of hydrogen based on lifecycle GHG emissions intensity

118.1 Please explain what is meant by expanding the definition of hydrogen in the preamble.

Response:

Currently only green and industrial byproduct hydrogen are identified as prescribed undertakings under the GGRR. Expanding the definition or type of hydrogen as a prescribed undertaking in the GGRR from green and waste hydrogen to a lifecycle GHG emissions intensity basis is expected to enable faster development of production and deployment. In this way, regulations would allow for any hydrogen with a GHG emissions intensity below a certain threshold to be eligible as a prescribed undertaking.

I. KELOWNA ELECTRIFICATION CASE STUDY

119.0 Reference: KELOWNA ELECTRIFICATION CASE STUDY

Exhibit B-20, pp. 3–4

Assumptions Used for Modelling

On page 3 of the Kelowna Electrification Case Study (Study), FEI and FBC state:

> To isolate the impacts that increasing proportions of electrification have on peak demand for the City of Kelowna, the "electrification of gas demand" setting was changed from zero percent to 25, 50, and 100 percent…

> Within the simulation, the peak daily demand for gas was converted to the electricity equivalent (in megawatt hours (MWh)) and both fuel types were converted to a peak hour factor utilizing internal billing data from 2018 to 2020.

119.1 Please discuss whether the electrification of gas demand settings of 25, 50, and 100 percent were applied to gas demand from all customer classes and end-uses in a uniform manner.

Response:

FEI confirms that the electrification of gas demand settings was applied to gas demand from all customer classes and end-uses in a uniform manner. The input data used in the model comprised actual (metered) aggregate daily consumption data and cannot be further segregated by customer class or end use.

119.1.1 Please discuss whether the Study takes into account any end-uses where electrification is not considered feasible.

Response:

The Study does not take into account end-uses that may not be considered feasible, whether known today, or possible through technology improvements by 2040. This assumption was made given that the residential and commercial gas demand within the City of Kelowna comprises approximately 98 percent of the total gas load in the Study,[60] and equivalent electric space heating, domestic hot water heating, and cooktop equipment currently exists.[61]

[60] Under FEI Rate Schedules RS 1, 2, 3, and 5 which were used for the Study.

[61] As discussed in the fifth bullet point of Section 3.1 of the Study, the non-space heating load was converted utilizing a 30 percent efficiency gain to broadly account for all other end-uses.

Therefore, the Study examines electrification of gas demand scenarios nearly entirely for residential and commercial gas customers, as industrial customers primarily take service under the Transportation model and were not included within the Study. For clarity, the remaining industrial gas load for which marketers or third-parties purchase gas for was not analyzed as to whether electrification is currently or expected to be possible by 2040.

119.1.2 Please discuss why a 75% electrification increment was not modelled for all aspects of the Study.

Response:

Many electrification increments were modelled, including the 75 percent increment, but were omitted from the report in the interest of brevity and the time required to analyze the output from each scenario. The results of the 75 percent scenario are consistent with the findings of the 50 percent and 100 percent scenarios. A figure illustrating the 75 percent electrification scenario was included as Figure B-2 of Appendix B to the Study.

FEI provides an updated Table 4-4 below which includes the costs of the 75 percent scenario.

Updated Table 4-4: Summary of System Impacts and Land Acquisition Costs Required for Electrification Cases by 2040

	Project Costs ($ Millions)			
Peak Demand and Electrification Cases	**711 MW (25%)**	**950 MW (50%)**	**1,190 MW (75%)**	**1,429 MW (100%)**
System Upgrades (Table 4-2)	930	1,550	1,720	1,890
Land Acquisition (Table 4-3)	345 – 776	605 – 1,361	643 – 1,446	680 – 1,531
Total	**1,275 - 1,706**	**2,155 - 2,911**	**2,363 – 3,236**	**2,570 - 3,421**

119.2 Please confirm, or explain otherwise, that FEI does not have hourly billing data for its customers.

119.2.1 Please further explain how peak daily demand for gas was converted to a peak hour factor.

Response:

FEI confirms that it only has monthly billing data for most of its gas customers, and daily billing data for a small number of (typically large) customers. As discussed in the CPCN for Approval of the FEI AMI Project Application, the AMI Project would provide hourly consumption interval readings from FEI's approximately 1,100,000 residential, commercial, and industrial customer meters.

This data limitation is why FEI had to apply a peak hour factor to convert the daily gas load into a peak hourly demand equivalent for the Study. As discussed in the response to BCUC IR1 54.1, for system planning purposes, FEI determines a "peak hour factor" from the relationship of peak hour observed at local gate stations and is defined as the ratio of the peak hour gas flow to the total daily gas flow. For the Inland region, a peak hour factor of 6 percent is used to convert the daily gas demand to peak hourly demand by multiplying the daily gas demand by the peak hour factor. In other words, while one hour represents 4.2 percent of the length of one day, 6 percent of the total daily consumption is used during the peak hour.

