Diane Roy
Vice President, 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: (604)576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
www.fortisbc.com

November 10, 2021

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

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: FortisBC Energy Inc. (FEI)

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

Response to the Commercial Energy Consumers Association of British Columbia (CEC) Information Request (IR) No. 2

On December 29, 2021, FEI filed the Application referenced above. In accordance with the regulatory timetable established in British Columbia Utilities Commission Order G-185-21 for the review of the Application, FEI respectfully submits the attached response to CEC IR No. 2.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

100. Reference: Exhibit B-15, BCUC 1.1.3.1

Given that a no-flow incident on the T-South system is the most impactful supply disruption to the Lower Mainland, FEI commissioned an analysis to explore the probability of a T-South failure. This independent expert analysis is detailed in the response to BCUC IR1 1.5.

> 1.3.1 Please discuss whether FEI is aware of any lessons learned or actions taken by Westcoast since the T-South Incident which would reduce the time needed to re-establish supply to one of the pipelines in the event of a rupture or other supply disruption.
>
> **Response:**
>
> The timing for re-establishing supply to a particular pipeline segment of the T-South system may vary considerably according to the type of incident and depending on several factors, including the following:
>
> - cause/severity of the incident – whether it is a physical issue with the pipeline or a cyber-attack, and does the event require investigation and assessment by multiple authorities, including the Canada Energy Regulator (CER);
> - time of year – incident occurring during favorable or unfavorable conditions for work to be done to resume gas flow; and
> - incident location – ease of access to incident location.
>
> FEI is aware that Westcoast has completed a comprehensive review of its integrity management program for the T-South system and identified several improvements to enhance pipeline safety, including additional in-line inspection assessments and shortening re-inspection intervals. This review also resulted in the completion of additional integrity digs on many segments of the T-South system. FEI is of the view that while Westcoast's integrity management program is important for reducing the likelihood of integrity-related incidents occurring, it does not address all potential sources of disruption and is unlikely to reduce the time needed to re-establish supply in the event of a future rupture or other supply disruption for the reasons set out above.

100.1. Please explain what types of potential disruptions Westcoast's integrity management program does not address.

Response:

Of the examples of potential disruptions listed in the response to BCUC IR1 1.3, the following would not typically be addressed by an operator's integrity management program:

- a precautionary shut-down of an adjacent pipeline for non-integrity reasons;
- ruptures due to intentional causes (i.e., sabotage); and
- a cyber-attack which disrupts Westcoast's ability to control or operate the T-South system, resulting in a shutdown similar to that which caused a multi-day outage on the Colonial Pipeline oil pipeline in the eastern US.

With respect to the second and third bullets above, the CSA Z662 standard addresses the matter of security management as separate from integrity management, and it is typical practice for operators' programs to mirror the structure and requirements from this source.

100.2. Please elaborate on why the review is unlikely to reduce the time needed to re-establish supply.

Response:

As noted in the preamble, the Westcoast review of its integrity management program for T-South was undertaken to improve the program's effectiveness. A more effective program should more readily identify potential integrity concerns so that they can be addressed in a timely manner.

However, improvements to the operation of the integrity program will not address all potential causes of a disruption, nor will it necessarily reduce the time needed to re-establish supply following a disruption for the reasons included in the preamble, because they are an issue separate from the cause of a disruption itself. For example, depending on the cause/severity of the incident, the timing for re-establishing supply may not be entirely in Westcoast's control, as the Canadian Energy Regulator or law enforcement agencies may impose their own timelines based on inspection and/or emergency response requirements.

101. Reference: Exhibit B-19, CEC 1.2.1

2.1 Please confirm that FEI, for the T-South incident event, did have the ability to survive and recover from the adverse events in question.

Response:

Confirmed. However, FEI's ability to withstand and recover from the T-South incident was dependent on several favourable conditions, as set out in Sections 3.4.2.2 and 3.4.4.1 of the Application. These conditions included the following:

- The time of year (i.e., not in a winter peak demand period); Mild weather immediately following the incident resulted in continued low demand;
- The incident site was an accessible location for repair crews, and weather conditions were favourable for performing the work;
- Westcoast was able to determine relatively quickly that the rupture only affected one of the two lines, and hence was able to get clearance from its regulator to resume flows on the other line; and
- Mutual aid partners were able to assist and had resources to supply FEI gas through this agreement.

