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March 20, 2025

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
Vancouver Centre II
2900 – 733 Seymour Street
Vancouver, BC
V6B 0S6

Attention: Patrick J. Weafer

Dear Patrick J. Weafer:

**Re: FortisBC Energy Inc. (FEI)**

**Application for a Certificate of Public Convenience and Necessity (CPCN) for the Tilbury Liquefied Natural Gas Storage Expansion (TLSE) Project (Application)**

**Response to the Commercial Energy Consumers Association of British Columbia (CEC) Information Request (IR) No. 5**

On December 29, 2020, FEI filed the Application referenced above and on October 24, 2024, FEI filed its Supplemental Evidence to the Application. In accordance with the regulatory timetable established in British Columbia Utilities Commission Order G-324-24 for the review of the Application, FEI respectfully submits the attached response to CEC IR No. 5.

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

If further information is required, please contact the undersigned.

Sincerely,

**FORTISBC ENERGY INC.**

***Original signed:***

Sarah Walsh

Attachments

cc (email only): Commission Secretary
Registered Interveners

**133. Reference: Energy Transition - BCUC Order G-62-23 pages 52-53 (pdf download version)**

FEI cites Guidehouse's concern that BC is "highly dependent on a single midstream pipeline for natural gas supply and has minimal on- and off-system storage, resulting in a system that does not have an abundance of inherent resiliency. [emphasis added]"[171] However, in the longer term (post 2030), as the amount of hydrogen on the system increases, the consequences of a no-flow event on the T-South become less severe if natural gas represents a decreased proportion of the fuel delivered by the pipeline and the total amount of fuel delivered also may be less.

We are also concerned that it is unclear as to the extent to which hydrogen will be used in the future and what the implications will be on the overall system.

There is considerable uncertainty concerning the role of the natural gas system in an increasingly decarbonized British Columbia. Further there is little in the way of Provincial Government policy that speaks directly to this role. While there is an opportunity for natural gas utilities to deliver lower or zero GHG emitting gas, the ability to do so depends in part on technology and business practices that are not fully developed or even understood at this point in time.

We acknowledge the difficulty of navigating a path to clean gas given these new technologies and business practices that must be considered. However, we share the CEC's concerns that "a higher level of confidence in terms of the risk being assessed and the expected life for the assets to be used and useful"[172] is necessary to assess whether further resiliency investments are in the public convenience and necessity. In light of the current uncertainty with respect to the continued role of the natural gas system in British Columbia, we find insufficient evidence to conclude that the risk of stranding of the Project is acceptable especially considering its expected life.

171 FEI Final Argument, pp. 11-12.

We acknowledge that the issue of future demand for natural gas is also under consideration in the 2022 LTGRP proceeding. However, we have specific concerns about the potential stranding of this Project as well as the lack of a holistic resiliency plan addressing our concerns as outlined above. Out of fairness to FEI and due to the timing of these two concurrent proceedings, we consider it unwarranted to deny the CPCN Application without giving FEI the opportunity to address these concerns in this proceeding. Accordingly, our determination is to adjourn this proceeding at this time.

133.1 The CEC submits that in the event of declining natural gas usage over time, including ones FEI has submitted into evidence in this proceeding, there is a significant likelihood that concomitant with the decreases the BC Hydro electric system could and perhaps would increasingly become the end customer's resiliency option. Please explain why FEI has primarily focused on LNG for resilience and not: (a) looked at what resilience the electric system could provide, in particular with FEI assistance; (b) why the FEI application does not reflect a robust working relationship with BC Hydro on resilience; (c) why FEI continues with LNG as its focus without heeding the Commission's concerns about the significant uncertainties in regard to "Energy Transition" impacts and FEI's own lack of certainty for plans to deliver a 100% clean gas system in the future as an alternative; (d) why FEI's analysis of future impacts of a T-South failure are not examined for the declined use of natural gas scenario, where the use of natural gas might be substantially lower than it is now, particularly by 2050; and (e) why FEI has not considered the resilience planning of its customers and the degree to which in emergency circumstances they may have or could been enabled by FEI to have many mitigating options.

**Response:**

FEI disagrees with the premise that BC Hydro's electric system will be the primary form of resilience for FEI's natural gas system (i.e., provide sufficient capacity to take on loads served by the gas system during or after a disruption) in the short, medium or long term.

With regard to parts (a) and (b) of this question, on peak days, FEI's gas system currently delivers approximately double the energy capacity of BC Hydro's system. This is because the gas system has unique properties, including abundant low-cost storage and high deliverability, giving it considerable flexibility to ramp-up to meet winter peak demand. Conversely, the electric system, while having a significant degree of hydro-electric storage, does not have the same ramping capability nor the transmission and distribution infrastructure to take on the winter peak heating load that is currently served by the gas system. Please also refer to the response to Sentinel IR1 97 for a discussion of the energy, capacity and cost that would be required to have BC Hydro's electrical system absorb FEI's annual and peak energy loads. Additionally, even in a scenario of declining load on the gas system and a corresponding increasing load on the electric system, the gas system would have greater potential to provide resilience as it has the capacity to do so. Please also refer to the response to BCUC IR5 124.2.

With regard to parts (c) and (d) of this question, please refer to the response to CEC IR5 134.7 for a discussion of how FEI's customers and load continue to grow at this time. Also, please refer to Section 4.5.5 of the Supplemental Evidence and the response to BCUC IR5 129.1 for a discussion of how the TLSE Project continues to be useful by providing resiliency and gas supply benefits to customers for the duration of its expected service life, irrespective of hypothetical adverse load loss (energy transition) scenarios.

With regard to part (e) of this question, FEI assumes that CEC is suggesting that FEI rely on its customers to mitigate resiliency risk. BC's primary energy systems (natural gas and electricity) are very reliable, consistent with customer expectations and public utility regulation, to ensure the delivery of safe and reliable energy services. Of FEI's over 1.2 million customers, approximately 91 percent are Rate Schedule (RS) 1 (residential) customers and, in FEI's experience, most residential customers do not have back-up energy systems nor do they plan for, or expect, prolonged energy outages. FEI's 2024 Resiliency Plan considers risks to the system holistically and assesses which vulnerabilities should be prioritized to address the greatest risk/consequence for the benefit of FEI's customers.

Finally, as set out in the response to BCOAPO IR5 1.2, FEI's interactions with the Province suggest that they have been generally supportive of FEI's efforts to enhance the resiliency of its system through investments that address resiliency risk. The Province recognized the key role of the gas system and its contribution towards the resilience of BC's energy system in its recent climate and energy strategy, *Powering our Future*.[1]

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[1] https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/community-energy-solutions/powering_our_future_-_bcs_clean_energy_strategy_2024.pdf, p. 19 and 28.

**134. Reference: Exhibit B-60, Pages 145, 146, 147, 148, 149, 150, and 170**

See Figure 4-9 Sensitivity for 2% customer decline (from 600,000 to 400,000 by 2050)

See Figure 4-10 Sensitivity for 5% customer decline (from 600,000 to 200,000 by 2050)

See Figure 4-11 Sensitivity for 2% UPC load decline (from 120,000 TJ to 80,000 TJ by 2050)

See Figure 4-12 Sensitivity for 5% UPC load decline (from 120,000 TJ to 60,000 TJ by 2050)

See Figure 4-13 Load Duration for 2% decline (peak from 875 MMCF to 581 MMCF by 2050)

See Figure 4-14 Load Duration for 5% decline (peak from 875 MMCF to 460 MMCF by 2050)

See Table 4-13 Extension of Resilience Hours

See Table 4-17 Reductions in Customer Outage Days for 2% decline and 5% decline

(from baseline 2.4 to Baseline 1.3 for 2% decline and .47 for 5% decline)

134.1 Please confirm that UPC decline and customer # decline are two separate processes which would compound on each other for total load decline.

**Response:**

Confirmed. This is why, in addition to the assumptions set out in Section 4.5.5 of the Supplemental Evidence, FEI adjusted both customer count and use per customer (UPC) to determine the annual and daily load for both the mDEP 2% and mDEP 5% scenarios.

134.2 Please also confirm that in the event of compounded load decline or any load decline the FEI ‘delivery costs’ per GJ unit of gas delivered would increase.

**Response:**

FEI confirms that, all else equal, its delivery rates would increase in the event of compounded load decline or any load decline. However, there are various components within FEI’s revenue requirement that could impact, both positively and negatively, its delivery rates. Thus, the overall changes in FEI’s delivery rates need to be considered holistically and not in isolation of load decline over any particular period of time.

134.3 Please provide the 'delivery cost' changes year by year for each of a 2% decline in load and a 5% decline in load through to 2050.

**Response:**

As discussed in the response to CEC IR5 134.2, FEI's revenue requirement involves many components that could impact its delivery rates each year, positively and negatively, and which may be influenced by factors beyond the number of customers served, including FEI's response to such declines. Given these uncertainties, FEI is unable to provide a meaningful forecast of its delivery costs (or delivery margin) to 2050.

However, all else equal, FEI confirms that if its delivery costs increase, delivery rates would also likely increase to recover the higher delivery costs.

134.4 Please confirm that as FEI's costs increase, rates to the customer would need to increase to recover cost for FEI and please translate the above 'delivery cost' changes year by year into rate increase increments required to recover the costs.

**Response:**

Please refer to the response to CEC IR5 134.3.

134.5 Please confirm the customer usage and retention can both decline because of price or rate increases or that elasticity impacts of price or rate increase can be expected to further drive down the loads and duration curve peaks.

**Response:**

Price elasticity of natural gas demand is one of the factors that can influence customer consumption and retention depending on the time frame considered.

In the short term, natural gas demand is highly inelastic, meaning that increased prices could only have a small downward impact on consumer demand (for instance by changing the thermostat setting). In the long run, consumers have more choices and could respond to higher natural gas prices by purchasing higher efficiency gas-fired appliances (reducing their consumption while remaining a gas customer) or by replacing their gas heating equipment with other options (impacting customer retention). Therefore, the long-run price elasticity of natural gas demand, while still inelastic (less than 1), is higher than the short-run price elasticity.

Price changes for natural gas service cannot be considered in isolation, since the cost of alternatives like electricity is also increasing. FEI also notes that while price changes can affect long-term natural gas demand, other non-price considerations such as new technologies, type of housing mix and the size of new dwellings, customer perceptions (including reliability and affordability concerns with alternatives) and government policy (including building codes changes) are taking on greater importance in the decisions of energy consumers.

134.6 Please provide FEI's assumptions about the appropriate elasticity % for customer cost for natural gas supply.

**Response:**

FEI interprets the question to be asking for the appropriate price elasticity estimates of natural gas demand. The price elasticity assumptions for residential, commercial and industrial sectors considered as part of FEI's 2022 Long-Term Gas Resource Plan (LTGRP) are provided below. FEI is currently working to develop its 2026 LTGRP and may change these estimates based on more recent studies (if available).

| Sector | Short-Run Price Elasticities of Demand | Long-Run Price Elasticities of Demand |
|---|---|---|
| Residential | -0.278 | -0.380 |
| Commercial | -0.205 | -0.350 |
| Industrial | -0.709 | -0.700 |

134.7 Please confirm that legislative and regulatory climate change initiatives from governments (both provincial and municipal) are currently and may continue to precipitate declines in FEI's customer base and UPC.

**Response:**

Not confirmed. At this time, FEI continues to add customers each year and continues to see increases in its peak day and annual energy demand. Table 1 below sets out the average customer count and net customer additions for FEI since 2015. As shown in the table, customer additions vary from year to year and do not reflect a downward trend.

**Table 1: FEI Average Customer Count and Net Customer Additions**

| Year | | Average # of Customers | Net Customer Additions |
|---|---|---|---|
| 2015 | Actual | 968,766 | |
| 2016 | Actual | 983,807 | 15,041 |
| 2017 | Actual | 997,380 | 13,573 |
| 2018 | Actual | 1,016,353 | 18,973 |
| 2019 | Actual | 1,031,862 | 15,509 |
| 2020 | Actual | 1,044,623 | 12,761 |
| 2021 | Actual | 1,057,086 | 12,463 |
| 2022 | Actual | 1,067,191 | 10,105 |
| 2023 | Actual | 1,080,379 | 13,188 |
| 2024 | Actual | 1,093,663 | 13,284 |

While customer UPC is influenced by a number of factors, including customer behavior, climate regulation and technology (building envelope, appliances, etc.), FEI has continued to experience increases in its overall peak day and annual loads. Please refer to the response to BCUC IR5 118.1 for a figure showing the increase in annual and peak day load over the last 10 years.

134.8 Please confirm that competing local thermal energy systems (TES) are displacing potential FEI customer additions and retentions.

**Response:**

For clarity, TES are downstream of the traditional utility meter and use a variety of input energy sources, including natural gas, electricity and waste heat recovery. As a result, some TES can have the effect of displacing potential gas customer additions, although this is not always the case.

For instance, as discussed in FAES' response to BCUC IR1 1.1 in the 2024 Stage 2 Generic Cost of Capital (GCOC) proceeding, the historical share of natural gas usage as part of FAES' Delta School District TES energy sources has varied between 96.1 to 99.6 percent, while another FAES TES project (TELUS Garden) does not directly use any natural gas in its energy mix.[2] In other words, the impact of increased TES adoption on natural gas consumption may change on a project-by-project basis, as the energy sources used in TES projects are not homogenous in nature.

[2] TELUS Garden energy sources consist of steam, electricity and waste heat.

Regardless of the energy source for heating buildings, gas is often used for peaking and/or convenience appliances such as fireplaces and cook tops. Therefore, while TES may impact load or the nature of service, they may not displace potential FEI customer additions or retention.

TES can alter FEI's ability to have a direct relationship with the end-user customer. In the case of a traditional agreement between utility and customer, the strata or property management company would receive a monthly invoice from FEI and would benefit from all the services that FEI provides. However, with a TES provider, FEI's customer may not be the building owners themselves, but the owner/operator of the TES. The TES owner/operator then invoices the customer based on their independent contractual agreement.

Finally, while TES can lower energy consumption through technologies that recover waste heat, the impact of lower energy consumption can be offset by the significant increases in density associated with redevelopment.

Ultimately, while TES developments may result in some customer attrition, the TES providers typically continue to remain a customer and rely on FEI's system as a primary or back-up energy source. As such, the impact on FEI's total load will be less pronounced than what may be assumed in the question.

134.9 Please provide FEI's forecast of TES developments and their anticipated loads for the period 2025 to 2050.

**Response:**

FEI does not have a forecast of TES developments and their anticipated load from 2025 to 2050; however, it has provided adverse load loss scenarios as part of its analysis as a proxy for customers' adoption of other energy sources over time, including TES.

As discussed in Section 4.5.5.2.1 of the Supplemental Evidence, FEI's analysis assumes no new customer additions after 2030 and a loss of residential and commercial customers each year, including their associated load. Thus, since in its mDEP scenarios FEI did not include any new customers (and included customer losses) after 2030, any new and deeply renovated, residential and commercial premises would have to be served with a combination of electricity and/or an alternative energy source, not natural gas.

Please also refer to the response to CEC IR5 134.8, which explains that FEI may maintain customer connections in buildings served by a TES and that increased density associated with redevelopment offsets some of the lost it may experience with TES.

Finally, because the forecasts in FEI's 2022 LTGRP are based on end-use (customers using natural gas), the natural gas annual load forecasts in the LTGRP implicitly account for premises choosing not to use natural gas.

134.10 Please confirm that if the FEI loads are declining there are three potential consequences for the BC Hydro electricity system: (a) the BC Hydro electricity system is providing alternative electrical energy heating; (b) the BC Hydro/FEI customer may be supplying its own diversified supply for heating; or (c) the customer has achieved reductions in its needs for heating (heating being primarily what FEI is providing).

**Response:**

All else equal, FEI expects that any reduction of the load on its gas system would need to be filled by other means, including alternative energy sources (such as electricity) and/or investments in demand-side management (DSM) activities. FEI cannot confirm the potential consequences to BC Hydro's system or the investments in generation, transmission and distribution infrastructure that would be required. However, FortisBC Inc.'s (FBC) Kelowna Electrification Case Study examined the potential impacts of electrification in Kelowna, which was estimated to drive billions of dollars of electricity system upgrades.[3]

As discussed in the response to CEC IR5 134.7, FEI's load continues to increase at this time. Regardless, FEI examined hypothetical load loss sensitives (mDEP 2% and mDEP 5%) in the expanded alternatives analysis, which confirmed that the TLSE Project will remain useful by providing resiliency and gas supply benefits to customers for the duration of its expected service life.

134.11 Please explain why FEI's resilience plans are almost exclusively focused on LNG solutions, and do not include a robust analysis and approach to engaging with customer premises-based options.

**Response:**

FEI does not consider installing small natural gas storage assets at customer premises to be feasible to address the risk of a winter T-South no-flow event. As described in the 2024 Resiliency Plan, and affirmed in Guidehouse's independent expert report (Appendix A to the Application), the resiliency of a natural has system refers to preventing, withstanding, and recovering from

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[3] Exhibit B-20, FEI 2022 LTGRP proceeding: https://docs.bcuc.com/documents/proceedings/2023/doc_70278_b-20-fei-evidentiary-update.pdf.

system failures or unforeseen events. This includes preparing for, operating through, and recovering from significant disruptions, no matter the cause.

FEI maintains that, at a foundational level, three elements contribute to the resiliency of FEI's gas system:

1. Diverse Pipelines and Supply;
2. Ample Storage; and
3. Load Management Capabilities.

The TLSE Project will provide dependable gas supply and is needed to mitigate the significant resiliency risk that hundreds of thousands of customers in the Lower Mainland will lose service for many weeks following a winter no-flow event on T-South.

The expanded alternatives analysis properly includes all of the alternatives and considerations identified by the BCUC in Decision and Order G-62-23 (Adjournment Decision), and builds on the original alternatives analysis which considered load management approaches, on- and off-system storage, and four different regional pipeline solutions.

**135. Reference: Exhibit B-60, page 7**

> FEI has confirmed the need for resiliency-driven investment to mitigate FEI's greatest customer outage risk that is due to a winter T-South no-flow event (Assessed Vulnerabilities (AV) 1, 2, 3 and 54), as well as risk associated with AV 18. New and larger on-system LNG at Tilbury will mitigate both risks.
>
> Four other AVs have been identified as warranting further investigation, but FEI is not recommending at this time any additional investment where the primary driver is resiliency.
>
> Based on FEI's current analysis, the AVs other than those noted above are already managed in a reasonable manner accounting for the magnitude of the risk of customer outages and the cost of mitigation, recognizing it is not feasible to fully mitigate every outage risk on a natural gas system.

135.1 Please briefly discuss the four other Assessed Vulnerabilities (AV) that FEI deems to warrant further investigation, and please explain why they do not require additional investment at this time.

**<u>Response:</u>**

FEI determined that AVs 5, 47, 48, and 52 do not require investment at this time based on the severity of the risk posed by each AV as calculated in the 2024 Resiliency Plan, relative to AVs 1, 2, 3 and 54 (i.e., the risk of a winter T-South no-flow event).

Please refer to Section 7.2 of the 2024 Resiliency Plan for a discussion of these AVs. Additional information about these AVs beyond what is stated in that section is security sensitive and was provided to the BCUC only in appendices to the 2024 Resiliency Plan.

135.2 Would the cost of addressing any or all of the four other Assessed Vulnerabilities be impacted by the current Project, or are they entirely separate? For instance, could the proposed Project, either as recommended or with modifications, result in cost savings for the other Assessed Vulnerabilities?

135.2.1 If the other vulnerabilities could be impacted, please elaborate in what manner, and provide any estimated cost impacts if available.

**Response:**

The cost of addressing any or all of the four other AVs would not be impacted by the TLSE Project. They are entirely separate.

The TLSE Project cannot provide mitigation for AVs 5, 47, 48, and 52 (i.e., the AVs identified as not warranting resiliency driven investment but warranting further investigation). This is due to the location of these AVs relative to the TLSE Project. If any of the AV 5, 47, 48, or 52 events were to happen, because of the event, gas from the TLSE Project would not be able to physically flow to the impacted areas.

**136. Reference: Exhibit B-61, Appendix RP2, pages 21-22**

> 49. Per general good industry practices, subsequent to a proactive-risk assessment evaluation, the high-risk scenarios should be reduced to acceptable levels. For example, subsequent to most Hazard and Operability ("HAZOP") studies, the High/Red Risk levels are typically mitigated. Similarly, subsequent to most failure modes and effects analysis ("FMEA"), the high-Risk Priority Number ("RPN") scenarios are typically mitigated to be below a certain RPN number, and subsequent to the more quantitative QRA studies, the likelihood for a specific hazard scenario(s) is usually mitigated below a predetermined frequency and brought into an as-low-as-reasonably-practicable ("ALARP") zone. Fatality risk is often a common criterion for such risk mitigation efforts, but it is not the only one. Safety risk (risk of serious injury), Asset Risk (loss of asset, production outage, financial loss), Environmental Impact, etc., are also considered for risk mitigation. In quantitative studies, if the risk is already mitigated to be within the ALARP zone, then some formal Cost Benefit Analysis studies are often conducted to support additional risk mitigation investments. However, Cost Benefit Analysis/studies are not performed for a majority of proactive Risk Assessment projects, and usually a collective team judgement is adequate to approve/green light additional risk mitigation investments.

136.1 Exponent discusses fatality risk, injury, and asset risk as criteria for risk mitigation efforts. Please explain whether provincial GDP is usually considered as a typical criterion for risk mitigation.

**<u>Response:</u>**

**The following response has been provided by Exponent:**

For entities such as utilities, which largely benefit the general public, metrics that consider the welfare of the general public are appropriate criteria for risk mitigation. Consideration of loss of economic activities is common in the utilities industry. For example, cost benefit analysis for wildfire mitigation projects in California must consider equivalent value of safety (fatalities), financial (e.g., mitigation or operations costs), and reliability (customer-minutes interrupted). The customer minutes interrupted metric is based on the Value of Loss of Load ("VoLL") which is based on the value of electricity to end users, representing the customer's willingness to pay to avoid an outage, as opposed to purely the lost revenue to the utility for the service interruption. Consideration of GDP is consistent with this concept.

In addition to considering GDP, Exponent considered customer-outage days and customer outages to collectively assess public benefit of the Tilbury mitigations.

**137. Reference: Exhibit B-61, Appendix RP2, Appendix U pages U-80 and U-81 and Exhibit A-49, BCUC IR 117.6.1**

*BCUC IR 117.6.1*

On page U-81 of Appendix U to the Exponent Report, Exponent provides Figure U.44 as reproduced below.