On page 4, FEI and FBC state:

> Heat pumps, and their efficiencies as currently represented in the BC Cold Climate Field Study, essentially provide the same efficiency as electric resistive heating at temperatures below approximately -18 C, while the average daily temperature for Kelowna during the winter can be -26 C or lower (with nighttime temperatures well below -30 C). Accordingly, at temperatures colder than -18 C for the 25 percent and 50 percent electrification cases, and at temperatures colder than -20 C for the 100 percent electrification case, it is assumed that heating load is served through the auxiliary / resistive heating mode on the heat pump or by less-efficient electric heating appliances.

119.3 Please discuss whether there are electric heat pump models that would have a Coefficient of Performance (COP) of greater than 1 at temperatures below -18 C, up to and including the lowest Kelowna winter temperatures. If so, please include any relevant studies.

Response:

Given that the RDH BC Cold Climate Field Study was conducted in local regions as compared to other studies in different regions and weather climates, FEI used the BC Cold Climate Field Study as it is the most relevant to the Kelowna Electrification Study. Notwithstanding that, FEI is aware of additional heat pump field studies that have been conducted. In other studies, COP values between 1.0 and 1.5 have been achieved at temperatures between -12 C and -18 C. To FEI's knowledge, no current research has identified heat pumps with COP values greater than 1.0 at the Kelowna design temperature of -25.9 C. Until such time as heat pump technology advances to deliver COP values significantly greater than 1.0 at the Kelowna design temperature, the Kelowna peak electric demand requirements will not be affected.

Two relevant field studies that demonstrated comparable results to the RDH BC Cold Climate Field Study are as follows:

- The Cold Climate Air Source Heat Pump Final Report[62] by the Conservation Applied Research and Development shows that heating events in Minnesota where only heat pumps were used resulted in a COP of 1.3 at temperatures around -12 C.
- The Government of Yukon Air-Source Heat Pump Monitoring Project Technical Report[63] showed in their field trials that some of their cold climate units achieved a COP less than 1, while the best performing unit had a COP as high as 1.5 at -18 C.

119.3.1 Please explain whether FEI and FBC considered using a COP based upon the highest performing cold weather heat pumps available on the market.

Response:

As discussed in the response to BCUC IR2 119.3, FEI used the most recent and available field study (BC Cold Climate Field Study) for heat pump efficiencies within BC for the Study. FEI believes the highest performing cold weather heat pumps available in the BC market were used for the Study.

For the purposes of the Study, FEI conducted a speculative sensitivity analysis for hypothetical heat pump efficiency improvements that may occur before 2040. The highest performing heat pumps in the BC Cold Climate Field Study have a COP of 3.5 at 0 C.

If heat pump technology improves to the point where field-measured COP's reach 5.0 at 0 C, and if 100 percent of all FortisBC customers install such equipment before 2040, then the peak load in the 100 percent electrification case could potentially be reduced from 1,429 MW to 1,153 MW (a reduction of approximately 20 percent). This amount of peak demand still dramatically exceeds current system capacity limits and would continue to require most of the infrastructure investments identified in the Study.

119.4 Please discuss whether the peak hour for the electricity system is modelled based upon the average daily low temperature, the hourly low temperature, or other.

62 https://www.mncee.org/sites/default/files/report-files/86417-Cold-Climate-Air-Source-Heat-Pump-%28CARD-Final-Report-2018%29.pdf.

63 https://yukon.ca/en/air-source-heat-pump-monitoring-project-technical-report-2021-2022.

Response:

There is no certainty or expectation that the peak hour electric demand occurs at the lowest temperature. The lowest temperature in the winter usually occurs overnight while the peak electric demand normally occurs in the early evening (typically between 5 and 6 PM). As a result, and consistent with the gas model methodology (as described in Footnote 7 of the Study), the peak demand is modelled against the mean daily temperature (MDT).

The peak hour electric demand is then determined based upon the design MDT of -25.9 C, as described in Footnote 1 of the Study.

119.5 Please confirm, or explain otherwise, that the Study did not make any assumptions for electric heat pump efficiency improvements over time.

119.5.1 If confirmed, please further explain.

Response:

Please refer to the response to BCUC IR2 119.3.1.

120.0 Reference: KELOWNA ELECTRIFICATION CASE STUDY

Exhibit B-20, pp. 9–11

Costs and Rate Impacts

On page 9 of the Study, FEI and FBC state:

> For the purpose of the Study, FortisBC based potential system impacts and estimated upgrade costs for the City of Kelowna on the analysis produced for the 2021 LTERP, which examined the impacts of alternate future load scenarios. The results discussed in this section are high-level estimates and may change as more detailed analysis for each of the projects is conducted in the future.

