Sarah Walsh
Director, Regulatory Affairs

Gas Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

Electric Regulatory Affairs Correspondence
Email: electricity.regulatory.affairs@fortisbc.com

FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (778) 578-3861
Cell: (604) 230-7874
Fax: (604) 576-7074
www.fortisbc.com

May 22, 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. 6

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. 6.

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

155. Reference: Exhibit B-66, CEC 5.133.1 and B-63 BCUC 5.124.2, 5.124.3.1

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.

Response:

FEI and BC Hydro have not formally coordinated to assess the potential for cascading failures between the gas and electric systems in the Lower Mainland, and have not developed specific scenarios in which a gas outage could result in brown outs. FEI does not have the ability to perform that analysis unilaterally, given that it would need detailed technical information on the characteristics of BC Hydro's distribution system.

155.1 In BCUC 5.124.2, FEI states that FEI and BC Hydro have not formally coordinated to assess the potential for cascading failures between the gas and electric systems in the Lower Mainland and redacts the remainder of its response. Please explain whether FEI has made any attempt to discuss the possibility of planning for a coordinated response with BC Hydro (or other electricity provider) to a winter no-flow event and provide documentation of the details of any such communications.

Response:

As explained in the responses to BCUC IR5 124.2 and 124.3, a Non-Disclosure Agreement with BC Hydro precludes FEI from providing a public response regarding its discussions with BC Hydro in this regard.

As demonstrated by the analysis provided in both the Supplemental Evidence and FEI's 2024 Resiliency Plan, absent the TLSE Project, a winter T-South no-flow event lasting only a matter of hours will, without question, have catastrophic consequences (i.e., hundreds of thousands of customers in the Lower Mainland losing service for many weeks) and represents a significant resiliency risk to FEI's system. FEI considers that such consequences and the probability-adjusted risk, in and of themselves, support the need for the TLSE Project without quantifying the cascading impacts on the electric system. The potential for cascading failures between the gas and electric systems only strengthens the associated Project need.

155.2 FEI indicates that BC Hydro does not have the capacity or ramp up capability to take on FEI's winter heating requirements. Please provide an FEI estimate of the proportion of heating requirements that BC Hydro, possibly in coordination with other electricity providers, could potentially take on under selected realistic no flow circumstances (i.e., vary on duration, winter temp etc.), and please provide the basis for these estimates.

155.2.1 Please also provide a discussion, with quantification, of the potential reduction in LNG that would be required if BC Hydro were able to take on a portion of FEI's heating and other requirements, if the disruption event occurred at times not coincident with the winter peak and also if the disruption occurs at the winter peak event but the winter peak at that time is below the BC Hydro design peak capabilities at the time.

Response:

FEI is unable to provide the requested analysis. It is not possible to estimate the extent that BC Hydro's system can respond without detailed engineering analysis of their electric system. The extent of the support provided depends on the capacity of local distribution systems, the capacity of all of the transmission infrastructure that delivers the electricity to the affected areas, and the available generation capacity. Understanding how all of the components work together requires sophisticated system modelling capabilities.

The premise of the question is also flawed, as the large volume of gaseous energy needed for space and water heating during a cold winter day far exceeds the current BC Hydro system capability[1] and there are no tools available to control electric customers' use of alternative electric devices such as portable space heaters, electric hot water tanks, and electric hot plates, even if they could be sourced, in excess of the available capacity of the BC Hydro system. As such, designing the TLSE Project such that it relies on an uncontrolled switch to electric appliances would endanger both systems – there would be greater potential for electrical shortages and the TLSE Project would be undersized to respond to a winter T-South no-flow event.

[1] For example, footnote 5 in the response to MS2S IR1 4.iii provides the following comparison of peak demand: "On January 14, 2020, the peak volume of gas delivered between 7:00 a.m. and 8:00 a.m. was equivalent to over 18,000 MW of electrical generating capacity, approximately 60% greater than the peak on the electric system during the same day and 50% larger than the entire hydroelectric generating capacity owned by BC Hydro (11,900 MW)." The figure provided in the response to CEC IR5 148.2 compares the winter peak demand from the past three years, which reached 21,763 MW on the gas system and 11,300 MW on the electric system in January 2024.

Please refer to the responses to CEC Confidential IR1 69.1 and MS2S IR1 4.iii for further information regarding the amount of equivalent capacity delivered by the gas system during a cold day and the challenges of using the electric system as an alternate source of energy during a no-flow event.

155.3 In the event BC Hydro agreed to cooperate or was ordered to cooperate with FEI, could BC Hydro customers be encouraged and/or required to reduce their usage to accommodate non-discretionary heating or other services during an FEI winter no flow event? Please explain why or why not.

155.3.1 If FEI has not had any such discussions with BC Hydro, please explain why not.

155.3.1.1 Please provide the estimated time that would be required for FEI to have such discussions and organize such planning with BC Hydro.

Response:

As explained in Section 3.2.2.1.2 of the Supplemental Evidence, absent the TLSE Project, all of the Lower Mainland will lose natural gas supply within hours of a winter T-South no-flow event. Therefore, even if the BC Hydro system had the capability to accommodate a large portion of FEI's winter heating load and FEI's customers could switch from a gas to an electric heat source, FEI would not be able to reduce gas demand sufficiently quickly and to an extent that would prevent a system shutdown because shifting winter heating load will likely take much longer than a few hours to preserve FEI's system.

With the TLSE Project in place, FEI will have additional time to respond to a winter T-South no-flow event, including the potential for voluntary curtailment to have a real impact in delaying or limiting the impacts on both the gas and electric systems. However, as discussed in the responses to BCUC IR1 13.3 and 19.2, it is important to recognize the limits of voluntary curtailment even when there is sufficient time to respond to a no-flow event. FEI's experience during the 2018 T-South Incident demonstrates the practical limits of voluntary curtailments. In particular, curtailing and making public appeals to reduce consumption only reduced expected natural gas demand by approximately 20 percent on the first day of the 2018 T-South Incident and, even so, customers quickly reverted back to their previous energy consumption patterns.[2] FEI expects that the same would likely be the case, both in the context of BC Hydro's customers reducing their electricity usage and, importantly, FEI's customers shifting from gas to electric heating in a timely manner.

[2] Exhibit B-15, BCUC IR1 13.3.

BC Hydro and FEI have a history of working together, including during the 2018 T-South Incident when BC Hydro scaled back its use of natural gas.[3] BC Hydro is aware of this Application, the 2024 Resiliency Plan, and FEI's assessment of the scope and scale of a natural gas outage. FEI has every reason to expect that cooperation would continue with BC Hydro.

3 As discussed in the response to BCUC IR5 124.2.

156. Reference: Exhibit B-66, CEC 5.133.1 and excerpt from CEC 5.144.6

> 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

> 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.

156.1 Please confirm that individuals and businesses frequently adopt measures to address energy supply risk, such as in locations where energy supply is known to be subject to risk of disruption.

<u>Response:</u>

In FEI's experience, in locations where energy supply is known to be subject to risk of disruption, it is generally natural gas (not electricity) that tends to be the back-up to address energy supply risk. For residential customers, the risk of electricity disruption is generally mitigated with natural gas fireplaces and cooktops that are able to operate when electric outages occur. More recently, some commercial customers have installed back-up natural gas generators or, in some cases, combined heat and power (CHP) units to mitigate the risk of electricity disruptions.

156.2 Please confirm that there is no regulatory, legal or other prohibition for customers to contribute to mitigating very low likelihood resiliency risk.

<u>Response:</u>

FEI disagrees with CEC's statement that resiliency risk associated with a winter T-South no-flow event has a "very low likelihood". As set out in the response to BCUC IR5 126.1, the cumulative probability of such an event is between 93 and 100 percent over the expected service life of the TLSE Project.