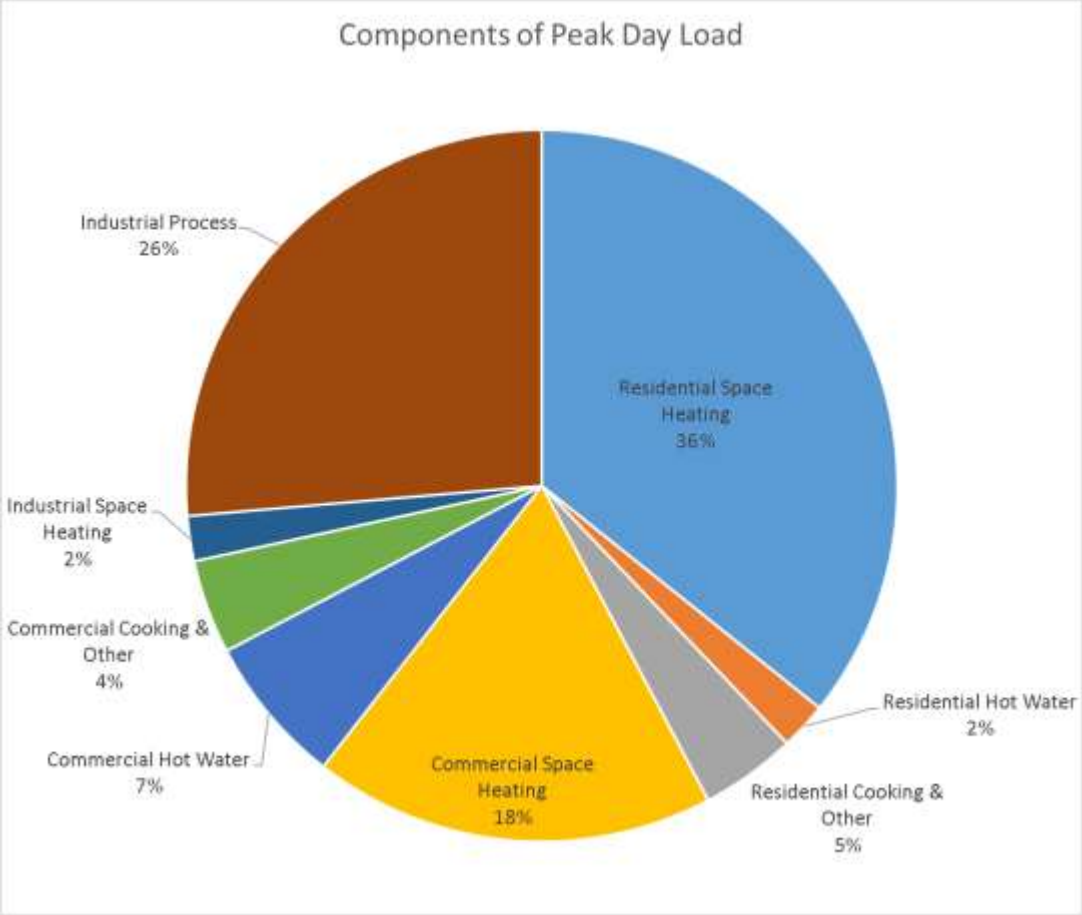
Some or our all of these favourable conditions may not be present during a future no-flow event.

101.1. Please provide an approximate percentage break down of FEI's winter peak demand by end-use (i.e. heating, cooking, etc.).

Response:

The estimated breakdown of peak day demand by various end-uses is shown in the following figure. Interruptible volumes are included in the "Industrial Process" category.

The figure demonstrates the extent to which space and water heating make up winter peak load, and the consequent challenge associated with shedding significant load in winter.



101.2. Could customers temporarily make use of electric heating instead of natural gas heating during a natural gas supply shortage? Please explain.

Response:

FEI expects some customers with immediate access to portable space heaters might use them in response to appeals to reduce gas consumption. Otherwise, there are practical constraints on temporary fuel switching in a very short time horizon. Whether such switching would be practicable, or indeed economical, likely depends on the availability of electric heating equipment and the individual customer's ability to temporarily connect to electricity in their home or business for this purpose.

Temporary fuel-switching of this kind could adversely impact BC Hydro's system depending on the amount and location of FEI's heating load switching to electric heating.

101.3. Could BC Hydro's electricity grid accommodate temporary heating demand arising from a natural gas supply shortage? Please explain why or why not.

Response:

Please refer to the response to CEC IR2 101.2.

101.4. Please identify any non-natural gas alternatives that customers could use in place of their natural gas during a supply outage and explain how these could be used for each end-use.

Response:

Potential non-natural gas alternatives that customers could use in place of their natural gas during a supply outage and how these could be used for each end-use is difficult to answer as there are unique variables between customers. Customers would also need to consider factors such as the length of expected outage and the expected weather conditions to prioritize what is most important to them – in particular with regards to their own safety.

Commercial and industrial customers would need to consider potentially unique factors relevant to the operation of their business and, in particular, whether they could continue to operate their facilities safely and cost effectively. Similarly, residential customers would need to make decisions related to their respective cooking, heating, and hot water requirements.

For example, two residential customers could have very different energy consuming equipment, as well as potential redundancy in their end-use appliances. Depending on each customer's unique circumstances, one customer may have redundancy in their heating systems and could easily switch energy sources (propane, electricity, wood) for their heating, while their neighbour may not have any redundancy and would be trying to heat their home with small portable plug-in space heaters. This highlights the unique circumstances and challenges that customers would need to consider depending on the weather and expected duration of an outage. If the weather forecasts are mild, customers may just be able to use extra blankets and/or layer-up their clothing. However, if a residential customer could not safely stay warm in their home with whatever non-natural gas alternatives were available then they may need to consider staying with friends/family or seek separate temporary accommodations at a hotel or public shelter that has access to an alternative heating source.

