Sarah Walsh
Director, Regulatory Affairs

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

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

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

May 22, 2025

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Dear Commission Secretary:

Re: FortisBC Energy Inc. (FEI)

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

Response to the British Columbia Utilities Commission (BCUC) Information Request (IR) No. 6

On December 29, 2020, FEI filed the Application referenced above and on October 24, 2024, FEI filed its Supplemental Evidence to the Application. In accordance with the regulatory timetable established in BCUC Order G-324-24 for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 6.

Treatment of Confidential Information

FEI has filed Attachment 143.6 on a confidential basis as identified in the response to BCUC IR6 143.6. FEI has redacted certain information contained in Attachment 143.6 that, consistent with Order G-19-25, is Restricted Confidential Information, unrelated to the current proceeding, and should only be accessible to the BCUC.

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

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Registered Interveners

Table of Contents **Page No.**

A. PROJECT NEED

142.0 Reference: PROJECT NEED

Exhibit B-63, BCUC IR 116.4.1, p. 7

AV-1, AV-2, AV-3 and AV-54 Probability of Failure

On page 7 of FortisBC Energy Inc.'s (FEI) response to the British Columbia Utilities Commission's (BCUC) information request (IR) 116.4, Exponent stated:

> Exponent understands that JANA's analysis considers application of FEI's integrity management program in determining internal failure rates. Exponent based internal failure rates for T-South on the most similar of FEI's pipelines for which JANA calculated internal failure rates. Exponent does not respond to BCUC IR5 116.4.1 in light of the answer to BCUC IR5 116.4.
>
> Exponent considers its values to be appropriate. For this analysis, there were two relevant datasets: JANA's analysis of FEI's pipelines with similar ages and diameters; and JANA's analysis of generic pipelines using the PHMSA and TSB data representing pipelines with current integrity management practices. The mean rupture rate using the PHMSA data (a much larger dataset than the TSB data) was 3.1e-5/km/year, which is similar to the value used by Exponent.
>
> Nevertheless, to assess the sensitivity of the expected annual GDP loss reduction at average winter temperature of the combined AV-1, -2, -3, and -54 to the internal failure rate, Exponent performed a sensitivity study in which the internal failure rate used in its report was reduced by 20% (Figure 1). The values can be compared with those shown in Figure 41 of Exponent's report (reproduced as Figure 2 here). It is seen that the expected annual GDP loss reduction for Supplemental Alternatives 7 and 9 (Preferred) decreases from $166 million CAD to $151 million CAD (a 9% reduction) when the internal failure rate is reduced by 20%

142.1 Please provide the expected annual GDP loss reduction for Supplemental Alternatives 7 and 9 if the internal failure rate used by Exponent in its analysis is based on PHMSA data (i.e. 3.1e-5/km/year).

Response:

The following response has been provided by Exponent:

The expected annual GDP loss reduction for Supplemental Alternatives 7 and 9 is $129.0 million CAD when using an internal failure rate of 3.1e-5/km/year. This is a significant loss reduction.

143.0 Reference: PROJECT NEED

Exhibit B-63, BCUC IR 118.1, 118.2, 118.3

Peaking Supply Requirements

In response to BCUC IR 118.1, FEI provided its ACP Annual Design Load and Peak Day Demand Increase and stated:

> … over the last 10 years, ACP annual design load and peak day demand has increased by 39 Bcf and 129 MMcf/d, respectively. This load increase was primarily driven by Transportation customers returning to Core customers (i.e., RS 23 returning to RS 3). This increase has required FEI to contract additional resources from the market.

143.1 Please explain how gas was supplied to RS 23 customers prior to their return to RS 3.

Response:

FEI's Annual Contracting Plan (ACP) resources are designed to serve RS 1 to 7 customers. Prior to their return to RS 3, RS 23 customers contracted with Shipper Agents (gas marketers) who source gas from the market and then make transportation arrangements to deliver gas to FEI's system.

143.2 Please explain, when RS 23 customers returned to RS 3, whether there was any capacity released into the market that was previously used to serve RS 23 customers.

Response:

FEI is not aware of any T-South capacity that has been released by gas marketers since RS 23 customers returned to RS 3. This is because most of the customers who returned to bundled service were purchasing their gas at Sumas historically and did not hold T-South capacity as part of their procurement strategy.

143.3 Please elaborate on how the return of Transportation customers to Core customers (i.e., RS 23 returning to RS 3) has impacted RS 3 winter and peak day demand. In your response, please include a discussion on the typical load profiles for such customers.

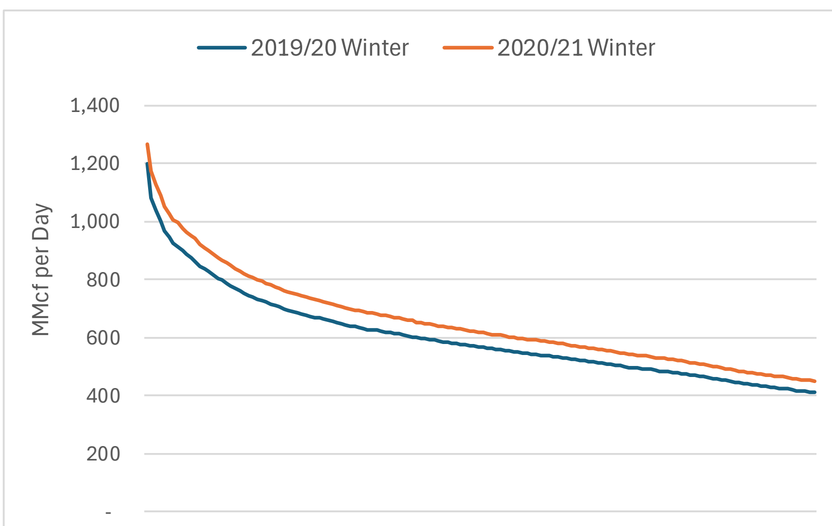
Response:

FEI develops its ACP load forecast by studying the daily send-out data of RS 1 to 7 customers as a single group, without separating RS 3 customers from the aggregated core demand. When Transportation customers elected to return to being Core customers, the consumption of those who switched from RS 23 to RS 3 shifted to daily Core demand and, therefore, was incorporated into the ACP load forecast.

Customer migration occurs constantly, and the impact to ACP load is blended with the organic customer growth and reflected in the annual update to the ACP load forecast. FEI saw the largest migration of Transportation customers in gas year 2020/21 in which ACP winter design load increased by 8 Bcf (9 percent) compared to the previous year. Peak day demand also increased by 65 MMcf/d (or 5 percent) in one year. Figure 1 below compares the design load profile of the 2019/20 and 2020/21 winter season (November to March) and shows the impact of a significant number of Transportation customers returning to being Core customers.

Figure 1: Comparison of Design Load Profile 2019/20 and 2020/21

(in MMcf)	2019/20	2020/21	% Increase
Design Winter Demand	91,357	99,594	9%
Peak Day	1,200	1,265	5%



In an unconstrained market, FEI would contract a mix of additional resources (i.e., pipeline, storage and peaking assets) to meet a significant load increase of the kind shown in Figure 1 above; however, as there are limited storage resources available in the Pacific Northwest region, FEI had to serve the majority of this incremental demand with pipeline capacity. Using pipeline capacity to meet short-duration load (i.e., peak day) increases is suboptimal (i.e., less cost-effective than an optimized, balanced portfolio). The TLSE Project, which will provide short-duration peaking supply, will better optimize FEI's gas supply portfolio to the benefit of FEI's customers.

Further, FEI also stated:

> In the 2022/23 ACP, FEI provided an analysis to show the impact that the TLSE [Tilbury LNG Storage Expansion] Project would have on the gas supply portfolio. The analysis shows if FEI had the option to increase Tilbury peak day supply from 0.6 to 1 Bcf, peak day sendout would increase from 150 to 190 MMcf/d for the gas year 2026/27. <u>The details of the analysis are included in Appendix C of the 2022/23 ACP</u>. [Emphasis added]
>
> Despite the reduced operating capacity of the Tilbury Base Plant, <u>FEI has retained the same Tilbury LNG capacity (0.6 Bcf and 150 MMcf/d) in the ACP portfolio and, to date, has temporarily contracted pipeline and storage resources to meet the increasing ACP demand</u>. … [Emphasis added]
>
> <u>The TLSE Project will allow FEI to reduce some of the amount of supply provided through these short-term contracts. … The TLSE Project will provide new optionality to the ACP, with the availability of additional peaking supply</u>. [Emphasis added]

In response to BCUC IR 5.118.2, FEI stated:

> While, to date, FEI has met its peaking supply requirements with a combination of 150 MMcf/d 38 and 0.6 Bcf from Tilbury (now comprised of 0.35 from the Base Plant and 0.25 Bcf from Tilbury 1A, due to the Base Plant operating at reduced fill levels) and additional pipeline capacity on T-South, this approach is suboptimal and only a temporary measure. <u>Through portfolio optimization modelling, FEI determined that 200 MMcf/d of regasification capacity and 1 Bcf of storage for peaking supply was appropriate</u>. [Emphasis added]

In response to BCUC IR 118.3, FEI stated:

> FEI has not experienced any actual supply shortage on peak day or the during winter season; however, the requirements for peaking supply have increased from a planning perspective beyond what the Tilbury Base Plant can provide. To meet increasing peaking demand requirements, FEI has contracted additional resources from the market (i.e., peaking call options and pipeline resources) in a less optimal way than if FEI had more peaking resources than the existing allocation from Tilbury (150 MMcf/d of regasification capacity and the 0.6 Bcf of LNG storage). [Emphasis added]

143.4 Please provide annotated load duration curves for FEI's design year, which illustrate FEI's possible gas supply portfolio assuming:

i) 1 Bcf storage and 200 MMcf/day regasification; and

ii) 0.6 Bcf storage and 150 MMcf/day regasification.

143.4.1 Based on these diagrams, please further explain why FEI considers 0.6 Bcf storage and 150 MMcf/day regasification is sub-optimal.

Response:

As discussed in the response to BCUC IR5 118.1, the annual design load and peak day demand have increased significantly during the past 10 years, but FEI has not been able to add any peaking assets to the ACP resource portfolio (except a temporary increase of Mist storage until 2026/27 before a significant amount of Mist storage is recalled). To meet the increased demand, FEI has been relying on:

1) Pipeline capacity to meet all incremental load, including peak day load. In an unconstrained market, FEI would add a mix of resources including pipeline, storage and peaking assets (such as LNG storage) so that its gas supply portfolio remains cost effective. However, because regional resources are fully contracted, the only resource FEI had access to at reasonable costs was T-South capacity.

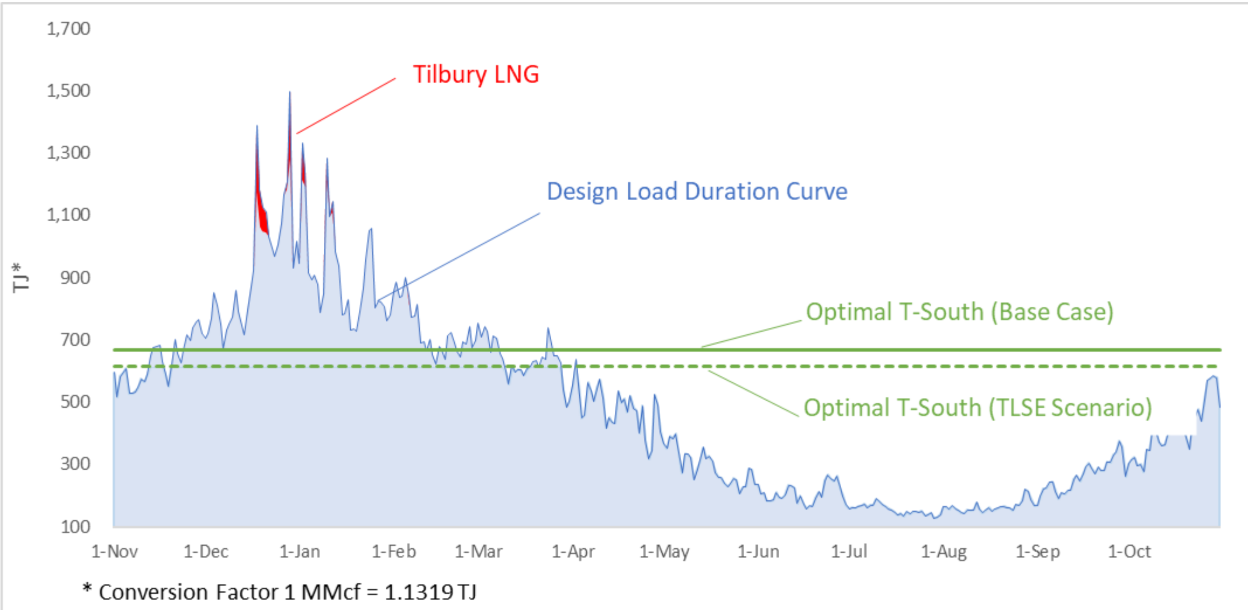
2) Peaking call options, which are short-term commercial transactions for FEI to receive peaking gas at the East Kootenay interconnect (EKE) when additional supply is needed on cold days.

Additional Cost to Customers Associated with Sub-Optimal Portfolio

The cost implications of this approach can be determined using FEI's portfolio optimization modelling, which it has used for a number of years in BCUC-accepted ACPs. This modelling allows for the comparison of FEI's existing gas portfolio costs to the costs assuming additional on-system LNG (0.4 Bcf) was available. As the tolls on T-South are expected to increase when Enbridge's Sunrise Expansion Project is in-service by 2028, FEI estimated $7.9 million in annual savings if an additional 0.4 Bcf of LNG was included in the ACP portfolio. Please refer to the response to BCUC IR5 131.3 for the details of the financial analysis underlying these T-South savings.

The following two charts provide the load duration curve (peak day 1,498 TJ or 1,323 MMcf/d) comparing the utilization of LNG supply in the base case (Tilbury Base Plant capacity 0.6 Bcf reserve and 150 MMcf/d regasification capacity) and the TLSE Project scenario (1 Bcf reserve and up to 800 MMcf/d regasification capacity). The TLSE Project scenario assumes 1 Bcf of LNG is reserved as peaking supply and 800 TJ (approximately 800 MMcf/d) of daily send-out is available in alignment with the proposed TLSE Project's regasification capacity.

The modeling done in Appendix C from the 2022/23 ACP suggests 215 TJ (approximately 190 MMcf/d) is the optimal LNG send-out on the peak day of 2026/27, which exceeds the current Base Plant regasification capacity. Assuming this additional LNG peaking supply were available, the required T-South capacity decreases from 667 TJ/d (589 MMcf/d) (requirement of base case analysis) to 615 TJ/d (543 MMcf/d). The analysis indicates that the Tilbury Base Plant is under-sized to meet current ACP demand.



Consistent with the above, the Preferred Alternative will increase storage for gas supply from 0.6 Bcf to 1 Bcf and peak day send-out from 163 TJ (approximately 150 MMcf/d) to 215 TJ (190 MMcf/d), thus providing an additional two days of LNG supply. In addition, as the load duration curve changes constantly, the 800 MMcf/d regasification capacity provides valuable options for the model to increase peak day send-out if it is needed in the future.

Commodity Price Exposure and Counterparty Default Risk

As discussed in the ACP, FEI's contingency resources have been eroding. In response, FEI has had to transact short-term commercial deals such as EKE peaking call options to meet peaking supply requirements. These peaking deals are associated with potential commodity price exposure, as well as counterparty default risk when regional gas demand increases significantly. Please refer to the response to BCUC IR5 139.2 for a discussion on commodity price risk associated with the spot market. Further, FEI cannot send more EKE supply to the Lower Mainland and Interior because the SCP, which is required to move EKE supply, is already fully utilized on the peak day.

Ultimately, FEI's ACP modelling demonstrates that customers will benefit from having additional LNG peaking supply on its system from the TLSE Project.

143.5 Please discuss whether FEI is able to meet peak day demand from 2024/2025 to 2028/2029 using the amount of peak day supply from Tilbury Base Plant that is included in the 5-year ACP for that period.

143.5.1 If FEI is able to meet peak day demand without increasing the existing capacity of peak day supply from Tilbury Base Plant, please explain whether the increase of 150 MMcf/day to 200 MMcf/day is necessary.

Response:

FEI has been able to meet peak day demand with the existing supply from the Tilbury Base Plant; however, as discussed throughout the TLSE Project proceeding, FEI has been meeting peak day demand in a suboptimal manner. As described below, this suboptimal approach could continue to meet demand, albeit with additional cost and risk to customers relative to an optimized portfolio, but only so long as the existing LNG regasification capacity and storage at Tilbury remains available.

As the table below illustrates, the majority of resources contracted to meet the demand growth of FEI's Core customers over a 10-year period have been pipeline capacity. It would be beneficial for customers, and more consistent with ACP portfolio design principles, for FEI to have access to more peaking resources given the amount of load that has materialized, rather than meeting most of the demand with pipeline capacity.

Peak Day Portfolio	2025/2026 (MMcf/day)	2016/2017 (MMcf/day)	Change (MMcf/day)
Pipeline Capacity	776	672	104
Market Area Storage (Mist & Jackson Prairie)	214	187	27
Peaking Resources (Ind Curtailement, Mt Hayes & Tilbury)	314	316	-2
Peak Day Demand (MMcf/day)	**1,304**	**1,175**	**129**

Based on the analysis underlying the 2025/26 ACP and future years through the 2029/30 gas year, FEI will continue to meet increases to peak day demand in a suboptimal manner by utilizing the remaining portion of FEI's supplemental pipeline capacity on T-South, as well as securing short-term commercial deals which will likely be tied to a Sumas forward price that will be costly for customers. Given the market conditions, FEI can no longer secure assets from pipelines (i.e., T-South) or storage (i.e., Mist/JPS) at low-cost embedded tolls. Until new infrastructure is built (including the TLSE Project), all prices that FEI pays for resources to meet customer demands over time will be significantly higher than pipeline tolls or storage rates at JPS and Mist.