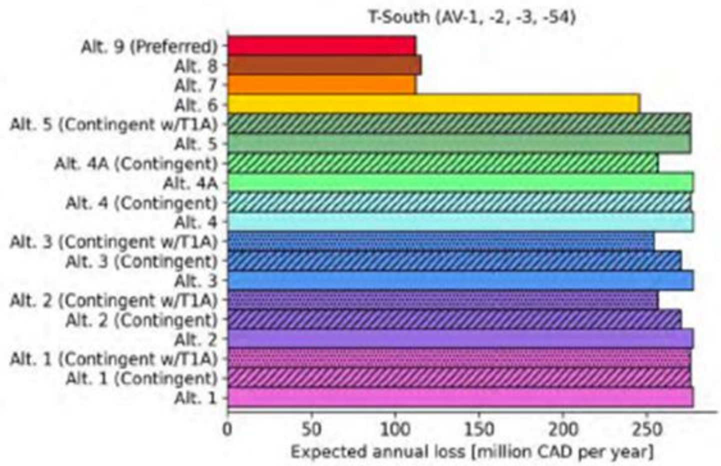



Figure U.44. Expected annual winter-only GDP loss in million CAD per year for T-South (AV-1, -2, -3, and -54) for the Tilbury Alternatives.

**117.6 Please confirm, or explain otherwise, that Figure U.44. provides the residual risk of winter-only GDP loss following implementation of the various Tilbury Alternatives. For example, the residual risk of winter-only GDP loss following implementation of Alternative 8 is approximately $115 million.**

**117.6.1 If confirmed, does FEI consider the residual risk following implementation of Alternatives 7, 8, and 9 to be acceptable or within the ALARP zone.**

104. For T-South, the expected 23-year winter-only GDP loss with status quo mitigation from Alternative 1 (Planning) is $6.4 billion CAD, as shown in Figure U.47. With the mitigation provided by Alternatives 7 and 9, the expected 23-year winter-only GDP loss falls to approximately $2.6 billion CAD. Alternative 8 results in an expected 23-year winter-only GDP loss of $2.7 billion CAD. The mitigation provided by the other Tilbury Alternatives results in much smaller, and sometimes limited, reductions in the expected 23-year winter-only loss.

105. For T-South, the expected 67-year winter-only GDP loss with status quo mitigation (Alternative 1) is approximately $18.6 billion CAD, as shown in Figure U.47. With the mitigation provided by Alternatives 7 and 9, the expected 67-year winter-only GDP loss falls to approximately $7.5 billion CAD. Alternative 8 results in an expected 67-year winter-only GDP loss of $7.7 billion CAD. The mitigation provided by the other Tilbury Alternatives results in much smaller, and sometimes limited, reductions in the expected 67-year winter-only loss.

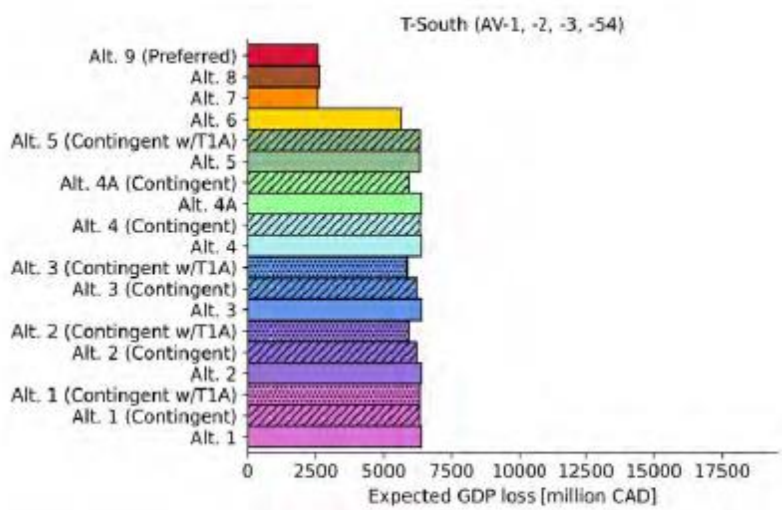



Figure U.47. Expected 23-year winter-only GDP loss in million CAD for T-South (AV-1, -2, -3, and -54) for the Tilbury Alternatives.

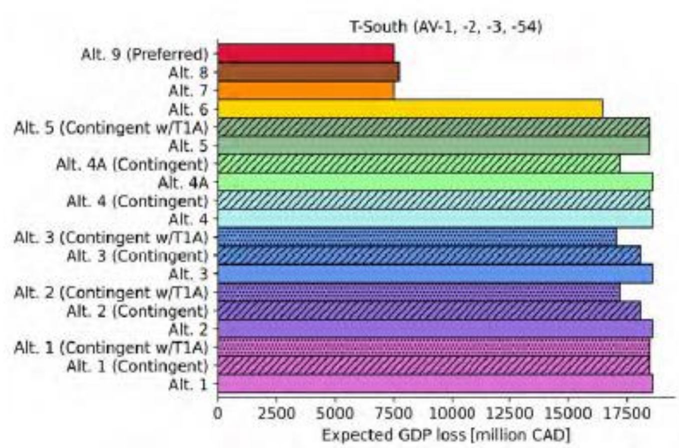



Figure U.50. Expected 67-year winter-only GDP loss in million CAD for T-South (AV-1, -2, -3, and -54) for the Tilbury Alternatives.

137.1 Please confirm that 'GDP loss' refers to BC GDP.

**Response:**

**The following response has been provided by PwC:**

All of the GDP loss figures related to the Reviewed Scenarios and sub-regional scenarios within the PwC report refer to BC GDP and are derived from Statistics Canada data at the provincial and sub-provincial levels. The data used in the updated PwC report was extracted in December 2023.

137.2 Please provide the quantity loss and % loss over the whole BC GDP forecast for the period 2025 to 2050 year by year, post a sample T-South No-Flow event in year occurring in 2045.

**Response:**

**The following response has been provided by Exponent:**

As part of developing the resiliency plan, analysis was conducted for a single year based on the current configuration and condition of the system. The results thus represent a snapshot of the system. FEI cannot be aware of how third parties will act in ways that will change the behavior of the system. Additionally, FEI does not currently have models that consider future degradation or changes to the system configuration. Resiliency plans are intended to be refreshed periodically.

For the purposes of calculating losses over 23 and 67 years (or any other time period), it was assumed that the average loss is the same in all years. As the yearly events are independent, the expected (average) loss in a given year will be the same as other years.

137.3 Please provide examples of specific outcomes related to 'GDP loss' such as government revenue, average wages, and employment, and please provide quantification for these outcomes to the extent possible.

**Response:**

**The following response has been provided by PwC:**

The scope of the PwC report did not include developing a breakdown of the components of GDP losses. However, from the primary research undertaken, stakeholders commented that a range of impacts would occur, including:

- Loss of employment at businesses forced to shut down fully or reduce output;
- Consequent reductions in labour income;
- Consequent reductions in company profits; and
- Consequent reductions in business tax payments.

137.4 Please provide a discussion with quantification of the range of $ loss that could accrue to each rate class using the 23-year, and 67-year terms as the basis for when to assume a T-South No-Flow events occur and provide the anticipated losses based on the Diversified Planning Scenario and the Load Decline Scenarios.

**Response:**

For the reasons discussed below, the scope of, and inputs to, the Exponent Report did not assess the $ loss that could accrue to each rate class.

PwC's economic impact analysis estimates the economic impact (GDP losses) associated with natural gas outage scenarios provided by FEI (Reviewed Scenarios). PwC's analysis is not narrowly focused on the impacts to FEI's customers broken down by rate class, but rather, considers the direct, indirect and induced effects of the Reviewed Scenarios on British Columbia's economy. Each Reviewed Scenario simulates an outage affecting a different geographic region based on the Assessed Vulnerabilities (AVs) identified in FEI's 2024 Resiliency Plan and estimates the associated economic harm that would result.

FEI provided the economic loss outputs from PwC's analysis to Exponent to calculate the overall risk associated with each AV through a quantitative (probability x consequence) risk analysis. The resulting GDP loss calculation simulates the impact of a failure on each AV, including a winter T-South no-flow event – which extends beyond FEI's customers alone.

As explained in Section 4.5.5 of the Supplemental Evidence, even under the most adverse hypothetical load loss sensitivity (mDEP 5%), FEI would still be serving hundreds of thousands of customers in the Lower Mainland in 2050. These customers would still be exposed to a significant customer outage – with all of the associated social, human health and economic consequences – following a winter T-South no-flow event.

137.5 Please confirm that the $18.6 billion Expected GDP loss for 67 years is depicted in Figure U-50 and not Figure U-47 as written on page U-80, pp 105.

**Response:**

**The following response has been provided by Exponent:**

That is correct – the reference at U-80, para. 105 should be to Figure U-50.

137.6 The total GDP loss under the 23-year scenario is substantially lower than even Alternative 1 under the 67-year scenario. Please discuss whether or not the residual risk, following implementation of any of the Alternatives, would be acceptable or within the ALARP zone under the 23-year scenario.

137.7 Please provide FEI's views as to the ALARP zone with respect to the $5 billion risk over 23 years and the $18.6 billion risk over 67 years

137.7.1 To the extent that FEI considers that a $5 billion risk would be acceptable, but an $18.6 billion risk would be unacceptable, please provide the turning point risk level, and period at which that would occur.

**Response:**

Please refer to the response to BCUC IR5 117.3.

137.8 Please explain whether the Provincial government has made any statements with respect to the potential GDP loss.

**Response:**

FEI is not aware of any statement(s) from the Province regarding the potential GDP loss associated with customer outages following a winter T-South no-flow event.

**138. Reference: Exhibit B-60, page 58**

**Table 3-3: Exponent's Calculated Cumulative Probability of T-South No-Flow Event in Winter[99]**

| Calculation Horizon | Basis for Horizon | Exponent's Calculated Cumulative Winter Only (90 Days) Probability |
|---|---|---|
| **67 years** | Expected Life of TLSE Project | 95% - 100% |
| **23 years** | Hypothetical adverse sensitivity assumes no further use of Tilbury facility for resiliency or gas supply after 2050 | 65% - 97% |

138.1 Please provide the GDP impacts for the T-South No-Flow event in winter based on GDP loss derived from loss of supply by customer class (industrial, commercial, and residential) and show the loss impacts by day over the duration of the lack of supply and show the daily supply recovery by day over the same time frame (please use year 23 and 67 as the years for the specific T-South No-Flow event).

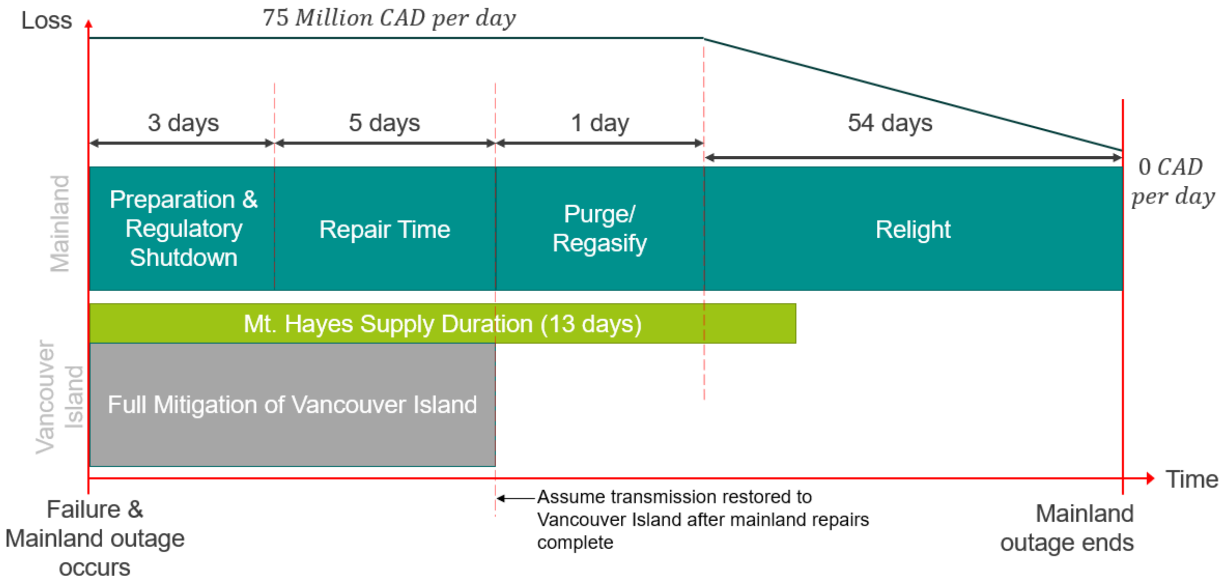
**Response:**

**The following response has been provided by Exponent:**

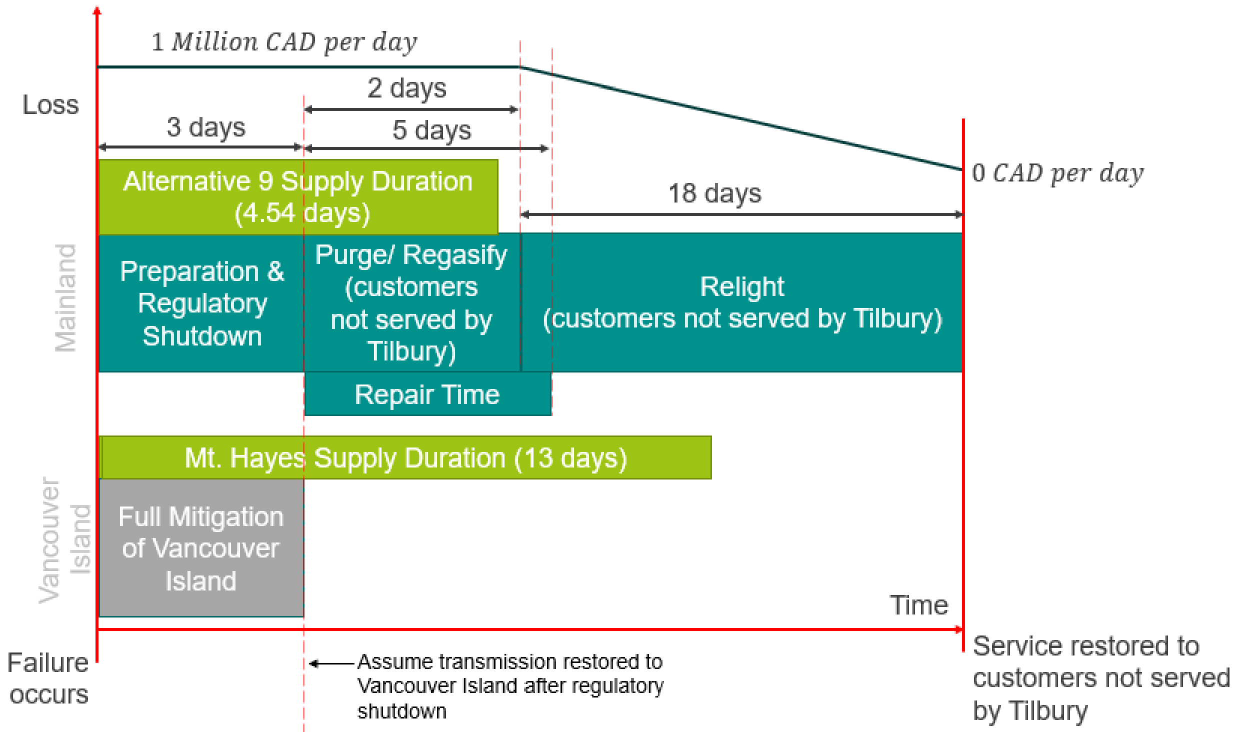
PwC's analysis did not divide GDP loss associated with loss of supply by customer class, therefore Exponent is unable to produce the requested figure precisely as requested. Additionally, the analysis was not specific to a given year.

To determine expected GDP losses, Exponent performed a Monte Carlo analysis, which produced many realizations of no-flow events, each with different simulated recovery times, dependent on, among other things, the repair time, which will differ for each simulation. The loss impacts by day also vary depending on whether the no-flow event impacts both pipes or a single pipe, which depends on the realization, as well as the precise mitigation scenario considered. The calculations for total losses corresponding to different no-flow scenarios are provided in Appendix U to the Exponent Report. Exponent cannot reasonably provide the loss impacts by day for all realizations, but provides the below examples of loss impacts by day over the duration of an outage event.

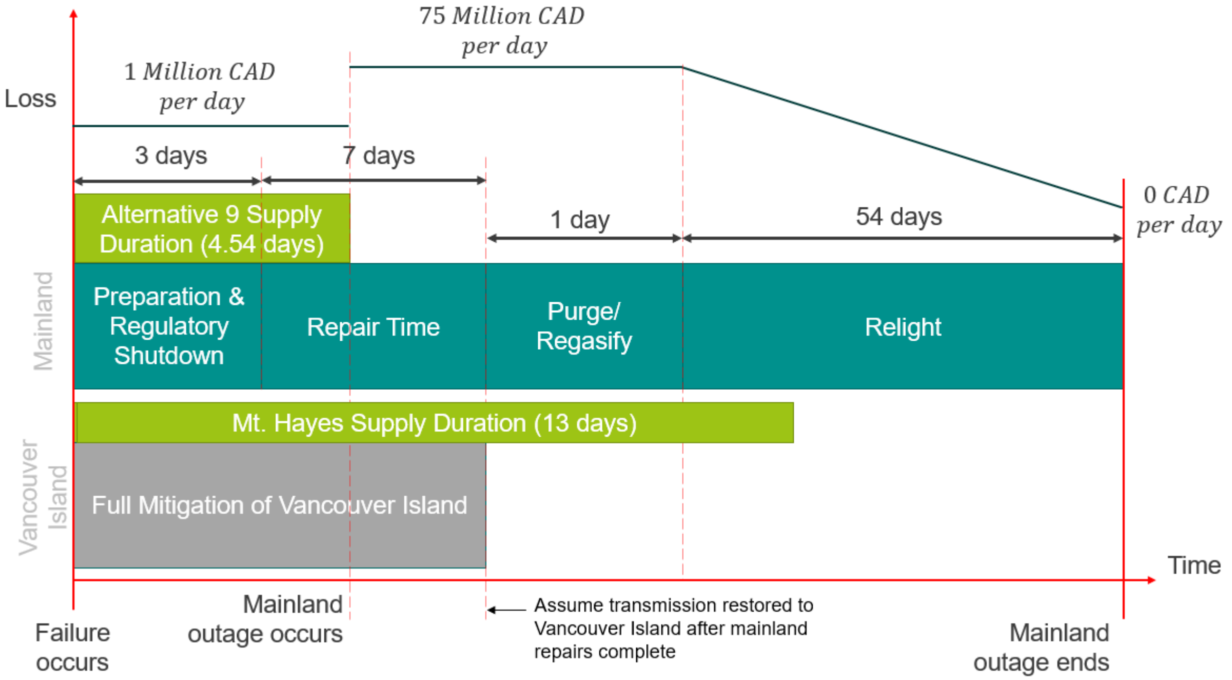
The figure below illustrates how daily GDP loss for AV-1 varies after a failure that requires five days to repair. AV-1 has a controlled shutdown, resulting in the 1-day purge/regasify period and 54-day relight period. Because Mt. Hayes provides 13 days of backup supply to Vancouver Island – which is supplied under normal circumstances by AV-1 – no outage occurs on Vancouver Island, and so there is no associated loss from Vancouver Island.




The figure below illustrates how daily loss varies with time elapsed after a failure on one of the two parallel pipes that comprise AV-1. After the failure, the 3-day Preparation & Regulatory Shutdown begins, during which Supplemental Alternative 9 supplies the customers it can serve. Customers not served by Tilbury experience an outage as soon the Preparation & Regulatory Shutdown occurs and therefore must go through a Purge/Regasify period and a Relight period as soon as the Preparation & Regulatory Shutdown ends and gas resumes flowing through the undamaged pipe. After the Preparation and Regulatory Shutdown ends, repairs also commence on the damaged pipeline while gas flows through the undamaged pipe. Therefore, the daily losses stem from the outage experienced by the customers not served by Tilbury. No outage occurs on Vancouver Island because Mt. Hayes provides backup supply to customers there, and normal service from AV-1 resumes after the Preparation & Regulatory Shutdown ends. Therefore, there are no losses from Vancouver Island.




The below figure shows how daily loss evolves after a failure of both pipelines within AV-1. Because both pipelines are damaged, customers on the mainland not served by Tilbury experience an immediate outage. The remainder of customers on the mainland don't experience an outage until the backup supply from Tilbury is exhausted, at which point a full outage on the mainland occurs while repairs on the damaged pipes continue. No outage occurs on Vancouver Island because Mt. Hayes has a backup supply that lasts longer than the combined Preparation & Regulatory Shutdown and Repair Time. Therefore, no losses occur on Vancouver Island.




138.2 Please explain FEI's policies and approaches to the allocation of and recovery of supply to each rate class and/or breakdown of the rate class to customer groupings, if different customer groupings have substantially different contributions to the losses from the duration before recovery of supply to the load.

**Response:**

FEI understands the question to be asking how FEI will prioritize the restoration of service following a no-flow event, and specifically whether it would prioritize a particular customer class. FEI will proceed using its BCUC-approved System Preservation and Restoration Plan (SP&R Plan). At a high level, the SP&R Plan contemplates restoration of service by area, regardless of customer class, as this is the most efficient approach. The potential exceptions would be attempting to first restore service to essential public services.

**139. Reference: Exhibit A-49, Commission IR 118.1 (inadequacy of 67 year load forecasts)**

In the FEI 2022 Long Term Gas Resource Plan (LTGRP) proceeding, on page 4-28 of Exhibit B-1 (2022 LTGRP), FEI provided the following figure which illustrates forecasted customer demand under different scenarios:

**Figure 4-9: Annual Demand Scenarios – Residential, Commercial and Industrial Sectors**


118.1 Please provide further supporting analysis to illustrate how demand growth has led to a requirement for 200 MMcf/d of regasification capacity and 1 Bcf of storage for peaking supply. For example, but not necessarily limited to: historical and forecasted demand trends and methodologies, explanation of how the load duration curve for the design year informs regasification and storage needs, and supporting commentary to explain key assumptions.

139.1 Please confirm, or otherwise explain, that predictions related to the use of energy, including natural gas demand over a 67-year period, is extremely uncertain.

**Response:**

FEI notes that the method used to prepare the long-term demand forecast represented in Figure 4-9 from FEI's 2022 LTGRP, which CEC included in the preamble, does not extend out 67 years.