101.5. Please identify what portion of FEI's peak demand could be reasonably considered as 'essential' vs 'non-essential' and explain the breakdown.

Response:

Within FEI's tariffs, customers are able to obtain "firm" or "interruptible" service. Beyond these service categories, FEI does not segment its customers by their end use or treat certain customers as "essential" within a rate class.

In an emergency situation due to a no-flow event on the T-South system, FEI is guided by its System Preservation and Restoration (P&R) Plan. The P&R Plan is security sensitive, but has been reviewed by the BCUC and determined to be in the public interest. FEI can confirm that the curtailment priority in the P&R Plan contemplates interruptible customers being curtailed first. As among firm customers, the P&R Plan is explicitly informed by the principle that maintaining the operating stability, security and safety of the natural gas system will allow the system to continue serving customers to the greatest extent possible and minimize overall harm. There is also explicit recognition in the P&R Plan that the loss of heat or hot water can represent a safety risk in certain circumstances (e.g., locations where people reside or are cared for, emergency services providers).

However, unless there is gas to physically serve customers, a widespread controlled shutdown becomes inevitable regardless. As discussed in the response to BCUC IR2 78.1, FEI would fall well-short of being able to serve the Lower Mainland system during a winter supply interruption and very widespread loss of load would be inevitable on the first day of a no-flow event.

102. Reference: Exhibit B-19, CEC 1.3.4

See BCUC 1.64, 1.13.3 and 1.13.4and CIA 1.13.1.

102.1. Would FEI characterize commercial use as being more or less essential than residential or industrial use? Please explain.

Response:

FEI's commercial and industrial rate classes comprise a vast number of end-use segments, including multi-family dwellings. As such, FEI is unable to apply broad generalizations across customer segments that cover multiple rate classes and end uses.

103. Reference: Exhibit B-19, CEC 1.4.4

4.4 Has FEI intervened in the regulation of Enbridge to address the impacts and potential mitigations from a disruption caused by a pipeline rupture

Response:

FEI is not aware of any regulatory intervention that has been initiated with the CER, either by the CER itself, by Enbridge, or by a third party, to address the impacts and potential mitigations from a disruption caused by a pipeline rupture. Current federal regulations are concerned primarily with managing the safety, security, and the environmental protection of facilities through their life- cycle.

FEI believes that the most effective approach for managing potential impacts of an upstream pipeline rupture is to have a portfolio of resiliency resources that provide supply, storage, and pipeline diversity. This Application addresses a key part of this need by proposing the construction of the TLSE Project.

103.1. Are there any ways in which FEI can work with other energy providers, such as BC Hydro to increase resiliency for customers? Please explain.

103.1.1. If yes, what actions does FEI undertake to do so?

Response:

FEI believes that maintaining and improving a diverse energy system, including maintaining and improving both electricity and gas system infrastructure, will best support the resiliency of the province's energy system. With respect to gas supply resiliency for hundreds of thousands of FEI customers in the Lower Mainland, the TLSE Project is the only solution to address the Minimum Resiliency Planning Objective. Please also refer to the response to MS2S IR1 4iii for an explanation of why electricity cannot provide an alternative to the TLSE Project.

104. Reference: Exhibit B-19, 1.42.1 and Exhibit B-15, BCUC 1.21 series

42.1

Is the production of LNG equally compatible with Renewable Natural Gas or with any of potential evolutions of the gas supply that FEI could be planning for the purposes of improving GHG emissions, such as H2, or for any other reason? Please explain.

42.1.1 If there are any incompatibilities, please elaborate.

> 21.1 Please explain the impact of increasing hydrogen content in FEI's gas supply network on FEI's liquefaction and regasification processes.
>
> **Response:**
>
> FEI does not anticipate impacts on the TLSE Project, nor on its liquefaction process, as a result of increasing hydrogen content in the gas stream as hydrogen can be separated if introduced upstream of the Tilbury facility.
>
> There are two potential options available to mitigate the impact on LNG operations from increasing hydrogen content in the gas system:
>
> - hydrogen would be removed by separating it from the gas supply upstream of the LNG facility and then redirected to a different part of the gas network; or
> - hydrogen would enter the LNG facility but would be extracted prior to liquefaction and stored separately onsite for use in gaseous or liquid form (e.g., for fuel cell electric vehicle refueling).
>
> This would mitigate:
>
> - Impacts on the rate of boil-off gas generation from the LNG storage tank;
> - The risk of stratification within the LNG storage tank; and
> - The impact on FEI's long-term LNG storage operations.
>
> Both options would remove the hydrogen from the gas stream prior to liquefaction and hence the LNG tank would continue to only store liquid natural gas. As such, there are no increased capital or operating costs included in the TLSE Project associated with the future use of hydrogen in FEI's gas supply network.

