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September 13, 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. 1

FEI respectfully submits the attached response to TWN IR No. 1 in the Application referenced above.

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

INTRODUCTION AND SUMMARY

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

> The T-South Incident resulted in a 2-day "no-flow"[1] period, despite favourable conditions that facilitated Westcoast's efforts to restore gas flows on the T-South system. After the T-South Incident, supply to FEI's system remained constrained for approximately 14 months. The experience informed FEI's determination of a specific minimum resiliency objective for prospective planning:
>
> > *Having the ability to withstand, and recover from, a 3-day "no-flow" event on the T-South system without having to shut down portions of FEI's distribution system or otherwise lose significant firm load.*
>
> FEI uses the term "**Minimum Resiliency Planning Objective**" in this Application to signify this identified prospective minimum resiliency need. FEI has characterized this planning objective as a *minimum* objective because (i) a "no-flow" event could last longer than 3 days, and (ii) supply
>
> [1] FEI uses "no-flow event" in this Application to refer to an incident affecting regional pipeline infrastructure that results in the total interruption of gas flows on the pipeline. Similarly, the "no-flow" period is the period following the event that results in a total interruption of gas flows from that pipeline.
>
> can remain constrained even after the resumption of flows (as occurred with the T-South Incident); during this subsequent period, commonplace gas supply and peak demand events take on greater significance from the standpoint of maintaining uninterrupted service to customers.

1.1 Please provide the evidence that would define the probability of the occurrence of a 3-day "no flow" event on the T-South system.

<u>Response:</u>

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.

1.2 Please provide the evidence that would define the probability of the occurrence of a 14 months constrained capability for T-South system flows after such a "no flow" event and the expected levels of capacity service during that time.

Response:

Please refer to the response to BCUC IR1 1.5 which defines the likelihood of occurrence of rupture events on the T-South system.

As discussed in the response to BCUC IR1 1.3.1, the timing to re-establish 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 – may require investigation and assessment by multiple authorities, including the CER;
- time of year – incident occurring during favorable or unfavorable conditions with respect to work that needs to be done to resume gas flow; and
- incident location – ease of access to incident location.

Further, as explained in the responses to BCUC IR1 1.9 and 2.2, supply disruptions can occur due to a variety of causes. While FEI cannot assess all of the conditions that could lead to supply disruptions on other operators' systems and resulting levels of capacity, FEI has assessed the conditions that can lead to an incident to FEI's system with significant consequences (e.g., widespread and lengthy service outages). Given the potential significant consequences, the TLSE Project is a reasonable and appropriate response to mitigate the risk of reduced pipeline flows following a no-flow event and will significantly improve FEI's ability to maintain continuity of service to customers.

1.3 Please provide the evidence of what the owners of the T-South system have done, are doing and/or plan to do in order to prevent a reoccurrence of the "no-flow" event and what they have done, are doing, and/or plan to do in order to mitigate the impacts of a "no-flow" event.

Response:

Please refer to the response to BCUC IR1 1.3.1.

1.4 Please provide the evidence of what the owners of the T-South system have done, are doing, and/or plan to do in order to prevent a reoccurrence of the "14 months constrained capability" event and what they have done, are doing, and/or plan to do in order to mitigate the impacts of a reoccurrence of the "14 months constrained capability" event.

Response:

Please refer to the response to BCUC IR 1.3.1.

FEI is not aware of specific actions being undertaken by Westcoast to prevent or mitigate the impacts from a reoccurrence of a "14 months constrained capability" event, but FEI recognizes that many of the factors listed in the response to BCUC IR1 4.3 are outside of the direct control of the operator.

1.5 Please provide FEI's understanding of the types of damages its customers suffered during the "no-flow" period and the "constrained capability" period and FEI's estimate of the damages its customers suffered during these two periods. Please explain whether or not FEI did work on capturing specific estimates of the customer impacts of this event.

Response:

Please refer to the response to BCUC IR1 4.1 for a discussion of gas cost and delivery rate impacts associated with the T-South Incident.

2. Reference: Exhibit B-1, Page 2

> Resiliency – the ability to respond to, survive and recover from significant adverse events – is an essential consideration in system planning. The Project will significantly improve FEI's ability to maintain continuity of service and avoid widespread and lengthy service outages in the event that the supply of upstream natural gas is disrupted. FEI recognizes that the Project cost is significant, but based on the experience of the T-South Incident, it is evident that a significant investment of some kind is required – i.e., doing nothing is unrealistic. The Project represents the best way to achieve the targeted resiliency cost-effectively, and it provides ancillary benefits for customers.

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.

<u>Response:</u>

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.

2.2 Please quantify the degree of improvement anticipated from the Tilbury LNG Expansion project, in absolute and percentage terms, in FEI's estimates of customer damages from lack of continuity of service and from widespread and lengthy service outages.

Response:

As noted in Section 3.5.4.1.5 of the Application, the current regasification capacity at Tilbury (150 MMcf/day) would provide FEI only 17 percent of gas required to meet the Lower Mainland design day load (865 Mmcf/day[1]). The regasification capacity for the TLSE Project (800 MMcf/day) would enhance the percentage of gas required to meet the Lower Mainland design day load to 92 percent (or 100 percent for all but the highest design day).

Section 3.5.4.1.5 of the Application also noted that the storage tank capacity needs to be considered in tandem with expanded regasification, since a higher rate of regasification will empty a tank faster. If the regasification constraint was removed without addressing the size of the tank, then the 0.6 Bcf Base Plant tank would only be able to provide approximately 17 hours of resiliency support during peak winter load conditions. In contrast, the TLSE Project will have 3 Bcf of storage, of which 2 Bcf is set aside as a minimum reserve and the remaining 1 Bcf will offer resiliency benefits and help FEI manage through the period following the no-flow event as well as other ancillary benefits. The number of hours of resiliency support during peak winter load conditions from the minimum reserve of 2 Bcf will increase to approximately 57.5 hours[2].

These enhancements would greatly improve FEI's ability to manage through a no-flow event. However, FEI would still be at some risk (albeit much lower than today) of either controlled or uncontrolled shutdowns, at any time that customer demand exceeds available supply, especially during a lengthy supply outage. As discussed in the response to BCUC IR1 4.4, the TLSE Project will significantly improve FEI's ability to maintain continuity of service either by withstanding the supply disruption entirely or by "buying time" to shut down the system in a controlled manner.

2.3 Please provide FEI's evidence of its assessment that "doing nothing is unrealistic".

Response:

As discussed in Section 3.4.2 of the Application, the T-South Incident brought into sharp focus the risk of supply interruption for FEI's customers. FEI obtains most its natural gas supply for the Lower Mainland through the T-South system, making a disruption on the T-South system the greatest supply risk facing FEI at present. Please also refer to the responses to BCUC IR1 9.1 and 14.5 for a discussion of why the TLSE Project is need at this time.

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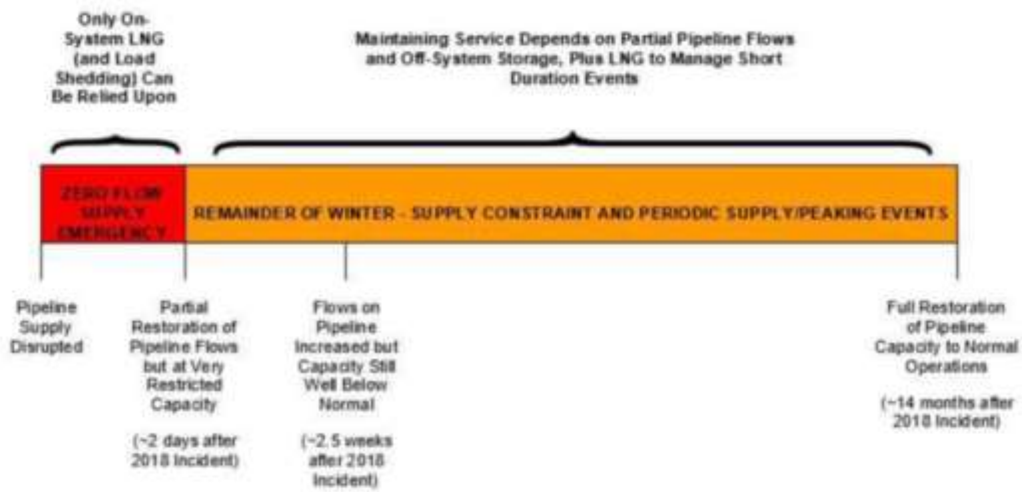
1 As discussed in the response to BCUC IR1 19.1, FEI updated design load forecast for the gas year 2019/20 excluding Rate Schedule 7 and Whistler customers to 865 MMcf/day, which is slightly lower than the previous forecast (871 MMcf/day).

2 This is conservative calculation for quantifying the amount of resiliency support the TLSE project will provide as it assumes a constant 800 MMcf/day of regasification. FEI would expect the actual duration of resiliency support to be longer.

Although supply emergencies are rare, they do occur, and if nothing is done to address FEI's dependence on the T-South system, the potential consequences of a future supply disruption would be significant, and would not be acceptable to FEI, its customers, or the province of BC as a whole. Please refer to Section 3.4.4 for the potential consequences of such an outage.

3. Reference: Exhibit B-1, Page 4

Figure 1-2: Illustrative Timeline of T-South Supply Emergency and Available Resources



Pipeline disruptions are rare, but the T-South Incident was not unique. During the past decade, there have been ten other supply disruptions in North America of varying severity.

3.1 Please provide the total known significant disruptions of supply for natural gas to the major BC population centres since the inception of natural gas service in BC based specifically from disruption of supply from Northeastern BC natural gas fields.

Response:

Please refer to the response to BCUC IR1 3.1.

3.2 Please fill out the following table with respect to the recent 10-year set of supply disruptions in BC, across Canada, and in the US, identifying the duration of flow disruption, the number of customers affected by class (residential, commercial, institutional and industrial – or such other categorization as may be available).

Natural Gas Supply Disruption Events 2009 - 2019 in BC, Canada and Northwest US

Province	Date	Location	Description	Units	Flow Disrpution Duration Days	End Customers Impacted # of Customers	Days of No Supply to End Customers Days	Days Supply Restricted Days
BC								
	9-Oct-18	Prince George	Enbridge T-South Rupture		9	999,999	99	99
	28-Jun-12	Buick	Enbridge Nig Creek Rupture		9	999,999	99	99
	23-Jun-12	Fort St. John	Enbridge Valve Enclosure Fire		9	999,999	99	99
	20-Feb-09	Wonowon	Enbridge Alaska Highway Pipeline Sending Barrel Rupture		2	999,999	99	99
MB								
	25-Jan-14	Otterbourne	TC Mainline Rupture		9	999,999	99	99
AB					9	999,999	99	99
	17-Oct-13	Fort McMurray	TC NOVA Rupture		9	999,999	99	99
ON								
	19-Feb-11	Beardmore	TC Line Explosion & Fire		9	999,999	99	99
	26-Sep-09	Marten River	TC Line 100 Rupture		9	999,999	99	99
	12-Sep-09	Englehart	TC Line 2 Rupture and Fire		9	999,999	99	99
WA								
	9-Mar-16	Seattle	Puget Sound Energy Distribution Line Rupture		9	999,999	99	99
	31-Mar-14	Plymouth	Williams and Plymouth LNG Facility Explosion & Fire		9	999,999	99	99

Response:

Please refer to the response to BCUC IR1 64.1.

3.3 Please provide the FEI natural gas revenues and number of customers for each of the last 20 years and note any supply disruptions and the estimated revenue loss on account of the event.

Response:

The table below provides the actual natural gas revenues (sales and transportation service) and the 12-month average number of customers from 2001 to 2020.

For this information request, FEI interprets supply disruption as the failure to deliver natural gas or propane from an upstream supplier due to a failure on the upstream supplier facilities. In this context FEI excluded extreme cold weather conditions that might have resulted in curtailment of gas to interruptible service customers over the years. In the past 20 years the only supply disruption resulting from upstream failure was the one that occurred in October 2018 on the T-South system.

For the estimated financial impacts to customers related to the T-South Incident, please refer to the response to BCUC IR1 4.6.

Year	Actual Revenues ($000s)	Actual Average # of Customers
2001	$1,358,772	760,236
2002	$1,174,488	766,929

Year	Actual Revenues ($000s)	Actual Average # of Customers
2003	$1,306,709	770,624
2004	$1,344,895	779,461
2005	$1,422,823	791,593
2006	$1,518,645	802,778
2007	$1,436,104	816,421
2008	$1,482,036	825,693
2009	$1,338,741	832,751
2010	$1,306,986	839,017
2011	$1,198,353	845,282
2012	$1,128,226	834,888
2013	$1,093,973	841,175
2014	$1,196,084	851,341
2015	$1,313,229	968,766
2016	$1,179,701	983,807
2017	$1,213,947	997,380
2018	$1,173,516	1,016,353
2019	$1,246,351	1,031,862
2020	$1,338,747	1,044,623

3.4 Please provide all of the information FEI collected from the 2018 Enbridge T-South Rupture event to indicate (a) how many customers were completely without natural gas service and for how long they were without service, (b) how many customers had FEI constrained service and for how long the constraints were in place, (c) how many customers had full service but were asked by appeal to constrain their own usage, and (d) any information FEI collected from customers with respect to mitigation the customers were able to employ and the business impact to those customers related to a lack of natural gas supply.

Response:

Please refer to the response to RCIA IR1 13.1 for the number of customers that had their gas supply curtailed during the T-South Incident. These included major gas consumers such as pulp and paper, wood products, refineries, manufacturing, food and beverage, chemical, cement, and greenhouse industries, in addition to hospitals.

FEI started contacting its largest customers on October 9 and 10, 2018 declaring *force majeure* and requesting that they curtail their firm and interruptible consumption during the no-flow timeline.

Once Westcoast re-established some gas flow on its system, FEI started to allow customers to resume firm natural gas usage on October 11, 2018, as long as their gas marketer had the physical supply available for them. Interruptible usage was also allowed to resume on October 13, 2018, subject to the customer's gas marketer having the physical supply available for them. The majority of FEI's largest customers utilize gas marketers for their physical supply so once gas resumed flowing on Westcoast 's system, FEI eased restrictions on its customers; however, they were limited to the amount of gas that was available off the Westcoast system that their gas marketer could procure for them. These supply constraints were constantly changing and the PNW region experienced these restrictions until the Westcoast pipeline resumed at 100 percent operation roughly 14 months after the original pipeline incident.

In addition to the restrictions discussed above, FEI made public appeals through media channels to all of its remaining approximately 1 million customers to reduce their consumption during the no flow event. Given that FEI supplies the gas commodity to the majority of these customers, FEI continually engaged with them to provide education and updates on the status of changing supply constraints in the region. Continual engagement was necessary in the event that FEI required customers to take additional measures to reduce usage if the gas supply situation had deteriorated.

FEI did not collect and compile any information regarding mitigation that customers employed or the business impacts related to the lack of natural gas supply. However, FEI did hear complaints about the impacts related to the T-South Incident. For example, customers commented on high prices following the event across the region and mentioned business and production losses following the event. Some industrial customers reported challenges restarting their business following the no-flow event due to supply constraints in the region.

4. Reference: Exhibit B-1, Page 5

> FEI has characterized this resiliency planning objective as a *minimum*, in recognition of:
>
> - the potential for the "no-flow" period to exceed 3-days, and
> - the fact that a significant interruption will result in ongoing pipeline supply constraints that can pose challenges when responding to common demand and supply events.

4.1 Please confirm that the October 9, 2018 event had a period of 2 days with "no flow".

Response:

Confirmed.

4.2 Please describe any discussions or communications with Enbridge that would indicate that they take the "no-flow" conditions in a disruption event seriously and identify everything Enbridge is planning to do to shorten the time it takes to relieve a "no flow" condition caused by a rupture event and to shorten the length of time it takes to recover to full capacity service.

Response:

Please refer to the responses to BCUC IR1 1.6.1 and 1.3.1.

4.3 Please identify what the CER, with regulatory responsibility for Enbridge, is doing with respect to the time it takes Enbridge to recover from a "no flow" event and the time it takes to recover to full capacity.

Response:

FEI is not aware of any regulatory direction from the CER to Westcoast aimed at accelerating the time to recover from a no-flow event.

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.

5. Reference: Exhibit B-1, Page 5

> FEI aims to avoid shutting down portions of FEI's distribution system or otherwise losing significant firm load because large scale load shedding has significant customer and broader socio-economic impacts. Shutting down portions of the system is irreversible in the short term, as customer restoration is a manual process that can take weeks.

5.1 Does FEI Plan to work with its commercial, industrial, and transportation customers to determine which customers want assurance of avoiding short term load-shedding in the event of a pipeline rupture event with very low probability of occurrence and does FEI plan to determine what level of insurance costs they would be prepared to cover in order to avoid such a disruption?

Response:

FEI does not plan to work with individual customers to determine which customers want assurance of avoiding short term load-shedding or to determine what level of insurance costs they would be prepared to cover to avoid such a disruption. FEI's primary objective in the event of a supply emergency – and FEI believes this is the appropriate objective – is to reduce the overall impacts of the event on customers and society by preventing a system collapse. Due to the potential rapid and widespread onset of a supply emergency, it is not practical, nor likely possible, to manage the additional objective of prioritizing supplying of gas to certain customers who wish to maintain service for their businesses even if they are prepared to pay a higher rate for such service.

Further, qualifying customers already have the option of moving to interruptible rate schedules if they feel that lower rates offset the reduced level of service reliability that may be received. These customers would then be responsible for their costs associated with interruptible service such as alternate fuel costs, equipment upgrades to enable multi fuels and/or even securing appropriate business interruption insurance (if available). Conversely, existing customers on interruptible rate schedules may opt to switch to a non-interruptible rate schedule should they require heightened service reliability.

FEI believes the appropriate response to the identified risk represented by a no-flow event on the T-South system is to improve FEI's ability to maintain continuity of service to <u>all</u> customers. The TLSE Project is an effective, and cost-effective, response.

6. Reference: Exhibit B-1, Page 7

Load Management	Automated Metering Infrastructure (AMI)	AMI remote shut-off capability will add resiliency by reducing the potential for an uncontrolled shutdown, but is best viewed as complementing supply-side solutions. Without additional supply in event of a "no-flow" event, large scale load shedding would be required, leaving many non-interruptible customers without service.

6.1 Is it possible that FEI could have a "no-flow" event, even with its preferred on-system storage solution and what does FEI estimate the probability of such an event being?

Response:

The TLSE Project does not change the likelihood or probability of a no-flow event; it only changes FEI's ability to address the consequences of such an event. This is consistent with FEI's determination of the MRPO (i.e., having the ability to withstand, and recover from, a no-flow event).

It is possible FEI could experience a no-flow event lasting longer than three days. The types of incidents and the timing to re-establish supply during a no-flow event were discussed in the responses to BCUC IR1 1.3 and 1.3.1, respectively. One of the reasons that FEI's preferred option is a 3 Bcf tank is that it will provide a resiliency margin above the 3-day no-flow event that FEI has characterized as a minimum (i.e., the MRPO). FEI is also pursuing a suite of resiliency investments to enhance FEI's system resiliency as discussed in the response to BCUC IR1 10.6. This includes the development of a Regional Gas Supply Diversity Solution, which could entail a pipeline flow path separate from the T-South system, providing a new route to serve the Lower Mainland.

Please also refer to the response to BCUC IR1 1.5.

6.2 Please confirm that remote shut-off must be accompanied by relighting, which at this time is a manual labour-intensive process.

Response:

Confirmed. Similar to manually closing the valve upstream of a meter at a customer's premise, the remote shutoff capability included in an AMI meter interrupts all gas flow to downstream customer appliances. When service is resumed by opening the valve in the AMI meter, any customer appliances employing standing pilot lights will need to be relit.

However, if the proposed AMI project is approved, remote monitoring and reconnection functionality available in the meter will provide FEI with flexibility to enhance the relight process to potentially be more timely and convenient for customers as discussed in the response to BCUC IR1 16.2.

6.3 Is FEI aware of any technologies, existing or being developed, which could enable controlled and automated relighting in the event of a shut down?

Response:

FEI is aware of appliance technologies that are already in widespread use that do not require manual relighting after a shutdown. These include intermittent pilots and other electronic ignition systems that are incorporated in end use appliances. However, appliances with traditional standing pilot lights continue to be in widespread use and are still being installed throughout FEI's system.

FEI does not know what type or how many gas appliances a customer has in their home so FEI expects it will still have to contact each customer before turning on their gas supply and commencing the required relight(s). Also, appliances with an automatic ignition will, in most cases, lock-out when gas supply is lost and it is FEI's experience that many customers require support when this occurs.

6.4 If FEI's AMI project included thermostat control capabilities would FEI have an ability to constrain use, but not shut down use, across the those accounts?

Response:

If FEI's AMI Project included thermostat control capabilities, FEI would have the ability to reduce gas use with respect to space heating; however, this is the only reduction that could be achieved because all other gas appliances (e.g., stoves and hot water tanks) are manually controlled by the customer. Further, unlike electric AMI meters, gas AMI meters are battery powered and have limited communication capabilities. The meter's battery life would be degraded by communications between the meter and other customer devices, including thermostats. Therefore, FEI does not plan on having any network connections between the meter and other customer devices.

It is possible to manage customer devices such as thermostats through other third-party owned communication networks, but this would result in additional costs and is not necessary to successfully implement the AMI project. As such, this option was not included in the scope of the proposed AMI project.

Please refer to the response to BCUC IR1 13.3 for a discussion of the potential for customers to respond to load curtailment requests during cold winter weather.

6.5 If some customers wanted to avoid the costs of avoiding load shedding, please explain how FEI could accommodate their interests and service the load-shedding in a major disruption event.

Response:

FEI interprets the question as asking how FEI could accommodate the desire of customers who wanted to continue receiving service in a major disruption event. FEI believes that the TLSE Project provides the most effective means of minimizing the need for load shedding during an emergency and explains in more detail below.

In a major disruption event, FEI ultimately needs to balance the supply and demand on the system to avoid an uncontrolled shutdown of the system. Depending on the nature of the event, FEI would need to determine if its supply resources are sufficient to meet demand, and if not, would need to reduce demand on the system through load shedding. The TLSE Project provides needed supply during an emergency and is an effective means of potentially avoiding load shedding, depending on the nature of the emergency. However, without further resiliency resources like the TLSE Project, FEI would have a higher probability of restricting service to interruptible customers and potentially to firm customers to preserve the system. In addition, the AMI Project can minimize load shedding by enabling FEI to shed load in a more controlled fashion instead of shutting off gas to large sections of the gas system or entire communities, which FEI might need to do in the absence of this technology.

7. Reference: Exhibit B-1, Page 7

SCP Expansion to Huntingdon	New regional pipeline adds resiliency by diversifying supply into the Lower Mainland. Some gas will still be available if there is a failure on one pipeline system (T-South or expanded SCP). However, even if constructed, new storage would still be required to supplement remaining pipeline flows and avoid significant load shedding. Cost savings from reducing the size of on-system LNG are limited due to inherent economies of scale.

7.1 Would SCP Expansion at Huntington be capable of providing diversified supply to the Pacific Northwest, given that this area also has little unutilized capacity and has expanding demand?

7.2 If so, how would FEI gain the participation of partners in the Pacific Northwest to mitigate the financial costs of diversification?

Response:

The SCP expansion would allow parties in the Pacific Northwest to access diversified incremental supply from a new market hub, the AECO/NIT market, and flow it on a new path to Huntingdon where the Northwest Pipeline system begins.

To explore interest in such a project, FEI would enter into confidential discussions with key parties in the Pacific Northwest regarding the SCP expansion to Huntingdon. Within these discussions, FEI could discuss offering firm capacity for contracting on the new line at negotiated tolls, which would help mitigate some of the annual cost of service of the expansion. This would be consistent with past practice. For example, FEI has worked with third parties to support recovering SCP costs through commercial arrangements.

As discussed in the response to BCUC IR1 10.6, FEI is completing initial work scoping and plans to proceed with developing a Regional Gas Supply Diversity (RGSD) solution which would entail building a new pipeline route to the Lower Mainland connecting to the SCP. FEI has had some preliminary discussions with prospective market participants.

8. Reference: Exhibit B-1, Page 7

	On-System Storage at a New Site	Would provide resiliency but is more costly than expansion at an existing brownfield site, and would require construction of liquefaction in addition to storage and regasification.

8.1 Did FEI consider on-system storage in the form of compressed natural gas as a service at some site with proximity to the FEI CTS such that it could service disruption events without the needs for liquefaction, deep cold storage and regasification? If so, please supply FEI's consideration of such a solution.