FEI used the adverse hypothetical load loss scenarios to account for uncertainty when it comes to energy use over long horizons. Please refer to the response to BCUC IR5 129.1 for a discussion of how FEI has incorporated hypothetical adverse sensitivities related to load decline as part of the Supplemental Evidence.

139.2 Please provide expected certainties for FEI's demand for each five-year period up to 70 years.

**Response:**

FEI is unable to provide expected demand certainties for 70 years. The method used by FEI to prepare the long-term demand forecast represented in Figure 4-9 from the 2022 LTGRP, which CEC included in the preamble, does not extend out 70 years and does not attempt to establish probabilities (certainties) to the forecast demand in any scenario. FEI's Supplemental Evidence used adverse load loss sensitivities in recognition of future uncertainty.

Please refer to the response to BCUC IR5 129.1 for a discussion on how FEI has incorporated hypothetical adverse load loss sensitivities as part of the Supplemental Evidence.

139.3 Please provide FEI's forecast load for the 2025 to 2050 years by rate class.

**Response:**

FEI interprets CEC's requests as asking for information consistent with Figure 4-9 from the 2022 LTGRP as provided in the preamble, which shows annual demand. Please refer to the response to BCUC IR5 118.1 which explains that the annual demand forecast presented in Figure 4-9 of the 2022 LTGRP does not, and is not intended to, represent the peak demand requirements that will be served by the TLSE Project. Rather, Figure 4-9 shows the demand that is forecast to be used by residential, commercial and industrial customers over the entire year, for each year of the forecast at the time of filing the 2022 LTGRP. It does not correlate to the demand from these customer groups during a short-term peak event (daily or hourly), nor the amount of demand that might occur during an outage on the upstream delivery system. Please also refer to the response to BCUC IR5 118.5 for further discussion regarding FEI's peak day demand forecast.

However, in order to be responsive, FEI provides Tables 1 to 3 below which provide the prior years' actual customers, load and UPC from 2004 to 2023 for residential, commercial and industrial customers. Prior years' actual residential and commercial demand has been normalized for weather. Tables 4.1 and 4.2 below (for readability, the data has been broken into two tables) provide the forecast residential, commercial and industrial customers, demand and UPC for the forecast period from 2022 to 2042 as provided for the Diversified Energy (Planning) Scenario in the 2022 LTGRP. Tables 5.1 and 5.2 below (for readability, the data has been broken into two tables) provide the forecast residential, commercial and industrial customers, demand and UPC for the forecast period from 2022 to 2042 as provided for the Deep Electrification Scenario in the 2022 LTGRP. The 2022 LTGRP demand forecast extends to 2042. FEI has not developed a forecast of this information beyond 2042.

1 **Table 1: Actual Customers from 2004 – Residential, Commercial and Industrial**[4]

| Customers | | | |
|---|---|---|---|
| Year | Residential | Commercial | Industrial |
| 2004 | 710,767 | 77,195 | 1,188 |
| 2005 | 721,935 | 78,910 | 1,173 |
| 2006 | 730,872 | 79,921 | 1,119 |
| 2007 | 742,882 | 81,020 | 1,063 |
| 2008 | 750,838 | 82,318 | 1,057 |
| 2009 | 755,660 | 82,615 | 1,008 |
| 2010 | 762,496 | 82,765 | 960 |
| 2011 | 862,358 | 93,120 | 909 |
| 2012 | 855,997 | 88,266 | 914 |
| 2013 | 865,148 | 89,635 | 944 |
| 2014 | 875,623 | 90,837 | 930 |
| 2015 | 888,132 | 92,582 | 979 |
| 2016 | 899,473 | 93,551 | 958 |
| 2017 | 912,812 | 94,608 | 958 |
| 2018 | 932,061 | 96,397 | 990 |
| 2019 | 942,649 | 97,004 | 1,021 |
| 2020 | 955,626 | 97,383 | 1,023 |
| 2021 | 965,847 | 97,855 | 1,026 |
| 2022 | 976,170 | 98,281 | 1,050 |
| 2023 | 985,844 | 99,487 | 1,067 |

2

3 **Table 2: Actual Demand from 2004 – Residential, Commercial and Industrial**

| Demand, TJ. | | | |
|---|---|---|---|
| Year | Residential | Commercial | Industrial |
| 2004 | 72,673 | 44,789 | 65,954 |
| 2005 | 70,581 | 43,449 | 66,553 |
| 2006 | 70,268 | 44,381 | 65,812 |
| 2007 | 70,910 | 45,787 | 61,625 |
| 2008 | 69,109 | 46,148 | 58,805 |
| 2009 | 70,265 | 47,471 | 51,399 |
| 2010 | 70,312 | 46,931 | 52,476 |
| 2011 | 74,152 | 56,005 | 66,605 |
| 2012 | 74,729 | 56,654 | 69,647 |
| 2013 | 72,960 | 55,341 | 84,591 |
| 2014 | 73,457 | 55,320 | 83,976 |
| 2015 | 74,378 | 56,022 | 82,402 |
| 2016 | 78,203 | 57,950 | 86,460 |
| 2017 | 77,800 | 58,612 | 91,179 |
| 2018 | 78,543 | 59,274 | 91,054 |
| 2019 | 77,276 | 58,142 | 94,525 |
| 2020 | 81,836 | 58,155 | 92,669 |
| 2021 | 82,481 | 59,531 | 94,170 |
| 2022 | 80,650 | 60,932 | 80,882 |
| 2023 | 80,281 | 61,878 | 74,146 |

4

[4] Customer count is the number of customers at the end of the year, whereas the customer count provided in response to CEC IR5 134.7 is the annual average number of customers.

1 **Table 3: Actual UPC from 2004 – Residential, Commercial and Industrial**

| UPC, GJ | | | |
|---|---|---|---|
| Year | Residential | Commercial | Industrial |
| 2004 | 102.2 | 580.2 | 55,517 |
| 2005 | 97.8 | 550.6 | 56,737 |
| 2006 | 96.1 | 555.3 | 58,813 |
| 2007 | 95.5 | 565.1 | 57,972 |
| 2008 | 92.0 | 560.6 | 55,634 |
| 2009 | 93.0 | 574.6 | 50,991 |
| 2010 | 92.2 | 567.0 | 54,662 |
| 2011 | 86.0 | 601.4 | 73,273 |
| 2012 | 87.3 | 641.9 | 76,200 |
| 2013 | 84.3 | 617.4 | 89,609 |
| 2014 | 83.9 | 609.0 | 90,297 |
| 2015 | 83.7 | 605.1 | 84,169 |
| 2016 | 86.9 | 619.4 | 90,250 |
| 2017 | 85.2 | 619.5 | 95,176 |
| 2018 | 84.3 | 614.9 | 91,974 |
| 2019 | 82.0 | 599.4 | 92,581 |
| 2020 | 85.6 | 597.2 | 90,586 |
| 2021 | 85.4 | 608.4 | 91,784 |
| 2022 | 82.6 | 620.0 | 77,030 |
| 2023 | 81.4 | 622.0 | 69,490 |

2

**Table 4.1: Forecast Customers, Annual Demand and UPC by Rate Class for the Forecast Period from 2022 to 2042 for the Diversified Energy (Planning) Scenario as Presented in the 2022 LTGRP (2022-2032)**

**Year End Customers by Rate Schedule**

| Rate Class | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| RATE1 | 968,373 | 975,522 | 982,245 | 988,426 | 994,357 | 1,000,045 | 1,005,513 | 1,010,764 | 1,015,826 | 1,020,705 | 1,025,417 |
| RATE2 | 91,605 | 92,482 | 93,357 | 94,231 | 95,108 | 95,979 | 96,852 | 97,731 | 98,593 | 99,467 | 100,339 |
| RATE3 | 7,731 | 7,979 | 8,228 | 8,474 | 8,743 | 9,012 | 9,293 | 9,579 | 9,866 | 10,154 | 10,455 |
| RATE4 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 |
| RATE5 | 580 | 582 | 585 | 585 | 585 | 585 | 585 | 585 | 585 | 584 | 584 |
| RATE6 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| RATE7 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 |
| RATE22 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| RATE23 | 974 | 1,010 | 1,046 | 1,080 | 1,115 | 1,156 | 1,192 | 1,231 | 1,269 | 1,313 | 1,358 |
| RATE25 | 525 | 525 | 525 | 525 | 525 | 525 | 525 | 525 | 525 | 525 | 525 |
| RATE27 | 102 | 102 | 102 | 102 | 102 | 102 | 102 | 102 | 102 | 102 | 102 |
| RATE46 | 12 | 13 | 14 | 14 | 14 | 8 | 8 | 8 | 8 | 8 | 8 |
| **Grand Total** | **1,070,028** | **1,078,341** | **1,086,228** | **1,093,563** | **1,100,675** | **1,107,538** | **1,114,196** | **1,120,651** | **1,126,900** | **1,132,984** | **1,138,914** |

**Annual Use Rate per Customer by Rate Schedule (GJ)**

| Rate Class | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| RATE1 | 77.2 | 75.8 | 74.4 | 73.1 | 71.9 | 70.8 | 69.7 | 68.6 | 67.6 | 66.6 | 65.7 |
| RATE2 | 306.9 | 304.4 | 301.7 | 299.6 | 297.4 | 295.2 | 292.8 | 290.8 | 289.5 | 286.1 | 282.6 |
| RATE3 | 3,170.4 | 3,135.0 | 3,101.2 | 3,072.6 | 3,044.1 | 3,013.1 | 2,986.8 | 2,962.3 | 2,943.4 | 2,910.1 | 2,875.2 |
| RATE4 | 9,538.2 | 9,550.9 | 9,473.1 | 9,436.7 | 9,397.0 | 9,347.2 | 9,297.9 | 9,250.4 | 9,206.1 | 9,136.7 | 9,062.9 |
| RATE5 | 10,077.4 | 9,998.1 | 9,936.9 | 9,949.0 | 9,982.2 | 9,982.3 | 9,989.2 | 10,003.5 | 10,026.7 | 10,006.1 | 9,963.7 |
| RATE6 | 3,186.0 | 3,181.0 | 3,175.6 | 3,170.8 | 3,165.9 | 3,160.9 | 3,155.8 | 3,151.2 | 3,147.1 | 3,138.8 | 3,128.5 |
| RATE7 | 78,058.9 | 77,164.5 | 76,514.3 | 76,231.3 | 75,970.3 | 75,570.5 | 75,441.5 | 75,339.6 | 75,232.5 | 75,104.9 | 74,974.3 |
| RATE22 | 825,589.7 | 815,961.5 | 802,572.6 | 800,822.7 | 797,779.1 | 793,206.1 | 790,814.3 | 788,417.0 | 785,812.2 | 782,945.8 | 779,963.6 |
| RATE23 | 8,359.9 | 8,211.2 | 8,131.8 | 8,022.8 | 7,968.8 | 7,866.9 | 7,782.4 | 7,710.2 | 7,683.5 | 7,583.3 | 7,493.7 |
| RATE25 | 27,133.4 | 26,884.2 | 26,705.9 | 26,606.5 | 26,500.1 | 26,363.0 | 26,276.6 | 26,206.2 | 26,150.6 | 26,036.7 | 25,915.9 |
| RATE27 | 61,364.2 | 60,744.1 | 60,333.1 | 60,125.5 | 59,914.8 | 59,611.2 | 59,467.4 | 59,344.5 | 59,227.6 | 59,061.4 | 58,889.3 |
| RATE46 | 395,406.0 | 927,765.0 | 1,654,923.8 | 2,316,983.1 | 2,794,788.8 | 5,728,540.4 | 6,904,462.4 | 7,390,684.9 | 7,940,809.2 | 7,971,084.1 | 8,009,953.1 |

**Annual Demand by Rate Schedule (GJ)**

| Rate Class | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| RATE1 | 74,769,168 | 73,909,772 | 73,079,683 | 72,281,038 | 71,507,036 | 70,755,304 | 70,040,606 | 69,350,083 | 68,680,800 | 68,024,435 | 67,387,096 |
| RATE2 | 28,112,883 | 28,153,136 | 28,167,283 | 28,229,158 | 28,288,499 | 28,333,246 | 28,357,732 | 28,423,528 | 28,538,612 | 28,460,145 | 28,358,563 |
| RATE3 | 24,510,673 | 25,013,992 | 25,516,895 | 26,037,358 | 26,614,600 | 27,153,733 | 27,756,067 | 28,375,602 | 29,039,225 | 29,549,048 | 30,060,394 |
| RATE4 | 152,611 | 152,815 | 151,569 | 150,987 | 150,352 | 149,555 | 148,767 | 148,007 | 147,297 | 146,187 | 145,007 |
| RATE5 | 5,844,881 | 5,818,918 | 5,813,066 | 5,820,159 | 5,839,614 | 5,839,627 | 5,843,666 | 5,852,020 | 5,865,629 | 5,843,575 | 5,818,817 |
| RATE6 | 47,791 | 47,715 | 47,634 | 47,562 | 47,488 | 47,414 | 47,337 | 47,267 | 47,207 | 47,082 | 46,928 |
| RATE7 | 3,512,650 | 3,472,404 | 3,443,142 | 3,430,408 | 3,418,665 | 3,400,671 | 3,394,868 | 3,390,281 | 3,385,462 | 3,379,721 | 3,373,845 |
| RATE22 | 41,279,485 | 40,798,074 | 40,128,632 | 40,041,134 | 39,888,957 | 39,660,305 | 39,540,715 | 39,420,852 | 39,290,612 | 39,147,291 | 38,998,179 |
| RATE23 | 8,142,590 | 8,293,316 | 8,505,827 | 8,664,595 | 8,885,263 | 9,094,189 | 9,276,569 | 9,491,251 | 9,750,333 | 9,956,930 | 10,176,482 |
| RATE25 | 14,245,012 | 14,114,180 | 14,020,611 | 13,968,390 | 13,912,530 | 13,840,557 | 13,795,228 | 13,758,280 | 13,729,056 | 13,669,289 | 13,605,824 |
| RATE27 | 6,259,150 | 6,195,895 | 6,153,976 | 6,132,802 | 6,111,313 | 6,080,338 | 6,065,679 | 6,053,142 | 6,041,218 | 6,024,265 | 6,006,705 |
| RATE46 | 4,744,871 | 12,060,945 | 23,168,933 | 32,437,764 | 39,127,043 | 45,828,323 | 55,235,699 | 59,125,479 | 63,526,473 | 63,768,673 | 64,079,625 |
| **Grand Total** | **211,621,766** | **218,031,162** | **228,197,253** | **237,241,355** | **243,791,362** | **250,183,263** | **259,502,932** | **263,435,793** | **268,041,925** | **268,016,640** | **268,057,466** |

**Table 4.2: Forecast Customers, Annual Demand and UPC by Rate Class for the Forecast Period from 2022 to 2042 for the Diversified Energy (Planning) Scenario as Presented in the 2022 LTGRP (2033-2042)**

**Year End Customers by Rate Schedule**

| Rate Class | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|---|---|---|---|---|---|---|
| RATE1 | 1,029,967 | 1,034,365 | 1,038,609 | 1,042,710 | 1,046,668 | 1,050,486 | 1,054,180 | 1,057,756 | 1,061,334 | 1,064,902 |
| RATE2 | 101,214 | 102,074 | 102,940 | 103,787 | 104,616 | 105,429 | 106,238 | 107,023 | 107,820 | 108,616 |
| RATE3 | 10,757 | 11,064 | 11,364 | 11,679 | 11,985 | 12,300 | 12,609 | 12,921 | 13,234 | 13,551 |
| RATE4 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 |
| RATE5 | 584 | 584 | 584 | 584 | 584 | 584 | 584 | 584 | 584 | 584 |
| RATE6 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| RATE7 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 |
| RATE22 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| RATE23 | 1,401 | 1,445 | 1,492 | 1,531 | 1,578 | 1,627 | 1,668 | 1,719 | 1,760 | 1,811 |
| RATE25 | 525 | 525 | 525 | 525 | 525 | 525 | 525 | 525 | 525 | 525 |
| RATE27 | 102 | 102 | 102 | 102 | 102 | 102 | 102 | 102 | 102 | 102 |
| RATE46 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| **Grand Total** | **1,144,684** | **1,150,293** | **1,155,750** | **1,161,052** | **1,166,192** | **1,171,187** | **1,176,040** | **1,180,764** | **1,185,493** | **1,190,225** |

**Annual Use Rate per Customer by Rate Schedule (GJ)**

| Rate Class | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|---|---|---|---|---|---|---|
| RATE1 | 64.8 | 64.0 | 63.1 | 62.3 | 61.6 | 60.8 | 60.1 | 59.4 | 58.7 | 58.0 |
| RATE2 | 279.3 | 275.9 | 272.7 | 269.4 | 266.4 | 263.3 | 260.4 | 257.5 | 254.9 | 252.2 |
| RATE3 | 2,846.6 | 2,813.0 | 2,782.2 | 2,751.1 | 2,721.9 | 2,693.5 | 2,665.8 | 2,636.9 | 2,612.2 | 2,588.8 |
| RATE4 | 8,990.2 | 8,912.8 | 8,836.1 | 8,755.2 | 8,674.1 | 8,590.0 | 8,506.6 | 8,420.9 | 8,337.5 | 8,252.8 |
| RATE5 | 9,924.2 | 9,880.4 | 9,839.3 | 9,793.6 | 9,750.6 | 9,705.1 | 9,662.6 | 9,618.4 | 9,580.6 | 9,543.5 |
| RATE6 | 3,118.7 | 3,106.8 | 3,095.7 | 3,082.7 | 3,070.1 | 3,056.0 | 3,041.8 | 3,026.0 | 3,010.6 | 2,994.8 |
| RATE7 | 74,843.3 | 74,724.8 | 74,580.7 | 74,429.7 | 74,268.6 | 74,109.0 | 73,942.9 | 73,764.6 | 73,583.7 | 73,399.2 |
| RATE22 | 776,880.3 | 773,771.0 | 770,349.8 | 766,780.4 | 762,955.1 | 759,055.7 | 755,013.3 | 750,733.0 | 747,192.2 | 744,621.2 |
| RATE23 | 7,417.1 | 7,731.7 | 7,616.5 | 7,531.9 | 7,425.0 | 7,353.0 | 7,283.2 | 7,191.1 | 7,122.7 | 7,053.6 |
| RATE25 | 25,805.7 | 25,691.8 | 25,578.1 | 25,456.8 | 25,337.8 | 25,215.6 | 25,095.6 | 24,969.5 | 24,852.5 | 24,734.7 |
| RATE27 | 58,718.7 | 58,551.9 | 58,372.4 | 58,184.5 | 57,991.2 | 57,797.3 | 57,600.0 | 57,388.2 | 57,184.9 | 56,981.2 |
| RATE46 | 8,048,821.9 | 8,087,691.5 | 8,126,793.9 | 8,166,174.7 | 8,205,554.7 | 8,244,935.3 | 8,286,500.6 | 8,323,979.4 | 8,363,882.0 | 8,403,783.5 |

**Annual Demand by Rate Schedule (GJ)**

| Rate Class | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|---|---|---|---|---|---|---|
| RATE1 | 66,767,797 | 66,163,581 | 65,574,203 | 64,998,212 | 64,434,632 | 63,881,942 | 63,340,445 | 62,810,408 | 62,294,559 | 61,791,438 |
| RATE2 | 28,271,974 | 28,158,786 | 28,070,948 | 27,961,120 | 27,868,778 | 27,762,780 | 27,669,537 | 27,560,758 | 27,480,037 | 27,398,116 |
| RATE3 | 30,620,788 | 31,122,727 | 31,616,757 | 32,130,465 | 32,622,260 | 33,129,490 | 33,613,393 | 34,070,974 | 34,569,559 | 35,081,039 |
| RATE4 | 143,843 | 142,604 | 141,378 | 140,084 | 138,785 | 137,440 | 136,105 | 134,734 | 133,401 | 132,045 |
| RATE5 | 5,795,746 | 5,770,127 | 5,746,148 | 5,719,469 | 5,694,336 | 5,667,768 | 5,642,940 | 5,617,154 | 5,595,093 | 5,573,400 |
| RATE6 | 46,780 | 46,603 | 46,435 | 46,240 | 46,052 | 45,840 | 45,627 | 45,389 | 45,158 | 44,922 |
| RATE7 | 3,367,946 | 3,362,615 | 3,356,131 | 3,349,338 | 3,342,089 | 3,334,904 | 3,327,430 | 3,319,405 | 3,311,266 | 3,302,962 |
| RATE22 | 38,844,014 | 38,688,550 | 38,517,489 | 38,339,018 | 38,147,754 | 37,952,783 | 37,750,663 | 37,536,652 | 37,359,612 | 37,231,060 |
| RATE23 | 10,391,297 | 11,172,246 | 11,363,796 | 11,531,294 | 11,716,684 | 11,963,276 | 12,148,432 | 12,361,494 | 12,535,983 | 12,774,105 |
| RATE25 | 13,547,983 | 13,488,178 | 13,428,505 | 13,364,820 | 13,302,330 | 13,238,210 | 13,175,165 | 13,108,987 | 13,047,568 | 12,985,701 |
| RATE27 | 5,989,309 | 5,972,291 | 5,953,987 | 5,934,819 | 5,915,104 | 5,895,320 | 5,875,201 | 5,853,596 | 5,832,855 | 5,812,084 |
| RATE46 | 64,390,575 | 64,701,532 | 65,014,351 | 65,329,397 | 65,644,438 | 65,959,483 | 66,292,005 | 66,591,835 | 66,911,056 | 67,230,268 |
| **Grand Total** | **268,178,053** | **268,789,839** | **268,830,128** | **268,844,277** | **268,873,241** | **268,969,236** | **269,016,942** | **269,011,386** | **269,116,148** | **269,357,138** |

*Notes to Tables 4.1 and 4.2:*

1. All values in the tables are end-use, annual demand forecast values for the Diversified Energy (Planning) Scenario per the 2022 LTGRP.
2. Forecast demand is before consideration of DSM.
3. Forecast demand is exclusive of the demand from the Woodfibre LNG project.
4. Forecast values will not completely align with Figure 4-9 from the 2022 LTGRP due to Figure 4-9 intending to show only the demand related to the built environment, while the CEC request has asked for all demand (notwithstanding note 2) and therefore includes the transportation sector demand.