104.1. Under a scenario in which hydrogen forms a significant portion of the gas supply, is it fair to say that the use of LNG would be considered as having higher GHG emissions than the regular gas supply? Please explain.

Response:

FEI can confirm that the hydrogen must be physically removed before liquefaction takes place, such that the LNG will be comprised of a mix of natural gas and RNG (RNG is also methane gas, but derived from biogenic sources, and does not need to be removed). Regardless, FEI believes that this is too narrow of a view.

As outlined in FEI's responses to BCUC IR1 21.4 and 63.1, the TLSE Project is part an evolving energy system that has lowered, and will continue to lower, GHG emissions over time as the

province's gas system continues to decarbonize by supplying a growing and diversified fuel mix. Being able to efficiently and cost effectively store energy in the province's major demand centre through the TLSE Project will continue to be important as FEI's decarbonization initiatives advance.

104.2. Please provide a brief comment on the additional capital that would be required to separate hydrogen out from the gas supply once it had already been inserted.

Response:

Please refer to the response to BCUC IR2 83.3.

104.3. To the extent that FEI is examining multiple alternatives to assist in the reduction of GHG emissions, how does FEI's increase in LNG storage fit with FEI's plans to bring in new technologies or alternative fuel? E.g. How does the additional LNG availability support FEI's long term resource plan? Could the need for LNG be displaced before the end of the service life? Please explain.

Response:

The TLSE Project is a resiliency project, with ancillary supply and operational benefits, and a significant portion of the storage in the proposed 3 Bcf tank will be set aside to be available during a no-flow event. FEI's proposed increase in LNG storage through the TLSE Project is compatible with its plans to bring on new technologies and alternative fuels to lower GHG emissions. For example, in the response to CEC IR2 104.1, FEI confirmed that hydrogen will not affect LNG processes as it can be removed prior to liquefaction. The carbon intensity of LNG can be continually reduced over time by increasing blends of renewable natural gas.

105. Reference: Exhibit B-19, CEC 1.13.2

plate boundary (Cascadia subduction zone) event is about 0.5 metres high at the western shore of the delta bordering Richmond. Also, computer models of large subaqueous block slides on the western fore-slope of the Fraser delta indicate that waves of about 2 metres high would strike the adjacent shoreline shortly after the landslide. Based on this information, FEI concludes that tsunamis do not present a significant threat to the Tilbury site.

105.1. What is the minimum wave height FEI would consider as a threat to the Tilbury site? Please provide the rationale.

Response:

A wave would have to be in excess of 3.5 metres to make contact with the Tilbury site and substantially higher still to be considered a threat to the Tilbury site. This is because the crest of the existing dike along the bank of the Fraser River has a nominal elevation of 3.5 metres above sea level. The grade of the Tilbury site has also been raised to 3.5 metres above sea level (geodetic datum).

106. Reference: Exhibit B-19, CEC 1.17.1

Westcoast does not publicly disclose the shippers that were awarded the capacity until closer to the expansion commencement date (estimated November 2021), but the weighted average term of the agreements was around 60 years. The long-term contractual agreements underpinning this expansion were well above FEI's bid, which made it clear that shippers in the region were placing more value on T-South capacity. FEI did not place a high value on its bid given that FEI was already holding excess pipeline capacity since contracting for an additional 66 MMcf/day of T-South Huntingdon Delivery capacity in October 2014. With this information, FEI recognized that the regional marketplace was becoming more constrained.

106.1. Please briefly describe FEI's understanding of the reasons that are causing the regional marketplace to become more constrained, and why FEI was not aware of this situation earlier.

Response:

The regional marketplace has become more constrained because of several factors that were detailed in Section 3.4.3 of Appendix C to the Application (ACP Compliance Report). In general, the main factors include the following:

- Increasing demand within FEI's natural gas service areas and within regional local distribution utilities in the Pacific Northwest during the winter season. The load profile of the demand is also changing, specifically due to the gas power generation in the region, as curtailable load declines. This puts a strain not only on peaking resources, but on baseload resources during the winter period. As illustrated in the response to the BCUC IR1 46.1 (Figure 2) there have been several periods of extreme pricing volatility at the Huntingdon marketplace, which reflects when demand in the Pacific Northwest region exceeds the delivery capacity of pipelines into the region.
- The Woodfibre LNG project has already secured firm transportation capacity on existing regional pipelines for a portion, if not all, of its supply requirements. At present, their capacity has been temporarily released in the secondary market. However, once the project comes online, the regional gas flow and prices for all customers may be impacted.[1]

FEI has been aware of the regional market constraints since 2013, and has taken action to mitigate these risks for its customers through its Annual Contracting Plans. These actions were further discussed in the response to Sentinel IR1 30.

[1] This market factor has been updated since the ACP Compliance Report was filed, given that one of the industrial projects in the region that secured firm transportation capacity recently cancelled its plan.