On page 11, Table 4-2 outlines the additional projects required to meet a peak demand of 25%, 50% and 100% electrification cases by 2040

120.1 Please discuss whether FortisBC has undertaken high level analysis of the electric rate impacts of the additional projects outlined in Table 4-2, and taking into account the increased electric demand.

<u>Response:</u>

FortisBC provides below an analysis of the incremental impact to FBC's electric rates due only to the capital expenditures as shown in Table 4-2 and Table 4-3 of the Study, plus an estimate of the incremental power supply costs from BC Hydro and the offsetting revenue resulting from the increased electric demand from Kelowna only.

This analysis is only a high-level indication of the <u>lower bound</u> of costs and is not directly comparable to other rate impacts in the LTGRP due to the following limitations:

- The Study only represents an estimate of peak demand (capacity) under cold temperatures at a single point in time (i.e., 2040).
- The Study did not account for, nor analyze, the impacts to peak demand in the summer under hot temperatures.
- The Study was not based on an energy model that includes forecasts of changes that could occur over time to the end of the forecast duration (e.g., a 20-year planning period).
- The Study did not include the entire power supply costs that would be required on both a capacity and energy basis to serve the electricity needs of Kelowna and did not include generation resources in the Kelowna region as a result of any analysis – it only provided resources located within the Kelowna region as approved in the preferred portfolio in FBC's 2021 LTERP as a point of reference. The Study does not account for or consider the potential capital expenditures or electric demand if electrification were to occur for the entire FBC electric service territory.

- The rate impacts estimated as of 2042 do not account for various factors in FBC's revenue requirement such as, but not limited to, the potential changes or growth of the load energy forecasts and power supply requirements within FBC's service territory over the 20-year period, the efficiency conversion resulting in reduced gas demand, the capacity and energy demand from electric vehicle (EV) charging, or future income tax consideration as well as changes in FBC's regular capital (sustainment and other) and O&M expenses.

Please see Table 1 below (with assumptions provided further below) which shows that the capital expenditures for Kelowna alone[64] would result in significant rate impacts to FBC's electric customers that range from increases of 129 percent to 145 percent by 2042[65] when compared to the 2023 Approved rates. This result is reflective of the increase required to FBC's current 2023 Approved rate base of approximately $1.6 billion, which under the 100 percent electrification scenario in Kelowna alone would increase by $2.5 billion to $3.4 billion as shown in Table 4-4 of the Study (i.e., an increase of approximately 156 percent to 213 percent from FBC's 2023 Approved rate base).

Any level of electrification will have a significant impact not only to electric customers but to gas customers under the same or similar scenarios. In other words, the scenarios should be viewed in consideration of the rate impacts to all energy consumers (gas and electric customers) as a whole. This is further discussed in the response to BCUC IR2 120.2, where FortisBC has provided high-level rate impacts to both FBC's electric customers and FEI's gas customers under the DEP and Deep Electrification Scenarios from the LTGRP.

Table 1: Cumulative Rate Impacts to FBC Residential Customers by 2042 due to the Capital Expenditures for Electrification in Kelowna Only

FBC Residential	25% Electrification	50% Electrification	100% Electrification
Cumulative Rate Impact by 2042 (Incl. Capital due to Kelowna Only plus Annual General Rate Increase, Compared to 2023 Approved Rates)	129%	143%	145%

The rate impact analysis shown in Table 1 above is based on the following assumptions:

- Capital expenditures and land costs based on information in Table 4-2 and Table 4-3, respectively, of the Kelowna Electrification Case Study (in 2021$);
- Incremental revenue was based on the incremental winter peak demand of 851 MW (with adjustments for summer and shoulder seasons) and energy of 1,596 GWh from Table 2-1 of the Study;

[64] Net of the incremental power supply costs from BC Hydro and offsetting revenue from the increased electric demand plus a 4 percent FBC annual general rate increase.
[65] Year 2042 to align with the 20-year planning period of FEI's LTGRP.