FEI is unable to say with certainty whether regulatory, legal or other prohibitions would prevent customers from contributing to mitigating resiliency risk. FEI agrees that there is no legal impediment to customers buying a space heater or blankets, for instance. However, more complex solutions, like permanent back-up energy systems (i.e., redundancy), may be subject to regulations or laws that prevent or restrict their installation.

Even assuming all potential mitigations were allowable, FEI considers that there would be practical limitations to what customers would be able to achieve in terms of risk reduction. As noted in the preamble, even CEC's suggested approach of purchasing electric heaters would be unrealistic in practice given the scale of the impact a winter T-South no-flow event would have on the Lower Mainland. Ultimately, FEI does not consider relying on customers to adopt their own mitigation measures to mitigate upstream supply risk to be reasonable or realistic.

Please also refer to the responses to CEC IR6 155.2, 156.3 and 156.4.

156.3 Please provide the expected cost of portable stand-by heating equipment, or other appropriate equipment, that would be sufficient for a selection of residential customers (e.g., average apartment, single family home etc.) to remain safe during a winter, design day no flow event, and please provide the basis for the cost estimates.

Response:

FEI does not have sufficient information to properly size and cost out portable stand-by heating equipment for residential (or commercial) customers to remain safe during a winter, design day, no-flow event. Such an estimate would likely be meaningless in any event given the significant variability in the heating needs of these customers driven by differences in building vintage, method, characteristics (i.e., multi vs. single family), building code requirements, energy efficiency measure uptake, location, wind and weather exposure, and elevation, among other factors. Even if customers were able to access and purchase portable electric heating systems, the portable system would more than likely be inadequate to keep a home safe, warm and free from damage (i.e., keep pipes from freezing) during an extended outage in the winter. Additionally, using multiple portable heaters in a multi-unit residential building could increase the risk of an electrical system failure if the system was not engineered to accommodate the substantial electric load of the building residents using those heaters.

Ultimately, FEI considers relying on portable electric heaters to heat homes designed to be heated with gas is not feasible, including during a winter, design day, no-flow event.

Please also refer to the response to CEC IR6 155.2 regarding the feasibility of using the electric system as an alternate source of energy during a no-flow event.

156.4 Please address all the ways in which joint FEI and BC Hydro customers could proactively prepare for the winter no flow events (relevant to this proceeding) with stand-by portable heating units and/or any other appropriate emergency heating equipment or methods.

Response:

FEI disagrees with the premise of the question that in the event of a sudden, wide-scale gas outage during the winter season that large numbers of gas customers could use portable stand-by heating equipment without dire consequences to the electric system.

FEI does not have the information to be able to determine all the ways joint FEI and BC Hydro customers could prepare for winter no-flow events; however, in order to be responsive, FEI provides an overall assessment of relying on customers to proactively prepare for such events.

While joint FEI and BC Hydro customers could proactively prepare for winter no-flow events by purchasing backup systems for space heating, water heating and cooking (whether electric or propane-powered, or utilizing some other fuel source), FEI considers that relying on customers is not a reasonable approach and could lead to negative outcomes for the following reasons.

- First, not all customers will purchase, or be in a position to purchase, back-up energy systems. As noted in the preamble, in FEI's experience, residential customers do not have back-up energy systems nor do they plan for, or expect, prolonged energy outages. Therefore, relying on customers to do so would require a significant change in customer behaviour and, in any event, would likely lead to a patchwork of preparedness. This would likely be particularly acute for low-income and other marginalized communities.
- Second, relying on customers to proactively prepare for a winter no-flow event would create challenges for FEI from a planning perspective. FEI has limited information regarding the back-up systems of its customers, particularly residential customers, which are likely the most vulnerable if such an event were to occur during cold winter conditions. While FEI recognizes that some proportion of customers may be able to rely on back-up systems, FEI cannot plan or prioritize its resiliency investments based on assuming customers have taken proactive steps to prepare for winter no-flow events. This is especially the case given that the Supplemental Evidence demonstrates that, absent the TLSE Project, a winter T-South no-flow event lasting only a matter of hours will, without question, affect hundreds of thousands of people and have catastrophic consequences. As discussed in the response to CEC IR6 155.2, this could also create challenges for BC Hydro from a planning perspective as BC Hydro would also lack visibility into how many customers purchase back-up electric devices and the tools to manage how many customers use back-up devices during a no-flow event.
- Third, given that the Lower Mainland distribution system would lose pressure within hours during a winter T-South no-flow event, it would not be possible for FEI to communicate

with its approximately 600,000 Lower Mainland customers, and for these customers to switch to their back-up systems.

- Fourth, while Exponent calculated a very high cumulative probability of a winter no-flow event on the T-South system (93 to 100 percent probability over a 60-year time horizon), the timing of such an event is not clear. As such, customers may need to, for example, retain and maintain stand-by portable heating units over an extended period of time. This is likely not realistic over an extended time horizon.
- Fifth, as noted in the PwC Report, even if customers are able to acquire a backup system, the ability of the electrical grid to make up for the loss of natural gas is likely to be limited and may lead to infrastructure damage or the need for mitigation actions such as managed power brownouts to protect the grid.
- Finally, please refer to the response to MS2S IR1 4.iii, CEC IR5 148.2 and CEC IR6 155.2 for a discussion of how much capacity FEI's natural gas system delivers compared to BC Hydro's electric system on cold winter days. It is clear that asking customers to use portable electric heaters as back-up to their gaseous energy systems would overwhelm BC's electricity supply systems, thus worsening the already significant consequences associated with a winter T-South no-flow event.

Ultimately, the Supplemental Evidence demonstrates that, absent the TLSE Project, a winter T-South no-flow event lasting less than a day represents FEI's single largest customer outage risk and, without sufficient alternative supply, would leave FEI's customers without gas for space heating, hot water and cooking. FEI believes it should take reasonable steps to mitigate the risk exposure associated with a winter no-flow event for the benefit of its customers, including with the development of the TLSE Project.

Exponent also provided the following response:

It would not be industry practice for FEI and BC Hydro (as utilities) to rely on its customers to proactively prepare for "no gas flow" winter events. While customer preparedness could be a complementary layer of resilience, the utility has the primary duty to ensure reliable service, have contingency plans, and support vulnerable customers with system-wide emergency planning.

FEI and BC Hydro, as regulated entities, have a responsibility to provide safe and reliable energy to their customers. Relying on customers (to mitigate resiliency risk) would shift the burden of systemic risk mitigation from the utility (which has the expertise and infrastructure) to individual customers, many of whom may not have the knowledge or resources. Not all customers can afford or know how to source appropriate stand-by heating equipment. Vulnerable populations (elderly, low-income, disabled) could face life-threatening situations if the utility assumes personal preparedness will fill the gap. Gas outages could occur on a wide scale (during landslides, earthquake events, etc.). Portable or individual solutions may not scale to meet large scale systemic outages effectively without coordinated and rapid deployment of utility-owned resources. Customers expect utilities to manage such infrastructure risks proactively. Failing to do so and expecting customers to carry this resiliency risk mitigation burden can erode public trust and lead to reputational, legal, and regulatory risks.

It would also be challenging for gas utilities to rely on customers – especially renters – to proactively prepare for “no gas flow” winter events for several key reasons such as frequent tenant turnover and potential for additional human error risks while installing or operating alternative heating methods. Tenants are constantly changing and frequently moving, and new renters may not be informed about prior preparations or emergency procedures. Unlike homeowners, renters are less likely to have long-term investment in maintaining any installed alternative heating methods. Renters often assume that landlords or property managers are responsible for utilities and emergency preparedness. Renters may not receive clear guidance or training from their landlords on what to do during a no flow gas winter event. Even if one tenant prepares (e.g., purchases alternative heating methods), the next tenant may not maintain or even be aware of those measures. In emergencies, renters unfamiliar with the prior installed alternative heating methods may respond poorly, risking injury or property damage.