106.2. Please confirm or otherwise explain that had FEI been able to contract, and had contracted, significantly more supply, it would not have impacted the need for the current project.

Response:

Confirmed. As discussed in Section 4.3.4.2 of the Application, the T-South expansion would provide very little new resiliency from FEI's perspective, since it does not reduce the current single point of failure risk.

107. Reference: Exhibit B-19, CEC 1.27.1

Response:

Please confirm that demand side options for managing peak natural gas usage would also qualify as a portfolio planning measure and would also qualify as a contributing factor for resilience planning.

27.1

DSM measures targeting peak demand, such as demand response and geo-targeted DSM activity, remain new to the gas utility industry and are being explored by FEI and other utilities.

However, many uncertainties exist with respect to the extent of peak demand reductions and resiliency benefits that could be deployed and relied upon within FEI's service territory. FEI would require that more granular and timely consumption data collection be available to resolve these uncertainties than currently exists. FEI's currently proposed AMI Project, if approved by the BCUC, will improve FEI's understanding of peak demand usage and trends. FEI's investigations to date have explored the theoretical use of end use demand forecasting methods for their potential in forecasting peak demand and peak demand impacts of DSM. FEI is exploring how automated metering may assist in analyzing peak demand trends and the impacts of DSM on peak, and understanding how gas utilities in other jurisdictions are addressing the potential for DSM to help manage peak demand. FEI continues to explore advancements in these areas and consider alternative actions it may take to further explore the potential for DSM to impact peak demand on the gas infrastructure system in BC, including understanding the potential cost effectiveness of such measures.

107.1. When does FEI expect that it would have enough data from its AMI project to resolve the uncertainties?

Response:

If the AMI Project is approved and FEI is able to execute the meter deployment on the proposed schedule included in the AMI Application, the first meters will be installed in spring of 2023 and the final meters will be installed by late fall 2026. However, information sufficient to understand, verify, and fully apply meaningful changes to system planning processes, supported by data, and to apply those changes to the system at a larger scale will require data collection and assessment through multiple winter periods in all FEI operating regions. FEI expects this to take a few years beyond 2026 to complete.

While AMI will provide a significant improvement to understanding peak demand usage and trends, AMI on its own will not resolve all uncertainties in this regard. FEI would still need some understanding of the energy equipment and consumption patterns beyond the customer meters

in order to understand the impact on peak demand of changing equipment technology, building envelopes, or customer behaviour influenced by DSM programs. This type of information might be gained through end-use surveys of those customers for which AMI is deployed, through a sub-metering program that measures consumption at the end-use equipment, through sufficient pre- and post-measure installation monitoring of hourly load profiles, or some combination of these information sources.

107.2. What specific actions is FEI undertaking to learn how peak demand can be managed from other jurisdictions? Please explain.

Response:

In preparation for the 2022 LTGRP, FEI has commissioned a study, which is currently in progress, to review notable developments in other jurisdictions that are exploring non-pipe solutions (NPS) for addressing peak demand. The objective of the study is to inform how FEI may pursue non-pipe solutions by providing:

- Details regarding the relative impact on peak demand savings for different types/categories of DSM and demand response measures, including any details with regard to the reliability of peak demand savings and how quickly they occur;
- A summary of pilot project results from other jurisdictions, describing the different types of NPS pilot projects and providing insight into the ideal locations for such pilot projects;
- Insights into AMI's role in tracking impacts and enabling NPS, smart meter limitations/challenges, the implications of not having smart meters (e.g., safety factors), and the approaches that other utilities are using in the absence of smart meters; and
- Details regarding the timing requirements for the implementation of NPS as an alternative to facility investments, including recent developments in thinking on this topic from other jurisdictions.

Further, FEI monitors the integrated resource planning activities of a number of other gas utilities in Canada and the US, some of which are also exploring opportunities for non-pipe solutions. FEI will be reporting on its learnings in the 2022 LTGRP.

108. Reference: Exhibit B-19, CEC 1.28.1

Has FEI considered offering time of use pricing and more particularly critical peak pricing as a means of managing the peaks on the system and moving from an initial voluntary opportunity to an opt out opportunity to an eventual mandatory service to a particular point of reasonable service, and if so, could FEI provide information on its assessment?

FEI has not considered offering time of use pricing and critical peak pricing as a means of managing the system peak demand, as FEI's peak demand is primarily driven by space heating during extreme cold temperatures, which can happen anytime during the day. Also, FEI's infrastructure limitations would make such service offerings only available to a limited portion of customers, many of which already have access to interruptible rates considered in FEI's peak demand forecasting.

108.1. Does FEI offer interruptible rates to commercial customers?

108.1.1. If no, please explain why not.

Response:

Customers who wish to be on interruptible service will generally be under Rate Schedule (RS) 7 (sales service), RS 27 (transportation service), or RS 22 (large industrial transportation service)[2].

