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FortisBC Energy Inc.

Application for a Certificate of Public Convenience and Necessity for the Tilbury Liquefied Natural Gas Storage Expansion Project

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Decision
and Order G-62-23

March 23, 2023

Before:
A. K. Fung, KC, Panel Chair
T. A. Loski, Commissioner
R. I. Mason, Commissioner
D. M. Morton, Commissioner

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Executive summary

The Panel finds that an adjournment of this proceeding is warranted. Therefore, this proceeding is adjourned pending the filing of the evidence described below.

On December 29, 2020, FortisBC Energy Inc. (FEI) filed an application with the British Columbia Utilities Commission (BCUC) pursuant to sections 45 and 46 of the *Utilities Commission Act* (UCA) for the approval of a Certificate of Public Convenience and Necessity (CPCN) for the Tilbury Liquefied Natural Gas (LNG) Storage Expansion (TLSE) Project (Application).

FEI predicates the need for the TLSE Project (Project) based on the ability of its system to withstand and recover from a 3 day no-flow event as its "specific minimum resiliency objective for prospective planning" (Minimum Resiliency Planning Objective), but provides no broader context for this specific choice of a resiliency objective. There is no probabilistic analysis to demonstrate this is a more likely event than a ten day no-flow event, for example. Further, FEI does not demonstrate that a 3 day no-flow event is more likely to occur during winter when the consequence could be significant, including the probability of a prolonged outage. As a result of the inadequate analysis and lack of detailed evidence pertaining to the resiliency needs of the FEI system in this Application the Panel finds that FEI's stated Minimum Resiliency Planning Objective is not sufficient justification for the need for this Project. Resiliency objectives must be looked at holistically. Strengthening portions of a system shouldn't happen in a vacuum. Further, the economic impacts to the ratepayer of resiliency measures must be considered.

As FEI argues, this Project deals with a <u>specific</u> resiliency need - the ability for FEI to withstand a no-flow event of up to 3 days on Westcoast Energy's T-South system (T-South System). If FEI were to construct the Tilbury Liquefied Natural Gas Storage Expansion (TLSE) Project and was able to withstand a 3 day no-flow event, this would not necessarily mean that the FEI system would then be considered "resilient." There will always be residual resiliency risks no matter what and how many projects FEI puts forward.

As a result of the various concern we have identified in the proceeding, we are unable to conclude definitively as to whether the public necessity and convenience require this Project but are prepared to give FEI a fair opportunity to address these concerns by filing a detailed resiliency plan that addresses the following resiliency issues:

- What are the current and future threats to the resiliency of FEI's system in addition to the 3 day no-flow event identified in this Application?
- What assets provide resiliency in FEI's current system and what and where are the gaps in resiliency?
- How do FEI's other planned projects address or mitigate these gaps – e.g. automated metering infrastructure, regional gas supply diversification and what is the relationship and extent of overlap between those planned projects and the TLSE Project?
- What steps can be taken to fill those gaps in the short, medium, and long term and what are the costs associated with these options? This should include analysis of some of the alternatives discussed in the proceeding, including:

    - Additional regasification and liquefaction at Tilbury;
    - Assessment of the remaining life of the existing Tilbury Base Plant; and
- The impact, if any, of the loss of contracted storage on resilience.

We invite FEI to file, in this proceeding, a resiliency plan that addresses the points laid out above.

The Future Demand for Natural Gas

As the TLSE Project is a long-term investment, the Panel must also consider both the short term and long term no-flow event risks to FEI's system when considering Project need. In Section 5.2.1 of this Decision, we discuss the issue of future demand for natural gas and find a significant probability that demand for natural gas will be reduced compared to the demand today. In a scenario with reduced demand, the consequences of a no-flow event on the T-South System are less severe. Further, if the throughput of natural gas is reduced due to a decrease in demand, the size of a tank and the amount of regasification required would likely be reduced. The issue of future throughput on the system is an important one when assessing the need for no-flow mitigation.

We acknowledge the difficulty of navigating a path to clean gas given these new technologies and business practices that must be considered. However, we share the Commercial Energy Consumers Association of British Columbia's concerns that "a higher level of confidence in terms of the risk being assessed and the expected life for the assets to be used and useful"[1] is necessary to assess whether further resiliency investments are in the public convenience and necessity. In light of the current uncertainty with respect to the continued role of the natural gas system in British Columbia, we find insufficient evidence to conclude that the risk of stranding of the Project is acceptable, especially considering its expected life.

FEI is invited to file further evidence that addresses the Panel's concerns about the stranding risk of the TLSE Project.

We acknowledge that the issue of future demand for natural gas is also under consideration in the 2022 Long-Term Gas Resource Plan proceeding. However, we have specific concerns about the potential stranding of this Project as outlined above. Out of fairness to FEI and the timing of these two concurrent proceedings, we consider it unwarranted to deny the CPCN Application without giving FEI the opportunity to address these concerns in this proceeding. Accordingly, our determination is to adjourn this proceeding at this time.

[1] CEC Final Argument, p. 2.

1.0 Introduction

On December 29, 2020, FortisBC Energy Inc. (FEI) filed an application with the British Columbia Utilities Commission (BCUC) pursuant to sections 45 and 46 of the *Utilities Commission Act* (UCA) for the approval of a Certificate of Public Convenience and Necessity (CPCN) for the Tilbury Liquefied Natural Gas (LNG) Storage Expansion (TLSE) Project (Application).

The TLSE Project entails replacing the 50-year old Tilbury Base Plant (Base Plant) with a new 3 billion cubic feet (Bcf) LNG storage tank and 800 MMcf/day of regasification capacity at a cost of $768.998 million in as spent dollars and including Allowance for Funds Used During Construction (AFUDC). FEI states that the TLSE Project is a resiliency investment, which will significantly improve FEI's ability to maintain continuity of service in the event of a disruption in the supply of natural gas to FEI's system. While primarily targeted at improving resiliency, FEI asserts that the TLSE Project will also bring valuable ancillary benefits for system operations and customers.[2]

1.1 Approvals Sought

Pursuant to sections 45 and 46 of the UCA, FEI requests that the BCUC grant a CPCN for the construction and operation of the TLSE Project, which includes the addition or modification of any necessary auxiliary systems, and demolition of the above-ground portion of the Tilbury Base Plant LNG storage tank and liquefaction facilities. Additionally, FEI requests the following related financial approvals pursuant to sections 59 to 61 of the UCA:

- A depreciation rate of 1.67 percent and a net salvage rate of 0.67 percent applicable to the new 3 Bcf LNG tank;
- A new non-rate base deferral account: the "TLSE Application and Preliminary Stage Development Costs" deferral account; and
- A deferral account to capture the mark-to-market valuation of any foreign currency forward contracts entered into related to construction of the Project: the "TLSE FX Mark to Market" deferral account.[3]

1.2 Regulatory Process

The BCUC established regulatory timetables for the review of the Application.[4] The regulatory process included:

- A workshop dated March 11, 2021;
- An *in-camera* technical session to address the confidentiality of security sensitive information in the Application;
- Two rounds of written information requests (IRs);

[2] Exhibit B-1-4, p. 1.
[3] Ibid., pp. 12 – 13.
[4] By Orders G-26-21, G-165-21, G-9-22, G-29-22, G-58-22, G-100-22, G-113-22, G-117-22, G-132-22, G-208-22, G-223-22, and G-267-22.

- Filing of intervener evidence, rebuttal evidence, and IRs on the same;
- One round of Panel IRs;
- A further round of written IRs regarding the signing of the Tilbury LNG Projects Agreement by the Musqueam Indian Band and FortisBC Holdings Inc.; and
- Written final arguments by FEI and interveners, and reply argument by FEI.

The following parties registered as interveners in this proceeding:

- British Columbia Old Age Pensioners' Organization et al. (BCOAPO);
- BC Sustainable Energy Association (BCSEA);
- Citizens for My Sea to Sky Society (MS2S);
- Commercial Energy Consumers Association of British Columbia (the CEC);
- Musqueam Indian Band (Musqueam);
- Residential Consumer Intervener Association (RCIA);
- Sentinel Energy Management Inc. (Sentinel Energy); and
- Tsleil-Waututh Nation (TWN).

RCIA filed written intervener evidence regarding FEI's proposed actions during a depressurization of the gas system. TWN filed written intervener evidence and provided oral evidence in camera regarding consultation, and potential impacts of the TLSE Project on TWN's Indigenous rights and title.

On October 24, 2022, FEI filed its final argument. On November 21, 2022, BCOAPO, BCSEA, the CEC, RCIA, Sentinel Energy and TWN filed final arguments. On December 12, 2022, FEI filed its reply argument.

1.3 Legislative Framework

Sections 45 and 46 of the UCA set out the legislative framework for the BCUC review of CPCN applications. Section 45(1) of the UCA states:

> Except as otherwise provided, after September 11, 1980, a person must not begin the construction or operation of a public utility plant or system, or an extension of either, without first obtaining from the commission a certificate that public convenience and necessity require or will require the construction or operation. [Emphasis added]

Neither the UCA nor the BCUC's CPCN Guidelines[5] provide a definition of public convenience and necessity.

[5] https://docs.bcuc.com/documents/Guidelines/2015/DOC_25326_G-20-15_BCUC-2015-CPCN-Guidelines.pdf

The BCUC has previously relied upon *Memorial Gardens Assn. (Can.) Ltd. v. Colwood Cemetery Co.,* as the leading case on the definition of public convenience and necessity and it stated in FortisBC Inc.'s CPCN for the Advanced Metering Infrastructure Project Decision:

> Abbott J. for the majority, after commenting that it would "be both impracticable and undesirable to attempt a precise definition of general application of what constitutes public convenience and necessity" and that "the meaning in a given case should be ascertained by reference to the context and to the objects and purposes of the statute in which it is found," describes the determination of public convenience and necessity as follows:
>
> "As the Court held in the Union Gas case the question whether public convenience and necessity requires a certain action is not one of fact. It is predominantly the formulation of an opinion. Facts must, of course, be established to justify a decision by the Commission but that decision is one which cannot be made without a substantial exercise of administration discretion. In delegating this administration discretion to the Commission the Legislature has delegated to that body the responsibility of deciding in the public interest, the need and desirability of additional cemetery facilities, and in reaching that decision the degree of need and of desirability is left to the discretion of the Commission." (p. 357)[6]

Section 46(3) of the UCA states that the BCUC may issue or refuse to issue a CPCN or may issue a CPCN for the construction or operation of only a part of the proposed facility, line, plant, system or extension, and may attach terms and conditions to the CPCN.

Section 46 (3.1) of the UCA requires that the BCUC consider the following in determining whether to issue a CPCN:

a. the applicable of British Columbia's energy objectives,

b. the most recent long-term resource plan filed by the public utility under section 44.1, if any, and

c. the extent to which the application for the CPCN is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act* (CEA).

1.4 Decision Outline

The remainder of the Decision is structured as follows:

- Section 2 examines the need for the TLSE Project;
- Section 3 considers the extent to which the proposed TLSE Project would address FEI's resiliency needs, and the ancillary benefits of the TLSE Project;
- Section 4 reviews the TLSE Project alternatives presented by FEI, and other alternatives explored in the proceeding;

[6] FortisBC Inc. Certificate of Public Convenience and Necessity for the Advanced Metering Infrastructure Project, Decision and Order C-7-13 dated July 23, 2013, Memorial Gardens Assn. (Can.) Ltd. v. Colwood Cemetery Co., [1958] S.C.R. 353, 1958 CanLII 82 (Memorial Gardens) pp. 7-8; Memorial Gardens, p. 357.

- Section 5 summarizes the TLSE Project cost estimates and rate impacts;
- Section 6 addresses issues raised in the proceeding respecting consultation;
- Sections 7 and 8 consider the applicable of British Columbia's energy objectives, and the most recently filed long term resource plan respectively; and
- In section 9, the Panel provides its overall determination.

2.0 What is the Need for the TLSE Project?

2.1 Meeting Resilience Objectives

FEI describes the proposed TLSE Project as "a *resiliency* investment [emphasis in original]," further submitting that "it will significantly improve FEI's ability to maintain continuity of service in the event of a disruption in the supply of natural gas to FEI's system. While primarily targeted at improving resiliency, it will also bring valuable ancillary benefits for system operations and customers."[7]

There has been a substantial discussion during the proceeding of the need for resiliency and the role of on-system storage in providing resiliency. However, FEI submits a more specific reason for the TLSE Project:

> In October 2018, FortisBC Energy Inc. ("FEI") experienced the situation that this Application is intended to address: a no-flow event on the T-South system ("T-South Incident"), on which FEI must rely for most of its supply to the Lower Mainland.[8]

FEI relies on the Westcoast Energy's T-South system (T-South System) for approximately 85 percent of the gas entering the FEI system.[9] The T-South System consists of two looped gas transmission pipelines operating as a single system. On October 9, 2018, one of the two pipelines ruptured, the natural gas escaping from that pipeline ignited and Westcoast Energy shut down the adjacent NPS 30 pipeline as a precaution and monitored it to evaluate its condition (T-South Incident). For a 48-hour period, gas supply on the T-South System was reduced to zero. Approximately three weeks following the T-South Incident, gas supply remained constrained, as Westcoast Energy reinstated the non-ruptured pipeline at a reduced capacity and the ruptured NPS 36 pipeline remained out of service. For approximately 13 months further, capacity restrictions remained in place on the T-South System.[10]

The experience of the T-South Incident informed FEI's determination of a specific minimum resiliency planning objective (Minimum Resiliency Planning Objective) for prospective planning: "*Having the ability to withstand, and recover from, a 3-day 'no-flow' event on the T-South system*

[7] Exhibit B-1, p. 1.
[8] FEI Final Argument, p. 1.
[9] Exhibit B-1-4, p. 37.
[10] Ibid., pp. 39–41.

without having to shut down portions of FEI's distribution system or otherwise lose significant firm load [Emphasis in original]".[11]

In the T-South Incident, FEI was able to mitigate the worst consequences of that no-flow event, but, according to FEI, only because: "[m]any factors had to go in FEI's favour to allow it to withstand that two-day no-flow period, chief among which was the time of year / warmer weather."[12]

FEI asserts that "[t]he Lower Mainland will, without question, experience a widespread outage on the very first day of a similar no-flow event occurring any time during a typical winter" [Emphasis in original]. Further, as a result of the time required to shutdown and repressurize the system, purge gas, perform leak surveys and conduct extensive relighting, FEI anticipates that "[h]undreds of thousands of FEI customers in the Lower Mainland will lose service for up to nine or ten weeks, leaving customers without heat or hot water, impairing the ability of businesses and social service providers to operate, and cascading economic impacts throughout the Province."[13]

FEI submits stored LNG at Tilbury is the only available source of supply for the Lower Mainland during a winter no-flow event affecting the southern portion of the T-South System. If a disruption only affects the northern portion of T-South (such that Southern Crossing Pipeline capacity is available), FEI is still reliant on LNG at Tilbury to serve the vast majority of the Lower Mainland load. In either case, FEI adds the existing regasification equipment with a capacity of 150 million cubic feet per day (MMcf/day) at the Tilbury facility is much too small to support the Lower Mainland daily load in the winter.[14]

Positions of the Parties

BCOAPO submits that FEI's Minimum Resiliency Planning Objective has been advanced prematurely as part of this Application, and that such an objective is best reviewed in the context of FEI's Long-Term Gas Resource Plan (LTGRP). The review of this Application could have been much clearer if the evaluation of FEI's resiliency objective had occurred first.[15]

2.1.1 Potential Causes and Probability of No-Flow Events

FEI argues that "The T-South Incident provides definitive proof that a real potential exists for a multi-day T-South no-flow event, so as to make it an appropriate planning consideration. Moreover, JANA Corporation's (JANA) cumulative probability assessment based on industry data on integrity-related rupture events indicates that a reoccurrence of a multi-day no-flow event over the expected service life of the TLSE Project is not only a possibility, but likely."[16]

[11] Exhibit B-1, p. 1.
[12] FEI Final Argument, p. 1.
[13] Ibid.
[14] Ibid., p. 27.
[15] BCOAPO Final Argument, pp. 3–4.
[16] FEI Final Argument, p. 22.

FEI provides some examples that may result in a supply interruption lasting longer than two days, with no-flow on both pipelines on the T-South System, although it states it is unable to rank these examples by probability:

- A pipeline rupture mid-span of an aerial crossing where the rupture of one pipeline causes a rupture or damage to the adjacent pipeline;
- A pipeline rupture of one pipeline causes a rupture or damage to the adjacent pipeline within the same right-of-way because of the presence of integrity issues (e.g., stress corrosion cracking, corrosion, etc.) on the adjacent pipeline;
- A precautionary shut-down of an adjacent pipeline (even if it is not necessarily ruptured or damaged) for other reasons (e.g., engineering assessments, police investigations, etc.);
- Any type of major facility or equipment failure at a compressor station and associated facilities where the two pipelines join together within a compressor station compound;
- A cyber-attack which disrupts Westcoast's ability to control or operate the T-South System resulting in a shutdown similar to that which caused a 3 multi-day outage on the Colonial Pipeline oil pipeline in the eastern US;
- A geohazard on or near a steep slope in mountainous terrain that results in a landslide that exposes and damages both pipelines; and
- A high water event that causes a washout of both pipelines under an active and fast moving creek/river, resulting in irreparable damage to one or both pipelines.[17]

FEI's consultant JANA provided analysis based upon historical pipeline rupture data from Canada and the US. JANA forecasts the cumulative probability of a rupture event to be between 83.1 percent to 97.9 percent and the cumulative probability of an ignited rupture to be between 53.4 percent and 73.9 percent over the 67-year economic life of the TLSE Project.[18] The rupture rates represent the average performance of North American pipelines and could be used to provide high level directional information on any pipeline system.[19] For reported ruptures where data was available, JANA notes 29 out of 30 events resulted in an outage duration of ≥ 2 days, and 27 out of 30 had an outage duration of ≥ 3 days. For ignited ruptures, 22 of 23 events resulted in an outage duration of ≥ 3 days.[20]

JANA notes that the rupture data represent the collective pipeline performance for North American pipeline operators employing currently available integrity management practices. There are potential factors that could, over time, cause these number to decrease (e.g., evolving integrity management practices, regulatory changes, etc.) or increase (e.g., increasing age of the pipelines, increasing frequency of extreme weather events, etc.) that were not considered in its analysis.[21]

[17] Exhibit B-15, BCUC IR 1.3, Exhibit B-26, BCUC IR 66.1.
[18] Exhibit B-15, BCUC IR 1.5.
[19] Exhibit B-26, BCUC IR 68.4.
[20] Ibid., BCUC IR 68.2.
[21] Ibid., BCUC IR 68.9.