Relying on renters for proactive preparation would also introduce a discontinuity of knowledge, reduced accountability, and higher risk of safety failures. For these reasons, it would be better for the gas utilities to adapt a more centralized, utility-led approach to preparation and emergency response for such potential “no gas flow” winter events.

157. Reference: Exhibit B-66, CEC 5.134.2 and 5.134.3

> 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.

157.1 Acknowledging the various components of the revenue requirement impact on delivery rates, please elaborate on why FEI appears unable to isolate the impact to the delivery cost from a future load reduction assumption.

Response:

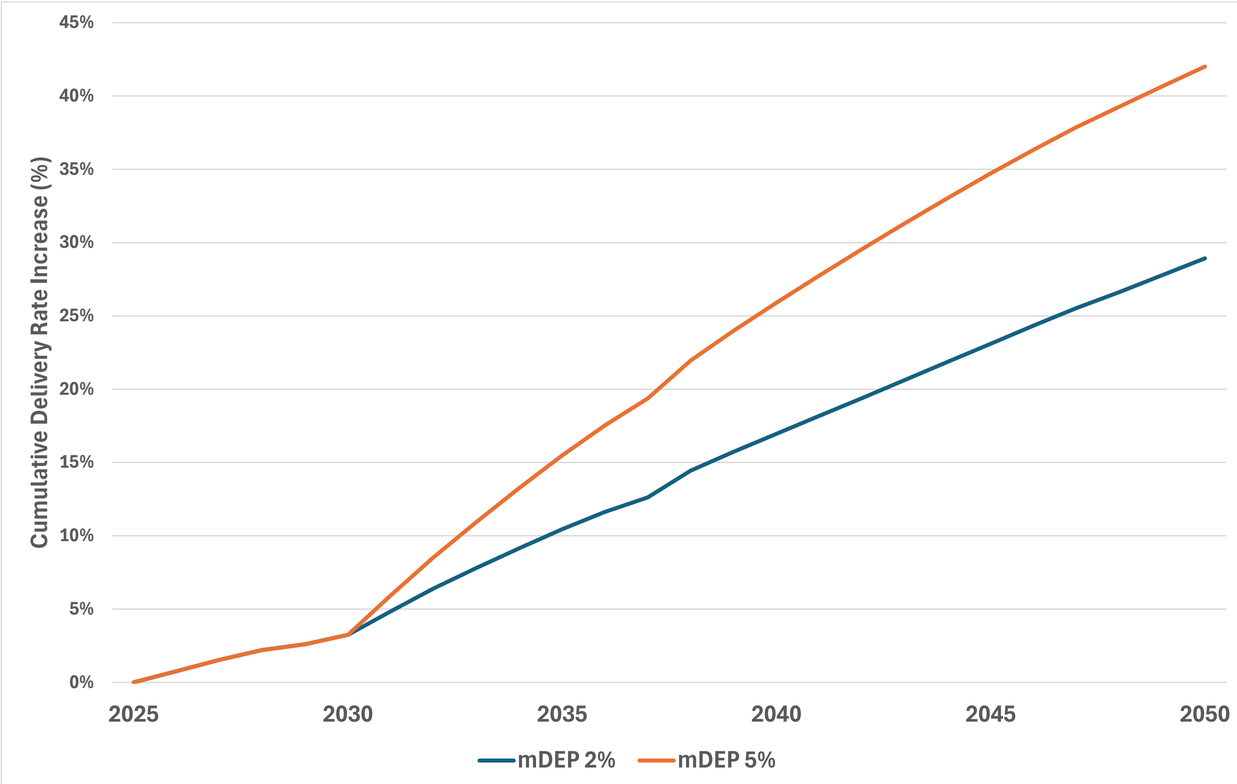
As explained in the response to CEC IR5 134.3, there are various factors beyond FEI's control that could impact FEI's revenue requirement and delivery rates positively or negatively over the next 25 years. These factors could include, among others, government policy (e.g., environmental, tax, etc.), economic circumstances (both regional and global), and the political environment (within BC and Canada, as well as globally), all of which could influence FEI's throughput and operating costs. For example, since FEI's filing of responses to BCUC and Intervener IR5 in this proceeding, the carbon tax on natural gas was eliminated by the Province. The impact of the removal of the carbon tax for an average residential customer is a significant reduction in their total natural gas bill by approximately 24 percent, which is more than double the delivery rate impact (excluding the cost of gas) estimated for the TLSE Project (as shown in Table 6-5 of the Supplemental Evidence). While the elimination of the carbon tax does not impact FEI's delivery rates, this is an example of an unanticipated (and quickly implemented) change in government policy.

Depending on a variety of factors, there are many different load throughput scenarios over the next 25 years, ranging from varying degrees of customer/load growth to varying degrees of customer/load reduction, and the resulting impact on FEI's operating costs within its revenue requirement. Therefore, any long-term forecast of FEI's delivery rates needs to consider a range of scenarios rather than just isolating a single factor (i.e., a hypothetical load reduction by two or five percent per year), as in the absence of a holistic consideration of factors, the delivery rate forecast is misleading and uninformative. FEI notes that evaluating long-term load throughput, as well as costs over various scenarios, is appropriately considered as part of the Long-Term Gas Resource Plan (LTGRP).

However, in order to be responsive, Figure 1 below provides a high-level estimate of the delivery rate impact under the assumption that FEI's customer count declines by two percent (mDEP 2%) or by five percent (mDEP 5%) per year. As shown in Figure 1, the cumulative delivery rate increase from 2025 to 2050 would be approximately 29 percent (based on an mDEP of 2%) and 42 percent (based on an mDEP of 5%). This is equivalent to an annual growth in delivery rates of approximately 1.2 percent and 1.7 percent, respectively, over the 25-year period. Except for FEI's O&M, the estimated delivery rate increases to 2050 assume all components of FEI's currently approved revenue requirement remain unchanged. FEI has assumed that O&M would decrease from the current level in accordance with the decline in the number of customers under the mDEP 2% and mDEP 5% scenarios, based on the currently approved O&M formula[4], with no changes to the underlying unit cost of O&M. FEI also notes that, as Figure 1 presents the estimated delivery rate increase to 2050 due to the hypothetical load reduction under the mDEP 2% and mDEP 5% scenarios, there is no consideration of the overall bill impact, which would include changes to the cost of gas and changes to other items impacting the total bill, such as the recent elimination of the carbon tax.

[4] Approved as part of Decision and Order G-169-25 regarding FortisBC's 2025-2027 Rate Setting Framework.

Figure 1: Estimate of Cumulative Delivery Rate Increase from 2025 to 2050 due to Load Reduction Only under the mDEP 2% and mDEP 5% Scenarios



157.2 Please describe the possible FEI responses to load declines that would serve to moderate delivery rate impacts from reduced load requirements.

Response:

As discussed in the response to CEC IR6 157.1, various scenarios could unfold over the next 25 years (both within and outside of FEI's control) that could mitigate the delivery rate impacts from reduced load. For example:

- As noted in the high-level delivery rate analysis provided in the response to CEC IR6 157.1, FEI's annual O&M would likely decrease (or increase to a lesser extent) with a decline in customers based on the currently approved formulaic approach to the majority of FEI's O&M, thus partially offsetting the increase in delivery rates due to a reduction of load throughput; and
- As discussed in Section 4.2.2.1 of the Supplemental Evidence, LNG sales through RS 46 are expected to increase significantly with the construction of the Tilbury Marine Jetty,

which could offset the delivery rate increase due to declining load throughput from FEI's other customers.