Response:

CNG was not considered for on-system storage for resiliency purposes. The sheer volume of CNG that would need to be stored for resiliency purposes (2 Bcf) makes this option technically impractical. The 600 to 1 volume reduction that occurs during liquefaction makes LNG the only viable solution for storage of large quantities of natural gas. FEI has experience with the storage of compressed natural gas in 35,100 cubic foot bullet tanks. To store the equivalent of 2 Bcf as compressed natural gas would require over 56,000 bullet tanks which is clearly an impractical solution for this volume of gas storage. LNG storage and regasification has been successfully employed at Tilbury for 50 years, and is a mature technology used worldwide.

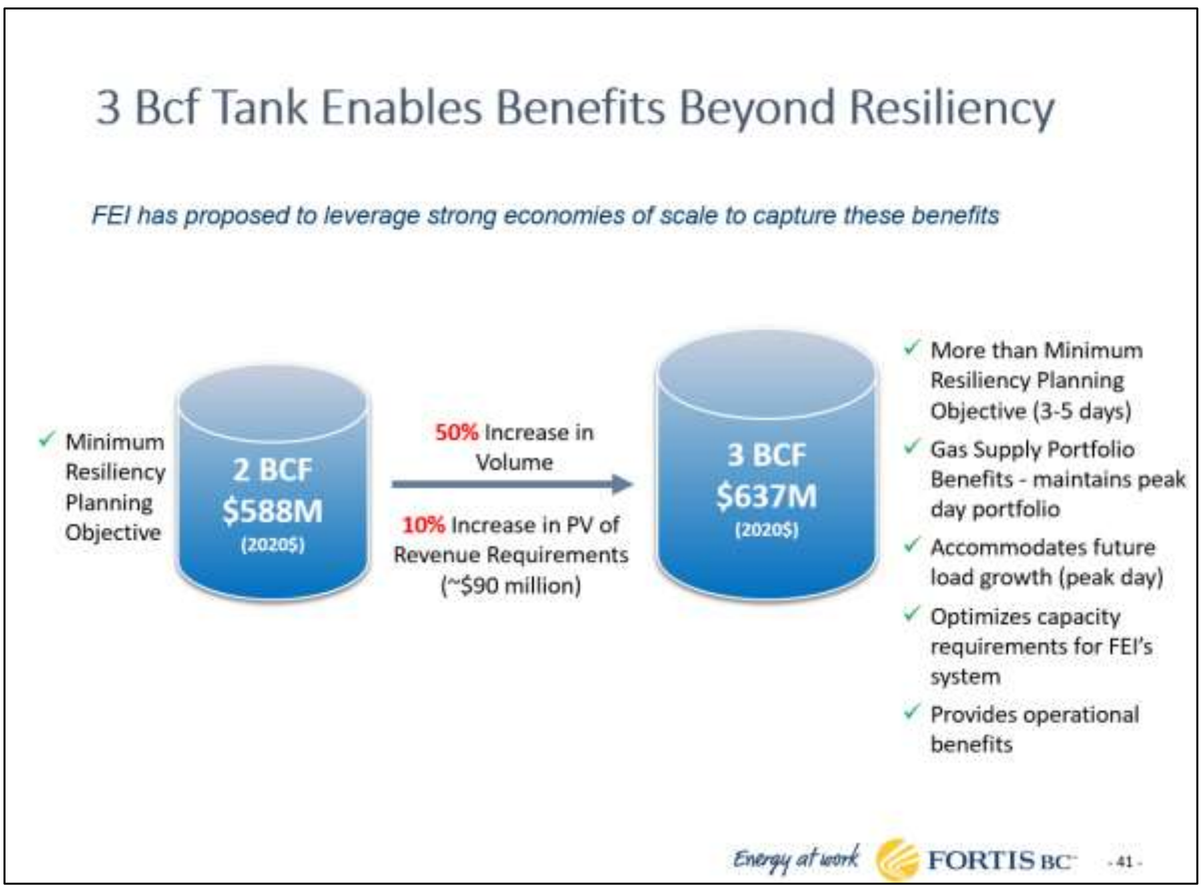
9. Reference: Exhibit B-1, Page 10

Ancillary Benefits	3 Bcf	• Both the 2 Bcf and 3 Bcf tanks provide ancillary benefits. The additional 1 Bcf within the 3 Bcf tank allows FEI to access additional ancillary benefits, including some that the 2 Bcf tank cannot provide.

9.1 Please describe and value the ancillary benefits of the additional 1 Bcf in the FEI proposal as compared to the $50 million marginal capital cost addition.

Response:

The ancillary benefits of the additional 1 Bcf are described in Sections 4.4.1.4 to 4.4.1.6 of the Application, and further explored in the TLSE Workshop presentation (slides 41 to 43 of Exhibit B-4, reproduced below for convenience). The value of the gas supply benefits is discussed in the response to BCUC IR1 46.2. As discussed in that response, the value of the gas supply benefits alone outweigh the incremental costs of the additional 1 Bcf such that customers are better off with the 3 Bcf tank than a 2 Bcf tank. The other ancillary benefits associated with the 1 Bcf storage as defined in the Application cannot have a value attributed to them at this time.



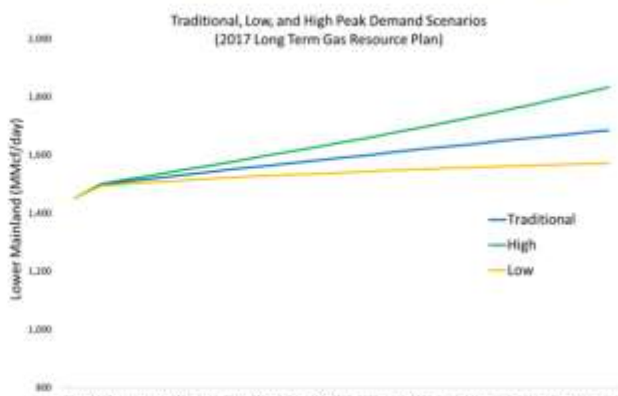
Gas Supply Portfolio Benefits

Peak Day Portfolio	MMcf/day
Total Commodity Supply	753
Off System Storage	185
Mt. Hayes LNG	150
Tilbury Base Plant LNG	150
Industrial Curtailment	25
Peaking Resources	-
Total Resources	**1,263**
Peak Day Demand	**1,263**

- Maintains peak day avoided costs while helping with future growth
- Mitigation of third-party off-system storage risk (i.e., Mist)
- Improved security of supply
- ~ 0.3 Bcf of storage inventory (Tilbury Base Plant) required

Energy at work FORTIS BC - 42 -

Accommodates Future Load Growth



- FEI expects that the annual and peak demand on the system will continue to grow
- Storage and regasification capacity not only provides better functionality to meet current demands, but also provides greater flexibility to accommodate future load growth

Energy at work FORTIS BC - 43 -

9.2 Would there be additional ancillary benefits possible if the project provided an additional 1 Bcf for a further $50 million marginal capital cost addition? If so, please describe these and value them as well.

Response:

FEI's analysis of tank sizing showed that the economies of scale associated with larger tanks begin to diminish at sizes larger than the 3 Bcf proposed in the Application. As the tank size increases beyond 3 Bcf, the complexity of both the design and construction increases. For example, additional tank height would exceed the limit where conventional construction methods could be used and specialized cranes would be required to lift tank components into place. At larger tank sizes the foundation design also becomes more complicated and costly.

FEI believes that the increased costs, complexities, and risks associated with building a tank larger than 3 Bcf outweigh any additional ancillary benefits that a larger tank may provide. Ultimately, FEI determined that 3 Bcf was the approximate limiting size for its requirements such that the tank could be constructed using conventional technology while also maximizing the tank volume and associated ancillary benefits.

9.3 Could an additional 1 Bcf of storage on the FEI system provide benefits to the US natural gas energy supply systems interconnected with FEI and might this be a value added to the whole Pacific Northwest supply system, and has FEI considered this?

Response:

FEI's on-system storage assets are designed for its own requirements, specifically to help meet peaking weather conditions and other operational emergencies. An additional 1 Bcf of storage would not likely provide any substantial benefit to other utilities in the US Pacific Northwest. This is because these utilities have access to underground storage facilities at Mist and Jackson Prairie that provide 44 Bcf of on-system storage, which is considerably more than the amount of on-system storage in the Lower Mainland (as shown in the figure below). As such, an additional 1 Bcf of overall supply in the region would not be considered material.

Further, Section 3.4.2.1 of the TLSE Application explores the resource characteristics in the region, and why system resiliency requirements for the utilities in the Pacific Northwest may look different than the needs of FEI's service region.

Regional Resources to Meet Load

Winter (151 day) Pipeline Supply (Bcf)		
T-South to Huntingdon		257
Gorge		81
	Total	338

Storage Assets		
Jackson Prairie (Washington)		25
Mist (Oregon)		19
On-System Storage (Tilbury & Mt Hayes)		2
	Total	46

10. Reference: Exhibit B-1, page 13

1.3.2.2 TLSE Application and Preliminary Stage Development Costs Deferral Account

FEI is seeking approval of a new non-rate base deferral account, the "TLSE Application and Preliminary Stage Development Costs" deferral account. This non-rate base deferral account would attract financing at FEI's weighted average cost of capital until it enters rate base. Consistent with FEI's previous CPCN applications, FEI proposes to transfer the balance in the deferral account to rate base on January 1 of the year following BCUC approval of the Application and commence amortization over a three-year period thereafter.

10.1 The CEC notes that the Commission is currently engaged in a Cost of Capital proceeding which could affect FEI. To the extent that the Commission issues a decision on that proceeding prior to issuing a decision on this proceeding, would FEI accept whatever terms the Commission may decide with respect to the appropriate interest for such deferral accounts, should it differ from what FEI is proposing? Please explain why or why not.

Response:

In Order G-205-21, dated July 7, 2021, the BCUC panel determined that the review of deferral account financing costs should be subject to a generic proceeding after the completion of stage 1 and stage 2 of the Generic Cost of Capital (GCOC) proceeding. Considering the regulatory process and the timetable for the GCOC proceeding, it is highly unlikely that a decision on deferral account financing cost will be issued prior to issuing the decision in this proceeding.

Notwithstanding, after an order is issued in that proceeding, FEI will carefully review the decision and any implications for existing or future deferral accounts.

PROJECT NEED AND JUSTIFICATION

11. Reference: Exhibit B-1, Page 20

> FEI manages the integrity of its gas system assets in order to achieve its goal of zero incidents of significant consequences. An incident of significant consequence can be generally defined as an event involving the functionality of a gas system asset which materially impacts safety, the environment, or continuity of service to a large number of customers.

11.1 Please provide a list and description, with relevant quantitative impacts, regarding the last 20 years of information with respect to integrity incidents for the FEI gas system.

Response:

In the last 20 years, FEI has recorded the following integrity incidents for its gas transmission system that involved a release of gas. FEI has not experienced any incidents having significant environmental, health and safety or financial consequences over this time period.

Year	Pipeline	Cause of Failure	Failure Type	Description
2000	Kingsvale Oliver 323	Material defect	Leak	Leak survey identified leak in girth weld.
2000	Galloway Lateral 60	Corrosion	Leak	Leak survey identified leak.
2000	Salmon Arm Lateral 114	Weld defect	Leak	Leak survey identified leak in seam weld.
2001	Penticton Trail 273	Corrosion	Leak	Leak identified during integrity dig.
2002	Savona Penticton 323	Crack in dent	Leak	Small leak originated from minor dent in pipe, identified through a public notification to FEI. A nearby landowner detected the smell of mercaptan odorant (which is added by FEI to natural gas to enable early detection of leaks).
2004	Trail Castlegar 219	Corrosion	Leak	Leak identified during integrity dig.
2004	Fernie Lateral 88.9/168	Corrosion	Leak	Leak identified on a weld.
2014	Savona Penticton 323	External Corrosion	Leak	Leak identified during integrity dig.
2020	Savona Penticton 323	External Corrosion	Leak	Leak identified during integrity dig.

11.2 Please confirm the expected decrease in integrity events expected from the CTS, VITS, and ITS projects, in quantitative terms of the reduced probability of such an event impacting customers.

Response:

FEI implements and continually improves its Integrity Management Program for Pipelines (IMP-P) in order to achieve its goal of zero incidents of significant consequences. Integrity-driven CPCN projects under construction, in BCUC regulatory review, or planned for the CTS and ITS are listed below along with FEI's assessment of their expected impact in preventing integrity failures. Until such time that FEI has verified in-line inspection and integrity dig data for the relevant lines, and FEI has implemented a sustainable quantitative risk management program and assessed those lines, FEI does not have a method for quantifying the reduced probability of relevant integrity events from impacting customers.

FEI has not identified any integrity-driven CPCN projects for the VITS at this time.

CPCN Project	Description	Status	Expected Impact in Preventing Integrity Failures
Inland Gas Upgrade (IGU)	Mitigating the potential for rupture failure due to external corrosion of FEI's smaller-diameter laterals in FEI's ITS	Approved January 21, 2020 through Order G-12-20	Post-project integrity management activities (i.e., in-line inspection and integrity digs) will mitigate the potential for rupture failure due to external corrosion, which reduces the potential for time-dependent failures impacting FEI's energy delivery to customers. This project does not mitigate other integrity threats, such as third-party damage.
Coastal Transmission System – Transmission Integrity Management Capabilities (CTS TIMC)	Mitigating the potential for rupture failure due to cracking threats of susceptible pipelines in FEI's CTS	CPCN application submitted February 11, 2021	Post-project integrity management activities (i.e., in-line inspection and integrity digs) will mitigate the potential for rupture failure due to cracking threats, which reduces the potential for time-dependent failures impacting FEI's energy delivery to customers. This project does not mitigate other integrity threats, such as third-party damage.
Interior Transmission System – Transmission Integrity Management Capabilities (ITS TIMC)	Mitigating the potential for rupture failure due to cracking threats of susceptible pipelines in FEI's ITS.	Planned for CPCN application submission in 2022	Post-project integrity management activities (i.e., in-line inspection and integrity digs) will mitigate the potential for rupture failure due to cracking threats, which reduces the potential for time-dependent failures impacting FEI's energy delivery to customers. This project does not mitigate other integrity threats, such as third-party damage.

Any decrease in integrity events on FEI's Coastal, Vancouver Island, or Interior transmission systems would do nothing to reduced the probability of a T-South no-flow event occurring and disrupting supply to customers in the Lower Mainland that will be addressed by the TLSE Project.

12. Reference: Exhibit B-1, Page 20 & 21

> - From the perspective of **adequacy**, maintaining reliability requires utility operators to have sufficient resources to balance their energy supply capacity with customer demand
>
> throughout the year. This is necessary to ensure adequate energy supply even during peak demand periods, while also being able to deal with the expected variability in customer demand at other times. To assist with this balance, energy can be stored directly (e.g., natural gas can be compressed, liquefied, or stored underground), or as a different form (e.g., in the electricity context, water held behind a hydroelectric dam).

12.1 Has FEI examined the potential for customer-based responses to adequacy of supply in emergency situations, which could provide cost savings to the customers and enable a leaner form of adequacy for FEI to develop and maintain, beyond the load curtailment of interruptible customer service and if so, what has FEI examined?

<u>Response:</u>

Please refer to the responses to BCUC IR1 13.3 and 13.4.

12.2 Has FEI examined electricity-based heating solutions, which might enable mitigation of emergency response requirements as an option, if they were widely available to handle a portion of heating requirements and if so, what has FEI examined?

<u>Response:</u>

Please refer to the response to MS2S IR1 4.iii.

13. Reference: Exhibit B-1, Page 22

> In a similar fashion, resiliency is achieved by selectively building system redundancy via commercial agreements with tangible upstream physical assets and on-system physical assets to respond to unexpected physical events. Resiliency embedded in the system enables the system to manage and recover from unexpected events more effectively and expeditiously.

13.1 Please describe the potential impacts on the FEI natural gas delivery systems in the event of a maximum design earthquake and FEI's potential resiliency in the context of these potential disruptions and in particular the potential for impacts affecting the concentration of LNG assets at Tilbury.

Response:

As part of its Integrity Management Program for Pipelines (IMP-P), FEI evaluates and mitigates its high pressure natural gas transmission system to maintain pressure integrity (mitigating significant safety hazards) following an earthquake event with a mean return period of 2,475 years.

FEI's seismic analysis has also encompassed facilities including its LNG facilities at the Tilbury site. The site-specific engineering criteria for FEI's seismic assessments and mitigation activities provides the basis for FEI's expectations of asset performance following a maximum design earthquake, and is independent of the concentration of LNG assets at Tilbury. As discussed in Section 5.3.1.2, and further explained in the response to CEC IR1 38.2, the TLSE tank and associated facilities will be designed to continue operating following an Operating Basis Earthquake (OBE), and hence would be available to support the Lower Mainland system if a no-flow incident also occurred as a result of the seismic event.

13.2 Is there a possible tsunami effect from earthquakes, which might significantly impact the Tilbury site and its functional operations?

Response:

With respect to tsunamis, FEI has taken guidance from the *Tsunami Hazard to North and West Vancouver*[3] report prepared by the Simon Fraser University Centre for Natural Hazard Research. While the focus of the report was North and West Vancouver, the report does contain a number of comments with respect to the potential for tsunami waves in the Delta and Richmond areas. Their research found no evidence of such waves in the geological record; however, based on computer simulation models, the report concluded that the potential for tsunami waves from a

[3] https://nsem.ca/sites/default/files/2020-02/tsunami-hazard-report.pdf.

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.

14. Reference: Exhibit B-1, Page 22

> • **First, resiliency requires not just acquiring contractual rights to supply, but also backing by physical assets.** This is a critically important concept. In essence, the point is that no amount of contracted supply from off-system sources, or offers of mutual aid from neighbouring utilities, will assist unless the physical infrastructure required to get the supply to the utility's own system is in place. As Guidehouse states, "if the underlying physical asset is not operational due to a disruption, the contractual arrangements do not provide, in and of themselves, resiliency."[5] Similarly, a significant adverse event in the region could mean that regional supply resources are unavailable, with suppliers having declared *force majeure* under supply agreements. As discussed later, this scenario materialized during the T-South Incident, where normal market transactions and contractual arrangements were suspended and utilities in the region were left largely with whatever natural gas was stored on-system or was still physically capable of flowing to their systems by another path.

14.1 Please provide a collective total quantitative understanding of the degree to which the physical assets in the Pacific Northwest have been for the last ten years and are currently available for the next ten years to provide mutual aid support.

<u>Response:</u>

FEI is a voluntary member of the Northwest Mutual Assistance Agreement (NWMAA), comprised of entities which use, operate or control natural gas transportation and/or storage facilities in the Pacific Northwest (British Columbia, Alberta, Washington, Oregon, Nevada and Idaho). As discussed in Section 3.4.2.2.1 of the Application, all participants within the agreement have a vested interest in maintaining a secure reliable regional natural gas system, and recognize that combined assistance will minimize the impact and duration to affected regional markets under emergency conditions.

FEI cannot quantify the degree to which the physical assets under the NWMAA are available because the support provided by NWMAA is on a best effort basis by all parties. As stated in Section 3.5.6 of the Application mutual aid agreements rely on one or more of the members having physical access to gas that (a) is in excess of what is required to prevent hydraulic collapse on their own systems, and (b) can be physically moved to where it is most needed.[4]

Therefore, while mutual aid can be an important tool (as it was during the T-South Incident) FEI cannot *plan* based on the assumption that regional parties will make physical resources available in emergency situations.

14.2 To what extent would the FEI proposed investment in resiliency become an asset available to provide assistance in the Pacific Northwest?

[4] TLSE CPCN Application, Section 3.5.6, p. 75.

Response:

All of the physical resources operated and controlled by the members of the Northwest Mutual Aid Assistance Agreement are assets that could be available in an emergency condition, so any FEI proposed investment in resiliency would be included. However, it would only be on a best effort basis, which under certain market conditions may not be the case, as discussed in the response to CEC IR1 14.1. Please also see the response to CEC IR1 16.1.

15. Reference: Exhibit B-1, Page 23 & 26

Page 23

> - When the pressure in a portion of the gas system experiences a hydraulic collapse, FEI is unable to directly determine which customers are receiving sufficient pressure to operate their appliances or equipment safely. These pressure variations can vary both in time (as the event progresses) and location (from area to area or even street to street). This uncertainty greatly complicates the ability of FEI to localize, manage and respond to the supply deficiency.

Page 26

> The rates of reliability would suggest that, on average, a typical natural gas customer would expect 69 seconds of service outage per year,[11] compared to almost four hours per year for a typical electric customer in BC (even with the high standards of redundancy on the electric system).[12] In practice, the vast majority of FEI's customers have never experienced a single natural gas outage, other than for planned reasons such as a meter exchange.

15.1 Please provide the gas system pressure at which the hydraulic collapse is thought to take place.

<u>Response:</u>

There is no specific pressure at or below which hydraulic collapse resulting in customer outages would occur. The pressure that would result in downstream customer outages depends on the demand on the system at the time and the capacity of the gate stations to deliver the required downstream demand during low inlet pressures. This is unique to each facility throughout the system as each facility has different inlet pressure requirements for delivering the downstream demand.

15.2 Has the FEI system ever experienced, in the last 20 years or longer, a hydraulic collapse and if so, please describe any and all of the events?

<u>Response:</u>

FEI has not experienced hydraulic collapse as a result of a failure of upstream gas supply into any of its transmission or distribution systems such as those experienced by some other utilities, as discussed in the response to BCUC IR1 5.2.1.

15.3 Has the FEI system ever experienced a significant controlled shut down in the last 20 years and if so, please describe any and all such events?

Response:

Please refer to the response to CEC IR1 15.2.

15.4 Please quantify the number of customers that have experienced a significant unplanned system level natural gas outage and describe the events and the duration in time and the extent in GJ of supply outage of those affected.

Response:

Widespread outages are rare and FEI has not experienced an incident at a scale similar to that which might have occurred if, for instance, the T-South Incident no-flow period had been longer in duration or occurred in colder weather.

Following are the details of the two FEI incidents where the entire local system was affected:

Fort Nelson, early October 1998[5]: A valve near the Fort Nelson Gate Station that was temporarily accessible due to ongoing station work was closed by an unknown person resulting in the loss of all the downstream distribution system customers. Total outages numbered approximately 2100. Approximately 30 service technicians and contractors conducted the shutdown and relights for all customers and restored full service approximately three days later. The extent of the outage in terms of undelivered GJ's was not measured. The valve was secured against any future misuse during the ongoing station work following the incident.

Lumby, November 20, 2014: A public motor vehicle left the road and struck and damaged an isolation valve on the intermediate pressure system feeding the community of Lumby, causing a loss of containment. In total, 1279 customers in the community lost gas supply in the course of isolating and repairing the damage. The incident occurred at 9:23 am November 20, 2014. The 1279 customers were shut in, repairs and regasification of the systems were completed, and the first customer relights began 28 hours later at approximately 13:15 November 21. Customer relights were considered 94 percent complete by 16:00 November 22 and 100 percent complete by 16:00 November 28. The extent of outage in terms of undelivered GJs was not measured.

[5] FEI does not have a record of the exact date and details of this incident and the description of the event comes from the recollection of the remaining employees who were involved in or aware of the incident.

16. Reference: Exhibit B-1, Page 26 & 27

> Gas pipeline failures are thus relatively rare occurrences; however, they can be high consequence events. If a rupture followed by ignition occurs, the result may be significant property damage, or harm to individuals in the vicinity of the failure. Further, if there is insufficient pipeline redundancy in the region, the reduced transportation capacity can potentially lead to gas shortages or outages to large numbers of downstream customers. This
>
> was demonstrated during the T-South Incident in October 2018, which restricted supply to BC and the US Pacific Northwest.

16.1 Please describe the duration in time and the extent in GJs of supply not provided for the Pacific Northwest and the resiliency FEI's proposed project would or could supply to T-South customers in the US.