FEI notes that a precautionary shut-down of an adjacent pipeline does not necessarily mean a no-flow event on both pipelines lasting longer than two days; however, JANA has expressed the view that: "It is also considered likely, given the activities required to assess the integrity of the adjacent line, that the adjacent line would be out for a period of two days or longer." For instance, JANA notes in the T-South Incident, the NPS 30 pipeline was not exposed during the rupture of the NPS 36 pipeline, but was still taken out of service and subject to investigation.[22]

FEI is not aware of any evidence to suggest the occurrence of an unplanned pipeline disruption is affected by the time of year.[23] FEI notes the timing for re-establishing supply to a particular pipeline segment of the T-South System may vary considerably according to the type of incident and depending on several factors, including the following:

- Cause/severity of the incident – whether it is a physical issue with the pipeline or a cyber attack, and does the event require investigation and assessment by multiple authorities, including the Canada Energy Regulator (CER);
- Time of year – incident occurring during favorable or unfavorable conditions for work to be done to resume gas flow; and
- Incident location – ease of access to incident location.[24]

Positions of the Parties

RCIA recommends that both probability and consequence be included in the risk evaluation of a T-South System outage.[25] FEI proposes TLSE with a maximum regasification of 800 MMcf/day, which is still 71 MMcf/day short of the design day demand. As a result, RCIA concludes that FEI does consider probability in its risk management decisions, which RCIA agrees with. Consequently, the difference between RCIA's and FEI's positions is the degree to which probability is weighted, as RCIA is of the view that the Regional Gas Supply Diversification (RGSD) project, as proposed in the 2022 LTGRP, provides enough capacity to address nearly all of the risk of a T-South outage.[26] RCIA submits an issue with FEI's use of JANA's cumulative probabilistic analysis is that the cumulative probability includes the probability of a risk materializing far into the future. FEI's interpretation ignores the time-value of the money being spent in the next several years on TLSE Project to address a risk that may occur 67 years from now, which is significant given that RGSD project is planned to be online by 2030, and will mitigate the vast majority of the risk that would occur for the approximately six decades of service life remaining in the proposed TLSE facility.[27]

In reply to RCIA, FEI submits that RCIA's efforts to downplay and whittle-down: (1) the probability that a no-flow event would result in significant loss of load; and (2) the magnitude of the harm that

[22] Exhibit B-26, BCUC IR 66.4, 68.8.
[23] Exhibit B-15, BCUC IR 11.5.1.
[24] Ibid., BCUC IR 1.3.1.
[25] RCIA Final Argument, p. 32.
[26] Ibid., p. 7.
[27] Ibid., p. 19.

would result in the event of a widespread outage, cannot obscure the fact that the probability is material and the consequences would be catastrophic.[28]
BCSEA accepts that there is a possibility of a multi-day no-flow event on the T-South System. It has already happened once, and it could happen again. However, BCSEA does not accept that a future multi-day no-flow event on the T-South System should be considered "likely," as FEI submits.[29]

BCOAPO agrees that FEI needs to assess its system for the highest risk issues, particularly where FEI has little tolerance for variation, and determine how to manage those highest risks. The T-South System serves hundreds of thousands of customers and FEI has identified there is a significant likelihood that a catastrophic event will occur at some point over the life of the Tilbury facility. BCOAPO cannot in good conscience suggest that FEI do nothing and hope that such an event will not occur.[30]

The CEC agrees that there is a significant possibility that there could be a multi-day no-flow event when considered over a 67-year period. The CEC submits that it would be appropriate for the BCUC to consider the appropriateness of using a 67-year term to evaluate the likelihood of a no-flow event occurring, when FEI has provided evidence that the utility is potentially facing an existential threat.[31] While the CEC agrees FEI has successfully identified a significant possibility of a no-flow incident occurring over the long term, and identified a need for increased resiliency, the CEC does not find that the Project is required urgently.[32] In the CEC's view, the 'event' duration which requires mitigation is a significant unknown. FEI has provided evidence to suggest that 3 days are a reasonable expectation for a no-flow event, which the CEC submits can be relied upon as the correct term for consideration. The CEC recommends that the BCUC provide little weight to any benefits applied to covering a longer event.[33]

Sentinel Energy submits FEI's premise in justifying the need for the proposed Project is hinged on a failure condition that would occur extremely rarely, involving a complete failure of the T-South System, assuming zero linepack, on a very cold day that extends throughout the Pacific Northwest.[34]

FEI notes in its reply argument that using JANA's analysis, the cumulative probability of a rupture occurring between November 1 and March 31 over the 67-year analysis period would be between 34.6 and 40.8 percent.[35]

Panel Discussion

The Panel agrees with FEI that there is a potential for a multi day no-flow event on the T-South System. The T-South Incident in 2018 demonstrates this potential and also illustrates some of the potential consequences of such an event.

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28 FEI Reply Argument, p. 2-3.
29 BCSEA Final Argument, p. 5.
30 BCOAPO Final Argument, pp. 5–6.
31 CEC Final Argument, pp. 9, 13.
32 Ibid., pp. 12, 47.
33 Ibid., p. 30.
34 Sentinel Energy Final Argument, pp. 7–8.
35 FEI Reply Argument, p. 4.

There is, however, uncertainty whether the risk of no-flow events on the T-South System may increase or decrease in the future. Factors that could contribute to increasing the probability of a no-flow event include the aging of the T-south pipeline, increased severity or extreme weather events and the potential for increased cyber and physical security incursions. With regards to extreme weather events, we note the significant physical exposure the pipeline faced during the floods of 2021 when water erosion left significant portions of the pipeline exposed – although that did not lead to a no-flow event.

On the other hand, there are factors that reduce the probability of a no-flow event, including the development of enhanced integrity management practices and technology and improved cyber security practices and potential actions taken by the utility to replace aging sections of the pipeline.

Further, there is no evidence in the proceeding that a rupture is more likely to occur at any particular time of the year or in any season or within a specific location on the T-South System, nor is there conclusive evidence of the duration of the ensuing no-flow event. However, in FEI's view there would be a higher likelihood of inclement weather or snow making access to a rupture site more challenging, and, therefore, increasing the time to investigate, repair, and determine if and when service on one or both pipelines could be restored. The Panel also considers that it may well be the case that the probability of a no-flow event caused by weather risk is somewhat elevated in the winter, but there is no evidence on the record to support that conjecture.

An additional consideration is the time scale over which the risk of a no-flow event is considered. FEI states that over the service life of the TLSE Project, a multi-day no-flow event is likely. While we would not go so far as to characterize a no-flow event as likely, we do agree that the longer the service life the greater the probability of a no-flow event – it is a truism that as the period under examination increases, the probability of the event happening during the period increases towards 100 percent. Conversely, the shorter the service life, the less likely the occurrence of a no-flow event.

JANA's evidence is that 27 out of 30 reported pipeline ruptures and 22 of 23 ignited ruptures resulted in an outage of more than three days. Based on this evidence we find an event of more than three days more likely than an event of 3 days or less. [36] In this regard, we also note FEI and JANA's submissions that even a precautionary shutdown of one of the two pipelines due to a rupture in the other pipeline would likely result in the adjacent line being out for a period of two days <u>or longer</u> [Emphasis added].[37]

2.1.2 Consequences of No-Flow Events

Relative to probability, FEI states that consequence is of greater importance in the case of a material disruption to the T-South System.[38] FEI believes that the potential for a widespread system collapse to result from a no-flow event on the T-South System, combined with the existence of a tangible

[36] Exhibit B-26, BCUC IR 68.2.
[37] Ibid., BCUC IR 66.4, 68.8.
[38] Exhibit B-22, RCIA 31.1.

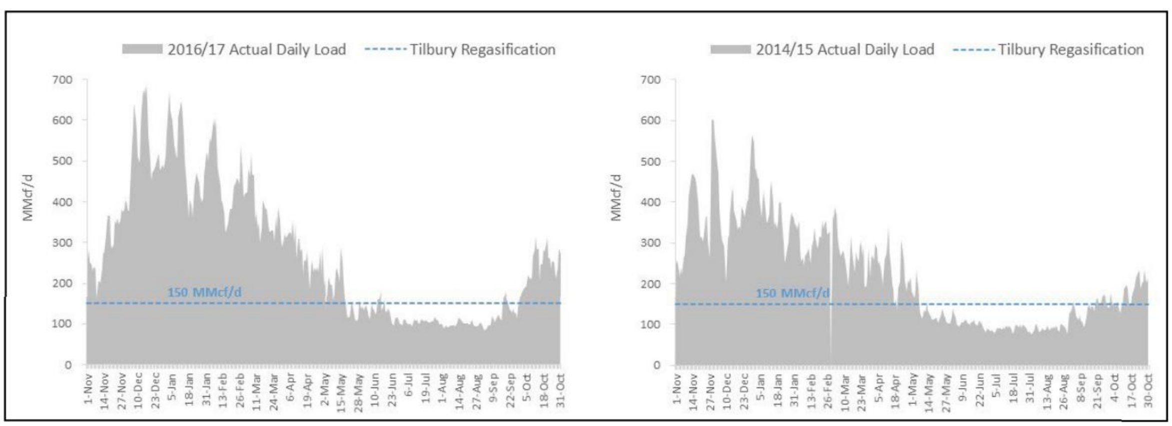
example of a significant disruption on the T-South System, is a valid basis on its own to warrant investments in improved resiliency.[39]

FEI submits that most Lower Mainland customers would lose service on the first day following a no-flow event, occurring on the design day.[40] An outage can result from "hydraulic collapse" (or uncontrolled shutdown) due to the system having insufficient pressure to continue functioning. However, it can also result from deliberate actions taken by FEI to isolate and depressurize certain portions of the system in order to prevent hydraulic collapse on the system as a whole.[41] FEI considers hydraulic collapse to be the most severe outcome of a no-flow event on the T-South System, but notes that widespread outages are rare and have never occurred on FEI's systems at the significant level that might have occurred if the T-South Incident had been longer in duration or occurred in colder weather [42] FEI submits that an uncontrolled shutdown is chaotic because, as customers continue to consume gas within a wide geographical region, some locations would randomly experience critical low pressures creating dangerous fluctuations in supply during the collapse that cannot be controlled or predicted in advance. These unpredictable fluctuations can result in customers losing, then temporarily regaining, and then losing supply during the collapse, which creates a more dangerous situation than if FEI were able to shut down its system methodically.[43]

FEI also states that[44]

> For approximately 200 days of the year, FEI would not be able to supply the single-day load requirements of the Lower Mainland. Large portions of the Lower Mainland system, equivalent to entire municipalities, would have to be shut down within hours of a no-flow event on the T-South system occurring in a normal winter. This is due to the fact that, no matter how much storage is assumed to be available at Tilbury (including the Tilbury T1A tank), the limited regasification capacity at Tilbury (150 MMcf/day) constrains FEI's ability to regasify and send-out stored volumes of LNG at Tilbury into FEI's Lower Mainland system.

Figure 1: Tilbury Regasification Capacity Relative to Lower Mainland Load



[39] Exhibit B-15, BCUC IR 1.5.2
[40] FEI Final Argument, p. 33.
[41] Exhibit B-1. p. 50.
[42] Exhibit B-15, BCUC IR 4.6, 5.2.
[43] Exhibit B-46-1, p. 9.
[44] Exhibit B-26, BCUC IR 2.78.1.

FEI estimates that to restore service to the Lower Mainland following a widespread system outage would take nine to ten weeks. FEI submits that Pricewaterhouse Cooper's (PwC) independent expert report filed as part of the Application shows that a widespread outage will have direct health and safety and economic impacts as well as causing cascading harm to British Columbians generally.[45]

Positions of the Parties

BCSEA considers that it can be reasonably expected that the Lower Mainland would experience outages on day 1 of a winter no-flow event on the T-South System in the absence of the TLSE Project. BCSEA accepts that a no-flow event on the T-South System during the winter, in the absence of the TLSE Project, would cause substantial inconvenience and potential harm to FEI customers.[46]

The CEC submits that the risk of the event occurring in winter can be considered as a worst-case scenario. The CEC finds the PwC evidence to be persuasive.[47]

Panel Discussion

It is important to consider not only the probability but also the consequence of a no-flow event occurring. The occurrence of a no-flow event alone does not necessarily result in severe negative consequences. As demonstrated in the T South Incident, there are instances where FEI can withstand – and has withstood - a supply disruption.

Typically, a probability/consequence analysis involves multiplying probabilities and consequences. However, in this instance a quantification of probability multiplied by consequence would likely be impossible, since there are a number of factors affecting consequence (e.g. outage duration, time of year, rupture location, availability of alternate supply options), some of which could be estimated but others of which are uncertain. Further, as discussed in Section 2.1 of this Decision, we have no evidence concerning the specific probabilities associated with outage duration, time of year or rupture location.

However, we do find that the consequence of a no-flow event is proportional to the duration of the no-flow event. Further, the consequence is higher during colder months. A five day no-flow event coinciding with a particularly cold spell in January has significantly greater consequence than a one day no-flow event in July. Rupture location and availability of alternative supply options also affect the consequence of a no-flow event, but we have no evidence of the specific risk related to these factors.

FEI frames the resiliency need for this Project on the need to mitigate a no-flow event of up to 3 days, during extreme low temperature conditions but not including the peak design day, on the T-South System.

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[45] FEI Final Argument, p. 37, Figure 3-14.
[46] BCSEA Final Argument, pp. 7–8.
[47] CEC Final Argument, pp. 15 – 16.

The general issue of resiliency has been discussed at some length in this proceeding. The Panel accepts the need for resilient utility infrastructure and the importance of resiliency in the provision of safe and reliable service. The Panel considers resiliency objectives are best assessed on a holistic level by comparing various resiliency options and prioritizing and planning against various outage scenarios, and then developing a comprehensive resiliency plan. Ideally, this planning would be completed in the context of the development of a LTGRP. A robust resiliency plan should consider multiple credible threats to the FEI system, along with an assessment of the likelihood and consequence of each threat. Proposed solutions to mitigate those threats should consider the ability of a solution to mitigate one or more of the threats and a cost benefit analysis of that solution. The Panel considers that the assessment of resiliency through such a plan is needed before concurring with FEI that "storage is the only practical and effective way to bridge a winter no-flow event on the T-South system."[48]

The need for this Project as set out in the Application does not benefit from such a resiliency plan. Instead, FEI singles out one specific outage scenario on the T-South System as the basis for this resiliency Project without a fulsome analysis of the likelihood of that scenario or whether there are any other scenarios of similar or greater likelihood.

Therefore, we find that FEI has not established that mitigating a no-flow event on the T-South System of up to 3 days, during extreme low temperature conditions but not including the peak design day, is a reasonable criterion by which to assess whether this Project is required for the public convenience and necessity.

2.2 Replacement of the Base Plant

The original Base Plant was built and sized to support peak demand. Thus, its purpose was to ensure that adequate natural gas supply was available to provide service to FEI customers on the coldest days, managing the very short durations when demand during cold weather events exceeded contracted supply. Because Tilbury is located on-system, it also provides benefits related to security of supply, reliability and flexibility to serve loads within FEI's system.[49]

FEI argues that:

> Although the TLSE Project is properly characterized as a resiliency project, it would be incorrect to conceptualize the full project cost as the cost of increasing resiliency. As explained in Part Five, Section D, the TLSE Project also replaces the existing Tilbury Base Plant tank, which is now over 50 years old – well-beyond its expected service life. In the absence of the TLSE Project, FEI would still need to maintain the current gas supply and operational benefits provided by the Base Plant. Given the tank's age, even with significant additional capital investment, the extent of additional operational life that FEI would be able to achieve is unclear. FEI's financial

[48] FEI Final Argument, pp. 2-3.
[49] Exhibit B-1, p. 62.

analysis shows that customers are better off replacing the Base Plant now, as proposed.[50]

FEI states that the remaining lifespan of the current tank is unknown. FEI recently completed a seismic analysis of the Base Plant tank that led to derating the operating capacity of the Base Plant tank to align with current day seismic design standards.[51] While FEI could continue to perform sustaining capital maintenance on the Base Plant, this maintenance would be an added cost to customers and the additional operational life that might be achieved through such sustaining capital activities is uncertain given that the tank is already 50 years old.[52] In order to properly assess the expected remaining operational life of the Base Plant, FEI would need to conduct an internal inspection of the tank, requiring the tank to be drained to allow safe entry and assessment. Based on the costs of a previous tank inspection in 2002 and, taking into account the tank's increased age, FEI estimates costs for an inspection would range from $8 million to $16 million, and take seven to eight months, or longer in the case of major issues requiring repair. Additionally, during the inspection, FEI would need to find a replacement in the open market for what the Base Plant currently provides to FEI's existing gas supply resource stack.[53]

Positions of the Parties

In RCIA's view, if the RGSD project proceeds, FEI can and should continue operating the Base Plant in conjunction with the RGSD project to address the resiliency objective, as opposed to proceeding with the TLSE Project. RCIA recommends that FEI continue its integrity management program for the Base Plant. This integrity management program previously identified a problem with the Base Plant which FEI successfully addressed.[54]

In reply, FEI submits RCIA's approach is at odds with the purpose and design of the Base Plant facilities. The facilities are designed to support peak demand for very short durations when demand during cold weather events exceeds contracted supply, not to set aside the volume as a resiliency reserve.[55]

BCSEA acknowledges that the existing Base Plant is aging and will need replacing at some point. However, BCSEA notes that the TLSE Project is much larger than what would be required to merely replace the Base Plant.[56]

BCOAPO submits FEI did not present alternatives to address the age of the Tilbury facility and this is not a reason to proceed with the TLSE Project.[57] BCOAPO submits that while a portion of the cost of FEI's proposed 3 Bcf tank would be incurred regardless due to the end of useful life of the existing

[50] FEI Final Argument, p. 9.
[51] Exhibit B-22, RCIA IR 18.3.
[52] Ibid., RCIA IR 18.1.
[53] Exhibit B-22, RCIA IR 18.3, Exhibit B-26, BCUC IR 79.1.1.
[54] RCIA Final Argument, pp. 27 – 28.
[55] FEI Reply Argument, p. 18.
[56] BCSEA Final Argument, pp. 6 – 7.
[57] BCOAPO Final Argument, p. 13.

Base Plant, there does not appear to be any analysis on the record to understand the costs to rebuild the existing facility.[58]

In reply to BCOAPO, FEI submits that replacing the Base Plant like-for-like is not an alternative, as it would not achieve the stated Project objective. FEI considers replacing the Base Plant alone would be a fundamentally different project. FEI did consider an alternative involving replacing the Base Plant at a later date while augmenting the Base Plant with a 1.4 Bcf tank in the meantime, but determined that this approach would result in higher costs for customers than the TLSE Project and would have feasibility challenges.[59]

Panel Discussion

FEI states that "even with significant additional capital investment, the extent of additional operational life that FEI would be able to achieve is unclear". Given this uncertainty regarding the cost of extending the life of the existing tank and the amount of extended life that can be achieved, the Panel is unable to assess the cost effectiveness of the TLSE Project as a replacement for the Base Plant. In any event, the Panel notes that FEI has not attempted to justify the TLSE Project as a like-for-like replacement of the Base Plant, which would be "a fundamentally different project." [60]

FEI's analysis of ancillary benefits, as discussed further in Section 3.3 of the Decision, does not assess the ability of the TLSE Project to replace the functions or capacity currently provided by the Base Plant with regards to peaking supply.

3.0 The TLSE Project

The proposed TLSE Project consists of the following components:

- Regasification capacity of 800 MMcf/day, which allows FEI to inject sufficient natural gas from Tilbury into the Lower Mainland system each day to retain an acceptable percentage of load service capability to FEI's customers. FEI notes the proposed equipment will provide a response time of two hours between notification from FEI Gas Control to gas delivered to the system, which is quicker than the present configuration;
- LNG storage Tank of 3 Bcf, providing sufficient LNG supply to serve FEI's Lower Mainland winter design load for three days without depleting the entire inventory of LNG. The new LNG tank will be designed according to current design standards to provide safe and reliable operations;
- Addition or modification of any necessary auxiliary systems including power supply, utility pipe racks, in-tank pumps, piping, cable trays, instrument air compressors, boil-off gas compressors, connectivity to Tilbury 1A LNG storage tank, and connections to the sendout gas pipeline; and

[58] Ibid., p. 8.
[59] FEI Reply Argument, pp. 30 – 31.
[60] Ibid., p. 30.

- Demolition of above-ground portion of the Tilbury Base Plant LNG storage tank and liquefaction facilities.[61]

FEI notes the TLSE Project would be constructed within the existing site boundaries of the current Tilbury LNG facilities on Tilbury Island, Delta. The Project is designed and engineered to meet all applicable codes, standards, and BC OGC regulations.[62] FEI's Project schedule assumed completion of construction by September 2026, based upon BCUC approval by December 2021.[63]

3.1 Meeting FEI's Resiliency Requirement

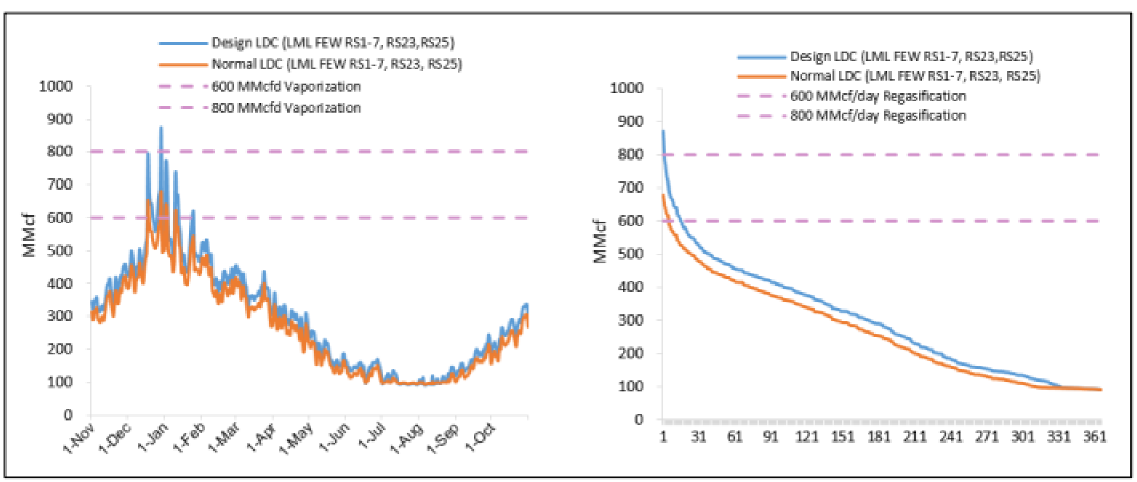
FEI argues that adding more on-system regasification and storage is the only practical and effective way to bridge a winter no-flow event on the T-South System. FEI also submits that:

> The associated regasification equipment, sized at 800 MMcf/day, will be capable of supporting the daily Lower Mainland demand on all but the coldest design day. FEI will reserve sufficient LNG in a new 3 Bcf tank (also referred to as the "TLSE tank") so that FEI can always bridge a no-flow event lasting 3 days (a 2 Bcf reserve based on current load). The remaining 1 Bcf in the TLSE tank (i.e., the "third Bcf") will provide a resiliency margin, replace the gas supply functions the Tilbury Base Plant provides today, and deliver a variety of other operational benefits. The financial value of the gas supply portfolio benefits alone that are associated with the "third Bcf" exceeds the incremental capital cost of the larger tank. All of these benefits will continue for decades.[64]

3.1.1 Does the Replacement Deal with the Coldest Day?

Based on the load duration curve below, the design peak demand for the Lower Mainland is 871MMcf/day for 2019/20.