Further, the loss of future access to the Tilbury Base Plant, which has reached end-of-life (assumed to be 2030 in the Supplemental Evidence) will jeopardize FEI's ability to meet the existing and future peak day demand. Please refer to Section 3.3.4.3 of the Supplemental Evidence where FEI explains that fully-contracted regional infrastructure would preclude replacing Tilbury's existing peaking capabilities. This was also supported by the findings in the Ray Mason report (Appendix F to the Supplemental Evidence).

143.6 Please indicate the page number in Appendix C of 2022/2023 ACP that contains the analysis that shows the impact that the TLSE Project would have on the gas supply portfolio.

Response:

The analysis showing the impacts that the TLSE Project would have on the gas supply portfolio is included on pages 11 to 16 (PDF pages 165 to 170) of Appendix C to the 2022/2023 ACP, provided as Confidential Attachment 143.6. In particular, please refer to page 13 of Appendix C, Table C-5: “Five-Year Alternative Scenario Portfolio Optimization (Based on SENDOUT)”. In the scenario, Tilbury on-system storage send-out would increase from 163 TJ/d in 2025/26 to 215 TJ/d in 2026/27, once the TLSE Project enters service.

FEI has conducted the same analysis during the development of past ACPs, and the results consistently show that with the TLSE Project in place, Tilbury send-out will replace the T-South capacity used to meet peak demand and reduce the amount of EKE peaking supply needed on the peak day.

FEI is requesting that Attachment 143.6 be filed on a confidential basis and held confidential by the BCUC in perpetuity, pursuant to Section 18 of the BCUC’s Rules of Practice and Procedure regarding confidential documents as set out in Order G-296-24, and section 71(5) of the *Utilities Commission Act*. Consistent with the reasons identified in the FEI 2022/2023 ACP, FEI requests that the BCUC exercise its discretion under Section 6.0 of the Rules for Natural Gas Energy Supply Contracts and allow this document to remain confidential due to its commercially sensitive nature. In addition, FEI has redacted certain information contained in Attachment 143.6 that, consistent with Order G-19-25, is Restricted Confidential Information, unrelated to the current proceeding, and should only be accessible to the BCUC.

144.0 Reference: PROJECT NEED

Exhibit B-63, BCUC IR 118.1, 118.5

Peak Demand

In response to BCUC IR 118.1, FEI stated:

> FEI clarifies that the annual demand forecast presented in Figure 4-9 of the 2022 LTGRP (included in the preamble to this information request) <u>does not, and is not intended to, represent the peak demand requirements that will be served by the TLSE Project</u>. [Emphasis added]
>
> FEI files the ACP with the BCUC annually (May 1) based on a portfolio optimization model that assesses FEI's 5-year resource requirements. The purpose of the model is to determine the least cost solution to meet customer demand at various locations across the entire year, using the following inputs: (1) demand; (2) supply; (3) transportation and storage capacity; and (4) the costs of securing gas supply resources from the market. <u>Changes to these inputs impact the overall optimization results as the model rebalances the utilization of resources each year</u>. [Emphasis added]

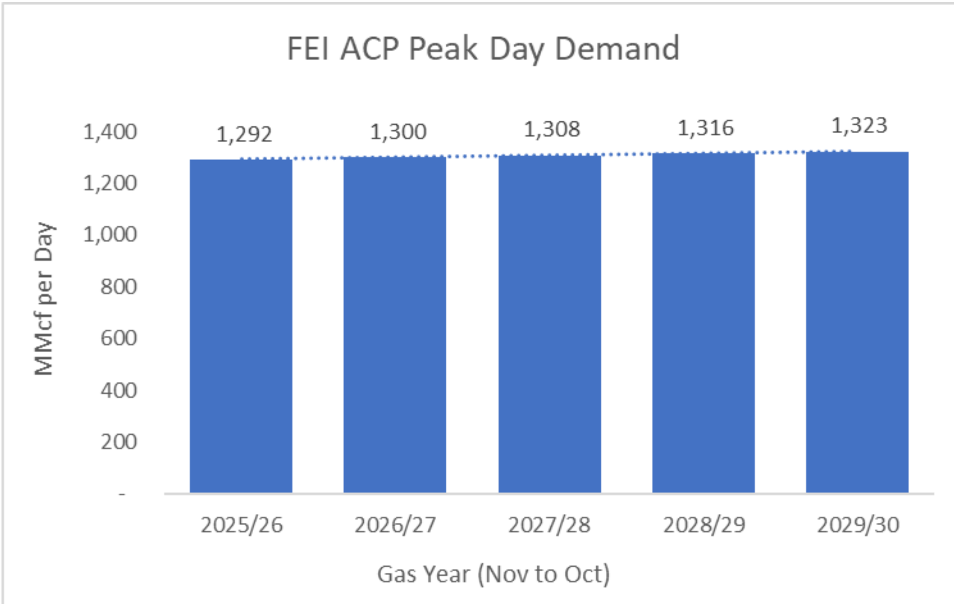
In response to BCUC IR 118.5, FEI stated:

> … FEI designs the capacity of its system to meet peak demand in cold temperatures and not averages. …
>
> FEI does not explicitly project any bias related to future temperature and climate uncertainty in determining design temperature used to determine peak demand. FEI uses historical weather to statistically predict the likelihood of cold weather and periodically refreshes its calculations, bringing the most recent weather extremes into the 60-year data set used in determining the design temperatures.
>
> At this point in time, FEI's considers its determination of design temperatures used to forecast peak demand to be appropriate and not requiring adjustment to effectively deal with and account for climate change. In particular, <u>the current process allows for observed changes in the occurrence of cold temperatures to be incorporated periodically</u>. [Emphasis added]

144.1 Please provide a graph showing the future peak demand forecast that would be used for the purposes of supply planning, and discuss the observed trend over time.

<u>Response:</u>

FEI develops a peak day forecast for the purposes of supply planning as part of its ACP filing. The ACP focuses on the upcoming gas year for supply plan contracting and provides an outlook for resource requirements in the next five years. The figure below provides the most recent peak day forecast used for 2025/26 ACP gas supply planning.



As shown in the figure above, peak day demand is forecast to increase by 8 MMcf/d each year in the next five years (2025-2030). The ACP load forecast is developed based on actual daily consumption in the past three years with a moderate projection of customer additions for the next five years, based on the principle that the most recent past is the best predictor of the near-term future. FEI validated the forecast with the actual consumption in the past few years, as the model used to develop the ACP load forecast has provided accurate projections compared to actuals during recent winter events that have approached the design weather conditions used in the model.

In an unconstrained market, FEI would source a mix of resources, including pipeline (151 or 365 days), storage (20-60 days), and peaking assets such as LNG (1-10 days) to serve the incremental load growth. However, due to the lack of new gas infrastructure development in the region, the only resource FEI was able secure at a reasonable cost was T-South pipeline capacity – which FEI has been using to meet incremental annual demand, including peak day demand. This has resulted in FEI's ACP portfolio being suboptimal and more costly for customers. The proposed TLSE Project will provide an additional 0.4 Bcf of LNG peaking gas supply. The 800 MMcf/d of regasification capacity, which is required for resiliency but can also be used for gas supply without diminishing resiliency, will also provide valuable options in the portfolio optimization and reduces commodity price risk on cold days.

144.2 Please describe the inputs FEI uses to estimate Core customers peak demand forecast that will be served by the TLSE Project. For example, peak use per customer (UPCpeak), number of firm customers, design degree days, and other relevant inputs.

Response:

FEI estimates Core customer peak demand for supply planning as part of the ACP using a scatter plot and piecewise linear spline model/method (referred to as the ACP Spline Model).

The inputs to the ACP Spline Model include actual daily send-out from the prior three gas years, along with the average daily temperature from the regional airport. The ACP Spline Model is created by plotting the actual daily send-out data against the average daily temperature and then fitting a piecewise linear spline model through the data points. Once the ACP Spline Model is created, it is extrapolated out to the regional design temperature and the peak daily demand forecast is established. This is repeated for all regions in FEI's service territory. The ACP Spline Model is a direct regression between actual customer demand and actual weather; therefore, the model does not use other inputs such as peak UPCs, number of firm customers, design degree days, or any other input.

The ACP Spline Model has provided particularly accurate results in recent years, as several winter events have approached the design weather used in the model.

144.3 Please discuss any changes in UPCpeak, number of firm customers, design degree days, or any other key inputs over the past ten years that have contributed to the increase in FEI's peak demand forecast.

Response:

The ACP Spline Model, discussed in the response to BCUC IR6 144.2, establishes a relationship between daily gas usage and average daily temperatures. The daily gas usage is affected by several factors, the most significant of which is the number of firm customers. As FEI adds customers, the peak demand forecast also increases at the design temperature, all else equal. UPCPeak is not a direct input to the model because the model uses actual demand, which embeds the UPC. The peak day design temperature does not change year over year, so design degree days are not a factor in the increased peak demand forecast.

144.4 Please explain whether FEI anticipates any significant changes in the key inputs used to estimate peak day demand that may result in a decrease in peak day demand forecast.

Response:

The input data to the ACP Spline Model, discussed in the response to BCUC IR6 144.2, is limited to the most recent three years of actual individual daily gas usage volumes, aggregated across all Core rate classes. Any significant changes to aggregated consumption will therefore be incorporated in the peak day demand as it occurs.

However, the need for the TLSE Project is not based on meeting growing demand, rather, it is needed to mitigate resiliency risk and replace FEI's LNG peaking supply (which cannot be replaced in the market). As discussed in Section 4.5.5.4 of the Supplemental Evidence and in response to BCUC IR5 129.1, even in an extreme hypothetical scenario where future load decreases at 5 percent each year, the TLSE Project will still be useful for gas supply, as FEI would still be serving hundreds of thousands of customers in the Lower Mainland in 2050 and the Lower Mainland and FEI's other service areas would still need peaking supply. Even under this scenario, FEI would still have the opportunity to optimize its portfolio by substituting LNG storage for other contracted resources and/or mitigate peaking supply to the market.

144.5 Please explain whether historical actual peak day demand has any influence on peak demand forecasts, including whether actual values are used to update inputs such as UPCpeak or the number of firm customers when forecasts are refreshed for ACP planning purposes.

Response:

Actual historical peak day demand is one of the two inputs into the ACP Spline Model, as discussed in the response to BCUC IR6 144.2. Historical daily demand of FEI's Core customers is used to develop the model so the use rate and number of firm customers are included (or embedded) in this data. The input data is updated annually to reflect any changing trends in the source data.

145.0 Reference: PROJECT NEED

Exhibit B-63, BCUC IRs 139.1, 139.2.1, 139.3; Appendix F, Raymond Mason Report, p. 33

Peaking Supply Requirements

In response to BCUC IR 139.1, FEI stated:

> The actual usage of on-system LNG peaking supply depends on the extent of winter weather experienced across the FEI system each year, as well as unplanned operational disruptions which occur during cold weather events and lead to unplanned outages of other planned resources.

FEI provided Table 1, showing the number of days FEI used LNG supply from Tilbury and Mt. Hayes facilities to meet gas demand from 2019 to 2024, and Table 2, identifying which LNG tank was used, and the overall volume of gas supplied to the gas pipeline.

145.1 Based on the data in Table 1, please explain the considerations FEI uses to determine which storage tank (i.e., T1A, Base Plant, or Mt. Hayes) is utilized for send-out.

__Response:__

FEI generally considers the following factors when determining whether to use the Tilbury or Mt. Hayes facilities for send-out (not necessarily in the order below):

1) **Velocity of Cold Weather Event:** The location of a storm system affects the amount of time available for planning. In the case of an unanticipated weather event affecting the Lower Mainland (i.e., the Coastal Transmission System (CTS)), FEI would likely consider using Tilbury send-out before Mt. Hayes because it can be deployed rapidly for short-term relief in the region. If a more prolonged weather event were forecast for Vancouver Island (i.e., the Vancouver Island Transmission System (VITS)), FEI would likely consider using a longer-term supply source such as the Mt. Hayes facility.
2) **Location of Imminent Cold Weather Event:** Both the Tilbury and Mt. Hayes facilities are separated geographically, which improves FEI's ability to deliver supply where it is required (i.e., CTS or VITS).
3) **Duration of Cold Weather Event:** The Tilbury facility provides supply relief for short-term durations (0.35 Bcf from the Base Plant and 0.25 Bcf from Tilbury 1A), whereas Mt. Hayes can serve load for a longer time given it has a larger LNG tank (1.5 Bcf). As described in point #1 above, if an unanticipated cold weather event occurs, FEI would likely consider using Tilbury before the Mt. Hayes facility to provide immediate short-term relief. If a longer-term supply source was needed to support the VITS, then FEI would likely consider using the Mt. Hayes facility.
4) **Deliverability and Demand Response:** As an example, if the decision for LNG send-out is not made 24 hours prior to cold weather, then Tilbury is a better option because the

supply relief provided by Mt. Hayes send-out is not immediate. The CTS does not benefit from the reduced demand at V1 due to Mt. Hayes send-out during cold weather until several hours later.

5) **Transmission System Line-Pack Levels:** As an example, if VITS linepack is reduced due to unexpected weather demand and drafted shippers, then LNG from the Mt. Hayes facility may be required to assist with restoring pressure to the system.

6) **Post-Event Liquefaction Capacity:** Before deploying LNG from a particular storage tank, FEI may consider the LNG production rate of each plant. All else being equal, because Mt. Hayes has higher liquefaction capacity than Tilbury (i.e., allocated to gas supply), FEI prioritizes its use first because it can be refilled faster.

7) **Regional Pipeline Constraints:** Gas supplied by LNG that is geographically located near gas demand has the benefit of providing supply into the local transmission system close to the load center and is not reliant on functioning regional pipeline infrastructure. If there was a significant disruption in gas supply flowing to the Lower Mainland, the Tilbury Base Plant's capacity of 150 MMcf/d would only be able to serve a small percentage of peak day requirements.

8) **Storage Inventory Levels:** All of FEI's downstream storage assets have their own unique withdrawal rates, days of use, and decline deliverability considerations. LNG may be an ideal substitute, for example, when considering the duration of the cold weather event and time of year (i.e., whether it is late in the winter heating season). While both the JPS and Mist facilities are peaking storage facilities, with high deliverability capabilities, deliverability declines as storage inventory declines. Mist has a slower decline rate than JPS and, depending on the time of year, FEI may call upon LNG from the Tilbury or Mt. Hayes facilities if these assets have lower inventory levels or have already been utilized.

FEI optimizes all ACP resources to meet firm Core load requirements, respond to operational changes and to balance the system throughout the year. FEI expects actual LNG utilization to be very low (relative to planned) given its characteristics and its function as the last resource on FEI's resource stack. As such, FEI would only call upon Tilbury LNG when other resources are deployed at maximum capacity. LNG storage is finite, relatively small, and is the last resource that FEI calls upon to meet customer demand because it is intended to meet peak day demand. While FEI has not experienced design day temperatures in the Lower Mainland in recent winters, it has reached close to design day temperatures. As such, if design temperatures were to occur in a particular year, the last supply to meet that demand would come from on-system LNG. Ultimately, a high degree of LNG utilization consistently from year-to-year would signal that customers are at risk of losing service during cold weather events.

145.2 Using the historical data provided in Table 2, please describe the average daily send-out volume from the Tilbury Base Plant due to cold weather, as well as the number of days per year the plant has been utilized.

Response:

The Tilbury Base Plant has been used to support FEI's system in response to cold weather, as well as operational upsets that have occurred during cold weather periods.

FEI would only call upon Tilbury LNG when other resources are deployed at maximum capacity, making it the resource of last resort (please refer to the response to BCUC IR6 145.1). Given its intended purpose as a supply of last resort, a high degree of LNG utilization consistently from year-to-year would be indicative of very significant risk of firm customer outages each year.

Use of the Tilbury Base Plant has increased in the last 10-15 years. This is due to unplanned operational disruptions, as described in the response to BCUC IR5 139.1, but also an increase in demand due to cold weather that is indicative of the portfolio being strained. The average daily send-out volume can also fluctuate depending on the circumstances surrounding the send-out decision.

The table below provides the average send-out volume from the Tilbury Base Plant due to cold weather events over the last five years.

Send-out from Tilbury Base Plant due to Cold Weather Demand

Year	Total Send-out Volume (MSCF)	Days Used	Average Daily Volume (MSCF)
2019		0	
2020		0	
2021	47,600	2	23,800
2022	327,400	8	40,925
2023	41,845	3	13,948
2024	174,400	4	43,600

145.3 Based on the historical data in Table 2, please identify the maximum daily send-out volume (MMcf/day) from the Tilbury Base Plant and indicate the purpose of the send-out (e.g., system maintenance, cold weather response). Please express this volume as a percentage of the Tilbury Base Plant's existing capacity.

Response:

FEI has assumed the "the maximum daily send-out volume" refers to the largest amount of gas vapourized and pushed into the pipeline on a given day from the historical dataset used to prepare Table 2.

The Tilbury Base Plant sent out 74.5 MMcf/d of gas on December 22, 2022, representing the highest single day send-out volume and 12 percent of the facility's LNG storage capacity (assuming 0.35 Bcf of the Tilbury Base Plant and 0.25 Bcf of Tilbury 1A). FEI relied on the Tilbury Base Plant on this day because of several unplanned regional pipeline outages which led to a reduction of firm T-South capacity.