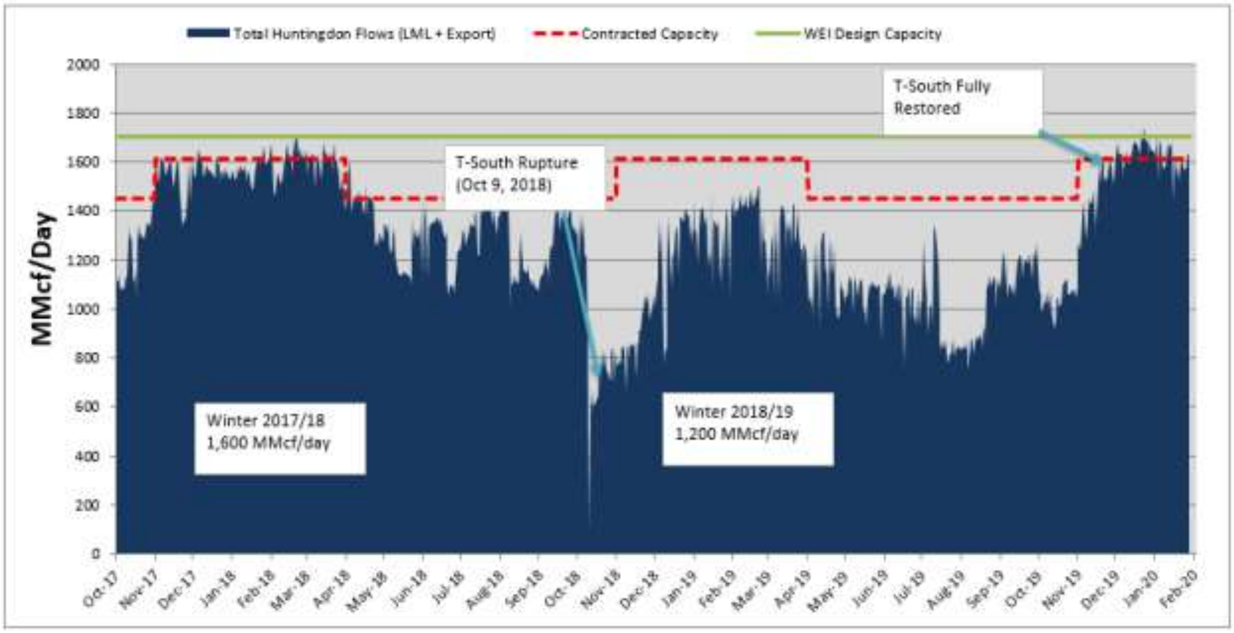
Response:

In the context of Phase 1 of the T-South Incident, the US Pacific Northwest utilities received gas supply until the pressure on the Westcoast system dropped to a point that Northwest Pipeline (NWP) compressors could not take any more. At that point, they utilized their gas supply resources (i.e., JPS, Mist, NWP Gorge Supply and curtailment of power plants) and provided FEI with mutual aid assistance[6] as Figure 3-7 of the TLSE Application illustrates.

As the region transitioned out of mutual aid, all T-South firm shippers experienced supply restrictions on T-South until December 1, 2019, approximately 14 months after the T-South Incident. FEI cannot quantify the extent in GJs of supply not provided for the Pacific Northwest during the entire 14-month period. However, as illustrated in Figure 3-10 of the Application (provided below for ease of reference), gas deliveries at Huntingdon via the T-South system averaged 1,200 MMcf/day for the 2018/19 winter season (November to March), 400 MMcf/day less than the previous winter. The lower deliveries reflected the reduced capacity that was available on the T-South system.

[6] The Northwest Mutual Aid Assistance Agreement is on a best effort basis by the parties. For further details, please refer to Section 3.4.2.2.1 of the Application, page 43.

Figure 3-10: T-South to Huntingdon Flows (T-South Capacity Restrictions)



The TLSE Project could theoretically provide supply to customers in the US during a future supply disruption through mutual aid. However, FEI's on-system storage assets are designed for its own requirements and the size of the TLSE Project will not likely provide any substantial benefit to the utilities in the US Pacific Northwest. As discussed in the response to CEC IR1 9.3, the US Pacific Northwest utilities have greater pipeline diversity (NWP's Gorge Capacity) and access to more underground storage on-system or nearby (Jackson Prairie Storage and Mist).

16.2 Please describe the potential responsibility for Pacific Northwest resiliency, the degree to which utilities in the Pacific Northwest are investing in resiliency and or could or would pay for resiliency supplied or provided from FEI, since the October 9, 2018 event.

<u>Response:</u>

FEI has ongoing discussions with the utilities and pipeline operators in the Pacific Northwest to discuss ways to enhance system resiliency and meet the needs of the region. Further, FEI is a member of the Northwest Gas Association to discuss a variety of topics, including resiliency. Based off of these discussions and in light of the T-South Incident, there is consensus that investments are needed to address the risk of reliance on a single pipeline system providing the majority of gas supply to a vast region. However, as discussed in Section 3.4.2.1, the utilities in the US Pacific Northwest are not as dependent on the T-South system in comparison to FEI's

Lower Mainland service area, as they have greater physical pipeline diversity and access to more on-system storage (i.e., NW Natural's on-system storage at Mist). This was also evident with the Mutual Aid Assistance that was provided to FEI during phase one of the T-South incident (Figure 3-7 of the TLSE Application). Therefore, the resiliency requirements for each utility in the Pacific Northwest are going to be different depending on their own portfolio of resources, and how their service areas connect into these resources.

The TLSE Project is specifically designed for FEI and its unique circumstances, location, and system configuration. The MRPO articulates that specific identified risk exposure associated with a no-flow event on the T-South system. The MRPO has been determined so that the system supplying customers in the Lower Mainland (LML) region could withstand and recover from a three-day no-flow event during the coldest period of the year. The TLSE Project preferred option of a 3 Bcf tank meets that minimum requirement, while providing FEI with a resiliency margin above the minimum and flexibility to realize ancillary benefits.

With that said, most parties in the region will likely agree that a new pipeline expansion into the region could provide many benefits. These include meeting regional gas demand and growth opportunities, transitioning to cleaner energy, while also providing much needed gas supply diversity in the region.

As discussed in the response to BCUC IR1 10.6, FEI is completing initial work scoping and plans to proceed with developing a Regional Gas Supply Diversity (RGSD) solution which would entail building a new pipeline route to the Lower Mainland connecting to the Southern Crossing Pipeline (SCP) in the BC interior. This project will enhance gas supply resiliency in the region; however it does not replace the need for the TLSE Project, as discussed in the response to BCUC IR1 16.1. FEI has had some preliminary discussions with prospective market participants and expects there will be ongoing support for its RGSD solution.

16.3 How did the Pacific Northwest manage resiliency for the October 9, 2018 event, please provide any detail defining the number of customers impacted and the GJ constraint they faced and the durations for those constraints?

Response:

FEI is not able to quantify the number of customers impacted or the amount of constrained supply the Pacific Northwest faced during the T-South incident. As discussed in Section 3.4.2.1 of the Application and in the response to CEC IR1 16.2, the utilities in the US Pacific Northwest are not as dependent on the T-South system for the physical delivery of gas in comparison to FEI's Lower Mainland service area, as they have greater physical pipeline diversity and access to more on-system storage. Therefore, the constraint these utilities faced during the T-South incident was shorter in duration. As an example, the customer conservation request from the utilities in the US

Pacific Northwest was lifted a few days after the T-South pipeline ruptured, whereas FEI's conservation message lasted a far longer time.

Further, some of the initial steps that the utilities and pipeline operators along the I-5 corridor took in terms of curtailing customers helped FEI manage through phase one of the T-South incident. For instance, the mutual aid response by the US entities enabled the curtailment of natural gas based power plants on the Northwest Pipeline system. This was one of the factors discussed in Section 3.4.2.1 of the Application that contributed to the avoidance of a pressure collapse to FEI's system.

16.4 Has FEI engaged with the Pacific Northwest to discuss resiliency impacts in the Pacific Northwest and how they may best be met?

Response:

Please refer to the response to CEC IR1 16.2.

17. Reference: Exhibit B-1, Page 27 & 28

> 1. **Diverse Pipelines and Supply:** Pipelines can continuously transport a significant amount of gas supply to the market centres on a daily basis, and therefore address customers' baseload and seasonal demand requirements. Having access to multiple regional pipelines, preferably separated geographically, to serve the distribution system improves a utility's ability to dependably collect and deliver gas supply to consumers.
>
> 2. **Ample Storage:** Access to storage, preferably located on a utility's own system, allows a utility to manage expected or unexpected changes in supply for a period of time. It can bridge a shortfall in supply entering the utility system, or if necessary, provide time to shed load or implement a controlled shutdown of portions of the system to avoid hydraulic collapse. Two common gas storage methods are underground and LNG.

3. Load Management:

> during a rapid-onset supply disruption. Even measures directly in the control of the utility (e.g., closing valves or shutting-in stations supplying entire communities), may not be sufficiently responsive. Newer technology (for example, the deployment of Advanced Metering Infrastructure (AMI) with remote-shutoff valves) instead allows the utility operator to quickly, accurately, and directly target any required customer load shedding. Relying on load management inherently means disrupting service to customers, and is ideally used in conjunction with other supply-based solutions. FEI's ability to manage load is discussed further in Section 3.3.2.

17.1 Has FEI moved to contract any of the 190 MMcf/day of capacity Enbridge is adding to its T-South supply?

Response:

In April 2017, Westcoast offered 190 MMcf/day of T-South capacity for interested parties to contract through an open season. In the 2017/18 Annual Contracting Plan, FEI requested to bid up to 35 MMcf/day on the Westcoast open season as a portfolio strategy to meet future load growth. On July 5, 2017, Westcoast confirmed that the open season was fully subscribed and FEI was unsuccessful in its bids.

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.

In 2019, FEI was further able to purchase 66 MMcf/day of Winter Firm Service[7] capacity on T-South from Northwest Innovations Works and obtained additional Southern Crossing Pipeline capacity, which was historically contracted out to NW Natural. This additional capacity has been a part of FEI's Annual Contacting Plan strategy for holding contingency resources within its portfolio to enhance gas supply resiliency. This strategy was detailed in Appendix C of the TLSE Application (Exhibit B-1-3), pages 26-28.

Since the 2018 T-South Incident, and after subsequent evaluation of its resource needs, FEI believes a better strategy is to expand capacity from its Southern Crossing Pipeline to achieve more diversity of supply.

17.2 Please describe and quantify the duration required to make an orderly shutdown of portions of the natural gas supply system, across a range of scenarios of different impacts, if there are different conditions that would affect the timing.

Response:

Please refer to the response to BCUC IR1 6.1.

17.3 Please confirm that FEI will be proposing an AMI project for the purpose of adopting technology which will give FEI much improved speed and accuracy in managing a required shutdown constraint to match the potential requirements in a risk situation where hydraulic collapse may become a reality.

Response:

Confirmed. On May 5, 2021, FEI submitted an Application for a CPCN for the Advanced Metering Infrastructure (AMI) Project.

Among other capabilities, AMI will allow FEI to monitor, in near-real time, the performance of all stations throughout FEI's affected system and to monitor customer consumption. As a result, FEI will be able to determine the granular demand on specific parts of the system. The near-real time aggregated total demand on the system of interest, and supply performance, could be used by FEI to determine which parts of FEI's system are vulnerable to a pressure collapse.

[7] Winter Firm Service as described in Article 21 of the WEI Tariff is specifically Southern from a Receipt Point at Compressor Station No. 2 (CS2) to a Delivery Point within the Huntingdon Delivery Area and provided only between November 1 and March 31 of each year.

AMI will also allow FEI to remotely disconnect customers in order to decrease the possibility of a pressure collapse. Please also refer to the response to BCUC IR1 16.1 for additional details.

18. Reference: Exhibit B-1, Page 31

> investments complement this optimal mix of resources. A cost-effective way to build resiliency is to employ a mix of pipeline redundancy and expanded storage and peaking resources that dovetails with the optimized supply portfolio. This is discussed further in Section 4.2 of the Application.

18.1 Please describe the trade-off values and the decision criteria between the component resources (pipeline redundancy, expanded storage, and peaking resources), required to establish the cost-effectiveness decision making for optimize supply to end customers.

<u>Response:</u>

FEI's decision criteria to establish a cost-effective way to enhance system resiliency followed the same principles that FEI applies to its gas supply portfolio through its Annual Contracting Plan. Section 4.3.1.1 of the Application details the fundamental principle for constructing a gas supply portfolio, which is to match the resource characteristics to the characteristics of demand (i.e., peak day, winter seasonal or year-round). In broad terms, that efficient supply portfolio consists of:

- Holding pipeline capacity to address long duration supply or base load (i.e., consistent demand throughout the year);
- Off-system underground storage to provide short to medium duration seasonal supply; and
- On-system storage resources for short duration supply to cover events such as winter peak demand which occur for short periods driven by weather conditions.

Just as FEI's Annual Contracting Plan combines assets with distinct attributes to meet the shape of FEI's load profile, a portfolio approach to resiliency incorporates enhancements with distinct attributes that, together, provide a cost-effective approach to resiliency.

Figure 4-3 in Section 4.3.1.2 shows how expanded peaking resources like on-system LNG storage can be used efficiently, in combination with redundant pipeline capacity. For example, the value of on-system LNG storage is its ability to respond immediately to a critical emergency, enhancing the survival of FEI's system as in Phase 1 of the T-South Incident. FEI's ability to rely on on-system resources in the event of a supply disruption does not depend on the physical or contractual availability of alternate pipeline capacity upstream of FEI's system. However, on-system LNG has limitations in addressing long-term capacity shortfalls or long-duration issues that were experienced during Phases 2 and 3 of the T-South Incident. This shows the value of having an additional pipeline (preferably in a different corridor from the T-South system), as it would further mitigate the risk of a prolonged reduction in gas supply.

FEI did evaluate whether it makes sense to pursue either a pipeline or on-system LNG solution exclusively; however, the analysis indicated that looking to only one measure to address all resiliency needs was either too costly or not feasible. Therefore, FEI evaluated multiple solutions and identified a mix of investments as the most cost effective and optimal solution to address its resiliency needs. These investments are discussed in the response to BCUC IR1 10.6.

19. Reference: Exhibit B-1, Page 31

> • **Interruptible loads provide a valuable peaking resource:** FEI's efficient supply portfolio has been constructed in recognition that some of FEI's industrial customers take service on an interruptible basis. FEI has also entered into peaking supply agreements with certain customers, like Island Generation[20], that allow FEI to recall supply and capacity during peak periods (i.e., cold winter days when residential and commercial customers turn-up the heat). These are valuable resources and FEI continues to use them as part of an efficient supply portfolio.

19.1 Please describe the bill cost incentive for FEI customers to provide valuable peak resource as part of an efficient supply portfolio.

<u>Response:</u>

Rate schedules and/or special contracts/agreements provide valuable peak resources as part of an efficient supply portfolio as described below.

Special agreements related to natural gas service to BC Hydro's Island Generation include a peaking agreement. The peaking agreement allows FEI to call back a portion of BC Hydro's firm capacity under the Transportation Service Agreement if FEI requires it to meet the remaining firm demands on its system. The availability of the capacity right is based on Island Generation's fuel switching capability and FEI has a Capacity Right Payment that is applicable whether or not the Capacity Right is used in any winter period. The Capacity Right Payment is based upon the demand charge credit and a distillate carrying charge associated with the maximum curtailment volume available to FEI each winter.

Rate Schedule (RS) 22A also includes a peaking service. RS 22A is a firm and interruptible rate class; however, the majority of the load is contracted on a firm basis. RS 22A allows for a curtailment of firm service provision that provides peaking gas supply to sales customers. RS 22A customers can be curtailed to one half of their firm service for up to 5 days per year. The related supply from this curtailment is included as part of FEI's Annual Contracting Plan as a gas supply portfolio resource that is available to meet needle peaking requirements for extreme weather conditions. RS 22A is a closed and grandfathered rate schedule not open to new customers and the bill cost incentive is part of the rate schedule.

FEI also has interruptible rate schedules under RS 7, RS 27 and RS 22 that allow FEI to curtail service to these customers under peak weather conditions to free up capacity and natural gas supply for firm service customers. In recognition of this, the Interruptible Rate Schedules, through the rate design process, have delivery rates that are generally based upon the concept of a discount to firm service. The rate design methodologies around the interruptible rates were discussed and reviewed in FEI's 2016 Rate Design Application.

19.2 Has FEI assessed its potential to get other customers to provide interruptible peaking resources and if so, what is the magnitude of the potential assessed?

Response:

FEI has not assessed the potential to get other customers to provide interruptible peaking resources. The largest users are already on contracts that are interruptible, partly interruptible or have peaking arrangements, and FEI already has the ability to curtail firm loads in an emergency situation.

Please also refer to the responses to BCUC IR1 12.1 and 12.2.

20. Reference: Exhibit B-1, Page 32

> In 2021, FEI expects to file an application for a CPCN to install AMI. The AMI project would include the installation of new gas meters equipped with remotely-operable shutoff valves for the vast majority of FEI's customers. These shutoff valves could be used to provide more direct and near real-time ability to flexibly manage load during times of system constraint, thereby reducing the probability of a hydraulic collapse or uncontrolled shutdown of the entire gas system. The AMI project would thus complement the Project as a resiliency tool.

20.1 Will the FEI AMI meter proposal only have remotely operable shut off valves resulting in either on or off supply or would the technology have the ability to constrain supply to specific quantities over specific periods of time, such that 75% supply, 50% supply and 25% supply might be possible in addition to the either on or off supply?

Response:

The meters to be used on the proposed AMI project have valves supporting on or off only. The valve technology will not facilitate constraining supply over a specific period of time by reducing the total supply available to a customer, nor are customer appliances designed to accommodate varying inlet pressures as means to control heat output.

21. Reference: Exhibit B-1, Page 34

> • Enlisting mutual aid arrangements, assuming supply is not required by other parties to mutual aid agreements and supply is physically accessible.

21.1 Please describe the local LNG supply market and whether or not at any given time there may be capacity available to truck or barge LNG to an appropriate FEI location or other Pacific Northwest location on relatively short notice.

Response:

There are three operating LNG facilities in BC: FEI's Tilbury plant, FEI's Mt. Hayes plant on Vancouver Island, and a facility owned by Cryopeak in Northern BC. There are two additional LNG facilities in Alberta and one in the State of Washington, USA.

The non-FEI facilities are small and would not be able to supply LNG in the volumes that would be required to support a significant system disruption, such as the T-South Incident. As described in the Application, the volume of LNG storage required to meet the MRPO is 2 Bcf, or approximately 92,000 cubic metres. The largest non-FEI facility in the region is Puget LNG in Washington State, which can produce 1,000 cubic metres per day and has a storage capacity of 8,000 metres^3.[8] Cyropeak's facility in northern BC, Ferus' NGF LNG facility, and the Cavalier LNG facility (the latter two in Alberta) can each only produce between 100 to 200 cubic metres of LNG per day.

Relying on the local LNG supply market for resiliency purposes is not practical for the following reasons:

- FEI does not own the resources required to supply LNG locally to FEI locations, including trucks and remote re-gasifying units;
- FEI would require system upgrades to be able to inject gas remotely across its system, which could be very costly;
- LNG transportation is limited by trailer availability and the ability to truck-in supply would not be able to support a significant FEI system distribution; and
- A significant gas disruption, such as the T-South Incident, would not be limited to FEI and would likely impact other utilities and LNG facilities, including those in Washington State. These other LNG facilities would likely have existing obligations to meet before being able to provide assistance to others. As a result, FEI does not and cannot plan based on the assumption that these sources of supply will be available in an emergency.

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[8] https://www.rivieramm.com/news-content-hub/news-content-hub/large-capacity-lng-bunker-vessels-to-serve-lsquoxl-sizersquo-ships-59059#:~:text=With%20a%20nameplate%20capacity%20of%201%2C000%20m%203,is%20being%20developed%20at%20a%20cost%20of%20US%24310M.

21.2 How might these potential sources of resiliency be incorporated into FEI planning and to what extent are there on-going discussions that might enhance this resource and its applicability to FEI's situation.

Response:

Please refer to the response to CEC IR1 21.1.

22. Reference: Exhibit B-1, Page 35

> It is unlikely that the end of a "no-flow" event on the T-South system will mean full resumption of supply for FEI. Rather, it can be expected that the pipeline system will continue to operate at significantly reduced capacity for an extended period. This occurred following the T-South Incident in 2018. Natural gas resumed flowing on the T-South system after two days, but capacity on that system was held to approximately 50 percent of firm capacity for about 45 days (i.e., until December 1, 2018). The T-South system did not return back to full firm capacity for approximately 14 months (i.e., until December 1, 2019), which included the entirety of the 2018-19 winter load period. During this subsequent period of constraint, access to on-system LNG remained important to FEI from a resiliency standpoint.

22.1 Please confirm the following matches the FEI actual experience.

22.1.1 The Enbridge new releases confirm that the T-South system 30" pipeline was fit for service at 80% of capacity and Enbridge began this return to service October 10, 2018.

22.1.2 As of October 14, 2018 Enbridge was laying mats and preparing for construction crews to begin repair of the 36" pipeline.

22.1.3 As of October 19, 2018 Enbridge was setting expectations that the repair of the ruptured 36" pipeline would take until mid-November and be back in service at 80% of normal capacity.

22.1.4 As of October 30, 2018 Enbridge advised that it had completed repair of the 36" pipeline and that subject to 48 hours of testing it would begin putting this line back into service and increasing supply to 80% of operating capability.

22.1.5 As of November 17, 2018 the NEB authorized Enbridge to increase capacity from 80% to 85% on the 36" pipeline.

22.1.6 As of November 30, 2018 Enbridge returned the portion of the 36" pipeline from Chilliwack to the border to full capacity.

22.1.7 As of September 30, 2019 Enbridge began increasing the capacity of the 36" pipeline from 90% capacity to 95% capacity by November 1, 2019.

22.1.8 As of December 1, 2019 Enbridge returned its entire T-South pipeline to full capacity service.

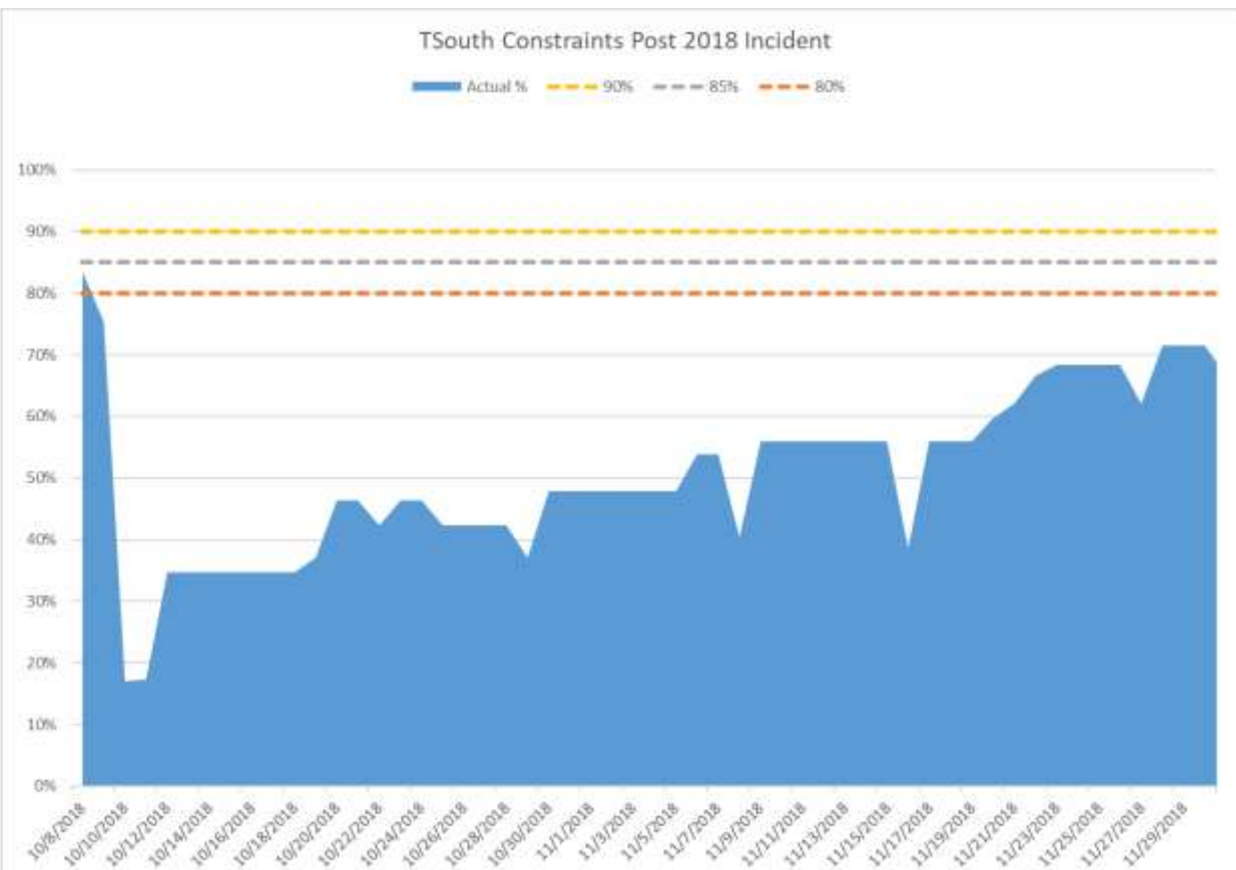
Response:

FEI confirms that Enbridge provided the news releases mentioned in CEC IR1 22.1.1 to 22.1.7; however, the majority of these news releases did not have a significant impact on how Enbridge actually operated through the T-South Incident in setting the total firm shippers' capacity entitlement on the system as a whole.