- Annual rate increases of 4 percent per year to 2042 from FBC's 2023 Approved rates and revenue requirement (i.e., $426 million) as approved by BCUC Orders G-382-22 and G-87-23. The 4 percent annual increase is based on the average of FBC's approved rate increases in 2021, 2022, and 2023, which were 4.36 percent, 3.47 percent, and 3.98 percent[66], respectively. FBC notes the 4 percent annual increases are for the general rate increases of the electric service before the incremental rate impact due to the capital expenditures and land costs of electrification in Kelowna;
- FortisBC has not completed an analysis of the incremental sustainment capital and O&M expenditures required due to the electrification in Kelowna and, as such, other than the generic annual increase of 4 percent discussed above, FortisBC has conservatively assumed no incremental sustainment capital and O&M due to the additional assets resulting from the electrification in Kelowna for this high level analysis;
- FortisBC has not completed detailed analysis on the potential resources needed for the incremental power supply as well as the associated costs. The supply resources could be from BC Hydro, the market, or additional generation from FBC itself. However, in order to account for the incremental costs in the high-level analysis due to the additional power supply requirement, a proxy was included using BC Hydro's Rate Schedule (RS) 3808, plus an assumed annual rate increase of 2 percent per year for BC Hydro's general electricity rates to 2042. Additionally, for the purpose of this high-level rate impact analysis, FortisBC assumed all incremental power supply will be sufficiently provided by BC Hydro through RS 3808 in the calculation of this proxy. FortisBC also conservatively did not include any assumption of additional cost sharing with BC Hydro for any transmission upgrades that would likely be required to deliver the power to FBC's system in Kelowna;
- Average depreciation rate of 2.87 percent based on FBC's 2023 Approved rate base;
- Average property tax rate of 0.75 percent of FBC's 2023 Approved gross plant-in-service with escalation of 2 percent per year; and
- FBC's currently approved capital structure.

As mentioned in Section 6 of the Study, FortisBC plans to complete a further bottom-up analysis to consider all required aspects of electrification within FortisBC's service territory in order to holistically represent what the cost and rate impacts may be under load shifting scenarios within the greater shared service territory.

120.2 Please provide a high-level analysis of gas customers' rate impacts associated with a 25%, 50% and 100% electrification case, all else being equal.

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[66] Interim Approval pursuant to BCUC Orders G-382-22 and G-87-23.

Response:

FEI does not have directly equivalent scenarios in its LTGRP that would represent the 25 percent, 50 percent, and 100 percent electrification scenarios shown in the Kelowna Electrification Case Study, and FEI has not developed separate scenarios in the LTGRP under these specific percentages of electrification.

However, FEI considers the DEP Scenario in its LTGRP would be similar to a 25 percent electrification case while the Deep Electrification Scenario in its LTGRP would be similar to a 100 percent electrification case. There are no scenarios in FEI's LTGRP that would be similar to a 50 percent electrification case (or a 75 percent case as discussed in the response to BCUC IR2 119.1.2), but FEI expects the rate impacts under these cases would fall between the DEP and Deep Electrification Scenarios.

Please see Table 1 below which shows the illustrative rate impacts by 2042 under the DEP and Deep Electrification Scenarios from Section 9.4 of the LTGRP for gas residential customers that would be similar to the 25 percent and 100 percent electrification scenarios, respectively. FEI also includes the high-level rate impacts by 2042 from the response to BCUC IR2 120.1 that would be equivalent impacts to FBC's electric customers under the same scenarios of 25 percent and 100 percent electrification in Kelowna only (due to the capital expenditures required only). As stated above, FEI does not have a similar scenario for 50 percent or other percentages between 25 percent and 100 percent and, as such, these scenarios are not included in Table 1 below. Also, for clarity, both FEI and FBC are under common rates throughout each utility's respective service territories and, as such, the rate impact shown in the response to BCUC IR2 120.1 due to electrification in Kelowna only will impact all of FBC's customers and, similarly, the rate impacts shown in Section 9.4 of the LTGRP for the DEP and Deep Electrification Scenarios for gas are applicable to all of FEI's customers.

It is important to note that the illustrative rate impacts shown in Table 1 below should not be viewed as a direct comparison *against* each other (i.e., gas versus electric rate impacts). Rather, the two illustrative rate impacts should be viewed together as the total impact to energy consumers in BC. For example, under the 100 percent electrification or FEI's Deep Electrification Scenario, FBC's electric customers could potentially see a rate impact of 145 percent (just for electrification in Kelowna only) while FEI's gas customers, at the same time, would see a potential rate impact of 235 percent when compared to today's rates. In other words, the illustrative rate impacts shown in Table 1 below indicate that both gas and electric customers would benefit from lower rate impacts under a Diversified Pathway instead of an Electrification Pathway (even with just Kelowna electrified). And the advantage of the Diversified Pathway is expected to be even greater if the capital costs to electrify FBC's entire service territory (or the entire Province) are considered.