Figure 2: Lower Mainland Load Duration Curves



[61] Exhibit B-1, pp. 120-121.
[62] Ibid.
[63] Exhibit B-1, pp. 145–145.
[64] FEI Final Argument, pp. 2-3.

FEI notes that the load duration curve declines steeply, such that the second coldest day on the design load duration curve (blue) is 793 MMcf/day. FEI submits that the figures above demonstrate that the proposed regasification capacity of 800 MMcf/day is adequate to cover Lower Mainland load during a complete T-South outage if it occurred on the coldest days of the winter, with the exception of the single peak design day.[65]

FEI believes regasification capacity at this level is reasonable given the remote probability of a "no-flow" event occurring simultaneously with the design peak day. Further, regasification capacity at this level will allow FEI to supply enough load so as to make it more realistic to balance the system through targeted load shedding or other emergency measures at times when it is colder.[66]

One of the key benefits of the TLSE Project is that it "buys time" for FEI to gather information, assess the situation, and make and execute a plan to address the emergency event. The TLSE Project will provide a three-day supply under peak conditions, and more time in more favourable weather conditions, providing FEI reasonable time to understand the incident, formulate a response, and then execute a controlled load-shedding strategy (if and when necessary).[67] In contrast, under peak winter conditions, the full 0.6 Bcf storage at the Base Plant equates to around 17 hours of supply. However, the regasification constraint of 150 MMcf/day also limits the Base Plant to supporting, at most, a small fraction of the Lower Mainland winter load.[68]

Panel Discussion

The existing system currently has limited ability to mitigate a three day no-flow event. While it may be able to do so in July, it would be very challenged to do so in cooler months and not at all likely to be able to do so in a typical December or January.

The Panel is satisfied with the evidence provided by FEI on the limitations of the system's ability to mitigate a 3 day no-flow event and finds that the TLSE Project will mitigate a 3-day no-flow event, provided the no-flow event does not occur simultaneously with the design peak day. In that latter circumstance, there would be insufficient regasification capacity. However, we accept FEI's assertion that even in this circumstance, the TLSE Project would provide FEI more time to conduct a more orderly shutdown than it otherwise would be able to conduct within the limits of the existing infrastructure.

3.2 Broader Resiliency Issues

FEI must initiate a controlled shut-down many hours before supply is expected to run out.[69] With the TLSE Project in place, there is still some possibility that a sustained no-flow event followed by a partial restoration of service from the T-South System at reduced flow could result in the need for

[65] Exhibit B-1, pp. 116 – 117, Figure 4-12.
[66] Exhibit B-1, p. 118
[67] Exhibit B-15, BCUC IR 18.2; Exhibit B-26, BCUC IR 70.2.
[68] Exhibit B-21, MS2S IR 9i; FEI Final Argument, p. 18.
[69] FEI Final Argument, p. 36.

some form of controlled shutdown to minimize the overall impact to FEI's customers.[70] FEI states that once gas supply is shut down, the time it would take FEI to restore service to customers following a resumption of supply from the T-South System is dependent on the number of customers that lost gas service. The shutdown and relight procedures at customer premises do not differ depending on whether pressure is lost in a controlled or uncontrolled manner.[71]

Panel Discussion

The Panel recognizes that the proposed TLSE Project would improve resiliency, but only in certain circumstances. It will not mitigate all resiliency risks, and indeed, FEI may never be able to mitigate all resiliency risks.

There may be circumstances where FEI still needs to initiate a widespread controlled shutdown, even with the TLSE Project in place – for example, a no-flow event lasting longer than 3 days in winter. Additionally, uncontrolled shutdowns could still potentially occur, for instance if there was an earthquake that ruptured the pipeline in Delta running to/from Tilbury.

This underlines the importance of developing different use cases representing catastrophic failures and approaches to mitigating those failures identified and the cost of those approaches considered in order to properly assess resiliency needs.

3.3 Ancillary Benefits of the TLSE Project

FEI's design and actual load curves demonstrate that storage of at least 2 Bcf is required to bridge a 3-day "no-flow" period.[72] FEI concluded a 3 Bcf tank is most appropriate given the additional resiliency and ancillary benefits of the larger tank and the economies of scale associated with increasing the size from 2 Bcf to 3 Bcf. FEI estimates the incremental capital cost of a 3 Bcf tank is approximately $50 million compared to a 2 Bcf tank.[73] These ancillary benefits are described further below, followed by our assessment of the value of those benefits as justification for the Project.

3.3.1 Additional Resiliency

FEI submits that all else being equal, a 3 Bcf tank provides FEI with superior functionality, as compared to a 2 Bcf tank, to cover subsequent gas supply events that occur following the initial emergency. While a larger tank size will not eliminate system risk, it will provide much greater ability to manage a range of emergency and gas supply events.[74]

Additionally, FEI notes that a 3 Bcf tank provides flexibility to accommodate load growth that may occur in future.[75]

[70] Exhibit B-26, BCUC IR 70.2.1.
[71] Exhibit B-39, Panel IR 3.2.1 B-46, p. 8.
[72] Exhibit B-1, p. 94.
[73] Ibid., pp. 103, 108.
[74] Ibid., pp. 105–106.
[75] Ibid., p. 109.

3.3.2 Mitigation of Third-party Storage Risk

FEI submits that “The addition of on-system storage above FEI’s Minimum Resiliency Planning Objective mitigates the risk of losing access to third-party off-system storage assets at JPS and Mist, which are both critical components of FEI’s resource stack to balance seasonal supply and demand.” FEI contracts for both of these assets, but does not have renewal rights for Mist.[76]

FEI expects increased competition for storage assets and states that there is a risk that it may not be able to retain its off-system storage assets. FEI expects the value of storage to increase, driven by the increased need for firming of electricity supply using natural gas power generation in support of the increase in renewable power generation (wind and solar) in the US.[77]

3.3.3 Improved Security of Supply

FEI submits that “[e]nhanced security of supply, a key element of reliable service, is an important ancillary benefit of adding on-system LNG at Tilbury. There are two aspects to this additional supply security:

- First, additional on-system storage and regasification backstop existing off-system storage resources (e.g., JPS and Mist) in the event of a failure at those facilities. While reliability at those off-system storage facilities is generally good, interruptions can occur; and
- Second, and more significantly, new on-system LNG will improve FEI’s physical security of peaking supply as FEI’s customer demand grows. Existing resources in the region are constrained. The costs of acquiring resources have increased over time as market participants compete for resources. for instance, FEI has recently experienced a rise in costs to renew its market area storage resources”. Going forward, it is reasonable to expect that contracting peaking resources could be challenging and costly absent new infrastructure being built.”[78]

FEI further states that all available storage is fully contracted and supplies the following analysis in support of that assertion:[79]

[76] Exhibit B-1, Redacted Application, p. 110.
[77] Exhibit B-1, p. 11.
[78] Exhibit B-1, Redacted Application, p. 111.
[79] Ibid., Redacted Application, Table 4-7, p. 112.

Table 1: Existing Pipeline and Storage Resources in the Regions

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).

FEI goes on to acknowledge that "[t]here are other alternatives for future peaking supply. FEI explained that absent the Base Plant resource, FEI would have to find a replacement in the open market. Contracting for a 150 MMcf/day peaking asset in the open market would be challenging and costly, absent new infrastructure being built.[80] In FEI's view, new on-system LNG storage provides the greatest flexibility as a potential supply resource. New on-system LNG storage also avoids assuming additional resiliency risk associated with peaking call options and off-system storage."[81]

FEI argues that "[t]he financial value of the gas supply benefits alone is so significant as to more than offset the incremental capital cost of the larger [3 Bcf vs 2 Bcf] tank."[82] FEI goes on to explain that "[w]hen factoring in the additional annual costs required to secure capacity from the market, the total PV of incremental revenue requirement over a 67-year period for a 2 Bcf tank would be $313 million higher than the proposed TLSE Project. A 2 Bcf tank scenario would also result in a higher levelized delivery rate impact over 67 years by approximately 2.01 percent and a higher cumulative delivery rate impact from 2022 to 2027 by approximately 2.68 percent. Put simply, it would be significantly more costly for customers to contract for a peaking resource than using the storage available from the proposed 3 Bcf storage tank."[83]

[80] Exhibit B-15, BCUC IR 22.7, 46.1.
[81] Exhibit B-1, Redacted Application, p. 112.
[82] FEI Final Argument, p. 93.
[83] Ibid., p. 94.

3.3.4 Enhanced Daily Balancing Capability

FEI submits that "[c]onstructing more regasification capacity and storage at Tilbury will allow FEI to deliver a large amount of supply within a short period of time, providing FEI with additional operational flexibility to manage daily balancing."[84]

3.3.5 Increased Operational Flexibility and Efficiency

In the Application, FEI states that:

> Additional storage capacity at Tilbury could be used to support maintenance activities on FEI's pipelines, without necessarily waiting for a period of low demand on the system to perform maintenance activities. FEI is currently developing a CPCN application for the Transmission Integrity Management Capabilities (TIMC) Project. A primary driver for this project is that it will improve FEI's ability to manage the integrity of its transmission pipelines by using new inline inspection (ILI) tools able to detect stress corrosion cracking and other crack-like features. In order to effectively gather data using ILI technology, specific gas velocities are required. This is because ILI tools typically have a limited range of travel speeds within which they collect accurate data.
>
> Normally, the flow rates in FEI's transmission pipelines are dictated solely by the customer demand on the system. Consequently, there are extended periods during the year when gas flow rates in pipelines supplying the Lower Mainland are too high to accommodate running ILI tools. This is particularly true with the NPS and NPS transmission pipelines originating at the Huntingdon Station. By regasifying the LNG stored at the Tilbury facility and injecting it into the CTS, the upstream gas flow rates (i.e., the supply from the Huntingdon Station) would be reduced. This is because the gas supplied from Tilbury would be used to supply a portion of the customer load, and hence reduce the supply requirement from the Huntingdon Station. The reduced flow rates could provide greater timeframes during which ILI tools and other necessary pipeline maintenance could be accommodated, without having to wait for customer consumption to be reduced.
>
> Therefore, construction of additional storage capacity above the amount required to meet FEI's Minimum Resiliency Planning Objective provides FEI with greater operational flexibility to inspect and perform maintenance activities on its pipelines.[85]

3.3.6 Potential to Reduce Customer Rates through Storage Lease Opportunities

In the Application, FEI states:

> The construction of a 3 Bcf tank versus a 2 Bcf tank provides opportunities for load growth that would have the potential to reduce rates for customers. The construction of a new pipeline in BC will proceed when supported by load growth in the region. Additional pipeline capacity into the region could provide the

[84] Exhibit B-1, Redacted Application, p. 112.
[85] Ibid., pp. 114-115.

> opportunity for further expansion of the Tilbury site with additional liquefaction to support LNG for export. Discussions have been ongoing over the past number of years with several overseas customers who have interest in exporting LNG from Tilbury to destinations in Asia. LNG from Tilbury has a production carbon intensity up to 30 percent lower than global average LNG. Its use can reduce GHG emissions from marine shipping by up to 27 percent compared to petroleum-based fuels. Further, its use can reduce industrial GHG emissions in China by 30 to 50 percent compared to domestic energy sources such as coal.
>
> This potential scenario provides significant future optionality and a potential reduction in FEI's customer rates in the scenario where a new pipeline into the Lower Mainland is constructed that follows an entirely separate corridor from the T-South system along with an expansion at the Tilbury site.[86]

Panel Discussion

The construction of a 3 Bcf tank has several potential benefits compared to a 2 Bcf tank, and we make the following observations:

- We appreciate that there is a potential benefit provided that the TLSE Project may serve as a replacement for storage at JPS or Mist.
- We agree with FEI that on-system storage near major load centres enhances reliability. Further if the incremental 1 Bcf could be used as a replacement for Mist when that contract expires, there are potential benefits and cost savings from having that additional on-system storage versus reliance on the Mist off-system storage. However, the cost justification for the larger [3 Bcf vs 2 Bcf] tank is based on forecasts over 67 years at a time when the future of natural gas and the pipeline system is uncertain. The Panel reviews these uncertainties in Section 5.2.1 of this Decision.
- Although the larger tank may enhance FEI's operational flexibility, it is unclear whether regasification capacity, tank capacity or both are required to provide additional operational flexibility to manage daily balancing.
- The TLSE Project would provide additional operational flexibility to the deployment of new in-line inspection (ILI) tools. However, there were no issues raised concerning operational flexibility when the BCUC approved the Coastal Transmission System - Transmission Integrity Management Capabilities (CTS-TIMC) project. Further, while the TLSE Project may provide additional flexibility in the deployment of ILI tools, FEI has provided no quantification of the benefits of this increased operational flexibility.
- We acknowledge the potential benefits of LNG to reduce greenhouse gas (GHG) emissions for marine shipping and the potential for exports to reduce industrial emissions in locations such as China. If LNG used for these purposes is shipped through the FEI pipeline system, there is a potential to reduce customer rates. However, we have concerns about the potential costs and increased risks to FEI's customers arising from the provision of additional infrastructure so that the FEI system can transport and/or liquefy LNG for export.

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[86] Ibid., p. 115.

Significant exports of LNG using the FEI system could require additional system upgrades and adequate protection from any stranding risk must be provided to FEI customers.

- The risk inherent in export sales would require ensuring that customers are held harmless. Therefore, if any portion of the TLSE Project is intended to be used for export, regulatory principles require that that portion of the tank reserved for export purposes be adequately "ring fenced". Such ring fencing typically involves the participation of an unregulated subsidiary to bear costs and risks that are not appropriate to allocate to ratepayers.
- The larger tank provides flexibility to accommodate future load growth that may occur. However, given the current emphasis on electrification and decarbonization in BC, it is unclear whether FEI will experience significant, or even any, future natural gas load growth. The larger tank means greater risk of a stranded, or partially stranded, asset in the event that FEI's increased load does not emerge or decreases beyond the current load.

While there is no quantification of these acknowledged benefits, on balance, we consider such benefits cumulatively would likely justify an incremental TLSE Project cost of $50 million. However, the Panel does not consider the ancillary benefits alone provide sufficient justification showing that the TLSE Project, with a total present value in revenue requirement of approximately $1 billion, is required for public convenience and necessity.

4.0 Project Alternatives

4.1 FEI's Proposed Alternatives

FEI submits that it considered all of the potential storage, pipeline and load management options identified by FEI and Guidehouse that would contribute to the resiliency of FEI's system.[87] The table below outlines the alternatives considered by FEI, including a description of why these alternatives were screened out. In addition, other alternatives not considered by FEI in the Application were explored in this proceeding. Select alternatives are discussed in the subsequent subsections.

[87] FEI Final Argument, p. 66.

Table 2: Summary of Alternatives Considered to Meet Minimum Resiliency Planning Objective[88]

Resiliency Elements	Alternatives	Reason Why Not an Alternative to On-System Storage at Tilbury
Load Management	Automated Metering Infrastructure (AMI)	AMI remote shut-off capability will add resiliency by reducing the potential for an uncontrolled shutdown, but is best viewed as complementing supply-side solutions. Without additional supply in event of a "no-flow" event, large scale load shedding would be required, leaving many non-interruptible customers without service.
Diversified Pipeline Supply	T-South Expansion	Expansion in the same corridor would still leave FEI subject to single point of failure risk, such that new storage would still be required to meet FEI's Minimum Resiliency Planning Objective even if the pipeline was constructed.
	Expansion to Northwest Pipeline's (NWP) Gorge Capacity	Expansion would add little resiliency for FEI. FEI must rely on displacement to access Gorge capacity, such that T-South gas must be physically flowing. Even if Gorge expansion was constructed, new storage would still be required to meet FEI's Minimum Resiliency Planning Objective.
Regional Gas Supply Diversity (RGSD) Project	SCP Expansion to Kingsvale (i.e., interconnecting with the T- South system 172 km north of FEI's Lower Mainland system)	New regional pipeline would add resiliency by reducing single point of failure risk north of Kingsvale on the T- South system. Even if constructed, new storage would still be required to address single point of failure risk for the 172 km south of Kingsvale on the T-South system.
	SCP Expansion to Huntingdon	New regional pipeline adds resiliency by diversifying supply into the Lower Mainland. Some gas will still be available if there is a failure on one pipeline system (T- South or expanded SCP). However, even if constructed, new storage would still be required to supplement remaining pipeline flows and avoid significant load shedding. Cost savings from reducing the size of on- system LNG are limited due to inherent economies of scale.
Storage	Contract Additional Off- System Storage	Contracting additional off-system storage would still leave FEI subject to single point of failure risk, since FEI would remain dependent on the T-South system to access the storage resource. (Access to JPS and Mist is only by displacement and the displacement commercial transactions require physical flows on the T-South system.)
	On-System Underground Storage	Not feasible within the FEI service territory.
	On-System Storage at a New Site	Would provide resiliency but is more costly than expansion at an existing brownfield site, and would require construction of liquefaction in addition to storage and regasification.
	Use the Existing Base Plant Storage (including regasification) and Add Additional Storage	This option would not leverage the economies of scale of a single, larger tank. It would be more costly over time because the existing Base Plant facilities would still require replacement at some point.
	On-System Storage at Tilbury (< 2 Bcf)	Does not meet the Minimum Resiliency Planning Objective described in Section 3.
	On-System Storage at Tilbury (> 3 Bcf)	Diminishing economies of scale beyond 3 Bcf due to constructability challenges.

FEI concluded that "[s]torage at Tilbury is the only practical and effective option for mitigating the known consequences of a winter no-flow event."[89]

With respect to the RGSD alternative above, FEI is completing the initial scoping and planning for the RGSD solution which would entail building a new pipeline route to the Lower Mainland at Huntingdon connecting to the Southern Crossing Pipeline (SCP) in the BC Interior at Oliver. The design of the RGSD project would be optimally sized to form a cost-effective resiliency solution in combination with FEI's other gas supply assets. The RGSD project would enhance gas supply resiliency by providing needed pipeline diversity in the region, as well other benefits, including helping to serve load growth in the region and assisting with the transition to a lower carbon energy future.[90]

FEI states that an SCP expansion to Huntingdon would be able to mitigate the risk of a no-flow event during low demand (i.e., summer) periods, as well as help address the risks of a prolonged supply disruption. However, FEI states it is unlikely to be feasible or economic that this pipeline expansion alone would be able to fully withstand a no-flow event on the T-South System during the winter season. In a scenario where the RGSD project is complete and a T-South rupture occurs, FEI system demand would still far exceed the available pipeline capacity during the winter, such that on-system storage would still be required.[91]

Positions of the Parties

RCIA questions whether "FEI need[s] TLSE if the RGSD project provides nearly the same resiliency benefits? Although FEI provided an analysis which shows that, with the Tilbury Base Plant and RGSD project, FEI can meet its customers' demand most days of the year, the combined capacity falls short of many of the winter days which are of primary concern from a negative consequences perspective."[92]

RCIA adds that in FEI's 2022 LTGRP, the RGSD project has a potential 450 MMcf/day capacity for delivery to Huntingdon. RCIA notes this capacity is different from what FEI assumed in the Application. RCIA submits this capacity change, assuming it is all available to FEI in the event of a T-South outage, coupled with the send-out from the existing Base Plant of 150 MMcf/day for a total of 600 MMcf/day, addresses all but 15 days of demand in a design year and all but five days of demand in a normal year. Therefore, even if not all of this capacity is available to FEI, the RGSD project provides a substantial resource that allows FEI to continue service over the vast majority of days of the year during a worst case T-South outage.[93]

In reply to RCIA, FEI submits the resilience benefits of the RGSD project are qualitatively different from those of the TLSE Project. Additionally, in order for the RGSD project to provide the equivalent protection against a winter T-South outage, FEI would need to hold double the pipeline capacity it requires for ordinary operations throughout the year. Given the early stage of the RGSD project development, FEI has yet to determine the project's size or the capacity it would retain if developed.