The majority of the news releases were only about operating pressures for either one of the two T-South pipelines or just a certain segment of the T-South system, which did not necessarily translate into actual total capacity that FEI and other T-South shippers were entitled to on a daily basis.

For operational and planning purposes, the “Operationally Available Capacity” reports that Enbridge released on a monthly basis summarized the planned capacity taking into account these operational changes. These reports provided more clarity as to what T-South shippers including FEI could expect in terms of available capacity for the upcoming month during the T-South Incident.[9] However, even these forecasted monthly reports were subject to changes as Enbridge adjusted the total firm shipper entitlements on a daily basis as the month progressed.

To support this point, FEI has provided the actual daily percentage of the available T-South capacity for the total firm shippers between October 8, 2018 and November 30, 2018, which covers the timeline for the Enbridge news releases for CEC IR1 22.1.1 to 22.1.7:



[9] For reference, FEI has provided the Westcoast Critical Notices that were released in November and December. Critical Notice 51146 “Operationally Available Capacity for December 2018 and Estimates for January and February 2019.” Critical Notice 51263 “Operationally Available Capacity for January 2019.” These critical notices are located on the Westcoast website (https://noms.wei-pipeline.com/notice/display/launch.php).

FEI confirms that Enbridge was able to return the T-South system back to normal operating pressure by December 1, 2019, approximately 14 months after the incident.

22.2 Does FEI understand that this length of time for return to full capacity was a period within which Enbridge was conducting integrity checking for the entire T South pipeline system?

Response:

FEI was aware of the Enbridge's engineering assessments and integrity checks for the entire T-South pipeline system. Throughout the approximately 14-month period of reduced capacity, FEI worked with Enbridge and other interconnecting pipelines to help facilitate several of these assessments and checks.

Enbridge also periodically updated all shippers on the T-South system, including FEI, of its schedule for integrity checks, as all such checks resulted in various levels of reduction in the T-South system's delivery capacity.

22.3 If Enbridge has sufficiently greater checking of the integrity of its T-South pipeline would a future rupture be likely to return to full capacity in a similar time frame to the one above or might it return to service sooner?

Response:

It is possible that Enbridge's current integrity checks could reduce the time frame for return to service, although this would be dependent on factors related to the specific situation. As such, FEI is unable to speculate whether, or how much, the return to full capacity timeframe could be reduced.

As discussed in the response to BCUC IR1 4.3, an extended period of reduced capacity would result from several potential stages following the incident itself:

- Initial pipeline shut-in which results in no-flow on the system.
- The parallel pipeline may also be shut-in, depending on the nature of the incident. For example in the 2018 T-South Incident, the parallel pipeline was also shut-in as a safety precaution, due to its proximity to the explosion location.

- Immediately after an incident, the site may be in law-enforcement's jurisdiction for investigation purposes and cannot be accessed.
- Regulatory directives may be issued that limit and restrict resumption of gas flow. In the 2018 T-South Incident these directives were accompanied by orders for completing engineering assessments and integrity verifications.
- The necessary engineering assessments and integrity verifications can take an extended period and require flow reductions to varying degrees. As an example, the 2018 T-South Incident resulted in ongoing flow reductions over the period of a year.

22.4 Please confirm that the T-South supply to FEI is not a single pipeline but is two pipelines, one a 30" pipeline and the second a 36" pipeline and that this was a valuable feature of the T-South in the event of a rupture on one of the pipelines.

<u>Response:</u>

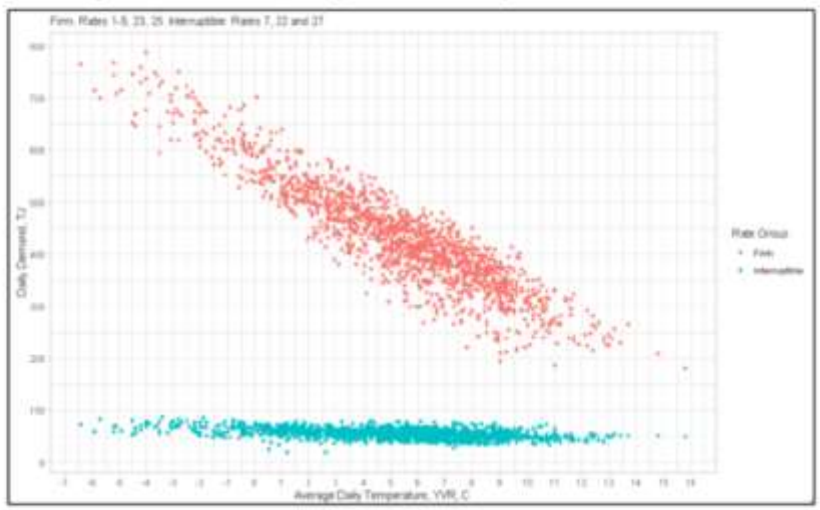
FEI confirms that the Westcoast T-South system consists of two parallel pipelines, an NPS 30 and an NPS 36 respectively. However, because the parallel pipelines of the T-South are operated as one pipeline system, this feature (the parallel pipelines) was not of value immediately after the rupture.

Immediately after the rupture, Westcoast shut in both pipelines for two days as a precautionary safety measure until Westcoast could ascertain that the NPS 30 pipeline was undamaged and that it could be returned to service, albeit at a reduced pressure and capacity level. As such, the two-pipeline feature of the T-South system was of no value during this time.

In the longer term, the two pipeline feature of the T-South system provided some value as Westcoast could resume service at a reduced capacity until the NPS 36 pipeline was repaired and returned to service (also at a reduced capacity).

23. Reference: Exhibit B-1, Page 59

Figure 3-12: Weather Sensitivity of Firm and Interruptible Lower Mainland Loads



23.1 Please provide the TJ totals for the Firm and Interruptible Customers in the Lower Mainland and similar information for Vancouver Island and the Interior portions of the FEI system.

<u>Response:</u>

The data from Figure 3-12 of the Application was based on ten years of data (2010 to 2019) for the winter seasons only (November to March). The intent of this Figure was to illustrate that during the winter there is not a lot of change in terms of how much supply FEI can curtail from interruptible customers in the event of an emergency.

The table below provides the annual average consumption (in TJs) of the firm and interruptible customers by region for the years 2017-2019.

2017-2019 Average Annual Demand, TJs	Lower Mainland	Interior	Vancouver Island and Whistler*	Total
Firm	104,165	36,377	13,902	154,445
Interuptible	21,685	31,168	8,191	61,044
Total	125,850	67,546	22,093	215,489

*Excludes BCH Island Cogen

Firm (RS1-6, RS23, RS25)

Interruptible (RS7, RS22, RS27)

24. Reference: Exhibit B-1, Page 64

> 3.5.4.1.4 TILBURY 1A FACILITIES ARE REQUIRED TO SERVE LNG SALES CUSTOMERS
>
> While the LNG in the Tilbury 1A tank may be used during an emergency to avoid widespread outages, FEI cannot plan on the availability of LNG in the Tilbury 1A tank (leaving aside its interim operating strategy noted above) during the normal course of business. Inventory levels in the Tilbury 1A tank are expected to fluctuate with the needs of the LNG sales customers; therefore, Tilbury 1A facilities cannot be relied upon from a planning perspective to meet FEI's resiliency objectives.

24.1 Please provide a full understanding of the LNG customer base by types of customers with respect to the type of LNG use being made.

Response:

FEI does not produce different types of LNG at Tilbury. The domestic LNG customers at Tilbury typically use LNG as a transportation fuel for trucking and shipping. Export customers use LNG typically as a fuel to run gas generators to produce electricity. Between January 1, 2017 and June 30, 2021, approximately 8 percent of LNG sales from Tilbury were for the export market, while the remaining 92 percent of sales were for domestic transportation use including the marine market.

24.2 Please describe any assessment of the potential for emergency constraint on this use of natural gas, which might become part of the FEI resiliency.

Response:

There would be no operational constraint in utilizing any available LNG from the T1A tank in the event of an emergency since the T1A tank will be interconnected with the TLSE tank to facilitate tank filling. FEI would need to comply with its Tariff and, as applicable, the order of shut-down set out in its BCUC-approved System Preservation and Restoration Plan. Please refer to the response to BCUC IR1 11.9 for an explanation of why FEI has no certainty that there will be any available LNG in the Tilbury 1A tank for resiliency purposes.

25. Reference: Exhibit B-1, Page 70

> 3.5.4.3.1 ACCESS TO JPS AND MIST DEPENDS ON GAS PHYSICALLY FLOWING ON T-SOUTH
>
> FEI maintains off-system storage contracts with JPS and Mist. These underground storage facilities are located near load centres in Washington and Oregon and far from FEI's service area (see Figure 3-18). They are not connected to FEI's CTS and as such are only available to support gas supply requirements during normal operations via displacement, a process which will be described in the paragraphs that follow. The important point is that commercial arrangements involving displacement require gas to be physically flowing on the T-South system, which (as was the case in the T-South Incident) may not be possible in an emergency scenario.

25.1 Do or could the JPS and Mist facilities have any capacity to expand storage?

Response:

Over time, both the Jackson Prairie (JPS) and Mist storage facilities have undergone expansions in order to meet the growing demand in the region, and both have the potential to expand further.

The most recent expansion was the North Mist expansion in May 2019, which was underpinned by Portland General Electric. FEI is aware that NW Natural is currently working to identify the scope and cost of the next possible expansion; however, no expansion project is currently underway.

It is FEI's understanding that there are risks to future reservoir expansions at JPS, and therefore the owners of JPS (Puget Sound, Northwest Pipeline, and Avista) have no plans for future development.

Although any future JPS and Mist expansion would help enhance the system resiliency for the US Pacific Northwest utilities, it will provide limited benefits to enhancing FEI's system resiliency because of how the gas physically flows. As mentioned in the preamble above, FEI would still need to rely on displacement, which is dependent on physical gas flow on the T-South system to Huntingdon, and would be reliant on the cooperation and effort of mutual aid partners to physically flow gas northward during a "no-flow" or emergency event. This would be highly unlikely under certain conditions, specifically during the winter season.

25.2 Has FEI examined the potential for connecting the JPS facility back to the FEI CTS and could such a connection provide some significant contribution to FEI resiliency?

Response:

The JPS facility is approximately 350 km from the Canadian border and any connection to the CTS. A pipeline running from JPS to Canada would pass through heavily populated coastal areas as well as mountainous terrain. Disregarding the challenges associated with gaining permission to construct such a project outside of Canada, a project of this magnitude would be far more expensive than constructing on-system storage at Tilbury. Based on the typical cost of constructing large-diameter transmission pipelines through difficult terrain, FEI would expect this project to be in the billions of dollars.

Furthermore, in order to fully rely on JPS storage, FEI would also be required to contract additional storage and deliverability at JPS. This will come at additional cost, and it is highly unlikely that FEI could contract sufficient storage given that there are no plans for future development at JPS (please refer to the response to CEC IR1 25.1). As a result, FEI has not fully investigated this as it does not consider this to be a viable project alternative to address the identified risk of a no-flow event on T-South system.

25.3 Could this remove the concern about dependence on the T-South pipeline for effective support from JPS?

Response:

Please refer to the response to CEC IR1 25.2 for an explanation of why this is not a viable project alternative.

DESCRIPTION AND EVALUATION OF ALTERNATIVES

26. Reference: Exhibit B-1, Page 79

> • Pipeline capacity is expensive, and it must be purchased for long durations (generally year round). It would not make economic sense to try to hold sufficient pipeline capacity to serve a winter demand peak lasting only a few days each winter, while leaving significant capacity unused for approximately 350+ days each year. Instead, it makes economic sense to buy capacity for the more consistent year-round loads, and supply the winter peak demand with other shorter term resources like on- and off-system storage.

26.1 The FEI LNG capacities are maintained all year round 365 days per year, as a cost, and are reserved for very limited use in any given year. Please supply the days of LNG use per year for the last 10 years and the forecast for the next 10 years.

Response:

The Tilbury Base Plant was designed to meet FEI's peak demand, and other operational requirements including supply interruptions. Given its purpose, the yearly sendout from this resource is low given that FEI tries to manage the need for supply from other resources where possible.

FEI's peak day is associated with a 1-in-20 year extreme weather event, which the Lower Mainland has not experienced in the past ten years. Therefore, the actual use of the Tilbury Base Plant has been lower compared to plan. The estimated LNG use for planning purposes is currently approximately 300 MMcf per year to meet peak demand, as per FEI's Annual Contracting Plan. From a planning perspective, the remaining LNG would be utilized for operational purposes and as emergency supply.

The table below provides the number of days and the quantity of Tilbury LNG that was sent out from the Base Plant for each of the last 10 years.

Year	Number of Days	Supply Quantity (MMcf)
2008	1	8
2010	2	81
2012	3	39
2013	4	37
2014	3	29
2015	3	13
2016	4	28
2017	2	11
2019	9	29
2020	7	18

26.1.1 Can FEI confirm that the question of pipeline capacity as a solution is not a question of unused capacity throughout the year but is a question of the economic cost to supply natural gas at a particular "no flow" disruption event or peak use at future point in time when these events occur?

Response:

Confirmed. These questions are explored in detail in Section 4.3.4.5.2 of the Application.

27. Reference: Exhibit B-1, Page 80

Figure 4-3: Resiliency Measures Should Reflect Optimal ACP Supply Portfolio

27.1 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.

<u>Response:</u>

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.

27.2 Please confirm that the peak usage in winter is driven primarily by space heating requirements and therefore cold temperatures.

Response:

Confirmed.

27.3 To what extent has FEI assessed the potential for demand side initiatives to provide some of this capability and at what cost could demand side measures be seen as cost-effective for the portfolio?

Response:

Please refer to the response to CEC IR1 27.1.

28. Reference: Exhibit B-1, Page 83

Alternatives	Reason Why Not an Alternative to On-System Storage at Tilbury
Automated Metering Infrastructure (AMI)	AMI remote shut-off capability will add resiliency by reducing the potential for an uncontrolled shutdown, but is best viewed as complementing supply-side solutions. Without additional supply, large scale load shedding would be required in event of a "no-flow" event, leaving many non-interruptible customers without service.

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?

Response:

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.

Please also refer to the response to BCUC IR1 13.3 for a discussion of the limitations of customer demand response during cold winter weather.

28.2 Please provide the temperature range that moves from defining the base load up to the temperature that establishes the peak usage and please correlate the quantity of natural gas peak above the base service needed at each degree of temperature level above the base supply from the pipeline. Please also provide a graphic of this data.

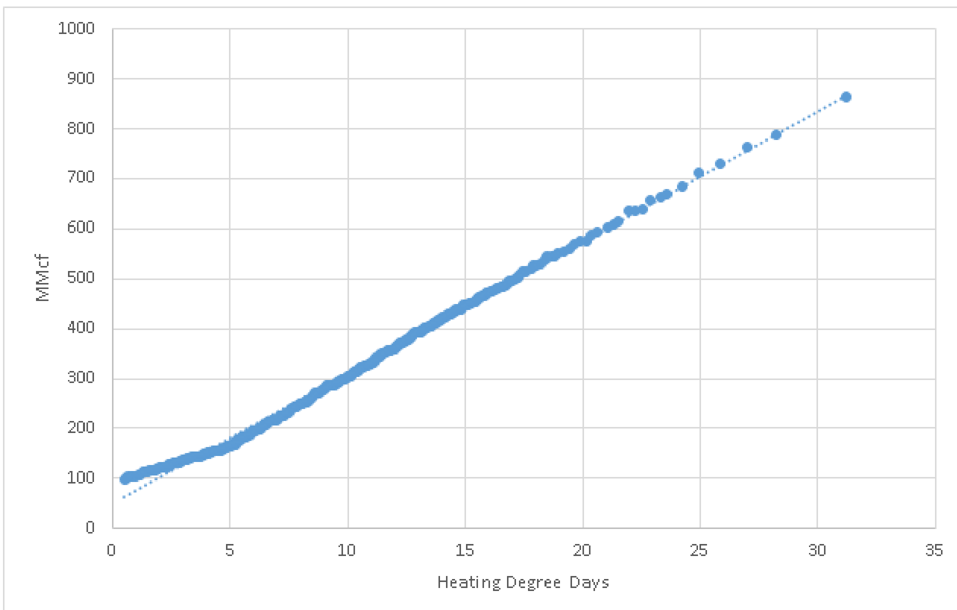
Response:

FEI clarifies that there are different ways to define "base load." For example, the essential service model defines baseload as the amount of gas required to meet customers' forecasted annual normal load. For the purposes of this response, FEI has defined "base load" using the concept of Heating Degree Days (HDD), and that there is a non-heat-sensitive system load that exists on a 0 Degree Day (which is equal to daily average temperature of 18 degrees Celsius). For every degree below 18 degrees Celsius, there is an increasing heat-sensitive load component. For the purpose of the demand forecast, the relationship between ambient temperature and heat-sensitive load is linear.

The temperature range from base load to peak is 18°C (base load) to -13.2°C (peak).

The following chart correlates daily demand with HDD in the temperature range from base load (0 HDD or 18°C) through the peak (31.2 HDD or -13.2°C).

Correlation of HDD with Daily Load



29. Reference: Exhibit B-1, Page 88

Alternatives	Reason Why Not an Alternative to On-System Storage at Tilbury
New SCP to Huntingdon Pipeline	New regional pipeline adds resiliency by diversifying supply into the Lower Mainland. Some gas will still be available if there is a failure on one pipeline system (on T-South or SCP). However, even if constructed, new storage would still be required to supplement remaining pipeline flows, and avoid significant load shedding. Cost savings from reducing the size of on-system LNG are limited due to inherent economies of scale.

29.1 Has FEI assessed whether or not the Fortis Inc. subsidiary HIPCO could work with the Gas Transmission Northwest owners to connect to Jackson Prairie and enable flow to FEI when needed and discuss expansion of storage and sourcing of gas to be stored?

Response:

FEI already flows gas supply through HIPCO[10] under normal operating conditions. Please refer to the responses to CEC IR1 25.1 and 25.2 regarding FEI's assessment of expanding storage and sourcing gas from the south (i.e., NW Natural from Mist, Northwest Pipeline from JPS, etc.) to enable flow to FEI.

[10] The facilities operated by HIPCO consist primarily of two short, large diameter pipelines that cross the Canada-US border at Huntingdon, BC. The facilities of HIPCO directly connect with the FEI system at its Huntingdon Station and with Northwest Pipeline.

30. Reference: Exhibit B-1, Page 90

> [redacted] The economies of scale associated with tank sizing mean that a reduction in tank size will result in proportionately low cost savings. In other words, the risk mitigation benefits decrease faster than the associated costs. Considering the uncertainty over whether a pipeline expansion will be constructed, which alternative is constructed, and when such an expansion will be in service, FEI believes that maintaining a larger tank size will maximize benefits to customers while mitigating significant uncertainty regarding future pipeline expansions.

30.1 The economies of scale at the margin for the capital expenditure investment once there is a commitment to provide an LNG solution become an significant advantage and opportunity to consider additional storage capacity but can FEI confirm that once the size is set and the facility is built the marginal cost for more incremental capacities become very large until considering another large increment?

<u>Response:</u>

FEI understands the question as referring to a scenario where the LNG storage tank is built at a particular size (i.e., 1.4 Bcf) and incremental capacity is added afterward. In this scenario, FEI confirms that the marginal costs for incremental capacity would be very high and that economies of scale would not apply. However, FEI clarifies that this is not the scenario referenced in Section 4.3.4.5.1 of the Application, as referenced in the preamble above.

In Section 4.3.4.5.1, FEI is comparing the economies of scale between constructing either a 1.4 Bcf storage tank or a 2 Bcf tank (i.e., not adding the additional 0.6 Bcf to the 1.4 Bcf tank at a later date). The analysis shows that there are strong economies of scale in building a slightly larger storage tank at the outset, as shown by the increase in tank volume relative to a proportionately small increase in cost. In other words, a larger tank size allows FEI to realize significant additional benefits for its customers for a relatively small increase in costs.

31. Reference: Exhibit B-1, Page 100

Table 4-4: Comparison of the Capital Costs to Build a Single, Larger Tank (2020$)

Scenario	Comparison	Tilbury Base Plant Tank Age at Replacement			
		~55 Years (2025)	~60 Years (2030)	~65 Years (2035)	~70 Years (2040)
2 Bcf Tank and 800 MMcf/d regasification now	PV of Capital Costs ($ millions)	588	588	588	588
1.4 Bcf Tank and 650 MMcf/day now + second 0.6 Bcf tank and 150 MMcf/day in the future	PV of Capital Costs ($ millions)	785	742	706	676
Difference	PV of Capital Costs ($ millions)	**(197)**	**(154)**	**(118)**	**(88)**
2 Bcf Tank and 800 MMcf/d regasification now	PV of Annual Rev. Requirements ($ millions)	951	951	951	951
1.4 Bcf Tank and 650 MMcf/day now + second 0.6 Bcf tank and 150 MMcf/day in the future	PV of Annual Rev. Requirements ($ millions)	1263	1,145	1,093	1,049
Difference	PV of Annual Rev. Requirements ($ millions)	**(312)**	**(194)**	**(142)**	**(98)**

31.1 Do the annual revenue requirement present values above include the cost of maintaining the inventory of natural gas frequently unused, until realization of a “no flow” or other critical disruption event, as part of the investment?

Response:

The annual revenue requirement present values shown in the table in the preamble above do not include any costs of the natural gas commodity (i.e., the LNG itself). These costs are considered flow-through and FEI’s assumption for the purpose of evaluating the different scenarios is the LNG storage tank will have a one-time fill after construction is complete with the tank being held for future resiliency events. Given this assumption, the one-time commodity costs to fill the LNG storage as well as the associated carrying cost to maintain the LNG inventory[11] are relatively small. As a result, adding these costs to the analysis in Table 4-4 will not change the outcome of the comparison. For example, the one-time commodity costs for 0.6 Bcf (i.e., the difference between a 2 Bcf tank and a 1.4 Bcf tank) is approximately $1.8 million and the PV of the carrying costs over a 67-year period to maintain this 0.6 Bcf LNG inventory is approximately $1.6 million[12]. When adding these costs to Table 4-4 (which already shows the difference in PV of annual revenue requirements between the 2 Bcf and 1.4 Bcf tank ranges from $98 to $312 million, depending on the replacement year of the Tilbury Base Plant) the outcome of the analysis remains

[11] For the time between when the LNG storage tank is first filled and when the LNG is first regasified, i.e., the period of time which FEI is “maintaining” or “holding” the LNG inventory, the value of this LNG inventory is recorded in Gas in Storage in FEI’s rate base, attracting a return on rate base. FEI considers this to be the cost of maintaining the inventory of natural gas being unused.

[12] Based on 0.6 Bcf (0.633 PJ) and current September 2021 commodity cost rate of $2.844/GJ. The PV of carrying costs is based on the rate of return on FEI’s 2021 approved rate base over a 67-year period.

unchanged. As such, FEI does not believe it is necessary to include these costs in the financial comparison shown in Table 4-4 above.

The following are the relevant assumptions for the financial comparison shown in Table 4-4 of the Application. FEI notes that, as mentioned above, FEI's assumption for the financial analysis is that the LNG storage tank is filled once initially, thus there is no annual liquefaction costs and no annual regasification costs. The one-time liquefaction cost (not the commodity cost) of the initial fill is included in O&M as described below.

FEI also notes that Table 4-4 of the Application compares the scenarios of either a 1.4 or 2 Bcf tank with replacement of the existing Base Plant occurring between 5 and 20 years in the future. Please also refer to the response to BCOAPO IR1 4.1 which discusses the difference in commodity costs between a 2 and 3 Bcf tank. That response demonstrates how the 3 Bcf tank is still the preferred solution for the TLSE Project.

Inflation: For both scenarios, FEI assumed 2 percent annually for the incremental O&M, property tax, and future capital replacement costs during the post-Project analysis period.