Table 1: Illustrative Rate Impact for Gas (FEI) and Electric (FBC) Customers under 25% and 100% Electrification (with Electric Rate Impacts for Electrification in Kelowna Only)

	Reference	FEI's DEP Scenario (25% Electrification)	FEI's Deep Electrification (100% Electrification)
FEI's Residential Illustrative Gas Rate Impact by 2042	Figure 9-7 of Application	118%	235%
FBC's Residential Illustrative Electric Rate Impact by 2042 (Kelowna Only)	BCUC IR2 120.1	129%	145%

Table 2 below demonstrates the total estimated annual bills for FEI's gas and FBC's electric customers by 2042 based on the rate impacts shown in Table 1 above and at today's rates. FEI makes the following observations:

- The total estimated annual bills for both FEI's gas and FBC's electric customers would be lower under the DEP Scenario, while potentially being able to achieve similar GHG emission reductions as the Deep Electrification Scenario as shown in Section 9.2.1.6 of the Application (or Figure 9-2 of the Application); and
- If an FEI residential gas customer is to convert to electricity under the Deep Electrification Scenario, the total estimated annual bill by 2042 would be approximately $1,416 (i.e., $3,945 less $2,530) higher than remaining as a gas customer under FEI's DEP Scenario. Note that this comparison does not account for the additional conversion costs from gas heating equipment to an electric heat pump required for the homeowner.

Table 2: Illustrative Bill Impact for Gas (FEI) and Electric (FBC) Customers under 25% and 100% Electrification by 2042

	FEI's DEP Scenario (25% Electrification)	FEI's Deep Electrification (100% Electrification)
Avg. Residential Customer (GJ)[1]	76	76
Equivalent Avg. Residential Customer (kWh)[2]	10,172	10,172
Total Estimated Residential Bill (FEI-Gas) in 2042	**$ 2,530**	**$ 3,888**
Total Estimated Residential Bill (FBC-Elec) in 2042	**$ 3,691**	**$ 3,945**

Notes to table:

[1] From Table 2-1 of the Kelowna Electrification Case Study, i.e., 3 PJ / 39,325 customers x 1,000,000 = 76 GJ.

[2] Assumed 96 percent gas efficiency and 200 percent COP for electric heat pump (Table 2-1 of the Application).

120.2.1 Please describe at a high level the other factors that would need to be considered to perform a more robust gas rate impact analysis.

Response:

FEI considers that the rate impact analysis for gas customers as provided in Section 9.4 of the Application (and also included in the response to BCUC IR2 120.2) is sufficiently robust to provide an illustrative 20-year view of how rates would be impacted by the different future scenarios. As discussed in Section 9.4 of the Application, the illustrative rate impacts should not be viewed as a detailed rate forecast as various components of a utilities' revenue requirements were not considered in this Application, which would be reviewed and analyzed as part of a rate-setting proceeding.

On page 15, FEI and FBC state:

> To mitigate some of the above costs, instead of building or upgrading infrastructure, FBC would pursue and deploy measures including siting localized generation, EV charging shifting, and demand response. However, as noted in Section 4.3, the local generation as outlined in the 2021 LTERP would reduce the peak demand by only 173 MW.

120.3 Please briefly discuss the potential future role of distributed generation and storage as a means of reducing the peak demand.

Response:

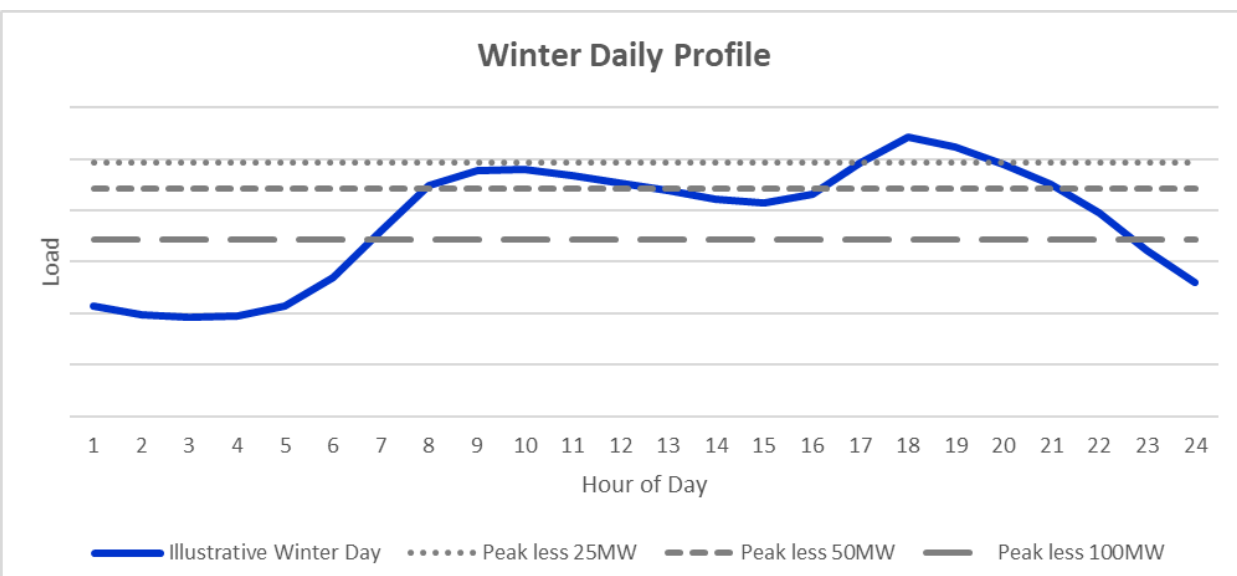
FBC customer initiatives such as distributed generation and storage have some potential to supplement, but not replace, utility initiatives to cost-effectively meet peak demand.