[88] Exhibit B-1, pp. 81-82.
[89] FEI Final Argument, p. 71.
[90] Exhibit B-15, BCUC IR 10.6.
[91] Ibid., BCUC IR 16.9.
[92] RCIA Final Argument, p. 6 of 32.
[93] Ibid., p. 6.

FEI also considers that if RCIA considered a pipeline-based solution such as the RGSD project to be a more effective alternative to the TLSE Project, it ought to have submitted evidence to support its assumptions.[94]

Sentinel Energy submits FEI should be encouraged to bring forward its RGSD proposal with a direct feed to the Sumas hub, to provide ongoing supply in the event of other pipeline failures and another source of linepack.[95]

Panel Discussion

The Panel notes that FEI's screening of alternatives analysis is based on the premise that an alternative must meet FEI's Minimum Resiliency Planning Objective. As outlined earlier in Section 2.1.2 of this Decision, we find that FEI has not established that this planning objective is a reasonable criterion by which to assess whether this Project is in the public convenience and necessity. The Minimum Resiliency Planning Objective narrows FEI's alternatives analysis, and results in the screening out of alternative options that may also improve the resiliency of FEI's system to varying degrees compared to today, potentially with other associated benefits and/or at different costs. FEI's analysis did not facilitate the evaluation of alternatives against broader criteria of costs and benefits. Further, as noted in the following subsection, parties raised several other potential alternatives in this proceeding that were not contemplated in the Application and therefore were not fully explored by FEI.

Additionally, as noted earlier, the TLSE Project would improve FEI's resiliency compared to today, but it will not mitigate all resiliency risks. In this regard, the TLSE Project would not make FEI's system "resilient" in an absolute sense. In our view, this reinforces the need to consider alternatives that offer different resiliency benefits from those that the TLSE Project purports to provide – whether such alternatives offer greater, lesser, or qualitatively different levels of resiliency benefits relative to TLSE. While the TLSE Project may be FEI's preferred alternative to meet the stated Minimum Resiliency Planning Objective, the Panel is unable to find that the TLSE Project is the preferred alternative to address the need for resiliency more generally on FEI's system.

The RGSD project is currently being planned by FEI. RCIA has identified a difference in the intended capacity of that project. Given this uncertainty we are unable to make any finding regarding how the RGSD project may or may not impact the need for the TLSE Project. This further supports the need for a more holistic resiliency plan to better understand the interaction of different projects that FEI may be contemplating in order to achieve greater resiliency.

[94] FEI Reply Argument, pp. 14–17.
[95] Sentinel Energy Final Argument, p. 6.

4.2 Other Alternatives Explored in the Proceeding

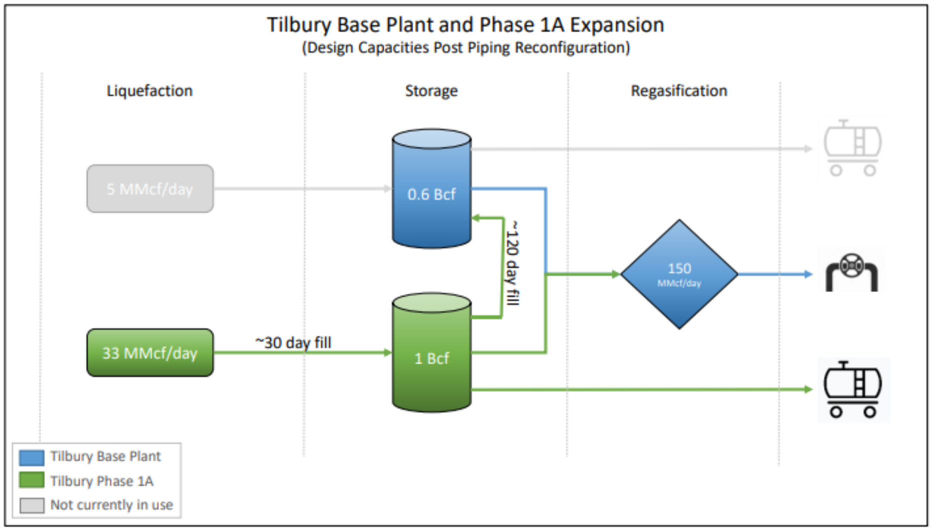
4.2.1 Tilbury Tank 1A

In its Application, FEI states:

> The original Tilbury Base Plant was built and sized to support peak demand. Thus, its purpose was to ensure that adequate natural gas supply was available to provide service to FEI customers on the coldest days, managing the very short durations when demand during cold weather events exceeded contracted supply. Because Tilbury is located on-system, it also provides benefits related to security of supply, reliability and flexibility to serve loads within FEI's system. Although it was not designed to provide supply in the event of a gas supply disruption to the Lower Mainland, it did fulfill that function during the latter phases of the T-South Incident.
>
> The Tilbury 1A facilities were built pursuant to an Order in Council (OIC)55 to support LNG sales and came into service in 2019. They consist of a new liquefaction plant with a capacity of 33 MMcf/day of LNG and 1 Bcf of storage capacity, with new LNG truck loading facilities. The commercial operation of the Tilbury 1A facilities effectively separated LNG sales under RS 46 from the Base Plant, allowing both facilities to serve their distinct purposes.
>
> Although the Tilbury 1A facilities are intended to serve LNG customers, FEI has recently constructed an interconnecting line between the Tilbury 1A tank and the Base Plant tank in recognition of the age of the Base Plant facilities and the increased potential for equipment reliability issues. The Base Plant liquefaction equipment reliability has been declining due to equipment condition and it is preferable to utilize 5 MMcf/day of liquefaction from the new Tilbury 1A liquefaction unit to fill the Base Plant tank. This interconnecting line also allows FEI to regasify LNG from either the Base Plant tank or the Tilbury 1A tank in the event that there is an equipment failure or issue with the Base Plant equipment.[96]

[96] Exhibit B-1, Redacted Application, p. 82.

Figure 3: Tilbury Base Plant and Tilbury 1A Facilities – Current Configuration (2020) [97]



In the Application, FEI also states:

> Although the design capacity of the Base Plant tank is 0.6 Bcf as shown in Figure 3-13 above, FEI is currently operating the tank at a reduced capacity while it assesses the future operability of the tank. In the interim, FEI will temporarily utilize a portion of the capacity of the Tilbury 1A tank to replace the reduction in the Base Plant tank storage. FEI's interim operating strategy, relying in part on the Tilbury 1A facilities, has several advantages, including increased equipment reliability, decreased time to replenish LNG inventory, and improved environmental performance. The following table summarizes the design capability of the Tilbury LNG facility today:[98]

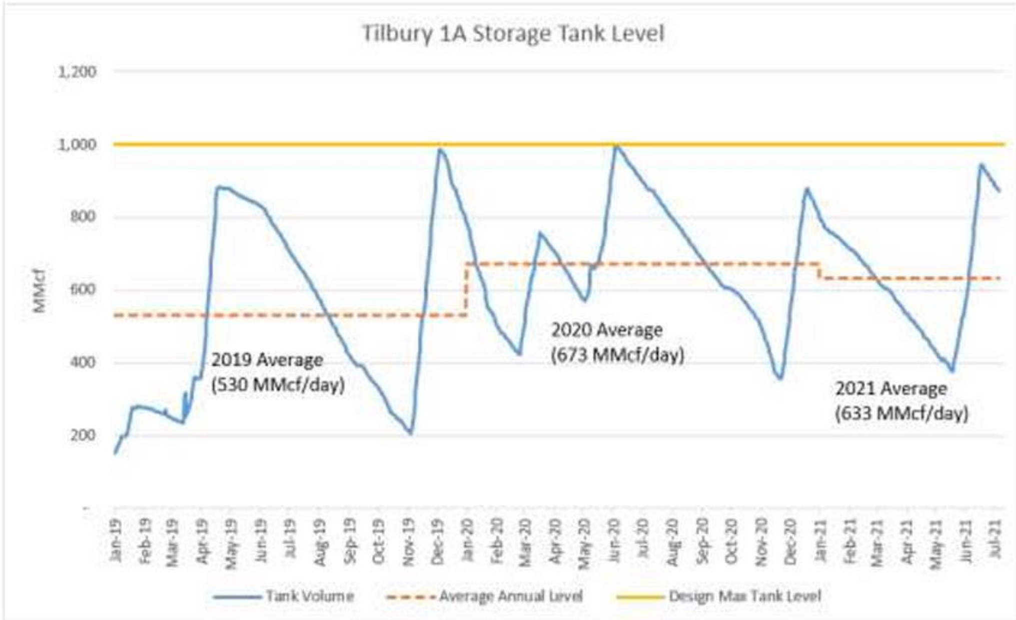
Table 3-2: Summary of Tilbury LNG Facility Design Capabilities

Plant	Liquefaction	Storage	Regasification	LM Peak Design Load
Base Plant	5 MMcf/day 120 days to fill	0.6 Bcf 0.69 days reserve	150 MMcf/day	871 MMcf/day
Tilbury 1A	28 MMcf/day 36 days to fill	1.0 Bcf Storage reserve to support RS 46 sales only	Zero	N/A - Facility designed to support RS 46 sales only

In the proceeding, the potential to use Tank 1A was explored. The figure below shows the historical storage tank level from January 2019 to July 2021.[99]

[97] Ibid., Redacted Application, Figure 3-13, p. 63.
[98] Exhibit B-1, Redacted Application, p. 83.
[99] Exhibit B-15, BCUC IR 11.9.2.

Figure 4: Tilbury 1A Storage Tank Level



When asked why FEI does not seek to maximize storage volumes, it responded:[100]

> When considering the optimum storage levels for the Tilbury T1A tank, FEI must consider the cost of LNG production. The Tilbury T1A liquefaction facility produces up to 1500 cubic metres of LNG per day, which would fill the T1A storage tank from empty in approximately 30 days. The draw-down of LNG from the tank depends on the volume of LNG sales. From 2019 to present, LNG sales have not been equal to the LNG production capacity. As a result, the liquefaction plant must shut down to allow the LNG storage levels in the tank to drop sufficiently to restart liquefaction.
>
> Each startup of the liquefaction facility requires additional effort, including pre-start checks and activities, and there is increased stress on rotating equipment during starts and shutdowns. For these reasons it is desirable to minimize the number of startups throughout the year. While FEI could run the plant at lower rates to fill the tank more slowly, the energy efficiency of the plant is impacted at lower production rates, meaning there would be a higher cost to produce LNG. Based on the above considerations, FEI balances the overall cost and equipment impacts by optimizing production runs to reduce operator effort during startups, preserve energy efficiency (i.e., run at design rates), and minimize the number of stops and starts during the year. Tilbury T1A has only been in operation for two years (including operating through the COVID-19 pandemic, which has impacted LNG sales). As a result, the storage levels reported in the above graph may not be indicative of future storage levels.
>
> Further, as explained in the response to BCUC IR1 11.9.2, tank levels will be managed considering both LNG sales and maintenance activities. From an operational perspective, it is preferable to keep LNG storage levels high to provide inventory in the event of an unplanned liquefaction outage; however, the ability to

[100] Exhibit B-26, BCUC IR 76.2.

> keep tank levels high will continue to be impacted by the considerations described above.

Positions of the Parties

Sentinel Energy submits that while Tilbury Tank 1A was built to develop the use of LNG as a transportation fuel, it can also provide a portion of the resiliency FEI is advocating for. Sentinel states the BCUC should direct FEI to build the required regasification facilities to optimize Tilbury 1A, and pair them with the Base Plant.[101]

Panel Discussion

We appreciate that the primary purpose of Tilbury Tank 1A is to serve FEI's existing and future LNG customers. Further FEI appears to operate the tank for that purpose. As a result, the average storage volumes are about two thirds of the tank capacity. At any given time, however, there have been volumes ranging from 200 MMcf/day to 1,000 MMcf/day that appear to be available for resiliency purposes.

The evidence shows that FEI's existing liquification capacity would allow FEI to keep Tilbury Tank 1A more full than it currently chooses to do for operational reasons. With additional liquefaction the average storage volume could be increased thereby providing additional capacity available for resiliency purposes. While there is evidence that this would be more costly than the current operational strategy, the cost benefit analysis is incomplete. In order to fully evaluate a potential role of Tilbury Tank 1A in FEI's resiliency portfolio, a more fulsome analysis is required.

4.2.2 Utilizing Excess Capacity at Woodfibre

The CEC explored the possibility of using the Woodfibre LNG facility. It asked FEI whether it considered combining the requirements of the TLSE Project into the Woodfibre project and taking advantage of the economies of scale for both parties and if not why not?[102]

FEI responded that it had 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.

[101] Sentinel Energy Final Argument, p. 7.
[102] Exhibit B-19, the CEC IR 1.35.1.

Panel Discussion

The proposed Woodfibre LNG storage facility could potentially be utilized in an emergency to provide additional resilience to the system. While we appreciate this is (or will be) a customer owned facility and may require some supplementary assets and infrastructure such as a tanker and a jetty, FEI could explore contractual agreements with Woodfibre that would make the gas in the tank available to the FEI system in the case of a force majeure event. In addition, there may be significant line-pack in the Eagle Mountain pipeline that could be utilized in the event of a no-flow incident. In any event, as a result of the lack of a detailed resiliency plan assessing such option, the Panel is unable to conclude whether this is a viable mitigation option to address a no-flow incident should the Project not proceed.

4.2.3 Marine Storage

FEI was asked whether it has considered the feasibility of floating LNG storage and regasification or floating LNG storage and land-based regasification, and the pros and cons of such alternatives.

FEI responded that it did not consider floating LNG storage and regasification or floating LNG storage and land-based regasification as viable alternatives and went on to state:

> Floating LNG facilities are often used to take advantage of offshore natural gas fields. These facilities can process, liquefy, store and transfer LNG, which would otherwise be difficult to access. In this case, however, FEI plans to liquefy natural gas from its own transmission system. It is far more efficient to store LNG at or near the location that it is produced, and FEI has adequate space at its existing Tilbury site to construct a new storage tank adjacent to its liquefaction facilities. Similarly, it is more efficient to regasify LNG in close proximity to both the LNG storage and to the system into which the gas will be injected. FEI's Tilbury site is adjacent to its transmission pipeline system and near major load centers, making it an optimal location for storage and regasification.
>
> An expansion of FEI's land-based facility, which will occur entirely on FEI's existing property, will be much less expensive and less complex than construction of a new, floating facility with LNG and natural gas transportation to and from the offshore structure. FEI sees no benefits to this approach but only significant added costs, complexity, and risk to the Project. For these reasons, FEI does not consider this alternative to merit further investigation.[103]

Panel Discussion

FEI's rejection of the floating LNG storage options appears to be based on its assessment that these facilities are primarily intended to take advantage of offshore natural gas fields which would otherwise be difficult to access. Since FEI is able to liquefy natural gas from its own transmission system for storage on system at Tilbury, it views the floating LNG storage options as being much more expensive and complex than the TLSE Project. However, this begs the question whether, absent access to an expanded facility at Tilbury, the floating LNG storage options are a viable means of mitigating the impacts of a three day no-flow event. In this regard, the analysis of these options

[103] Exhibit B-15, BCUC IR 1.20.1.

would have benefited from a holistic resiliency plan that assessed the relative merits and demerits of various alternatives having regard to the prioritization of resiliency needs on the entire FEI system. For further discussion relating to the need for a holistic resiliency plan, see the Panel's CPCN Determination in Section 9.0 of our Decision.

4.2.4 Increasing Tilbury Regassification Capability

In response to BCUC IR 2.78.1, FEI stated that "no matter how much storage is assumed to be available at Tilbury (including the Tilbury T1A tank), the limited regasification capacity at Tilbury (150 MMcf/day) constrains FEI's ability to regasify and send-out stored volumes of LNG at Tilbury into FEI's Lower Mainland system."

Under the assumed conditions, FEI would likely have to begin a controlled shutdown of large parts of the Lower Mainland system within two days of the no-flow event to avoid running out of supply on the third day of a no-flow event occurring in winter. This is because expanding the regasification capacity would quickly exhaust the existing storage (measured in Bcf) volumes. These scenarios reinforce why FEI needs both additional regasification capacity and storage at Tilbury for resiliency purposes (i.e., a minimum of 2 Bcf of storage and 800 MMcf/day of regasification).[104]

FEI addressed the issue of upgrading the regasification capability without replacing the Base Plant. In its view, resolving the regasification capacity limitation, in practice, means constructing a new facility at Tilbury that incorporates both storage and regasification. Attempting to attach new regasification units to the existing 50-year-old Base Plant storage facility to increase its regasification capacity would be technically challenging and costly to the point where FEI would not consider it to be a prudent investment. [105]

According to FEI, it is impractical to add regasification capacity without also replacing the Base Plant:

> First, there would be significant costs and engineering challenges with this approach, so as to render it impractical. An AACE Class 5 cost estimate for the minimum infrastructure investment alone is approximately $215 million. This new equipment would still be connected to storage assets that were not designed to operate with a five-fold increase in regasification output. There would be other significant engineering and capital costs to ensure the existing system could operate reliably under very different operating parameters. Before even attempting that work, FEI might need to drain the tank to conduct an internal inspection and complete structural reinforcements to ensure the ability of the tank to meet current seismic requirements. Regardless, the Base Plant tank is also over 50 years old, and would still need to be replaced at some point.[106]

FEI further submits that moreover, even if for the purposes of this hypothetical scenario the Base Plant regasification constraint at Tilbury is ignored and one were to assume that FEI would choose to imprudently add regasification to the undersized 50-year old Base Plant facility, the dependable

[104] Exhibit B-26, BCUC IR 78.1.
[105] Ibid.
[106] FEI Final Argument, p. 81.

storage volume available at Tilbury would have to be much larger than it is now to outlast a significant no-flow event.[107]

Panel Discussion

FEI argues that the TLSE Project is required to mitigate T-South System outages of up to 3 days. Broadly speaking, the Project consists of a new tank, larger than the existing Base Plant, and a larger regasification capability.

FEI submits that “most of the existing Base Plant infrastructure is not adequately sized for the volume of regasification required” and that “to increase its regasification would be technically challenging and costly to the point where FEI would not consider it to be a prudent investment.” However, in the absence of an assessment of the remaining life of the Base Plant and the quantum of the costs that FEI describes as “other significant engineering and capital costs to ensure the existing system could operate reliably under very different operating parameters,” we are not able to definitively determine the prudency of investing in an upgrade to the existing regasification capacity to 800 MMcf/day. In addition, there is no evidence concerning what level of regasification capacity could be added while still remaining, in FEI’s view, a prudent investment; or the duration and nature of a no-flow event that the existing infrastructure (Base Plant and Tilbury Tank 1A) with increased gasification could withstand.

FEI also provides no information on whether, should the regassification capacity of the existing facility be increased, it would be compatible with a new tank, should one subsequently be approved and built.

We recommend that FEI consider the potential costs and benefits associated with supplementing the existing storage assets at Tilbury with increased gasification. We note that such an alternative provides a potential bridging mechanism to enhance resiliency while allowing more time to understand the future of natural gas demand and supply in the Lower Mainland.

4.3 Existing Options to Mitigate No-Flow Events

FEI argues that the only way to effectively mitigate against the consequences of a three day no-flow event is with additional on-system storage and increased regasification capacity.[108]

During the T-South Incident, FEI was able to avoid a pressure collapse and outage on its system due to several factors, which included:

- FEI’s Mt. Hayes LNG on-system storage facility was able to supply all of the demand for the Vancouver Island system while also providing some supply to the Lower Mainland;
- Southern Crossing Pipeline was able to deliver a quantity of supply at Kingsvale on the T-South system;

[107] Exhibit B-26, BCUC IR 78.1.
[108] FEI Final Argument, p. 155.

- Mutual aid response from parties in the US;
- Gas held in the T-South system to the south of where the incident occurred (line pack);
- Public appeals for customers to limit their natural gas use; and
- Curtailment of FEI's interruptible and large industrial customers.[109]

FEI submits that an inability to access one or more of these resources would have resulted in a corresponding loss of customer load in the Lower Mainland, meaning a widespread and prolonged outage. FEI adds that stored LNG at Tilbury is the only available source of supply for the Lower Mainland during a winter no-flow event affecting the southern portion of the T-South System.[110]

FEI notes that the total Base Plant capacity of 0.6 Bcf of LNG would last less – generally significantly less – than three days at any point during the design winter (the typical basis for utility planning) or the coldest and warmest winters of the past decade. The primary existing constraint at Tilbury is the limited regasification capacity of 150 MMcf/day, which falls well short of being able to meet the daily Lower Mainland load in winter. Even with the regasification constraint removed, it would take only approximately 17 to 18 hours to consume 0.6 Bcf of LNG during winter peak load conditions.[111]

Panel Discussion

We agree that there are limited existing options for mitigating no-flow events of up to 3 days occurring during periods of high demand. The existing Base Plant, with a capacity of 0.6 Bcf has provided LNG for multiple purposes for a number of years, as has Mt. Hayes. These purposes include peaking and, in some cases, insurance against loss of supply. Which particular need or needs either of these tanks fulfils at any given time depends upon FEI's operational strategy.