145.4 Using the same data, please identify the maximum daily send-out volume (MMcf/day) from the Tilbury Base Plant specifically attributed to cold weather events. Please express this volume as a percentage of the plant's existing capacity.

Response:

FEI provides the daily send-out volume on an assumed daily net flow basis from the Tilbury Base Plant attributed to cold weather events in Table 2 of the response to BCUC IR5 139.1 and percentages based on: (1) a 0.35 Bcf capacity, which represents the Tilbury Base Plant's reduced tank capacity; and (2) a 0.6 Bcf capacity, which comprises 0.35 Bcf from the Base Plant and an additional 0.25 Bcf from Tilbury 1A. As explained in Section 4.4.1 of the Supplemental Evidence, the additional capacity from Tilbury 1A will no longer be available.

Send-out from Tilbury Base Plant for Cold Weather Demand

Date	Maximum Daily Send-Out Volume (MMcf/day)	Existing Base Plant Capacity with T1A 0.6 BCF	Derated Capacity of Base Tank 0.35 BCF
30-Dec-21	23.6	4%	7%
31-Dec-21	23.4	4%	7%
6-Jan-22	28.9	5%	8%
7-Jan-22	3.7	1%	1%
19-Dec-22	6.1	1%	2%
20-Dec-22	40.3	7%	12%
21-Dec-22	51.2	9%	15%
22-Dec-22	74.8	12%	21%
23-Dec-22	69.9	12%	20%
24-Dec-22	3.6	1%	1%
24-Feb-23	28.8	5%	8%
25-Feb-23	2.1	0%	1%
20-Apr-23	10.2	2%	3%
11-Jan-24	37.3	6%	11%
12-Jan-24	67.7	11%	19%
13-Jan-24	61.6	10%	18%
14-Jan-24	7.9	1%	2%

145.5 Based on the response to the previous question, please explain whether the cold weather event referenced corresponds closely to FEI's design peak day (defined as the coldest day expected to occur once every 20 years).

145.5.1 If the cold event is close to the design peak day, please clarify whether FEI currently has sufficient peaking capacity to meet demand on the coldest day, and whether the proposed increase to 200 MMcf/day of capacity from the Tilbury Base Plant is necessary.

Response:

The cold weather event that occurred in January 2024 was a multi-day cold weather event that resulted in high levels of customer demand. January 12, 2024 was very close to meeting FEI's design peak day criteria.

During the cold weather event, the Pacific Northwest region experienced several supply reliability challenges (due to unplanned outages) and energy emergencies that affected all regional pipelines. In particular, there were unplanned outages on the TransCanada Foothills, and Gas

Transmission Northwest (GTN) (which impacts the Pacific Northwest region) systems, as well as at the JPS facility. LNG resources at Tilbury and Mt. Hayes helped FEI manage its system in response to dramatic changes in the actual hourly weather during this event that impacted customer demand, while also providing supply to manage outages related to the above-noted regional supply resources. This event demonstrates the important role of LNG resources in maintaining reliable supply for FEI's customers during cold weather events given their real time dispatchability, which helps FEI to manage the changing conditions that can unfold during cold weather events.

Please also refer to the response to BCUC IR5 118.1.

145.6 Similarly, please explain whether the coldest winter observed from 2019 to 2024 corresponds closely to FEI's design year.

145.6.1 If the coldest winter is close to the design year, please clarify whether FEI currently has sufficient peaking storage to meet demand on the coldest year, and whether the proposed 1 Bcf of storage from the Tilbury Base Plant is necessary.

Response:

Design forecasts are based on statistical extremes and not recent trends. FEI has not experienced a design year winter; however, the absence of a peak design load winter in recent years does not reduce the probability of such an event occurring.

The design temperature for the Lower Mainland region is -13.2 degrees Celsius. On December 27, 2021, the average day temperature was recorded at -12.7 degrees Celsius, the coldest relative to the Lower Mainland design temperature. The following table provides the observed cold days in the past five winters with average daily temperature below zero. Several observations can be made from the recorded weather data:

1) The number of cold days has been increasing;
2) The observed total Heating Degree Days (HDD), which measures how cold a weather event has been, has doubled in the past five years compared to prior periods; and
3) The duration of the cold periods ranges from 5 to 12 days.

FEI has been managing the gas supply during these cold weather events with existing Tilbury LNG supply and market area resources in a less cost-effective way. As discussed in Section 3.3.4.2 of the Supplemental Evidence, FEI's peaking requirements exceed Tilbury's current capacity. The weather data in the table below provides further support for FEI's assessment that additional peaking supply is required. FEI's design load changes annually as the ACP model is updated, which FEI uses to proactively plan its gas supply portfolio to ensure operational readiness. Based on this modelling, the proposed 1 Bcf of storage that will be provided by the TLSE Project is necessary and beneficial for FEI’s customers. FEI’s gas supply portfolio has included LNG storage since 1971, which is now at its end of life. Further, the expected costs associated with the T-South pipeline capacity are expected to increase due to Enbridge’s Sunrise Expansion Project, providing additional benefit associated with optimizing the gas supply portfolio.

Winter	Year	Month	Day	LML Temp (Celsius)	HDD18	Total HDD	Number of Days
2019/2020 Winter	2019	Nov	29-Nov	-0.35	18	212	10
	2019	Nov	30-Nov	-0.82	19		
	2019	Dec	1-Dec	-0.46	18		
	2020	Jan	12-Jan	-0.06	18		
	2020	Jan	13-Jan	-6.26	24		
	2020	Jan	14-Jan	-8.96	27		
	2020	Jan	15-Jan	-6.40	24		
	2020	Jan	16-Jan	-4.07	22		
	2020	Jan	17-Jan	-4.25	22		
	2020	Feb	4-Feb	-0.30	18		
2020/2021 Winter	2020	Dec	24-Dec	-0.98	19	161	8
	2021	Jan	23-Jan	-0.27	18		
	2021	Feb	9-Feb	-1.97	20		
	2021	Feb	10-Feb	-3.08	21		
	2021	Feb	11-Feb	-3.87	22		
	2021	Feb	12-Feb	-4.51	23		
	2021	Feb	13-Feb	-2.06	20		
	2021	Feb	14-Feb	-0.27	18		
2021/2022 Winter	2021	Dec	17-Dec	-0.59	19	349	15
	2021	Dec	20-Dec	-1.58	20		
	2021	Dec	21-Dec	-2.72	21		
	2021	Dec	25-Dec	-4.14	22		
	2021	Dec	26-Dec	-9.73	28		
	2021	Dec	27-Dec	-12.71	31		
	2021	Dec	28-Dec	-10.67	29		
	2021	Dec	29-Dec	-8.48	26		
	2021	Dec	30-Dec	-6.20	24		
	2021	Dec	31-Dec	-7.18	25		
	2022	Jan	1-Jan	-6.05	24		
	2022	Jan	5-Jan	-3.26	21		
	2022	Jan	6-Jan	-1.87	20		
	2022	Feb	22-Feb	-1.42	19		
	2022	Feb	23-Feb	-2.59	21		
2022/2023 Winter	2022	Feb	24-Feb	-1.02	19	454	21
	2022	Nov	28-Nov	-0.28	18		
	2022	Nov	29-Nov	-2.08	20		
	2022	Dec	1-Dec	-4.61	23		
	2022	Dec	2-Dec	-3.99	22		
	2022	Dec	3-Dec	-0.62	19		
	2022	Dec	4-Dec	-1.54	20		
	2022	Dec	5-Dec	-3.22	21		
	2022	Dec	18-Dec	-3.08	21		
	2022	Dec	19-Dec	-8.95	27		
	2022	Dec	20-Dec	-9.30	27		
	2022	Dec	21-Dec	-10.58	29		
	2022	Dec	22-Dec	-10.52	29		
	2022	Dec	23-Dec	-4.59	23		
	2023	Jan	29-Jan	-0.69	19		
	2023	Jan	30-Jan	-2.73	21		
	2023	Jan	31-Jan	-0.39	18		
	2023	Feb	22-Feb	-0.65	19		
	2023	Feb	23-Feb	-2.42	20		
	2023	Feb	24-Feb	-3.90	22		
	2023	Feb	25-Feb	-1.31	19		
2024/2025 Winter	2024	Jan	11-Jan	-2.59	21	436	20
	2024	Jan	12-Jan	-11.65	30		
	2024	Jan	13-Jan	-9.72	28		
	2024	Jan	14-Jan	-6.55	25		
	2024	Jan	15-Jan	-4.16	22		
	2024	Jan	16-Jan	-3.09	21		
	2024	Jan	17-Jan	-1.54	20		
	2024	Jan	18-Jan	-1.27	19		
	2025	Feb	2-Feb	-1.20	19		
	2025	Feb	3-Feb	-4.47	22		
	2025	Feb	4-Feb	-4.51	23		
	2025	Feb	5-Feb	-4.84	23		
	2025	Feb	6-Feb	-2.67	21		
	2025	Feb	7-Feb	-4.35	22		
	2025	Feb	8-Feb	-0.83	19		
	2025	Feb	9-Feb	-1.35	19		
	2025	Feb	10-Feb	-2.48	20		
	2025	Feb	11-Feb	-3.88	22		
	2025	Feb	12-Feb	-3.62	22		
	2025	Feb	13-Feb	-1.28	19		

1

145.7 Please indicate whether there have been instances when the Tilbury Base Plant send-out reached 150 MMcf/day. If so, please specify when these instances occurred and explain the reasons for the high send-out (e.g., maintenance activities, cold weather, etc.).

Response:

FEI has not recently experienced a peak day weather event in the Lower Mainland. The only example of send-out as high as 150 MMcf/d was during a test run conducted for a few hours on November 25, 2024. Regardless, the absence of a peak day weather event in recent years does not reduce the potential for it to occur in a future year or alleviate the need for FEI to retain sufficient resources to serve this peak.

In response to BCUC IR 139.2.1, FEI stated:

> For example, the current ACP portfolio includes approximately 1.7 PJ (1.5 Bcf) of daily priced supply received at Kingsvale/East Kootenay, with a daily volume up to 100 TJ (88 MMcf) transacted through peaking call options. This amount of supply is needed in a design year. … FEI would not implement this buying strategy at Huntington/Sumas, as the market characteristics are different. For example, if FEI did not have Tilbury currently in the supply stack of the ACP portfolio, FEI would be left with trying to secure 150 MMcf/d of peaking supply under "spot market transactions". … [Emphasis added]
>
> As the figure below shows, the actual supply received by FEI in the past three years was between approximately 11,000 to 42,000 GJ/day (10 to 37 MMcf/day). [Emphasis added]

In response to BCUC IR 139.3, FEI stated:

> … FEI could not replace 150 MMcf/d and 0.6 Bcf of peaking supply in the market. Relying on the spot market for all of FEI's peaking supply would be a significant deviation from FEI's longstanding practice of relying on on-system resources and would put its firm customers at a significant risk of losing service.
>
> […]
>
> … and FEI has never attempted to buy this much supply (i.e., up to 150-200 MMcf/day on cold days at Sumas).

On page 33 of the Raymond Mason Report, Mason stated:

> … the NGTL West Path pipeline expansion ("NGTL Expansion") has been approved, underpinned by 250 MMcf/d of firm service contracts. … This expansion could represent incremental SCP take away capacity if the SCP were to expand through compression/looping. … All SCP expansion initiatives would provide the benefit of newer infrastructure than the T-South alternative, and would diversify FEI's supply and access to supply.

145.8 Please elaborate on the concept of a call option in the context of a gas supply contract and explain its operational mechanism.

Response:

Call options allow FEI to request deliveries of the contracted quantity from counterparties on any day during the Delivery Period (i.e., December to February). The contract specifies the number of days (e.g., 15 days) that FEI can exercise the option during the Delivery Period. The daily quantity delivered is no greater than the contracted quantity specified in the contract. FEI pays a demand charge (call option premium) to the counterparty to reserve the option to receive additional supply when it is needed. If FEI executes the call option, FEI pays for the commodity supplied under the contract at a price that is tied to the daily index at the market hub where FEI receives the supply.

There are some important differences between the call option arrangements described above and on-system LNG which can pose risks to the gas supply portfolio, including:

- FEI must notify the counterparties one business day in advance to execute on these call options. Not having the ability to call or adjust the volumes on these arrangements during the day hinders FEI's ability to manage load fluctuations and exposes FEI to price risk and supply risk.
- There are limited counterparties that would structure these types of arrangements so there are risks to the portfolio if FEI's call option requirements continue to increase.
- While FEI considers the call options at East Kootenay to be a tool to help diversify and optimize the portfolio, they cannot replace on-system LNG requirements due to the constraints described above.

145.9 Please indicate the year in which FEI first includes 100 TJ/day of supply from East Kootenay in its ACP portfolio. Additionally, please explain the extent to which the inclusion of 100 TJ/day from East Kootenay in the ACP portfolio is due to Mist storage recall.

Response:

FEI first included 100 TJ/d of peaking supply from East Kootenay in its ACP portfolio in the 2020/2021 gas year when FEI took Southern Crossing Pipeline (SCP) capacity back from NW Natural, who was holding 52.6 TJ/d (approximately half of the SCP capacity). The incremental SCP capacity allowed FEI to increase the seasonal supply from AECO/NIT for Lower Mainland customers, replacing the East Kootenay seasonal supply that was included in previous ACPs. The change in SCP capacity resulted in the need for East Kootenay peaking supply with up to 100 TJ of spot supply. Because of the short-duration but high-deliverability on the day, FEI transacted peaking call options, anticipating the supply would only be required when the design winter weather occurs.

FEI made the decision to take the SCP capacity back from NW Natural because, at the time, it was the most cost-effective means of diversifying its supply portfolio away from its heavy reliance on the T-South system, and was needed to serve increasing demand in the Lower Mainland caused by Transportation Service customers returning to FEI's bundled service.

While the Mist storage recall was always a known risk for FEI, it had no material bearing on the decision to include East Kootenay peaking supply in its ACP portfolio.

145.10 When FEI's actual supply received from East Kootenay is significantly lower than 100 TJ/day (e.g., between 10 and 37 MMcf/day), please clarify whether the remainder of the contracted capacity is simply unused.

145.10.1 If the remaining capacity is unused, please discuss whether FEI could allocate part of that unused East Kootenay supply to offset the capacity requirements currently assigned to the Tilbury Base Plant in the ACP portfolio.

Response:

A portion of the 100 TJ/d of East Kootenay peaking supply was unused; however, as explained below, any remaining capacity cannot simply be used to offset capacity requirements currently assigned to the Tilbury Base Plant in the ACP portfolio.

- First, the 100 TJ/d of East Kootenay peaking supply is required to meet "design-day" weather conditions. While it is common for actual weather to deviate from the planning weather scenario, FEI (like other utilities) must nonetheless plan for the design day weather scenario to occur. Even though FEI did not experience peak day weather, resulting in actual usage of the East Kootenay capacity being lower than the planned quantity in the ACP, FEI did experience short periods with weather close to design conditions.

- Second, FEI has been able to access intra-day interruptible capacity on the TC system to move gas from AECO over the past three years, thus avoiding calling on East Kootenay peaking supply. This approach was more cost effective than paying the contracted pricing for East Kootenay supply. However, the availability of interruptible capacity depends on the ongoing operation conditions of the TC system, and FEI cannot plan the ACP portfolio on the basis that unknown interruptible capacity will be available.
- Third, the ACP portfolio optimization model currently sizes resource requirements based on the assumption that 0.6 Bcf of LNG will be available to meet the demand. Therefore, replacing the capacity currently assigned to the Tilbury Base Plant would increase the required peaking supply from East Kootenay in the model. As discussed in the response to BCUC IR6 145.9, FEI's gas supply strategy is to secure physical resources to serve the demand since replacing existing physical assets with market area commercial deals will increase both costs and risk to FEI's customers and deviate from ACP objectives. The volume of gas that FEI can reasonably secure from the commercial marketplace is also limited by the counterparty's willingness to execute these arrangements at various market hubs, depending on the characteristic of each hub.

145.11 Please discuss whether FEI has the ability to contract additional capacity from East Kootenay beyond the current 100 TJ/day.

Response:

Given the current pipeline constraints on the SCP (250 MMcf/d or 270 TJ/d), FEI does not have the ability to contract additional supply from East Kootenay beyond the current 100 TJ/d. FEI currently contracts 170 TJ/d of AECO supply and 100 TJ/d of East Kootenay supply, both of which FEI transports on the SCP. Together, the East Kootenay and AECO contracted supplies, at 270 TJ/d, fill the capacity of the SCP.

145.12 Please discuss whether FEI could diversify the replacement of the 150 MMcf/day capacity requirement at the Tilbury Base Plant across multiple sources, such as East Kootenay, Station 2, the AECO/NIT spot market, or through a portion of the 250 MMcf/day available from the NGTL Expansion.

Response:

No, as discussed in Section 3.3.4.3 of the Supplemental Evidence and the response to BCUC IR6 145.11, FEI cannot replace the existing Tilbury Base Plant gas supply with market resources such as Station 2, AECO/NIT, East Kootenay or the NGTL expansion, because each of the suggested supply sources would require transmission capacity on the T-South, TC NGTL, TC Foothills and/or SCP systems. All of these pipelines are fully contracted at FEI connection points and, as such:

1) Large volume long-term contracts on existing infrastructure are not available;

2) Replacing on-system Tilbury LNG supply with spot supply from market area resources (i.e., Mist and/or JPS) would require further expansion of the existing pipeline or storage infrastructure beyond any currently planned expansions; and

3) Any additional pipeline or storage capacity expansions, or trying to secure resources in the secondary market, would have significant associated costs for FEI.