Further, when considering the total bill impact to customers (not just the delivery rate impact), there are other factors which could mitigate customer rate impacts. For example:

- As discussed in Section 4.5.5.4 of the Supplemental Evidence, even in the event of adverse load declines, FEI could allocate more of the TLSE tank to the gas supply portfolio, thus creating opportunities to substitute other more expensive supply resources or generate more mitigation revenue. This would ultimately benefit FEI's customers by reducing the cost of gas charges on their bills; and
- Changes in government policies, such as the recent elimination of the carbon tax noted in the response to CEC IR6 157.1, which resulted in a significant reduction in customers' total natural gas bills by approximately 24 percent.

FEI believes there are various scenarios over the long-term that could moderate or offset potential rate increases resulting from a decline in its load throughput. As noted in the response to CEC IR6 157.1, long-term forecasting and scenario analyses is most appropriately considered in FEI's LTGRP. FEI's next LTGRP will be filed in 2026.

157.3 Please confirm that undertaking major capital projects serves to increase delivery rates, and please describe the other types of FEI activities that would serve to exacerbate the impacts of reduced load.

Response:

Not confirmed. First, some major projects are undertaken for the purpose of creating revenue generation opportunities, such as projects intended to serve the LNG marine fueling market. Second, some major projects, while creating an upfront incremental cost, are necessary to enable FEI's transition to low carbon fuels and/or to decarbonize the gas system, which may result in lower overall customer rate impacts in the long term. Finally, and irrespective of potential delivery rate impacts, FEI must undertake major projects for integrity, reliability and resiliency purposes, in order to ensure that the Company is able to continue to provide safe, reliable and resilient service for customers.

For example, based on the list of currently approved (or in the case of the TLSE Project, in progress) CPCN and OIC projects provided in the response to RCIA IR5 69.2, the majority of the projects are integrity, reliability, or resiliency related. However, some of the major projects have or will bring new growth opportunities as well as future operational savings:

- Integrity, reliability, or resiliency-related:

    - Inland Gas Upgrades (IGU) CPCN Project
    - Coastal Transmission System (CTS) Transmission Integrity Management Capabilities (TIMC) CPCN Project
    - Interior Transmission System (ITS) TIMC CPCN Project
    - Gibson Capacity Upgrade (GCU) Project
    - Okanagan Capacity Mitigation Plan (OCMP) CPCN Project
    - Tilbury LNG Storage Expansion (TLSE) CPCN Project
- Load Growth Opportunities (with new offsetting revenues):
    - Direction No. 5 (OIC) Tilbury Phase 1A
    - OIC Tilbury Phase 1B
    - OIC Eagle Mountain Pipeline
    - OIC CTS Upgrade
- Long-term Operational Benefits:
    - Advanced Metering Infrastructure (AMI) CPCN Project
- Other:
    - Pattullo Gas Line Replacement (PGR) CPCN Project – required due to the Pattullo Bridge replacement project by the Province

Besides major capital projects, FEI is also undertaking important investments in renewable gas and Demand Side Management (DSM) programs to lower GHG emissions. These activities are important and necessary as they help transition and maintain the usefulness of the gas system, which mitigates against future load decline. However, these investments may ultimately have an impact on FEI's rates.

FEI acknowledges that major capital projects or decarbonization activities will put upward pressure on rates, however, these projects or activities should be viewed through the lens of maintaining the use of the gas system and FEI's ability to complete these projects at the lowest reasonable cost, while also maintaining safe, reliable, and resilient service.

158. Reference: Exhibit B-66, CEC 5.134.6

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

158.1 Please provide FEI's definition of 'short-run' and 'long-run' in this context.

Response:

In elasticity studies, the short-run is generally defined as a period over which capital stock remains fixed while in the long-run all inputs are variable. In the context of natural gas demand, it would be likely that operations could vary in the short-run (i.e., a homeowner changing their thermostat setting) while capital stock is fixed (i.e., the natural gas furnace remains the main heating source). In the long-run, however, operations and capital can both vary. Because the typical service lifetime of installed capital can vary among economic sectors, energy end uses, and equipment types, the definitions of short-run and long-run can vary from study to study. Nevertheless, elasticity studies ordinarily define short-run as 1 to 3 years, while long-run is for 20 years or more.

158.2 Please confirm that FEI will provide the updated elasticities if the information becomes available prior to the end of this proceeding.

Response:

Confirmed. In the course of developing its 2026 LTGRP, FEI has already updated some of its price elasticity figures and has provided them below.

Table 1: 2026 LTGRP Long-Run Own-Price Elasticity of Demand by Fuel and Sector

	Own-price elasticity for natural gas[5]
Residential	-0.23
Commercial	-0.28

158.3 Please confirm that the current evidence is that Residential customers are about 2.5 times less likely to switch due to price than are Industrial customers.

158.3.1 Please provide FEI's view as to why this occurs.

Response:

Not confirmed. The own-price elasticity of demand estimates do not provide any direct information on fuel switching; rather, the estimates simply describe the impact of price changes on consumption. The elasticity estimates in the table provided in the response to CEC IR5 134.6 indicate that, over the short term, the inverse impact of a one percentage change in natural gas prices on industrial demand is more than twice the impact on residential demand, meaning that industrial customers are more sensitive to price changes than residential customers.

The elasticity estimates calculated for industrial customers have a high level of aggregation. Among industrial customers, the responsiveness of demand to price may vary greatly from one industry to another depending on factors such as the customer's ability to hedge against price volatility, degree of fuel substitution capabilities, and the ability to accommodate reductions in production levels. Particularly in the short-term, industrial customers typically have more tools for managing price changes than residential customers, which explains the higher relative elasticity estimates shown in the table provided in the response to CEC IR5 134.6.

---

5 Price Elasticity for Energy Use in Buildings in the US. Energy Information Administration, January 2021. Available at: https://www.eia.gov/analysis/studies/buildings/energyuse/pdf/price_elasticities.pdf.

159. Reference: Exhibit B-66, CEC 5.136.1

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.

Response:

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.

159.1 Please explain whether or not the cost benefit analysis undertaken for the wildfire mitigation projects in California are based on electricity or natural gas.

Response:

The following response has been provided by Exponent:

Exponent understands these to have been conducted for electricity.

159.2 Please discuss and quantify how the Value of Loss of Load for natural gas is calculated and please explain how this compares to that for electricity.

Response:

The following response has been provided by Exponent:

Exponent understands Value of Loss of Load to be an electric utility industry term. Per Gorman (2022):[6]

> The value of lost load is an electric industry metric meant to encapsulate the societal benefits of reduced outages in a monetary figure. More formally, it represents society's willingness-to-pay (WTP) to avoid a power outage and can be estimated using various units of analysis. For instance, the VoLL is sometimes presented as willingness-to-pay to avoid 1 h of outage (i.e. $/hour). Alternatively, researchers sometimes measure willingness-to-pay on a kWh basis (i.e. $/kWh), effectively representing the amount an individual would pay to consume a certain amount of electricity during an outage.

Additional details are available in Gorman (2022).

Exponent is not aware of this metric's use in gas utilities.

[6] Gorman, W., 2022. The quest to quantify the value of lost load: A critical review of the economics of power outages. *The Electricity Journal*, *35*(8), p.107187.

160. Reference: Exhibit B-66, CEC 5.137.3

> 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.

160.1 Please provide the assumption in the GDP reduction calculations regarding the length of time businesses would be expected to be shut down.

Response:

The following response has been provided by PwC:

The assumptions in the research test that, to varying degrees, businesses in some sectors would not be able to operate at full capacity as a result of the supply disruption. The level of reduction in output assumed for different sectors is set out in Appendix 1 of the PwC report.