Therefore, the ability of the existing FEI's existing Tilbury assets, including the Base Plant and Tilbury Tank 1A to provide resiliency – specifically for a three day no-flow event on the T-South System – is dependent upon a number of other factors, including weather and short term expected demand and other operational factors.

5.0 Project Costs Estimates and Rate Impacts

5.1 Project Costs

The table below summarizes the total Project estimated capital cost in both 2020 and as-spent dollars. The Project capital cost estimate meets the criteria for an AACE Class 3 Cost Estimate as required by the BCUC's CPCN Guidelines.

[109] Exhibit B-1, pp. 46, 60, 74.
[110] FEI Final Argument, pp. 26–27.
[111] Ibid., pp. 82, 86

Table 3: Breakdown of the TLSE Project Cost Estimate ($ millions)[112]

2020 $		As-Spent $
Engineering and Development	23.653	25.609
Material	144.589	151.623
Construction – Direct and Indirect	317.043	357.325
Base Plant Demolition	12.297	13.827
FEI Project Management and Owner's Costs	31.521	32.928
Subtotal Capital Cost	529.103	581.312
Contingency	108.200	118.384
Subtotal Project Capital Costs w/ Contingency	637.303	699.696
CPCN Application	0.600	0.600
CPCN Preliminary Stage Development	1.546	1.546
Subtotal w/ Deferral Costs	639.449	701.842
AFUDC	-	69.796
Tax Offset	-	(2.640)
TOTAL Project Cost	639.449	768.998

Notes:

1. The as-spent cost is equal to the amount in 2020 dollars plus escalation. The total escalation is $62.393 million (Section 5.4.4.5), which includes $52.209 million of escalation on capital cost and $10.184 million of escalation on contingency.

The TLSE Project cost estimate, reflected in the table above, is based on the following:

- A base cost estimate of $531.249 million in 2020 dollars developed by FEI, in conjunction with Linde, Clough, HCBI, Golder, and SMCI as described in Section 5.4.1 and Confidential Appendix J-4 of the Application. The base cost estimate includes:
  - $521.472 million of base capital costs;
  - $7.631 million of Project development costs incurred between April and December 2020 (actual from April to November 2020 and projected for December 2020); and
  - $2.146 million of actual deferred costs for the Application and 1 Preliminary Stage Development Costs discussed in Section 6.4.4.
- A contingency estimate of $108.200 million in 2020 dollars (approximately 20 percent of the base cost estimate of $531.249 million in 2020 dollars) provides a total capital budget at a P50 confidence level as discussed in Section 5.4.4.4 of the Application;
- A P50 escalation value of $62.393 million during the Project from 2020 to 2026, as discussed in Section 5.4.4.5 of the Application applied to both the base capital cost and contingency. The escalation is used to convert the Project capital cost from 2020 dollars to as-spent dollars; and

[112] Exhibit B-1, p. 159.

- AFUDC, assumed at FEI's 2021 AFUDC rate of 5.47 percent, which is equal to FEI's after-tax weighted average cost of capital.[113]

FEI described its calculation of the escalation amount:

> Escalation per AACE 12, 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 or decreases beyond 2020, including contingency, must be covered by the escalation estimate.
>
> 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)
>
> The HIS Markit Q3 2020 forecast is showing minimal cost escalation through 2022 (with the exception of pipe steel) and a slight decrease forecast for the remainder of 2020. However, global and regional capital spending is forecast to rebound by 2022 with the weighted annual price increase forecast to peak at 2.8 percent.[114]

FEI provided its probabilistic analysis, which takes into account the historical standard deviation in price changes from the mean, and is the source for the P50 escalation value of $62.393 million included in the TLSE Project cost.[115]

FEI states that "project costs can be affected by inflation; however, at this stage the utility cannot predict how any such pressures will affect the Project closer to, and throughout, its construction (construction is not expected to commence for some time still)."[116]

FEI provided estimated capital costs and financial evaluation of on-system storage with alternative sizing specifications than the preferred 3 Bcf tank option, as outlined in the table below:

[113] Exhibit B-1, pp. 159–160.
[114] Exhibit B-1-4, pp. 142-143.
[115] Ibid., p.144, Table 5-8.
[116] FEI Reply Argument p. 33, para. 87.

Table 4: Estimated Capital Cost[117]

	1.0 BCF & 800 MMcf/d	1.5 BCF & 800 MMcf/d	2 BCF & 800 MMcf/d (Table 4-6 of Application)	3 BCF & 800 MMcf/d (Table 4-6 of Application)	3.5 BCF & 800 MMcf/d
Total Project Capital Costs, 2020 dollars ($ millions)	492	547	588	637	713
Capital Cost per unit of storage ($ millions/BCF)	492	365	294	212	204
PV of Incremental Revenue Requirement 67 years ($ millions)	861	918	951	1,042	1,105
Levelized Delivery Rate Impact 67 years (%)	5.51%	5.88%	6.09%	6.67%	7.07%
Levelized Delivery Rate Impact 67 years ($/GJ)	0.249	0.265	0.275	0.301	0.319
Average Residential Use per Customer (GJ)	90.0	90.0	90.0	90.0	90.0
Average Annual Residential Bill Increase ($)	22.4	23.9	24.8	27.1	28.7
Average Annual Residential Bill Increase (%)	3.71%	3.95%	4.10%	4.49%	4.76%

FEI states a 1.5 Bcf tank would have the ability to withstand a 2 day no-flow event in winter except for the coldest two-day period of the year, and withstand a 3-day no-flow event for 326 days in a year.[118] FEI notes that a tank size exceeding 3 Bcf would introduce unique design and constructability challenges that while not insurmountable, would require additional engineering and costs to overcome.[119]

Additionally, FEI outlined reducing the regasification capacity from 800 MMcf/day to 600 MMcf/day would result in an estimated cost reduction of $14.5 to $23.5 million.[120] FEI notes that 600 MMcf/day capacity would have been insufficient to meet daily Lower Mainland demand on 15 days of the design year, or 5 days of a normal winter.[121] FEI submits a lower regasification capacity (such as 200 or 400 MMcf/day) would not meet the load requirements during a significant part of the year, and would therefore not provide resiliency to the system.[122]

Panel Discussion

The Panel is satisfied with FEI's analysis of the Project costs when considered at the time the estimate was made. However, we are concerned that the escalation amount of $62.393 million included in the TLSE Project contingency may be understated due to current inflationary pressures. The Panel accepts that TLSE Projects costs can be affected by inflation, and that it is difficult to predict how inflationary pressures will ultimately impact the Project. Nonetheless, actual CPI for BC in 2022 (6.9 percent)[123] is significantly higher than the inflation rate used in the escalation analysis, thereby causing concern for the Panel that the escalation amount calculated may be understated. Adding to the Panel's concerns is the P95 value for escalation calculated in the probabilistic analysis is $202.604 million,[124] more than $140 million greater than the P50 amount. An increase in TLSE Project costs of this amount would lead to significant upward pressure on the rate impacts of the TLSE Project.

117 Exhibit B-15, BCUC IR 16.27.
118 Ibid., BCUC IR 16.23.
119 Exhibit B-1, pp. 102 – 103.
120 Ibid., BCUC IR 19.5.
121 Ibid., BCUC IR 19.3.
122 Exhibit B-15, BCUC IR 19.6.
123 Exhibit B-26 BCUC IR 92.1.1.
124 Exhibit B-1-4, p. 144, Table 5-8.

5.2 Depreciation and Return

5.2.1 Useful Life

FEI notes the average service life for a new 3 Bcf LNG tank is 60 years as recommended by Concentric Advisors, ULC (Concentric), which 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 proceeding. FEI is seeking approval for a depreciation rate of 1.67 percent (equivalent to 60 years) for the new 3 Bcf LNG tank.[125]

However, FEI anticipates that in 2042 on an annual basis FEI will be providing just over 43 percent of the projected annual demand as renewable or low carbon gases. Approximately 80 percent will be on-system and 20 percent will be supplied and consumed outside of FEIs service territory. In the CTS, the hydrogen will be delivered in dedicated systems and blended into the distribution systems in larger volumes.

By 2042 in the Lower Mainland, 16 years into the 60-year life of the tank, FEI expects that approximately 20 to 25 percent of the forecast peak demand would be served by hydrogen. FEI submits that the remaining 75 to 80 percent of the peak demand in 2042 will be provided by natural gas or RNG that could be supported by the TLSE Project storage and regasification.[126]

Evidence submitted by FEI in other proceedings reinforces the considerable uncertainty around the expected future demand for natural gas. In the BCUC Generic Cost of Capital Stage 1 (GCOC) proceeding, FEI submitted that "the provincial government's recently updated CleanBC Roadmap to 2030 (Roadmap)…. is anticipated to have a significant impact on FEI's competitive and operational landscape with implications for FEI's customer rates and <u>throughput</u>."[127] [Emphasis added]

FEI further provided this summary of risk:

> Overall, since the 2016 Proceeding, FEI's demand/market risk has increased. Customers' energy choices are increasingly influenced by a desire to minimize negative environmental impacts. While Renewable Gas can be a relatively affordable option to achieve this goal, the electric options such as high-efficiency heat pumps are gaining faster and more widespread traction among customers and policy makers. FEI is already experiencing the effects of this shift in its net customer additions, particularly in the residential sector, where due to BC's high turnover rate, a large segment of its existing customers homes may be torn down and rebuilt with electric-only options to meet more stringent code requirements. Further, the gradual decline in the single-family dwelling segment, where FEI has higher capture rates, in favour of multi-family dwellings and the downward trend in the share of natural gas in space heating and water heating applications continue to impact FEI's risk profile. FEI's new residential customers continue to have lower use per customer (UPC) than average residential customers do. This is somewhat offset by

[125] Exhibit B-1, p. 160.
[126] Exhibit B-39 BCUC Panel IR1.1.
[127] BCUC GCOC proceeding 2022, Exhibit B-1-8, https://docs.bcuc.com/Documents/Proceedings/2022/DOC_65493_B1-8-FEI-FBC-Evidence-on-Stage1.pdf.

load growth in the more volatile and economically sensitive transportation and industrial sectors.[128]

In the CTS-TIMC proceeding, FEI stated that "by 2030, FEI envisions that blending of hydrogen would expand across the low-pressure gas distribution system, and as demand grows between 2030 and 2050, the existing gas system pipeline corridors would be retrofitted, upgraded, and expanded to transport an increasing share of hydrogen."[129]

FEI does not anticipate impacts on the TLSE Project, nor on its liquefaction process, as a result of increasing hydrogen content in the gas stream as hydrogen can be separated if introduced upstream of the Tilbury facility. It suggests two potential options available to mitigate the impact on LNG operations from increasing hydrogen content in the gas system:[130]

- hydrogen would be removed by separating it from the gas supply upstream of the LNG facility and then redirected to a different part of the gas network; or
- hydrogen would enter the LNG facility but would be extracted prior to liquefaction and stored separately onsite for use in gaseous or liquid form (e.g., for fuel cell electric vehicle refueling). This would mitigate:
    - Impacts on the rate of boil-off gas generation from the LNG storage tank;
    - The risk of stratification within the LNG storage tank; and
    - The impact on FEI's long-term LNG storage operations.

Positions of the Parties

RCIA notes that FEI's 2022 LTGRP does not provide any percentages of the on-system supplies that will be produced in the Lower Mainland area. FEI anticipates that the majority of this RNG supply will be secured outside of FEI's service areas (i.e., off-system supply). However, any supplies directly connected to the Coastal Transmission System, to the downstream system, or directly to customers will be available throughout a T-South outage, reducing the demand that must be supplied by TLSE or by FEI's other resiliency assets such as the Base Plant and the RGSD project.[131] In reply, FEI submits that, although FEI is planning on the basis that renewable and low carbon gas will comprise an increasing share of its total supply over the next 20 years and beyond, the amount of each resource to be acquired and delivered to customers throughout the planning period will ultimately be predicated on a number of variables. These variables include: (1) the quantity and timing of resource availability; (2) how renewable and low carbon gases are developed and delivered; and importantly, (3) the geographic location where renewable and low carbon supply production is physically delivered.[132]

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[128] Ibid, Appendix A, pp. 15-16.
[129] FEI – CTS-TIMC Decision and Order C-3-22 dated May 18, 2022, p. 9.
https://docs.bcuc.com/Documents/Proceedings/2022/DOC_66603_C-3-22-FEI-CTS-TIMC-CPCN-Decision.pdf.
[130] Exhibit B-15, BCUC IR 21.1.
[131] RCIA Final Argument, p. 30.
[132] FEI Reply Argument, p. 20.

BCSEA emphasizes that the TLSE Project is not featured as a necessity in the 2022 LTGRP, nor is the TLSE Project a requirement of the continued role of the gas system through the energy transition.[133] In reply to BCSEA, FEI submits it describes the TLSE Project as a "key component" of its portfolio approach to resiliency in the 2022 LTGRP while providing other valuable benefits to customers, and the BCUC should reject BCSEA's submissions on this point.[134]

The CEC finds that FEI's justification (need and value) of FEI's TLSE Project is heavily dependent on the assumption of an ongoing, robust, and potentially growing need for natural gas in the Lower Mainland over the course of nearly 70 years. The CEC considers this assumption is a weak foundation for the TLSE Project, in that it is inconsistent with the evidence currently being presented in the BCUC GCOC proceeding, which suggests that the long-term future use of natural gas in the Lower Mainland is uncertain at best.[135] In reply to the CEC, FEI submits it is unreasonable to expect that the demand risk identified by the CEC will be resolved within two to three years, noting the energy transition remains in a state of constant evolution and will be impacted by the political and regulatory landscape in the years and decades to come.[136]

FEI submits in its reply argument the TLSE Project is consistent with its statutory duty under the UCA to provide safe and reliable service to customers, both today and in the future. FEI adds that it would be inappropriate and contrary to the public interest for the utility to allow the system to deteriorate based on speculation that the system will no longer have a role decades in the future.[137] FEI submits the evidence filed in this proceeding is consistent with the BCUC GCOC proceeding, and includes the same long term load forecast scenarios.[138]

Panel Discussion

FEI argues that the proposed life of the TLSE Project, for depreciation purposes, is 60 years. However, given Federal and Provincial Government GHG reduction targets for 2030 through 2050, the Panel finds a significant probability that demand for natural gas will be reduced as compared to the demand today. It is therefore unclear to the Panel that there will be sufficient demand for natural gas to support the continued use of FEI's pipeline system including Tilbury as currently configured for the next 60 years.

According to FEI the mix of fuel will change, and hydrogen will form an increasing proportion of the mix. Its evidence is that while hydrogen will only form a few percent of the mix in 2030, 16 years into the 67-year life of the tank, hydrogen will form 20 to 25 percent of the fuel mix in the CTS. The implications of a hydrogen mix for this project are two fold:

1. There is evidence in this proceeding that any hydrogen blended with the natural gas delivered to Tilbury must be separated prior to liquefaction and that FEI has to date completed only preliminary desktop studies of hydrogen separation technologies. Even if

[133] BCSEA Final Argument, p. 12.
[134] FEI Reply Argument, p. 11.
[135] CEC Final Argument, p. 1.
[136] FEI Reply Argument, p. 12.
[137] Ibid., pp. 7 – 8.
[138] Ibid., p. 10.

separation were possible, there would need to be space onsite for hydrogen separation and storage equipment. FEI has not investigated the capital and operating costs required to acquire and operate hydrogen separation equipment.

2. An increasing mix of hydrogen implies a reduction in the amount of natural gas needed to serve customer load. Any reduction of natural gas needed to serve customer load means less reliance on T-South and a less severe consequence of any no-flow event in terms of number of affected customers.

Beyond 2030, with a target of net zero GHG emissions by 2050, it is not clear how much natural gas will be transported by the FEI pipeline system. Currently, deemed zero emission RNG makes up approximately 15 percent of supply but we have no evidence whether this proportion is expected to be greater or less in 2050. There is also no evidence in this proceeding regarding other ways to achieve net zero by 2050 – such as carbon capture and sequestration or offsets.

Because of these concerns we are unable to find a 60-year life to be appropriate for the purpose of amortization. Given the uncertainties around the useful life, a shorter amortization period may be more appropriate.

5.3 Rate Impact

Given FEI's assumptions about useful life, the TLSE 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.[139]

Positions of the Parties

The CEC finds the rate impact for the proposed TLSE Project is very high, and could be higher than expected if the useful life of the assets, or useful size of the assets, is diminished by declining natural gas use in the Lower Mainland.[140]

BCOAPO submits the rate impacts of the TLSE Project alone are near the level of rate shock and once other anticipated cost pressures are factored in, rates will nearly double by 2027.[141]

RCIA expects a large group of residential customers would oppose the rate increases resulting from the TLSE Project as the benefit of avoiding an interruption may never be realized, FEI's other resiliency assets can manage through the outage during the vast majority of the year, or it may be realized decades into the future. RCIA expects another group of customers to be in favour of such an investment.[142]

[139] Exhibit B-1, p. 168.
[140] CEC Final Argument, p. 35.
[141] BCOAPO Final Argument, p. 17.
[142] RCIA Final Argument, p. 26.

Panel Discussion

The cost of this Project is significant. Given FEI's 60-year useful life assumption the rate impact is almost 1.5 percent per year. However, we have concerns that the TLSE Project will not remain used and useful for the entire term, thereby giving rise to the potential of significant stranded asset risk associated with this Project. In the alternative, reducing the amortization term would increase rate impacts to customers.

6.0 Consultation

6.1 Indigenous Consultation

TWN submits that it does not oppose the CPCN, nor does it seek additional consultation, but it hopes that:

> …the Panel will consider TWN's perspective on how consultation as part of the BCUC regulatory process can be fulfilled moving forward in a manner that is consistent with the United Declaration on the Rights of Indigenous Persons ("UNDRIP"), the Declaration on the Rights of Indigenous Peoples Act, S.B.C. 2019, c. 44 ("DRIPA"), and the constitutional imperative of reconciliation.[143]

TWN states that its aim in providing these submissions is to ensure that the Crown consultation process on BCUC decisions is clarified for future BCUC processes. TWN is seeking engagement with the BCUC and the Ministry of Energy, Mines, and Low Carbon Innovation (EMLI) on how the Crown's constitutional obligations in relation to BCUC decisions can be fulfilled in the future and how to ensure that the BCUC's processes reflect modern Indigenous law principles.[144]

TWN also suggests that the BCUC undertake the following when analysing whether the Crown has fulfilled its duty to consult in relation to the BCUC regulatory process:

(a) Recognition that the BCUC process triggers the duty to consult and that it is the Crown, not a proponent, who owes the duty;

(b) Determination of whether any aspects of consultation have been delegated to a proponent;

(c) Recognition that the consultation triggered by, for example, the CPCN is distinct and separate from the consultation triggered by the Environmental Assessment Certificate ("EAC"); and

(d) Engagement with impacted First Nations on how consultation will be fulfilled with the Crown.[145]

[143] TWN Final Argument, p. 1.
[144] Ibid.
[145] Ibid., p. 2.

TWN submits that:

> The Supreme Court of Canada ("SCC") has established that regulatory agencies act on behalf of the Crown when making a final decision on a project application and such final decisions trigger the duty to consult. A "final decision" is one where a regulatory body makes an enforceable order, without needing confirmation by another authority.4 The substance of the duty to consult does not change when a regulatory body holds final decision-making authority. If a regulatory process does not provide adequate consultation, the Crown is responsible for taking further measures.
>
> In Clyde River (Hamlet) v Petroleum Geo-Services Inc., 2017 SCC 40, a case involving the National Energy Board (the "NEB"), the SCC commented on the relationship between regulatory agencies and the Crown's duty to consult when regulatory agencies are charged with making final decisions:
>
> Put plainly, once it is accepted that a regulatory agency exists to exercise executive power as authorized by legislatures, any distinction between its actions and Crown action quickly falls away. In this context, the NEB is the vehicle through which the Crown acts. Hence this Court's interchangeable references in Carrier Sekani to "government action" and "Crown conduct" (paras. 42-44). It therefore does not matter whether the final decision maker on a resource project is Cabinet or the NEB. In either case, the decision constitutes Crown action that may trigger the duty to consult [Emphasis added].
>
> Analogously, the BCUC is an independent regulatory agency of the provincial government. It exists to exercise executive power as authorized by the legislature and is the vehicle through which the Crown acts when making decisions on CPCNs.
>
> Further, the decision by the BCUC whether to grant a CPCN for the TLSE Project is a "final decision" pursuant to s. 45 of the Utilities Commission Act, R.S.B.C. 1996, c. 473 (the "Utilities Act"), as the BCUC is making an enforceable order without needing confirmation from another authority. Therefore, the decision to grant a CPCN triggers the Crown's duty to consult with impacted Indigenous Nations, on how granting the CPCN will affect their Aboriginal rights and title.[146]

TWN seeks clarification on which entity was fulfilling Crown's duty to consult. It argues:

> In the current circumstances, it was never made clear to TWN how the Crown was fulfilling its duty to consult in relation to the CPCN decision. To date, TWN has not been notified either that:
>
> (a) EMLI is relying on the BCUC to fulfil consultation (in fact, the BCUC has emphasized that its role is simply adjudication of the adequacy of consultation and that it is not responsible for fulfilling the Crown's obligations of consultation; or
>
> (b) EMLI has delegated any procedural aspects of this consultation to FEI.