146.0 Reference: PROJECT NEED

Exhibit B-63, BCUC IRs 23.1, 23.2, 86.1, 119.2, 127.5

Tilbury Phase 1B and Phase 2 LNG Expansion Project

In response to BCUC IR 119.2, FEI stated:

> Any increased liquefaction capacity built as part of the Tilbury Phase 2 LNG Expansion Project will be dedicated to the customer or market that the plant is built to support, and would not be available to support FEI's non-LNG customers on a planned basis as part of its ACP. Further, the Tilbury 1A liquefaction facility was constructed to support the transportation fueling market (including marine fueling) and has sufficient capacity to maintain the required LNG inventory in the Tilbury 1A tank to support expected RS 46 sales. Similar to the increased liquefaction from the Tilbury Phase 2 LNG Expansion Project, Tilbury 1A storage will not be available to support FEI's non-LNG customers on a planned basis as part of its ACP.

In response to BCUC IR 127.5, FEI stated:

> The Tilbury Base Plant tank is operating at a reduced operating level of 0.35 Bcf due to seismic reasons, and FEI is relying on 0.25 Bcf of supply from the Tilbury 1A tank as a stop-gap measure (i.e., FEI is relying on LNG storage that is intended to serve RS 46 sales under Special Direction No. 5). Changing market conditions, along with the approval of the Tilbury Jetty and the anticipated delivery of an LNG marine bunker vessel to service the Port of Vancouver, have resulted in an expected increase in RS 46 sales.

146.1 Please provide an update regarding plans for the Phase 1B liquefaction facility, including the status of any outstanding permitting, as well as the anticipated timing for construction and operation.

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

FEI continues to evaluate the potential to expand liquefaction capacity at Tilbury through the construction of the Phase 1B liquefaction facility; however, the construction of the Phase 1B facility is dependent on a positive final investment decision for the Tilbury Marine Jetty (owned by Tilbury Jetty General Partnership), as well as market conditions. Market conditions for the marine fueling market are favourable. FEI observes:

- An increasing number of LNG duel-fueled vessels built and on order;
- A growing number of LNG-fueled vessels calling the Port of Vancouver;[1]
- LNG pricing that is favourable to conventional fuels;

[1] https://www.portvancouver.com/article/first-cruise-ship-refuels-lng-vancouver-important-step-forward-journey-reduce-emissions-and.

- LNG bunkering vessels available in the Port of Vancouver for fueling service; and
- Growing volumes of LNG delivered under RS 46 to Seaspan's bunker vessels.[2]

Following a positive final investment decision on the Tilbury Marine Jetty, FEI will advance engineering and permitting activities on Phase 1B. While the timing of construction and commercial operations is contingent on a positive final investment decision, the Phase 1B liquefaction facility could enter construction as early as 2027 and enter service as early as 2030.

Please also refer to the response to BCUC IR5 119.1.

146.2 Please provide the typical volume of LNG required by marine transportation fueling customers that are anticipated to berth at the Tilbury Jetty. If marine transportation fueling customers will be served by LNG stored within the proposed TLSE tank, how long will it take to refill the TLSE tank following delivery of LNG to a typical marine transportation customer?

Response:

FEI intends to serve marine fueling customers using Tilbury 1A and 1B liquefaction and the Tilbury 1A storage tank, as these facilities were authorized to be constructed pursuant to Direction No. 5 to the BCUC for the purpose of LNG sales. The TLSE tank, in contrast, is proposed to support FEI's resiliency and gas supply needs.

FEI expects that the typical volume of LNG required by a single marine transportation customer could range from several hundred cubic meters (truck-to-ship fueling) up to the capacity of marine bunker vessels which is expected to be between 7,500 m^3 and 18,000 m^3 (ship-to-ship fueling).

In response to BCUC IR 23.1, FEI stated:

> The Liquefaction Facility [the liquefaction component of the Phase 2 Project Environmental Assessment] may or may not require storage, and if the TLSE Project were unavailable the storage could be constructed by the party developing the Liquefaction Facility. There is, however, a potential benefit to FEI customers of using the TLSE Project to provide storage for LNG from the Liquefaction Facility.

[2] At the time of preparing these IR responses, FEI had provided LNG for 8 bunker vessel loadings, facilitated by Seaspan's temporary loading manifold.

In response to BCUC IR 23.2, FEI stated:

> The 3 Bcf storage tank proposed in the TLSE Project and the Liquefaction Facility would be physically connected through piping. The proposed 3 Bcf storage tank requires both BCUC and EA approval. However, the TLSE Project tank and the Liquefaction Facility have different purposes.
>
> The purpose of the TLSE Project is to address the resiliency needs of FEI customers. The TLSE Project components are summarized in Table 5-1 and described in detail in Section 5 of the Application. The purpose of the Liquefaction Facility is to provide LNG as a transportable and storable low carbon-intensity fuel for use in the marine fueling or export markets. This may ultimately require some form of LNG storage, which may be provided by the TLSE tank if approved. If the TLSE tank is not approved, and if LNG storage is required to support the Liquefaction Facility, the LNG storage could be built and paid for by the entity developing the Liquefaction Facility.

In response to BCUC IR 86.1, FEI stated:

> If the Liquefaction Facility is constructed, it would require storage to operate. FEI had intended to convey that the Liquefaction Facility may not necessarily need new storage. <u>If a smaller Liquefaction Facility were built to further support sales under Rate Schedule 46 (i.e., LNG as a low carbon transportation fuel), then it may be possible to leverage the existing Tilbury 1A storage capacity</u>.
>
> However, if the Liquefaction Facility <u>were constructed to support larger volume LNG shipments</u>, it would require additional storage capacity. If the TLSE Project is approved and constructed, the party developing the Liquefaction Facility could seek to obtain that storage contractually from FEI, including the remaining 1 Bcf of storage discussed in the preamble, subject to ensuring FEI's resiliency and/or supply and operational requirements are maintained. Any such contract would be subject to further BCUC oversight. [Emphasis added]

146.3 Please provide the currently anticipated capacity for the Phase 2 Expansion Liquefaction Facility. Please explain whether the Phase 2 Expansion Liquefaction Facility will be constructed to "further support sales under Rate Schedule 46" or "to support larger volume LNG shipments" or for some other purpose.

<u>Response:</u>

The maximum capacity proposed for the Phase 2 Liquefaction Facility is 2.5 million tonnes per annum (MTPA); however, at this time, development has not progressed to the point of narrowing the facility's anticipated capacity or which market it will serve.

146.4 Please confirm which LNG storage tank at the Tilbury site will store LNG produced by the Phase 2 Expansion Liquefaction Facility (i.e. Tilbury 1A or the TLSE tank).

146.4.1 Please explain whether FEI considers there to be sufficient space at the Tilbury site to construct another LNG storage tank in the future, in addition to the proposed TLSE tank.

Response:

While FEI does not have any plans to utilize the TLSE Project to provide LNG storage capacity for the Phase 2 Expansion Liquefaction Facility, at this time, development of the Phase 2 Expansion Liquefaction Facility has not progressed to the point of narrowing the facility's anticipated capacity or which market it may ultimately serve. The Phase 2 Expansion Liquefaction Facility was included in the ongoing environmental assessment for the Tilbury Phase 2 LNG Expansion Project, in part, because all potential emission sources must be identified for the Tilbury site. FEI notes the following:

- Should the Phase 2 Liquefaction Facility be used to support regulated sales under RS 46, FEI anticipates that the Tilbury 1A tank would be used, consistent with its purpose to support transportation markets.
- Should the Phase 2 Liquefaction Facility be built larger to support the export market, it would require additional storage as noted in the preamble. It is physically possible to configure the facility to access LNG stored in the TLSE tank or the Tilbury 1A tank as well. However, the use of the TLSE tank or the Tilbury 1A tank for that purpose would be subject to further BCUC oversight and FEI's gas supply and resiliency needs otherwise being met.

Under the current site build out configuration, there would not be sufficient space to construct an additional LNG storage tank at the Tilbury site in addition to the TLSE tank without acquiring additional land.

146.5 Please confirm how much LNG storage volume is required for the Phase 2 Expansion Liquefaction Facility (in m3 of LNG or equivalent Bcf of natural gas units).

Response:

The volume of LNG storage required for a liquefaction facility is dependent on the market that is being serviced by that liquefaction, as follows:

- For a bulk export market, the LNG storage volume required would, at minimum, need to be equal to the volume of the vessel taking service from the facility less the LNG produced during the loading process. Some buffer would be ideal to allow for short unplanned outage events. For example, a 100,000 m^3 vessel may require up to 2 Bcf of storage capacity.

- For a marine bunkering market, the LNG storage volume would need to be large enough to allow for yearly plant maintenance activities, thereby ensuring ongoing service for marine fueling customers. For example, a plant with 0.65 MTPA of capacity could require up to 0.9 Bcf.

As explained in the response to BCUC IR6 146.4, development of the Phase 2 Expansion Liquefaction Facility has not progressed to the point of narrowing the facility's anticipated capacity or which market it may ultimately serve. However, if the facility were built to support regulated sales to the marine fueling market, FEI expects that the Tilbury 1A tank would be sufficient.

146.6 Please explain how FEI can continue to provide 1 Bcf of gas supply reserve, and the associated gas supply benefits, while also potentially providing LNG storage capacity for the Phase 2 Expansion Liquefaction Facility.

Response:

In Section 4.4.1.5.5 of the Application, FEI discussed an option to lease storage space to a third-party as a potential benefit to FEI customers. In particular, FEI presented a hypothetical scenario where additional pipeline capacity into the Lower Mainland (e.g., through an SCP expansion) could potentially reduce the size of the resiliency reserve, thus allowing FEI to lease storage space and recover a portion of the TLSE Project's cost of service while maintaining sufficient resiliency to sustain the system in response to a winter T-South no-flow event.

As explained in Section 3 of the Supplemental Evidence, the TLSE Project is needed for both resiliency and gas supply purposes which, as the expanded alternative analysis demonstrates, are best addressed by the Preferred Alternative (i.e., a 2 Bcf resiliency reserve and 1 Bcf for gas supply). If these needs were to change in the future (e.g., a reduction in peak demand), FEI could consider re-allocating a portion of the 3 Bcf tank by leasing storage space to a third-party to support the proposed Phase 2 Expansion Liquefaction Facility. FEI could also consider leasing the tank storage to a third-party if the associated benefits outweighed having additional LNG peaking supply provided by the 1 Bcf gas supply reserve. In either case, leasing the storage space in the TLSE tank would be the subject of BCUC review and approval.

At this time, FEI does not have any plans to utilize the TLSE Project to provide LNG storage capacity for the Phase 2 Expansion Liquefaction Facility.

146.7 Please confirm, or explain otherwise, that FEI included the entire 1 Bcf of gas supply reserve, and the associated gas supply benefits, when determining the PV and levelized total rate impact of Alternative 9 (i.e. PV and levelized total rate impact of Alternative 9 does not take into consideration that the TLSE Project allocates LNG storage capacity to the Phase 2 Expansion Liquefaction Facility).

Response:

Confirmed. The gas supply benefits associated with the entirety of the 1 Bcf of gas supply reserve (i.e., the third Bcf under Supplemental Alternative 9) are included in the calculation of the PV and levelized total rate impact over the 67-year analysis period. The analysis does not consider allocating any of the TLSE Project storage capacity to the Tilbury Phase 2 Liquefaction Facility.

The hypothetical scenario where FEI sells storage capacity from the TLSE tank is only a potential risk mitigation approach in the future if the full capabilities of the TLSE Project were not required for FEI's gas supply, operational and resiliency requirements. FEI notes that the response to BCUC IR2 86.1 (referenced in the preamble above) is only highlighting the fact that if there was a contract with a third party to obtain storage capacity from the TLSE Project in the future, subject to FEI meeting its resiliency, supply and operational requirements, the contract would be subject to BCUC oversight and approval.

146.8 Please explain whether it is necessary to determine the required capacity of the Phase 2 Expansion Liquefaction Facility and the Phase 1B liquefaction facility prior to proceeding with the TLSE project.

Response:

It is not necessary to determine the capacity of the Phase 2 Expansion Liquefaction Facility or Phase 1B liquefaction facility prior to proceeding with the TLSE Project for the reasons below.

1) As discussed in Section 3 of the Supplemental Evidence, the TLSE Project is needed to mitigate the significant resiliency risk posed by a winter no-flow event on T-South and to ensure dependable peaking supply to be able to serve firm customers during normal operations, as the existing Tilbury Base Plant has done for more than 50 years. This need is independent from, and not contingent upon, the Phase 2 Expansion or the Phase 1B liquefaction facilities. As demonstrated by the expanded alternatives analysis, the Preferred Alternative (a 3 Bcf tank with 800 MMcf/d of regasification capacity) delivers on the Project objectives in a way that provides superior customer value.

2) The Phase 1B liquefaction facility does not require any additional LNG storage from the TLSE tank, as it will rely on the existing Tilbury 1A tank.

3) As discussed in the response to BCUC IR1 23.2, the Phase 2 Expansion Liquefaction Facility is not dependent on the approval or construction of the TLSE tank nor is the TLSE Project dependent on the approval or construction of the Phase 2 Expansion Liquefaction Facility. The Phase 2 Expansion Liquefaction Facility was included in the ongoing environmental assessment for the Tilbury Phase 2 LNG Expansion Project, in part, because all potential emission sources must be identified for the Tilbury site. Further, while FEI identified a potential future use of the TLSE Project to support the Phase 2 Liquefaction Facility should it serve export markets, such use would be subject to BCUC approval and oversight and FEI otherwise being able to meet its gas supply, operational and resiliency needs. Moreover, as discussed in the responses to BCUC IR6 146.3 and 146.6, the development of the Tilbury Phase 2 Liquefaction Facility has not progressed to the point of narrowing the facility's anticipated capacity or which market it will serve, and FEI does not currently have any plans to provide LNG storage capacity for the Phase 2 Expansion Liquefaction Facility. Therefore, the sizing of the Phase 2 Liquefaction Facility is not relevant to proceeding with the TLSE Project.

147.0 Reference: PROJECT NEED

Exhibit B-60, p. 53.

Economic impact of a T-South no-flow event

On page 53 of Exhibit B-60, FEI states:

> PwC's key findings in respect of the impacts associated with a T-South no-flow event are explained in Section 2.2 of the 2024 Resiliency Plan. In short, PwC has estimated that a single incident on any segment of T-South (AV-1, AV-2, AV-3 or AV-54) during an average winter in the Lower Mainland would result in catastrophic economic harm well in excess of the cost of the Preferred Alternative.

147.1 If FEI did not construct the proposed TLSE Project and a T-South no-flow event occurred in the future, please discuss whether FEI considers that it would be liable for the economic harm that would be experienced by FEI's customers if there was a loss of service.

Response:

No, FEI does not believe it would be liable for the economic harm. Without purporting to address legal causes of action and defenses exhaustively, it is clear that FEI cannot construct the TLSE Project without BCUC approval. FEI is taking reasonable steps in making its case for why the BCUC should approve the TLSE Project, including by filing the 2024 Resiliency Plan and independent expert evidence quantifying the significant expected harm and high cumulative probability of a no-flow event. FEI believes the evidence supporting investment to mitigate this significant known customer outage risk is compelling, and that the TLSE Project as proposed provides cost-effective resiliency. However, it is ultimately up to the BCUC to determine whether the significant level of risk at present is nonetheless acceptable in light of the Project cost.

B. RESILIENCY PLAN

148.0 Reference: RESILIENCY PLAN

Exhibit B-63, BCUC IR 120.4

Pipeline Separation

In response to BCUC IR 120.4, Exponent states:

> Based on review of the CER Interactive Pipelines Map, for at least 123 km, the AV-1, AV-2, AV-3 and AV28 54 pipelines are separated by distances greater than 4.5 m, sometimes as much as a kilometer. Assuming these larger separations have zero probability of simultaneous failure due to landslides, the maximum probability of simultaneous failure for the referenced pipelines reduces to 0.87 (excluding 123 km out of 917 km). It is our view that both pipelines will not always fail in the same landslide, thus engineering judgement was used to reduce the probability of simultaneous failure from 0.87 to 0.65.

148.1 Please confirm that Exponent has assumed that both pipelines would not fail due to landslides where the separation is greater than 4.5m, or explain otherwise.

<u>Response:</u>

The following response has been provided by Exponent:

While Exponent does not know the exact separation distance along the entire pipeline, we have used engineering judgement in combination with our review of typical pipeline separation distances to assume the rate of simultaneous failure based on general separation distances. Exponent has not explicitly assumed that both pipelines would not fail due to landslides where the separation distance exceeds 4.5 m. For pipelines separated a distance greater than 4.5 m, simultaneous pipeline ruptures due to a nearby landslide would depend on local soil factors, topography, the size of the landslide, and whether any site-specific measures were in place. There are instances in which neither pipeline will fail, other instances in which only one pipeline will fail, and other instances in which both pipelines are likely to fail. Exponent considers that it would be impractical to perform a more granular analysis of the issue at a system-wide level, and that the uncertainty in a more granular calculation would remain even if such an analysis were to be performed. Therefore, informed by general knowledge about separation distances, Exponent considers our general assumption regarding the probability that both pipelines fail simultaneously to be appropriate.

148.2 Please provide further support for Exponents view that both pipelines will not always fail in the same landslide, including whether this is supported by industry data.

<u>Response:</u>

The following response has been provided by Exponent:

While Exponent is not aware of industry data regarding parallel pipeline performance in landslides, if the pipelines are far apart near the location of the landslide, they are unlikely to both fail because the landslide is unlikely to affect both pipelines. The example below (50°44'53.65"N, 120°51'18.55"W) shows a large separation distance near Enbridge Compressor Station 07.[3]

[3] https://www.arcgis.com/apps/webappviewer/index.html?id=2d11fd4e6a7a4f4ba7fe6bdf51ae52de; approximate location shown in isometric view.