O&M: The assumptions for determining O&M include:

- Approximately $5.961 million in 2020 dollars of new annual O&M costs, including electricity costs, associated with the new 2 Bcf tank and the new 800 MMcf/day regasification equipment. FEI notes the O&M costs for the 2 Bcf tank are scaled based on the estimates completed by Partners in Performance (PiP) for the 3 Bcf tank, as discussed in Section 6.3 and Confidential Appendix N of the Application, plus a one-time liquefaction cost (for the first fill) of $12.175 million[13];

- Approximately $5.756 million in 2020 dollars of new annual O&M costs, including electricity costs, associated with the new 1.4 Bcf tank and the new 600 MMcf/day regasification equipment. FEI notes the O&M costs for the 1.4 Bcf tank are scaled based on the estimates completed by PiP for the 3 Bcf tank, as discussed in Section 6.3 and Confidential Appendix N of the Application, plus a one-time liquefaction cost (for the first fill) of $8.522 million; and

- Avoided annual O&M costs, including electricity costs, of approximately $2.263 million in 2020 dollars associated with the demolition of the Tilbury Base Plant, as discussed in Section 5.3.5 of the Application. This is based on the average actual O&M costs from 2008 to 2019 as discussed in Section 6.3 of the Application.

Property Tax: Incremental property tax as a result of the new 2 and 1.4 Bcf tanks based on the 2020 tax rate. The incremental property tax is assumed to occur in phases based on percentage

[13] Based on the current RS 46 facility charge plus electric surcharge of $5.13/GJ, escalated at 2% annually to 2027, which is $5.77/GJ, when the new tank is scheduled to be complete. E.g. For 2 Bcf: 2.11 PJ x $5.77/GJ = 12.175 million, For 1.4 Bcf: 1.477 PJ x $5.77/GJ = $8.522 million.

completion of the LNG tank construction between 2023 and 2026. FEI notes this assumption is the same for the proposed 3 Bcf tank, as discussed in Section 6.3 of the Application.

Incremental sustainment capital: For both the 2 Bcf and 1.4 Bcf tank scenarios, FEI used an estimate of sustainment capital, which is an average of 1 percent per year for the mechanical equipment capital expenditures (LNG tank, regasification equipment, auxiliary equipment), developed based on estimates completed by a third party as discussed in Section 6.3 and Confidential Appendix N of the Application. FEI notes this assumption is the same for the proposed 3 Bcf tank.

Future capital replacement: For both the 2 Bcf and 1.4 Bcf tank scenarios, FEI included future replacement of the regasification and auxiliary systems at the end of their estimated average service life of 40 years. FEI notes this assumption is the same for the proposed 3 Bcf tank as discussed in Section 6.3 of the Application. Please also refer to BCUC IR1 41.1 for more detail regarding the estimated average service life of 40 years for the regasification and auxiliary system.

31.2 Please provide the value for 1Bcf of natural gas and would this natural gas have carbon tax applied or is that only applied upon use?

Response:

The value of 1 Bcf of natural gas is approximately $3 million, which is based on an energy equivalence of 1.055 PJ and the current approved (September 2021) cost of gas rate of $2.844 per GJ. FEI notes the Table 4-4 reference in the preamble above is a comparison between a 1.4 Bcf tank and a 2 Bcf tank. The value for the difference of 0.6 Bcf (0.633 PJ) is approximately $1.8 million based on the current 2021 approved cost of gas rate of $2.844 per GJ.

The values above do not include carbon tax. FEI collects carbon tax on behalf of the provincial government at end-use through customer bills and remits it to the government (i.e., it is a flow-through cost and not part of FEI's revenue requirement).

31.3 Please provide the annual revenue requirement assumptions with respect to annual liquefaction costs, the regasification costs and the operating, maintenance costs and such other costs as may be relevant.

Response:

Please refer to the response to CEC IR1 31.1.

32. Reference: Exhibit B-1, Page 108

Table 4-6: Financial Evaluation of Alternatives (2 and 3 Bcf Tanks)[92]

	2 BCF	3 BCF	Incremental from 2 BCF to 3 BCF
AACE Class Estimate	Class 3	Class 3	
Total Project Capital Costs, 2020 dollars ($ millions)	588	637	50
Capital Cost per unit of storage ($ millions/BCF)	294	212	(81)
PV of Incremental Revenue Requirement 67 years ($ millions)	951	1,042	91
Levelized Delivery Rate Impact 67 years (%)	6.09%	6.67%	0.58%
Levelized Delivery Rate Impact 67 years ($/GJ)	0.275	0.301	0.026
Average Residential Use per Customer (GJ)	90.0	90.0	90.0
Average Annual Residential Bill Increase ($)	24.8	27.1	2.3
Average Annual Residential Bill Increase (%)	4.10%	4.49%	0.39%

32.1 Please define the portion of the 3Bcf of storage that would be expected to go unused each year (absent an emergency event) and the portion that would be expected to handle peak reduction.

Response:

From a planning perspective, FEI would expect 2 Bcf of storage will be reserved as a minimum resiliency requirement. The remaining 1 Bcf portion of storage above this minimum will provide resiliency as well, but comes with some flexibility to use it for operational and gas supply needs, which may include growth in peak demand.

33. Reference: Exhibit B-1, Page 112

Table 4-7: Existing Pipeline and Storage Resources in the Region

Pipeline	Daily Deliverability[1] (MMcf/day)	Total Winter Supply (Bcf)	Contract Status
Enbridge T-South (Huntingdon Delivery Area)	1702	257	Fully Contracted
Enbridge T-South (BC Interior)	224	34	Fully Contracted
FortisBC SCP (Oliver North)	140	21	Fully Contracted
FortisBC SCP (Oliver to Kingsvale)[2]	105	16	Fully Contracted
TCPL (FoothillsBC)	2930	442	Fully Contracted
NWP Gorge	534	81	Fully Contracted
Market Area Storage	**Daily Deliverability (MMcf/day)**	**Storage Capacity (Bcf)**	
Jackson Prairie (JPS)	1161	25	Fully Contracted
Mist	637	19	Fully Contracted
On System Storage	**Daily Deliverability (MMcf/day)**	**Storage Capacity (Bcf)**	
Mt. Hayes LNG	150	1.5	Fully Utilized on Peak Day
Tilbury LNG	150	1.35	Fully Utilized on Peak Day

1. Daily deliverability is the maximum amount of gas that can flow on the pipeline or the maximum amount of gas that can be withdrawn out of storage. It is important to note that the daily deliverability out of the market area storage is assuming storage inventories are full. These resources do have withdrawal rates decline as working gas volumes decline.

2. The 105 MMcf/day is included in the 1,702 MMcf/day Huntingdon Deliveries (i.e. Kingsvale to Huntingdon).

33.1 **Please discuss whether or not the Jackson Prairie facility or the Mist Facility, being fully contracted, have any plans to enable further capability development.**

Response:

Please refer to the response to CEC IR1 25.1.

33.2 **Please discuss whether or not the formation in which they store natural gas may have additional capability to store natural gas.**

Response:

Please refer to the response to CEC IR1 25.1.

34. Reference: Exhibit B-1, Page 112

> FEI plans the next-day gas supply based on a weather forecast, which can deviate significantly from the actual weather experienced during the day as Lower Mainland demand increases by approximately 25 MMcf/day when temperature decreases by one degree Celsius. [redacted] as depicted in the illustrative figure below. When this happens, one of four things must

34.1 Is the 25 MMcf/day relationship to temperature change in the winter a linear relationship?

<u>Response:</u>

Please refer to the response to CEC IR1 28.2. It is also important to note that the approximate 25 MMcf/day for the Lower Mainland is an estimate based on past history, as ambient temperature is the most important, but not the single defining factor for heat-sensitive loads. System loads are also affected by other meteorological factors, such as precipitation, cloud cover, wind chill, etc.

34.2 Please provide a table showing the requirements above base load in relationship to temperature, in order to demonstrate the critical peaking based on temperature and also please provide the same information graphically.

<u>Response:</u>

Please refer to the response to CEC IR1 28.2.

35. Reference: Exhibit B-1, Page 114

> FEI has limited options when this occurs, and the options will potentially become more limited in the coming years for two reasons:
>
> - First, if the construction of the Woodfibre LNG project proceeds, it will change the demand profile on FEI's transmission system, reducing line pack and making daily load balancing more challenging.

35.1 Has FEI considered combining its requirements into the Woodfibre project and taking advantage of the economies of scale for both parties and if not why not?

Response:

No, FEI has not considered combining its storage and resiliency requirements into the Woodfibre LNG project, or amalgamating the Woodfibre project into the Tilbury project. The Woodfibre project is owned by a third-party, not FEI, and is currently progressing on its own timeline and requirements.

The Woodfibre LNG project is not situated in FEI's load center, and is limited by the current and planned interconnecting pipeline capacity. Further, additional investment in vaporization, an LNG storage tank and additional pipeline capacity would be needed to ensure sufficient quantities of gas are available to FEI for resiliency purposes. Given the necessary infrastructure investments that would be required over and above those identified for the TLSE Project, this option would be more costly than the TLSE Project with no projected offsetting benefits.

35.2 Has FEI considered amalgamating the Woodfibre project into the potential for FEI to export LNG from Tilbury and generate economies of scale for both parties at Tilbury?

Response:

Please refer to the response to CEC IR1 35.1.

PROJECT DESCRIPTION

36. Reference: Exhibit B-1, page 121

> **5.3 THE PROJECT IS DESIGNED AND ENGINEERED TO MEET APPLICABLE CODES, STANDARDS AND REGULATIONS**
>
> The TLSE Project is being designed in conjunction with a number of specialized consultants with experience in the development of LNG projects. FEI will develop the Project in accordance with all applicable statutory codes and standards, including FEI's internal standards, and all British Columbia Oil and Gas Commission (BCOGC) regulations.

36.1 Please identify and describe any of FEI's internal standards that are different from those of the industry or the BCOGC.

36.1.1 If FEI has standards that are different from those of industry or the BCOGC, please explain why for each standard identified.

<u>Response:</u>

FEI's internal standards do not differ from those of the industry or the BCOGC. The umbrella document is CSA Z276-18 *Liquefied natural gas (LNG) - Production, storage, and handling*.

Please also refer to the response to BCUC IR1 25.2, which discusses how the standards would be applied in the event of an inconsistency or conflict.

37. Reference: Exhibit B-1, page 125-126

Tank Physical Characteristics

- The LNG tank will have a working volume of 142,400 m3 between the minimum normal operating level and the maximum normal operating level;
- The inner tank will be 71.5 m diameter x 38.8 m high;
- The outer concrete tank inside diameter will be 73.5 m and the outer tank overall wall height will be 43.75 m above the top of the foundation;
- The foundation will be a concrete base slab on grade with ground improvement. The slab will be 1.10 m thick at the edge and will be supported on improved ground. The top of the slab is approximately 0.45 m above grade;
- The inner tank will consist of a 9 percent nickel steel wall with an aluminum suspended deck. The tank will include Thermal Corner Protection, which consists of a 9 percent nickel steel system protecting the lower 5.0 m of concrete wall from subzero temperatures should an LNG leak occur. The outer concrete wall will be protected with an inner carbon steel wall liner, extending from the top of the slab to the roof liner;
- This is a full-containment LNG tank designed in accordance with CSA Z276, API 625 and ACI 376. Full containment refers to the ability of the tank to contain the entire volume of stored LNG even in the event of a breach of the inner steel tank;
- The LNG inner tank will be tested with water to a level according to API 620 Annex Q 6.2. Potable water will be utilized for the test. The LNG outer tank will be tested pneumatically to a pressure of 1.25 times the design vapour pressure;
- External tank lighting for maintenance and aeronautical obstruction lights for visibility will be provided; and
- Lightning protection and grounding system will be supplied in compliance with electrical codes.

37.1 Please provide the minimum and maximum volumes for the tank.

Response:

The volume from the minimum nominal operating level (at 1.8 metres from the bottom of the tanks) to the maximum nominal operating level (at 37.39 metres), is 142,400 $metres^3$. The minimum level at 1.8 metres is set based on the in-tank pump requirements for suction head and the liquid coverage of the entire pump, taking into account the pump well shrinkage and the space required under the pump for the foot valve to open. The maximum normal operating capacity, from the bottom of the tank to the maximum nominal level at 37.39 metres is 149,612 $metres^3$.

The maximum liquid capacity is 150,813 $metres^3$, from the bottom of the tank to 37.69 metres. There is a high level trip at this level. This provides an overflow protection of 300 mm.

37.2 Please describe the types of events that can cause leakage of LNG.

Response:

The types of events that could cause a leakage of LNG are provided below. These types of events are considered rare or unlikely, and in most cases leaks would be contained by the outer concrete containment.

- **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.
- **Gasketed Joint Failure:** Improper torqueing of flange pairs, flange face scratches, or other defects during construction could cause LNG to leak between flanges in sufficient quantities to pool and flow. There will be flange pairs at both the tank roof platform and at various valve platforms surrounding the tank. The tank design includes flange shields that will direct the flange leaks to the concrete roof. Sacrificial roof concrete and curbing will be provided to direct any leakage to a containment area. The containment area will be instrumented with leak detection and will have fire-fighting equipment (foam systems) installed. The instrumentation that detects the leaks would stop the pumps and close any Emergency Shutdown Valves. These two actions will stop the LNG leaking from the failed joint. In any case, the LNG that leaks will not leak from the tank itself, but from piping surrounding the tank. Once the pumps are shut down, no further LNG can leak from inside the tank.
- **High Energy Impacts:** The outer wall of the tank is reinforced, post-tensioned concrete designed to withstand projectile impacts. The tank is further protected from projectile-type impacts by the 16 mm stud connecting the outer tank wall inside face liner and the minimum 10 mm inner tank shell. It is extremely unlikely that a projectile impact could result in a leak of the inner tank product.

37.3 What are the potential risk outcomes of an LNG leak? Please explain.

Response:

Given the numerous safety precautions which will be designed into the TLSE Project, it is highly unlikely that an LNG leak would occur. However, in the unlikely event it does occur there could be several outcomes depending on the extent of the leak:

- **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.

FEI has extensive experience with these risks and has safely and effectively managed them at the Tilbury facility since the Tilbury Base Plant was first brought into service 50 years ago. The TLSE Project will include multiple layers of safety measures to prevent and mitigate LNG leaks, including design measures, instrumentation and automated control systems, operational procedures, and gas detection systems.

37.4 Do the inner and outer walls protect against different types of risks? Please explain.

Response:

The outer concrete tank wall protects the inner tank and contents against the following risks:

- Projectile Impact;
- Blast;
- External Fire; and
- SSE_{AFT} (Aftershock).

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.

37.5 Why is the Thermal Corner Protection limited to protecting the lower 5.0 m of concrete as opposed to the entire wall?

Response:

The Thermal Corner Protection (TCP) is designed to protect the monolithic base slab to wall joint from the excessive thermal stress caused by the cryogenic temperatures imposed on the joint during an earthquake spill event from the inner tank. The rigidity of this fixed connection creates much higher thermal stresses which cause expansion or contraction that the base of the wall would not be able to structurally accommodate. As such, the base of the wall is protected from the cryogenic LNG temperature by the TCP. Above approximately 5 metres, the wall is much more flexible relative to the base slab to wall joint and therefore is not subjected to such high thermal stresses and therefore does not need additional protection. This is a common design practice for above ground LNG tanks.

37.6 How do the tank physical characteristics differ from FEI's existing tanks? Please explain.

37.6.1 To the extent they are different, please explain why FEI is using different technologies than those in the existing plant.

Response:

FEI is using the same technologies in the proposed TLSE tank to those technologies used during its most recent expansion (the Tilbury 1A expansion). This design ensures the highest tank integrity in the industry for above-ground LNG storage

Tank Type	Same - TLSE and T1A are both Full Containment Concrete Tanks	The BPT is a single containment tank with bund wall
Capacity	TLSE: 142,400 m^3, T1A: 46,000 m^3	BPT: 27,825 m^3
Secondary Containment – Thermal Corner Protection	Same – Both tanks include a 9% Nickel secondary bottom and a corner protection to protect from inner tank ruptures	BPT does not have a secondary containment or Thermal Corner Protection

Secondary Containment – Concrete Outer Tank	Same – Both tanks have a post-tensioned concrete outer tank	No secondary containment in the BPT
Shell Penetrations	Same – no shell penetrations (LNG cannot flow unless it is pumped)	BPT has shell penetrations. LNG can flow if outside valves are open.
Placement of LNG Pumps	Same – pumps are placed inside the tanks and LNG can only be pumped over the outer tank wall	The BPT has the pumps on the outside of the tank. LNG must flow freely from the inside of the tank (gravity fed) to the pumps.
Seismic Isolation	Same – TLSE and T1A are not seismically isolated	The BPT is not seismically isolated

38. Reference: Exhibit B-1, page 126

> ***5.3.1.2 Safety Systems***
>
> The safety systems associated with the proposed LNG tank will be designed and provided in accordance with accepted industry practices and any applicable standards.
>
> The fire and gas detection system will consist of flame detectors, gas detectors, manual call points, audible alarms and beacons, and low temperature alarms. These detection and protection systems will be monitored 24/7 by LNG plant operators from the plant control room.
>
> The storage tank will be designed for two levels of ground motion: the Operating Basis Earthquake (OBE) and the Safe Shutdown Earthquake (SSE). The OBE earthquake is represented by a once in 475 (500) year return period event; that is, an earthquake of this magnitude is statistically likely to occur once in a 475 year period. The SSE earthquake is represented by a once in 2,475 (2,500) year return period event. These return periods are specified in the API 625 standard.

38.1 Can FEI attribute seismic levels to the probabilities? i.e. What magnitude level of earthquake is represented by a one in 475 year return period, or 2475 year return period?

<u>Response:</u>

The design seismic ground motions are established based on probabilistic methods of seismic hazard analyses. These consider, for varying earthquake magnitudes, pairs of data the same distance from the earthquake epicenter associated with the different seismic source zones.

The peak design ground motion amplitudes (such as peak ground acceleration) that correspond to return periods of 475 years (OBE) and 2475 years (SSE) have the following distribution of contributions from the different magnitude earthquakes:

Design EQ Scenario (M= magnitude)	< M5	M5-M5.5	M5.5-M6	M6-M6.5	M6.5-M7	M7-M7.5	M7.5-M8	M8-M9	M9+
OBE (475-yr)	0.8%	2.1%	4.1%	12.7%	34.4%	32.8%	0.8%	7.3%	4.5%
SSE (2475-yr)	1.2%	2.5%	2.4%	6.6%	29.7%	47.6%	1.4%	4.9%	3.4%

For design purposes, a mean earthquake magnitude of M 7 (approximate) occurring at a mean distance approximately 70 km from the site is representative of the OBE ground motions, and a mean earthquake magnitude of M 7.1 (approximate) occurring at a mean distance approximately 60 km from the site is representative of the SSE ground motions.

38.2 Please elaborate on what is meant by an 'Operating Basis Earthquake' (OBE) versus a 'Safe Shutdown Earthquake' (SSE) apart from their differing return year periods and/or magnitudes. Would FEI expect to continue operating during an OBE, but shut down during an SSE?

Response:

The OBE and the SSE are both scenarios of ground motion for which the tanks will be designed. In the OBE scenario, the tank system will be designed to continue to operate during and after the event. In the SSE scenario, the tank system will be designed to provide for no loss of containment capability of the primary container and it will be possible to isolate and maintain the tank system during and after the event. FEI would not expect to continue operating during an SSE event and, depending on the severity of the event, remedial work may be required prior resuming normal operations after an SSE event.

38.3 Are earthquakes considered to be the largest safety threat to the LNG plant? Please explain and identify any other risks that FEI considers to be significant.

Response:

While there are safety risks associated with building and operating any large process plant, the TLSE Project has been designed to eliminate or mitigate these risks in accordance with accepted industry practices and applicable standards.

Although the seismic risk is present, it is difficult to state that it would represent the largest safety threat. Risks to the facility are based on both likelihood and consequence. A significant seismic event could have the largest consequence of the safety risks identified, however it also has a very low likelihood and in any event has been accounted for in design as per Canadian and BC regulations. There is a small risk that a seismic event, falling outside the design parameters (one in 2475-year earthquake) will occur, but this is remote and does not constitute a significant risk factor.

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

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

39. Reference: Exhibit B-1, page 126 and 127

> Overpressure protection is provided by three pilot operated pressure relief valves and three pallet type vacuum relief valves. There is one spare pressure relief valve and one spare vacuum relief valve. This design (and redundancy) will ensure that the tank pressure protection is capable of safely relieving any internal overpressure or underpressure condition to prevent damage to the inner tank vessel.

39.1 What issues can cause over- or underpressure to arise?

Response:

There are several upset conditions that could lead to over- or under-pressure in an LNG system, such as excessive vaporization of the LNG in the tank or the inadvertent start of the BOG compressor. These conditions are addressed during detailed design through design review and process hazard analysis such as HAZOP. Appropriate design measures are put in place and the overprotection system is an additional layer of protection to ensure the integrity of the inner tank vessel.

39.2 Please describe the potential risk outcomes of over- or underpressure situations occurring.

Response:

Safeguards including the pressure relief valves and vacuum relief valves ensure that no serious outcomes result from an over- or under-pressure situation. The undesired outcome of an over- or under-pressure situation would be the potential for an uncontrolled release of methane from the tank.

40. Reference: Exhibit B-1, page 127

> ***5.3.1.3 Venting Design***
>
> Venting from the new storage tank will be required during the initial fill operations (due to LNG flashing to vapour as it contacts the uncooled inner vessel). Venting following the initial tank filling would generally be a result of a process upset condition in the plant and is expected to be a rare event.
>
> During normal operations, venting to the atmosphere is expected to be a very unlikely event. Any vapour or boil off gas (BOG)[106] from the tank will be contained by the boil off gas system and returned to the pipeline. However, in the event that there is an upset condition that exceeds the capability of the boil off gas system, the overpressure will be released to the atmosphere through pressure safety valves on the tank top. This is considered standard industry design. The other operating condition that may require minimal venting to the atmosphere would occur during maintenance activities, where equipment intended to capture the boil off gas is required to be out of service.
>
> The Project is being designed from a reliability perspective such that there is redundant equipment to prevent situations where any venting to the atmosphere would be required. As such, venting to the atmosphere is expected to be a very unlikely event.

40.1 Please describe the risks associated with LNG flashing if it is not properly vented.

<u>Response:</u>

The tank has been designed to properly vent natural gas under all conditions. If it was not properly designed, the tank integrity could become compromised due to overpressure resulting in loss of containment.

41. Reference: Exhibit B-1, page 127

> ***5.3.1.4 Filling Methodology***
>
> Construction of additional liquefaction is not within the scope of the TLSE Project. Rather, the 3 Bcf LNG tank will be filled using reserve capacity (approximately 5 MMcf/day) from the Tilbury 1A LNG liquefaction system, which has been reserved for utility use, including for peak shaving, emergency depletion, and replacement of LNG lost as boil off gas.
>
> The initial filling of the 3 Bcf tank will utilize any available capacity from the Tilbury liquefaction facilities. These facilities are intended to provide service to LNG customers under Rate Schedule 46 (RS 46); however, the capacity of these plants may not be fully subscribed initially or periodically during the year due to the inherent peaks and valleys associated with LNG sales. In particular, as the market for LNG marine fueling matures in the Port of Vancouver, FEI expects there will be spare capacity available in the timeframe required for the initial filling of the 3 Bcf tank.
>
> Once full, the 3 Bcf tank may be cycled by utilizing the reserve capacity from Tilbury 1A (as well as any excess capacity) as noted above. This reserve capacity could provide about 1 Bcf of liquefaction capacity each year in the time frame outside of the winter heating season (during which time FEI would work to maximize the tank fill volume).

41.1 How long does FEI expect it to take to fill the 3Bcf tank?

<u>Response:</u>

Please refer to the response to BCUC IR1 30.1.

41.2 Why is it necessary for FEI to maximize the tank fill volume? Please explain.

<u>Response:</u>

Maximizing the tank fill volume ensures the greatest volume of LNG is on standby in the event of a supply disruption. In the case of a 3 Bcf tank, the “third Bcf” also provides flexibility to realize ancillary benefits.

41.3 Could there be cost savings or other benefits from only filling the tank partway? Please explain why or why not.

41.3.1 If there are any benefits from filling the tank partway, please explain why FEI is planning to fill the tank to capacity.

Response:

The operations and maintenance requirements for the LNG tank and associated equipment do not change depending on the volume of LNG stored in the tank. There are no operations savings or benefits associated with partially filling the LNG tank. FEI notes that not filling the 3 Bcf tank would mean foregoing the potential of realizing ancillary benefits. As discussed in the response to CEC IR1 31.2, the commodity value of 1 Bcf of natural gas is approximately $3 million based on the current approved (September 2021) cost of gas rate. In comparison, as described in the response to BCUC IR1 46.2, the gas supply benefits associated with the “third Bcf” are approximately $30 million per year, which makes a 3 Bcf tank less costly for customers than a 2 Bcf tank and significantly outweighs the estimated one-time $3 million savings of commodity costs from only filling the tank partway to 2 Bcf.