[146] TWN Final Argument, p. 3.

EMLI advised TWN that it was the Crown body for consultation, but nothing further transpired. TWN was left with an administrative gap and not provided with clarity on how the Crown's constitutional obligations on the CPCN decision would be fulfilled.

Ultimately, EMLI is responsible for fulfilling the duty to consult to Indigenous Nations in relation to the CPCN decision and never delegated that duty to either the BCUC or FEI. The engagement activities set out in the FEI consultation log do constitute "consultation" as it would relate to the Crown.

The lack of clarity in the BCUC's processes has created an administrative gap which has hindered adequate Crown consultation. TWN repeatedly sought answers for this oversight but has received none and would like to see the BCUC's processes clarified for future decisions.

If the BCUC does not have the regulatory processes or jurisdiction to assume the role of Crown consultation, then it is the Crown's responsibility to take further measures to meet its duty.[147]

Panel Discussion

The BCUC does not have a duty to consult on behalf of the Crown. Regulatory agencies are confined to the powers conferred upon them by the legislature.[148] The duty to consult may be delegated from the Crown to regulatory agencies but any delegation must be express or implicitly conferred upon it by statute.[149]

As the Supreme Court of Canada held in Rio Tinto, the UCA does not confer the power to engage in consultation on the BCUC. Instead, the UCA only confers on the BCUC the power to consider whether adequate consultation has taken place.[150]

Although the BCUC's decision to grant a CPCN may trigger an independent duty to consult, the BCUC does not have the statutory power to engage in consultation on behalf of the Crown, nor has the Crown delegated that duty to the BCUC in this instance. Instead, the duty to consult remains with the Crown.

The BCUC's framework on how to assess the duty to consult is laid out by the Supreme Court in such decisions as *Rio Tinto, Haida Nation v British Columbia (Minister of Forests),* 2004 SCC 73*, Clyde River (Hamlet) v Petroleum Geo-Services Inc.,* 2017 SCC 40.

Also, we note the following regarding TWN's submission:

- Determination of whether any aspects of consultation have been delegated to a proponent:
    - The BCUC will not know this either (with any certainty) until it is in a position to review the evidence regarding consultation - at the close of the evidentiary record and at the point of decision-making as to whether any project proponent has been delegated the

[147] TWN Final Argument, p. 6.
[148] R. v. Conway, 2010 SCC 22.
[149] *Rio Tinto Alcan Inc. v. Carrier Sekani Tribal Council*, 2010 SCC 43, at paras. 56-61 (*"Rio Tinto").*
[150] in *Rio Tinto* at para. 74.

duty of consultation by the Crown, unless both the proponent and the Crown have expressly acknowledged same prior to or during the proceeding.

- Clarification on which entity was fulfilling crown's duty to consult:
  - The Crown cannot rely on the BCUC to fulfil consultation because the BCUC has not been delegated this power.
  - Whether EMLI has been delegated any aspect of consultation is something for EMLI to answer, not the BCUC.

However, we agree with TWN that consultation triggered by the CPCN is separate from consultation triggered by the *Environmental Assessment Act* (EAC) and the BCUC recognizes this.

An Indigenous group that is party to a CPCN application and with whom the duty to consult is triggered must identify what concerns/issues it has with any CPCN, but if some issues are similar to or distinct from the EAC process that would be helpful for the BCUC to know. A consideration of the adequacy of consultation may well determine if the issues with a CPCN have been addressed through consultation in the EAC process. If the EAC process deals with the consultation issues in the CPCN then the distinction may not matter. However, if the issues are not addressed in the EAC process (or the EAC process has not concluded) then the BCUC still needs to determine whether consultation to the point of issuing the CPCN was adequate.

We agree with TWN that the BCUC must consider UNDRIP and reconciliation – this forms part of the BCUC's determination of the public interest, public convenience and necessity, and adequacy of consultation.

7.0 The Applicable of British Columbia's Energy Objectives

FEI submits the TLSE Project will support the British Columbia energy objective in section 2(k) of the CEA "to encourage economic development and the creation and retention of jobs." Positive impacts of the Project will include the creation of additional employment within the Project scope, the procurement of local goods and the use of local services. There is also potential for new employment and contracting opportunities that will contribute to the local economy. Additionally, FEI notes the objective related to retention of jobs is also served by reducing the potential for a loss or a disruption of gas supply. The PwC Report describes the economic impacts of a loss or disruption of gas supply that may result in permanent business closures and loss of jobs.[151]

FEI does not expect the TLSE Project to contribute to GHG emissions. Rather, the TLSE Project is a resiliency project that dovetails with FEI's planned transition to a low-carbon energy system.[152]

[151] Exhibit B-1, pp. 206 – 207.
[152] FEI Final Argument, p. 152.

Panel Discussion

The Panel considers the following energy objectives, from the *Clean Energy Act*, are applicable to this Project:

(g) to reduce BC greenhouse gas emissions

i. by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007,
ii. by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,
iii. by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,
iv. by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and
v. by such other amounts as determined under the *Climate Change Accountability Act*;

(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;

(j) to reduce waste by encouraging the use of waste heat, biogas and biomass;

(k) to encourage economic development and the creation and retention of jobs;

(l) to foster the development of first nation and rural communities through the use and development of clean or renewable resources;

(n) to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia;

(o) to achieve British Columbia's energy objectives without the use of nuclear power.

Regarding objectives (g), (h), (j), (l) and (n), if constructed, the TLSE Project would provide additional resiliency and additional ancillary benefits. These benefits, taken together, would contribute to a more resilient and reliable system. Whether so doing will enable the TLSE Project to meet these particular objectives depends largely on the source and the carbon intensity of the gas stored in the tank and, therefore, delivered to FEI's customers. There is insufficient evidence in this proceeding for the Panel to fully determine what this mix will be. Regarding objective (n), a system that provides zero carbon intensity gas for domestic consumption can support the export of surplus electricity to reduce GHGs in other regions.

Regarding objective (k), by contributing to improved resiliency and the ancillary benefits cited by FEI, the Panel considers that FEI has adequately demonstrated that the TLSE Project could encourage economic development.

Regarding objective (o) this Project does not use or rely on nuclear power.

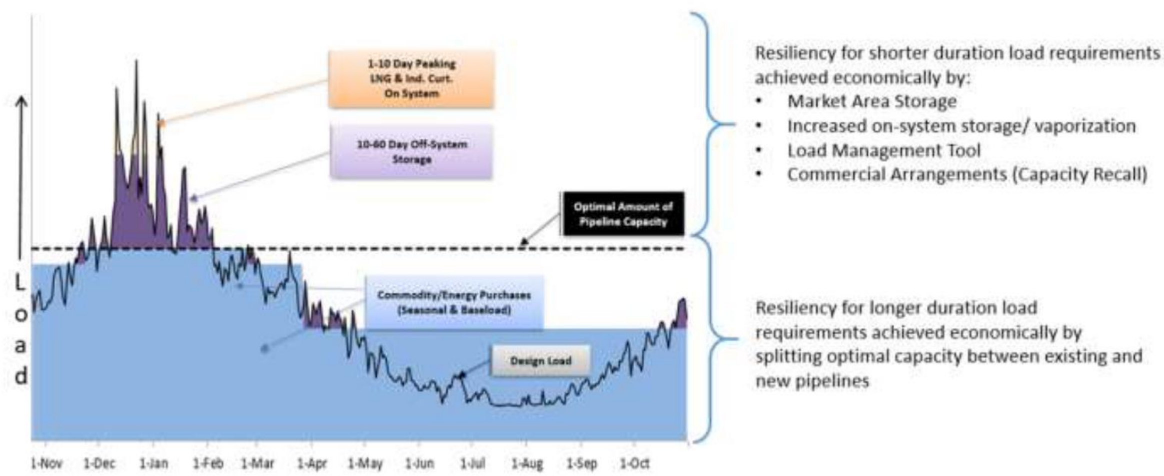
8.0 The Most Recent Long-term Resource Plan Filed Under Section 44.1

In May 2022, FEI filed its 2022 LTGRP. FEI states that the TLSE Project is consistent with the 2022 LTGRP in the sense that it supports the continued role of the gas system through the energy transition.[153]

In the 2022 LTGRP, Appendix E contains FEI's resiliency plan (System Resiliency Plan or SRP) with a discussion of the plan in section 7.5. FEI did not reference these sections in this proceeding.

In the SRP, FEI provides the Figure, reproduced below, which it states, "illustrates how diverse pipeline capacity can be used efficiently, in combination with expanded peaking resources like on-system LNG storage, to build resiliency."

Figure 5: Resiliency Measures Should Reflect Optimal ACP Supply Portfolio[154]



FEI further explains that:[155]

> While FEI's ability to rely on the TLSE project 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, the TLSE project has limitations in addressing long term capacity shortfalls or duration issues, as experienced during phases 2 and 3 of the T-South Incident. The RGSD project would help manage a long-duration supply disruption while also meeting the commercial needs of the region.
>
> If FEI proposed enhancing supply resiliency in the Lower Mainland with RGSD only, the pipeline would need to be sized to provide full replacement capacity for T-South if that system was not available for any reason. While building a new pipeline of this size may be technically possible, this would not be a cost-effective option for customers. It would come at a higher cost than FEI's portfolio approach to

[153] FEI Final Argument, p. 153.
[154] FEI 2022 LTGRP, Appendix E, System Resiliency Plan, Figure 5, p. 29.
[155] Ibid., pp. 29-30.

> resiliency, given that FEI would 1 need to hold excess total capacity on both pipelines (to ensure that full supply could be maintained in the event of an interruption on either the T-South or RGSD pipelines). This would result in FEI's customers paying demand charges for capacity on two pipelines with a significant portion going unused.
>
> Moreover, the size of a pipeline expansion into the region would depend on potential interest from third-party shippers. Although the market requires additional pipeline capacity to satisfy growing gas demand, diversify market access especially during the winter, and provide much-needed gas supply resiliency to the region, at this time FEI does not believe there is enough support from third-party shippers to build a pipeline of that capacity (i.e., 800 MMcf per day).
>
> For the above reasons, the optimal solution is to balance the benefits and costs of additional and strategically located pipeline capacity with the benefits and costs of on-system storage located near the load centre. The optimal solution is therefore combining the benefits of the RGSD project with those of the TLSE project to cost-effectively provide broader resiliency benefits and improved flexibility to meet a range of potential supply disruptions and growing demand while also enabling the transition to renewable and low-carbon gas supplies.[156]

FEI concludes:

> In this [System Resiliency Plan], FEI has discussed its overall approach to system resiliency, including how resiliency builds upon the foundations of system integrity and reliable infrastructure. It also described the three elements which contribute to system resiliency, namely: diverse pipelines and supply; load management capabilities; and ample on-system storage. As it stands, FEI is pursuing two major projects which will each contribute to increased system resiliency, the AMI project (which amongst other things will provide FEI with the ability to manage load at individual customer premises) and the TLSE project (which will add storage within the Lower Mainland region to allow the system to withstand a T-South no-flow event), and exploring one further project, the RGSD project (which would increase regional pipeline diversity). Finally, FEI intends to further develop its resiliency criteria for the distribution system, which it intends to include in a subsequent resource plan. [157]

Panel Discussion

Although FEI did not file a resiliency plan as part of this proceeding, it has filed a resiliency plan in the 2022 LTGRP proceeding. We have considered that plan as we are required to do pursuant to section 44.1 of the UCA, and find it falls short of what we need in this proceeding.

[156] FEI 2022 LTGRP, Appendix E, System Resiliency Plan, pp. 29-30.
[157] Ibid., p. 31.

These shortcomings include the following:

- There is no assessment of the type or severity of the risks to the resiliency of the FEI system, the probabilities of these risks occurring and the resultant consequences of these risks materializing.
- There is no analysis of costs and related benefits. In conclusion the resiliency plan asserts that “the TLSE project will be the most cost-effective resource to respond immediately to withstand a short-term critical emergency that disrupts supply to FEI’s Lower Mainland system, such as in phase 1 of the T-South Incident.”[158] However, the citation for this statement references “Appendix E – Gas System Resiliency Plan” and no further discussion of costs is contained in the plan.
- While there is an assessment of two concurrently planned projects – AMI and RGSD – there is no consideration of other potential projects. Further, the resiliency plan does not set out any alternatives to the TLSE Project for on-system LNG storage that can serve the Greater Vancouver area.
- The resiliency plan states: “Finally, FEI intends to further develop its resiliency criteria for the distribution system, which it intends to include in a subsequent resource plan.”[159]
- The resiliency plan distinguishes between resiliency measures on the distribution system and the transmission system. Regardless of that distinction, resiliency measures are all funded by the same ratepayer and the plan fails to prioritize resiliency investments in a way that allows us to understand the impact on rates of varying levels of investment.
- The resiliency plan states that the RGSD project “would allow FEI to split the optimal amount of pipeline capacity between T-South and RGSD, thereby reducing FEI’s current heavy dependence on the T-South system.”[160] However, IR responses filed in both proceedings suggest that reduced dependence on the T-South System has little to no impact on the TLSE Project.[161] In any event, due to uncertainties in the scope of the RGSD project, we noted in Section 4.1 of our Decision that we are unable to make any finding regarding how the RGSD project may or may not impact the need for the TLSE Project.

Further, the resiliency plan filed in the 2022 LTGRP and the evidence contained therein have not been tested in this proceeding nor has the BCUC made any final determinations to date on that plan in the 2022 LTGRP proceeding. Accordingly, the Panel’s comments above on the 2022 LTGRP are not findings and are subject to review in this proceeding.

[158] FEI 2022 LTGRP, Appendix E, Gas System Resiliency Plan p. 29.
[159] Ibid., p. 29.
[160] Ibid., p. 28.
[161] Exhibit B-26, BCUC IR 82.1; FEI 2022 LTGRP Proceeding, Exhibit B-6, BCUC IR 57.3

9.0 CPCN Determination

FEI submits that it knows with certainty that:

- integrity-related disruptions occur regularly in North America and that the outages frequently last three days, and that non-integrity events (e.g., cyberattacks) have caused multi-day energy infrastructure outages;
- hundreds of thousands of people in the Lower Mainland will lose gas service on the first day of a no-flow event occurring in winter; and
- the loss of space and hot water heating for many weeks will represent a hardship for people and businesses, and a health and safety risk to vulnerable populations.

FEI submits that these facts make a compelling case for investments to mitigate the known risk of a three day no-flow event on T-South, and the TLSE Project is the only way to do so effectively. Accordingly, FEI submits that the TLSE Project should be approved on the terms sought.[162]

Positions of the Parties

BCSEA submits that the TLSE Project is not in the public interest and should not be issued a CPCN under the UCA. BCSEA is resistant to new investment in natural gas infrastructure in BC in the absence of solid justification, because of the risk of locking-in fossil-fuel gas infrastructure and inhibiting the reduction of GHG emissions. BCSEA submits that the high cost and rate impact of the TLSE Project are out of proportion to the resiliency benefits taking into consideration the urgency of decarbonizing the natural gas distribution system in BC.[163] BCSEA opposes a CPCN for the TLSE Project, but in the alternative, submits that the Project should be limited to the minimum adequate sizing.[164]

BCOAPO did not state a position as to whether the BCUC should grant a CPCN. BCOAPO expresses rate impact and affordability concerns with respect to the Project.[165]

While the CEC accepts that resiliency is an important aspect of long-term risk management, it does not find evidence of particular urgency for this Project. Citing rate impacts of the TLSE Project are greater than 9 percent in 2027, and more than 6.5 percent on a 67-year Levelized Delivery rate basis, it submits that it would not be in the public interest for the BCUC to approve a very large and costly Project for FEI until there is consensus as to the future of the natural gas demand and which is properly reflected in the risk assessment and financial analysis, including the Levelized Cost calculations.[166] The CEC recommends that the BCUC defer approval of the TLSE Project until it has a higher level of confidence in terms of the risk being assessed and the expected life for the assets to be used and useful.[167]

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162 FEI Final Argument, p. 15.
163 BCSEA Final Argument, p. 4
164 Ibid., p. 8.
165 BCOAPO Final Argument, pp. 15 – 17.
166 CEC Final Argument, p. 1.
167 Ibid., p. 2.

RCIA submits FEI has not justified the TLSE Project is an effective use of ratepayer funds and the delivery rate impacts are not justified considering it is proposing to construct the RGSD project anyway. As proposed by FEI, the $770 million cost to construct the TLSE Project is not justified by the incremental resiliency benefits over the RGSD project that it provides. Accordingly, RCIA recommends that the BCUC reject the TLSE Project.[168]

Sentinel believes the BCUC should deny the CPCN for the TLSE Project in favour of making incremental changes to the existing distribution system that will achieve most of the resiliency required. Further, approving such a facility would continue BC's reliance on fossil fuels far into the future and would run counter to the Province's stated policy to reach net-zero carbon emissions by 2050.[169]

TWN does not oppose the TLSE Project.[170]

Panel Determination

For the reasons set out below, the Panel finds that an adjournment of this proceeding is warranted. Therefore, this proceeding is adjourned pending the filing of the evidence described below.

<u>Resiliency Objective</u>

The Panel acknowledges that, currently, there are circumstances where FEI's customers would lose service as early as the first day of a no-flow event. The Panel is persuaded by FEI's evidence and finds that there are no existing options to completely mitigate the negative consequences if the event occurs during a sufficiently cold period of time. In this regard, we note that even with the proposed TLSE Project a no-flow event on the design day would not be mitigated given the regasification equipment specified in the Project proposal.

Further, the Panel observes that FEI has been exposed to such risks since the T-South pipeline was constructed. The questions that arise are: why this Project, and why now? As discussed in Section 2.1, in the absence of a more fulsome resiliency plan these questions remain largely unanswered.

In Section 2.1.2, the Panel finds that FEI has not established that mitigating a no-flow event on the T-South System of up to 3 days, during extreme low temperature conditions but not including the peak design day, is a reasonable criterion by which to assess whether this Project is required for the public convenience and necessity. FEI presents a 3 day no-flow event as its "specific minimum resiliency objective for prospective planning" but provides no broader context for this specific choice of a resiliency objective. There is no probabilistic analysis to demonstrate this is a more likely event than a ten day no-flow event, for example. Further, it does not demonstrate that a 3 day

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[168] RCIA Final Argument, p. 32.
[169] Sentinel Energy Final Argument, pp. 2, 11.
[170] TWN Final Argument, p. 1.

no-flow event is more likely to occur during winter when the consequence could be significant, including the probability of a prolonged outage.

Because of the inadequate analysis and lack of detailed evidence pertaining to the resiliency needs of the system in this Application, we have not attempted to review the broader issue of resiliency of FEI's system. As FEI argues, this Project deals with a specific resiliency need - withstanding a no-flow event of up to 3 days on the T-South System. If FEI were to construct the TLSE Project and were able to withstand a 3 day no-flow event, this would not necessarily mean that the FEI system would then be considered "resilient". There will always be residual resiliency risks no matter what and how many projects FEI puts forward.

The costs and benefits of this particular proposed Project should be evaluated against other alternatives that would provide fewer, equivalent or even potentially more resiliency benefits to customers – for example, an alternative that could withstand a 5 or 6 day event in winter, or the ability to withstand a 3 day no-flow event on 90 percent of days. Or, put another way, if FEI's ratepayers are going to spend $1 billion, is this the best alternative to improve system resiliency?

As we previously indicated, resiliency investments need to be considered on a wider system basis, and a LTGRP is an appropriate place to assess this. However, in the 2017 LGTRP, there was no discussion of resiliency and this "minimum resiliency objective" was not put forward. In that proceeding, the BCUC directed FEI "to address security of supply concerns in its next LTGRP", which was effectively directed in response to the T-South Incident, which occurred shortly before the decision. The current 2022 LTGRP presents a Resiliency plan. However, that plan has not been filed in this proceeding nor has the review of it been completed in the 2022 LTGRP proceeding.