Table 1 (Page 6) of the PwC report sets out the outage durations assumed for each of the Reviewed Scenarios during which some businesses face disruption and loss of economic output. The outage durations for the Sub-Regional Scenarios are also set out in Table 5 (Pages 12/13).

160.2 Please confirm the CEC's interpretation of the above that the loss to GDP would essentially stem from the requirement for certain businesses to shut down or reduce output for a period of time. If not confirmed, please explain why not.

Response:

The following response has been provided by PwC:

The loss stems from reduced output at businesses for a period of time due to the disruption to natural gas supply. It should be noted that in no case was a 100% economic output reduction assumed for any sector of the economy, so no sectors are assumed to be fully “shut down” during a natural gas outage.

160.3 Please provide examples of the types of businesses that would be forced to shut down fully or reduce output.

Response:

The following response has been provided by PwC:

Appendix 1 of the PwC report describes examples of the types of businesses that may face reduced output in the event of a natural gas supply disruption. The disruption is assumed to affect a range of sectors of the economy including retail, manufacturing and greenhouse production.

160.4 Please provide quantification of the proportion of GDP loss that would arise from the impacts occurring to each of industrial customers, commercial customers and residential customers.

Response:

The following response has been provided by PwC:

The PwC approach estimated the economic impact on both FEI customers and non-customers. Direct impacts from the outage scenario were applied only to FEI customers, however, disruption to economic output for these FEI customers would have a knock-on effect across the whole BC economy. For example, if an industrial customer were to experience reduced economic output due to a natural gas supply disruption, it will likely reduce its supply chain expenditure on inputs (indirect effects) and potentially lay-off workers (leading to induced impacts through lower labour income). These indirect and induced multiplier effects would impact both FEI customers and non-customers.

In terms of the sectoral breakout, the PwC scope did not include quantified analysis of the impacts on the residential sector. Many of these are not directly related to GDP and can include impacts on health, education (through school closures) and welfare effects resulting from inconvenience and disruption to everyday life.

The analysis did include an estimate of the approximate split of impacts across different sectors of the economy, which can be classified in terms of industrial or commercial users. The following splits were estimated for these two user types:

- Industrial sectors (including manufacturing, mining and construction, healthcare, greenhouses) 48% of total economic impact.
- Commercial sectors (including retail, hotels and restaurants, government offices, professional and business services) 52% of total economic impact.

These results correspond to Reviewed Scenario AV-3 and include the combined impact on both FEI customers and non-customers for the total GDP impact (sum of direct, indirect and induced). The non-GDP impacts on the residential sector are also discussed in the response to CEC IR6 162.3.

161. Reference: Exhibit B-66, CEC 5.137.4

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.

161.1 Please confirm, or otherwise explain, that (assuming availability of relevant appliances and electricity) a very large proportion of uses for residential natural gas can be replaced with electricity within a short time frame, whereas this is much less likely the case for commercial and industrial customers.

Response:

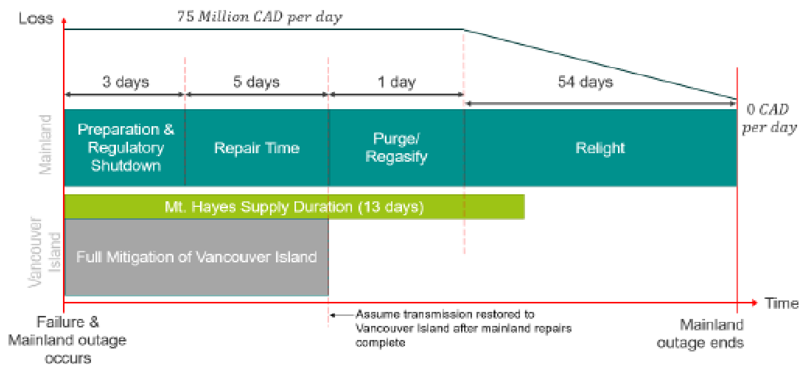
Not confirmed. The premise of the question significantly oversimplifies the challenges associated with electrifying the existing gas use of hundreds of thousands of residential customers in the region. In particular, appliance and electricity availability are central to this premise being workable in practice and, given the associated challenges, cannot simply be assumed. Further to the response to the CEC IR6 155 series, FEI identified the following critical challenges that would need to be addressed to transition residential load to the electric system in a short timeframe, including (but not limited to):

- **Technical Feasibility:** Transitioning residential gas load to the electric system in a short timeframe would require build-out of the electric transmission and distribution systems and would likely be hampered by planning cycles, land acquisition, supply chain and labour issues, as well as construction challenges. Further, the rapid loss of load on the gas system would create challenges for the gas system to continue to serve customers who remain on the system.
- **Affordability:** Transitioning residential gas load to the electric system in a short timeframe would also have significant cost implications for the gas and electric utility, which would ultimately be borne by customers or, at least partially, by taxpayers.
- **Workforce Limitations:** There would likely be a shortage of technically qualified labour given the magnitude of such a transition in a short timeframe. There is sufficient workforce to complete existing HVAC work, but to complete a fast switch out of equipment would require a workforce substantially larger than what currently exists, which would necessitate using workforces from across North America.
- **Disruption and Immediate Cost to Residential Customers:** Even assuming appliance availability, transitioning residential gas load to the electric system would disrupt customers and businesses impacted by the transition (e.g., due to electric infrastructure build-out and/or heating system change-out). Further, there would be significant costs incurred by residential customers to pay to switch out their gas equipment. A fast switch out to electric equipment would only be feasible if the equipment was paid for by someone other than the customer.

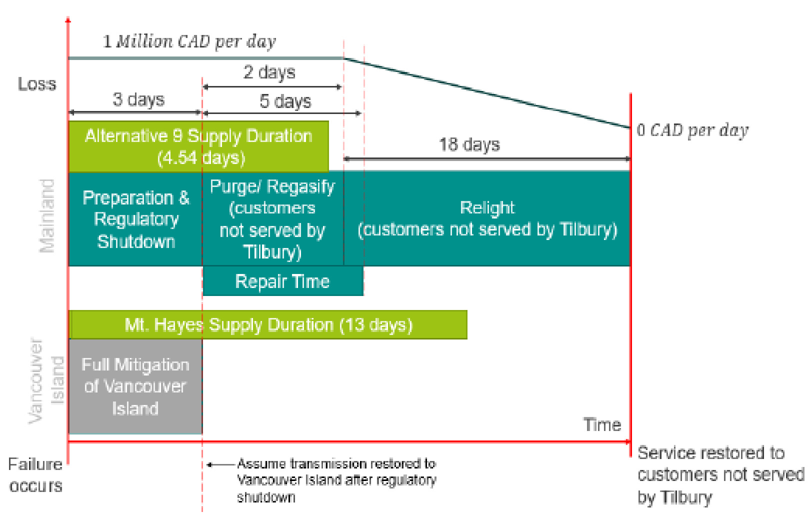
The above considerations would, in practice, preclude the approach suggested in the question.

162. Reference: Exhibit B-66, CEC 5.138.1 and CEC 5.142.1

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.

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.

Response:

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.

162.1 Please explain whether FEI's relighting plan prioritizes residential customers over commercial and industrial customers or assumes that customer relighting is equally done for all customer classes over the 54 days relighting period.

162.1.1 If so, please explain whether FEI would be able to conduct its relighting to minimize loss to GDP, such as by prioritizing the industrial and commercial companies, with large GDP impact, ahead of residential customers.

Response:

Please refer to the response to CEC IR5 138.2 which discusses FEI's approach to restoring service, including whether or not FEI prioritizes restoration based on customer rate class.