RS 7 and 27 are the rate schedules for FEI's General Interruptible Service available to commercial and industrial customers who have the ability to curtail their usage with short notice. Although there is no minimum volume requirement under RS 7 and 27, these might not be the most economic rate schedules for commercial customers. For example, based on the current October 2021 rates, an RS 3 large commercial customer would have to consume at least 4,000 GJ per year in order to break even for switching to RS 7, and an RS 23 large commercial transportation customer would have to consume at least 4,700 GJ per year to break even for switching to RS 27.

RS 22 is meant for large volume transportation customers with a minimum monthly charge for 12,000 GJ per month. The delivery charge is applied to the greater of 12,000 GJ or actual volume in determining the total monthly charges.

In addition to volume commitment, customers who wish to take interruptible service under RS 7, 27, and 22 need to consider other factors such as:

- the customer's capital costs to install a backup energy system;
- the cost of the alternate backup fuel;
- the opportunity cost to the customer of potential lost production, should they need to curtail their operations; and

[2] RS22 also include RS 22A and RS 22B, however both are currently closed for new customers. As such, customers from other rate schedules or new customers cannot switch to or take service under these two rate schedules.

- the potential frequency and level of service curtailment to the customer.

Curtailments generally occur when extreme cold weather restricts capacity in local area(s) for interruptible customers. The duration can be for a few hours; however, there have been instances when curtailment was for an entire day. During curtailment, customers under interruptible service will have to switch to their own alternate fuel system.

In summary, commercial customers generally do not choose to take service under interruptible rate schedules due to the consideration of volume commitment, the costs, and availability of alternative/backup fuel. However, interruptible service is available to commercial customers.

108.2. To what Rate Schedules does FEI offer interruptible rates?

Response:

Please refer to the response to CEC IR2 108.1.

108.3. Please provide the total Tjs annually consumed by each rate schedule.

Response:

Please refer to the table below for the following information for each of Rate Schedules (RS) 7, 27, and 22:

1. the total annual demand in GJ;
2. the average daily demand in GJ;
3. the non-coincident peak demand in GJ; and
4. the date of the peak demand in 2018, 2019, and 2020.

For system planning purposes, the interruptible load is treated as a zero peak load as interruptible service customers would be curtailed in order for FEI to meet the firm load customer's peak demand.

Line	Particulars	2018	2019	2020
1	Rate Schedule 22			
2	Total Annual Demand (GJ)	14,945,219	13,806,820	11,123,727

Line	Particulars	2018	2019	2020
3	Average Daily Demand (GJ)	40,946	37,827	30,393
4	Non-Coincident Peak Demand (GJ)	63,168	56,621	42,986
5	Date of Peak Demand	Apr. 5, 2018	Apr. 17, 2019	Apr. 13, 2020
6	Rate Schedule 7			
7	Total Annual Demand (GJ)	906,123	2,968,882	6,463,207
8	Average Daily Demand (GJ)	2,483	8,134	17,659
9	Non-Coincident Peak Demand (GJ)	5,544	27,102	44,459
10	Date of Peak Demand	Dec. 4, 2018	Nov. 29, 2019	Jan. 14, 2020
11	Rate Schedule 27			
12	Total Annual Demand (GJ)	6,612,514	5,882,034	4,606,615
13	Average Daily Demand (GJ)	18,116	16,115	12,586
14	Non-Coincident Peak Demand (GJ)	33,773	31,173	24,056
15	Date of Peak Demand	Feb. 21, 2018	Feb. 4, 2019	Jan. 13, 2020

108.4. Please breakdown the Peak Demand by rate schedule.

Response:

Please refer to the response to CEC IR2 108.3.

109. Reference: Exhibit B-15, BCUC 1.13.3

> 13.3 Please explain whether FEI has any evidence that customers would not respond to public appeals for curtailment in cold winter weather.
>
> **Response:**
>
> While some customers may respond to public appeals during cold winter weather, for the majority of FEI's customers, the energy used for space heating and hot water is vital to their health and safety; therefore, the non-discretionary nature of this load imposes inherent limitations on the extent to which load can be managed and relied upon during a supply emergency.
>
> Customer behavior suggests that, unless the customer understands the nature of the emergency and how their actions could help, the customer will be less likely to take action. Customers' knowledge of energy usage and energy systems, specifically the gas system and how it functions, is low and as such, while FEI saw reductions in gas usage following initial public appeals, customers quickly reverted back to their previous energy consumption patterns. Further, public appeals had a diminishing effect the longer the appeals continued as customers became fatigued with repeated requests for conservation.
>
> Further, the primary energy sources in BC for cooking, space heating, and hot water are natural gas and electricity. If large amounts of gas load temporarily switched to electricity during public appeals for curtailment, this could overload the electrical grid, which could lead to brownouts or blackouts.

109.1. Is FEI referencing residential customers in this response? Or is it referring to a majority of all of its customers?

Response:

FEI's response is referring to the majority of all of its customers; however, for clarity, of the utility's approximately 1,050,000 customers, over 99 percent are in residential or small commercial rate schedules.