As a result of the lack of analysis and evidence, the Panel is unable to find FEI's stated Minimum Resiliency Planning Objective to be an appropriate objective or sufficient justification for why this Project is required for the public convenience and necessity at this time. Resiliency objectives must be looked at holistically. Strengthening portions of a system shouldn't happen in a vacuum. Further, the economic impacts to the ratepayer of resiliency measures must be considered.

In order to properly assess the need for this Project we require a plan that addresses the following resiliency issues:

- What are the current and future threats to the resiliency of FEI's system in addition to the 3 day no-flow event identified in this Application?
- What assets provide resiliency in FEI's current system and what and where are the gaps in resiliency?
- How do FEI's other planned projects address or mitigate these gaps – e.g. AMI, RGSD - and what is the relationship and extent of overlap between those planned projects and the TLSE Project?
- What steps can be taken to fill those gaps in the short, medium and long term and what are the costs associated with these options? This should include analysis of some of the alternatives discussed in the proceeding, including:
    - Additional regasification and liquefaction at Tilbury;
    - Assessment of the remaining life of the existing Base Plant

- The impact, if any, of the loss of contracted storage on resilience.

We invite FEI to file, in this proceeding, a resiliency plan or further evidence that addresses the concerns set out above.

As we noted in Section 8 of this Decision, although FEI filed a resiliency plan as part of the 2022 LTGRP proceeding, no resiliency plan has been filed in this proceeding. Therefore, the resiliency plan filed in the 2022 LTGRP and the evidence contained therein have not been tested here nor has the BCUC made any determinations to date on that plan in the 2022 LTGRP proceeding.

Notwithstanding, we have noted in Section 8 of this Decision some shortcomings related to the plan that has been filed in that proceeding as they relate to the TLSE Project. However, as acknowledged above, the Panel's comments on the 2022 LTGRP are not findings and are subject to review in this proceeding.

<u>The Future Demand for Natural Gas</u>

Although FEI has not provided a holistic resiliency plan in this proceeding, it has demonstrated that the TLSE Project would provide protection from most no-flow events of no longer than 3 days. The current system only provides limited no-flow event protection and in many cases, there would be a system shutdown on the first day. Therefore, while this Project does provide a marginal increase in resiliency, this increase comes at significant cost and rate impacts even when the costs are amortized over the 60-year life of the TLSE Project.

A 60-year amortization assumes that the TLSE project will be used and useful for 60 years. The Panel has concerns about this assumption and has discussed these concerns in Section 5.2.1 of this Decision. To the extent that a shorter amortization period would address these concerns, it would increase the rate impacts. Further, it is not clear what a shorter amortization period should be.

As the TLSE Project is a long-term investment, the Panel must also consider both the short term and long term no-flow event risks to FEI's system when considering project need. In Section 5.2.1, we discuss the issue of future demand for natural gas and find a significant probability that demand for natural gas will be reduced compared to the demand today. In a scenario with reduced demand, the consequences of a no-flow event on the T-South are less severe. Further, if the throughput of natural gas is reduced due to a decrease in demand, the size of a tank and the amount of regasification required would likely be reduced. The issue of future throughput on the system is an important one when assessing the need for no-flow mitigation.

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

[171] FEI Final Argument, pp. 11-12.

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

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

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

BCSEA is resistant to "new investment in natural gas infrastructure in BC in the absence of solid justification, <u>because of the risk of locking-in fossil-fuel gas infrastructure and inhibiting the reduction of GHG emissions</u>. [emphasis added]."[173] While the Panel is resistant to investment in <u>any</u> utility infrastructure without a solid justification, there is a role in BC for reduced and zero-emission gas for heating and a system to store and transport that gas. Furthermore, both the shareholder and ratepayers of FEI have already made a significant existing investment in the FEI pipeline system to deliver that gas. As long as the pipeline system remains used and useful, investments for resiliency, reliability and safety continue to be required and, where appropriate, should be justifiable on that basis provided that FEI is able to demonstrate that the project in question is required for the public convenience and necessity.

FEI is invited to file further evidence that addresses the Panel's concerns about the stranding risk of the TLSE Project.

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

[172] CEC Final Argument, p. 2.
[173] BCSEA Final Submission, p. 4.

DATED at the City of Vancouver, in the Province of British Columbia, this 23rd day of March 2023.

Original signed by:

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A. K. Fung, KC
Panel Chair / Commissioner

Original signed by:

____

T. A. Loski
Commissioner

Original signed by:

____

R. I. Mason
Commissioner

Original signed by:

____

D. M. Morton
Commissioner

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ORDER NUMBER
G-62-23

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc.
Application for a Certificate of Public Convenience and Necessity
for the Tilbury Liquefied Natural Gas Storage Expansion Project

BEFORE:
A. K. Fung, KC, Panel Chair
T. A. Loski, Commissioner
R. I. Mason, Commissioner
D. M. Morton, Commissioner

on March 23, 2023

ORDER

WHEREAS:

A. On December 29, 2020, FortisBC Energy Inc. (FEI) filed an application with the British Columbia Utilities Commission (BCUC) pursuant to sections 45 and 46 of the *Utilities Commission Act* (UCA) for the approval of a Certificate of Public Convenience and Necessity (CPCN) for the Tilbury Liquefied Natural Gas (LNG) Storage Expansion (TLSE) Project (Application);

B. FEI also requests the following related financial approvals pursuant to sections 59-61 of the UCA:

- A depreciation rate of 1.67 percent and a net salvage rate of 0.67 percent applicable to the new 3 Bcf LNG tank;
- A new non-rate base deferral account: the "TLSE Application and Preliminary Stage Development Costs" deferral account; and
- A deferral account to capture the mark-to-market valuation of any foreign currency forward contracts entered into related to construction of the Project: the "TLSE FX Mark to Market" deferral account;

C. By Orders G-26-21, G-165-21, G-9-22, G-29-22, G-58-22, G-100-22, G-113-22, G-117-22, G-132-22, G-208-22, G-223-22, and G-267-22, the BCUC established and amended regulatory timetable for the review of the Application. The regulatory process included: a workshop; an *in-camera* technical session to address the confidentiality of security sensitive information in the Application; two rounds of written information requests (IRs); filing of intervener evidence, rebuttal evidence, and IRs on the same; one round of Panel IRs; a further round of written IRs regarding the signing of the Tilbury LNG Projects Agreement by the Musqueam Indian Band and FortisBC Holdings Inc.; and written final arguments by FEI and interveners, and reply argument by FEI;

D. The following parties registered as interveners: British Columbia Old Age Pensioners' Organization et al. (BCOAPO); BC Sustainable Energy Association (BCSEA); Citizens for My Sea to Sky Society; Commercial Energy Consumers Association of British Columbia (the CEC); Musqueam Indian Band; Residential Consumer Intervener Association (RCIA); Sentinel Energy Management Inc. (Sentinel Energy); and Tsleil-Waututh Nation (TWN);

E. On October 24, 2022, FEI filed its final argument. On November 21, 2022, BCOAPO, BCSEA, the CEC, RCIA, Sentinel Energy and TWN filed final arguments. On December 12, 2022, FEI filed its reply argument; and

F. The BCUC has reviewed the Application, evidence and submissions in this proceeding and determines the adjournment of the proceeding is warranted.

NOW THEREFORE for the reasons outlined in the accompanying Decision, the BCUC adjourns the proceeding, pending the filing of evidence described in section 9 of the Decision.

DATED at the City of Vancouver, in the Province of British Columbia, this 23rd day of March 2023.

BY ORDER

Original signed by:

A. K. Fung, KC
Commissioner

Attachment

FortisBC Energy Inc.
Application for a Certificate of Public Convenience and Necessity
For the Tilbury Liquefied Natural Gas Storage Expansion Project

Acronym List

ACRONYM	DESCRIPTION
AFUDC	Funds Used During Construction
Application	An application for the approval of a Certificate of Public Convenience and Necessity for the Tilbury Liquefied Natural Gas Storage Expansion Project
Base Plant	Tilbury Base Plant
Bcf	Billion cubic feet
BCOAPO	British Columbia Old Age Pensioners’ Organization et al.
BCSEA	BC Sustainable Energy Association
CEA	Clean Energy Act
CEC	Commercial Energy Consumers Association of British Columbia
CER	Canada Energy Regulator
Concentric	Concentric Advisors, ULC
CPCN	Certificate of Public Convenience and Necessity
CTS-TIMC	Coastal Transmission System - Transmission Integrity Management Capabilities
DRIPA	*Declaration on the Rights of Indigenous Peoples Act*
EAC	*Environmental Assessment Act*
EMLI	Ministry of Energy, Mines, and Low Carbon Innovation
FEI	FortisBC Energy Inc.
GCOC	Generic Cost of Capital
GHG	Greenhouse gas
GJ	Gigajoules
ILI	in-line inspection
IRs	Information requests
JANA	JANA Corporation
LNG	Liquefied Natural Gas

ACRONYM	DESCRIPTION
LTGRP	Long-Term Gas Resource Plan
MMcf/day	Million cubic feet per day
MRP	Multi-Year Rate Plan
MS2S	Citizens for My Sea to Sky Society
Musqueam	Musqueam Indian Band
NEB	National Energy Board
OIC	Order in Council
PwC	Pricewaterhouse Cooper
RCIA	Residential Consumer Intervener Association
RGSD	Regional Gas Supply Diversification
RNG	Renewable natural gas
Roadmap	CleanBC Roadmap to 2030
SCC	The Supreme Court of Canada
SCP	Southern Crossing Pipeline
Sentinel Energy	Sentinel Energy Management Inc.
TLSE Project	Tilbury Liquefied Natural Gas Storage Expansion Project
T-South system	Westcoast Energy's T-South system
TWN	Tsleil-Waututh Nation
UCA	Utilities Commission Act
UNDRIP	United Declaration on the Rights of Indigenous Persons

FortisBC Energy Inc.
Application for a Certificate of Public Convenience and Necessity
For the Tilbury Liquefied Natural Gas Storage Expansion Project

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	1. Letter dated January 11, 2021 – Appointment of Panel for the review of FortisBC Energy Inc.'s Application for a Certificate of Public Convenience and Necessity for the Tilbury Liquefied Natural Gas Storage Expansion Project
A-2	Letter dated January 26, 2021 – BCUC Order G-26-21 establishing the regulatory timetable
A-3	Letter dated February 17, 2021 – BCUC providing guidance and information regarding upcoming Workshop
A-4	Letter dated March 17, 2021 – BCUC Order G-80-21 suspending the regulatory timetable
A-5	Letter dated March 22, 2021 – BCUC acknowledging FEI's filing dated March 18, 2021
A-6	Letter dated April 1, 2021 – BCUC providing information to FEI for an *in camera* technical session scheduled for Wednesday, April 7, 2021 for the Panel, BCUC staff and legal counsel, and FEI staff and legal counsel
A-7	Letter dated April 14, 2021 – BCUC outlining further process concerning security-sensitive information
A-8	Letter dated May 12, 2021 – BCUC Order G-147-21 with Reasons for Decision
A-9	Letter dated May 27, 2021 – BCUC Order G-161-21 with Reasons for Decision
A-10	Letter dated May 28, 2021 – BCUC Order G-165-21 establishing a further regulatory timetable
A-11	Letter dated June 16, 2021 – BCUC Order G-185-21 amending the regulatory timetable
A-12	Letter dated June 17, 2021 – BCUC Information Request No. 1 to FEI
A-13	**CONFIDENTIAL** Letter dated June 17, 2021 - BCUC Confidential Information Request No. 1 to FEI
A-14	Letter dated July 8, 2021 – BCUC response to the CEC's extension request to file Information Requests

A-15	Letter dated September 8, 2021 – BCUC response to the FEI's extension request to file responses to BCUC and Intervener Information Requests No. 1
A-16	Letter dated September 27, 2021 – BCUC addressing the filing of intervener evidence and matters to be addressed at the procedural conference
A-17	Letter dated October 6, 2021 – BCUC Information Request No. 2 to FEI
A-18	**CONFIDENTIAL** Letter dated October 6, 2021 - BCUC Confidential Information Request No. 2 to FEI
A-19	Letter dated October 6, 2021 – BCUC response to the CEC's extension request to file Information Request No. 2
A-20	Letter dated October 8, 2021 – BCUC response to the CEC's further extension request to file Information Request No. 2
A-21	Letter dated November 16, 2021 – BCUC providing Procedural Conference information
A-22	Letter dated December 16, 2021 – BCUC Update after Procedural Conference to follow
A-23	Letter dated January 13, 2022 – BCUC Order G-9-22 establishing a further regulatory timetable with Reasons for Decision
A-24	Letter dated January 19, 2022 – Panel Information Request No. 1 to FEI
A-25	**CONFIDENTIAL** - Letter dated January 19, 2022 – Panel Confidential Information Request No. 1 to FEI
A-25-1	**CONFIDENTIAL** - Letter dated January 24, 2022 – Amended Panel Confidential Information Request No. 1 to FEI
A-26	Letter dated February 10, 2022 – BCUC Order G-29-22 amending the regulatory timetable with reasons for decision
A-27	Letter dated February 25, 2022 – BCUC Order G-51-22 amending the regulatory timetable
A-28	Letter dated March 1, 2022 – BCUC Order G-58-22 amending the regulatory timetable
A-29	Letter dated March 29, 2022 – BCUC providing Oral Hearing Information
A-30	Letter dated April 12, 2022 – BCUC Order G-100-22 amending the regulatory timetable
A-31	Letter dated April 21, 2022 – BCUC Information Request No. 1 to RCIA on Intervener Evidence
A-32	Letter dated April 29, 2022 – BCUC Order G-113-22 amending the regulatory timetable
A-33	Letter dated May 2, 2022 – BCUC Information Request No. 1 to TWN on Written Evidence

A-34	Letter dated May 3, 2022 – BCUC Order G-117-22 amending the regulatory timetable
A-35	Letter dated May 16, 2022 – BCUC Order G-132-22 amending the regulatory timetable with Reasons for Decision
A-36	Letter dated May 20, 2022 – BCUC confirming the regulatory timetable established in Order G-132-22
A-37	Letter dated June 23, 2022 – BCUC Information Request No. 3 to FEI
A-38	Letter dated July 25, 2022 – BCUC Order G-208-22 with a regulatory timetable and reasons for decision
A-39	Letter dated August 12, 2022 – BCUC response to Musqueam Indian Band's request to intervene
A-40	Letter dated August 12, 2022 – BCUC Order G-223-22 amending the regulatory timetable
A-41	Letter dated August 23, 2022 – BCUC Information Request No. 4 to FEI
A-42	Letter dated September 26, 2022 – BCUC Order G-267-22 establishing a further regulatory timetable
A-43	Letter dated November 22, 2022 – BCUC response to BCOAPO extension request

COMMISSION STAFF DOCUMENTS

A2-1	Letter dated August 12, 2022 – BCUC Staff submission: Press Release – Musqueam Indian Band and FortisBC Holdings Inc. sign Tilbury LNG Projects Agreement

APPLICANT DOCUMENTS

B-1	**REDACTED – FORTISBC ENERGY INC. (FEI OR THE COMPANY)** – Application for a Certificate of Public Convenience and Necessity (CPCN) for the Tilbury Liquefied Natural Gas (LNG) Storage Expansion Project (Application) dated December 29, 2020
B-1-1	**CONFIDENTIAL –** FEI Application for a CPCN for the Tilbury LNG Storage Expansion Project dated December 29, 2020
B-1-2	**CONFIDENTIAL –** Letter dated January 27, 2021 – FEI submitting confidential Unredacted Highlighted Application
B-1-3	Letter dated March 25, 2021 – FEI submitting revised redacted Application – Public
B-1-3-1	**CONFIDENTIAL**– Letter dated March 25, 2021 – FEI submitting revised confidential Application

B-1-4 Letter dated May 19, 2021 – FEI submitting Updated Public Application

B-2 **CONFIDENTIAL** – Letter dated February 26, 2021 - FEI submitting confidential Financial Models

B-3 Letter dated March 4, 2021 - FEI submitting Workshop Agenda

B-4 Letter dated March 11, 2021 - FEI submitted Workshop Presentation

B-5 Letter dated March 11, 2021 - FEI submitted Workshop Guidehouse Presentation

B-6 Letter dated March 18, 2021 – FEI submitting update on timing for revised redacted Application

B-7 **CONFIDENTIAL** – Letter dated April 7, 2021 – FEI submitting confidential In-Camera Technical Session Material

B-8 **CONFIDENTIAL** – Letter dated April 19, 2021 – FEI submitting proposed redactions to confidential In-Camera Technical Session Transcript and Materials

B-9 Letter dated April 20, 2021 – FEI submitting notice of redacted confidential In-Camera Technical Session Transcript and Materials to Intervener Counsels

B-10 Letter dated May 3, 2021 – FEI submitting reply to Intervener Counsel Submissions regarding security sensitive information

B-11 Letter dated May 6, 2021 – FEI submitting response to Sentinel Energy submission request for access to security sensitive information

B-12 Letter dated May 21, 2021 – FEI submitting reply to Intervener submissions on Non-Disclosure Agreement

B-13 Letter dated June 14, 2021 – FEI submitting request to amend the Regulatory Timetable

B-14 Letter dated September 7, 2021 – FEI submitting request for extension to respond to Information Requests No. 1

B-15 Letter dated September 13, 2021 – FEI submitting redacted response to BCUC Information Request No. 1

B-15-1 **SECURITY CONFIDENTIAL -** Letter dated September 13, 2021 – FEI submitting response to BCUC Information Request No. 1

B-16 Letter dated September 13, 2021 – FEI submitting redacted response to BCUC Confidential Information Request No. 1

B-16-1 **COMMERCIALLY CONFIDENTIAL -** Letter dated September 13, 2021 – FEI submitting response to BCUC Confidential Information Request No. 1

B-16-2	**SECURITY CONFIDENTIAL -** Letter dated September 13, 2021 – FEI submitting response to BCUC Confidential Information Request No. 1
B-17	Letter dated September 13, 2021 – FEI submitting response to BCOAPO Information Request No. 1
B-18	Letter dated September 13, 2021 – FEI submitting response to BCSEA Information Request No. 1
B-19	Letter dated September 13, 2021 – FEI submitting response to CEC Information Request No. 1
B-20	Letter dated September 13, 2021 – FEI submitting redacted response to CEC Confidential Information Request No. 1
B-20-1	**COMMERCIALLY CONFIDENTIAL –** Letter dated September 13, 2021 – FEI submitting response to CEC Confidential Information Request No. 1
B-20-2	**SECURITY CONFIDENTIAL –** Letter dated September 13, 2021 – FEI submitting response to CEC Confidential Information Request No. 1
B-21	Letter dated September 13, 2021 – FEI submitting response to MS2S Information Request No. 1
B-22	Letter dated September 13, 2021 – FEI submitting redacted response to RCIA Information Request No. 1
B-22-1	**SECURITY CONFIDENTIAL –** Letter dated September 13, 2021 – FEI submitting response to RCIA Information Request No. 1
B-23	Letter dated September 13, 2021 – FEI submitting redacted response to RCIA Confidential Information Request No. 1
B-23-1	**COMMERCIALLY CONFIDENTIAL –** Letter dated September 13, 2021 – FEI submitting response to RCIA Confidential Information Request No. 1
B-23-2	**SECURITY CONFIDENTIAL –** Letter dated September 13, 2021 – FEI submitting response to RCIA Confidential Information Request No. 1
B-24	Letter dated September 13, 2021 – FEI submitting redacted response to Sentinel Information Request No. 1
B-24-1	**COMMERCIALLY CONFIDENTIAL –** Letter dated September 13, 2021 – FEI submitting response to Sentinel Information Request No. 1
B-24-2	**SECURITY CONFIDENTIAL -** Letter dated September 13, 2021 – FEI submitting response to Sentinel Information Request No. 1

B-25 Letter dated September 13, 2021 – FEI submitting response to TWN Information Request No. 1

B-26 Letter dated November 10, 2021 – FEI submitting redacted response to BCUC Information Request No. 2

B-26-1 **COMMERCIALLY CONFIDENTIAL –** Letter dated November 10, 2021 – FEI submitting response to BCUC Information Request No. 2

B-26-2 **SECURITY CONFIDENTIAL –** Letter dated November 10, 2021 – FEI submitting response to BCUC Information Request No. 2

B-27 Letter dated November 10, 2021 – FEI submitting redacted response to BCUC Confidential Information Request No. 2

B-27-1 **COMMERCIALLY CONFIDENTIAL –** Letter dated November 10, 2021 – FEI submitting response to BCUC Confidential Information Request No. 2