148.3 For segments of looped pipeline with larger separations, please discuss whether it is expected that the regulatory shutdown period for certain hazards (such as internal failures) would be reduced.

Response:

The following response has been provided by Exponent:

Exponent would expect that the regulatory shutdown period would be reduced for segments of looped pipelines with larger separations (for internal hazards), however, this is ultimately for the regulator to determine. We would expect a regulator to make an assessment of the failure type and potential impact on other pipelines and consider past performance, such as the 2018 T-South rupture incident. Exponent did not explicitly consider variable regulatory shutdown periods in its original analysis as we considered the 3 days provided by FEI to be reasonable and representative, however, variability in the regulatory shutdown period was considered in the response to BCUC IR5 120.6.

149.0 Reference: RESILIENCY PLAN

Exhibit B-63, BCUC IRs 120.6, 120.9

Regulatory Shutdown Period

In response to BCUC IR 120.6, Exponent stated:

> Exponent has conducted an analysis in which the regulatory shutdown period is a random variable, with probabilities indicated in the below table and figure:

Regulatory Shutdown Period [days]	Probability
0.5	0.02381
1.0	0.047619
1.5	0.071429
2.0	0.095238
2.5	0.119048
3.0	0.142857
3.5	0.142857
4.0	0.119048
4.5	0.095238
5.0	0.071429
5.5	0.047619
6.0	0.02381

149.1 Please explain the basis for the probabilities in the above table.

<u>Response:</u>

The following response has been provided by Exponent:

The basis of the probabilities of different regulatory shutdown periods was using an average duration around the 3 days assumed in Exponent's original analysis, and then assuming some uncertainty. The shortest regulatory shutdown period for the non-impacted pipeline could be just 1 day or less, if post incident investigation and mitigation efforts were streamlined (lower bound with less than 10% chance). The longest regulatory shutdown that Exponent estimated was approximately 6 days, assuming reasonable conservative estimates for post incident investigation and mitigation effort related delays (upper bound, with less than 10% chance). The purpose of this analysis was to illustrate that considering uncertainty in the regulatory shutdown period does not have a significant impact on the losses if the mean regulatory shutdown period is similar to the assumed deterministic value used in the original analysis.

In response to BCUC IR 120.9, Exponent states:

> The regulatory shutdown period may depend on the hazard, in particular if the hazard poses access difficulties or if the regulator is overwhelmed responding to multiple incidents in a broader region, which is more likely to occur during an earthquake than other hazard such as non earthquake induced landslides. The duration of a regulatory shut-down following a non-earthquake induced landslide could be longer or shorter than following an internal failure. A non-earthquake induced landslide that occurs close to a population center will likely be resolved more quickly than an internal failure that occurs further from a population center, and vice-versa.

149.2 Please clarify whether there is likely to be a difference in the regulatory shutdown period for a non-earthquake induced landslide and an internal failure, assuming the same incident location.

Response:

The following response has been provided by Exponent:

The period of regulatory shutdown could vary based on multiple factors, including the incident site location, type and cause of failure, ease of access to the pipeline post incident, feasibility of investigation/mitigation efforts, etc. Exponent estimates that the regulatory shutdown period for both non-earthquake induced landslide and an internal failure would likely fall within the range considered in the study conducted in the response to BCUC IR5 120.6. Besides the nature/root cause of the pipeline failure, multiple other factors including the incident site location, ease of access to the pipeline post incident, feasibility of investigation/mitigation efforts, etc. as well as various other non-engineering factors, would likely govern the overall likely period of the regulatory shutdown.

The regulatory shutdown period is highly likely to be longer than the existing resiliency capabilities.

150.0 Reference: RESILIENCY PLAN

Exhibit B-63, BCUC IR 123.1

Residual Risk Characterization and ALARP Determination

In response to BCUC IR 123.1, FEI stated:

> For the purposes of the 2024 Resiliency Plan and Supplemental Evidence, FEI defines "Lower Mainland" as including all of Metro Vancouver and the parts of the Fraser Valley that are fed by FEI's Coastal Transmission System (i.e., downstream of FEI's Huntingdon Control Station in Abbotsford). The Fraser Valley population centres included within FEI's definition of "Lower Mainland" include Abbotsford and Mission.
>
> The risk from a T-South no-flow event facing the parts of the Fraser Valley not included in FEI's definition of the "Lower Mainland" (e.g., Chilliwack and Hope) will not be mitigated by the TLSE Project. With the TLSE Project in place, the risk exposure facing these parts of the Fraser Valley is represented in Exponent's risk analysis as a subset of the residual T-South risk (i.e., the T-South risk with the TLSE Project in place).
>
> As noted in the response to BCUC IR5 117.2, within the ALARP framework suggested in the information requests, FEI would characterize the residual risk of a T-South no-flow event after the Preferred Alternative is in place as being as low as reasonably practicable (ALARP) such that no additional resiliency-driven investments are necessary. Any future investments in resiliency would thus be predicated on some change (e.g., technology change or a project with a non-resiliency driver) that made it practicable to reduce the risk further.

150.1 Please provide the total number of FEI customers located in the Fraser Valley communities not included within FEI's definition of the "Lower Mainland".

Response:

FEI provides service to approximately 40,000 firm customers located in the Fraser Valley communities that are not included within FEI's definition of the "Lower Mainland".

150.2 Please describe the methodology and criteria FEI used to determine that the residual T-South supply outage risk to these excluded communities meets the ALARP threshold. In the response, please: a) Identify the risk metrics and thresholds applied; b) Summarize the quantitative or qualitative assessments performed; and c) indicate whether this determination was reviewed by any third-party consultant or FEI internal risk committee.

Response:

The methodology FEI used to determine that the residual T-South supply outage risk to these excluded communities meets the ALARP threshold was to consider the risk facing the excluded communities within the context of the total residual T-South no-flow risk.

The total residual T-South risk consists of the residual risk facing the excluded communities, as well as the residual risk facing Lower Mainland customers that will receive mitigation from the Preferred Alternative (Supplemental Alternative 9).[4] As discussed in Table 1 of the response to BCUC IR5 117.3, with the Preferred Alternative in place, the total residual T-South risk to FEI's entire system is considered within the ALARP zone. As the total residual risk is considered ALARP, then the excluded community level contribution to the residual risk, which is a smaller subset of the total residual risk, is also considered to be within the ALARP zone.

To contextualize the T-South risk facing all excluded communities (i.e., all communities that will not receive mitigation from the Preferred Alternative in response to a winter T-South no-flow event), FEI requested that Exponent prepare the following figure which shows the breakdown of the residual T-South risk for each Supplemental Alternative. The darker segment of each bar on the right-hand side is the residual risk from the excluded communities that will not receive mitigation from the given Supplemental Alternative, and the remainder of the bar shows the residual Lower Mainland risk. The full bar represents the total residual T-South risk. As can be seen, the residual risk from the excluded communities is a very small subset of the total residual T-South risk.

Figure 1 below shows the expected annual winter-only GDP loss in million CAD per year for T-South (AV-1, -2, -3, and -54) for the Tilbury Alternatives. The darker segment of each bar is the residual risk from customers not served by the Tilbury facility. The remainder of the bar shows the Lower Mainland risk.

[4] With the Preferred Alternative in place, Lower Mainland customers will still face a residual T-South risk from the scenarios where the T-South no-flow duration exceeds the duration of support from the Preferred Alternative.

Figure 1: Expected Annual Winter-only GDP Loss in Million CAD for T-South

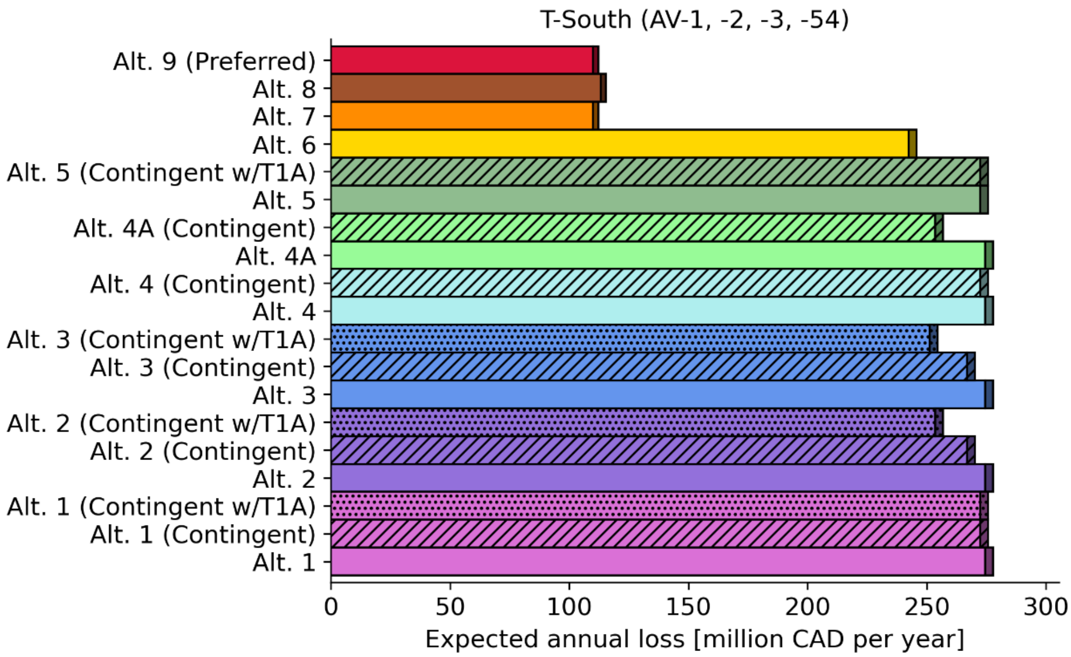
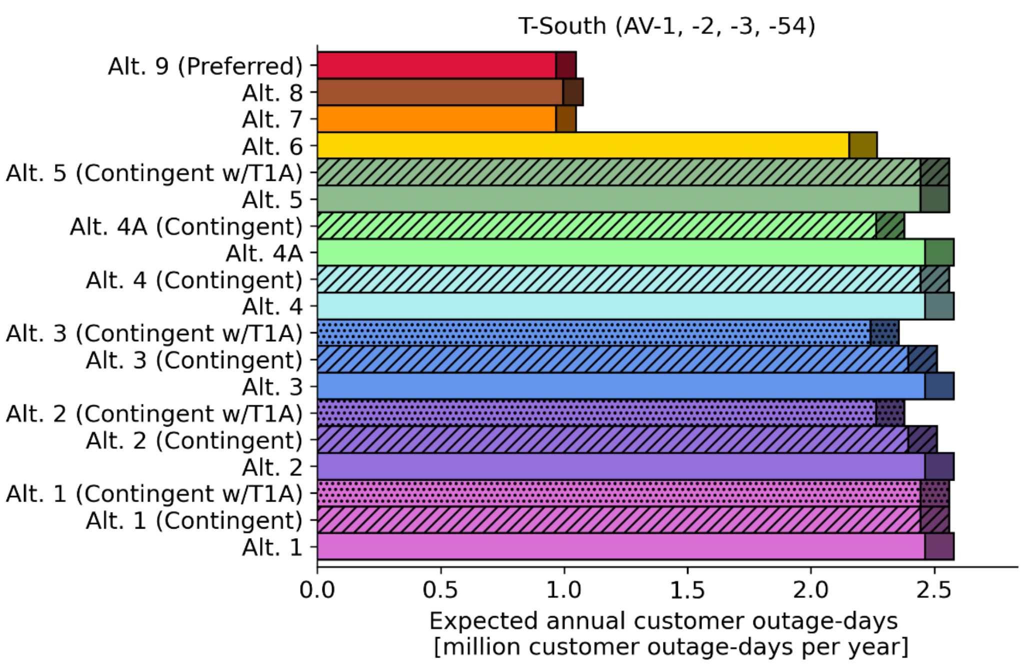


Figure 2 below shows the expected annual winter-only customer outage-days per year for T-South (AV-1, -2, -3, and -54) for the Tilbury Alternatives. The darker segment of each bar is the residual risk from customers not served by the Tilbury facility. The remainder of the bar shows the Lower Mainland risk.

Figure 2: Expected Annual Winter-only Customer Outage-Days for T-South



150.3 Please explain whether FEI considered any incremental resiliency-driven investments specifically for the excluded Fraser Valley areas either as part of the TLSE Project or in parallel.

150.3.1 If incremental resiliency-driven investments were considered specifically for the excluded Fraser Valley areas, please list and describe the options evaluated. For each option identified, please describe a) the scope and scale of the deployment considered; b) the estimated capital and operating costs; c) the potential impact on outage duration or consequence metrics; and d) the reasons FEI did or did not pursue these options.

150.3.2 If FEI did not assess any temporary or localized resiliency options for the excluded Fraser Valley communities, please explain why not.

Response:

FEI notes that the Fraser Valley area is similar to a number of other communities through the interior part of British Columbia that are served off the T-South pipeline, such as Merritt, Logan Lake or Ashcroft.

Depending on the location of the incident along the T-South pipeline, these communities may still be served as they were during the 2018 T-South Incident. During the 2018 T-South Incident, as the rupture was north of the Kingsvale tap, FEI was able to flow sufficient gas from the TC Energy system across FEI's Southern Crossing Pipeline and the Kingsvale Oliver 323 pipeline and into the Enbridge system at Kingsvale. This flow of gas was sufficient to keep communities between the rupture location and the Kingsvale tap served and online for the duration of the incident. This has been included in the overall risk modelling and contributes to these communities being considered in the ALARP zone.

The findings from the 2024 Resiliency Plan and the Supplemental Evidence did not support incremental resiliency-driven investments specifically for the excluded Fraser Valley areas. In particular, FEI assessed the risk of a T-South no-flow event at the system level, not at the community level (i.e., FEI calculated the total system risk, not the individual risk facing each impacted community). As such, when investigating supplemental alternatives to mitigate the risk, FEI's approach was to identify a single project that would mitigate the system level risk, as opposed to distributed projects providing mitigation to each individual community impacted by a T-South no-flow event. This is consistent with the BCUC's guidance in the Adjournment Decision to consider system resiliency holistically.[5]

[5] Adjournment Decision and Order G-62-23, pp. 51-52. For example, the Panel determined that it required a resiliency plan that addressed issues such as "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?" [Emphasis added]

Moreover, as supported by the analysis in Table 1 of the response to BCUC IR5 117.3, with the Preferred Alternative in place, the residual system level T-South risk was reduced to ALARP, which further supports studies at a more granular or community level not being warranted.

150.4 Please explain whether FEI has developed any long-term resiliency planning strategy for these communities beyond the TLSE Project, and if not, what criteria would trigger such planning in the future.

Response:

FEI's long-term resiliency planning strategy for these communities is to re-assess the need for a resiliency-driven project through any future updates to the Resiliency Plan, if required.

FEI noted in the 2024 Resiliency Plan that the plan may require updates from time to time to reflect any material changes to the risk profile.[6] Should a subsequent Resiliency Plan identify the need for FEI to investigate a potential resiliency-driven project targeted at these communities (e.g., due to an increase in risk), then, as was done for the TLSE Project, FEI would likely evaluate the merits of the potential project based on the unmitigated risk, the amount of risk mitigation provided by the proposed project, and the ratio of risk mitigation provided relative to the project's associated cost of service.

Another circumstance that may trigger FEI to investigate a resiliency project for these communities is the need for a project with non-resiliency drivers which would either provide, or could be expanded to provide, improved resiliency.

[6] 2024 Resiliency Plan, Section 9.

C. EXPANDED ALTERNATIVES ANALYSIS

151.0 Reference: EXPANDED ALTERNATIVES ANALYSIS

Exhibit B-63, BCUC IR 129.5.2, BCUC IR 129.5.3, BCUC IR 123.1.1

Underutilized Asset Risk

In response to BCUC IRs 129.5.2 and 129.5.3, FEI stated:

> Due to the unique versatility of on-system storage, there is negligible risk that the Preferred Alternative would be underutilized if market conditions were less favourable to selling excess supply. […] FEI would use on-system LNG as a substitute for other supply resources when optimizing its resource portfolio, thus maximizing the continued utilization of the TLSE Project and leveraging the versality [sic] of its on-system storage assets for the benefit of FEI's customers.

151.1 Please explain what is meant by "unique versatility" when referring to on-system LNG storage and compare the versatility of on-system storage to other supply resources.

151.1.1 Please identify any outage scenarios where other supply resources may be more beneficial for FEI and its customers.

<u>Response:</u>

The reference to the "unique versatility" of on-system LNG storage in the responses to BCUC IR5 129.5.2 and 129.5.3 was in response to issues raised regarding the risk of the TLSE Project being underutilized in the long term. In particular, the operational features of on-system LNG storage make the TLSE Project a resource that would continue to be used and highly useful. For example, on-system LNG storage can immediately respond (i.e., maximum deliverability in real time) to hourly changes in weather and gas demand, which helps ensure there is balance in the system and that system pressure is maintained so as to maintain reliability to customers. This versality contrasts with other supply resources that require commercial arrangements with up-stream pipeline companies and off-system storage operators that must be made 24 hours prior to receipt, or those that necessitate inefficient utilization (due to underutilized capacity in non-winter months) without similarly immediate deliverability. Moreover, there is no supply resource that achieves a greater reduction in risk associated with a winter T-South no-flow event across the system than the TLSE Project.

Even if FEI's annual demand were to fall over time, the TLSE Project will continue to be needed for system resiliency and gas supply purposes, and could also be used to support continued demand for LNG in the region over the life of the asset for the benefit of customer rates (e.g., mitigating excess LNG into the market and/or leasing a portion of the TLSE tank to a third-party).