**Table 5.1: Forecast Customers, Annual Demand and UPC by Rate Class for the Forecast Period from 2022 to 2042 for the Deep Electrification Scenario as Presented in the 2022 LTGRP (2022-2032)**

**Year End Customers by Rate Schedule**

| Rate Class | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| RATE1 | 958,311 | 964,200 | 969,655 | 974,644 | 979,303 | 983,715 | 987,779 | 991,740 | 995,502 | 999,231 | 1,002,653 |
| RATE2 | 88,628 | 89,133 | 89,642 | 90,141 | 90,649 | 91,136 | 91,631 | 92,131 | 92,620 | 93,099 | 93,596 |
| RATE3 | 7,266 | 7,451 | 7,638 | 7,837 | 8,033 | 8,248 | 8,461 | 8,693 | 8,918 | 9,144 | 9,386 |
| RATE4 | 3 | 2 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| RATE5 | 548 | 545 | 544 | 539 | 536 | 525 | 515 | 513 | 507 | 503 | 496 |
| RATE6 | 14 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| RATE7 | 45 | 45 | 44 | 44 | 44 | 44 | 44 | 44 | 42 | 42 | 42 |
| RATE22 | 46 | 44 | 44 | 44 | 40 | 40 | 40 | 40 | 39 | 35 | 35 |
| RATE23 | 847 | 864 | 875 | 891 | 915 | 939 | 964 | 984 | 1,004 | 1,031 | 1,056 |
| RATE25 | 438 | 428 | 420 | 415 | 408 | 399 | 390 | 383 | 376 | 363 | 357 |
| RATE27 | 94 | 93 | 93 | 89 | 87 | 84 | 81 | 80 | 78 | 78 | 77 |
| RATE46 | 12 | 12 | 12 | 12 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| **Grand Total** | **1,056,252** | **1,062,830** | **1,068,981** | **1,074,670** | **1,080,035** | **1,085,150** | **1,089,925** | **1,094,628** | **1,099,106** | **1,103,546** | **1,107,718** |

**Annual Use Rate per Customer by Rate Schedule (GJ)**

| Rate Class | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| RATE1 | 75.2 | 72.9 | 70.6 | 68.3 | 66.1 | 63.6 | 61.2 | 58.8 | 56.4 | 53.9 | 51.5 |
| RATE2 | 285.2 | 273.1 | 261.2 | 249.5 | 238.1 | 226.5 | 215.5 | 205.1 | 195.1 | 185.8 | 177.2 |
| RATE3 | 2,998.8 | 2,885.7 | 2,777.1 | 2,675.0 | 2,568.0 | 2,458.4 | 2,351.7 | 2,248.8 | 2,150.5 | 2,059.0 | 1,976.0 |
| RATE4 | 9,266.1 | 11,091.9 | 11,068.8 | 11,058.5 | 11,029.6 | 10,996.9 | 10,970.7 | 10,944.8 | 10,918.1 | 10,890.5 | 10,862.1 |
| RATE5 | 9,932.2 | 9,690.4 | 9,477.6 | 9,253.5 | 9,065.5 | 8,908.1 | 8,602.5 | 8,410.4 | 8,240.4 | 8,039.9 | 7,868.2 |
| RATE6 | 3,022.2 | 2,906.4 | 2,875.4 | 2,843.2 | 2,809.9 | 2,775.1 | 2,738.9 | 2,701.0 | 2,659.9 | 2,617.0 | 2,572.3 |
| RATE7 | 80,988.4 | 81,027.5 | 80,211.9 | 80,137.4 | 79,994.3 | 79,845.2 | 79,692.8 | 79,534.7 | 80,692.0 | 80,510.2 | 80,333.1 |
| RATE22 | 892,163.8 | 911,874.6 | 904,734.9 | 906,145.6 | 943,308.4 | 941,793.4 | 940,543.4 | 939,328.0 | 959,536.2 | 1,001,816.9 | 1,000,490.8 |
| RATE23 | 8,233.9 | 7,964.2 | 7,701.7 | 7,477.3 | 7,244.0 | 7,089.0 | 6,843.2 | 6,651.0 | 6,401.9 | 6,229.5 | 6,005.7 |
| RATE25 | 27,465.6 | 27,046.8 | 26,936.0 | 26,712.1 | 26,605.6 | 26,116.9 | 26,080.0 | 25,659.9 | 25,018.6 | 24,911.6 | 24,789.9 |
| RATE27 | 63,567.5 | 63,116.8 | 62,937.7 | 63,772.6 | 64,491.4 | 63,550.4 | 62,847.4 | 63,144.6 | 63,297.6 | 62,977.7 | 62,845.5 |
| RATE46 | 383,516.5 | 411,348.2 | 438,516.5 | 491,369.2 | 1,081,942.5 | 1,136,942.7 | 1,191,942.7 | 1,246,942.7 | 1,356,942.7 | 1,356,942.7 | 1,356,942.7 |

**Annual Demand by Rate Schedule (GJ)**

| Rate Class | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| RATE1 | 72,111,487 | 70,297,567 | 68,458,749 | 66,596,977 | 64,707,853 | 62,596,635 | 60,463,050 | 58,330,130 | 56,108,166 | 53,884,310 | 51,648,809 |
| RATE2 | 25,277,945 | 24,340,569 | 23,413,491 | 22,493,896 | 21,586,875 | 20,642,647 | 19,744,591 | 18,893,335 | 18,074,221 | 17,301,544 | 16,583,456 |
| RATE3 | 21,789,478 | 21,501,376 | 21,211,579 | 20,964,194 | 20,629,081 | 20,276,573 | 19,897,365 | 19,548,863 | 19,178,524 | 18,827,922 | 18,546,331 |
| RATE4 | 27,798 | 22,184 | 11,069 | 11,059 | 11,030 | 10,997 | 10,971 | 10,945 | 10,918 | 10,891 | 10,862 |
| RATE5 | 5,442,830 | 5,281,292 | 5,155,798 | 4,987,636 | 4,859,112 | 4,676,732 | 4,430,278 | 4,314,532 | 4,177,890 | 4,044,047 | 3,902,629 |
| RATE6 | 42,311 | 37,783 | 37,380 | 36,962 | 36,528 | 36,077 | 35,606 | 35,113 | 34,579 | 34,022 | 33,440 |
| RATE7 | 3,644,480 | 3,646,239 | 3,529,324 | 3,526,047 | 3,519,750 | 3,513,188 | 3,506,483 | 3,499,526 | 3,389,063 | 3,381,428 | 3,373,991 |
| RATE22 | 41,039,537 | 40,122,480 | 39,808,335 | 39,870,408 | 37,732,337 | 37,671,736 | 37,621,734 | 37,573,119 | 37,421,910 | 35,063,591 | 35,017,180 |
| RATE23 | 6,974,147 | 6,881,040 | 6,738,974 | 6,662,317 | 6,628,237 | 6,656,589 | 6,596,840 | 6,544,616 | 6,427,493 | 6,422,630 | 6,342,038 |
| RATE25 | 12,029,945 | 11,576,036 | 11,313,113 | 11,085,510 | 10,855,103 | 10,420,635 | 10,171,209 | 9,827,755 | 9,407,003 | 9,042,925 | 8,849,998 |
| RATE27 | 5,975,343 | 5,869,858 | 5,853,206 | 5,675,763 | 5,610,749 | 5,338,238 | 5,090,636 | 5,051,570 | 4,937,209 | 4,912,263 | 4,839,106 |
| RATE46 | 4,602,197 | 4,936,178 | 5,262,197 | 5,896,431 | 6,491,655 | 6,821,656 | 7,151,656 | 7,481,656 | 8,141,656 | 8,141,656 | 8,141,656 |
| **Grand Total** | **198,957,497** | **194,512,603** | **190,793,215** | **187,807,200** | **182,668,309** | **178,661,701** | **174,720,418** | **171,111,161** | **167,308,633** | **161,067,228** | **157,289,494** |

**Table 5.2: Forecast Customers, Annual Demand and UPC by Rate Class for the Forecast Period from 2022 to 2042 for the Deep Electrification Scenario as Presented in the 2022 LTGRP (2033-2042)**

**Year End Customers by Rate Schedule**

| Rate Class | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|---|---|---|---|---|---|---|
| RATE1 | 1,005,745 | 1,008,839 | 1,011,961 | 1,014,583 | 1,017,240 | 1,019,758 | 1,022,149 | 1,024,423 | 1,026,691 | 1,028,963 |
| RATE2 | 94,085 | 94,565 | 95,044 | 95,507 | 95,958 | 96,388 | 96,806 | 97,208 | 97,625 | 98,017 |
| RATE3 | 9,625 | 9,866 | 10,115 | 10,370 | 10,620 | 10,864 | 11,118 | 11,360 | 11,610 | 11,867 |
| RATE4 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| RATE5 | 489 | 482 | 477 | 471 | 471 | 468 | 466 | 463 | 461 | 460 |
| RATE6 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| RATE7 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 |
| RATE22 | 35 | 30 | 30 | 30 | 29 | 28 | 28 | 26 | 23 | 22 |
| RATE23 | 1,089 | 1,120 | 1,152 | 1,184 | 1,217 | 1,244 | 1,280 | 1,317 | 1,345 | 1,380 |
| RATE25 | 348 | 345 | 340 | 332 | 327 | 319 | 310 | 303 | 289 | 274 |
| RATE27 | 71 | 70 | 70 | 70 | 68 | 67 | 67 | 66 | 66 | 66 |
| RATE46 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| **Grand Total** | **1,111,549** | **1,115,379** | **1,119,251** | **1,122,609** | **1,125,992** | **1,129,198** | **1,132,286** | **1,135,228** | **1,138,172** | **1,141,111** |

**Annual Use Rate per Customer by Rate Schedule (GJ)**

| Rate Class | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|---|---|---|---|---|---|---|
| RATE1 | 49.0 | 46.4 | 43.9 | 41.3 | 38.7 | 36.3 | 34.2 | 32.3 | 30.6 | 29.1 |
| RATE2 | 169.1 | 161.7 | 154.8 | 148.5 | 142.6 | 137.2 | 132.2 | 127.5 | 123.2 | 119.1 |
| RATE3 | 1,894.2 | 1,823.3 | 1,755.8 | 1,696.8 | 1,644.9 | 1,590.5 | 1,542.5 | 1,496.7 | 1,452.8 | 1,413.1 |
| RATE4 | 10,832.8 | 10,803.2 | 10,771.9 | 10,739.5 | 10,705.9 | 10,671.4 | 10,635.4 | 10,598.2 | 10,559.4 | 10,519.5 |
| RATE5 | 7,621.8 | 7,487.8 | 7,310.0 | 7,198.5 | 7,037.8 | 6,915.8 | 6,772.2 | 6,660.7 | 6,518.7 | 6,398.2 |
| RATE6 | 2,528.7 | 2,488.3 | 2,450.9 | 2,416.2 | 2,384.0 | 2,354.3 | 2,326.7 | 2,301.1 | 2,277.4 | 2,255.4 |
| RATE7 | 80,159.7 | 79,988.9 | 79,818.5 | 79,645.7 | 79,465.3 | 79,267.8 | 79,034.1 | 78,726.8 | 78,270.8 | 77,698.7 |
| RATE22 | 999,129.3 | 1,029,924.4 | 1,028,370.9 | 1,026,645.7 | 1,049,941.1 | 1,060,432.2 | 1,056,546.9 | 1,112,164.4 | 1,156,954.3 | 1,178,784.4 |
| RATE23 | 5,844.8 | 5,723.3 | 5,539.3 | 5,393.1 | 5,271.0 | 5,128.8 | 4,994.6 | 4,903.1 | 4,794.8 | 5,111.7 |
| RATE25 | 24,323.4 | 24,122.1 | 24,045.8 | 24,036.2 | 23,877.4 | 23,143.5 | 23,365.4 | 23,380.2 | 22,874.8 | 22,631.5 |
| RATE27 | 62,474.3 | 62,863.2 | 62,584.1 | 62,303.6 | 62,072.6 | 61,973.2 | 61,646.8 | 60,856.7 | 60,387.8 | 59,852.4 |
| RATE46 | 1,356,942.7 | 1,356,942.7 | 1,356,942.6 | 1,356,942.6 | 1,356,942.7 | 1,356,942.7 | 1,356,942.6 | 1,356,943.0 | 1,356,943.0 | 1,356,943.0 |

**Annual Demand by Rate Schedule (GJ)**

| Rate Class | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|---|---|---|---|---|---|---|
| RATE1 | 49,266,436 | 46,841,107 | 44,385,320 | 41,895,772 | 39,416,326 | 37,047,317 | 34,923,024 | 33,044,376 | 31,388,406 | 29,932,793 |
| RATE2 | 15,914,199 | 15,292,157 | 14,716,366 | 14,182,261 | 13,687,477 | 13,227,344 | 12,797,543 | 12,396,778 | 12,024,948 | 11,673,461 |
| RATE3 | 18,231,668 | 17,989,101 | 17,760,183 | 17,595,435 | 17,468,853 | 17,279,520 | 17,149,118 | 17,002,158 | 16,867,469 | 16,768,952 |
| RATE4 | 10,833 | 10,803 | 10,772 | 10,740 | 10,706 | 10,671 | 10,635 | 10,598 | 10,559 | 10,519 |
| RATE5 | 3,727,044 | 3,609,110 | 3,486,878 | 3,390,486 | 3,314,813 | 3,236,575 | 3,155,853 | 3,083,910 | 3,005,135 | 2,943,176 |
| RATE6 | 32,873 | 32,348 | 31,861 | 31,410 | 30,993 | 30,605 | 30,246 | 29,914 | 29,606 | 29,320 |
| RATE7 | 3,366,708 | 3,359,535 | 3,352,376 | 3,345,118 | 3,337,543 | 3,329,249 | 3,319,433 | 3,306,525 | 3,287,374 | 3,263,344 |
| RATE22 | 34,969,524 | 30,897,733 | 30,851,126 | 30,799,371 | 30,448,292 | 29,692,101 | 29,583,314 | 28,916,273 | 26,609,949 | 25,933,257 |
| RATE23 | 6,365,028 | 6,410,048 | 6,381,273 | 6,385,414 | 6,414,778 | 6,380,279 | 6,393,110 | 6,457,329 | 6,448,985 | 7,054,191 |
| RATE25 | 8,464,558 | 8,322,136 | 8,175,571 | 7,980,031 | 7,807,921 | 7,382,779 | 7,243,265 | 7,084,209 | 6,610,804 | 6,201,042 |
| RATE27 | 4,435,679 | 4,400,421 | 4,380,885 | 4,361,250 | 4,220,938 | 4,152,203 | 4,130,333 | 4,016,543 | 3,985,596 | 3,950,261 |
| RATE46 | 8,141,656 | 8,141,656 | 8,141,656 | 8,141,656 | 8,141,656 | 8,141,656 | 8,141,656 | 8,141,658 | 8,141,658 | 8,141,658 |
| **Grand Total** | **152,926,205** | **145,306,155** | **141,674,266** | **138,118,945** | **134,300,296** | **129,910,300** | **126,877,531** | **123,490,270** | **118,410,489** | **115,901,975** |

*Notes to Tables 5.1 and 5.2:*

1. All values in the tables are end-use, annual demand forecast values for the Deep Electrification Scenario per the 2022 LTGRP.
2. FEI explained in the 2022 LTGRP that the Deep Electrification Scenario overlooks many very difficult to overcome challenges and is therefore not a reasonable forecast or planning scenario.
3. The forecast is before consideration of DSM.
4. The forecast demand is exclusive of the demand from the Woodfibre LNG project.
5. Forecast values will not completely align with Figure 4-9 of the 2022 LTGRP due to Figure 4-9 intending to show only the demand related to the built environment, while the CEC request has asked for all demand (notwithstanding note 2) and therefore includes the transportation sector demand.

139.4 Please provide the UPC by rate class for the last 20 years and forecasts for the period 2025 to 2050.

**Response:**

Please refer to the response to CEC IR5 139.3.

139.5 Please provide FEI's customer counts and loads by rate class for the last 20 years and forecasts for the period 2025 to 2050 assuming Scenarios for Diversified Planning and for Declines of Loads.

**Response:**

Please refer to the response to CEC IR5 139.3.

139.6 Please provide a current update with respect to FEI providing 'clean gas' (no GHG emission contribution) and provide the % of load expected to be 'clean' supply for each of the years 2025 to 2050 along with providing a description and quantification of clean supply additions for each of the years from 2025 to 2050.

**Response:**

FEI provided the following table in response to BCUC IR1 52.6[5] in the 2022 LTGRP proceeding. FEI expects a similar trajectory for growth of its renewable and low carbon gas from 2042 to 2050.

[5] doc_69352_b-6-fei-response-bcuc-ir1.pdf

**Table 1: Gas Supply Portfolio Illustrating the Proportion of Renewable and Low-Carbon Gas Over Time (in PJ)**

| | Natural Gas | RNG | Hydrogen | Syngas and Lignin | CCS | Total Demand | Total Renewable and Low Carbon Gas | Renewable and Low Carbon Gas as a percent of Total Demand |
|---|---|---|---|---|---|---|---|---|
| **2019** | 214.7 | 0.0 | 0.0 | 0.0 | 0.0 | 214.7 | 0.0 | 0.0 |
| **2020** | 215.9 | 0.3 | 0.0 | 0.0 | 0.0 | 216.1 | 0.3 | 0.1 |
| **2021** | 208.8 | 0.7 | 0.0 | 0.0 | 0.0 | 209.5 | 0.7 | 0.3 |
| **2022** | 201.1 | 5.8 | 0.0 | 0.0 | 0.0 | 207.0 | 5.8 | 2.8 |
| **2023** | 193.2 | 10.7 | 0.0 | 0.0 | 0.2 | 204.2 | 11.0 | 5.4 |
| **2024** | 185.2 | 12.9 | 2.7 | 0.4 | 0.3 | 201.6 | 16.3 | 8.1 |
| **2025** | 177.1 | 16.1 | 5.4 | 0.8 | 0.4 | 199.8 | 22.7 | 11.4 |
| **2026** | 168.6 | 19.3 | 8.1 | 1.6 | 0.6 | 198.1 | 29.5 | 14.9 |
| **2027** | 159.3 | 22.5 | 10.7 | 3.2 | 0.7 | 196.3 | 37.0 | 18.9 |
| **2028** | 150.2 | 25.6 | 13.4 | 4.7 | 0.8 | 194.8 | 44.6 | 22.9 |
| **2029** | 141.3 | 28.8 | 16.1 | 6.3 | 0.9 | 193.5 | 52.2 | 27.0 |
| **2030** | 132.3 | 32.2 | 20.0 | 6.7 | 1.3 | 192.5 | 60.2 | 31.3 |
| **2031** | 126.9 | 32.8 | 22.8 | 6.9 | 1.7 | 191.0 | 64.1 | 33.6 |
| **2032** | 121.6 | 33.3 | 25.5 | 7.0 | 2.1 | 189.5 | 68.0 | 35.9 |
| **2033** | 116.5 | 33.9 | 28.3 | 7.2 | 2.5 | 188.3 | 71.8 | 38.1 |
| **2034** | 112.0 | 34.5 | 31.0 | 7.4 | 2.9 | 187.7 | 75.7 | 40.3 |
| **2035** | 107.0 | 35.1 | 33.8 | 7.5 | 3.2 | 186.5 | 79.6 | 42.7 |
| **2036** | 102.1 | 35.6 | 36.5 | 7.7 | 3.6 | 185.5 | 83.5 | 45.0 |
| **2037** | 97.2 | 36.2 | 39.3 | 7.9 | 4.0 | 184.6 | 87.3 | 47.3 |
| **2038** | 92.6 | 36.8 | 42.0 | 8.0 | 4.4 | 183.8 | 91.2 | 49.6 |
| **2039** | 88.1 | 37.4 | 44.8 | 8.2 | 4.8 | 183.2 | 95.1 | 51.9 |
| **2040** | 83.6 | 37.9 | 47.5 | 8.4 | 5.2 | 182.6 | 99.0 | 54.2 |
| **2041** | 79.4 | 38.5 | 50.3 | 8.5 | 5.5 | 182.2 | 102.8 | 56.4 |
| **2042** | 75.4 | 39.1 | 53.0 | 8.7 | 5.9 | 182.1 | 106.7 | 58.6 |

139.7 Please confirm that it may be considerably easier for FEI to develop a ‘clean’ supply as and if the load declines, because the % of ‘clean gas’ already being supplied will go up as total load declines.

**<u>Response:</u>**

Not confirmed. FEI interprets the terms “clean” supply and “clean gas” in this request to refer to renewable and low carbon gas as set out by FEI in the 2022 LTGRP.[6] While the percentage of renewable and low carbon gas already being supplied would increase, as a percentage, with a decrease in load (all else equal), the relative ease at which FEI can acquire additional renewable and low carbon gas supply depends on much more than the overall market demand for gas. Market conditions, enabling policies and legislation, supply chain, emerging markets, technology advancements and economies of scale are all examples of factors that can impact the ability of

[6] FEI 2022 LTGRP Application, Exhibit B-1, Section 1.3, pp. 1-6 to 1-7.

FEI and other gas utilities to acquire renewable and low carbon supplies, regardless of whether FEI's future overall demand for gas is expected to increase or decrease.

**140. Reference: Exhibit A-49, BCUC IR 118.4 Follow Up**

118.5 Please confirm, or explain otherwise, that the peak day is assumed to be the coldest day that is expected to occur once in 20 years.

118.5.1 Please discuss if and how FEI's assumptions for peak day, and other cold days which would require peaking supply from Tilbury, consider potential warming trends resulting from climate change.

140.1 Please discuss how the Vancouver bylaws related to natural gas, and building codes can be expected to impact peak demand for natural gas in the future.

**Response:**

Vancouver bylaws related to the building code are targeting both new construction and existing buildings.

New construction only makes up a small percentage of load within the City of Vancouver. While FEI is still seeing new gas attachments in Vancouver, the overall number of new attachments and associated load is less than what would be expected without building bylaws that restrict gas usage. Though these bylaws affect new buildings, peak demand may or may not be affected as it is possible to have gas equipment installed for use only during peak winter periods. Therefore, while annual volume may be less in these buildings, the peak demand may be the same.

There are a number of City of Vancouver bylaws that impact existing building gas usage. The City of Vancouver's "Energize Vancouver" initiative currently requires large commercial buildings (over 50,000 square feet) to report their energy and carbon data, with an intent to implement 2026 and 2040 greenhouse gas and heat intensity limits. The Energize Vancouver initiative is set to be phased in over time and FEI does not anticipate a near-term material reduction in total energy load or peak demand from these buildings. To limit potential financial penalties from using natural gas, building owners can, for example, undertake various efficiency initiatives. While annual demand may decline as a result of an efficiency initiative, peak demand may or may not be affected.

Please also refer to the response to BCUC IR5 129.1 for a discussion of how provincial codes are reflected in FEI's scenario analysis in Section 4.5.5 of the Supplemental Evidence.

140.2 Please provide the years, and historical data, which was used to determine peak requirements.

**Response:**

Please refer to the response to BCUC IR5 118.5.