With respect to customer initiatives, the key is to ensure that the actions that the customer takes result in the desired outcome, which is the reduction of peak demand in this case. In particular, it is important to note that capacity savings do not automatically follow from energy savings that the customer may realize from demand-side measures such as heat pumps. The same complexity exists with distributed generation as well. The customer-controlled generation may produce a lot of energy, but the impact on peak capacity will depend on the timing of when that energy is produced. If it is produced when it is not needed, then it must be stored for later use. The effectiveness of the distributed generation at meeting peak demand depends entirely on if the energy produced is at the time it is needed or, if failing that, it can be successfully stored to be released to the grid at the required time.

Seasonal storage by customers is difficult and is best accomplished by systems such as large-scale hydro storage where energy in the form of water can be stored behind dams for release many months later. As such, effective seasonal storage can only be accomplished by the utility at this time.

However, behind-the-meter customer storage can effectively store energy through the use of batteries for a daily charge and discharge cycle. In this case, the benefit to peak demand will depend entirely on how the storage and discharge cycle is set up. For example, roof-top solar will produce very little energy during the winter compared to summer and none at all during utility peak winter hours, which occur after the sun has set. However, if the energy it has produced during the day is stored and set to discharge during the utility peak hour, there could be a significant reduction to peak demand. On the other hand, if the energy was simply consumed during the day at the time it was produced (no battery at all, for example), or the battery discharged prematurely before the peak hour occurred, then the impact to peak demand reduction will be extremely limited and likely zero. FBC considers that in order for behind-the-meter battery storage to provide meaningful benefits to peak capacity reduction, the battery must be controlled in some manner by the utility. This applies not only to traditional distributed generation initiatives, but also for new opportunities such as EV to grid technologies.

Finally, battery storage, regardless of whether it is utility or customer based, can only offset a relatively small portion of the peak daily requirements. As batteries are used to support greater portions of the peak load, the number of batteries needed grows proportionately higher as a result of serving a higher duration of load (represented by the area below the blue curve in relation to the various dashed lines in the figure below). In other words, the first 25 MW requires fewer batteries than the next 25 MW and so on, with the economics quickly becoming unfavorable at this time.



121.0 Reference: KELOWNA ELECTRIFICATION CASE STUDY
Exhibit B-20, pp. 2, 17, 18
Further Analysis

On page 2 of the Study, FEI and FBC state:

> The results of this Study are preliminary, should be considered as directional or indicative, and are subject to on-going refinement and more in-depth analysis. This Study is a precursor to further studies of load shifting and optimization technologies, such as hybrid heating systems, peak load shifting pilots, interruptible rates, and generation back-up systems, to understand the impacts of electrification on the combined service territory for FortisBC. The results of these studies could be used as a model elsewhere for optimizing and achieving the lowest cost per greenhouse gas (GHG) emissions reduction.

121.1 Please provide a brief overview of FEI's plans to undertake further studies referenced in the preamble, including timelines.

Response:

FEI expects that further studies related to the Kelowna Electrification Case Study will evolve as FEI and FBC together examine the potential for greater integration between the two energy systems and learn more through the implementation of more integrated solutions. For this reason, FEI cannot state the full extent of possible future studies. At this time, however, FEI and FBC envision the following high-level activities:

- Extending the examination of system integration potential to all of the FEI/FBC shared service territory;
- Examining the potential for optimizing the use of both gas and electricity systems to cost-effectively decarbonize energy use and enhance energy delivery resiliency through equipment (such as hybrid heating systems) and service offerings that can enable peak load shifting;
- Examining the potential to optimize the use and allocation of renewable and low carbon gases as well as clean and renewable electricity, and decrease the reliance on conventional sources of natural gas over time;
- Studying, developing and, where appropriate, implementing behavioral and/or equipment-based rebate programs and service offerings that increase the value of system integration to customers;
- Examining the potential for and implications of incorporating supply resources for renewable and low-carbon gas as well as clean and renewable electricity within the shared services territory as well as within BC but outside the shared services territory;

- Where appropriate, developing applications which seek approval from the BCUC for such programs, services and supply resources;
- Integrating the above activities with other initiatives that are underway or ongoing by the utilities, such as applying for DSM funding approval and considering EV charging mitigation measures, such as, for example, time-of-use rates, that will enable the growth of EV charging throughout the electric service area; and
- Incorporating the outcomes of these activities into future Long-Term Gas and Electric Resource Plans.