Further, in response to BCUC IRs 129.5.2 and 129.5.3, FEI states:

> FEI adjusts its ACP annually, which allows it to adjust or shed resources that are no longer needed due to changes in demand or load duration curves. For example, because FEI optimizes the utilization of ACP resources for all gas customers in the Lower Mainland, Interior and Vancouver Island regions, having extra peaking supply available in the Lower Mainland could potentially displace a portion of market area supply contracted for the Interior on cold winter days. In essence, the only way that this asset would be stranded is if there is both: (a) <u>less than 3 Bcf of demand on FEI's entire system</u>; and (b) no market to sell in to. This is extremely unlikely to occur over the life of the TLSE Project. [Emphasis added]

In response to BCUC IR 123.1.1, FEI stated:

> For the purposes of the 2024 Resiliency Plan and Supplemental Evidence, FEI defines "Lower Mainland" as including all of Metro Vancouver and the parts of the Fraser Valley that are fed by FEI's Coastal Transmission System.
>
> […] The risk from a T-South no-flow event facing the parts of the Fraser Valley not included in FEI's definition of the "Lower Mainland" (e.g., Chilliwack and Hope) will not be mitigated by the TLSE Project.

151.2 Please confirm, or explain otherwise, that the usefulness of the TLSE Project from a gas supply perspective is dependent on the demand on FEI's entire system and not specifically the Lower Mainland.

<u>Response:</u>

Confirmed that the TLSE Project will remain utilized and in the service of FEI customers as long as there is customer demand on the system generally (i.e., FEI would be able to use the TLSE Project in service of Interior demand even in a hypothetical circumstance where there was no load in the Lower Mainland). FEI optimizes its gas portfolio taking into consideration regional demand and all resources available, including on-system LNG. In addition to providing peaking gas supply to Lower Mainland customers, send-out from the TLSE Project could be used to displace the T-South supply designated to the Lower Mainland and/or upstream of the Lower Mainland in order to divert the T-South supply to the Interior if needed. This provides a valuable option for gas supply operation to balance the system under volatile winter weather conditions.

152.0 Reference: EXPANDED ALTERNATIVES ANALYSIS

Exhibit B-60, Section 6.4, p. 203; Section 4.5.4, p. 130, Table 4-9

Amortization Period Sensitivity

On page 203 of Exhibit B-60, FEI states:

> FEI continues to believe, based on the discussion in Section 4.5.5 of this Supplemental Evidence, that the TLSE Project will provide both resiliency and gas supply benefits for customers for the duration of its 60-year post-commissioning expected service life. However, to be responsive to the BCUC's commentary, FEI has also provided sensitivities based on a shorter amortization period by increasing the depreciation rates of the assets. FEI has performed an ancillary financial evaluation of the TLSE Project based on the PV of the incremental revenue requirement and the levelized total rate impact over a 27-year analysis period (including the construction years) assuming all new assets related to the Project will be fully depreciated (or amortized) by 2050.

In Table 4-9 on page 130 of Exhibit B-60, FEI provides a summary of capital costs, cost of service, gas supply costs/savings and levelized total rate impacts for the feasible supplemental alternatives considering a 67 year life of the assets.

	Alt 4 - 0.6 BCF 150 MMcf/d (No resl)	Alt 4A - 1 BCF 400 MMcf/d (No resl)	Alt 8 - 2 BCF 800 MMcf/d (1.4 BCF resl)	Alt 9 - 3 BCF 800 MMcf/d (2 BCF resl)
Total Capital Costs during Construction, As-Spent $ ($000s)	826,921	893,199	1,030,287	1,140,962
PV of Cost of Service, excl. Gas Supply Costs/Savings ($000s) over 67 years	790,047	892,612	1,133,983	1,240,821
PV of Gas Supply Cost/Savings ($000s) over 67 years	(366,362)	(517,554)	(366,362)	(517,554)
Total PV of Cost of Service over 67 years ($000s)	**423,685**	**375,059**	**767,621**	**723,267**
Levelized Total Rate Impact (Incl. Cost of Gas) 67 years (%)	1.44%	1.27%	2.60%	2.45%
Levelized Total Rate Impact (Incl. Cost of Gas) 67 years ($/GJ)	0.134	0.118	0.242	0.228

152.1 Please recreate the above table considering a 27-year analysis period and explain whether a shorter amortization favours a supplemental alternative aside from the preferred alternative.

Response:

Please refer to Table 1 below for a comparison of Supplemental Alternatives 4, 4A, 8, and 9 based on a 27-year analysis period assuming all new assets related to the TLSE Project will be fully amortized by 2050 (i.e., in-service for 20 years plus a 7-year construction period). All other assumptions, including the capital and annual operating cost estimates as well as the annual gas supply costs/savings remain the same as the financial analyses completed over the 67-year analysis period.

Table 1: Summary of Capital Costs, Cost of Service, Gas Supply Costs/Savings, and Levelized Total Rate Impacts for Supplemental Alternatives over 27-Years Analysis Period

	Alt 4 - 0.6 BCF 150 MMcf/d (No resl)	Alt 4A - 1 BCF 400 MMcf/d (No resl)	Alt 8 - 2 BCF 800 MMcf/d (1.4 BCF resl)	Alt 9 - 3 BCF 800 MMcf/d (2 BCF resl)
Total Capital Costs during Construction, As-Spent $ ($000s)	826,921	893,199	1,030,286	1,140,962
PV of Cost of Service, excl. Gas Supply Costs/Savings ($000s) over 27 years	781,402	869,990	1,084,485	1,199,207
PV of Gas Supply Cost/Savings ($000s) over 27 years	(235,136)	(339,861)	(235,136)	(339,861)
Total PV of Cost of Service over 27 years ($000s)	**546,267**	**530,129**	**849,350**	**859,346**
Levelized Total Rate Impact (Incl. Cost of Gas) 27 years (%)	2.26%	2.19%	3.51%	3.56%
Levelized Total Rate Impact (Incl. Cost of Gas) 27 years ($/GJ)	0.211	0.204	0.327	0.331

As shown in Table 1 above, when all assets related to the TLSE Project are assumed to be fully amortized by 2050, the PV of total cost of service of Supplemental Alternative 8 becomes slightly lower than Supplemental Alternative 9 by approximately $10 million. This small difference in PV over the 27-year analysis period is equivalent to approximately 0.05 percent or $0.004 per GJ in terms of levelized total rate impact, which is a difference of only approximately 36 cents per year for an average residential customer with 90 GJ of annual consumption. In fact, as shown in the response to BCUC IR6 156.1, within approximately two more years (i.e., a 29-year analysis period versus a 27-year analysis period), the PVs of Supplemental Alternatives 8 and 9 would be essentially equal.

The analysis in Table 1 above shows that even in the very adverse hypothetical scenario where the TLSE Project would only be useful post-commissioning for 20 years, the rate impact of Supplemental Alternative 9, which provides an additional 1 Bcf of LNG storage, is only slightly higher than Supplemental Alternative 8. Further, to the extent that, as FEI expects, the TLSE Project continues to operate beyond 20 years, Supplemental Alternative 9 will become increasingly more beneficial financially than Supplemental Alternative 8, thus offsetting the costs for the additional 1 Bcf of LNG storage. As discussed in Section 4.5.5 of the Supplemental Evidence, FEI does not consider it reasonable to assume that the TLSE Project will cease to be used and useful after 20 years. Therefore, the likelihood that Supplemental Alternative 8 will be better financially than Supplemental Alternative 9 is small.

152.2 Please discuss who should bear the cost (i.e., ratepayers or shareholders) in the event that the useful life of the TLSE Project is less than the expected lifespan of the TLSE Project.

Response:

If the TLSE Project is determined to be in the public interest and granted a CPCN, then in accordance with the UCA and the regulatory compact, FEI is legally entitled to recover prudently incurred costs and to be provided with an opportunity to earn a return on and of its invested capital.

Public utilities like FEI recover their prudently incurred capital (i.e., earn a return of capital) through depreciation expense. In the normal course, the BCUC sets depreciation rates based on the expected life of assets, as determined by a depreciation study. At the end of the expected life of the asset, the utility will have recovered all of its prudently incurred invested capital via accumulated depreciation expense, thereby meeting the “return of capital” requirement of the regulatory compact. This does not change even if the asset is retired early whether it is due to normal operation or other circumstances that are not within the control of FEI.

In the event that the TLSE Project assets are no longer used and useful in the future, FEI will follow the accepted practice for normal asset accounting for write-off and recover any remaining costs associated with the assets from customers through rates – i.e., when assets are retired, an accounting entry is done crediting plant in service and debiting accumulated depreciation, with any remaining net book value for the retired assets assigned to accumulated depreciation for recovery in future depreciation expense. The subject of retirement/asset losses and their recovery has been thoroughly explored in past FEI regulatory proceedings. As referenced in the response to BCUC IR1 40.5, in the BCUC’s decision on FEI’s 2012-2013 RRA, the BCUC approved the recovery of under-recovered depreciation (referred to as “Asset Losses”)[7]:

> The Commission Panel notes that in this case a number of factors resulted in the Asset Losses and there was no evidence of asset misuse by the Utilities. **Therefore, the Panel directs that the Asset Losses be recovered from ratepayers, as proposed, in current depreciation rates.**

Considering the value that the assets will continue to provide so long as some load remains on FEI’s system, and the mitigation options available in the hypothetical event that FEI no longer needs the assets for its own gas supply or resiliency purposes, FEI considers it very unlikely that the TLSE assets would be retired early.

[7] FortisBC Energy Utilities (FEU) 2012-2013 RRA Decision, p. 88.

153.0 Reference: EXPANDED ALTERNATIVES ANALYSIS

Exhibit B-63, BCUC IRs 130.3, 130.1

Resiliency When No-Flow Event is Too Long to Bridge

In response to BCUC IR 130.3, FEI stated:

> The average number of winter no-flow events on T-South over 20-, 23-, 60- and 67-year horizons is calculated and reported in the table below. These are calculated using the average of the upper bound and lower bound failure rates for T-South.

Mitigation Alternative	Residual Winter No-Flow Events in 23 years	Residual Winter No-Flow Events in 20 years	Residual Winter No-Flow Events in 67 Years	Residual Winter No-Flow Events in 60 years
Alternative 4 (Planning)	2.3	2.0	6.8	6.1
Alternative 4 (Contingent)	2.3	2.0	6.8	6.1
Alternative 4A (Planning)	2.3	2.0	6.8	6.1
Alternative 4A (Contingent)	2.2	1.9	6.3	5.7
Alternative 8	1.0	0.8	2.8	2.5
Alternative 9 (Preferred)	0.9	0.8	2.8	2.5

> For Supplemental Alternatives 7, 8, and 9, there is a residual risk of approximately 40% of the unmitigated risk. While this represents a still-significant risk, 60% of the risk has been mitigated, which is substantial and consistent with, for example, the widespread implementation of covered conductors to reduce wildfire risk in Southern California.

In response to BCUC IR 130.1, FEI states:

> Between 24 and less than 72 hours there is uncertainty as to whether implementing a controlled shutdown is possible. Therefore, if the Tilbury facility provides more than 24 hours but less than 72 hours of support, then the AV is analysed under both cases.

153.1 Please confirm, or explain otherwise, that the numbers in the table above represent the expected number of T-South no-flow events that would not be bridged by the stored LNG volume for each viable alternative.

153.1.1 If not confirmed, please reproduce the table with the expected number of T-South no-flow events that would not be bridged by the stored LNG volume for each viable alternative.

153.1.2 If confirmed, please explain why Alternatives 8 and 9 have the same expected number of T-South no-flow events that would not be bridged by the stored LNG volume over the lifespan of the Project.

Response:

The following response has been provided by Exponent:

Confirmed. However, Exponent clarifies that the number of T-South no-flow events are similar for Supplemental Alternatives 8 and 9, but not the same. For example, we note 1.0 vs 0.9 difference for Alternative 8 vs Alternative 9 under the 1st column. The other column numbers are similar and within the 1st decimal level accuracy levels.

It is also noted that there is an additional benefit at colder temperatures for Supplemental Alternative 9 compared to Supplemental Alternative 8 because it provides additional supply that can bridge the regulatory shutdown period, which is not captured in the results at average winter temperatures, i.e., the table shown above. See Section 9 of Exponent's report for the results of this cold temperature analysis.

153.2 Please explain what is meant by "there is a residual risk of approximately 40% of the unmitigated risk." For example, is the response to BCUC IR 130.3 referring specifically to residual non-safety risk?

153.2.1 Please explain whether this is considered to be an acceptable level of residual risk, and if so, how this was determined to be acceptable.

Response:

The following response has been provided by Exponent:

Estimates of the risk for Supplemental Alternatives 8 and 9 indicate that approximately 60% of the risk in Supplemental Alternatives 4 and 4A is mitigated, leaving a residual risk of approximately 40%. This refers to GDP and customer outage days, as Exponent did not consider fatality risk.

FEI provides the following response to BCUC IR6 153.2.1:

FEI considers the residual risk resulting from the implementation of Supplemental Alternatives 7, 8, and 9 to be as low as reasonably practicable. Please refer to the response to BCUC IR5 117.3 for further discussion on FEI's classification of the residual T-South risk with each of the Supplemental Alternatives in place.

153.3 Please elaborate on the implementation of covered conductors to reduce wildfire risk in Southern California and provide any relevant references.

153.3.1 Please discuss the relevance of the implementation of covered conductors to reduce wildfire risk in Southern California, and the corresponding level of risk mitigation, to the TLSE Project.

Response:

The following response has been provided by Exponent:

Conductors with a covering polymer are becoming a popular mitigation technique to reduce wildfire risk. The cover conductor reduces the likelihood of arcing between phases if they slap together or if objects bridge between them. Arcing can lead to melting the cover polymer material, and in the presence of dry brush, an ignition can occur, potentially leading to a wildfire.

There are varying levels of mitigation effectiveness for covered conductors, depending on the regime in which they are implemented. For example, a covered conductor will not reduce the wildfire risk if implemented in a location without much debris or where the conductor spacing is large compared to a location where there is ample debris and small spacing between the conductors (more likely to have contact or debris bridging).

The covered conductor example was given in response to BCUC IR5 130.3 to illustrate another type of mitigation for natural disasters that partially, but not fully, mitigates risk.[8]

153.4 Please reproduce the table above to show the anticipated number of uncontrolled shutdowns that would occur for each viable alternative following a no-flow event. In the response, please discuss the methodology used to determine the number of uncontrolled shutdowns and explain whether the uncertainty in the length of time required to achieve a controlled shutdown (i.e., 24 to 72 hours) is included.

Response:

The following response has been provided by Exponent:

The average number of winter uncontrolled shutdowns on T-South over 20-, 23-, 60- and 67-year horizons is calculated and reported in the table below, for average winter temperatures:

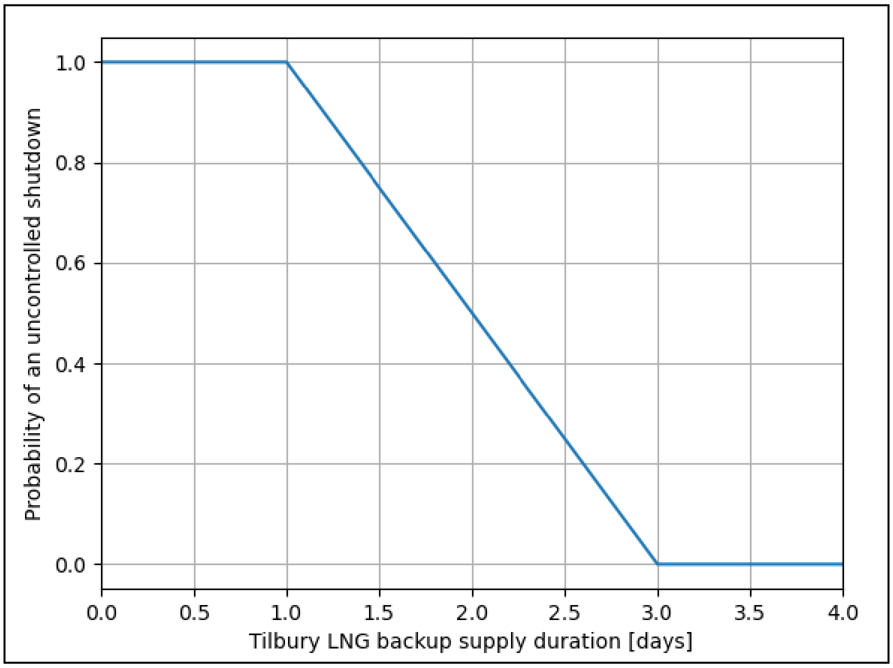
[8] See additional information here: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/wildfire-mitigation/2022_WMP_Update_Attachment_6_CC_Effectiveness_Workstream_R0.pdf.

Mitigation Alternative	Winter Uncontrolled Shutdowns in 23 Years	Winter Uncontrolled Shutdowns in 20 Years	Winter Uncontrolled Shutdowns in 67 Years	Winter Uncontrolled Shutdowns in 60 Years
Alternative 4 (Planning)	0.6	0.6	1.9	1.7
Alternative 4 (Contingent)	0.6	0.6	1.9	1.7
Alternative 4A (Planning)	0.6	0.6	1.9	1.7
Alternative 4A (Contingent)	0.4	0.3	1.1	1.0
Alternative 8	0.0	0.0	0.0	0.0
Alternative 9 (Preferred)	0.0	0.0	0.0	0.0

For a given hazard, AV, and alternative, the annual expected number of uncontrolled shutdowns is calculated as the product of the probability of an uncontrolled shutdown and the annual failure rate. The total number of annual uncontrolled shutdowns on T-South is the sum of uncontrolled shutdowns for each hazard for each of AV-1, -2, -3, and -54.