**141. Reference: Exhibit B-60, page 8**

**Table 1-1: Time to Failure Following T-South Winter No-flow Event – Status Quo (150 MMcf/d, Regardless of LNG Volumes Available)**

| Temperature Condition | Approximate Time Until Customers in the Lower Mainland Begin Losing Service[25] |
|---|---|
| -10.0°C (very cold Lower Mainland winter day)[26] | 2 hours |
| -1.4°C (warmest Lower Mainland winter in 10 years)[27] | 5 hours |
| +4.0°C (average Lower Mainland winter)[28] | 7 hours |

The Table 1-2 below summarizes **direct customer impacts** at average winter temperatures (+4°C) for the four anonymized segments of T-South.[29] The number of affected customers increases from the values shown as temperatures drop below

[23] As the BCUC has approved the AMI Project, the entirety of the analysis in this Supplementary Evidence and the 2024 Resiliency Plan assumes that residential and small commercial AMI is in place. The extent of the mitigation provided by AMI, in terms of reducing the extent and duration of an outage, was discussed in FEI's Rebuttal Evidence.

[24] The basis of the outage duration estimates was discussed in detail in FEI's Rebuttal Evidence.

[25] This represents the approximate duration of full firm load support from all on-system LNG and linepack from the CTS. The analysis also assumes that all interruptible customers are offline within 4 hours of the no-flow event.

[26] Due to the low probability of having multiple -10°C days in a row in the Lower Mainland, the -10°C temperature condition analysis assumes the following: the first day is -10°C, the second and third days are -7°C, the fourth day is -3°C, and all subsequent days are 4°C.

[27] The warmest winter in the last 10 years was found by determining the minimum daily average temperature for each year over a 10-year period from 2013-2022, then selecting the highest value. The analysis was based on data from the Vancouver International Airport (YVR).

[28] Defined as the average of the daily average temperatures for December, January, and February over a 10-year period from 2013-2022. The average winter day is based on data from YVR.

[29] See Section 3.2.2.1.1 of this Supplemental Evidence for a summary of the calculation parameters. The de-anonymized description of the four Assessed Vulnerabilities (AVs) comprising T-South are found in Appendices RP 4-01, 4-02 4-03 and 4-54 to the 2024 Resiliency Plan, which have been kept confidential for security reasons.

141.1 In Footnote 26, FEI assumes a rising temperature condition over four days. Does FEI's analysis assume that the -10°C occurs for the full 24 hr period, is a daily average, or a temporary minimum?

141.1.1 If FEI's evidence assumes that the -10°C lasts for the full 24-hour period, or is an average, please provide evidence or indicate where it may be found in the evidence.

**Response:**

FEI's analysis uses mean daily temperatures. Therefore, the -10°C refers to a mean daily temperature of -10°C.

FEI notes the following recent occurrences of a mean daily temperature of -10°C or colder at the Vancouver International Airport (YVR):

- 12/27/2021 (-11.6°C)[7]
- 12/21/2022 (-10°C)[8]

[7] Daily Data Report for December 2021 - Climate - Environment and Climate Change Canada.

[8] Daily Data Report for December 2022 - Climate - Environment and Climate Change Canada.

- 12/22/2022 (-10.2°C)[9]

FEI also notes the following recent occurrences of a mean daily temperature approaching -10°C at YVR:

- 12/26/2021 (-8.3°C)[10]
- 12/28/2021 (-8.6°C)[11]
- 1/12/2024 (-9.9°C)[12]
- 1/13/2024 (-8.5°C)[13]

141.2 Please provide and analysis of Vancouver temperatures over the course of the year for each of the 2024 through to 2000 in the following format:

\# of Days <-10°C , # of Days <-5°C , # of Days <-0°C

**Response:**

Please refer to Table 1 below, which summarizes the number of days the specified criteria are met. The temperature data used in the analysis is the mean daily temperature from YVR.

**Table 1: YVR Mean Daily Temperature Occurrences (Jan 1, 2000 to Dec 31, 2024)**

| | Criteria | | |
|---|---|---|---|
| Year | <-10C | <-5C | <0C |
| 2000 | 0 | 0 | 5 |
| 2001 | 0 | 0 | 0 |
| 2002 | 0 | 0 | 3 |
| 2003 | 0 | 0 | 2 |
| 2004 | 0 | 3 | 5 |
| 2005 | 0 | 1 | 12 |
| 2006 | 0 | 2 | 4 |
| 2007 | 0 | 0 | 8 |
| 2008 | 1 | 5 | 17 |
| 2009 | 0 | 0 | 15 |
| 2010 | 0 | 2 | 6 |

[9] Daily Data Report for December 2022 - Climate - Environment and Climate Change Canada.
[10] Daily Data Report for December 2021 - Climate - Environment and Climate Change Canada.
[11] Daily Data Report for December 2021 - Climate - Environment and Climate Change Canada.
[12] Daily Data Report for January 2024 - Climate - Environment and Climate Change Canada.
[13] Daily Data Report for January 2024 - Climate - Environment and Climate Change Canada.

| | Criteria | | |
|---|---|---|---|
| Year | <-10C | <-5C | <0C |
| 2011 | 0 | 0 | 10 |
| 2012 | 0 | 1 | 6 |
| 2013 | 0 | 1 | 12 |
| 2014 | 0 | 0 | 12 |
| 2015 | 0 | 0 | 4 |
| 2016 | 0 | 1 | 14 |
| 2017 | 0 | 0 | 22 |
| 2018 | 0 | 0 | 10 |
| 2019 | 0 | 1 | 16 |
| 2020 | 0 | 1 | 5 |
| 2021 | 1 | 5 | 14 |
| 2022 | 1 | 4 | 16 |
| 2023 | 0 | 0 | 5 |
| 2024 | 0 | 3 | 8 |
| Total | 3 | 30 | 231 |

141.3 Please confirm that the joint probability of a T-South No-Flow event occurring with cold winter days of various levels of low temperature would be the probability of the T-South No-Flow event for the year multiplied by the probability of the various low temperature day occurrences.

**Response:**

**The following response has been provided by Exponent:**

Confirmed. The correct phrasing is: the joint probability of a T-South No-Flow event occurring with cold winter days of various levels of low temperature would be the probability of the T-South No-Flow event for the year multiplied by the conditional probability of the various low temperature day occurrences.

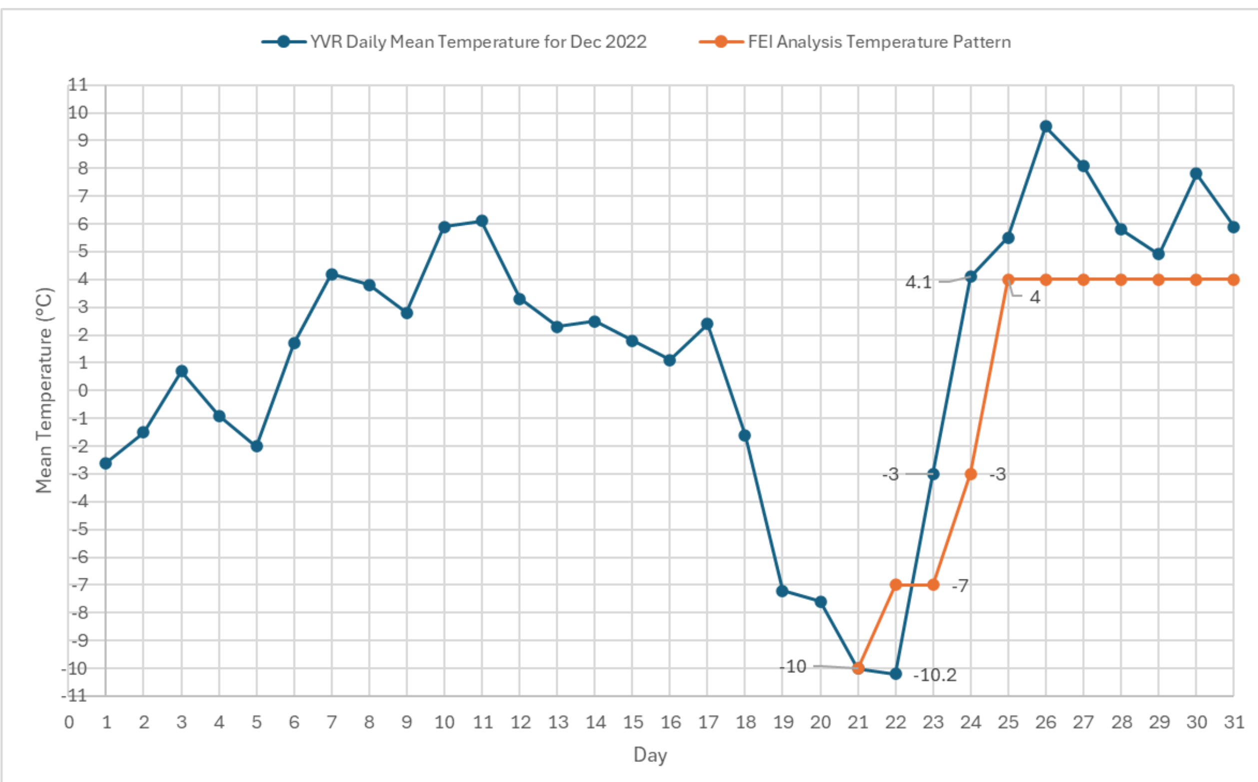
141.4 Please confirm that if FEI assumes that low temperature winter days are all described by -10°C for the first day -7°C for the second and third days and -3°C for the fourth day, followed by +4°C for the remaining days, such assumption may not be a correct representation of the past experience but is assumed for convenience of analysis.

**Response:**

FEI based the temperature pattern used for the "very cold Lower Mainland winter day" on a cold snap that occurred from approximately December 18 to December 24, 2022.

Figure 1 below plots the actual mean daily temperatures at YVR in December 2022 versus the assumed pattern used for FEI's analysis. As the figure demonstrates, the assumed pattern follows the trend of the actual temperatures that occurred during the cold snap. In the analysis, FEI assumed that the rupture incident occurs near the peak of the cold snap and, therefore, replaced the -10.2°C temperature condition that occurred on December 22 with a more conservative assumption of two consecutive days of -7°C. FEI made this substitution due to the low likelihood of having consecutive -10°C days. While consecutive -10°C days occurred in this cold snap, based on the YVR temperature dataset going back to 2008, this is the only occurrence of multiple consecutive -10°C or colder days.

**Figure 1: YVR Daily Mean Temperature for December 2022 vs. FEI Analysis Temperature Pattern**




141.5 Please confirm that the occurrence of a T-South No-Flow event just prior to a -10°C day or just after a -10°C day would make a significant difference for the resilience requirement.

**Response:**

**The following response has been provided by Exponent:**

The temperature conditions that occur during a no-flow event will primarily dictate the system load that must be supported, and thus will impact the resiliency requirement. However, there may be small variances due to the temperature before and after a no-flow event, as described in relation to each of the two hypothetical scenarios below:

- Occurrence of a no-flow event just prior to a -10ºC day: There would be a greater demand on the resiliency supply if the temperature drops to -10ºC after a no-flow event. Days at -10ºC in the Lower Mainland represent a small proportion of total days, however.
- Occurrence of a no-flow event just after a -10ºC day: The building envelope for structures heated by gas would be colder than if it were warmer the day before a no-flow event. While FEI has not modeled latent heat in structure impacts on gas usage, it is expected that there would be a difference in required supply at the time of the no-flow event, but that this difference would be minor compared to differences due to the temperature at the time of the no-flow event.

Given that the conditions that could occur during a no-flow event will primarily dictate the system load that must be supported, Exponent considers its treatment of temperature conditions to be appropriate.

**FEI also provides the following response:**

FEI agrees with Exponent that the temperature conditions that occur during a no-flow event will primarily dictate the system load that must be supported, and thus will impact the resiliency requirement. The system load in the days preceding a T-South no-flow event, which is largely driven by temperature, would be met by gas supply from T-South and FEI's other gas supply resources. As such, the temperature conditions preceding the T-South no-flow event would not impact the resiliency requirement.

**142. Reference: Exhibit B-60, page 41 and Exhibit B-61, page 27 (calculations supporting outage duration)**

**Table 3-1: Quantitative Metrics Related to Severity of a T-South No-Flow Event at Average Winter Temperatures by Incident Location**

| Type of Impact | Quantitative Metric | AV-1 Value | AV-2 Value | AV-3 Value | AV-54 Value |
|---|---|---|---|---|---|
| Direct customer service impact | Number of firm customers losing service on Day 1 | 640,100 | 600,400 | 640,400 | 600,400 |
| Direct customer service impact | Total Outage Duration[70] | 63.3 days | 60.2 days | 71.9 days | 66.3 days |
| Direct customer service impact | Total firm customer-outage-days | 24 million | 21 million | 32 million | 28 million |

[67] The reported customer outage numbers are from the risk assessment performed as part of the 2024 Resiliency Plan. As noted in the 2024 Resiliency Plan, the four AVs which represent T-South are based on specific failure locations and temperature conditions.

[68] The stated customer outage numbers are based on the duration of the T-South no-flow event being shorter than the duration that FEI's Mt. Hayes LNG Facility can support the Vancouver Island Transmission System (VITS). Under average winter conditions, Mt. Hayes can support the VITS for approximately 13 days. If the no-flow duration were to exceed the Mt. Hayes supply duration, then an additional 159,500 customers would lose service within FEI's VITS.

[69] These segments have been anonymized for security reasons using AV designations from the 2024 Resiliency Plan. Each of these AVs has a separate Confidential Appendix in the 2024 Resiliency Plan with restricted access.

[70] The Total Outage duration is defined as the estimated period (in days) starting on Day 1 of the customer outage to the day when service is finally restored to the last customer. Reported as the mean from Exponent's Monte Carlo analysis. Refer to Section 3.4.1.2 of the 2024 Resiliency Plan for additional information.

- Exponent calculated the overall risk for each Assessed Vulnerability by multiplying the individual consequences by their respective cumulative probabilities of occurrence over consistent time horizons. The risk of each AV is calculated using three different consequence metrics:
    - customer outage-days (a measure of the number of customers affected multiplied by the estimated number of days that the customers are without service);
    - customer outages; and
    - economic harm to society/GDP impact, which incorporates the work done by PwC.

142.1 For each AV, please provide the data and curve showing the number of customers out of service by day commencing on day 1 to the end of the outage duration, and please provide the average days of outage per customer by rate class.

**<u>Response:</u>**

**The following response has been provided by Exponent:**

FEI's study of customer outages that informed Exponent's study did not consider customer rate class, except to the extent FEI excluded interruptible customers from the inputs provided.

Exponent performed a Monte Carlo analysis that produced a large number of realizations of no flow events for each AV, all of which depend on the repair time, number of pipes impacted, and other factors for the particular realization. Exponent cannot reasonably provide curves for each realization for each AV. Appendix U of Exponent's report provides extensive discussion on how customer outage days is calculated for each of the numerous outage scenarios.

142.2 For each AV, please provide the data and curve showing the load loss and recovery by day commencing on Day 1.

**Response:**

While the impact to customer load was an input to PwC's analysis, the total impacted load (i.e., the total number of GJ impacted) was only determined for the Reviewed Scenarios (AV-3, AV-49, AV-4 (Columbia), AV-30, AV-33, AV-45 and AV-4 (Salmon Arm)). As such, the total impacted load is not available for all AVs (the Sub-Regional Scenarios). As the information was not required for PwC's analysis and determining the total impacted load would require significant time and expense, FEI has not performed the analysis for this response. Please refer to Appendix RP 3 of the 2024 Resiliency Plan which explains PwC's sub-regional analysis of the economic impact, and the response to BCUC IR5 141.2.

142.3 Please provide the calculations supporting the 'Total Firm Customer Outage Days' or indicate where this may be located in the evidence.

**Response:**

**The following response has been provided by Exponent:**

Total Firm Customer Outage Days is a measure of the number of firm customers losing service multiplied by components of the Total Outage Duration. The calculation accounts for: (a) 100 percent of the customers being without service for the time before relighting activity begins; and (b) half of the customers thereafter, so as to account for a linear relighting trajectory, and is defined on page 42 of FEI's 2024 Resiliency Plan (Exhibit B-61).

A simple example is shown below:

$$Total\ Firm\ Customer\ Outage\ Days = D_{before\ relight} \times N_{customers} + 1/2 \times D_{after\ relight} \times N_{customers}$$

Where $D_{before\ relight}$ is the number of days before relighting begins, $D_{after\ relight}$ is the number of days after relighting begins until all customers have been restored, and $N_{customers}$ is the number of customers experiencing an outage.

Variations on the above equation are used to calculate customer outage days for mitigation, resilience, and repair scenarios, as explained in Appendix U of Exponent's report.

**143. Reference: Exhibit B-60, Appendix F, page 19 (peak shaving possibility to reduce impacts)**

> i. *Interruptible Customer Peaking Resource*
>
> Access to "on-system" natural gas supplies, through the displacement of one customer (i.e., interruptible) for the benefit of others (i.e., core customers), is a method of managing capacity which should be maximized wherever possible.[6] Utilities and pipelines offer interruptible tariffs with the understanding that the customer can be interrupted and receive compensation for their displacement. Typically, these customers have an ability to fuel switch, leaving their supply and capacity available for other customers. The compensation provided to these customers could be a lower tariff, or compensation mechanism(s) to cover the underlying fuel cost and any operational disruption nuance(s) (i.e., increase labor expenses). Regardless, the customer acknowledges that their service can be interrupted.
>
> Based on information provided by FEI, its Lower Mainland region has seen a 10% decline in the number of interruptible customers between 2018 and 2023. As such, there is less of this contractual peaking resource available to FEI.

143.1 Please provide the number of interruptible customers that would also be affected by each AV, by rate class.

**Response:**

Since FEI's analysis in the 2024 Resiliency Plan is based on firm customers (i.e., all interruptible customers are already excluded from the analysis), FEI did not specifically identify the number of interruptible customers impacted by each AV and the information is not readily available. Table 1 below provides the number of interruptible customers by rate class broken down by region. FEI notes that the 97 interruptible customers in the Lower Mainland and the 7 customers in the Vancouver Island region would be affected by a T-South no-flow event (AVs 1, 2, 3, and 54).

**Table 1: Interruptible Customers by Region**

| Rate/Region | LML | VI | INL | COL | Total |
|---|---|---|---|---|---|
| **Rate 22/22A/22B** | 14 | 1 | 16 | 5 | **36** |
| **Rate 7** | 60 | 1 | 2 | 0 | **63** |
| **Rate 27** | 23 | 5 | 20 | 2 | **50** |
| **Total** | **97** | **7** | **38** | **7** | **149** |

143.2 Please provide the total proportion of interruptible customers by rate class.

**Response:**

FEI provides the below table setting out the customer and energy percentages under each interruptible rate schedule.

**Table 1: Interruptible Customers and Energy as a Percent of Total**

| Rate Schedule | % of Customers | % of Annual Energy |
|---|---|---|
| **22/22A/22B** | 0.003% | 17% |
| **7** | 0.005% | 3% |
| **27** | 0.005% | 2% |
| **Total** | **0.014%** | **22%** |

Interruptible customers represent less than 1 percent of FEI's total customer base, but account for approximately one quarter of FEI's annual energy throughput. Customers in RS 22/22A/22B[14] are also a mix of partially firm and partially interruptible customers. Interruptible customers can either be a sales service customer under RS 7, where they acquire gas from FEI, or they can be a transportation service customer under RS 27 or RS 22/22A/22B, where they acquire their commodity from a gas marketer or on their own. While the pipeline capacity for interruptible customers is freed-up if they are curtailed, there is no guarantee that FEI will have access to their natural gas supply. The interruptible customer, or their marketer, has no obligation to deliver to FEI the natural gas supply for the customers that have been curtailed; therefore, FEI cannot rely on that volume as a source of supply during a curtailment event.

143.3 Please provide the total proportion of interruptible load by rate class.

**Response:**

Please refer to the response to CEC IR5 143.2.

[14] RS 22A and 22B are grandfathered and closed rate schedules serving customers in FEI's Inland and Columbia regions, respectively. These rate schedules have rate structures similar to RS 22 with firm and interruptible components. However, RS 22A and 22B are designed to incent customers to maximize the firm component of their rate structures by making the interruptible component more costly. These rate structures, now closed to new customers, were designed in this way to incent customers to "firm-up" their demand, thereby providing a firm revenue source which helped underwrite the natural gas distribution system in those regions to the benefit of residential and commercial customers.

143.4 Please provide the annual cost benefits that customers can receive, by rate class, for being interruptible.

**Response:**

FEI offers interruptible services under RS 7/27 (Fully Interruptible Service), as well as RS 22 (Large Volume Transportation Service).[15]

For RS 7/27, the delivery rate is set based on a discount of approximately 18 percent from the effective rates of RS 5/25 (General Firm Service) with an effective RS 5/25 load factor of 90.9 percent. For the average RS 7/27 customer with an annual consumption of approximately 132,620 GJ, the total annual savings on the bill (including commodity costs) is approximately $56 thousand[16] or 7.5 percent when compared to taking firm service under RS 5/25 for the same volume at the currently approved 2025 rates (approved on an interim basis by Order G-313-24).

FEI notes that the above savings are based on an average RS 7/27 customer. The actual savings for individual customers will be dependent on the customer-specific load profile and annual demand. FEI is also not privy to the customers' costs related to maintaining a secondary backup fuel system in addition to the secondary fuel costs which could erode the cost benefit that customers may receive for being interruptible under RS 7/27.

For RS 22, FEI notes that the rates for RS 22 interruptible service are set to equal the <u>effective</u> firm charges (i.e., the effective delivery charges per GJ are the same between RS 22 interruptible and firm service <u>at equal volumes</u>). As such, customers shifting their existing interruptible volume to firm volume (without adding new volume) would not experience savings on their bill. Although there are no overall savings on the total bill, RS 22 customers that decide to firm-up some, or all of their volume, are required to pay for the firm volume of service (i.e., the portion paid under the Firm Demand Charge per month) regardless of whether they take the firm volume or not. Electing firm service ensures that some volume will be delivered to the RS 22 customer in a situation where interruptible customers are interrupted, with the trade-off that firm volume must be paid for regardless of whether it is taken or not.

143.5 Please provide a full discussion on what steps FEI has taken to maximize its interruptible load.

[15] Rate Schedules 22A and 22B are closed to new customers.

[16] Based on the 2025 Approved (Interim) rates, the total bill under RS 7/27 would be approximately $694,488 and the total bill under RS 5/25 would be approximately $750,735 for the same average annual consumption of 132,620 GJ.