There are no technical constraints that would prevent FEI from conducting relights in a manner that prioritizes relighting industrial and commercial customers. However, relighting industrial and commercial customers as a priority would contravene FEI's Gas Supply Shortfall System Preservation and Service Restoration (P&R) Plan that, by Letter L-32-18, the BCUC found is consistent with FEI's approved GT&Cs and tariff, is in the public interest, and is not unduly discriminatory as it is in accordance with FEI's approved tariff. At a high-level, the P&R Plan contemplates restoration of service by area, regardless of customer class, as this is the most efficient approach.

FEI's P&R Plan was developed based on extensive analysis and consideration of industry practices that seek to reduce the overall harm to customers and society. There are various considerations that make FEI's contemplated approach appropriate:

1. While prioritizing the restoration of industrial and commercial customers may increase the rate at which those customers are relit, overall customer relight rates would be reduced. For example, in a scenario where crews are dispatched to a mixed residential and commercial area, the relight approach proposed in the question would have the crews purge the local distribution pipe (DP) system (assuming an uncontrolled shutdown had occurred), relight the commercial customers, then travel to a different area to target the

next group of commercial customers. Once all commercial customers were relit, the crews would then have to revisit these mixed customer areas to then relight the residential customers. This would be less efficient than the existing P&R Plan approach and would result in lower overall customer relight rates. FEI expects that any attempt to prioritize a subgroup of customers, either by rate class or by some other criteria within a given rate class (e.g., by end use type), will result in lower overall customer relight rates.

2. FEI's analysis accounts for personnel from other utilities being provided to FEI through mutual aid to assist in the recovery effort. These are inherently temporary and voluntary resources, and as such should be utilized in the most efficient way possible.

3. As described by PwC in the response to CEC IR6 162.3, relighting industrial and commercial users as a priority would exacerbate the impacts and disruption to residential customers. This may have attendant economic effects. Further PwC notes that this approach would likely increase the negative effects on health, welfare, and other factors not quantified in the PwC analysis. Please refer to CEC IR6 162.3 for further information on these considerations.

162.2 Please explain whether FEI would be able to conduct its relighting for residential customers, who use limited natural gas for limited purposes, such as in apartments where heating and cooking use electricity but gas fireplaces are used for ambience, at a later time in the relighting schedule.

Response:

FEI does not maintain a register of each residential customer's end use case for natural gas, as such an approach is not technically feasible. Additionally, as described in the response to CEC IR6 162.1, this approach is inconsistent with FEI's P&R Plan and, in any event, FEI would not pursue this approach as it would result in a lower overall customer relight rate and greater harm to a large number of customers.

162.3 Please calculate the GDP loss in the event that industrial and commercial customers were relit as the top priority.

Response:

The following response has been provided by PwC:

An assessment of a scenario whereby large industrial and commercial customers were prioritized for relight was not part of the PwC scope of work.

If an analysis of this type were undertaken, a number of considerations should be accounted for, for example:

- Relighting industrial and commercial users as a priority may exacerbate the health, social, welfare impacts and disruption to residents caused by the outage (assuming residential relights would be de-prioritised under such a scenario and so residents face longer outages). These impacts are not quantified in the PwC analysis.
- This may have attendant economic effects, for example, many residents may not be able to work at a normal level or attend their workplace due to the need to care for children (due to school closures) and elderly and vulnerable adults (who may have no access to heating).
- Due to a combination of the two points raised above, extending the outage duration for residential customers would act as an offset for the potential mitigations to GDP loss that prioritisation of industrial and commercial users may offer. This is because deprioritising residential customers would increase the duration of social disruptions (e.g., school closures, need to care for elderly relatives), thus negatively impacting people's ability to work and/or their productivity, even if their workplace had access to natural gas. To quantify the balance of these competing factors is complex and would require substantial additional research. However, based on PwC's experience, they anticipate that such analysis would still point to significant negative impacts on GDP even under a prioritised industrial/commercial relight scenario.

162.4 Please discuss whether industrial and commercial customers could have personnel and/or contractors pre-qualified and certified to relight their own equipment without need for FEI personnel, other than coordination and communication from FEI about when to do the relighting.

Response:

Industrial and commercial customers may be able to relight their own appliances. FEI's analysis of the customer outage duration (and, accordingly, Exponent's and PwC's analysis) has accounted for this by assuming that 25 percent of all customers will complete their own relights.

Further, FEI's analysis assumes that all available Lower Mainland private contractors, as well as mutual aid from other utilities, would contribute to the relight effort. Therefore, there would not be any available contractors for commercial and industrial customers to contract to relight their appliances.

163. Reference: Exhibit B-66, CEC 5.139.3

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.

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	968
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

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	76,203	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

163.1 Please break down the above tables by rate class and indicate which rate schedules are included in each of Residential, Commercial and Industrial.

Response:

The following two tables provide the data shown in the preamble at the rate class level.

Table 1: Actual Customers from 2004 by Rate Class

Customers	Residential	Commercial			Industrial								
Year	RATE1	RATE2	RATE3	RATE23	RATE4	RATE5	RATE6	RATE7	RATE16	RATE22	RATE25	RATE27	LARGE TRANSPORT
2004	710,767	70,933	5,304	959	2	436	48	5		57	540	100	
2005	721,935	72,959	4,913	1,038	-	398	40	4		56	576	99	
2006	730,872	73,917	4,798	1,206	3	324	38	3		54	599	98	
2007	742,882	74,987	4,730	1,303	1	289	31	3		53	589	97	
2008	750,838	76,115	4,897	1,306	7	282	32	2		47	591	96	
2009	755,660	76,398	4,869	1,348	2	251	29	3		46	583	94	
2010	762,496	76,449	4,910	1,406	7	228	24	3		44	554	100	
2011	862,358	84,635	7,052	1,433	5	224	20	2		44	512	98	4
2012	855,997	80,047	6,699	1,520	11	222	16	3	3	47	510	98	4
2013	865,148	81,521	6,585	1,529	2	281	12	3	1	46	492	103	4
2014	875,623	82,689	6,626	1,522	2	281	12	3		43	485	100	4
2015	888,132	85,550	5,308	1,724	2	243	13	6		48	557	108	2
2016	899,473	86,552	5,196	1,803	1	238	7	6		50	546	107	3
2017	912,812	87,449	5,447	1,712	4	260	6	11		46	521	108	2
2018	932,061	88,717	6,032	1,648	2	311	6	15		49	508	97	2
2019	942,649	89,146	6,987	871	13	507	5	46		42	336	70	2
2020	955,626	89,815	6,822	746	9	553	2	47		43	298	69	2
2021	965,847	90,128	7,030	697	8	584	2	45		44	272	69	2
2022	976,170	90,421	7,240	620	9	632	2	46		45	248	67	1
2023	985,844	90,185	8,849	453	7	697	2	60		37	206	57	1