109.2. Does FEI experience any different responses from commercial and industrial customers than it does from residential customers? Please explain how they differ.

Response:

FEI does not have individual daily metering in place for its mass-market residential, small, and large commercial customers. Therefore, FEI cannot differentiate how these different customer groups responded to the public appeals, and in particular, how commercial and industrial customers that have daily metering would or did respond.

110. Reference: Exhibit B-19, CEC 1.37.2 and 1.37.4

Seismic Events: As discussed in the response to CEC IR1 37.4, the inner 9 percent Nickel tank is designed to maintain its structural integrity after a Safe Shutdown Earthquake (SSE) event with a return period of 2475 years. An SSE seismic event could theoretically cause leakage of the inner tank allowing the LNG product to gradually fill the outer concrete tank during this spill condition. The outer concrete containment is also designed to survive the SSE event and would contain the spilled product accordingly.

The inner tank is designed to withstand the risk of both OBE and SSE seismic events. The inner tank is designed to remain operable after an OBE earthquake and to maintain its structural integrity after an SSE earthquake.

110.1. Do the seismic events that would cause leaks consider the risk of liquefaction? Please explain why or why not.

110.1.1. If no, is there any risk of liquefaction on the site?

110.1.2. What would be the potential outcome of a seismic event that resulted in liquefaction on the site?

Response:

The risk of soil liquefaction is considered in the seismic design of the tank. As noted in the preamble, the foundations supporting the new tank and its secondary containment system will be designed to withstand the Operating Basis Event (OBE) and Safe Shutdown Event (SSE) seismic events. This addresses the effects of soil liquefaction and its associated consequences, such as seismic displacements, by constructing deep ground improvement measures to densify the soils both below the tank footprint and beyond. The implementation of the proposed deep ground improvement measures will provide the necessary safety margins and will control the foundation displacements or deformations to ensure the integrity of the storage tank.

If these ground improvement measures were not implemented, then a seismic event could cause soil liquefaction of unimproved soils (i.e., undensified soils), which would then result in a reduction of the ability of the foundation soils to support the load from the tank. Such soil liquefaction would result in vertical, lateral and rotational foundation displacements which could compromise the inner or outer LNG storage tank walls. In the event of a breach of the inner tank wall, the LNG would be contained by the outer tank wall. If both tank walls were to breach, it is possible that some LNG may spill to the external environment where it would pool and dissipate. In the unlikely event this were to occur, FEI would enact its response procedures to secure the site and respond to the spill.

111. Reference: Exhibit B-19, CEC 1.37.3

Exposure to cryogenic temperatures: At the leak source, LNG could come in contact with items in the immediate vicinity (i.e., structures, vegetation, etc.) which may not be suited to the shock of cryogenic temperatures. This exposure to cryogenic temperatures could cause damage (to structures) or low-temperature burns.

Displacement of atmosphere: Leaking LNG could come into contact with ambient-temperature objects and the atmosphere, which will cause it to vapourize (or "boil off"). Sufficient boil off could create a natural gas cloud which could displace air and create an unsafe breathing environment. Given that methane is lighter than air and will naturally rise, the more likely outcome of this potential risk is that the gas cloud will harmlessly dissipate into the atmosphere.

Explosion: If a large quantity of LNG vapourizes to gas, mixes with sufficient air, and reaches an ignition source, an explosion is possible. However, this is only possible if it were to occur in a confined area, and when the gas/air mixture is in a narrow range of combustibility. In open areas, if vapour clouds ignite they would normally burn slowly without creating an explosion. For further clarity, LNG itself is not combustible – it must be in vapour form to ignite.

Fire: If LNG vapourizes to gas, mixes with sufficient air, and reaches an ignition source it could burn back to the source and form a flame over the pool of LNG. For further clarity, LNG itself is not combustible – it must be in vapour form to ignite.

111.1. Please provide a map identifying, to the best of FEI's ability, the area that would be affected in each event.

Response:

These event types and associated risks have been evaluated as part of the quantitative risk analysis (QRA). The level of detail completed to date in the QRA is acceptable for this stage of the engineering design. Evaluating the area that would be affected by each event would require additional engineering to assess and would have a necessarily wide outcome of results at this stage of Project development, as more detailed design information is not available to conduct more accurate assessments.

These types of events will be assessed as part of the BC Oil and Gas Commission's oversight of the Project development. As part of its permitting process, risk analysis and mitigation of the events noted in the above preamble will be evaluated, considered and approved prior to the issuance of the operating permit.

112. Reference: Exhibit B-19, CEC 1.38.3

Other risks that are common to any natural gas processing facility include:

- Overpressure;
- Underpressure;
- Fire; and
- Gas releases.

112.1. Please confirm, or otherwise explain, that FEI's safety precautions can significantly mitigate the above natural gas processing facility risks.

Response:

FEI confirms that safety precautions can significantly mitigate all of the natural gas processing facility risks identified above.