**Response:**

Customers are able to receive service under any applicable rate schedule for which they meet the tariff requirements. Larger customers may be able to take service under many rate schedules such as RS 5/25, 7/27 and 22. FEI does not have the ability to force a customer who meets the applicable criteria of a rate schedule to take service under a different rate schedule. However, there is a financial incentive (in the form of lower interruptible rates) to take interruptible service if a customer's business model can accommodate interruptions or if they have access to backup fuels.

Given this financial incentive already exists, FEI's focus is on informing customers with respect to the different types of service available to them and customers are aware of the pro/cons of the different types of service. Ultimately it is the customer's choice as to the type of service they want to receive (firm or interruptible) and from who they wish to receive their commodity (FEI or a gas marketer).

143.6 Please provide the proportion of interruptible customers (transition from firm) that would be required to make a 5%, 10%, 25% difference in FEI's peaking requirements for each AV.

**Response:**

FEI cannot perform the requested analysis by AV as it does not have the details of each rate schedule's contribution to peak day load by AV. Further, FEI notes that interruptible customers are curtailed on peak and other cold winter days, and FEI does not contract peaking resources to meet interruptible load (RS 7/27, RS 22). FEI plans resources to meet firm peaking supply requirements based on updated load forecasts and does not make assumptions on future customer migration between the services under different rate schedules. It is ultimately a customer's choice to select firm or interruptible service.

FEI's peak day in the Lower Mainland is approximately 870 MMcf based on the forecast for gas year 2019/20, with 5 percent equaling 43.5 MMcf, 10 percent equaling 87.0 MMcf and 25 percent equaling 217.5 MMcf of the peak day. Table 1 below sets out each rate schedule's contribution to peak day demand and the approximate number of customers taking service by rate schedule.

**Table 1: Contribution to Peak Day Load and Number of Customers by Rate Schedule**

| Rate Schedule | MMcf | Number of Customers |
|---|---|---|
| 1 | 418.4 | 1,001,160 |
| 2 | 183.3 | 90,271 |
| 3/23 | 175.8 | 9,493 |
| 4 | 0.0 | 18 |
| 5/25 | 90.7 | 984 |
| 6 | 1.7 | 19 |
| **Total** | **870.0** | **1,101,945** |

FEI notes the following regarding the proportion of interruptible customers (transition from firm) that would be required to make a 5 percent, 10 percent, and 25 percent difference in FEI's peaking requirements:

- Approximately half of FEI's 984 RS 5/25 customers would need to elect interruptible service to shed approximately 5 percent of peak day load in the Lower Mainland.
- Nearly all of FEI's 984 RS 5/25 customers would need to elect interruptible service to shed approximately 10 percent of FEI's peak day load in the Lower Mainland.
- All 984 RS 5/25 customers and 72 percent of RS 3/23 customers (i.e., 6,835 customers), would need to elect interruptible service to shed approximately 25 percent of FEI's peak day load in the Lower Mainland.

FEI considers it very unlikely that any of the above scenarios would occur because there is already a material financial incentive for customers to take interruptible service if they are capable of accepting the commercial implications of being interrupted. The fact that they are not moving to interruptible rates suggests that they are prioritizing firm service over a lower service cost.

143.7 Please provide the total quantity of firm load for firm load customers for the period 2000 through to 2024.

**Response:**

FEI has assumed that the question is seeking firm load data for the Lower Mainland only, given the passage referenced by the CEC in the preamble. FEI's electronic records of firm load begin from 2003 onward and were used to prepare the following table.

| Year | LML Firm Load, GJ RS1-6, RS23, RS25 |
| --- | --- |
| 2003 | 82,366,175 |
| 2004 | 89,283,601 |
| 2005 | 97,171,246 |
| 2006 | 97,972,392 |
| 2007 | 104,653,691 |
| 2008 | 106,566,205 |
| 2009 | 105,975,721 |
| 2010 | 95,826,954 |
| 2011 | 108,015,319 |
| 2012 | 100,449,811 |
| 2013 | 100,311,299 |
| 2014 | 96,709,691 |
| 2015 | 87,739,798 |
| 2016 | 93,521,821 |
| 2017 | 109,425,180 |
| 2018 | 103,252,828 |
| 2019 | 106,010,868 |
| 2020 | 107,142,924 |
| 2021 | 107,813,988 |
| 2022 | 113,494,605 |
| 2023 | 107,255,220 |
| 2024 | 109,484,481 |

143.8 Please confirm that firm load customers are planned to be served through the normal peak requirements for FEI every year, but that in a T-South No-Flow event they may likely lose supply until there is sufficient recovery of supply from T-South.

**Response:**

FEI ensures sufficient peaking gas supply along with other supply resources are in place such that firm customers can be served through peaking events, design winters and normal years.

Under FEI's existing resiliency capabilities (i.e., without the TLSE Project), all firm customers in the Lower Mainland will lose service on the first day of a winter T-South no-flow event. Additionally, depending on the location of the T-South rupture, firm customers in other FEI service territories (e.g., the Interior) will also lose service. Firm customers served by the Vancouver Island Transmission System would not lose service on the first day of the event as they would be supported by the Mt. Hayes LNG facility.

With the TLSE Project in place, firm customers will have an additional source of supply. Firm customers in the Lower Mainland will be directly served by gas stored by the TLSE Project, while some firm customers in the Interior may also be served indirectly by the TLSE Project through displacement. Depending on the circumstances of the T-South no-flow event (i.e., the duration of the no-flow event and the temperature condition at which it occurs), the TLSE Project can bridge the loss of supply due to a T-South no-flow event (i.e., provide supply while T-South supply is temporarily unavailable), such that firm customers do not lose service. Even if the duration of the no-flow event exceeds the support duration that the TLSE Project can provide, it will still provide value by allowing FEI to execute a controlled shutdown.

Please refer to Section 4.7.3.1 of the Supplemental Evidence for why a controlled shutdown is much more desirable than an uncontrolled shutdown.

143.9 Please describe, in the case of a T-South No Flow event, the point at which firm load customers are supported by LNG for a period of time until they must be cut off because of the lack of supply.

**Response:**

The duration of support that can be provided to firm customers in the Lower Mainland from on-system LNG is provided in Table 4-18 in Section 4.7.2.2 of the Supplemental Evidence (reproduced below). Table 4-18 lists the support duration under different temperature conditions for both the existing Tilbury Base Plant and the Preferred Alternative for the TLSE Project. In principle, if gas were to resume flowing on T-South within the duration of support, no firm customer outage would occur. The important caveat is that, if FEI is anticipating running out of gas before gas flows resume, then FEI would have to begin a controlled shutdown before the supply ceases to avoid an uncontrolled system depressurization. This would involve firm customers progressively losing service before the durations in the table are reached.

**Table 4-18: Preferred Alternative Support of Lower Mainland Under Various Winter Temperatures**

| Temperature Condition (°C) | Existing Tilbury Base Plant (assuming full to 0.35 Bcf)[212] | Preferred Alternative – 2 Bcf resiliency reserve & 800 MMcf/d (Minimum 2 Bcf available in 3 Bcf tank on first day of no-flow event) |
|---|---|---|
| -10.0 (very cold winter day)[213] | 2 hours | 2 days and 17 hours |
| -1.4 (warmest winter in last 10 years)[214] | 5 hours | 3 days and 12 hours |
| +4.0 (average Lower Mainland winter)[215] | 7 hours | 4 days and 13 hours |

143.10 Please provide the timing for when firm supply customers may be provided supply again as the recover- of supply on T-South is restored.

**Response:**

The time that firm customers will be without service following a winter T-South no-flow event that results in customer outages depends on many factors. Most notably: (1) the duration of the no-flow event; (2) the nature of the shutdown (i.e., if the shutdown occurred in a controlled or uncontrolled manner); and (3) the number of customers affected by the outage.

Further, as customers will be gradually relit, the time without service can differ drastically depending on if a customer is amongst the first or last to be relit. This effect is particularly pronounced for outages that include a large number of customers, such as a Lower Mainland-wide outage. Even with mutual aid and sourcing local gas fitters (which have been assumed to be available in the 2024 Resiliency Plan, although their availability is not certain), it would take weeks to relight all Lower Mainland customers, and as such customer relights will occur in a gradual manner. Please refer to FEI's Rebuttal Evidence to RCIA (Exhibit B-46-1) which provides more information regarding FEI's expected timeline for the full resumption of service in the Lower Mainland following a system shutdown.

For the purposes of this response, FEI has used the restoration timeline for AV-2, as discussed in Section 3.2.2.1.3 of the Supplemental Evidence, and assumed a 3-day winter T-South no-flow event has occurred resulting in a controlled shutdown in the Lower Mainland.

Under this example scenario, some customers would begin being relit after an outage duration of 6 days. The last customers to be relit would experience the longest outage duration of 57 days.

As explained in Section 3.2.2.1.3 of the Supplemental Evidence, FEI's restoration timelines reflect a number of favourable assumptions that (other things being equal) may understate the total restoration duration. For example, FEI contemplates only relighting essential appliances within a premises to save time and assumes that 25 percent of customers relight their own appliances. FEI also assumes that it not only has full access to its own workforce, but also to the entire Lower Mainland gas contracting community and a large complement of mutual aid personnel from other utilities in the region. To the extent that any of these additional personnel fail to materialize, the duration of the relight process would be materially longer.

143.11 Please advise whether the FEI firm load customers generally have their own back up capabilities or generally do not have any.

**Response:**

**The following response has been provided by PwC:**

In addition, the PwC analysis factored in backup supplies where interviews indicated backups were in use within a certain industry. This was done by delaying the onset of economic losses following the natural gas supply outage to reflect the use of backup energy supplies. This had the effect of reducing the duration of the no-flow event for some sectors and reducing the estimated economic losses.

**FEI also provides the following response:**

FEI understands that most firm load customers do not have their own back up capabilities.

143.12 Please advise whether the FEI firm load customers have loss of business insurance and or could get loss of business insurance for this specific T-South No-Flow event.

**Response:**

**The following response has been provided by PwC:**

The PwC analysis did not provide insights into loss of business insurance availability or prevalence. It is also important to highlight that regardless of insurance or other measures, such as federal or provincial government support for affected businesses, the economic losses described in the analysis would still occur. The affect of insurance would be to transfer these losses, in whole or in part, to other parties like insurance companies. Any such transfer of losses may also be reversed over time, for example, through higher future premiums, or in the case of government support programs, higher future taxes.

**FEI also provides the following response:**

FEI is not aware of whether firm or interruptible customers have loss of business insurance, or whether it is commercially available for this type of loss. FEI does not require that a customer hold loss of business insurance as a condition of taking service.

143.13 Please advise whether FEI has approached its firm load customers with a proposition to accept early shutdown in a T-South No Flow event to assist with resilience and provide a rate incentive to gain their cooperation on resilience.

143.13.1 If FEI has done this, what has been the result and if not, why would this not be a potentially valuable addition to FEI's resilience?

**Response:**

FEI has not specifically approached its firm load customers with a proposition to accept early shutdown in a T-South no-flow event to assist with resiliency and provide a rate incentive to gain their cooperation.

Offering a specific option to be curtailed first in a supply emergency would significantly complicate the emergency shutdown response and fails to recognize that, in an emergency, FEI needs to act quickly to reduce enough load to avoid a Lower Mainland-wide pressure collapse. A very significant amount of firm load will need to be shed (i.e., a very significant number of customers will need to be cut off) irrespective of whether they were prepared to accept being curtailed first or not. FEI's approach to curtailment will follow its System Preservation and Restoration (SP&R) Plan, which the BCUC determined to be in the public interest and not unduly discriminatory[17]. The SP&R Plan is confidential but, broadly speaking, the approach in the plan is to minimize overall harm. The approach contemplated in the question is incompatible with the SP&R Plan, and with the principle of minimizing overall harm.

Otherwise, the approach referenced in the question is effectively the service offered under FEI's interruptible rate schedules. In particular, RS 7/27 and RS 22/22A/22B enable curtailment in exchange for a discounted service compared to RS 5 (General Firm Sales) and RS 25 (Transportation Service). While FEI's large firm service customers are generally aware of FEI's interruptible service offerings, FEI regularly works with its customers to determine their overall natural gas costs under various rate schedules and the risks associated with firm versus interruptible service for specific customer segments. Customers ultimately select the type of service that best fits their business needs.

As set out in the response to BCUC IR5 139.4, given the recent frequency and length of curtailment events, some customers are choosing to return to firm service – suggesting that customers prefer firm rather than interruptible service.

[17] Letter L-32-18 dated December 7, 2018.

**144. Reference: (Health impacts) Exhibit B-61, page 8, and page 17 and [https://www.nerc.com/pa/rrm/ea/Documents/February_2021_Cold_Weather_Report.pdf](https://www.nerc.com/pa/rrm/ea/Documents/February_2021_Cold_Weather_Report.pdf) and [https://en.wikipedia.org/wiki/2021_Texas_power_crisis](https://en.wikipedia.org/wiki/2021_Texas_power_crisis)**

> - Pricewaterhouse Coopers (PwC) has estimated that Assessed Vulnerabilities that result in a widespread winter outage in the Lower Mainland will have catastrophic economic consequences, far in excess of any other Assessed Vulnerabilities.
> - Health and safety may be impacted as cold residences and workplaces would likely lead to an increase in the incidence of poor health such as respiratory illnesses. Vulnerable populations can be at risk of death.[10]
>
> [10] NERC noted recently that hundreds of people died as a result of an electric outage in Texas that left people without heat for only four days. FERC - NERC - Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States (2021), pp. 9-10: https://www.nerc.com/pa/rrm/ea/Documents/February_2021_Cold_Weather_Report.pdf. See also Supplemental Evidence, Section 3.2.2.3.

> **Health and safety** may also be impacted, as cold residences and workplaces would likely lead to an increase in the incidence of poor health such as respiratory illnesses. There is extensive evidence of the link between temperature and poor health. For example, mortality rates in Canada are 11 percent higher in winter than in summer on a like-for-like basis, with death rates amongst the elderly rising by 1-2 percent for every 1°C drop in external temperature. This statistic does not incorporate any loss of heating capacity; thus, it is reasonable to assume that with loss of some heating capacity excess deaths would be higher than a typical winter. [Reference omitted]

> NERC noted recently that hundreds of people died as a result of an electric outag Texas that left people without heat for only four days:[23]
>
> > More than 4.5 million people in Texas lost power during the Event, and some went without power for as long as four days, while exposed to below-freezing temperatures for over six days. At least 210 people died during the Event, with most of the deaths connected to the power outages, of causes including hypothermia, carbon monoxide poisoning, and medical conditions exacerbated by freezing conditions. Among the deaths were a mother and her seven-year-old daughter, and an 11- year-old boy who died in his bed, who all died of carbon monoxide poisoning, and a 60-year-old disabled man who died of hypothermia. A grandmother and three children trying to keep warm using a wood-burning fireplace died in a house fire. In cities including Austin, Houston and San Antonio, over 14 million people were ordered to boil drinking and cooking water, and multiple cities ordered water conservation measures, due to broken pipes and power outages (which lowered water pressure). After the city of Denton, Texas, lost its gas supply, it was forced to cut power to nursing homes and water pumping stations. [Footnotes removed from original]

144.1 Please confirm that more than 4.5 million people lost power during the Texas power failure.

**Response:**

Confirmed, as reported by NERC in the report cited in the preamble.

144.2 Please confirm that the Texas power failure was in large part due to the state's lack of preparedness for the severity of the weather event, in which both the electric and gas infrastructure were insufficient.

**Response:**

Not confirmed. As explained in the NERC report cited in the preamble (pp. 11-12), the Texas power failure was primarily due to the failure of electricity generating units and reduced natural gas production, both triggered by freezing temperatures.

144.3 Please confirm that Texas homes are known to generally have poor insulation, and that standard winterizing is likely to be significantly less robust than that in the lower mainland which is reasonably accustomed to freezing temperatures.

**Response:**

Not confirmed. FEI is not aware of the specific insulation characteristics in Texas homes relative to those in the Lower Mainland. However, the NERC report does not reference poor insulation or less robust winterizing of homes as a driving factor behind the hundreds of deaths as a result of the electric outage.

144.4 Please confirm that FEI's analysis in this instance is focused on an event (no flow on T-South) which only directly impacts natural gas supply, and in which most if not all customers would continue to have electric supply.

**Response:**

The 2024 Resiliency Plan calculated consequences and risk based on the loss of gas supply, not electric supply. However, this understates the potential harm because there is the potential for impacts on the electric system as well. As noted in the PwC Report:[18]

> Natural gas supply outages in B.C. may also place a strain on the electrical grid as many households and businesses may seek to substitute the energy provided by gas to that from electricity. At peak hourly demand, B.C. consumes 65 TJ of natural gas, compared to only 37 TJ of electricity, so the ability of the electrical grid to make up for the loss of natural gas is likely to be limited, and attempts to do so may lead to infrastructure damage or the need for mitigation actions such as managed power brownouts to protect the grid.

144.5 Please confirm that BC Hydro does not have any significant reliance on natural gas sourced from the T-South for normal operations.

**Response:**

The vast majority of BC Hydro's in-province generation is from hydroelectric sources. However, FEI understands that BC Hydro continues to rely on a 275-megawatt natural gas-fired combined cycle facility located in Campbell River on Vancouver Island. Any gas used in this facility would pass through T-South.

144.6 Please confirm that it is, generally speaking, significantly easier, cheaper and safer to replace lost natural gas heating with temporary electric heating than it is to replace the loss of electric heating with natural gas, propane or other heat sources.

**Response:**

Not confirmed. Many gas fireplaces[19] can be used during an electric power outage to keep space within a home warm, no matter the principal heating energy type of the home (whether it is an electric based heating system or other system). Furthermore, permanent gas-fired backup

[18] Exhibit B-61, 2024 Resiliency Plan, Appendix RP 3 (PwC Report), p. 14.
[19] Such as described here: https://www.valorfireplaces.com/features/no-power-no-problem.php.

generators are commonly used to cover an electric outage, including keeping the central space heating system running.

FEI confirms that portable and safe electric heaters are typically available for purchase, although there may be insufficient portable electric heaters available in the market immediately following an outage to heat hundreds of thousands of homes. Please refer to the response to CEC IR5 144.4 for a discussion of the strain on the electrical grid should hundreds of thousands of households seek to substitute gas with electricity in a natural gas supply outage.

Please also refer to the responses to CEC IR2 101.2, 101.3 and 101.4.

144.7 Please confirm that FEI's references to 'death' are more conjecture than a proven likelihood.

144.7.1 If not confirmed, please provide estimated numbers and probabilities as to the deaths that could occur with the loss of T-South.

**Response:**

**The following response has been provided by PwC:**

The scope of the PwC report did not include the development of excess mortality estimates. However, excess winter deaths are a well documented phenomenon within Canada and many other countries. In light of this, it is not considered "conjecture" that a prolonged and widespread loss of heating during winter would increase excess winter deaths over their current level.

**FEI also provides the following response:**

FEI's statements with respect to the impacts of cold on health are based on the studies cited in the preamble, and not its own probability assessment. The studies cited suggest that there is a link between people losing access to heat in cold weather and adverse health impacts, including increased mortality rates. FEI considers that the link is self-evident, such that deaths are likely when a no-flow event on T-South occurs in winter and hundreds of thousands of people lose heat to their homes.

144.8 Please provide the recorded deaths directly attributable to the last failure of T-South experienced by FEI in the lower mainland and on Vancouver Island.

**Response:**

FEI is not aware of any deaths attributable to the 2018 T-South Incident. However, the 2018 T-South Incident did not result in a widespread and prolonged service disruption due to favourable conditions (the incident occurred in October, during warmer temperatures that were above average and mild for that time of year), and the actions FEI took to continue to serving customers, albeit at reduced loads.

**145. Reference: Exhibit B-60 pages 57, 58, and 59 (Probability of no-flow event)**

### *3.2.3.1 Exponent's Calculated Cumulative Probabilities*

FEI instructed Exponent to perform cumulative probability calculations for a winter-only disruption on all AVs based on two horizons:

1. The 67-year expected life of the TLSE Project, which FEI regards as the appropriate horizon; and
2. A 23-year sensitivity based on an assumed facility retirement in 2050, which FEI included to address the BCUC's commentary regarding the energy transition potentially shortening the useful life of a new LNG facility.

FEI explains in Section 4.5.5 of this Supplemental Evidence why it regards 23 years as being too short.[98] However, the cumulative probability is very high regardless, as shown in the table below.

**Table 3-3: Exponent's Calculated Cumulative Probability of T-South No-Flow Event in Winter[99]**

| Calculation Horizon | Basis for Horizon | Exponent's Calculated Cumulative Winter Only (90 Days) Probability |
|---|---|---|
| **67 years** | Expected Life of TLSE Project | 95% - 100% |
| **23 years** | Hypothetical adverse sensitivity assumes no further use of Tilbury facility for resiliency or gas supply after 2050 | 65% - 97% |

The Exponent Report explains these results.[100] A key factor driving the high probability of failure is the length of the T-South pipeline. Due to its length, T-South has increased exposure to all hazards. One cause of failure (also referred to as a "mode of failure"), that drives the high probability of a winter T-South outage, is the internal per kilometre rupture and ignited rupture rates when applied to a very lengthy pipeline like T-South. As occurred in the 2018 T-South Incident, rupture or ignited rupture of one of the two T-South lines could be expected to prompt a regulatory / precautionary shut-down of the other line in the same right-of-way, resulting in a no-flow event. In the 2018 T-South Incident, the regulatory shut-down/no-flow event lasted 2 days, followed by a long period of reduced flow. At present, Tilbury, regardless of the potential volumes in the Base Plant and Tilbury 1A, could not support Lower Mainland load for a single day in winter, such that the regulatory shutdown would cause Lower Mainland customers to lose service very quickly.

#### 3.2.3.1.1 EXPONENT'S APPROACH TO CALCULATING CUMULATIVE PROBABILITY

Exponent's calculated overall cumulative probability of a winter T-South no-flow event reflects:

- The combination of the annual failure rate associated with all of the modes of failure on the T-South system capable of being assigned a failure rate (cyberattacks and sabotage are not included, such that the cumulative probabilities are understated);
- The annual failure rate is translated into a winter-only rate by pro-rating to 90 days; and
- The winter-only annual failure rate is translated to a cumulative probability over a defined period. Exponent was instructed to assume 67 years (coinciding with the expected service life of the TLSE Project) and a 23-year shortened life sensitivity to 2050.