The probability of an uncontrolled shutdown for a given AV and alternative is calculated as follows:

- If the AV has controlled shutdowns without the Tilbury Facility, the probability of an uncontrolled shutdown is always 0. This is the case for AV-1 and AV-2.
- For other AVs, if the load support duration is less than 1 day, the shutdown will always be uncontrolled (P[uncontrolled] = 1). If the load support duration is greater than 3 days, the shutdown will always be controlled (P[uncontrolled] = 0).
- Otherwise, the probability of a controlled shutdown depends on the load support duration and is given by Figure U.2 in Appendix U, reproduced below. P[uncontrolled] decreases linearly from 1 at 1 day of load support duration to 0 at 3 days of load support duration.



Probability of an uncontrolled shutdown
1.0
0.8
0.6
0.4
0.2
0.0
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
Tilbury LNG backup supply duration [days]

154.0 Reference: EXPANDED ALTERNATIVES ANALYSIS

Exhibit B-63, BCUC IRs 22.6, 131.5, 131.6, 131.7; Exhibit B-60, p. 200

Avoided Gas Cost

In response to BCUC IR 131.5, FEI stated:

> FEI has the Gas Supply Mitigation Incentive Program (GSMIP) in place, which aligns the interests of customers and shareholders as a method for FEI to capture market opportunities on unutilized assets (commodity, storage and pipeline/transportation) provided for in the ACP. FEI optimizes contracted ACP assets on a daily and seasonal basis in order to meet firm core load for customers in Rate Schedules 1 to 7 and 46. In particular, FEI enters into commercial transactions with counterparties and market participants to extract value out of the unutilized assets, capturing these mitigation activities in the GSMIP and recovering costs in the Midstream Cost Reconciliation Account (MCRA).

In response to BCUC IR 131.6, FEI stated:

> FEI considers it reasonable to assume, for the purposes of determining avoided gas supply costs in the financial analysis, that FEI would be able to generate some mitigation revenue in non-peak periods from holding pipeline capacity.

In response to BCUC IR 22.6, FEI stated:

> The remaining 1 Bcf of the TLSE storage may be able to generate revenue; however, FEI is unable to speculate on this opportunity at this time as it is subject to multiple factors, including the following:
>
> - FEI has no historical data to utilize because FEI has not generated a significant amount of GSMIP revenue from the Tilbury Base Plant due to its relatively small tank size and its storage being primarily reserved for managing customer load on the coldest days of the winter or for emergency situations; and
> - Market conditions in the region that help generate revenue as part of the GSMIP are constantly changing, making it difficult to foresee what revenue could be generated.
>
> The TLSE Project is based on an identified need for system resiliency in the Lower Mainland region, and the GSMIP was not a factor in FEI proposing the need for the Project.

On page 200 of Exhibit B-60, FEI states:

> In preparing the updated financial evaluation of the Preferred Alternative (3 Bcf of LNG storage capacity and 800 MMcf/d of regasification), FEI has also included the gas supply benefits that were discussed in Section 4.5.4.1.2 of the Supplemental Evidence as avoided costs…

FEI discussed the gas supply benefits in the Application, as well as throughout the regulatory process prior to the Adjournment Decision; however, the original financial evaluation in the Application did not include the benefits of avoided costs, as the focus at that time was on the delivery rate impact only. FEI considers it reasonable and appropriate to include the gas supply benefits in the updated financial evaluation as part of this Supplemental Evidence to provide a more fulsome evaluation of the Preferred Alternative's total impact on customer bills, including both delivery rates and cost of gas.

154.1 Please confirm that FEI's updated financial evaluation of the Preferred Alternative, which includes the allocation of 1 BCF of LNG storage to gas supply for planning purposes, assumes that all gas supply benefit revenue generated using the proposed TLSE LNG tank goes to the benefit of the ratepayer.

154.1.1 If not confirmed, please explain.

Response:

For clarity, FEI did not forecast any offsetting revenue generated from the 1 Bcf of LNG storage allocated to gas supply as part of the updated financial analysis for the Preferred Alternative. Rather, FEI's forecast includes the avoided gas cost that would otherwise be required to replace FEI's current peaking gas supply requirements of 1 Bcf, paired with 200 MMcf/d that are currently being met through temporary and sub-optimal measures. These measures, described in FEI's ACPs, will either: (i) not be available in the future (due to the demolition of the Tilbury Base Plant, losing access to incremental LNG volumes from Tilbury 1A, and/or the lack of excess pipeline capacity from regional market infrastructure to replace existing measures); or (ii) will entail more expensive peaking gas supply options (e.g., triggering a regional infrastructure upgrade or a mix of both load shedding and expensive call options on the cold days of the year). The benefit of these avoided costs flow to the ratepayer.

As shown in Figure 4-7 and Table 4-11 of the Supplemental Evidence, FEI estimates that the annual cost of holding peaking supply requirements of 1 Bcf paired with 200 MMcf/d after 2035 could range from $63 million (assuming a regional storage upgrade) to $79 million (assuming a regional pipeline expansion) in the absence of Supplemental Alternative 9 (the Preferred Alternative).[9] In other words, having the Preferred Alternative in service could avoid annual peaking gas supply costs in the range of $63 million to $79 million from 2035 onwards. By avoiding these costs, customers will have lower bills than if FEI did not construct the TLSE Project.

To be conservative, FEI used the lower end estimate of $63 million as the avoided peaking gas supply cost in its financial evaluation; however, as set out in Table 4-9 of the Supplemental Evidence, the additional avoided cost of gas enabled by 1 Bcf being allocated to gas supply under Supplemental Alternative 9 (i.e., $151.192 million of additional avoided cost)[10] would more than

[9] For a peaking supply requirement of 0.6 Bcf paired with 150 MMcf/d (i.e., Supplemental Alternative 8), the estimated annual costs would range from $46 million to $59 million as shown in Figure 4-8.

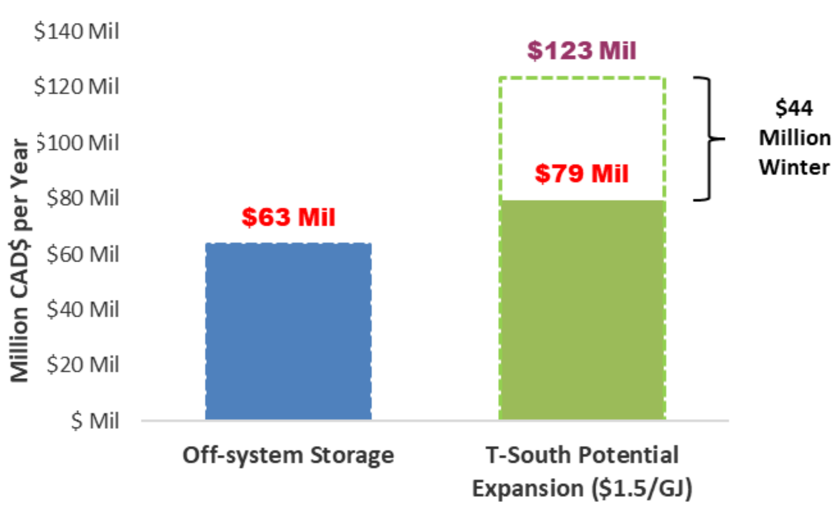
[10] Difference in the PV of Gas Supply savings over 67 years between the $517.555 million for Supplemental Alternative 9 and $366.362 million for Supplemental Alternative 8.

offset the incremental cost of service associated with the higher capital cost due to the additional 1 Bcf when compared to Supplemental Alternative 8 (i.e., $106.838 million of additional cost of service due to the higher capital cost).[11]

FEI also clarifies the mitigation revenue referenced in the preamble:

- The responses to BCUC IR5 131.5 and 131.6 relate to a scenario in which FEI is holding a peaking supply of 1 Bcf paired with 200 MMcf/d from a regional pipeline expansion <u>in the absence of the TLSE Project</u>. The cost of this scenario was illustrated in Figure 4-7 of the Supplemental Evidence (reproduced below). As discussed on page 137 of the Supplemental Evidence, FEI assumed that it would continue to seek mitigation for its gas supply costs by selling underutilized pipeline capacity into the market in non-peak times, thus reducing the total annual cost from $123 million to $79 million after mitigation.

Figure 4-7: Annual Cost (Post Mitigation) of Using Expanded Regional Infrastructure to Supply Equivalent of 1 Bcf, 200 MMcf/d



Therefore, the response to BCUC IR5 131.5 demonstrates FEI's historical success in reselling unused pipeline capacity, which supports its assumption that it would be able to continue mitigating its gas supply costs after 2035 if it is holding pipeline capacity from a regional pipeline expansion (i.e., the $44 million of winter mitigation shown in Figure 4-7). Further, the response to BCUC IR5 131.6 demonstrates that the supply/demand dynamics in the market would impact FEI's ability to resell unused pipeline capacity in the future.

If FEI is able to generate more mitigation revenue, then it would reduce the annual gas supply costs under the scenario of holding capacity from a regional pipeline expansion (i.e., reduce the $79 million in Figure 4-7), which in turn reduces the assumed benefits (i.e., avoided cost) of the TLSE Project. In other words, if the annual gas supply cost, net of mitigation for holding pipeline capacity from a regional pipeline expansion, is reduced

[11] Difference in the PV of cost of service (excluding gas supply savings) over 67 years between the $1,240 million for Supplemental Alternative 9 and $1,134 million for Supplemental Alternative 8.

below the $79 million shown in Figure 4-7, then the associated level of avoided costs enabled by the TLSE Project would be lower. However, as noted above, FEI ultimately conservatively assumes the lower end estimate of the annual gas supply costs of $63 million shown in Figure 4-7 based on the scenario of holding peaking supply capacity from a regional storage upgrade. As such, the amount of mitigation revenue assumed under the scenario of holding capacity from a regional pipeline expansion (i.e., the $44 million shown in Figure 4-7) was not actually included in the financial evaluation of any Supplemental Alternatives.

- The response to BCUC IR1 22.6, in contrast, discusses the possibility of generating mitigation revenue in the future by leveraging the capacity that could be provided by the TLSE Project if it is in-service. The potential mitigation revenue from the TLSE LNG storage is different than the revenue discussed in the responses to BCUC IR5 131.5 and 131.6. As discussed in Section 4.5.5 of the Supplemental Evidence, as well as the independent expert report of Ray Mason, it is reasonable to expect that there will continue to be ongoing demand for gas supply capacity in the Pacific Northwest region. Therefore, even in the event of extreme load declines, the TLSE Project will continue to provide value to FEI's customers, either by allocating more of the LNG storage to gas supply (thereby allowing it to substitute other more expensive supply resources) or by generating more mitigation revenue (as demonstrated in Figure 4-18 of the Supplemental Evidence). Both alternative uses will reduce FEI's gas supply costs for the benefit of its customers.
- Finally, page 200 of the Supplemental Evidence explains that gas supply benefits in the form of avoided costs are included in <u>all</u> of the financial evaluations provided in the Supplemental Evidence (i.e., the $63 million shown in Figure 4-7 as discussed above). The original financial evaluation provided in the Application filed in 2020 did not include any assumptions regarding gas supply benefits.

154.2 Please explain whether FEI intends to include gas supply benefit revenue generated using the proposed TLSE LNG tank as a mitigation activity within the GSMIP.

<u>Response:</u>

FEI does not intend to include gas supply benefit revenue generated using the 1 Bcf of TLSE LNG storage reserved for gas supply as a mitigation activity within the GSMIP at this time. On-system LNG is a valuable peaking asset in FEI's gas supply portfolio and, as discussed in Section 4.5.4.1.2 of the Supplemental Evidence, the TLSE Project will provide significant benefit in terms of avoided gas supply costs if gas infrastructure continues to expand in response to the constrained regional gas market.

In response to BCUC IR 131.7, FEI stated:

> As discussed in Section 4.5.5 of the Supplemental Evidence, even under the most extreme adverse hypothetical load loss scenarios, FEI would still be serving hundreds of thousands of customers in the Lower Mainland in 2050, with approximately 60 PJ (equivalent to approximately 53 Bcf) of Lower Mainland load per year and peak day demand of approximately 460 MMcf/d (Figure 4-12 and Figure 4-14, respectively). This is well-above the storage and regasification capacity that the TLSE Project can provide.

154.3 Please clarify why FEI states, in response to BCUC IR 131.7, that 460 MMcf/d is well-above the regasification capacity that the TLSE Project can provide if the Preferred Alternative for the TLSE Project proposes to install 800 MMCf/d regasification capacity.

Response:

FEI clarifies that 60 PJ (approximately 53 Bcf) and 460 MMcf/d of peak demand is well-above the Preferred Alternative's gas supply allocation of 1 Bcf of LNG storage and 200 MMcf/d of regasification. If the extreme hypothetical scenario, where Lower Mainland demand decreases to 60 PJ (approximately 53 Bcf) per year, were to occur, FEI would likely still hold some pipeline and market area storage capacity to serve the base load and seasonal supply and use the TLSE Project for peaking supply. Depending on the shape of the future load duration curve, the optimal amount of pipeline and storage required could be different from today.

FEI will continue to assess the optimal resource requirements in future ACPs as the load profile evolves. Having 800 MMcf/d of regasification will allow FEI to reallocate storage volume between a resiliency reserve and gas supply if the system requirements were to change in the future. In particular, the ability to increase the ACP peak day send-out above 200 MMcf/d would provide optionality for future portfolio optimization, including potentially shedding market area resources if it were cost-effective to do so.

155.0 Reference: EXPANDED ALTERNATIVES ANALYSIS

Exhibit B-63, BCUC IR 127.4

Contingent Scenarios

In response to BCUC IR 127.4, FEI states:

> The Contingent scenarios that reflect the full gas supply reserve in the new TLSE tank being available on the day of the winter T-South no-flow event (i.e., Supplemental Alternative 8 Contingent and Supplemental Alternative 9 Contingent) are not likely to represent real-life conditions.

155.1 Please confirm, or explain otherwise, that supplemental alternative analysis scenarios that assume <u>zero</u> gas supply reserve in the new TLSE tank being available on the day of the winter T-South no-flow event are also not likely to represent real-life conditions. Please discuss the benefits and drawbacks of assuming a mid-point availability (i.e. between full and empty) of contingent gas supply reserve for the purposes of supplemental alternative analysis.

<u>Response:</u>

FEI confirms that Supplemental Alternatives that assume <u>zero</u> gas supply reserve in the new TLSE tank being available on the day of the winter T-South no-flow event are not likely to represent real-life conditions. As discussed in the responses to BCUC IR6 145.1 and 145.2, LNG is the last resource that FEI calls upon to meet customer demand because it is intended to meet peak day demand. Given this role, FEI seeks to preserve its LNG storage volume as a resource of last resort; therefore, depleting it entirely during normal operations would leave FEI with little flexibility to respond to events, particularly on the day where LNG storage can be made available, unlike other resources.

However, a T-South no-flow event coinciding with a <u>significantly depleted</u> gas supply reserve may represent real-life conditions. As noted in Section 4 of Appendix C to the Supplemental Evidence, FEI took a typical utility reliability planning approach that is premised on sizing assets to be able to meet firm customer requirements consistently. With this approach it is not possible to plan for a resource to be available and dependable for two different purposes. Therefore, the Planning scenario for a given Supplemental Alternative reasonably assumes that zero volume is available from the gas supply reserve. Regardless, the conclusions of the Supplemental Evidence would not change had FEI conducted analysis assuming a mid-point availability, despite its challenges.

The challenge with using a mid-point availability (i.e., some point between full and empty) is that that the calculated level of risk mitigation will either be overestimated (i.e., in the case that the no-flow event actually occurs when the tank level is less than the mid-point) or underestimated (i.e., in the case that the no-flow event actually occurs when the tank level is greater than the mid-point). Due to the low likelihood that the no-flow event occurs when the tank level is precisely at the mid-point, using a mid-point is unlikely to represent the real-life risk mitigation conditions.

When contemplating scenarios from potentially available gas supply volumes, FEI considers it appropriate to use scenarios that represent the minimum (i.e., the Planning scenario where zero gas supply reserve is available) and maximum (i.e., the Contingent scenarios where the full gas supply reserve is available) availability. This approach bookends the two extremes of the potentially available risk mitigation, allowing FEI to conduct the alternatives analysis with a more comprehensive understanding of each Supplemental Alternative's risk mitigation capabilities.

Below, FEI explains why adopting a mid-point availability contingent scenario would not change the conclusions of the Supplemental Evidence for each of the applicable Supplemental Alternatives (i.e., Supplemental Alternatives that include a new tank with a gas supply reserve) below.

Supplemental Alternatives 4 and 4A:

As discussed in Section 4.5.1.2 of the Supplemental Evidence, FEI's scoring of the Resiliency Benefit criterion considered Supplemental Alternative 4 (Contingent) and Supplemental Alternative 4A (Contingent), both of which contemplate more LNG being available than a mid-point availability scenario. As such, using a mid-point availability scenario, which would contemplate less LNG being available, would not result in higher scores for Supplemental Alternatives 4 and 4A, and therefore would not change the conclusion of the alternatives analysis.

Supplemental Alternative 8:

FEI did not contemplate a contingent scenario for Supplemental Alternative 8 in the expanded alternatives analysis. To be responsive, FEI has conducted additional analysis on a new Supplemental Alternative 8 (Contingent-Midpoint) scenario which assumes that half the LNG allocated for gas supply is available on the day of the no-flow event and is available for resiliency. The Supplemental Alternative 8 (Contingent-Midpoint) modelling parameters are provided below in the revised Table C-23 from Section 5.4.11 of Appendix C to the Supplemental Evidence.