B-27-2 **SECURITY CONFIDENTIAL –** Letter dated November 10, 2021 – FEI submitting response to BCUC Confidential Information Request No. 2

B-28 Letter dated November 10, 2021 – FEI submitting response to RCIA Information Request No. 2

B-29 Letter dated November 10, 2021 – FEI submitting redacted response to RCIA Confidential Information Request No. 2

B-29-1 **SECURITY CONFIDENTIAL –** Letter dated November 10, 2021 – FEI submitting response to RCIA Confidential Information Request No. 2

B-30 Letter dated November 10, 2021 – FEI submitting response to BCSEA Information Request No. 2

B-31 Letter dated November 10, 2021 – FEI submitting response to MS2S Information Request No. 2

B-32 Letter dated November 10, 2021 – FEI submitting redacted response to BCOAPO Information Request No. 2

B-32-1 **COMMERCIALLY CONFIDENTIAL** – Letter dated November 10, 2021 – FEI submitting response to BCOAPO Information Request No. 2

B-33 Letter dated November 10, 2021 – FEI submitting response to CEC Information Request No. 2

B-34 Letter dated November 10, 2021 – FEI submitting public response to CEC Confidential Information Request No. 2

B-35	Letter dated November 10, 2021 – FEI submitting response to Sentinel Information Request No. 2
B-36	Letter dated November 10, 2021 – FEI submitting response to TWN Information Request No. 2
B-37	Letter dated November 23, 2021 – FEI submission for Procedural Conference
B-38	Letter dated March 1, 2022 – FEI submitting extension request to file responses to Panel Information Requests No. 1
B-39	Letter dated March 4, 2022 – FEI submitting response to BCUC Panel Information Request No. 1
B-40	**CONFIDENTIAL** - Letter dated March 4, 2022 – FEI submitting response to confidential BCUC Panel Information Request No. 1
B-41	Letter dated April 21, 2022 – FEI Information Request No. 1 to RCIA Intervener Evidence
B-42	Letter dated May 2, 2022 – FEI submitting Notice of Intent to file Rebuttal Evidence
B-43	**CONFIDENTIAL** - Letter dated May 19, 2022 – FEI submitting confidential Information Request No. 1 to TWN on Oral Evidence
B-44	Letter dated June 2, 2022 – FEI submitting Rebuttal Evidence to TWN Oral Evidence
B-45	Letter dated June 2, 2022 – FEI submitting response to MS2S Exhibit C3-9
B-46	**CONFIDENTIAL** - Letter dated June 2, 2022 – FEI submitting confidential Rebuttal Evidence to RCIA Evidence
B-46-1	**REDACTED** - Letter dated June 2, 2022 – FEI submitting redacted Rebuttal Evidence to RCIA Evidence
B-47	Letter dated June 27, 2022 – FEI submission on further process
B-48	Letter dated July 14, 2022 – FEI response to BCSEA Information Request No. 3 on Rebuttal Evidence
B-48-1	**CONFIDENTIAL** - Letter dated July 14, 2022 – FEI response to BCSEA Information Request No. 3 on Rebuttal Evidence confidential Attachment 14.2
B-49	Letter dated July 14, 2022 – FEI response to TWN Information Request No. 3 on Rebuttal Evidence
B-50	Letter dated July 14, 2022 – FEI response to RCIA Information Request No. 3 on Rebuttal Evidence

B-51	Letter dated July 14, 2022 – FEI response to CEC Information Request No. 3 on Rebuttal Evidence
B-51-1	**CONFIDENTIAL** - Letter dated July 14, 2022 – FEI response to CEC Information Request No. 3 on Rebuttal Evidence confidential responses to Questions 119.1 and 120.2 Pages 8 and 10
B-51-2	**UNREDACTED** - Letter dated September 16, 2022 – FEI unredacted response to CEC Information Request No. 3 on Rebuttal Evidence confidential responses to Question 119.1 Page 8
B-52	Letter dated July 14, 2022 – FEI response to BCUC Information Request No. 3 on Rebuttal Evidence
B-53	Letter dated July 14, 2022 – FEI reply submission on Further Process
B-54	**PUBLIC** - Letter dated September 16, 2022 – FEI response to BCUC Information Request No. 4
B-54-1	**CONFIDENTIAL** - Letter dated September 16, 2022 – FEI confidential response to BCUC Information Request No. 4
B-54-2	**CONFIDENTIAL** - Letter dated September 16, 2022 – FEI confidential response to BCUC Information Request No. 4 for Interveners
B-55	Letter dated September 16, 2022 – FEI response to BCOAPO Information Request No. 4
B-56	Letter dated September 16, 2022 – FEI response to BCSEA Information Request No. 4
B-57	Letter dated September 16, 2022 – FEI response to RCIA Information Request No. 4
B-58	Letter dated September 16, 2022 – FEI response to CEC Information Request No. 4
B-59	Letter dated September 16, 2022 – FEI response to TWN Information Request No. 4

INTERVENER DOCUMENTS

C1-1	**RESIDENTIAL CONSUMER INTERVENOR GROUP (RCIG) –** Letter dated January 29, 2021 Request to Intervene by Sam Mason
C1-2	Letter dated March 10, 2021 – RCIG submitting Confidential Declaration and Undertaking for Brady Ryall and Sam Mason
C1-3	Letter dated April 20, 2021 – RCIA submitting notice of Legal Representation and Confidential Declaration and Undertaking for Frederick Cass

C1-4	~~**CONFIDENTIAL**~~ - Letter dated April 28, 2021 – RCIA submitting Counsel Submissions regarding security sensitive information
C1-5	Letter dated May 18, 2021 – RCIA submitting comments on FEI Non-Disclosure Agreement
C1-6	Letter dated June 9, 2021 – RCIA submitting Non-Disclosure Agreement and Undertakings for Brady Ryall and Samuel Mason
C1-7	Letter dated July 9, 2021 – RCIA submitting Information Request No.1 to FEI
C1-7-1	**CONFIDENTIAL -** Letter dated July 9, 2021 – RCIA submitting confidential Information Request No.1 to FEI
C1-8	Letter dated October 6, 2021 – RCIA submitting Information Request No. 2 to FEI
C1-8-1	**SECURITY CONFIDENTIAL** – Letter dated October 6, 2021 – RCIA submitting Confidential Information Request No. 2 to FEI
C1-9	Letter dated January 21, 2022 – RCIA submission regarding TWN request to exclude interveners from the Oral Tsleil-Waututh Knowledge Hearing
C1-10	Letter dated March 18, 2022 – RCIA submitting evidence
C1-10-1	**CONFIDENTIAL –** Letter dated March 18, 2022 – RCIA submitting confidential unredacted evidence
C1-11	Letter dated May 2, 2022 – RCIA Information Request No. 1 to TWN on Written Evidence
C1-12	Letter dated May 6, 2021 – RCIA submission regarding TWN request for Redacted Transcript to Remain Confidential
C1-13	Letter dated May 11, 2022 – RCIA submitting responses to CEC Information Request No. 1
C1-14	Letter dated May 11, 2022 – RCIA submitting responses to FEI Information Request No. 1
C1-15	Letter dated May 11, 2022 – RCIA submitting responses to BCSEA Information Request No. 1
C1-16	**CONFIDENTIAL** – Letter dated May 11, 2022 – RCIA submitting confidential responses to BCUC Information Request No. 1
C1-16-1	**PUBLIC** - Letter dated May 11, 2022 – RCIA submitting redacted confidential responses to BCUC Information Request No. 1
C1-17	Letter dated May 18, 2022 – RCIA will not be submitting Information Requests to TWN on Oral Evidence
C1-18	Letter dated June 23, 2022 – RCIA submitting Information Request No. 3 to FEI on Rebuttal Evidence

C1-19	Letter dated July 5, 2022 – RCIA submitting comment on further process
C1-20	Letter dated September 1, 2022 – RCIA submitting Information Request No. 4 to FEI
C2-1	**BC SUSTAINABLE ENERGY ASSOCIATION (BCSEA)** – Letter dated January 30, 2021 Request to Intervene by William Andrews
C2-2	Letter dated April 12, 2021 – BCSEA submitting Confidential Declaration and Undertakings for William Andrews and Thomas Hackney
C2-3	~~CONFIDENTIAL~~ - Letter dated April 28, 2021 – BCSEA submitting Counsel Submissions regarding security sensitive information
C2-4	Letter dated May 19, 2021 – BCSEA submitting comments on FEI Non-Disclosure Agreement
C2-5	Letter dated July 9, 2021 – BCSEA submitting Information Request No.1 to FEI
C2-6	Letter dated October 12, 2021 – BCSEA submitting Information Request No. 2 to FEI
C2-7	2. Letter dated January 21, 2022 – BCSEA submission regarding TWN request to exclude interveners from the Oral Tsleil-Waututh Knowledge Hearing 3.
C2-8	Letter dated May 2, 2022 – BCSEA Information Request No. 1 to TWN on Written Evidence
C2-9	Letter dated April 21, 2022 – BCSEA Information Request No. 1 to RCIA on Written Evidence
C2-10	Letter dated May 5, 2021 – BCSEA submission regarding TWN request for Redacted Transcript to Remain Confidential
C2-11	Letter dated May 17, 2021 – BCSEA will not be submitting Information Requests to TWN regarding TWN Oral Evidence
C2-12	Letter dated June 23, 2022 – BCSEA Information Request No. 3 to FEI
C2-13	Letter dated July 5, 2022 – BCSEA submitting comment on further process
C2-14	Letter dated August 30, 2022 – BCSEA Information Request No. 4 to FEI
C3-1	**CITIZENS FOR MY SEA TO SKY SOCIETY (MS2S) –** Letter dated February 18, 2021 - Request to Intervene by Eoin Finn
C3-2	Letter dated April 19, 2021 – Devlin Gailus Watson notice of representation of MS2S also submitting Confidential Declaration and Undertaking for Tanner Doerges
C3-3	~~CONFIDENTIAL~~ - Letter dated April 28, 2021 – MS2S submitting Counsel Submissions regarding security sensitive information

C3-4 Letter dated May 19, 2021 – MS2S submitting comments on FEI Non-Disclosure Agreement

C3-5 Letter dated July 9, 2021 – MS2S submitting Information Request No.1 to FEI

C3-6 Letter dated September 29, 2021 – Tanner Doerges of Devlin Gailus Watson submitting they will no longer be representing MS2S in the proceeding

C3-7 Letter dated October 6, 2021 – MS2S submitting Information Request No. 2 to FEI

C3-8 Letter dated November 23, 2021 – MS2S submission for Procedural Conference

C3-9 Letter dated March 28, 2021 – MS2S late comment on FEI response to BCUC Information Request No. 1

C3-10 Letter dated September 1, 2022 – MS2S submission regarding Information Request No. 4 to FEI

C4-1 **British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, and Tenants Resource and Advisory Centre (BCOAPO et al.) –** Letter dated February 25, 2021 Request to Intervene by Leigha Worth and Irina Mis

C4-2 Letter dated March 22, 2021 – BCOAPO submitting Confidential Declaration and Undertakings for Janet Rhodes, Irina Mis, Darren Rainkie and Kelly Derksen

C4-3 ~~CONFIDENTIAL~~ - Letter dated April 27, 2021 – BCOAPO submitting Counsel Submissions regarding security sensitive information

C4-4 Letter dated May 19, 2021 – BCOAPO submitting comments on FEI Non-Disclosure Agreement

C4-5 Letter dated July 9, 2021 – BCOAPO submitting Information Request No.1 to FEI

C4-6 Letter dated October 6, 2021 – BCOAPO submitting Information Request No. 2 to FEI

C4-7 Letter dated November 23, 2021 – BCOAPO submitting Confidential Declaration and Undertaking for Kristin Baram

C4-8 4. Letter dated January 21, 2022 – BCOAPO submission regarding TWN request to exclude interveners from the Oral Tsleil-Waututh Knowledge Hearing

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C4-9 Letter dated May 5, 2021 – BCOAPO submission regarding TWN request for Redacted Transcript to Remain Confidential

C4-10 Letter dated May 18, 2021 – BCOAPO submitting request for access to TWN Redacted Oral Evidence Transcript

C4-11 Letter dated May 20, 2021 – BCOAPO submission advising they will not be filing Information Requests on TWN's Oral Evidence

C4-12	Letter dated July 6, 2022 – BCOAPO submitting comment on further process
C4-13	Letter dated September 1, 2022 – BCOAPO submitting Information Request No. 4 to FEI
C4-14	Letter dated November 21, 2022 – BCOAPO submitting extension request to file Final Argument
C5-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC) –** Letter dated February 25, 2021 by Christopher Weafer
C5-2	Letter dated March 11, 2021 – CEC submitting Confidential Declaration and Undertaking for Christopher Weafer
C5-3	Letter dated March 16, 2021 – CEC submitting Confidential Declaration and Undertaking for Patrick Weafer
C5-4	Letter dated March 16, 2021 – CEC submitting Confidential Declaration and Undertaking for Janet Rhodes
C5-5	**~~CONFIDENTIAL~~** - Letter dated April 28, 2021 – CEC submitting Counsel Submissions regarding security sensitive information
C5-6	Letter dated May 19, 2021 – CEC submitting comments on FEI Non-Disclosure Agreement
C5-7	Letter dated June 10, 2021 – CEC submitting Confidential Declaration and Undertaking for Christopher Weafer, Janet Rhodes and Patrick Weafer
C5-8	Letter dated June 14, 2021 – CEC submitting Non-Disclosure Agreement and Declaration for David Craig
C5-9	Letter dated July 7, 2021 – CEC submitting extension request to file Information Requests
C5-10	Letter dated July 12, 2021 – CEC submitting Information Request No. 1 to FEI
C5-11	**CONFIDENTIAL** – REVISED - Letter dated July 13, 2021 – CEC submitting Revised Confidential Information Request No. 1 to FEI
C5-12	Letter dated October 6, 2021 – CEC submitting extension request to file Information Request No. 2 to FEI
C5-13	Letter dated October 7, 2021 – CEC submitting second extension request to file Information Request No. 2 to FEI
C5-14	Letter dated October 12, 2021 – CEC submitting Information Request No. 2 to FEI
C5-15	**CONFIDENTIAL -** Letter dated October 12, 2021 – CEC submitting Confidential Information Request No. 2 to FEI

C5-16	Letter dated January 21, 2022 – CEC submission regarding TWN request to exclude interveners from the Oral Tsleil-Waututh Knowledge Hearing
C5-17	Letter dated April 21, 2022 – CEC Information Request No. 1 to RCIA Intervener Evidence
C5-18	Letter dated May 2, 2022 – CEC Information Request No. 1 to TWN Intervener Evidence
C5-19	Letter dated May 6, 2021 – CEC submission supporting BCOAPO regarding TWN request for Redacted Transcript to Remain Confidential
C5-20	Letter dated May 18, 2021 – CEC submitting request for access to TWN Redacted Oral Evidence Transcript
C5-21	Letter dated June 23, 2022 – CEC submitting Information Request No. 3 to FEI Rebuttal Evidence and TWN Intervener Evidence
C5-22	Letter dated July 6, 2022 – CEC submitting comment on further process
C5-23	Letter dated September 1, 2022 – CEC submitting Information Request No. 4 to FEI
C6-1	**SENTINEL ENERGY MANAGEMENT INC. (SENTINEL ENERGY)** - Letter dated March 5, 2021 Late Request to Intervene by Jim Langley – Change of status from Interested Party to Intervener
C6-2	**~~CONFIDENTIAL~~** - Letter dated April 28, 2021 – Sentinel Energy letter regarding security sensitive information
C6-3	Letter dated May 4, 2021 – Sentinel Energy submitting response regarding Further Process and Security Sensitive Information and Confidential Declaration and Undertaking for Charles W. Bois
C6-4	Letter dated May 6, 2021 – Sentinel Energy submitting clarification on Further Process
C6-5	Letter dated May 19, 2021 – Sentinel Energy submitting comments on FEI Non-Disclosure Agreement
C6-6	Letter dated May 27, 2021 – Sentinel Energy submitting Confidential Declaration and Undertaking for James Langley
C6-7	Letter dated June 11, 2021 – Sentinel Energy submitting extension request to file Information Requests
C6-8	**CONFIDENTIAL –** Letter dated July 9, 2021 – Sentinel Energy submitting confidential Information Request No. 1 to FEI
C6-9	**CONFIDENTIAL –** Letter dated October 15, 2021 – Sentinel Energy submitting Information Request No. 2 to FEI
C6-10	Letter dated November 23, 2021 – Charles W. Bois, Miller Thomson LLP providing notice no longer act as counsel to Sentinel Energy

C7-1	**Tsleil-Waututh Nation (TWN)** – Letter dated May 7, 2021 Request to Intervene by Deanna Shrimpton
C7-2	Letter dated July 9, 2021 – TWN submitting Information Request No.1 to FEI
C7-3	Letter dated October 6, 2021 – TWN submitting Information Request No. 2 to FEI
C7-4	Letter dated November 22, 2021 – TWN confirming attendance at the Procedural Conference
C7-5	Letter dated December 9, 2021 – TWN submitting intention to provide additional submissions at the Procedural Conference
C7-6	Letter dated December 17, 2021 – TWN submitting request for Confidential Oral TWN Knowledge Evidence Hearing
C7-7	Letter dated January 28, 2022 – TWN reply submission to Interveners regarding Oral Tsleil-Waututh Knowledge Hearing
C7-8	Letter dated February 23, 2022 – TWN submitting extension request to file written evidence
C7-9	Letter dated March 25, 2022 – TWN submitting written evidence
C7-9-1	**CONFIDENTIAL** – Letter dated March 25, 2022 – TWN submitting confidential written evidence
C7-10	Letter dated April 5, 2022 – TWN submitting comments regarding the provided Oral Hearing Information
C7-11	Letter dated April 11, 2022 – TWN submitting extension request to file redactions to the Oral Evidence Hearing Transcript
C7-12	Letter dated April 21, 2022 – TWN submitting notice of filing redactions to the Oral Evidence Hearing Transcript April 22, 2022
C7-13	Letter dated April 22, 2022 – TWN submitting proposed redactions to the Oral Evidence Hearing Transcript
C7-14	Letter dated May 11, 2022 – TWN submitting reply to Intervener submissions regarding Confidentiality of Oral Evidence Hearing Transcript
C7-15	Letter dated May 11, 2022 – TWN submitting responses to BCUC Information Request No. 1
C7-16	Letter dated May 11, 2022 – TWN submitting responses to CEC Information Request No. 1
C7-17	Letter dated May 11, 2022 – TWN submitting responses to RCIA Information Request No. 1

C7-18	Letter dated May 11, 2022 – TWN submitting responses to BCSEA Information Request No. 1
C7-19	Letter dated May 17, 2022 – TWN submitting possible extension request to file responses to formation Requests on Oral Evidence
C7-20	**CONFIDENTIAL** - Letter dated May 30, 2022 – TWN submitting confidential responses to FEI Confidential Information Request No. 1 on Oral Evidence
C7-21	Letter dated June 23, 2022 – TWN submitting Information Request No. 3 to FEI
C7-22	Letter dated July 6, 2022 – TWN submission on further process
C7-23	Letter dated August 5, 2022 – TWN submission on availability for Oral Final Argument
C7-24	Letter dated September 1, 2022 – TWN submitting Information Request No. 4 to FEI
C7-25	Letter dated October 7, 2022 – TWN submitting update on Final Arguments
C8-1	**MUSQUEAM INDIAN BAND (MUSQUEAM)** - Letter dated July 29, 2022 Request to Intervene by Chief Wayne Sparrow

INTERESTED PARTY DOCUMENTS

D-1	**ARMSTRONG, LYNN (ARMSTRONG)** - Submission dated January 12, 2021 request for Interested Party Status
D-2	**HUTTON, JOHN (HUTTON)** - Submission dated February 17, 2021 request for Interested Party Status
D-2-1	Hutton – Letter of Comment dated February 12, 2021
D-3	**REMOVED** – Now Exhibit C6-1
D-4	**DEROO, J. (DEROO)** - Submission dated March 9, 2021 request for Interested Party Status
D-5	**VAN DER VELDEN, P. (VAN DER VELDEN)** - Submission dated August 5, 2021 request for Interested Party Status
D-5-1	van der Velden – Letter of Comment dated August 5, 2021
D-6	**ROBERTSON ENVIRONMENTAL SERVICES LTD.** - Submission dated October 8, 2021 request for Interested Party Status
D-7	**REV, M. (REV)** - Submission dated July 15, 2022 request for Interested Party Status

LETTERS OF COMMENT

E-1	Reid, H. – Letter of Comment dated February 22, 2021
E-2	Ruthven, P. – Letter of Comment dated June 7, 2021
E-3	Axwik, G. – Letter of Comment dated July 15, 2021