### 3.2.3 High Cumulative Probability of T-South Winter No-Flow Event

The 2024 Resiliency Plan reflects Exponent's independent expert assessment of the probability of failure for the AVs based on various integrity-related (internal) and external causes. Exponent calculated a very high cumulative probability of a winter no-flow event on the T-South system. This is true regardless of whether the time horizon is the 67-year expected service life of the TLSE Project or the 23-year shortened life (i.e., to 2050) that FEI included as a sensitivity to be responsive to the Adjournment Decision. The 23-year winter-only lower and upper bound failure probabilities of a T-South failure are 65 percent and 97 percent, respectively. These already-high cumulative probability results are still understated as they do not reflect the potential for cyberattacks or other malicous action. Just as the 2018 T-South Incident highlighted FEI's exposure to a T-South supply interruption, there have been two more near-miss events on T-South since FEI filed this Application in 2020.

145.1 Please provide the historical year-by-year record of failure rates for T-South, which have caused loss of supply to customers in the lower mainland since the CTS was developed to supply lower mainland heating.

**Response:**

Only the 2018 T-South Incident has resulted in total loss of supply to FEI's customers. Please refer to the response to BCUC IR1 3.1 for a list of T-South equipment and pipeline failures experienced by Westcoast since 2000, which describes one prior event where a service interruption occurred. A list of T-South failures and service interruptions before 2000 is not available.

Please also refer to Section 3.2.3.2 of the Supplemental Evidence for a description of two additional recent upstream gas supply incidents on T-South.

**146. Reference: Exhibit B-61, pages 8-9**

- The risk posed by a T-South no-flow event in winter will remain significant in the future. Even in a low carbon future under hypothetical extreme load loss scenarios, hundreds of thousands of customers would still experience an outage. The probability of a no-flow event may increase with climate change.

146.1 Please describe the circumstances indicating that the probability of a no-flow event could increase with climate change, and please provide supporting evidence.

**Response:**

**The following response has been provided by Exponent:**

Numerous factors may contribute to changes in the probability of no flow events considering climate change. Several examples are listed below:

- Flooding: compressor stations are vulnerable to flooding. If flood risk changes due to climate change, then the probability of a no flow event will also change. Future flood risk is location-dependent.
- Landslide risk a function of several climate parameters, including precipitation and soil moisture. As precipitation and soil moisture change due to climate change, the landslide risk also changes. Pipelines and stations are both vulnerable to landslides.
- Gas pipeline assets are vulnerable to corrosion and other deterioration mechanisms, which are a function of temperature and precipitation. As temperature and precipitation change due to climate change, the internal failure rate of pipelines will also change.

It is generally expected that more no-flow events will occur when considering climate change because flooding, landslides, and corrosion are likely to accelerate. This will lead to increased overall expected losses, as well as an increased benefit to implementing the Tilbury facility.

146.2 Please confirm that temperature and weather forecasting can be reasonably accurate for a few days in advance.

**Response:**

Weather forecasting from reliable sources (e.g., Environment Canada) have been heavily relied upon to forecast short-term gas load for several decades and have proven to be a highly effective forecasting tool. Further, weather forecasting has become more reliable and accurate over time. These forecasts are used by FEI to provide a 5-day demand forecast for FEI's service areas.

Temperature highs and lows are the biggest driver for changes in FEI's demand each day, while other factors (e.g., wind, cloud cover, weekday versus weekend, etc.) beyond temperature can also impact demand.

FEI's Gas Control and Energy Supply departments work together to daily match supply and demand so that FEI does not materially impact the operational health of the inter-connecting pipelines from which FEI receives supply. This matching process can involve:

1. Making adjustments to supply from inter-connecting pipelines such as T-South when possible;
2. Utilizing line pack on FEI's system;
3. Calling on LNG send-out;
4. Restricting industrial customers to authorized volumes; and
5. Drawing on (or injecting into) off-system storage.

146.3 Please discuss any and all activities in regard to resilience that FEI does in advance based on forecast temperatures, as well as any benefits FEI achieves as a result of using forecast information.

**Response:**

When a cold weather event is forecasted, FEI prepares in advance by executing the following:

- Packing up pipelines prior to the cold weather event arriving.
- Notifying all field support staff of the possibility of moving higher volumes of gas that may require more compression to ensure they are prepared to provide support if required.
- Contacting interconnecting pipeline operators (Enbridge and TC Energy) to discuss high gas demand in the region, discussing any potential issues that may hinder meeting high demand and exploring what can be done (if anything) to mitigate these known concerns if they materialize.
- Notifying FEI's on-system LNG facilities to be prepared for sendout if called upon.
- Restricting industrial customers to authorized gas volumes in accordance with the tariff.
- Temporarily suspending imbalance return through the tariff.
- Suspending and/or curtailing any work that may be underway that affects throughput if possible.

FEI notes that "resilience" is a distinct, albeit related, concept to reliability. While the terms are used interchangeably, they are not synonymous. All of these actions contribute to increased service reliability for customers, but resiliency refers to the ability to prevent, withstand, and recover from system failures or unforeseen events. Please refer to Section 3.2.1 of the Application which addresses this distinction.

**147. Reference: Exhibit B-60, pages 69-70**

The three functioning send-out pumps have experienced a higher-than-normal failure rate over the past three years, including the following failures:

- **August 2020:** Pump "C" was removed, as it was seized. The pump was repaired and reinstalled.
- **November 2021:** Pump "A" seized during cool down. The pump was warmed up, and subsequently cooled down again. The pump unseized and was restarted.
- **December 2022:** The Pump "A" motor experienced high vibrations and subsequent arcing of the windings. As a result, FEI overhauled the pump motor, including rewinding the stator and machining the shaft.

- **August 2023:** Pump "B" had a seal failure which was repaired by the Original Equipment Manufacturer (OEM).
- **November 2023:**
  - Pump "A" had a higher-than-normal oil leak into the pump. In order to remain operational, the oiler required top up approximately every 4 hours to keep the pump running. This has subsequently been repaired.
  - Pump "B" had high bearing temperatures. The pump could only be operated for 15 minutes before it had to be shut down. Repairs to this pump have been completed.
  - Pump "C" seized on cool down due to a faulty temperature probe indicating a temperature higher than actual. In particular, the pump cooled down too quickly, resulting in the pump freezing in place. The pump worked normally after warming and cooling down again.

147.1 Please provide the original expected life of each pump, and the expected life of each pump following the repairs.

**Response:**

The remaining "life" on a pump is limited by the pump component that is most likely to fail, or has the shortest lifespan. For most pumps, including the LNG sendout pumps, the seals are the most vulnerable component, and the most likely to fail, followed closely by the bearings. Before the repairs described in the above preamble, the bearing and seal life could be estimated at 5-10 years. Following repairs, the bearing and seal life remain unchanged at 5-10 years. These estimates are averages and can vary based on the run hours, the number of starts and stops, as well as process upsets.

147.2 Please provide the costs for replacing all pumps with new pumps and adequate operating environments to avoid seized pump conditions.

**Response:**

There are two stages to improving the reliability and availability of the sendout pumps. The first stage is the installation of new pumps, and the second stage is the provision of sufficient isolation valves and associated piping such that each pump can be maintained without taking the other pumps offline. Modifying the piping requires demolition of existing equipment including the piping, pumps and shelter, and replacing with new equipment. Making these modifications would also necessitate de-inventorying and subsequent thermal cycling of the tank. A high level estimated cost for replacing the pumps, piping and shelter is $20 million; however, this does not take into account the uncertainties related to new code requirements above the legacy design. These uncertainties include replacement, or extensive modifications, to the piping near the tank, instrumentation, isolation valves and pearlite insulation. The full impact of warming up and thermal cycling an LNG tank of this age is also unknown. These uncertainties have the possibility to significantly increase the cost beyond $20 million or make the project not feasible from a technical perspective.

In addition, undergoing the above equipment replacements would necessitate having the sendout system offline during all or part of a winter season which carries a high risk to gas supply during the heating season. After resolving issues related to the pumps and piping, the remaining dated equipment in the sendout system, including aging isolation valves and the original (i.e., 1970s vintage) vaporizers, would remain. Failures on the vaporizers in the past four years that have delayed sendout include bath drains corroding through to atmosphere and faulty igniters.

For these reasons, FEI's decision has been to continue to maintain the current system as opposed to replacing the pumps and inlet/outlet piping to each pump.

147.3 Why would FEI not change out pumps that are having problems and avoid risks related to the pumps?

**Response:**

Please refer to the response to CEC IR5 147.2.

**148. Reference: Exhibit B-60, page 54**

3.2.2.2.1 PWC ECONOMIC IMPACT CALCULATIONS MAY BE SIGNIFICANTLY UNDERSTATED

PwC's calculations of economic harm, although already significant, are potentially understated. For instance, PwC assumed there are no impacts from economic sectors where they lacked certain data. PwC also excluded the impact of consequential outages on the Lower Mainland electric system. Technical discussions between FEI and BC Hydro following the 2018 T-South Incident concluded that a widespread gas outage could require rotating electric feeder outages (i.e., brown outs).[90] PwC provided a qualitative evaluation of how the loss of electric service would affect the GDP impact results:[91]

> Natural gas supply outages in B.C. may also place **a strain on the electrical grid** as many households and businesses may seek to substitute the energy provided by gas to that from electricity. At peak hourly demand, B.C. consumes 65 TJ of natural gas, compared to only 37 TJ of electricity, so the ability of the electrical grid to make up for the loss of natural gas is likely to be limited, and attempts to do so may lead to infrastructure damage or the need for mitigation actions such as managed power brownouts to protect the grid. In Appendix 4 we have reviewed literature on other utility outage events with a focus on electrical outages to give

148.1 Please provide the PwC economic harm estimates in two parts, the first for harm caused during the period of LNG support for the natural gas supply and the second for the period of time while recovery of supply is taking place for the relevant customers related to the incurrence of the harm.

**Response:**

**The following response has been provided by PwC:**

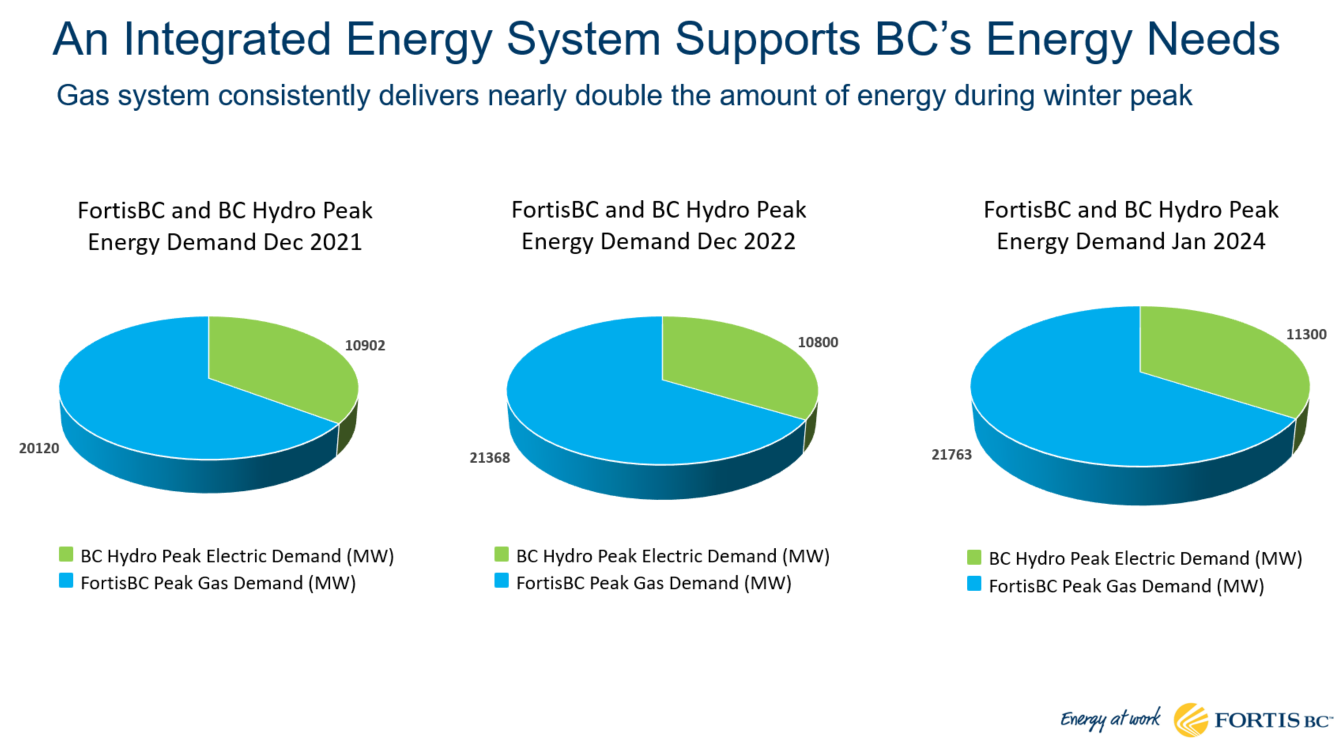
The analysis contained in the updated PwC report considered only the scenario where customer load is not supported following a natural gas supply disruption. If customer load was fully supported by LNG then no economic harm would be expected.

148.2 Please provide the expected capacity and storage of electricity in the lower mainland that could support resilience for the natural gas system outages for each of the years between now and 2050 under scenarios discussed with BC Hydro and using data for any such potential scenarios. (if no such discussions have taken place and or FEI anticipates that there is no such data available based on BC Hydro IRP planning data, please confirm that this is the case).

**Response:**

A study of this nature specific to the Lower Mainland service region has not been conducted. However, on a province-wide basis, published statistics related to recent winter cold-weather events indicate that BC has served record peak capacity over consecutive years with minimal available remaining capacity for export during those cold events, while the gas system delivered close to double the energy of the electric system during those same events. The respective system delivery peaks for these events are presented in Figure 1 below.

**Figure 1: Increasing Gas and Electric Peak Energy Requirements in BC**




For the December 2022 event, BC Hydro reported exports to Alberta of 200 MW against BC's total peak demand of 10,977 MW during the same period.[20] Though FEI cannot confirm how much capacity beyond this might have remained available during each of these events, the outcomes of this extreme weather event and the growing peak energy needs presented in Figure 1, suggest that there is very little available capacity on the electric system in the province, including the Lower Mainland, to provide resiliency support to those customers using the gas system for heating during winter peaks.

[20] BC Hydro Info Bulletin, Jan 14, 2024. BC Hydro meets record breaking electricity demand, helps neighbours

148.3 Please confirm that if FEI has declining customers and UPC as well as rising costs for delivery that its lower loads at peak winter requirements could pose less of an issue for resilience contributions from the BC Hydro electric system and/or the overlapping customers and their resilience options.

**Response:**

Not confirmed. Please refer to the response provided by Ray Mason in BCUC IR5 139.8 which explains that annual demand can decline while peak demand remains high.

Please also refer to: (1) the response to CEC IR5 133.1 for a discussion of how the gas system will continue to play a critical role in meeting BC's peak energy demand in the short, medium and long term; (2) the response to Sentinel IR1 97 for a discussion of the energy, capacity and cost that would be required to have BC Hydro's electrical system absorb FEI's annual peak energy loads; and (3) the response to CEC IR5 134.7 which shows that FEI's customer count and load continue to grow at this time.

**149. Reference: Exhibit B-60, page 104**

> All of the Supplemental Alternatives listed in the table below reflect a **planning view**, which means that they treat stored LNG as being available on a dependable basis for a single planned purpose, since it will not be dependable for any purpose if it is allocated to (or planned for) multiple purposes. This is the typical basis of utility planning, and FEI considers it should be used for the reasons described in Section 4 of Appendix C to this Supplemental Evidence.

149.1 Please confirm that alternative uses of the stored LNG can be allocated to multiple uses when shaped to the requirements for much lower loads at different times of the year and when LNG replacement is possible in short term, during low LNG requirements for resilience support (i.e. resilience requirements are not uniform across the year).

**<u>Response:</u>**

Not confirmed.

FEI would maintain the TLSE Project's 2 Bcf resiliency reserve across the year. Should an incident occur in non-winter months where T-South natural gas flow is curtailed or halted entirely, the resiliency reserve would continue to be an invaluable resource, providing system resiliency for longer periods than during the winter. Customers using natural gas for water heating, food production, or other industrial applications would directly benefit from the prolonged outage support provided by the TLSE Project.

The 1 Bcf reserved for gas supply will be an extremely valuable asset in handling the coldest and peak days of the winter or for emergency situations. During non-winter months, the 1 Bcf gas supply portion of the TLSE Project tank would be refilled and will remain stored until it is required for maintenance, other operational needs or an emergency situation. However, from a planning perspective, FEI intends for the portion of the TLSE Project reserved for gas supply to be full and ready to serve peak demand prior to the commencement of winter.

**150. Reference: Exhibit B-60, page 194 and 195**

> The updated base capital cost estimate is $731.067 million in 2023 dollars (before contingency, deferred costs and financing costs), which is an approximate 38 percent increase from the original base capital cost estimate of $529.103 million. The difference between the original and the updated base capital cost estimate is primarily due to inflationary increases in material and equipment costs and, to a lesser extent, increased labour costs consistent with the increases experienced across the industry since 2020 when the original estimate was completed. Please refer to Confidential Appendix G to this Supplemental Evidence for the updated summary of the total base capital cost estimate for the Project.

**Table 6-1: Breakdown of the TLSE Project Cost Estimate ($ millions)**

| | 2023 $ | As-Spent $ |
|---|---|---|
| LNG Tank (3 BCF) | 359.749 | 423.480 |
| Regasification Equipment | 141.483 | 166.547 |
| Ground Improvement | 60.944 | 71.740 |
| Auxiliary System | 153.964 | 181.239 |
| Base Plant Demolition | 14.927 | 17.571 |
| Subtotal Capital Cost | 731.067 | 860.578 |
| Contingency | 135.800 | 160.749 |
| Subtotal Project Capital Costs w/ Contingency | 866.867 | 1,021.327 |
| CPCN Application | 4.945 | 4.945 |
| CPCN Preliminary Stage Development | 1.546 | 1.546 |
| Subtotal w/ Deferral Costs | 873.358 | 1,027.818 |
| AFUDC | - | 120.096 |
| Tax Offset | - | (4.025) |
| ***TOTAL Project Cost*** | ***873.358*** | ***1,143.889*** |

150.1 Please provide a comparison of this Table with the equivalent table in the original application.

**<u>Response:</u>**

Please refer to the response to BCOAPO IR5 4.2.

**151. Reference: Exhibit B-60, page 194**

> - **Updated contingency:** For the updated contingency, based on the updated quantitative risk analysis, a total capital budget at a P50 confidence level was recommended by Validation Estimating, resulting in a contingency estimate of $135.800 million in 2023 dollars, which is approximately 19 percent of the updated base capital cost estimate. No specific management reserve was recommended by Validation Estimating. Please refer to Confidential Appendix I to this Supplemental Evidence for the updated Validation Estimating Contingency Report.
> - **Updated escalation, now based on P70:** The original escalation was performed based on a P50 confidence level. For the updated escalation, based on the updated escalation risk analysis completed by Validation Estimating, FEI is now applying a P70 escalation value of $154.460 million. Validation Estimating recommended a higher (P70) confidence level for escalation in consideration that the scale of the TLSE Project could put significant demands on local markets that would generate localized escalation. Further, the current base price forecast by S&P Global (formerly IHS Markit) is showing a trend of low prices through 2026, likely reflecting a combination of reduced steel prices and reduced industry capital spending in BC. However, from a pricing risk perspective, a low base forecast means the risk is high should there be a resurgence of inflation and/or competing capital spending, thus emphasizing the need to consider a higher confidence level (e.g., P70) when budgeting for escalation. Please refer to Confidential Appendix J to this Supplemental Evidence for the Validation Estimating Escalation Report.

151.1 Please provide the rationale for the contingency being set at a P50 level, when the escalation was increased to P70.

<u>**Response:**</u>

There is no requirement that the percentiles of confidence selected for contingency and escalation have to be equal. FEI's assignment of a P50 level of confidence for contingency and P70 level of confidence for escalation is consistent with AACE definitions of contingency and escalation, aligns with the industry best practices, and is based on the recommendations of a leading industry expert (Validation Estimating).

As noted in Section 6.1.1 of the Supplemental Evidence, FEI engaged Validation Estimating to conduct a risk analysis, and to develop contingency and escalation estimates. The analysis and/or assessments to support the selection of confidence levels individually for contingency and escalation are included in Confidential Appendices I and J, respectively, of the Supplemental Evidence.

In summary, the rationale for selecting P50 for contingency and P70 for escalation are as follows:

- ***Contingency:***
  - Validation Estimating noted that the P50 contingency would cover the worst-case of all risk event occurrences except soils (which Validation Estimating assigned a

percentage for soil problems to be approximately 4 percent of the Total Expected Value); and

- Given Validation Estimating's recommendation of low probability for soil related issues, FEI agreed with the recommendation of a P50 confidence level for contingency.

- ***Escalation:***
  - Validation Estimating recommended a higher (P70) confidence level for escalation in consideration that the scale of the TLSE Project could put significant demands on local markets that would generate localized escalation;
  - The current base price forecast by S&P Global (formerly IHS Markit) is showing a trend of low prices through 2026, likely reflecting a combination of reduced steel prices and reduced industry capital spending in BC; and
  - From a pricing risk perspective, a low base forecast means the risk is high should there be a resurgence of inflation and/or competing capital spending, thus emphasizing the need to consider a higher confidence level (e.g., P70) for escalation.

151.2 Please discuss the likelihood and risks of cost escalation arising from the current threat of 25% tariffs from the US and/or Canadian government.

**Response:**

Please refer to the response to BCSEA IR5 23.1.

**152. Reference: Exhibit B-60, page 200**

> **6.2.3 Importance of Recognizing Avoided Gas Supply Costs**
>
> In preparing the updated financial evaluation of the Preferred Alternative (3 Bcf of LNG storage capacity and 800 MMcf/d of regasification), FEI has also included the gas supply benefits that were discussed in Section 4.5.4.1.2 of the Supplemental Evidence as avoided costs.
>
> These avoided costs are related to the "third Bcf" allocated for planning purposes to gas supply (i.e., not the 2 Bcf resiliency reserve) and the associated increased regasification capacity. As highlighted in Section 4.5.4.1.2 of this Supplemental Evidence, FEI has estimated the avoided costs to be approximately $7 million (post mitigation) between 2030 and 2035. The avoided costs are based on the assumptions that peaking gas supply ceases to be available from Tilbury (when the existing Base Plant ceases operation due to its age and Tilbury 1A is fully subscribed through RS 46) and that third party regional pipeline or storage upgrades will not be completed until at least 2035. From 2035 onwards, FEI estimated the avoided costs to be between approximately $63 million and $79 million annually, as shown in Figure 4-7 of this Supplemental Evidence, reflecting the gas supply costs that FEI would incur by relying on regional infrastructure under the Base Case Scenario (i.e., Supplemental Alternative 1). For the financial analysis, FEI has used the lower bound of gas supply costs of $63 million.
>
> FEI discussed the gas supply benefits in the Application, as well as throughout the regulatory process prior to the Adjournment Decision; however, the original financial evaluation in the Application did not include the benefits of avoided costs, as the focus at that time was on the delivery rate impact only. FEI considers it reasonable and appropriate to include the gas supply benefits in the updated financial evaluation as part of this Supplemental Evidence to provide a more fulsome evaluation of the Preferred Alternative's total impact on customer bills, including both delivery rates and cost of gas.