112.2. Would FEI agree that earthquakes represent the most significant uncontrollable risk? Please explain why or why not.

Response:

FEI agrees that earthquakes in excess of design limits may represent an uncontrollable risk to the Tilbury facility, but FEI's system has been designed to comply with the most recent earthquake code requirements. FEI has not evaluated scenarios in which these design limits are exceeded and therefore cannot quantify the risk exposure this represents.

113. Reference: Exhibit B-19, CEC 1.45.2

1. Response:

FEI intends to competitively tender the EPC works for the project, as noted in the Application.

Some of the expert organizations used to develop the Class 3 estimate may be invited to participate in the bidding, and may be awarded work if they are found to have submitted the best- value bid.

113.1. Which party(ies) will be responsible for issuing the tenders and awarding work? Will this be outsourced or will FEI make these decisions internally? Please explain.

Response:

FEI will lead the tendering process and decisions with respect to awarding work. Furthermore, FEI retains responsibility to make all decisions related to the award of contracts. FEI may utilize contractors to support aspects of the work if required, under the direction of the FEI project management team.

114. Reference: Exhibit B-19, CEC 1.61.3

61.3

Response:

Would FEI agree that making payments in USD exposes ratepayers to market risk? Please explain why or why not.

Making payments in USD could expose ratepayers to a certain amount of foreign exchange risk, which is a type of market risk. However, FEI believes changes in CAD/USD foreign exchange are not an unnecessary or excessive amount of risk.

Furthermore, the value of USD in a global marketplace will always play a factor in project budgets regardless of whether FEI transacts with a Canadian supplier in CAD or a US supplier in USD. This is because most commodity prices for materials used in projects are benchmarked to USD. For example, a Canadian supplier who sources from a US supplier for components of their product will be exposed to foreign exchange risk, which is then passed on to FEI and ratepayers indirectly.

114.1. Please provide an estimated range associated with the USD foreign exchange risk.

Response:

In the response to BCUC IR1 45.1, FEI provided a table showing the capital cost and USD/CAD exchange rates used by consultants that developed the individual components of the cost estimates. As part of that table, there is approximately $214.190 million CAD included in the Project forecast that relates to underlying USD costs. FEI cannot speculate as to the degree of movement in foreign exchange rates in the future. However, to illustrate the sensitivity of foreign exchange rate changes, under a scenario where there is a 5 basis point shift (upwards or downwards) in the underlying USD/CAD exchange rate assumptions used in the development of the forecast Project costs, the resulting impact would be a change of approximately +/- $14 million CAD in Project costs.

115. Reference: Exhibit B-19, CEC 1.62.1

115.1. FEI provides a map with areas of Potential contamination. Is there potential for the contamination to reach the adjacent water? Please explain why or why not.

115.1.1. If yes, how would FEI address any contamination that extended to the water?

Response:

Given the proximity of the Tilbury facility to the Fraser River and Tilbury Slough, there is a potential for contamination to leave the site and reach adjacent waterways. The preliminary draft results of the Stage 2 PSI did not identify any offsite migration of contamination.

If offsite contaminant migration occurs, FEI would follow regulatory requirements in the BC *Contaminated Site Regulation*.

115.1.2. Is the greenspace at the water's edge open to the public?

115.1.2.1. If not, please explain why not.

115.1.2.2. If not, would FEI be willing to make the greenspace at the water's edge open to the public for recreation? Please explain why or why not.

115.1.2.3. If yes, what costs, if any would be incurred to open the greenspace to the public for recreation? Please quantify.

Response:

The green space along the northwest perimeter of the Tilbury site that separates the Fraser River from FEI's property is Crown Land and currently accessible from the dike via Hopcott Road. The TLSE Project does not limit access to this area.

116. Reference: Exhibit B-19, CEC 1.63.3

Response:

63.1 Please elaborate on the risks associated with Metro Vancouver permitting.

Under the Provincial Environmental Management Act, Metro Vancouver (MV) is the delegated authority to regulate air emissions in the Metro Vancouver Regional District. In November 2020, MV released a Discussion Paper, titled "Proposed Amendments to Air Quality Permit and Regulatory Fees in Metro Vancouver" (the Paper), to provide an overview of its future regulatory intentions. The Paper indicates that MV intends to regulate Greenhouse Gas (GHGs) from industrial facilities such as Tilbury and also that it intends to significantly increase fees associated with all emissions. In terms of GHG emissions, MV currently regulates only methane. The Paper also provides an outline of the resource and timeline challenges MV has under its current system in meeting its permitting mandate. Until these uncertainties are clarified, undertaking permitting with MV is viewed as having an increased risk.

116.1. Please provide an order of magnitude of the current fees and what may be considered a 'significant increase'.

Response:

As a result of Metro Vancouver's Proposed Amendments to Air Quality Permit and Regulatory Fees, the estimated total application fee for the TLSE Project will increase from $50 thousand to more than $200 thousand.