42. Reference: Exhibit B-1, page 129

5.3.2.3 Fuel Gas Is Readily Accessible from the FEI CTS

Start-up fuel gas for the regasification system will be taken from the incoming FEI CTS; necessary pressure reduction and fuel gas heating will be provided within the regasification system. Once the firing has started and vapourizers are in normal operation, part of the sendout gas will be recycled as fuel gas.

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.

<u>Response:</u>

Please refer to the responses to BCUC IR1 21.1 and 21.3.

43. Reference: Exhibit B-1, page 130

> Another design consideration is the response time required to achieve full sendout capacity. To ensure full sendout capacity is achieved rapidly, the regasification system will need to be designed to heat the water baths of all four vapourizers simultaneously. This, combined with pre-start activities will ensure that the time from initiating the start-up of the HP pumps and vapourizers to achieving full sendout capacity of 800 MMcf/day will be less than two hours.

43.1 Is 2 hours an important threshold for achieving full sendout capacity? Please explain.

43.1.1 If no, could FEI achieve any cost savings by extending the response time to achieve full sendout capacity? Please explain and quantify any savings.

<u>Response:</u>

Please refer to the response to BCUC IR1 31.4 for a discussion regarding the sendout response time.

There would be no expected capital savings by designing the system to sendout gas in a time greater than two hours as the required equipment is the same in any case. There would be some minor operational cost savings from no longer having to recirculate LNG through the sendout equipment (needed to maintain the low temperatures to keep the system ready to operate).

44. Reference: Exhibit B-1, page 132 – 133

5.3.3.5 Utilities

The Project will require numerous utilities to support the ongoing safe and reliable operation of the regasification system and 3 Bcf storage tank. These necessary systems will include:

- Electrical power, including 13.8 kV and 4.16 kV feeder lines to supply the LNG storage tank systems, BOG compressors, and regasification package;
- Instrument air compressors and gaseous nitrogen system to operate process control devices;
- A common remote instrument building for safety instrumentation systems, distributed control systems and other hardware devices (e.g. control switches, fire and gas monitoring panels);
- An emergency generator to provide electric supply for critical loads to ensure operations even during a site-wide power failure. At a minimum, these critical loads will include one in-tank LNG pump, three HP send-out pumps, three vapourizers, and instrument air compressors, as required;
- Potable water and firewater supply from city mains;
- Pressure reduction and gas heating station for the regasification package; and
- Modifications to the central control room of the Tilbury 1A LNG facility to house the operator consoles for the TLSE Project.

44.1 Please confirm that FEI is able to confidently acquire the necessary utilities for the safe and reliable operation of the regasification system.

Response:

Confirmed. FEI can acquire all the necessary utilities (including power and water) required for the Project.

44.2 At what stage are arrangements with BC Hydro for supply?

Response:

FEI has submitted a Transmission Voltage Connection application to BC Hydro as required to accommodate the TLSE Project electricity requirements. The application is complete and BC Hydro is preparing the cost estimate and agreement to undertake the required work for an update to the existing System Impact Study and Facility Impact Study.

45. Reference: Exhibit B-1, page 134

5.4.1 Base Cost Estimate (AACE Class 3) Developed With External Experts

FEI, in conjunction with Linde, Clough Enercore (Clough), Horton CB&I (HCBI), Golder, and Solaris Management Consultants Inc. (SMCI), developed the Project cost estimate using AACE International Recommended Practices 18R-97 and 97R-18 as guides. The AACE Class 3[107] cost estimate is based on quantities developed from designs and material take-offs completed by Linde, Clough, HCBI, Golder and SMCI, as the basis to develop the direct and indirect costs.

45.1 What process did FEI undertake to select the external experts? Please explain.

<u>Response:</u>

FEI typically selects external experts for project-related work through a Request for Proposal (RFP) process. FEI prepares a Scope of Work package outlining the objectives, services, key project roles, and qualifications required. The RFP is distributed to pre-qualified experts or consultants, or experts or consultants with which FEI has existing contracts and are currently working on other FEI projects. The proponents provide a proposal outlining their organizational qualifications, proposed project team, rates, availability, and schedule to perform the function as described in the Scope of Work. FEI reviews the proposals received, and conducts an evaluation on a best-value basis. The proponent's proposal that provides the best value to FEI is ranked first and is selected as the preferred proponent.

In instances where a recognized industry expert is required to perform specialized studies, analysis, or reviews, such as risk analysis, integrity assessment, or a complex engineering review or analysis, FEI may direct award to that expert based on negotiated hourly rates and a number of hours. The hourly rates are compared to FEI's internal data base of consultant's rates for similar or equivalent studies and analysis completed over the past few years. These rates are aligned with industry rates for specialized expert services. In addition, FEI may extend the scope of existing contractors where consultants or experts are performing well on other works.

In the case of TLSE Project, CB&I was chosen to develop the largest portion of the cost estimate (the tank) after a review of worldwide experience in tank construction at this size. CB&I is among the recognized leaders in this industry, with an extensive track record of constructing LNG tanks globally and an excellent understanding of the North American construction environment. Similarly, for the regasification scope, Linde is a recognized world leader in this area. In both cases, hourly rates were negotiated with the firms and are aligned to industry and internal rates for comparable services.

45.2 Are the experts developing the Base Cost Estimates the same parties that will be conducting the work? Please explain.

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.

46. Reference: Exhibit B-1, page 138

5.4.3 Cost Verification and Validation

Cost estimate quality assurance and validation reviews were completed to provide confidence that the estimate was developed based on AACE recommended practices and met the criteria for an AACE Class 3 estimate.

The quality assurance and validation consisted of a team thoroughly reviewing documents over a period of weeks as they were received by FEI. Reviews considered whether the estimate met the requirements, appropriate tools and data were used, and the estimate was complete for the respective scope. FEI discussed findings with all relevant consultants and updated the estimate as required.

Cost estimate quality assurance and validation activities included:

- Internal, Linde, Clough, HCBI, Golder and SMCI reviews that included peer reviews, document quality checks, and independent review;
- Validation reviews involving both Linde, Clough, HCBI, Golder and SMCI, and FEI team members, throughout the estimate development process to confirm that the estimate assumptions were valid and that a well-documented, reasonable and defensible estimate was developed; and
- FEI retained Validation Estimating LLC, USA (Validation Estimating), a company that provides services in estimate validation, risk analysis, and contingency estimation. Validation Estimating reviewed all the constituent estimates to confirm their suitability for inclusion in the AACE Class 3 estimate.

46.1 The CEC expects that Validation Estimating reviews the estimates with regard to thoroughness and adequacy. Does Validation Estimating also consider whether or not the estimates could be overly generous?

Response:

Validation Estimating does consider the reasonableness of the estimate. As part of the analysis, when assessing the estimate, Validation Estimating evaluates the bias in the base estimate. Based on the estimate bias, the cost risk or amount of contingency is quantified relative to the base estimate. That is, if the base estimate is conservative there will be less need for contingency and vice-versa for aggressiveness. The sum of the base estimate and contingency then reflects the expected costs of the project at the selected confidence level.

46.1.1 What are the metrics that Validation Estimating considers in reviewing the estimates?

Response:

Based on AACE guidelines, estimate review is a qualitative process, as such there are no metrics that are used as part of the estimate review process. AACE 31R-08 summarizes the review process as follows:

> The estimate "review" is typically qualitative in nature and focused on ensuring that the estimate technically meets requirements (i.e., it serves a quality assurance and control function). This quality review determines if the estimate was:
>
> - Developed using contractually or procedurally required practices, tools and data
> - Whether it covers the entire project scope
> - Whether it is free from errors and omissions (at a macro level; the validation step should reveal any errors or omissions from the specific details)
> - Whether it is structured and presented in the expected format
> - Others as deemed applicable

47. Reference: Exhibit B-1, page 138 and 139

5.4.4 Risk Analysis – Quantitative and Qualitative with Expert Support

FEI has performed an appropriate risk assessment process for this stage of the Project, which included identifying the key Project risks, treating and mitigating risks as appropriate, and taking an approach to risk quantification that is consistent with FEI's risk management framework. The risk assessment includes both qualitative and quantitative components.

FEI has set contingency and escalation amounts in addition to the Project base cost estimate to achieve a P50 confidence level to address foreseeable risks and changes in market conditions over time. Contingency and escalation are described as follows:

- **Contingency** is typically expected to be spent and is used as an allocation for risks that are known and likely to be encountered during Project execution.[108] For the TLSE Project, FEI will set the contingency at a cost value to achieve a P50 confidence level.

[108] Contingency is defined in AACE International Recommended Practices 10S-90: *Cost Engineering Terminology* as: An amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, and/or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs. Typically estimated using statistical analysis or judgment based on past asset or project experience." Contingency by AACE definition is expected to be spent.

As such, the Project contingency will be $108.200 million (20 percent) at the P50 confidence level.

- **Escalation funds** per AACE is "a provision in costs or prices for uncertain changes in technical, economic, and market conditions over time. Inflation (or deflation) is a component of escalation." The base estimate was developed using 2020 pricing data and conditions and does not inherently account for escalation. Price increases/decreases beyond 2020, including contingency, must be covered by the escalation estimate. FEI will set the escalation at a cost value of $62.393 million[109], which corresponds to the P50 confidence level.

[109] Escalation of $62.393 million is shown in Table 6-1 as the difference between the contingency-adjusted Base Cost Estimate of $699.696 million (As-Spent $) and the contingency-adjusted Base Cost Estimate of $637.303 million (2020 $).

47.1 Does FEI normally include an Escalation amount in its CPCN applications? Please explain.

47.1.1 If not, please explain why FEI has included it in this CPCN.

Response:

FEI has consistently included escalation in its CPCN applications. An escalation amount is required because the cost estimates are completed in current dollars, i.e., in 2020 dollars in the case of the TLSE Project, whereas the TLSE Project will be completed over multiple years. As such, escalation factors are included to consider potential economic and market conditions and thus cost in the years when the dollars are actually spent. As discussed in Section 5.4.4 of the Application and referenced in the above preamble, including escalation adheres to AACE, which is "a provision in costs or prices for uncertain changes in technical, economic, and market conditions over time. Inflation (or deflation) is a component of escalation."

47.2 Is an Escalation amount generally required in a Class 3 estimate? Please explain.

47.2.1 If no, please explain why FEI has included this in the CPCN.

Response:

As discussed in the response to CEC IR1 47.1, escalation is used to convert from current dollars to as-spent dollars. If the cost estimates are completed in current dollars but the actual spending occurs in future years, escalation is needed to convert to as-spent dollars regardless of whether the cost estimate is a Class 3 estimate or other class of estimate.

48. Reference: Exhibit B-1, page 140 and 141

Table 5-5: Risk Assessment Matrix

	Risk Impact Category (Cost, Schedule, Performance/Quality/Scope)				
	Impact				
Probability (Likelihood)	Very Low	Low	Medium	High	Very High
Very High (>75%)	Moderate	Moderate	Major	Major	Major
High (51 – 75%)	Minor	Moderate	Major	Major	Major
Medium (20 – 50%)	Minor	Moderate	Moderate	Major	Major
Low (5 – 19%)	Minor	Minor	Moderate	Moderate	Moderate
Very Low (<5%)	Minor	Minor	Minor	Minor	Moderate

Table 5-6: General Risk Management Criteria

Risk Level	Management Criteria
Major	Risk is unacceptable or exceeds tolerance threshold. If risk is red after mitigation, it requires acceptance by PM, and preparation of monitoring and controls and contingency plan. *WARNING: if risk is related to performance and HSE, do not proceed with activity. Field Supervisor and HSE personnel need to be involved in risk control plan to reduce risk level.*
Moderate	Risk controls/enablers should be applied where economical and practicable. Mitigate is most common response, else establish monitoring of risk. *ALERT: if risk is related to performance and HSE, Operations or HSE personnel shall be involved in risk control plan to reduce risk to as low as reasonably practical (ALARP).*
Minor	Risk level is tolerable as is, no response required, provided adequate monitoring and controls are in place and functioning effectively and due consideration has been given to reduce the risk.

48.1 Please describe the metrics which characterize Very Low, Low, Medium, High and Very High with regard to Risk Impact categories.

Response:

The metrics which characterize the Risk Impact categories can be found in Appendix 2 of Confidential Appendix K-1 to the Application. Please refer to the table in the referenced appendix for a detailed explanation of how each Risk Impact category is defined.

48.2 How did FEI arrive at those metrics?

Response:

Metrics are developed based on the characteristics of a project. The following project criteria defined the project specific risk prioritization matrix for the TLSE Project:

- Project capital cost of approximately $600 million CAD;
- Schedule based on successful turnover of mechanically completed facility to operations, for start-up and commissioning, by a milestone date defined in the baseline schedule; and
- Other impact criteria are defined in accordance with previously defined company risk assessment criteria (common for most projects).

Further detail can be found in Confidential Appendix K-1 to the Application.

49. Reference: Exhibit B-1, 143

> The AACE "by-period" method was applied to develop the cost escalation estimate. This method uses price indices by cost account applied to the annual cash flow by cost account. The base indices are forecasts provided by the economic consulting firm IHS Markit. These indices are used to develop weighted indices that match the cost types (e.g., pipeline material, construction labour, etc.). The indices are further adjusted for forecast global and regional capital spending market conditions (i.e., adjusts for bid mark-up behaviour as well as productivity trends in hot or cold markets).

49.1 What alternative methodologies are there for developing cost escalation estimates?

49.1.1 Why did FEI choose to use the 'by-period' method?

Response:

There are many recognized methodologies for calculating cost escalation. AACE methods and procedures are the standards used by the energy industry, and allow consistency and comparison across different projects and organizations. The BCUC recognizes the standard AACE cost estimation methodology.

The AACE "by-period" method allows for the differing cost growth/shrinkage of different cost areas (as described above) to be treated discretely and evaluated fairly across an appropriate period of time. Indices are generated by industry leaders such as (in this case) IHS Markit who provide this service on behalf of large project developers across North America. Using these indices "by-period" results is the most reliable estimation of escalation throughout the project that can be reasonably attained.

Alternative methodologies could include: (1) using less differentiation between cost account types for indexation; (2) using one set of indices for the entire timespan of the project; or (3) using other indices generated through methods less rigorous than those employed by industry-leading groups such as IHS Markit. All of these would result in less accurate results than generating the "by-period" estimate as per AACE guidelines.

50. Reference: Exhibit B-1, page 147

> ***5.5.3.1 Contractor Evaluation, Selection and Contract Award Managed through Procurement Processes***
>
> Given the size and complexity of the Project and the multiple interfaces between the work, FEI intends to initiate a competitive process to select and award the work to a single EPC contractor for the entirety of the scope. However, this would need to include a balance of risk and cost acceptable to both parties. FEI will also consider the possibility of awarding multiple contracts if required to properly manage the risk profile for the Project. The focus of the contracting effort will be to demonstrate competitive pricing for all Project scopes and responsible management of the capital outlay. The preference will be to award the contract(s) to a proven contractor(s) with a high level of experience in LNG and natural gas engineering projects, and a recent successful track record of execution. The successful contactor(s) will be chosen according to established procurement procedures. Methods of evaluating local opportunities and Indigenous participation in contracted scopes will form part of the contractor selection criteria.

50.1 Please elaborate on why FEI selected the EPC model (single contractor for Engineering, Procurement and Construction).

<u>Response:</u>

EPC is a general term for a contract structure in which a single entity (or single consortium) assumes most of the responsibility for the execution phase of the project (Detailed Design, Construction, Commissioning, and possible start-up). EPC is similar to the Design Build project delivery method. There are many variations and risk allocation strategies that FEI may choose to employ under the general heading of "EPC". A contract strategy that defines FEI's exact preferences will be developed post-CPCN approval, and then will be negotiated with the organizations that bid for the work.

FEI has broadly selected an EPC strategy for several reasons:

- FEI intends to award the work to an organization with proven capability in the execution of large LNG projects. Leveraging this existing capability to the greatest extent possible will provide the best value and minimize risk.
- Detailed Design has not yet been done; it is desirable for detailed design to proceed with the full involvement of construction and commissioning expertise to optimize decisions and facilitate efficient execution. The EPC model accomplishes this.
- Choosing one organization to execute the work will minimize the management of interfaces on the Tilbury site, and reduce overall execution risk (please also refer to the response to BCUC IR1 47.2).

50.2 What other types of contractor arrangements did FEI consider?

Response:

Other contract forms were considered by FEI, but none were found to offer the expected benefits of the EPC model. The exact form of EPC that FEI will employ has not yet been finalized and will be determined following BCUC approval.

Other forms that were considered:

- Design-Bid-Build – A form that employs separate contracts for engineering design and construction management, and for potentially other scopes. The engineering design is typically completed using a services contract for the complete design and for development of bid packages. The completed bid packages are then used to seek competitive pricing from contractors for the construction.
- Construction Manager at Risk (CMAR) – A collaborative form in which the owner contracts with two separate firms concurrently: an engineering firm to design the project (Design Firm), and a separate CMAR firm that will act as construction manager and general contractor.

Both of these forms have some advantages, but it was considered that these would be outweighed by the requirement for FEI to manage more interfaces between contracted parties than in an EPC model, and therefore accept more risk.

50.3 Please briefly list the benefits and drawbacks of each construction model considered.

Response:

While the preamble to the information request refers to contracting models, the question itself refers to construction models and as such FEI interprets the question as relating to construction models.

The detailed construction execution plan has not yet been finalized. This will be a central feature of the EPC bidding process and negotiations with the successful respondent(s).

The respondents to the Request for Proposals for the EPC contract will be asked to describe their chosen construction execution methodology and plans and these will be evaluated and ranked by FEI for overall value. As such, they have not yet been considered in more detail than that required to develop a Class 3 estimate.

There are fundamentally two broad construction execution methodologies that may be applied to Tilbury. Practically, the final model will almost certainly be a mix of the two:

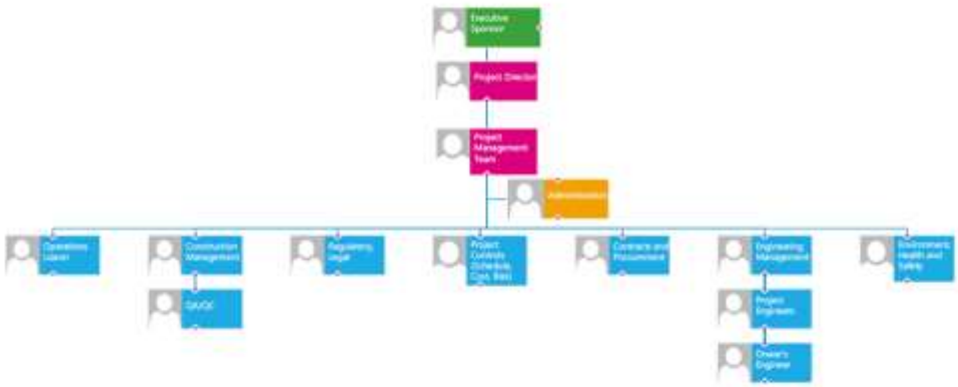
- Stick-Build – Delivery of individual components to site, with full assembly happening on-site.
- Modular – Assembly of components off-site (in dedicated fabrication facilities) into modules, which are then transported to site.

Stick-build has the advantage that separate facilities are not required, and the transport of large modules is avoided. Modular facilities are generally cheaper to construct and minimize the integration risks of dense construction in a confined site.

In general, the construction model for Tilbury will almost certainly involve stick-building the LNG tank (modularization is not possible) and some modularized piping and equipment construction. The proposed construction execution plan will be a key evaluation criterion during the EPC bidding process.

51. Reference: Exhibit B-1, page 151

Figure 5-6: Proposed Resources and Organizational Chart for TLSE Project



The key roles and personnel are as follows:

- The **Executive Sponsor** for the execution of the Project is the Vice President, Major Projects.
- FEI will have a **Project Director** who will manage all aspects of the Project including, but not limited to, permitting, engineering, procurement, and construction. The Project Director is responsible for overseeing all project activities.
- Additionally, FEI will have a **Construction Manager** on site who will ensure health and safety, quality, environment, schedule, outage staging and planning, and cost controls are all properly managed according to FEI standards.
- The **Project Management Team** will be supported by other members of the FEI Project Management Office (PMO) as required, such as Project Schedulers, Cost Analysts, and Administration. The Project will also be supported by other FEI departments, including Occupational Health and Safety, Operations, Environment, and Lands. The Project Management Team will be responsible for liaising with these other departments as required.
- FEI will have several dedicated **Project Engineers** and a supporting **Design Organization** assigned to manage the engineering component of the Project. Supplemental external engineering support will be required to complete various engineering designs, such as geotechnical, site preparation and excavation, concrete foundations and concrete containments, process piping, safety modelling and management, and logistics.

The CEC notes that FEI currently has the Inland Gas Upgrade CPCN application underway, as well as the Pattullo Gas Line Replacement Project application, the Coastal Transmission System Transmission Integrity Management Capabilities (TIMC) Project application and is planning to issue a CPCN for Automated Metering Information in August. In addition, FEI has indicated it will follow up with a CPCN for TIMC for Inland Gas and has other various applications ongoing as well.

51.1 Please discuss what process(es) FEI has put in place to ensure adequate human resources are available for the multiple major projects being undertaken in the next five years, if any.

Response:

FEI has the internal resources to manage each of the projects.

All FEI projects establish a project management team appropriate to the project stage. A staffing plan is generated to plan the human resource needs at each stage, and is continually challenged and updated to account for changing conditions if any exist. As the project progresses, resources are added as planned and required. These resources are supplemented by project management, specialist engineering, environmental and other resources from consulting firms that provide these services. In general, during execution, the project will primarily be staffed by the contractor firm(s) executing the work, with an FEI Owner's Team overseeing their work. The ability of contractor firms to staff the project appropriately is a key criterion by which their suitability to be awarded the work will be judged by FEI.

FEI also notes that many of the projects being undertaken are quite different in nature and as such they will draw on different internal and external resources and will impact separate business areas. For example, the resources required to execute on the AMI project are in many cases different than those required to execute on the TLSE Project.

51.1.1 Please provide the FTEs that will be attributed for each position noted and identify any areas of overlap with other projects.

Response:

The TLSE Project is a large and long-duration undertaking. It is not expected that human resources will be shared or overlap significantly with other projects outside of the TLSE Project, except for corporate communication and reporting functions. The roles described in Section 5.6.1 of the Application will be sourced from FEI departments as described, but key personnel will be dedicated to the TLSE Project for the duration of the execution phase.

The FTE count for the Project will vary according to the stage of execution. The AACE Class 3 estimate was generated using general assumptions and benchmarks for EPC-style execution and includes a cost allowance for the owner's team during Project execution. Post CPCN approval, a more detailed execution plan will be developed, including an updated staffing plan with specific FTE plans for each component of the organizational chart shown.

51.2 Is the pool of external engineering and other technical expertise related to gas limited in BC?

51.2.1 If yes, has FEI experienced, or does FEI expect to experience, any issues with procuring adequate external expertise given the number of projects ongoing? Please explain why or why not.

Response:

FEI is not aware of any significant market constraints in western Canada for LNG engineering and Project Management expertise at this time. The Project will leverage LNG experience both from within and outside of BC, depending on technical and commercial attractiveness.

Management of risk and issues such as the availability of external expertise given the number of projects ongoing is a continuous process throughout a project's lifecycle. FEI's continuous engagement with contractors for all projects within the Major Projects portfolio enables FEI to identify any changes to contractor capacity and availability early on.

51.2.2 Does FEI typically rely on the same set of vendors for any aspects of its multiple engineering projects, such as project design, estimating, estimate validation, engineering, procurement, construction, environmental and archaeological studies, environmental inspectors, regulatory approvals, etc.?

51.2.2.1 If yes, how does FEI ensure that the vendors remain competitive?

Response:

Where appropriate, FEI relies on the same set of vendors provided these vendors continue to demonstrate good performance on the projects they are engaged in. For the TLSE Project, it is possible that some vendors may be the same as those engaged on other FEI projects. However, given that much of the TLSE Project scope is unique to LNG facilities, it is more likely that the vendors engaged will have LNG-specific skill sets and will not overlap with vendors used on other FEI projects.

For the TLSE Project, the primary EPC contract comprising nearly all of the scope and cost will be awarded through a fully competitive process according to FEI's bidding and award procedures. Several contractors/consortiums will be invited to bid on the work. Bids will be assessed on many criteria, including cost, and the work will be awarded to the bid judged to represent the highest value to the Project.