152.1 Please provide a discussion of how the expected energy transition can affect the availability and cost of gas over the next thirty years and specifically address less use of lower cost gas available as the US is turning to Peaking Gas Plants. What is the future forecast for cost of gas supply to FEI and its customers for the period 2025 to 2050?

**Response:**

**The following response has been provided by Ray Mason:**

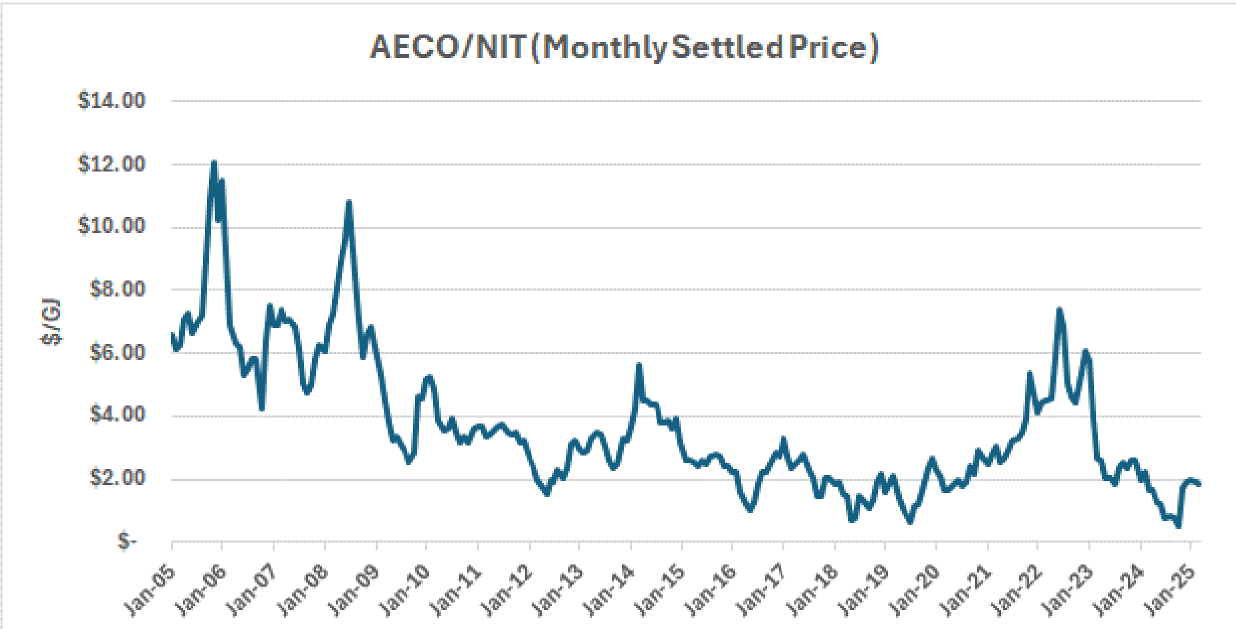
Please refer to my response to BCUC IR5 129.5, in which I discuss my expectation for the gas market conditions over the lifespan of the TLSE Project.

**FEI also provides the following response:**

The energy transition is just one factor that can have an influence on supply/demand dynamics and thus an impact on gas costs over time. The following discussion presents a number of other factors that will also influence the cost of gas. Ultimately, natural gas, and FEI's provision of it, has an important role to play in the energy transition. This includes providing safe, reliable cost-effective energy supply to customers while lowering carbon emissions, including supplying peak energy needs to homes and businesses. As such, FEI anticipates that gas costs will continue to fluctuate up and down, similar to historic trends, as all of these factors impact the supply/demand dynamic in different ways and at different times over the next 20 to 30 years.

While FEI does not forecast natural gas prices, the cost of gas has fluctuated (higher and lower) based on supply and demand dynamics over the last 20 years. The following figure shows AECO/NIT prices between 2005 and 2025 and illustrates the volatility in natural gas commodity prices. FEI expects that there will continue to be up and down movements in gas costs.

**Figure 1: Historical Monthly Settled AECO/NIT Prices**[21]




FEI selected the AECO/NIT monthly settled price as an indicator of the price of gas[22] (i.e., commodity) that FEI buys for its customers through the ACP as it has the greatest impact on the commodity rates for FEI's customers.

A number of drivers will influence supply/demand fundamentals over time, resulting in impacts to the cost of gas for customers. At a macro level, these drivers include: (1) production (and the cost to develop or produce the natural gas); (2) infrastructure (i.e., the cost to move the gas from the supply basin to FEI's service regions); and (3) demand from increasing power generation in North America and LNG exports from North America. FEI addresses each of these drivers below.

### *1. Production*

Due to the abundance of low-cost natural gas supply in northeast BC, FEI considers that the energy transition will have little to no impact on the availability of natural gas if the economics for production are viable for producers.

[21] GLJ (January 2025). "Current Commodity Price Forecast."

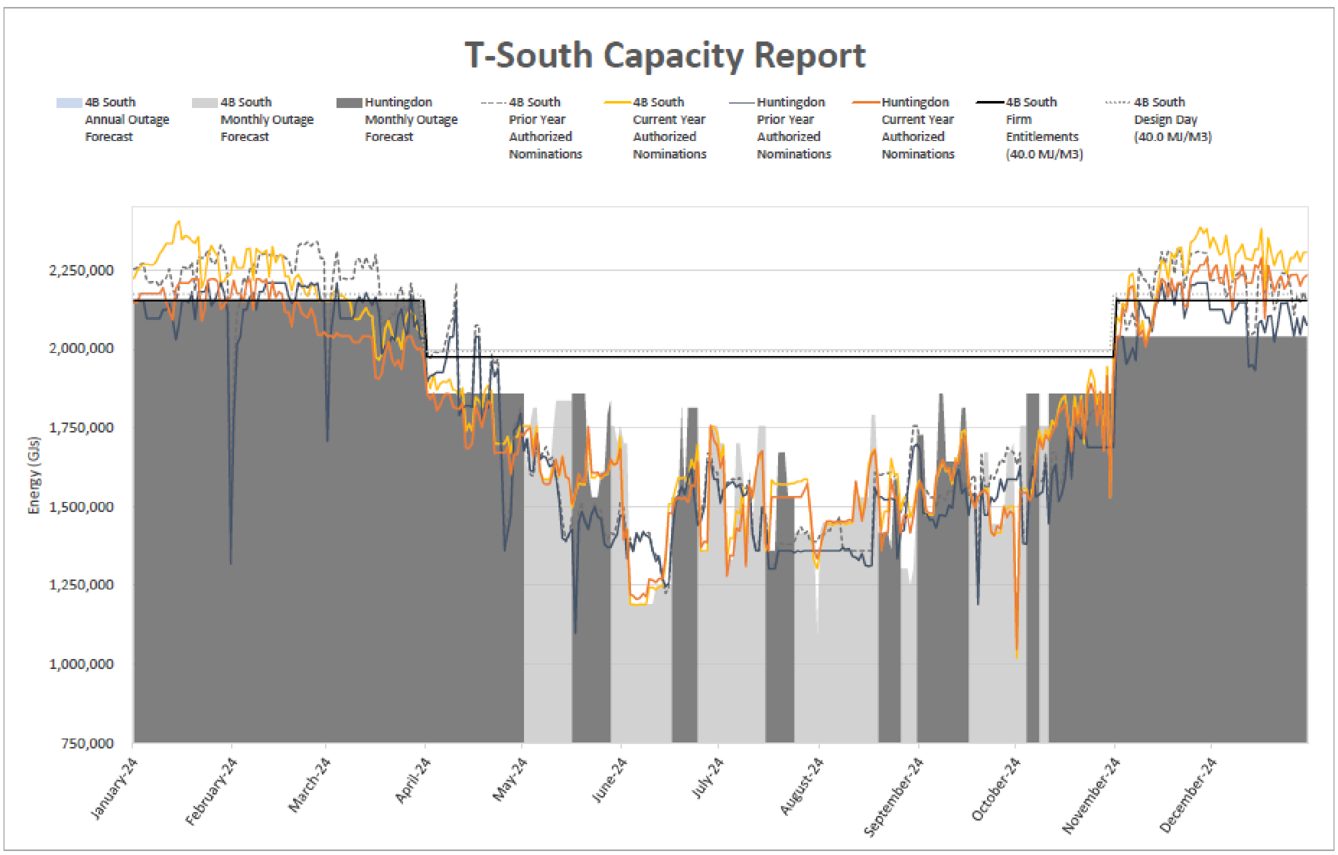
[22] While FEI purchases a significant amount of gas at Station 2, approximately 60 percent of FEI's term supply at Station 2 is priced off the AECO/NIT monthly index.

At the end of 2022, the estimated potential recoverable, sales-quality natural gas in BC was estimated to be 663 Trillion Cubic Feet (Tcf),[23] and with increasing demand for LNG exports from BC, natural gas demand remains strong.

### *2. Infrastructure*

Based on where the natural gas supply is located in BC, it requires growing infrastructure to bring the supply to the major demand centers (the Lower Mainland, Seattle and Portland) in the Pacific Northwest. The lack of infrastructure to flow natural gas to these demand centers continues to be an ongoing issue. This was more evident during the start of Winter 2024/25 when temperatures in November and December were well-above normal, yet the Westcoast T-South pipeline was flowing above firm capacity for most of the days to help meet increasing demand in the West side of North America. This can be seen in the figure below that shows the daily nominations being above the total firm capacity of the pipeline.

**Figure 2: T-South Capacity Report**[24]




[23] CER (November 2024). "Provincial and Territorial Energy Profiles – British Columbia."

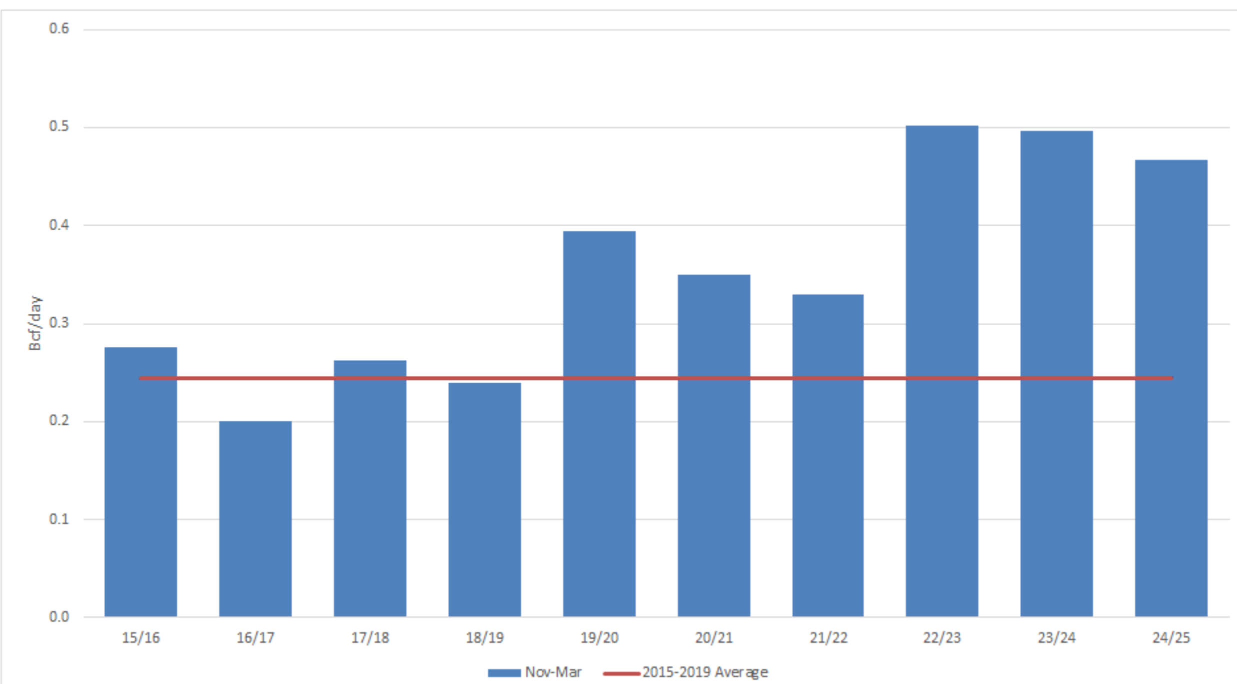
[24] Source: https://noms.wei-pipeline.com/notice/display/launch.php (December 2024 T-South Capacity Report, January 7, 2025). This figure contains forward-looking information including projections relating to current and/or future operations and capacity which may or may not occur. Enbridge makes no warranties as to the accuracy of the information and the recipient of this information should not place any reliance on this information. Enbridge is not liable for any damages sustained by reason of use of or reliance on such information.

This movement of gas on Westcoast T-South suggests that there is already a need for more infrastructure to connect the supply basin (AECO/Station 2) to the existing demand centers and this will be more important as demand increases due to new power plants that use natural gas to generate electricity in the load centers. The cost of these new pipeline additions is considerably higher than the current embedded transportation tolls of the pipeline grid and thus will impact the cost of gas over time.

### *3. Demand*

Figure 3 below provides the daily demand from the natural gas-fired generators that are directly tied to Williams' Northwest Pipeline. Historically, these gas-fired generators would generally purchase their gas supply at the Huntingdon/Sumas market and would only run on colder-than-normal days during the winter, with the ability to shut off when no longer needed to meet demand on peak (cold) days. This practice has fundamentally changed. Figure 3 shows that for the past three winter seasons, demand from these natural gas-fired generators averaged 245 MMcf/d higher than the 5-year average between 2016 and 2020, and that they operated at or near maximum capacity on a daily basis throughout the entire winter period. The incremental 245 MMcf/d coming from the natural gas-fired generation is approximately 33 Bcf over a 151-day winter season. This is a larger volume than what Jackson Prairie (25 Bcf) or Mist (19 Bcf) storage facilities could offer on their own. These developments have not only put a strain on peaking resources, but also on baseload and storage resources during the winter period. The issue has been compounded by the lack of development of additional infrastructure to meet this incremental demand.

**Figure 3: Natural Gas for Power Generation on Northwest Pipeline (Winter Averages in Bcf/Day)**



FEI does not expect the reliance on natural gas power generation to change any time soon. A recent NERC report concluded that Western North America is currently at an elevated risk of having insufficient capacity available and energy from resources during extreme and prolonged weather events.[25] Around the same time that this report was released, an assessment from the Western Electricity Coordinating Council (WECC) concluded that Western North America was not prepared to meet the rapidly increasing demand in the region over the next 10 years.[26] Currently, the only additions of new capacity are from renewable resources, which, are intermittent sources of energy. Given the increasing use of gas-fired power generation, FEI believes that natural gas can continue to play a critical role in the direct use of energy consumed by customers.

North American LNG exports also continue to provide the most significant demand growth for natural gas in the future. For example, LNG Canada is expected to ship its first cargo during Q2 of 2025 and reach full capacity by the end of the year, while the Woodfibre and Cedar LNG projects are expected to begin exports in 2027 and 2028, respectively. These projects in BC will add approximately 3 Bcf/day of demand by 2028; potentially increasing over the next 10 years with the addition of Phase 2 of the LNG Canada project. This increased demand could have impacts on the cost of gas if there is a mismatch between when the demand arrives and when the increased production is online to meet the demand.

In summary, natural gas will play an important role in the energy transition and the ultimate cost of gas to customers will be impacted by how the market unfolds over time given the market factors described above.

[25] NERC (December 2023). “2023 Long-Term Reliability Assessment.”
[26] Western Energy Electricity Coordinating Council (November 2023). “Western Assessment of Resource Adequacy.”

**153. Reference: Exhibit B-60, pages 201-202**

- **Incremental Sustainment Capital for Mechanical Equipment:** FEI continued to use an average of 1 percent per year of the revised mechanical equipment capital expenditures (LNG tank, regasification equipment, auxiliary equipment) in this Supplemental Evidence as an estimate of incremental sustainment capital due to the Project. As explained in

Section 6.3 of the Application, this assumption was developed by PiP based on the industry benchmark of similar operations and interviews with third party industry experts.[252] This benchmark applies to the capital cost of the mechanical equipment only, which does not include other indirect costs such as mobilization, engineering, contingency, etc.

153.1 Where are the indirect costs for incremental sustainment capital for mechanical equipment, such as 'mobilization, engineering and contingency' incorporated into the analysis? Please provide the evidence and explain how it was derived.

153.1.1 If it is not included, please explain why not.

**Response:**

FEI clarifies that the indirect costs such as mobilization, engineering, and contingency are incorporated into the financial analysis of the TLSE Project as part of the total Project costs (i.e., $1,143.889 million in Table 6-1 of the Supplemental Evidence). However, these indirect costs are not used to estimate future sustainment capital costs related to the TLSE Project, as further explained below.

The 1 percent per year is a proxy to estimate future sustainment capital costs related to the TLSE Project and is applied to the total capital cost of the mechanical equipment. The approach was recommended by Partners in Performance (PiP) based on industry benchmarks of similar operations and interviews with third party industry experts, and the intent is to provide a comprehensive financial analysis of the Project over the expected life of the assets. The statement on page 202 of the Supplemental Evidence is highlighting that the estimated future sustainment capital is only based on the total cost of the mechanical equipment. The 1 percent is not applied to the total indirect costs such as mobilization, engineering, and contingency because there is no specific future sustainment work required for these costs.

FEI further notes that the sustainment capital included in the financial analysis is not the actual sustainment capital plan for the proposed TLSE Project. FEI is not requesting approval of the sustainment capital included in the financial analysis as part of the TLSE Project.

**154. Reference: Exhibit B-60, pages 202-203**

### 6.3 UPDATED RATE IMPACT FOR THE PREFERRED ALTERNATIVE

The incremental delivery rate impact from 2026 to 2031 includes the amortization from the Application and Preliminary Stage Development Costs deferral account between 2026 and 2028, as discussed in Section 6.1.2.2 above, and the incremental impact of the capital costs which will enter FEI's rate base in phases between 2028 and 2031, as shown in Table 6-2 above.

The updated incremental delivery rate impact due to the Project is summarized as follows:

- Based on the updated capital cost estimate in Section 6.1.2 above, the Preferred Alternative will result in a cumulative incremental delivery rate impact of 11.03 percent by 2031 when compared to FEI's 2024 approved delivery rates.
- The year-over-year increase in delivery rate is shown in Table 6-5 below, with an average incremental delivery rate impact per year of approximately 1.78 percent over the six-year period from 2026 to 2031 when compared to FEI's 2024 approved delivery rates.

**Table 6-5: Summary of Delivery Rate Impact for the TLSE Project**

| | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|
| Annual Delivery Margin, Incremental to 2026 Approved, Non-Bypass ($ millions) | 1.328 | 1.456 | 13.834 | 33.280 | 54.792 | 125.920 |
| ***% Increase to 2026 Approved Delivery Margin, Non-bypass*** | ***0.12%*** | ***0.13%*** | ***1.21%*** | ***2.92%*** | ***4.80%*** | ***11.03%*** |
| ***Incremental % Delivery Rate Impact (Year-over-Year)*** | ***0.12%*** | ***0.01%*** | ***1.08%*** | ***1.68%*** | ***1.83%*** | ***5.95%*** |

However, when accounting for the cost of gas savings starting from 2031 (as discussed in Section 6.2.3 above) in addition to the incremental delivery rate impact from 2026 to 2031, the levelized total rate impact (levelized total bill impact) over the 67-year analysis period due to the Project is 2.45 percent or $0.228 per GJ. For the typical residential customer with an average annual consumption of 90 GJ, this is equivalent to a bill impact of approximately $20.55 per year over the 67-year analysis period.

154.1 Please provide the expected range of bill impacts for commercial customers.

**<u>Response:</u>**

Please refer to Table 1 below which provides the average bill impact per year for FEI's customers in Rate Schedules 1 to 7 based on the levelized total rate impact of $0.228 per GJ over the 67-years analysis period (as shown in Table 6-4 of the Supplemental Evidence). FEI has excluded transportation customers as FEI does not have insight into their total bill including their commodity charges.

**Table 1: Average Bill Impact Per Year Over 67-year Analysis Period by Rate Schedule**

| Average Bill Impact ($) | Avg. Use per Customer (UPC) in GJ | TLSE Project |
|---|---|---|
| Levelized Total Rate Impact (67-years), $/GJ | | $ 0.228 |
| Residential | | |
| Rate Schedule 1 | 90.0 | $ 20.55 |
| Commercial | | |
| Rate Schedule 2 | 324.8 | $ 74.17 |
| Rate Schedule 3 | 3,628.9 | $ 828.59 |
| Industrial | | |
| Rate Schedule 4 | 9,477.8 | $ 2,164.05 |
| Rate Schedule 5 | 18,940.9 | $ 4,324.76 |
| Rate Schedule 6 | 1,136.8 | $ 259.57 |
| Rate Schedule 7 | 132,620.3 | $ 30,281.01 |

154.2 Please provide the expected range of bill impacts for industrial customers.

**Response:**

Please refer to the response to CEC IR5 154.1.

154.3 Please provide FEI's rates of elasticity response to rate increases for each rate class, and please discuss when this elasticity measure was determined, and if it reflects current information related to the energy transition

**Response:**

Historically, FEI has relied on price elasticity studies conducted by reputable independent research entities for its elasticity estimates, rather than conducting its own FEI-specific price elasticity studies. The review of published elasticity studies indicates that although price elasticity estimates may change slightly by jurisdiction and over time, these variances do not change the overall conclusion that the majority of natural gas customers are price inelastic. There is no reason to expect that conducting an FEI-specific study would lead to a different conclusion.

FEI also notes that the price elasticity simply reflects the relationship between price changes and demand changes, and the factors influencing any price changes (energy transition related or not) do not necessarily impact the end results/conclusion. Further, as explained in the response to CEC IR5 134.5, non-price factors, such as the policies adopted by various levels of government to address the energy transition, may have a greater impact on long-term demand than the market driven price changes.