FortisBC's shared service territory affords the opportunity to ensure that both gas and electric ratepayers continue to be reliably and cost-effectively served, and that a transition to a low-carbon energy future considers the impacts to both. Such further studies will need to consider not only GHG emission reductions that could occur as a result of greater gas-electric system integration, but also understand and address the affordability perspective for customers and society as whole in utilizing the two energy systems to provide reliable and resilient energy services.

For the foreseeable future, FEI expects these activities to be ongoing. However, some near-term outcomes, such as further studies related to the potential integration of hybrid heating systems, could be completed by mid-2024.

On pages 17 and 18 of the Study, FEI and FBC state:

> This Study provides a starting point for further analysis to understand the holistic impacts of electrification, including the current state of the electric system's ability to accommodate electrified load, as well as in other regions that include a higher number of customers as well as a lower load factor (i.e. higher weighting to winter heating demand) highlighting the importance of collaboration and coordination between the gas and electric systems in the province.

121.2 In the context of FEI's entire service area, please characterize the overall load factor of the City of Kelowna. (For example, approximately average, above or below average, extremely high or low.)

Response:

As expected, the overall load factor for the City of Kelowna is lower (or below average) compared to FEI's entire service area due to the colder climate.

For the City of Kelowna, utilizing FEI's gas system hydraulic model as well as the available SCADA data for the major gate stations that serve the City of Kelowna, FEI's peak hour gas demand on December 22, 2022, is estimated to be 2.4 TJ, or 0.0024 PJ. This energy represents the amount supplied by those major gate stations serving Kelowna, which only captures approximately 80 percent of the total gas demand of the City of Kelowna. Note that the total annual gas demand of 6.2 PJ in 2022 presented in the Study represents the entire City of Kelowna, thus the annual consumption was prorated to 80 percent in order to compare with the peak hour gas demand on December 22, 2022. As a result, the estimated load factor of 0.23[67] for the City of Kelowna[68] was derived.

For the remaining regions, FEI provides the table below:

Region Requested	Load Factor	Service Area Description
City of Kelowna	0.23	Area fed by the Kelowna DP[69], Cary Rd and Quail Ridge Gate Stations: approximately 80 percent of demand of City of Kelowna.
Greater Victoria	0.32	Greater Victoria Area – all demand downstream of the Langford Gate Station.
Greater Vancouver	0.31	FEI cannot provide the load factor for the City of Vancouver due to lack of measurement data specific for the City proper. This area includes what is fed by the Fraser, Coquitlam, and Pattullo Gate Stations: Vancouver, Burnaby, Coquitlam, North Vancouver, New Westminster, Port Coquitlam, West Vancouver, Port Moody, Anmore, Belcarra.
Vancouver Island	0.37	Vancouver Island Transmission System (VITS) - all demand downstream of the Eagle Mountain Compressor Station.
Lower Mainland	0.34	Coastal Transmission System (CTS) and Zone 3 Laterals off the Westcoast System (Chilliwack, Hope etc.).

121.3 Please describe at a high level how the results of the Study would apply to milder climatic regions such as the Lower Mainland or Vancouver Island.

<u>Response:</u>

Given the complex interactions between regional energy systems, differing housing stock, regional growth rates, EV adoption rates, as well as climatic conditions, FEI cannot speculate on the direct applicability of the results of this Study to other regions. For example, while the Lower Mainland or Vancouver Island would have a milder climate and heat pumps would be more efficient at milder temperatures, this region also has, for example, a significantly higher population, differing gas use per customer rates, as well as likely greater amounts of EV charging.

[67] 6.2 PJ * 0.8 / (0.0024 PJ x 8760 hours).

[68] This estimate varies slightly from the load factor of 0.22 for the City of Kelowna in 2020 utilizing two different sources of data in Table 2-1 of the Study.

[69] Distribution Pressure system, the Kelowna IP (Intermediate Pressure) gate station serves West Kelowna and was excluded from this analysis to match the Study (and BC Hydro provides electricity service to West Kelowna).

FEI also does not have the electric billing data for the Lower Mainland or Vancouver Island required to complete a parallel analysis. Additionally, FEI does not know whether, or how much, surplus system capacity BC Hydro has available at a more granular city-level basis.

While the results of the Study cannot be reliably extrapolated to other regions, as described above, the foundational model that underlies the result, coupled with a relatively simple BC Hydro dataset, could be used to examine other areas of BC. If FEI were to receive the necessary data and assumptions from BC Hydro, then it could update the model to represent other locations in a similar manner to the Study for peak demand under cold temperatures.