Table 2: Actual Demand (TJ) from 2004 by Rate Class

Demand, TJ	Residential	Commercial			Industrial								
Year	RATE1	RATE2	RATE3	RATE23	RATE4	RATE5	RATE6	RATE7	RATE16	RATE22	RATE25	RATE27	LARGE TRANSPORT
2004	72,673	21,805	18,598	4,386	180	4,933	324	73		40,638	14,218	5,588	
2005	70,581	22,168	16,286	4,994	183	4,364	211	54		40,062	15,533	6,147	
2006	70,268	23,133	15,732	5,516	179	3,832	138	51		39,974	16,060	5,579	
2007	70,910	23,693	16,167	5,927	163	3,480	117	49		36,796	15,525	5,495	
2008	69,109	23,561	16,379	6,207	191	3,199	93	18		35,282	14,570	5,452	
2009	70,265	24,452	16,549	6,469	166	2,899	83	103		29,231	13,142	5,776	
2010	70,312	23,813	16,488	6,630	185	2,464	61	11		30,933	12,841	5,982	
2011	74,152	26,460	22,172	7,372	223	2,534	69	112		35,381	13,288	6,629	8,368
2012	74,729	26,892	21,960	7,802	169	2,385	62	87	172	38,520	12,884	6,372	8,996
2013	72,960	26,393	21,082	7,866	167	2,901	50	57	186	37,479	12,548	7,543	23,662
2014	73,457	26,895	20,450	7,975	138	3,378	43	49	177	36,506	12,403	6,646	24,635
2015	74,378	28,218	19,241	8,563	148	2,299	50	168		37,343	13,752	7,156	21,486
2016	78,203	29,227	19,429	9,294	150	2,429	41	207		40,492	13,916	6,793	22,433
2017	77,800	29,318	19,750	9,544	142	2,829	30	387		40,872	14,503	7,479	24,937
2018	78,543	29,266	20,960	9,048	163	3,784	26	899		42,042	13,973	6,423	23,745
2019	77,276	28,315	22,550	7,276	153	4,814	9	2,963		43,332	13,193	5,901	24,160
2020	81,836	28,873	24,720	4,562	143	8,144	4	6,460		39,003	9,977	4,607	24,331
2021	82,481	29,510	25,833	4,187	168	9,134	2	6,463		40,070	9,324	4,436	24,573
2022	80,650	30,212	26,772	3,948	172	9,846	1	6,244		38,612	9,077	4,328	12,602
2023	80,281	29,350	29,175	3,354	173	10,342	1	6,589		38,792	7,900	3,912	6,437

163.2 Please confirm, or otherwise clarify, the CEC's interpretation that, as of 2023, industrial customers, together, accounted for about 1 in 1000 customers, or 0.1%, and approximately 33% of total demand.

Response:

Please refer to the following table, based on the data provided in the response to CEC IR5 139.3, which shows the following as of 2023:

- Residential customers, together, account for approximately 91 percent of customers and 37 percent of annual demand;
- Commercial customers, together, account for approximately 9 percent of customers and 29 percent of total annual demand; and
- Industrial customers, together, account for approximately 0.1 percent of customers and 34 percent of total annual demand.

Table 1: Percent of Actual Residential, Commercial and Industrial Customers and Demand

	Residential	Commercial	Industrial	Total
Customers	985,844	99,457	1,067	1,086,368
Percentage	91%	9%	0.1%	
Demand, TJ	80,281	61,878	74,146	216,305
Percentage	37%	29%	34%	

163.3 Please confirm, or otherwise clarify, the CEC's interpretation that, as of 2023, commercial customers, together, account for about 10% of customers, and approximately 30% of demand.

Response:

Please refer to the response to CEC IR6 163.2.

163.4 Please confirm, or otherwise clarify, the CEC's interpretation that, as of 2023, residential customers accounted for about 90% of customers, and about 40% of demand.

Response:

Please refer to the response to CEC IR6 163.2.

164. Reference: Exhibit B-66, CEC 143.6

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**

164.1 Please confirm that the % of commercial customer load contribution to the peak day load is 41.28% and that the contribution of industrial customer load to the peak day load is 10.62%.

Response:

As discussed in the response to BCOAPO IR6 4.4, FEI does not separate its load forecast by customer group for gas supply planning purposes. To provide the response to CEC IR5 143.6, FEI was able to use its system planning model to estimate the contribution to peak day by rate schedule and apply it to the gas supply peak day load. Since FEI's system planning model is based on actual consumption data, it is a reasonable method to estimate a rate schedule's peak day contribution. Understanding that the response to CEC IR5 143.6 is an approximation of each rate schedule's contribution to peak day load, FEI confirms that commercial customers contribute approximately 41 percent to peak day load and industrial customers contribute approximately 11 percent.

164.2 Please confirm that if the 9.14% of customers, being industrial and commercial customers, were to have immediate relighting in the recovery process from a no-flow event at winter peak that the GDP impact would be substantially lower than FEI's current estimate from PwC based on different assumptions, used in response to the CEC (Exhibit B-66, CEC 5.138.1 and CEC 5.142.1) and please quantify the difference.

164.2.1 If so, please quantify the GDP impact of relighting industrial and commercial customers as a priority.

Response:

Not confirmed. Please refer to the response to CEC IR6 162.3.

165. Reference: Exhibit B-66, CEC 5.143.10 and CEC 5.154.2

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.

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

165.1 Please confirm, or otherwise explain, that a re-light focussing on the largest industrial and then commercial customers would drastically increase the proportion of natural gas being restored early, even if the number of customers being restored remained lower.

Response:

The requested analysis is significantly more complicated than simply comparing whether relighting a lower number of customers each day with a higher average UPC (i.e., the UPC would be a mix of commercial and industrial) would result in more natural gas load being restored earlier during the outage duration than relighting a greater number of customers each day with a lower average UPC (i.e., the UPC would be a mix of residential, commercial, and industrial).

In particular, while commercial and industrial customers have a much higher UPC than residential customers, meaning on a customer-to-customer basis restoring a commercial or industrial customer would result in a greater amount of load returning to FEI's system, the loss in relight productivity as a result of prioritizing relighting commercial and industrial customers over residential customers could counter this effect. Productivity is expected to drop due to the additional travel and mobilization time required to revisit areas that were already attended to for the relighting of industrial and commercial customers, but where the residential customers were left offline during the initial visit such that industrial and commercial could be prioritized. These areas would thus need to be revisited, leading to a drop in productivity. Please refer to the response to CEC IR6 162.1 for further discussion on why relight productivity would drop if commercial and industrial customers are prioritized over residential customers.

Further, as described by PwC in the response to CEC IR6 162.3, relighting industrial and commercial customers as a priority would exacerbate the impacts and disruption to residential customers. This may have attendant economic effects and, as noted by PwC, would likely increase the negative effects on health, welfare, and other factors not quantified in the PwC analysis.

Another factor that may prevent large customers from being prioritized for relight is the presence of on-going supply constraints. Depending on the customer's load, location, and the available gas supply, connecting a large customer may not be possible as doing so may lead to a supply/demand imbalance that puts the system at risk of hydraulic collapse.

165.2 Please confirm that relighting the largest industrial and commercial customers early would have the beneficial effect of limiting losses to GDP.

165.2.1 Please provide quantification for the reductions that would occur in the GDP losses assuming FEI were to focus on relighting the largest industrial and commercial customers first; and please provide the supporting calculations.

Response:

Please refer to the response to CEC IR6 162.3.

165.3 Please confirm that relighting industrial customers early would also have the beneficial effect of minimizing revenue losses to the utility.

165.3.1 Please provide quantification for the reduction in revenue loss that would occur assuming FEI relit industrial and commercial customers in priority by size of load demand.

Response:

Please refer to the response to CEC IR6 162.1 for a discussion of FEI's P&R Plan and the productivity implications of prioritizing the relighting of industrial and commercial customers. Also, please refer to the response to CEC IR6 165.1 for a discussion of gas demand load returning to the system. Accordingly, FEI cannot quantify the reduction in revenue loss resulting from prioritizing the relighting of industrial and commercial customers.

165.4 Please provide the number of days it would take to relight industrial customers, by rate class.

Response:

FEI has not estimated a relight productivity rate for the relight scenario where FEI deviates from its P&R Plan and prioritizes relighting industrial and commercial customers before residential customers.

However, in order to be responsive, FEI has provided the following table which estimates the number of days required to relight Lower Mainland commercial and industrial customers. As noted above, FEI has not estimated a relight productivity rate for the relight scenario where FEI deviates from its P&R Plan, but for the purposes of this calculation has assumed a relight productivity rate that is 25 percent of the rate used in the 2024 Resiliency Plan. FEI considers this assumption to be reasonable because, although the precise extent to which relight efficiency would be compromised by relighting industrial and commercial customers before residential customers is unknown, it is clear that the loss of efficiency would be significant. Travel time between customers is a material determinant of relight rates, and it would be more difficult to deploy and coordinate the work.