51.3 Please confirm that FEI expects to have adequate financial resources to meet all the CPCN and other project obligations over the next five years.

Response:

Confirmed. FEI has adequate financial resources, funded through both equity and debt components as approved by the BCUC, to manage and execute all the CPCNs and other project obligations over the next five years.

51.4 Could FEI experience any project benefits by delaying the project until other projects are completed? Please explain why or why not?

Response:

The TLSE Project will provide the greatest risk reduction benefit for customers if completed as soon as possible. There are no benefits to delaying the Project, only risks, as FEI is currently unable to meet the MRPO. Please also refer to the response to BCUC IR1 14.5 for a discussion of the need for and timing of the Project.

FEI does not foresee a conflict in contract resources between the TLSE Project and other projects. The TLSE Project requires different skillsets both for design and for construction when compared to FEI's other major pipeline projects, and hence there is little resource overlap. As such, there is no benefit in delaying the TLSE Project from a labour procurement perspective. Further, the internal resources assigned to the TLSE Project are primarily members of FEI's LNG team, rather than employees responsible for completion of other major pipeline projects.

PROJECT COST, ACCOUNTING TREATMENT & RATE IMPACT

52. Reference: Exhibit B-1, page 160 and page 101

> **6.3 FINANCIAL ANALYSIS**
>
> FEI has performed a financial evaluation of the Project based on the present value (PV) of the incremental revenue requirement and the levelized delivery rate impact to FEI's non-bypass customers over a 67-year analysis period. The 67-year analysis period is based on a 60-year post-Project analysis period plus seven prior years for the estimated Project schedule from 2020 to 2026 (with all new assets to be placed in-service by 2026). The 60-year post-Project analysis period is chosen based on the average service life (ASL) for a new 3 Bcf LNG tank as recommended by Concentric Advisors, ULC (Concentric), who completed FEI's most recent Depreciation Study approved by BCUC Order G-165-20 as part of FEI's 2020-2024 Multi-Year Rate Plan (MRP) Application. FEI is seeking approval for a depreciation rate of 1.67 percent (equivalent to 60 years) for the new 3 Bcf LNG tank, which is discussed in more detail in Section 6.4.1.

> The above analysis confirms that it is more economic to build a single, larger tank now rather than continuing to rely on the existing 0.6 Bcf tank and other Base Plant facilities only to replace them at some point in the future. The analysis also shows the existing Base Plant facilities at Tilbury would need to remain in place for another 44 years (i.e., to an age of 94) with no further sustainment capital expenditures to the Base Plant facilities for that scenario to make economic sense. Given that the Base Plant is currently 50 years old, FEI believes it is neither desirable nor likely that the Base Plant will remain in operation for another 44 years.

52.1 FEI is proposing to replace the existing 0.6 Bcf tank after 50 years. What was the expected service life of that tank and what would be the remaining service life without this Tilbury LNG Expansion project?

Response:

Based on FEI's most recently approved depreciation study[14], the average service life of the Base Plant tank is 40 years, which means that the life of the tank has already been extended by 10 years due to capital maintenance activities. Please refer to the response to BCUC IR1 40.1 for further details. FEI is unable to estimate how much longer it would be able to extend the Base Plant tank's service life through additional capital maintenance activities. However, as discussed in the response to BCUC IR1 16.22, even if the Base Plant tank reaches a 70-year service life, it is more economical to construct a new 2 Bcf tank now as opposed to constructing a 1.4 Bcf tank now and continuing to utilize the Base Plant tank.

52.2 Please confirm that FEI expects to utilize the new facilities for the duration of their expected service life, and has no reason to expect that the facility will be prematurely removed from service.

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[14] Approved by Order G-165-20.

Response:

Confirmed. Under normal operating circumstances, FEI expects to utilize the new facility for the duration of the assets' expected average service life. FEI expects to incur capital for sustainment activities involving replacement and renewal of major components of the assets over the years which will likely extend the life of the assets beyond the estimated average service life. However, FEI notes there are a number of possible reasons that might require removal of assets prior to end of life, including natural disaster, government policy/order, operational efficiency with benefits to customers, and safety/reliability reasons.

53. Reference: Exhibit B-1, page 168

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

	2022	2023	2024	2025	2026	2027
Annual Delivery Margin, Incremental to 2021 Approved, Non-Bypass ($ millions)	(0.162)	0.361	1.274	22.909	36.651	79.799
% Increase to 2021 Approved Delivery Margin, Non-bypass	*(0.02%)*	*0.04%*	*0.14%*	*2.60%*	*4.17%*	*9.07%*
Incremental % Delivery Rate Impact (Year-over-Year)	*(0.02%)*	*0.06%*	*0.10%*	*2.46%*	*1.52%*	*4.71%*
Average Annual % Delivery Rate Impact (6 years, 2022 - 2027)	1.47%					
Average Annual Delivery Rate Impact (6 years, 2022 - 2027), $/GJ	0.068					
Cumulative % Delivery Rate Impact (6 years, 2022 - 2027)	9.07%					
Cumulative Delivery Rate Impact (6 years, 2022 - 2027), $/GJ	0.409					

The Project will result in a cumulative delivery rate impact of 9.07 percent compared to FEI's 2021 approved delivery rates when all construction, including the Base Plant demolition, is completed and all capital costs have entered FEI's rate base. The average annual delivery rate impact over the six years from 2022 to 2027 is estimated to be 1.47 percent annually or $0.068 per GJ annually. For a typical FEI residential customer consuming 90 GJ per year, this would equate to an average bill increase of approximately $6.12 per year over the six years. As discussed in Section 6.3, the levelized delivery rate impact is 6.67 percent, which is equivalent to $0.301 per GJ for a typical FEI residential customer over the life of the assets.

53.1 Please provide the total rate impact over the next 15 years for all FEI's Projects that are currently underway and impacting rates during that period and break out these impacts by Project.

Response:

Please refer to the response to BCUC IR1 14.6 for the cumulative rate impact over a 10-year period from 2020 to 2030 due to FEI's completed, in-process, and anticipated major projects. FEI has not extended the analysis to 15 years as all proposed major projects are expected to have entered FEI's rate base prior to 2030. As such, there will be no additional rate impacts beyond 2030 due to all the currently proposed projects.

53.2 FEI includes demolition of the Base Plant in the costs of the Project. Were any of these costs or other end of service costs included in the original project application? Please explain.

Response:

If the "original project application" is intended to refer to the TLSE Application filed on December 29, 2020, FEI confirms there was no change in terms of cost estimates or any other end of service costs between the Updated Public Application filed on May 19, 2021 and the original application.

53.3 Please provide the estimated bill impacts for rate increase.

Response:

Please refer to the table below which provides the average bill impact per year for FEI's customers in Rate Schedules 1 to 7 based on the cumulative delivery rate impact of $0.409 per GJ from 2022 to 2027 for FEI's non-bypass customers due to the TLSE Project (as shown in Table 6-6 of the Application). FEI has excluded transportation customers as the utility does not have insight into their total bill including their commodity charges.

Average Bill Impact ($)	Avg. Use per Customer (UPC) in GJ	TLSE Project
Cumulative Effective Delivery Rate Impact (6 years, 2022 - 2027), $/GJ		$ 0.409
Residential		
Rate Schedule 1	90	$ 36.8
Commercial		
Rate Schedule 2	340	$ 139.1
Rate Schedule 3	3,770	$ 1,541.9
Rate Schedule 23	5,479	$ 2,240.8
Industrial		
Rate Schedule 4	9,050	$ 3,701.5
Rate Schedule 5	16,240	$ 6,642.2
Rate Schedule 6	2,060	$ 842.5
Rate Schedule 7	177,950	$ 72,781.6

53.4 Please advise whether or not interruptible customers would be paying for the costs implied in these rate increases.

Response:

At the time that the TLSE Project enters FEI's rate base, there will be delivery rate impacts to all non-bypass customers, including interruptible customers, as the general delivery rate increase applied for by FEI in that year as part of the annual rate-setting process, if approved, would be implemented for all non-bypass rate classes, including Rate Schedules 7, 22, and 27.

FEI will be filing an updated Cost of Service Allocation (COSA) in early 2023. If the TLSE Project is approved, the updated COSA would include an examination of the cost allocation for the TLSE Project, along with FEI's other costs. At that time, rates for the interruptible rate schedules can be reviewed to determine the appropriate cost allocation for LNG storage costs.

54. Reference: Exhibit B-1, page 161

The financial evaluation of the TLSE Project includes the following assumptions:

- **Inflation:** Two percent annually for incremental O&M, property tax, and future capital replacement costs during the post-Project analysis period. This is comparable to the historical 5-year average BC CPI from 2015 to 2019 which is also approximately two percent[122];

54.1 Please confirm that 2% annual inflation is historically low over a 100 years period.

Response:

FEI is unable to comment if the 2 percent annual inflation is historically low over a 100-year period as historical BC CPI data from BC Stats or Statistics Canada is only available starting in 1979[15]. FEI believes that basing inflation on the historical 5-year average, as proposed in the Application, is most appropriate, as it is supported by the current BC CPI forecasts provided by the Conference Board of Canada (CBOC)[16], as explained in the response to CEC IR1 54.2, and it more accurately reflects the cost of living and other market factors than an inflation estimate based on the average of many decades of inflation, such as 100 years.

54.2 Why did FEI select the last five years as the basis for its inflation rates, instead of another time frame, such as a 5 or 10 years average?

Response:

This response also addresses CEC IR1 54.3, 54.4, 54.4.1, and 54.5.

The purpose of adding inflation is to include reasonable forecasts of future incremental O&M, property tax, and capital replacement costs for the expected life of the TLSE Project in order to provide a complete financial analysis for evaluation. FEI notes the post-Project period is 60 years starting in 2027 (i.e., the forecast year in which all TLSE Project assets enter rate base).

The table below shows that the difference in the levelized delivery rate impact or bill impact to residential customers using a 10-year historical average, 5-year historical weighted average, 5-year median of historical BC CPI, or a 3 percent average of BC CPI is minor. The small difference

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15 BC Stat: https://www2.gov.bc.ca/assets/gov/data/statistics/economy/cpi/cpi_fiscal_year_2020_2021.pdf; Statistic Canada: https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1810000501&pickMembers%5B0%5D=1.26&cubeTimeFrame.startYear=1914&cubeTimeFrame.endYear=2020&referencePeriods=19140101%2C20200101.

16 https://www.conferenceboard.ca/e-data/browsedirectories.aspx?did=21.

among the various scenarios shown in the table below does not materially change the financial evaluation of the TLSE Project.

Particular	5-yr avg BC CPI (2015-2019); As per Application	5-yr Weighted Avg. (2015-2019)	5-yr Median (2015-2019)	10-yr avg BC CPI (2010-2019)	3% BC CPI
BC CPI (%)	2%	2.22%	2.10%	1.57%	3%
Levelized Delivery Rate Impact 67 years (%)	6.67%	6.77%	6.71%	6.49%	7.20%
Levelized Delivery Rate Impact 67 years ($/GJ)	0.301	0.305	0.303	0.293	0.325
Avg Annual Residential Bill Impact, 90 GJ ($)	27.1	27.5	27.3	26.4	29.3

As mentioned above, the post-Project period is 60 years starting in 2027. FEI is not aware of third party literature available for BC CPI that includes forecasts 7 years or more into the future. The BC CPI forecasts provided by the CBOC[17], available with subscription, are for a 5-year period only up to 2025. Further, the current CBOC forecast of BC CPI for 2025 is at 2.1 percent (February 2021), which is comparable to the 2 percent FEI used for the post-Project period.

FEI does not believe it is reasonable to use inflation rates of 4 or 5 percent, as suggested in CEC IR1 54.5, for the post-Project period. There is no reason to expect that this level of inflation would occur consistently over the 60-year post-Project period from 2027 to 2086 based on historical data or based on the forecast available from the CBOC. In fact, the last time BC CPI was higher than 4 or 5 percent was 30 years ago.

54.3 Why did FEI use an historical average, instead of any other option, such as a weighted average or median?

Response:

Please refer to the response to CEC IR1 54.2.

54.4 FEI's sources are all historical. Has FEI conducted any review of current literature related to forecast inflation rates in order to identify the likely direction of inflation rates? Please explain why or why not.

54.4.1 If yes, please provide an overview, with quantification, of any views FEI considers to be appropriate related to future inflation rates.

[17] https://www.conferenceboard.ca/e-data/browsedirectories.aspx?did=21.

Response:

Please refer to the response to CEC IR1 54.2.

54.5 Please quantify the impact if inflation rates were to average 3%, 4% and 5% over the post-Project analysis period.

Response:

Please refer to the response to CEC IR1 54.2.

54.6 Please explain how changes in inflation for O&M on a Project such as the Tilbury expansion are treated under FEI's current Multi-year rate plan.

Response:

As discussed in Section 6.5 of the Application, the TLSE Project assets are forecast to enter FEI's rate base from 2025 to 2027, which is after FEI's currently approved 2020-2024 MRP. FEI will include O&M forecasts for the TLSE Project assets in a future revenue requirement application in the years after the TLSE Project enters FEI's rate base in setting FEI's delivery rates for those future years. Depending on the rate-setting mechanism approved at the time the TLSE Project is in-service, the O&M could be escalated annually by some form of inflation factor which would account for inflationary increases in O&M (similar to the currently approved MRP), or the O&M could be forecast annually or bi-annually in a cost of service type revenue requirement application which would implicitly account for inflationary increases.

55. Reference: Exhibit B-1, page 162

> The O&M estimate for the new tank, regasification equipment and auxiliary systems reflects the work of Partners in Performance (PiP)[124]. The O&M estimate for the new tank and equipment is developed based on PiP's Q4-2019 benchmark study on known and similar operations globally, normalized with information collected from interviews conducted with FEI operations on the existing Tilbury facility, third party subject matter experts on similar operations, and Engineering, Procurement and Construction Companies (EPCs) who developed the cost estimates for the Project. This detailed estimate is included in Confidential Appendix N.
>
> [124] PiP is a global management consulting firm with specific expertise in industrial operations including LNG, oil and gas, and utilities. PiP has extensive experience in supporting oil and gas companies with existing LNG operations in Canada as well as globally, including Australia and the United States.

55.1 Has FEI worked with PIP before?

Response:

PiP has been involved in several projects for FEI dating back several years. They have primarily been engaged in the Operations and Construction planning areas.

55.2 Please provide PIP's Q4 – 2019 Benchmark study, confidentially if necessary.

Response:

FEI clarifies that the references to the benchmark study contained in Section 6.3 of the Application were made in error and should have referred to the estimates described in the PiP report filed as Confidential Appendix N (PiP Report). All of the information supporting the O&M and sustaining capital estimates is contained within the PiP Report. While there are references to benchmarks and a benchmark study in the PiP Report, these references pertain to a compilation of raw data in a Microsoft Excel spreadsheet collected by PiP on LNG plants around the world from public and pay-for-service sources. The relevant information was extracted from the raw data and has been provided in the PiP Report.

55.3 Please provide the number of operations included in PIP's benchmark study, and identify how many are located in Canada, US, Australia and other countries.

Response:

Please refer to the response to CEC IR1 55.2 clarifying the benchmark study. There are 203 LNG projects forming the dataset for the benchmarking information contained in the PiP Report (Confidential Appendix N to the Application) with the following composition: Canada (28), US (61), Australia (21), and rest of the world (93). Of these projects, 75 were operationally active and used for O&M estimate benchmarks, with the following composition: Canada (1), US (16), Australia (10), and rest of the world (48).

55.4 Are there significant operational differences between the existing Tilbury plant and the new plant, or is it mainly a matter of scale? Please explain.

Response:

The systems to be employed in the TLSE Project are broadly of the same type as those in the existing plant, and FEI does not expect significant operational differences aside from scale.

55.5 If there are significant operational differences between the two plants, how has FEI accounted for the 'learning curve' in its operations.

Response:

There are not expected to be significant operational differences between the existing Tilbury equipment and the proposed TLSE equipment, except for those related to scale and specific equipment type and manufacturer. FEI expects to leverage the operational capabilities built up through safe operation of the Tilbury 1A facility and the 50 years of experience operating the Base Plant.

FEI intends to involve its LNG Operations group during the detailed design of the new equipment. The TLSE Project will also include a detailed Operational Readiness component, which will ensure that a complete operations training and documentation program is developed. This will ensure that standard operating procedures are in place, and that all documentation required for ongoing operation, including maintenance plans, are established before plant start-up.

56. Reference: Exhibit B-1, page 162

- **Incremental sustainment capital:** FEI has used an estimate of sustainment capital prepared by PiP (Confidential Appendix N), which is an average of 1 percent per year for the mechanical equipment capital expenditures (LNG tank, regasification equipment, auxiliary equipment), developed based on an industry benchmark of similar operations and interviews with third party industry experts. This benchmark applies to the capital cost of the mechanical equipment only, which does not include other indirect costs such as mobilization, engineering, contingency, etc.; and

56.1 Please provide quantification of FEI's present incremental sustainment capital requirements for the existing Tilbury plants, and present it in the form of $/unit of LNG produced and stored per year.

56.1.1 Please provide similar quantification for the current Project.

56.1.2 If the current incremental sustainment capital requirements differ from the Project, please explain why.

Response:

FEI interprets this question as seeking to understand the difference in sustaining capital requirements for the existing Tilbury plants and the proposed TLSE Project. The question asks for present incremental sustainment capital requirements for the existing Tilbury plants; however, FEI interprets this to mean the total sustaining capital requirements for the existing plants as it is not clear what the capital expenditures would be incremental to.

In Table 1 below, FEI provides actual sustainment capital for the Tilbury Base Plant for years 2018 through 2020 and the forecast 2021 sustainment capital as well as the $ of sustaining capital per m^3 of installed storage capacity ($\$/m^3$ installed) per year. In Table 2 below, FEI provides the estimated annual sustaining capital expenditures for the TLSE Project and the $\$/m^3$ installed per year.

With regard to the information in the below tables, FEI notes the following:

- Since the Base Plant is the most similar to the proposed TLSE Project in terms of service/function, FEI has provided the sustaining capital expenditures for the Base Plant (as opposed to both the Base Plant and T1A).
- Since the actual sustainment capital expenditures for the Base Plant can vary significantly on an annual basis depending on the timing of turnaround and planned/unplanned replacements, FEI has provided the most recent three years of actual expenditures (2018 to 2020), as well as the current year forecast, and has provided an average of these four years.
- FEI has provided the $\$/m^3$ installed per year in the tables below. The "$\$/m^3$ installed" is similar to "$/unit of LNG stored". The difference is that by using the installed capacity of the tanks, the comparison between the Base Plant and the TLSE Project is more

consistent, as the volume of LNG stored can vary from year to year. For calculation purposes, the Base Plant tank has an installed storage volume of approximately 27,000 m^3 (or 0.6 Bcf), and the working volume of the TLSE tank is 142,400 m^3.

Table 1: Base Plant Annual Sustaining Capital (2018-2021 and Annual Average)

	2018 (Actual)	2019 (Actual)	2020 (Actual)	2021 (Forecast)	Average
Tilbury Base Plant ($)	$ 947,882	$ 3,354,501	$ 2,679,514	$ 688,000	$ 1,917,474
$/m^3 Installed Volume	$35.10/m^3	$124.24/m^3	$99.24/m^3	$25.48/m^3	$ 71.02/m^3

As explained in the Application, the sustaining capital estimates included in Table 2 below have been included for the purpose of evaluating the TLSE Project financially over a 67-year period. This estimate represents an annual average sustainment capital of $479 thousand per year in 2020 dollars plus 2 percent annual inflation, and it is based on approximately 1 percent of the mechanical equipment capital costs for the LNG tank, regasification equipment, and auxiliary system as recommended by PiP (See Confidential Appendix N) for the purpose of a financial analysis over a 67-year period.

Table 2: TLSE Project Estimated Annual Sustaining Capital

	Sustaining Capital Estimate (Annual Average over 67 years)	$/m^3 installed capacity
TLSE Project in 2020 Dollars ($)	$ 479,000	$3.37/m3

As shown with the actual sustainment capital of the Base Plant in recent years in Table 1 and explained above, the actual sustainment capital varies over the years depending on the timing of turnaround and planned/unplanned replacements.

While FEI has provided the annual sustaining capital expenditures for the Base Plant to be responsive to this information request, FEI does not consider a comparison of the current sustaining capital requirements for the existing Base Plant to the new TLSE assets to be appropriate, as the age of equipment and facilities is quite different. For example, the sustaining capital requirements of a facility that is 50 years old and has passed its expected service life of 40 years is not comparable to a completely new facility.

Further, a comparison of the sustaining capital expenditures for FEI's other LNG facilities (i.e., T1A and Mt. Hayes) to the TLSE Project would be even less appropriate due to the nature of the equipment and the types of activities the sustaining capital will be required to address. The T1A and the Mt. Hayes plants consist of pressure vessels and rotating equipment, in addition to the tanks.

Sustainment capital is estimated based on a number of factors such as maintenance requirements, turnaround planning and regulatory requirements. It is developed to ensure the reliability and availability of the equipment. Therefore, it is important to note that the sustainment capital included in the Application's financial analysis is not an actual sustainment capital plan for the proposed TLSE Project. It is an average estimate over the life of the TLSE Project assets and is included to provide a comprehensive financial evaluation of the Project over the expected life of the assets. As explained above, for the new TLSE facility, FEI used an estimate of 1 percent of the mechanical equipment cost for the average annual sustainment capital based on industry data from similar operations and interviews with industry experts. FEI considers this is a reasonable estimate for the purpose of the financial evaluation of the Project. A more detailed assessment of sustaining capital requirements will be developed with the EPC contractor once the facility is in-service based on the as-built specifications. FEI is not requesting approval for the level of sustainment capital included in the financial analysis for the TLSE Project.

57. Reference: Exhibit B-1, page 163

- **Future capital replacement:** The average service life for the regasification equipment and auxiliary system is both 40 years, which is shorter than the 60-year post-Project period used for the financial analysis. As such, FEI's financial analysis includes future replacement of the regasification and auxiliary systems at the end of their average service life at 40 years. The future capital replacement does not include the replacement of ground improvement work related to stone columns as discussed in Section 5.3.4. FEI does not expect the stone columns will need to be replaced within the 60-year post-Project period.

57.1 Please provide a list of key elements and their capital costs with their service life including the ground improvement work and stone columns.

Response:

As discussed in Section 6.3 of the Application and referenced in the preamble above, future capital replacement costs were included in the financial analysis for the regasification equipment and the auxiliary system. Both the regasification equipment and the auxiliary system are recorded under FEI's asset account "LNG Send Out Equipment" (44840) which has an estimated average service life of 40 years according to FEI's 2017 Depreciation Study approved by Order G-165-20. Please refer to the response to BCUC IR1 41.1 for more detail.

The future replacement costs for the regasification equipment and auxiliary system are based on the capital costs for the same equipment in today's dollars, escalated by 40 years based on an inflation of 2 percent per year. The table below summarizes the future capital replacement costs included in the financial analysis for the TLSE Project.

Key Element	Average Service Life (Yrs)	Replacement Year	Replacement Costs ($ millions)
Regasification Equipment	40	2066	357.710
Auxiliary System	40	2067	384.158

For the stone columns, please refer to the responses to BCUC IR1 41.2 and 42.3 for an explanation on why replacement costs are not included in the financial analysis for the TLSE Project.

57.2 If FEI replaces the regasification equipment and auxiliary system, will it only have a 20 years remaining service life? Or will it have another 40 years' service life? Please explain. Will it be possible to extend a normal service life of 40 years to 60 years with maintenance strategies?

Response:

As explained in the response to CEC IR1 57.1, both the regasification equipment and the auxiliary system are recorded under FEI's asset account "LNG Send Out Equipment" (44840), which has an estimated average service life of 40 years based on FEI's 2017 Depreciation Study, as approved by Order G-165-20. Based on this, the original costs of the regasification equipment and auxiliary system will be financially depreciated over a 40-year period. FEI notes that sustainment capital over the life of the assets will likely extend the physical life of the asset beyond 40 years with those replacement costs being depreciated on a renewed average service life at the time of the installation.

FEI is unable to comment on the length of the replacements' service life. This is because the replacements, for the purpose of the financial analysis, are forecast to occur 40 years in the future, and technologies in construction and materials will likely be vastly different from today's technologies. It is possible that technologies 40 years from now could lead to the future replacement regasification equipment and auxiliary system having a longer estimated average service life than the 40 years estimated for today's installation. Such a scenario is outside of the analysis period for the TLSE Project and would not change the financial evaluation.