121.4 Please discuss whether FEI has considered collaborating with BC Hydro to undertake further analysis of electrification on a province-wide basis.

Response:

A number of parties have expressed interest in FEI's views on collaborating with BC Hydro to study the impacts of electrification, examine opportunities for greater integration of electric and gas infrastructure in BC, and jointly model future scenarios in the next Long-Term / Integrated Resource Plans.[70]

FEI is supportive of collaboration with BC Hydro on ways to provide better and higher value energy services to all energy customers in BC and has considered that, with appropriate information sharing between the utilities, such collaboration is possible. However, due to the relative ease and expediency of sharing data and investigative resources between the two FortisBC utilities, FEI expects that focusing on the shared FEI/FBC service territory will provide valuable insights on the challenges of the low-carbon energy transition and how to overcome them, in a shorter time. The Kelowna Electrification Case Study provides a high-level examination and outline of the potential for a plan for further analysis of electrification studies. FEI expects that information and data sharing between the FortisBC utilities, as well as leveraging the systems experience of its staff first, will provide key benefits and insights for further collaboration with BC Hydro, of which FEI would encourage, on holistic decarbonization initiatives that are part of a diversified energy future. This understanding can then inform a closer examination of integrated gas and electric system decarbonization initiatives across BC.

At this time, FEI cannot confirm that the preparation and filing of FEI's next LTGRP will coincide with BC Hydro's preparation and filing of its next IRP. However, coincidental timing of these filings is not necessarily a prerequisite for continued collaboration between the utilities. FEI is open to continuing to exchange information with BC Hydro regarding the development and examination

[70] BCSEA IR2 54.1, MoveUP IR2 2.1, 2.2 and 2.2.1, and BCSSIA IR2 18.7 and 18.8.

of future alternative scenarios, but has not consulted BC Hydro regarding its views on collaboration. FEI offers the following:

- FEI recognizes the benefits to the BCUC and interveners in having comparative information from both utilities available during review of the respective resource plans; however, the resource planning process for each individual utility is complex and resource intensive. Introducing additional cross-utility tasks and interdependent submission requirements will substantially increase the complexity, timelines, and resource requirements for each utility. Expectations for introducing additional collaboration into these processes needs to be balanced against the imperative that swift action on climate change is required and the utilities need to become more, rather than less, agile in leveraging both the gas and electrical infrastructure in BC to reach carbon emission reduction targets.
- Outcomes of the resource planning process can have wide-ranging and significant impacts on the future of the utilities involved. This adds strategic importance to any collaboration activities that are placed upon the utilities. As such, important early steps in any deeper collaboration between the utilities will benefit from independent facilitation of the process and establishing a clear set of objectives and rules of engagement for successful outcomes.
- If the BCUC is contemplating introducing further collaboration recommendations or requirements between the utilities into the resource planning process, FEI encourages the BCUC to seek further input from the utilities and stakeholders on both process and scope in this regard.

Currently, the largest barriers to conducting a deeper analysis in areas of the Province served by FEI and BC Hydro are access to information and the lack of resources to undertake the work.

- Both utilities would need equal access to all of the information required to undertake such analysis. Currently, neither utility has adequate access to the other utility's information that would be required to complete the needed analysis.
- Conducting this type of analysis properly requires input from numerous departments within each utility and dedicated staff resources to bring together the required experts and information and then move the study forward. Such resources at FEI and FBC are currently fully committed on existing activities and FEI anticipates the same to be true for BC Hydro.

FEI would be supportive of, and would participate in, a review of the BCUC Resource Planning Guidelines, should the BCUC decide to undertake such a review. FEI notes the following:

- FEI considers that a BCUC-led informational proceeding would be an appropriate way to undertake such a review and that utilities and other stakeholders could be invited to participate and provide input.

- FEI considers that the objective of such a review should be to strengthen the guidelines, improve the resource planning process and provide the BCUC with improved information on which to seek input from interested parties and make decisions about the plans by utilities to meet their customers' energy needs over the long term. The Resource Planning Guidelines should not direct specific outcomes such as carbon reductions or specific carbon reduction initiatives, the former being the purview of provincial regulation to which resource plans must adhere and the latter being a matter for utilities to develop, plan for and implement.
- Any updates made to the Resource Planning Guidelines should be directed at improving the ongoing process of resource planning and should not aim to direct any energy transition, but to enable it through a good planning process.
- Parties involved should recognize that the BCUC Resource Planning Guidelines are in fact guidelines and not requirements, and that not all the guidelines contained therein will always be applicable to all utilities, for every resource plan submitted in all planning environments.