Table 1: Estimated Relight Duration for Industrial and Commercial Customers Based on Assumed Relight Rate

Category	Rate Class	Assumed Relight Rate	No. of Firm Lower Mainland Customers[7]	Estimated Relight Duration
Commercial	Rate 2	2,179	53,004	24.3 Days
	Rate 3	2,179	5,319	2.4 Days
	Rate 23	2,179	320	0.15 Days
Industrial	All firm industrial	2,179	1,124	0.5 Days
Total (Commercial & Industrial)	N/A	2,179	59,767	27.4 Days

165.5 Please provide the number of days it would take to relight commercial customers, by rate class.

Response:

Please refer to the response to CEC IR6 165.4.

[7] Customer numbers are based on 2022 year-end customers, as this was the dataset available when FEI began development of the Supplemental Evidence in 2023.

166. Reference: Exhibit B-66, CEC 5.143.7

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

166.1 Please break out the LML firm load by customer class and please provide the number of customers in the LML by rate class.

Response:

The requested data is presented in the following two tables.

Demand, GJ	RATE1	RATE2	RATE3	RATE4	RATE5	RATE6	RATE23	RATE25
2003	50,867,371	15,648,997	15,003,951	-	344,804	219,759	212,678	68,615
2004	49,413,761	14,862,654	14,006,212	65,791	2,540,145	285,755	2,291,991	5,817,292
2005	50,982,930	15,727,583	13,597,802	87,939	3,540,768	166,438	4,137,413	8,930,374
2006	51,295,643	16,305,832	13,150,011	82,920	3,177,108	136,972	4,511,206	9,312,699
2007	55,412,442	17,992,858	13,619,197	61,474	2,913,135	93,155	5,025,877	9,535,553
2008	55,979,496	18,784,723	14,070,238	91,528	2,722,049	79,459	5,400,080	9,438,632
2009	56,200,993	18,780,396	13,994,008	71,971	2,456,163	71,015	5,379,461	9,021,714
2010	49,745,603	16,726,251	13,266,427	78,913	2,119,325	60,681	5,151,334	8,678,421
2011	55,847,425	18,694,731	15,750,282	78,882	2,257,581	68,076	6,376,525	8,941,818
2012	52,093,256	17,444,378	13,751,736	66,803	2,114,341	57,107	6,392,856	8,529,335
2013	52,206,523	17,842,112	13,609,759	55,117	2,020,140	48,988	6,468,311	8,060,351
2014	49,880,523	17,512,199	13,380,877	50,044	2,017,303	42,963	6,072,639	7,753,143
2015	44,661,515	15,430,825	12,210,014	50,272	1,910,698	50,441	5,830,583	7,595,449
2016	47,648,645	16,660,170	12,889,180	61,062	2,133,667	37,112	6,254,758	7,837,227
2017	56,280,124	20,115,768	15,051,514	52,933	2,459,532	23,113	7,066,706	8,375,491
2018	52,640,672	18,292,372	15,258,176	55,297	3,013,956	15,766	6,307,935	7,668,654
2019	53,690,846	18,546,819	16,900,090	57,022	4,481,811	8,865	5,126,655	7,198,761
2020	54,930,762	18,521,767	19,036,294	32,221	7,074,871	4,256	2,648,780	4,893,965
2021	54,774,467	18,700,786	19,314,940	46,954	7,926,523	1,935	2,421,343	4,626,650
2022	57,467,881	20,508,871	21,009,663	54,339	8,205,009	1,273	2,237,776	4,007,696
2023	53,308,585	18,368,120	21,630,925	58,138	8,635,291	875	1,716,910	3,532,915
2024	53,128,423	17,960,977	22,479,522	53,758	11,452,524	650	1,378,728	3,024,904

Customer Count	RATE1	RATE2	RATE3	RATE4	RATE5	RATE6	RATE23	RATE25
2003	483,920	48,548	4,781	1	19	37	43	7
2004	493,725	49,372	4,634	35	409	37	869	472
2005	503,100	50,615	4,391	35	374	35	974	490
2006	508,694	50,454	4,144	34	330	32	1,053	533
2007	517,234	51,311	4,036	34	285	30	1,098	524
2008	521,183	51,896	4,188	32	261	29	1,153	503
2009	523,981	52,191	4,309	33	248	25	1,135	511
2010	528,809	51,777	4,133	31	220	22	1,188	504
2011	532,567	51,734	4,214	32	207	20	1,240	477
2012	535,564	51,920	4,159	32	202	17	1,265	471
2013	538,839	52,427	4,188	32	201	14	1,294	458
2014	542,925	52,957	3,981	31	204	13	1,280	451
2015	547,506	53,522	4,234	30	214	13	1,308	437
2016	552,611	54,141	4,214	29	213	12	1,322	425
2017	558,137	54,737	4,214	28	234	6	1,312	424
2018	563,830	55,582	4,680	28	268	5	1,243	421
2019	568,370	55,933	5,499	29	459	5	1,144	398
2020	574,420	56,487	5,624	28	499	5	507	249
2021	579,733	56,648	5,365	28	536	2	436	224
2022	583,285	56,855	5,563	28	560	2	395	197
2023	587,276	57,590	6,942	28	620	2	322	179
2024	590,820	57,791	7,028	28	641	2	218	139

167. Reference: Exhibit B-66, CEC 5.143.11

> 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.

167.1 Please explain whether or not FEI's response related to most firm load customers incorporates residential customers, or if the response is limited to commercial and industrial customers.

Response:

Residential customers are firm load customers. Further, FEI commonly defines firm load customers as customers that are not interruptible load customers.

167.2 Please provide an overview of the industries in which backup supplies were being used, and quantification as available to indicate if these industries were predominantly in the industrial or commercial rate classes.

Response:

The following response has been provided by PwC:

Appendix 1 in the PwC report sets out the instances where use of backup systems was identified through primary research.

One example was identified in the healthcare sector, where hospitals were reported to typically hold backup energy supplies to cover a three-to-seven day outage period.

A second example is in the greenhouse sector where the research identified the use of wood or diesel-based backup energy at some sites. These systems can provide backup heat, but not the CO_2 enrichment function also provided by natural gas furnaces (which increases the growth rate of plants) because the exhaust streams from wood or diesel are insufficiently clean for this purpose. As these examples show, the backups identified in the research spanned both industrial and commercial customers.

167.3 Please provide the quantity of backup recognized in the PwC analysis and the reduction in economic loss recognized on account of the backup supply.

Response:

The following response has been provided by PwC:

PwC asked each interviewee about backup energy supplies. Where backup energy supplies were identified they were factored into the output reduction assumptions documented in Appendix 1 of the PwC report. Expanding on the two examples provided in the response to CEC IR6 167.2, for hospitals, it was assumed that there would be no reduction in output in any scenario due to the availability of backup energy. This assumption was designed to be conservative and was founded on interview feedback that hospitals would likely be prioritized for fuel deliveries allowing continued operation even if the outage extended beyond the duration covered by their existing energy backup supplies. Therefore, the negative economic impacts in the heath sector arise only in facilities which were reported to generally not have backup, such as at family doctors and outpatient clinics.

In the case of greenhouses, it was reported that approximately 80% of greenhouses have backup energy. This was factored into the analysis by applying only a crop yield-based reduction of approximately 20% to the output of greenhouses with backup (due to the loss of CO_2 enrichment capability).

Factoring in backup energy supply into the approach provides additional conservatism to the PwC estimates. Additional measures to provide a conservative approach are outlined in the responses to CEC IR6 160.2 and BCOAPO IR6 2.3.