57.3 Please provide a revised NPV assuming a 40 years' service life and provide any assumptions.

Response:

The financial analysis discussed in Section 6.3 of the Application and referenced in the preamble above has assumed a 40 years average service life for the regasification equipment and auxiliary system. With regard to the capital replacement costs after 40 years, as explained in the response to CEC IR1 57.2, they are also depreciated based on a renewed 40-year average service life at the time of the installation. As such, there is no change to the present value calculation for the TLSE Project shown in Table 6-3 of the Application.

58. Reference: Exhibit B-1, page 163 and 164

6.4.1 LNG Tank Depreciation and Net Salvage Rate

FEI is seeking approval pursuant to sections 59-61 of the UCA for a depreciation rate of 1.67 percent and a net salvage rate of 0.67 percent applicable to the new 3 Bcf LNG tank as part of the Project. FEI consulted with Concentric, who recommended the average service life of a new 3 Bcf LNG tank would be 60 years (i.e., 1.67 percent = 1 / 60 x 100) based on recent experience, with a net salvage rate determined to be 40 percent of the capitalized value of the LNG tank over 60 years (i.e., 0.67 percent = 0.4 / 60 years x 100).

FEI currently has a depreciation rate of 1.23 percent (equivalent to 81 years) and a net salvage rate of 1.12 percent approved by the BCUC[125] for the Tilbury LNG tank (Account Class 44300). This rate is primarily determined based on historical assets (i.e., Tilbury Base Plant and Tilbury 1A facilities) within the same class that includes accumulated gains or losses embedded within the depreciation rates that existed at the time of the depreciation study. These historical gains or losses are unrelated to the prospective future life of the new LNG tank and the depreciation rate is not reflective of the average service life of 60 years expected from a new LNG tank as recommend by Concentric. Using the currently approved depreciation rate would result in a significant overdue cost recovery of the new LNG tank relative to the expected average service life (currently 1.23 percent for 81 years vs. the proposed 1.67 percent for 60 years). FEI believes it is more appropriate to depreciate the new LNG tank at the proposed depreciation rate of 1.67 percent with a net salvage rate of 0.67 percent that is aligned with the expected average service life of the asset. FEI notes the proposed depreciation rate and net salvage rate is for the new 3 Bcf LNG tank only. The depreciation and net salvage rates for the ground improvement, regasification, and auxiliary system will be based on the approved rates at the time they are included in rate base. The currently approved depreciation rate for ground improvements in asset class LNG Gas Structures & Improvements (44200) is 2.20 percent, or 45 years; and for regasification and auxiliary systems under asset class LNG Send Out Equipment (44861) is 2.41 percent, or 41 years.

58.1 Please explain the use of the word "overdue", in this context. Would not the lower historical rate for depreciation "under recover" costs for the shorter estimate service live?

Response:

In the context of the narrative provided, the reference to "overdue" is to highlight that use of the current (and lower) depreciation rate of 1.23 percent over 81 years for the proposed TLSE LNG tank would result in a longer cost recovery period than if the proposed depreciation rate of 1.67 percent for 60 years is used.

FEI further clarifies that, in this context, "overdue" was intended to indicate that if the lower depreciation rate of 1.23 percent is used, the costs of the LNG tank will be recovered over a period of 81 years for an asset that has an estimated average service life of 60 years. In other words, the costs of the LNG tank would not be under-recovered as suggested by the CEC in this information request; FEI would still recover the costs of the LNG tank, but recovery would be "overdue" by approximately 21 years.

FEI provides the following quantification in the table below with supporting calculations for the significant difference in the recovery of the cost of the LNG tank in depreciation expense that would occur if the depreciation rate of 1.23 percent is used. It can be seen that when the LNG tank reaches the estimated average service life of 60 years, a book value of approximately $104 million would still remain to be recovered from FEI's customers. As a result, FEI believes that it would not be appropriate to use the current lower depreciation rate of 1.23 percent when the proposed LNG tank has an estimated service life of 60 years. For the new TLSE tank, using the higher proposed 1.67 percent depreciation rate is consistent with an estimated service life of 60 years. Please also refer to the response to BCUC IR1 40.1 for further discussion about the estimated average service life of 60 years for the TLSE tank.

FEI also notes that, if the lower depreciation rate of 1.23 percent was used and at the end of the estimated useful life of 60 years the TLSE tank was retired, the remaining book value of approximately $104 million would be recorded in the accumulated depreciation account to be recovered through an adjustment to the depreciation rate in a future depreciation study.

Line	Particular	Reference	Amount
1	Rate Base addition of LNG Tank ($ million)	Table 6-4 of the Application	$ 401.272
2			
3	Current (Lower) Depreciation Rate (%)	1 / 81 Years x 100	1.23%
4	Annual Depreciation Expense at 1.23% ($ million)	Line 1 x Line 3	$ 4.954
5	Cumulative Depreciation recovered up to 60 years ($ million)	Line 4 x 60 years	$ 297.239
6			
7	Proposed Depreciation Rate (%)	1 / 60 Years x 100	1.67%
8	Annual Depreciation Expense at 1.67% ($ million)	Line 1 x Line 7	$ 6.688
9	Cumulative Depreciation recovered up to 60 years ($ million)	Line 8 x 60 years	$ 401.272
10			
11	Remaining Book Value to be recovered at the end of 60 years ($ million)	Line 9 - Line 5	$ 104.033

58.2 Please provide a quantification for the significant overdue cost recovery that would occur using the currently approved depreciation rate, and provide the calculations.

<u>Response:</u>

Please refer to the response to CEC IR1 58.1.

59. Reference: Exhibit B-1, page 165

> Once the Base Plant has been demolished, the assets will be retired following normal asset retirement accounting by crediting plant in service and debiting accumulated depreciation, as shown in Confidential Appendix M-1, Financial Schedule 9 (Line 33 to 46) and Financial Schedule 10 (Line 33 to 46), respectively. This entry by itself has no impact on rate base, but without further adjustments, would result in decreased depreciation expense at the time of retirement. However, since FEI's next depreciation study will be completed prior to 2025, and, if approved, this retirement will be known, future depreciation rates for the impacted asset classes will take the retirement of the Base Plant into account. All else equal, this retirement will result in an increased depreciation rate for the impacted accounts in order to recover the remaining net book value of the retired assets. FEI has not forecast a change to the depreciation rate in the financial analysis, as the impact of the retirement on future depreciation rates is unknown and will be confirmed with the next depreciation study.

59.1 Will the next depreciation study also examine the depreciation for the LNG tank?

59.1.1 If no, please explain why not.

<u>Response:</u>

The next depreciation study would examine depreciation rates for all asset classes, including the asset classes that contain the Base Plant and Tilbury 1A storage tanks. The next depreciation study would not include the TLSE storage tank (i.e., the proposed 3 Bcf tank) because the TLSE storage tank will not have entered rate base at the time of the next depreciation study. As such, FEI has requested approval of a 60 year life for the TLSE storage tank with this Application.

60. Exhibit B-1, page 165

> FEI is seeking approval to record these costs in a new non-rate base deferral account, the TLSE Application and Preliminary Stage Development Costs deferral account, attracting FEI's weighted average cost of capital until it enters rate base. Consistent with FEI's previous CPCN applications, FEI proposes to transfer the balance in the deferral account to rate base on January 1 of the year following BCUC approval of the Application and commence amortization over a three-year period thereafter.

60.1 Why did FEI select 3 years for the recovery period for the TLSE Application and Preliminary Stage Development costs, instead of any other time period such as 1, 2, 4 or 5 years?

<u>Response:</u>

Please refer to the response to BCUC IR1 44.1.

61. Exhibit B-1, page 166

6.4.5 TLSE Foreign Exchange (FX) Mark to Market Valuation

FEI is seeking BCUC approval under sections 59-61 of the UCA for a deferral account, entitled the "TLSE FX Mark to Market" deferral account, to capture the mark-to-market valuation of any foreign currency forward contracts entered into related to construction of the Project. The deferral account is an important tool to avoid uncontrollable external income statement volatility, as well as to avoid additional exposure to foreign currency exchange rate risk during the Project, and is similar to what the BCUC approved for the Mt. Hayes LNG Facility CPCN[128] as well as the Customer Care Enhancement CPCN[129].

A portion of the price of the Project may include US Dollar (USD) payments to the main Project contractor, giving rise to exchange rate risk. If a portion of the price is denominated in USD, then FEI would plan to hedge the risk by locking in the foreign exchange rate exposure using foreign exchange forward contracts to mitigate the risk of fluctuations in the value of USD/Canadian currency exchange rate differences.

While utilizing foreign exchange forward contracts will help mitigate the risk of exchange rate differences, these types of contracts are considered derivative instruments under FASB Accounting Standards Codification 815, Derivatives and Hedging, which would require FEI to fair value (mark-to-market) at the end of each accounting period. In the absence of an approved deferral account, those mark-to-market adjustments would be included in FEI's earnings for the period.

Due to the potential volatility in FEI's external financial statements arising from the required recognition of mark-to-market valuation of foreign exchange forward contracts, FEI requests approval of a deferral account to capture these mark-to-market adjustments over the course of the Project. The deferral account will not attract a financing return, as the mark-to-market adjustments are non-cash.

As stated previously, the BCUC approved a similar account for the Mt. Hayes Storage Facility Project and the Customer Care Enhancement Project.

The deferral account treatment of the mark-to-market adjustments related to the foreign exchange rate hedging for the Project will have no impact on customer rates. The use of the requested deferral account will not increase or decrease the expected cost of the Project because the hedging fixes the exchange rate for the USD denominated cost components and thus mitigates the foreign exchange risk upon settlement, or payment. The forward contracts will provide cost certainty as they lock in the foreign exchange rate for USD denominated cost components obtained by FEI for this Project. At the end of the Project, the amount of the deferral account will be zero, since the deferral account only captures any unrealized gains and losses related to the requirement to mark-to-market the foreign exchange derivative contracts.

The requested deferral account is beneficial to FEI and its customers. It allows FEI to mitigate the impact on its external financial statements arising from undertaking the hedging of the USD denominated payments during the Project execution. By doing so, it facilitates the use of foreign exchange forward contracts that will provide certainty to customers on the exchange rate used for the US dollar portion of the contract.

61.1 How often has FEI made payments in US Dollars to contractors? Please cite the projects where this has occurred over the last 10 years, and the value of the payments made in $Cdn.

Response:

Over the 10-year period from 2011 to 2020 inclusive, less than 11 percent occurred in US dollars.

See the table below for identification of projects where US dollar payments occurred.

FEI USD Payments 2011-2020 (in '000s)

BCUC Order	Description	USD	CDN	# of Vendors
n/a	Tilbury 1A – OIC Direction No. 5 Expansion Facilities	$ 5,083	$ 5,775	10
G-12-20	FEI Inland Gas Upgrades (IGU) CPCN	1,123	1,493	5
C-11-15	LMIPSU Projects CPCN (Coquitlam Gate IP Portion)	21	27	5
C-11-15	LMIPSU Projects CPCN (Fraser Gate IP Portion)	40	53	5
C-6-14	Huntingdon Bypass *	N/A	N/A	0
C-2-14	Muskwa River Crossing	3	3	1
C-1-11; C-6-11	Victoria (Langford) Operations Centre *	N/A	N/A	0
C-9-10	Kootenay River Crossing *	N/A	N/A	0
C-9-07	Mt. Hayes LNG Storage Facility	1,789	1,820	18

** No USD payments made*

61.2 Is FEI using the same contractor as that used for the Mt. Hayes Storage Facility? Please explain.

Response:

FEI has not selected an EPC contractor for the TLSE Project. To help ensure the Project is completed for the best value, the contractor (or consortium of contractors, or several contractors) will be chosen through a Request for Proposal process to be executed following BCUC approval of the Application.

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

Response:

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.

61.4 What practices did FEI follow in order to avoid or limit payments made in $US.

Response:

FEI has not specifically avoided or limited payments in USD, and will not do so throughout the Project execution period. Procurement for this Project is expected to be global in scope, so transactions in several foreign currencies are expected to be required.

Foreign exchange will be managed via FEI financial instruments to provide the most advantageous result for the Project, and therefore customers, given the specific situation. The nominated currencies in service and supply contracts will be the subject of negotiation with suppliers.

61.5 Does FEI make any effort to use Canadian companies where possible? Please explain why or why not.

Response:

FEI endeavors to use local and Canadian companies where possible. For the TLSE Project, FEI will embed preferences for local BC companies in the procurement and contracting process. FEI has supported local BC industry and will continue to do so.

Notwithstanding the above, there will be aspects of the Project that cannot practicably be sourced from within Canada due to unavailability of materials or expertise.

ENVIRONMENT AND ARCHAEOLOGY

62. Exhibit B-1, page 172

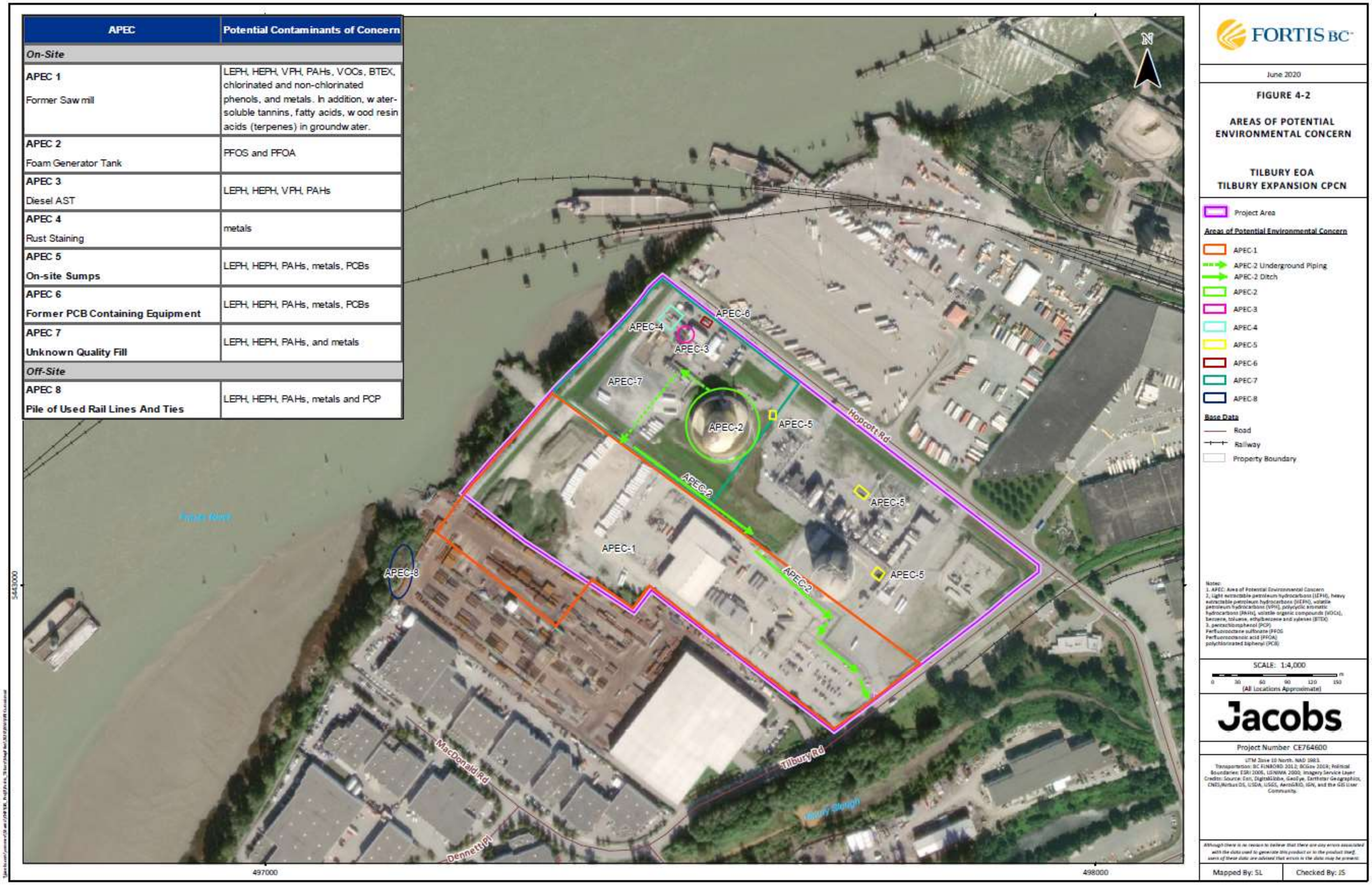
> The EOA also identified locations where FEI may potentially encounter soil or groundwater contamination within or near the Tilbury site, which may impact Project construction, costs and timelines. There are eight areas of potential environmental concern (APECs):[132]
>
> - APEC 1 – former sawmill site;
> - APEC 2 – foam generator tank;
> - APEC 3 – diesel aboveground storage tank;
> - APEC 4 – rust staining;
> - APEC 5 – on-site sumps;
> - APEC 6 – former PCB containing equipment;
> - APEC 7 – unknown quality fill; and
> - APEC 8 – pile of used rail lines and ties.
>
> Table 4-7 of the EOA (Appendix O) details the APECs, the potential contaminants of concern and the recommendation for each APEC. In particular, Jacobs recommends completing Stage 1 and 2 Preliminary Site Investigations (PSIs) to further understand the potential for contamination. FEI will be undertaking Stage 1 and/or Stage 2 PSIs as the need is triggered by Project activities.

62.1 Please provide a map with the contaminated sites identified.

<u>Response:</u>

FEI interprets this question to be about Areas of Potential Environmental Concern (APECs) identified on the Tilbury site. FEI clarifies that the APECs listed above are identified as having the <u>potential</u> for contamination, not confirmed contamination. The APECs will be further investigated in the Stage 1 and 2 Preliminary Site Investigations (PSI).

Figure 4-2 of the EAO included in Appendix O of the Application shows the location of the APECs at the Tilbury site. The figure is reproduced below for convenience.



APEC	Potential Contaminants of Concern
On-Site	
APEC 1 Former Saw mill	LEPH, HEPH, VPH, PAHs, VOCs, BTEX, chlorinated and non-chlorinated phenols, and metals. In addition, w ater-soluble tannins, fatty acids, w ood resin acids (terpenes) in groundw ater.
APEC 2 Foam Generator Tank	PFOS and PFOA
APEC 3 Diesel AST	LEPH, HEPH, VPH, PAHs
APEC 4 Rust Staining	metals
APEC 5 On-site Sumps	LEPH, HEPH, PAHs, metals, PCBs
APEC 6 Former PCB Containing Equipment	LEPH, HEPH, PAHs, metals, PCBs
APEC 7 Unknown Quality Fill	LEPH, HEPH, PAHs, and metals
Off-Site	
APEC 8 Pile of Used Rail Lines And Ties	LEPH, HEPH, PAHs, metals and PCP

62.2 Please identify which sites were contaminated by FEI activity, and which sites were contaminated by other parties.

Response:

FEI clarifies that the APECs listed above are identified as having the potential for contamination, not confirmed contamination. The APECs will be further investigated in the Stage 1 and 2 Preliminary Site Investigations (PSI).

The Stage 1 PSI was completed in 2021 and the Stage 2 PSI is currently underway. The early findings of the Stage 1 PSI, which are subject to further investigation, were that:

- APEC 1 is potentially contaminated by a past owner;
- APECs 2 to 7 are potentially contaminated by FEI activities; and
- APEC 8 is potentially contaminated by a past owner or current owner's activities (this property is not owned by FEI).

62.3 For any site contaminated by other parties, why did FEI not require environmental remediation by the owner at the time of acquisition?

Response:

Please refer to the response to CEC IR1 62.2. The APECs listed above have been identified as having the potential for contamination and do not represent confirmed contamination.

APEC 1 – this portion of the site was purchased by FEI in 2010 and does have a Certificate of Compliance (CoC) that shows the site was remediated to the Contaminated Sites Regulation numerical standards at that time. As the numerical standards for some contaminants have changed since the issuance of the CoC, the area remains an APEC that will require further investigation through the Preliminary Site Investigations (PSI).

APEC 8 – this area is adjacent to the Tilbury site but not located on FEI's property. During the Stage 1 PSI, it was determined to not be an APEC for the FEI site and has since been removed from the APEC list in the Stage 1 PSI report.

63. Reference: Exhibit B-1, page 174 and Appendix O page ES 2

While impacts to the atmospheric environment associated with this Project are expected to be minimal, the risks associated with Metro Vancouver permitting under the Greater Vancouver Regional District Air Quality Management Bylaw No. 1082, 2008 are considered medium to high. The potential risk associated with the permitting under this bylaw will be further assessed during the detailed engineering phase through air dispersion modelling and working through the Metro Vancouver permitting process.

The atmospheric environment receptor was determined to have a medium to high risk rating. A medium to high risk rating was determined because additional assessment is recommended to predict emissions to determine whether emissions are within applicable Ambient Air Quality Objectives and to obtain a Metro Vancouver Air Permit. Pending the outcomes of further emissions modeling, additional cost for the implementation of specialized mitigation measures or follow-up work are expected.

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

Response:

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.

63.2 Please explain why the risks associated with Metro Vancouver permitting are considered medium to high, when the impacts to the atmospheric environment are expected to be minimal.

Response:

The impacts to the atmospheric environment from the Project are expected to be minimal because the facility emissions are very low during regular operation. The Metro Vancouver (MV) permitting risk is considered medium to high due to uncertainty in future regulatory requirements. Please also refer to the response to CEC IR1 63.1.

64. Reference: Exhibit B-1, Appendix P, page 4

> **3.3 First Nations Heritage Policy and Permitting Systems**
>
> Many BC First Nations have developed their own heritage policies and permitting systems. Golder and the professional archaeological community largely respect these requirements, although they are not required by the Province to meet regulatory requirements. In general, the scope of these policies reflects a measure of oversight with archaeological research in each respective First Nation's territory so that particular cultural protocols are observed, particularly as they relate to ancestral remains and spiritual locations. While aspects of these policies parallel the HCA, many diverge when it comes to the definition of what constitutes a "heritage resource." Most First Nations heritage policies take a broader view of heritage resources than compared to the HCA (Mason 2011).

64.1 Please identify any aspects of its Project that FEI expects would not conform to First Nations' policies for permitting.

Response:

FEI expects that all aspects of the Project will conform to First Nations' policies for permitting.

64.2 If FEI undertakes activities based on required government permitting requirements, and the permitting rules changed in the future, could FEI be required to remediate any aspects of its work to conform to new policies? Please explain.

Response:

FEI is unable to comment on the hypothetical scenario where changes to government permitting requirements are applied retroactively. However, FEI would seek to maintain compliance with applicable legislation and policies as new requirements become known.

65. Reference: Exhibit B-1, Appendix P page 6

5.1 First Nations Communication and Permitting

Based on information obtained from CAD, the Study area is located within the area of interest of the following groups: Katzie First Nation, Kwantlen First Nation, Musqueam Indian Band, Semiahmoo First Nation, Stó:lō, Squamish Nation, Tsawwassen First Nation, and Tsleil-Waututh Nation. We also understand that the Study area falls within the marine traditional territory of Hul'qumi'num Treaty Group which includes Chemainus (Stz'uminus) First Nation, Cowichan Tribes, Halalt First Nation, Lake Cowichan First Nation; Lyackson First Nation, and Penelakut Tribe.

First Nation groups or organizations with potential interests in the Study area that require heritage investigation permits under their heritage policies include: Kwantlen First Nation (Seyem' Qwantlen), Musqueam Indian Band, Squamish Nation, Stó:lō, and Tsleil-Waututh Nation. The AOA was conducted under Musqueam Indian Band Heritage Investigation Permit MIB-2019-177-AOA, Seyem' Qwantlen Heritage Investigation Permit SQ 2020-47, Squamish Nation Archaeological Investigation Permit 19-0183, Stó:lō Heritage Investigation Permit 2019-252, and Tsleil-Waututh Nation Cultural Heritage Investigation Permit 2019-172. A Heritage Database Review was provided by the Stó:lō Research and Resource Management Centre.

One community member each from Katzie First Nation, Kwantlen First Nation, and Tsawwassen First Nation responded to the invitations and participated in the PFR.

65.1 Has FEI received approval from all affected First Nations?

65.1.1 If not, please identify those First Nations and indicate any areas of concern.

Response:

FEI and FortisBC Holdings Inc. intend to continue to engage with potentially affected First Nations with the aim of obtaining consent. None of the potentially affected First Nations have provided consent to the TLSE Project at this point in the process; however, consent or approval from First Nations is not a statutory or regulatory requirement for FEI for the Application. It is FEI's view that engagement activities to date have been appropriate for this stage of the Project planning and development, and sufficient in the context of the approval being sought from the BCUC.