Revised Table C-23: Alternative 8 Planning and Contingent Modelling Scenario

Supplemental Alt 8 Modelling Scenario	Description	Resiliency Modelling Parameters	Peaking Gas Supply Allocation (Normal Operations)[1]
Supplemental Alternative 8 (Planning)	New 2 Bcf Tank (1.4 Bcf Resiliency Reserve) and 800 MMcf/d Regasification[2]	1.4 Bcf at 800 MMcf/d	0.6 Bcf at 800 MMcf/d
Supplemental Alternative 8 (Contingent-Midpoint)	New 2 Bcf Tank (1.4 Bcf Resiliency Reserve) and 800 MMcf/d Regasification	1.7 Bcf at 800 MMcf/d	0.6 Bcf at 800 MMcf/d

<u>Notes to Table:</u>

1 *On a planning basis, since the tank is only partially allocated to the resiliency reserve, FEI would be able to meet the requirements of the ACP but would not be able to achieve incremental supply benefits relative to Supplemental Alternative 1 (Planning).*

2 *When there is a resiliency reserve, on a planning basis there is dependable LNG available on occurrence of a no-flow event. Hence the resiliency modelling parameter is 1.4 Bcf.*

With respect to the Resiliency Benefit criterion, to understand the performance of Supplemental Alternative 8 (Contingent-Midpoint) relative to Supplemental Alternative 9, FEI requested that Exponent reproduce the analysis presented in Section 4.5.1.4 of the Supplemental Evidence, which determined the temperature range at which Supplemental Alternative 9 can provide at least a 3-day support duration, but Supplemental Alternative 8 cannot. FEI selected this analysis because the resiliency benefit provided by Supplemental Alternative 9 at temperatures below the average Lower Mainland winter temperature is what distinguished it from Supplemental Alternative 8 in the expanded alternatives analysis.

The analysis presented in the Supplemental Evidence found that between -6.8°C to +1.7°C, Supplemental Alternative 9 can bridge the 3-day regulatory shutdown period, but Supplemental Alternative 8 cannot. It was also found that nearly a quarter of winter days fall in the range in which Supplemental Alternative 9 can bridge the regulatory shutdown period, but Supplemental Alternative 8 cannot.

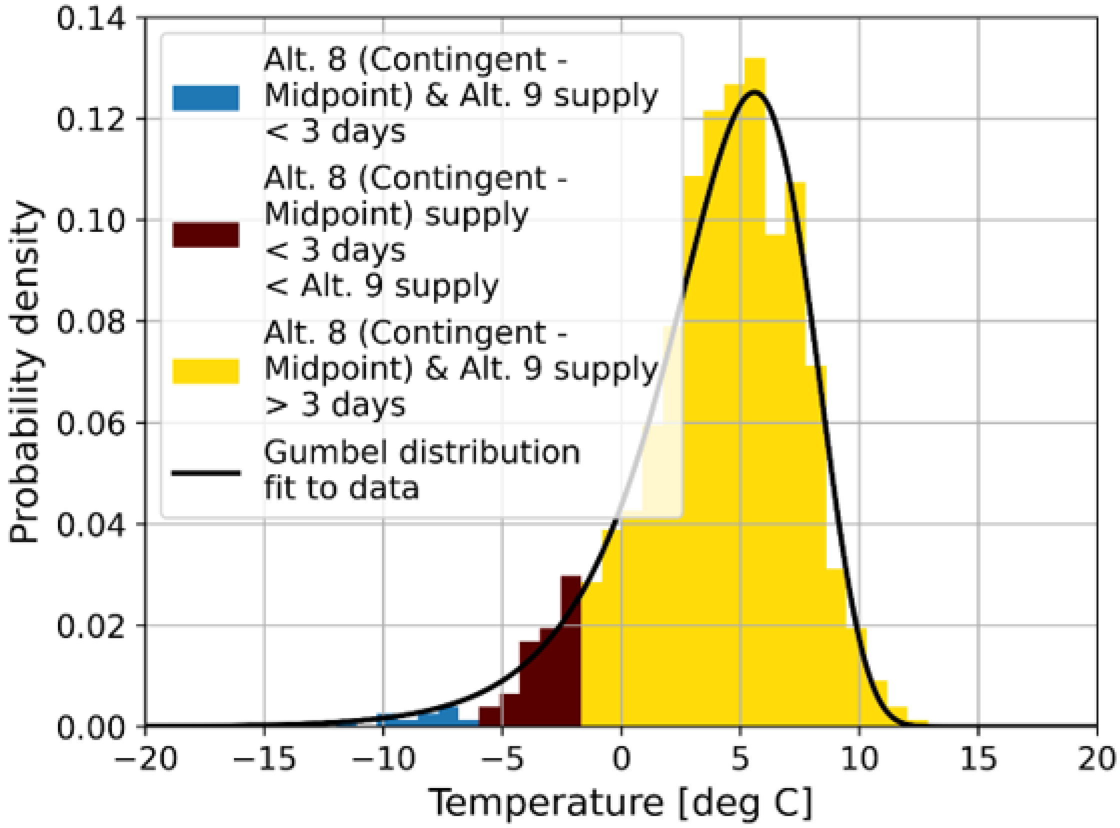
Similar to the original analysis, FEI provided Exponent with the Lower Mainland load support duration for each of Supplemental Alternatives 8, 8 (Contingent-Midpoint) and 9 at -10°C, -1.4°C, and +4°C, as shown in Revised Table 4-8 below. The results of the updated analysis conducted by Exponent are provided in Figure 1 below.

Revised Table 4-8: Load Support Duration in Days Provided by Supplemental Alternatives 8 and 9 at Different Temperatures

Temperature [degrees Celsius, °C]	Load support duration [days]		
	Alternative 8	Alternative 8 (Contingent-Midpoint)[12]	Alternative 9 (Preferred)
4	3.33	3.94	4.54
-1.4	2.54	3.04	3.5
-10	1.92	2.36	2.71

[12] Supplemental Alternative 8 (Contingent-Midpoint) load support durations were determined using linear interpolation, not using FEI's transient modelling tool.

Figure 1: Updated Variable Temperature Analysis with Supplemental Alternative 8 (Contingent – Midpoint)



From Exponent’s results in Figure 1, the temperature range at which Supplemental Alternative 9 provides at least 3 days of support but Supplemental Alternative 8 (Contingent-Midpoint) cannot (-6.8°C to -1.9°C) has narrowed relative to the range when Supplemental Alternative 8 is considered (-6.8°C to +1.7°C). Correspondingly, the percentage of winter days that fall in this region has also reduced from nearly 25 percent of winter days to approximately 6 percent.

Considering the results, FEI concludes the following:

1. Supplemental Alternative 9 provides superior risk mitigation when compared to Supplemental Alternative 8, even when the Contingent-Midpoint scenario is considered.

2. Although Supplemental Alternative 9 provides superior risk mitigation, with respect to scoring the Resiliency Benefit criterion, the performance of Supplemental Alternative 9 and Supplemental Alternative 8 (Contingent-Midpoint), before accounting for the additional risk associated with the contingent portion actually being present on the day of a winter no-flow event, are sufficiently similar to warrant the same score on this criterion. This conclusion is based on the finding that, again, assuming the contingent volume is present when it is needed, only approximately 6 percent of winter days fall within the range that Supplemental Alternative 9 can bridge the regulatory shutdown but Supplemental Alternative 8 (Contingent-Midpoint) cannot. This is in contrast to the nearly 25 percent of

winter days in which Supplemental Alternative 9 can bridge the regulatory shutdown but Supplemental Alternative 8 cannot, which FEI considers to be a large enough performance difference to warrant a different score.

3. A direct comparison of winter days as in point 2 above is "apples to oranges" in the sense that it is comparing an alternative with fully reserved volumes (Supplemental Alternative 9) to one where a material portion of the volume is at risk of not being present on the day of a no-flow event (Supplemental Alternative 8 (Contingent-Midpoint)). The fact that Supplemental Alternative 8 (Contingent-Midpoint) only achieves this performance when considering an uncertain contingent scenario must be considered in the scoring. As a result, the scores assigned to Supplemental Alternatives 8 and 9 for the Resiliency Benefit criterion of "Medium Positive Impact" and "High Positive Impact", respectively, do not change when Supplemental Alterative 8 (Contingent-Midpoint) is considered. The certainty in the risk mitigation performance provided by Supplemental Alternative 9 distinguishes it from Supplemental Alternative 8 (Contingent-Midpoint), and thus a higher score is warranted for the Resiliency Benefit criterion. The differentiation would only increase based on an "apples-to-apples" comparison where a contingent volume is assumed to be present for Supplemental Alternative 9 as well, over and above the 2 Bcf resiliency reserve (i.e., an "apples-to-apples" comparison with Supplemental Alternative 8 (Contingent-Midpoint)).

As a result, the relative scoring remains the same among the feasible alternatives.

While the preceding discussion is focused on the Resiliency Benefit criterion, FEI notes that Supplemental Alternative 8 (Contingent-Midpoint) has a negative impact on the Gas Supply criterion. If Supplemental Alternative 8 (Contingent-Midpoint) were to materialize (i.e., a T-South no-flow event occurred and 0.3 Bcf of the gas supply reserve happened to be available and was instead used for resiliency), then there would be a negative impact on FEI's ability to meet its gas supply needs for the remainder of the winter heating season. Please refer to the response to BCUC IR5 127.2 for further discussion on the importance of an on-system gas supply reserve following a major supply disruption.

156.0 Reference: EXPANDED ALTERNATIVES ANALYSIS

Exhibit B-63, BCUC IR 131.2

Regional Infrastructure Upgrades

In response to BCUC IR 131.2, FEI states:

> FEI also notes that, all else equal, if there are no regional infrastructure upgrades until year 2048, then the PV of Cost of Service over the 67-year analysis period for Supplemental Alternatives 8 and 9 would equal each other.

156.1 Please provide, all else equal, the assumed timing of a regional infrastructure upgrade which would result in the PV of Cost of Service over a 23-year analysis period for Supplemental Alternatives 8 and 9 to equal each other.

Response:

For clarity, the sensitivity analysis completed in Section 6.4 of the Supplemental Evidence was based on a hypothetical scenario of retiring the TLSE Project assets early in 2050, thus resulting in a financial analysis period of 27 years (comprised of a 20-year post-commissioning service life for the assets and a 7-year construction period). To be consistent with the analysis provided in Section 6.4 of the Supplemental Evidence, as well as the response to BCUC IR6 152.1, FEI is therefore responding to this question using a 27-year analysis period based on a hypothetical scenario of a 20-year service life to 2050 for the TLSE Project assets.

As shown in the response to BCUC IR6 152.1, when analyzing the TLSE Project financially over a 27-year period, the PV of total cost of service of Supplemental Alternative 8 would become slightly lower than Supplemental Alternative 9 by approximately $10 million. This small difference in PV is equivalent to a bill impact of only 36 cents per year for an average residential customer. However, in order to be responsive, as demonstrated by Table 1 below, if the regional infrastructure upgrade occurs two years earlier in 2033 instead of 2035, then the difference in the PV of total cost of service over a 27-year analysis period between Supplemental Alternatives 8 and 9 would become immaterial at $263 thousand. Further, as explained in the response to BCUC IR5 131.2, FEI believes the earliest time that a regional infrastructure upgrade could realistically occur is 2035.

Table 1: Total PV of Cost of Service Over 27-year Analysis Period for Earlier In-Service Years for Regional Infrastructure Upgrade ($000s)

Year by when regional infrastructure upgrade is in place	Alt 9 - 3 BCF 800 MMcf/d (2 BCF resl)	Alt 8 - 2 BCF 800 MMcf/d (1.4 BCF resl)	Variance
2031	733,894	744,616	(10,722)
2032	768,158	773,221	(5,064)
2033	800,410	800,147	263
2034	830,769	825,492	5,277
2035 (current assumption)	859,346	849,350	9,997

As discussed in the response to BCUC IR6 152.1 and discussed above, the difference in PV between Supplemental Alternatives 8 and 9 when hypothetically assuming the assets will only be used for 20 years is small (i.e., a difference of 36 cents per year in terms of bill impact to an average residential customer). FEI continues to expect the TLSE Project to continue to operate beyond 20 years and, as such, Supplemental Alternative 9 will become increasingly more beneficial financially than Supplemental Alternative 8.

It is important to note that there are various combinations between the number of years used for the analysis period and the year when the regional infrastructure upgrade occurs that would make Supplemental Alternatives 8 and 9 financially similar to each other. To illustrate this point, FEI provides Table 2 below which shows the impact of various combinations of the analysis period and the year of regional infrastructure upgrades on the difference in PV of the total cost of service between Supplemental Alternatives 8 and 9.

Table 2: Difference in the Total PV of Cost of Service Between Supplemental Alternatives 8 and 9 Over Various Combinations of Analysis Periods and Years of Regional Infrastructure Upgrade ($000s)

Analysis Period (Years)	Regional Infrastructure Upgrade in Place ->				
	2035	2040	2045	2048	2050
27	9,997	29,750	44,348	51,207	55,118
29	583	20,336	34,934	41,793	45,721
32	(8,411)	11,343	25,941	32,800	36,728
37	(19,956)	(202)	14,396	21,255	25,183
42	(28,277)	(8,523)	6,074	12,934	16,862
47	(34,279)	(14,526)	72	6,931	10,860
52	(38,607)	(18,853)	(4,255)	2,604	6,532
57	(41,722)	(21,968)	(7,370)	(511)	3,417
62	(43,958)	(24,205)	(9,607)	(2,747)	1,181
67	(46,404)	(26,650)	(12,052)	(5,193)	(1,265)

Notes to Table:

- *Green (negative) indicates Supplemental Alternative 9 is financially more favorable than Supplemental Alternative 8.*
- *Red (positive) indicates Supplemental Alternative 8 is financially more favorable than Supplemental Alternative 9.*
- *White indicates the two alternatives are essentially the same financially.*

FEI makes two key observations based on Table 2:

- The longer the in-service period, the more favourable Supplemental Alternative 9 becomes compared to Supplemental Alternative 8; and
- The further into the future that a regional infrastructure upgrade occurs, the more favourable Supplemental Alternative 8 becomes compared to Supplemental Alternative 9.

Irrespective of the combinations presented in Table 2, FEI considers that the assumptions in the financial evaluation underpinning the Supplemental Evidence are reasonable and supported by evidence for the reasons below.

First, as discussed in Section 4.5.5 of the Supplemental Evidence and throughout the proceeding, the risk that the TLSE Project will cease to be used and useful after 20 years is very remote. Even under the most extreme adverse hypothetical load loss scenarios, the TLSE assets would still remain useful from a gas supply perspective – providing opportunities to either substitute other more expensive supply resources or generate more mitigation revenue. As such, the likelihood that the useful life of the assets would be closer to or at least equal to the expected service life of 60 years (67-year analysis period when including the 7-year construction period) is high.

Second, as discussed in the response to BCUC IR5 131.2, the existing regional infrastructure in the Pacific Northwest is fully contracted and expected to remain highly constrained in the absence of further regional infrastructure upgrades. As such, regional infrastructure upgrades are necessary and likely to occur sooner rather than later, which FEI believes could occur by 2035 at the earliest.

Ultimately, the financial difference between Supplemental Alternatives 8 and 9 is therefore highly likely to be in the lower-left quadrant of the matrix shown in Table 2 above, with Supplemental Alternative 9 being financially superior to Supplemental Alternative 8.

D. PROJECT DESCRIPTION

157.0 Reference: Project Description

Exhibit B-60, pp. 69-70

Send-Out Pumps Rate of Failure

On pages 69 and 70 of Exhibit B-60, FEI states:

> The three functioning send-out pumps have experienced a higher-than-normal failure rate over the past three years, including the following failures: …
>
> Given the prevalence of send out pump failures over the past three years, even with plans for partial redundancy of a fourth send out pump, the reliability of the regasification equipment increases the risk to FEI's customers when relying on the Base Plant for peaking supply and resiliency purposes.

157.1 Please explain what FEI considers to be a normal failure rate for send-out pumps, as compared to the "higher-than-normal failure rate" of the current send-out pumps.

Response:

FEI considers a standard failure frequency for vertical deep-well send-out pumps to be 10^{-1} events per year (i.e., a rate of 0.1 per year), which is consistent with industry norms. FEI has experienced a pump failure rate at least 6 times greater than this threshold over the past 5 years.

Due to the nature of LNG send-out to meet immediate resiliency or gas supply needs, FEI depends on the reliable operation of its facility when required, including send-out pumps. Predicting the failure frequency for pumps that are only turned on intermittently during critical demand is complex, as failures may remain hidden until send-out is necessary. While FEI undertakes testing ahead of and during send-out season to try to detect hidden failures, even if a pump failure is discovered, the system cannot be taken down for repair until the send-out season is over. Isolating any pump for repair requires taking down the entire send-out system for 1-2 weeks to allow for system warm up, maintenance, and subsequent cool down.

The existing Tilbury Base Plant has a total of four send-out pumps (A, B, C, D). Pump D has been offline since before 2020, but the remaining three pumps have each experienced an average failure rate of 0.6 failures per year since 2020. This rate is higher than the standard frequency rate noted above. Pumps A, B and C are "deep-well" type pumps that are typically expected to run 5-8 years, before a seal or bearing fails, and 10-20 years before impeller or rotating assembly failures. Pump D is a canned motor type, with submerged bearings and no mechanical seals, that are expected to operate for over 10 years before requiring repair. Repairing a canned motor pump is more complex and time-consuming than a deep-well pump as the motor is integral to the pump. Pump D is currently being modified to act as a spare to Pumps A, B and C, and is expected to be installed in 2025.

As demonstrated in the response to RCIA IR5 63.1, the existing Tilbury Base Plant send-out pumps have experienced a number of malfunctions during both testing and when send-out was required. The number of malfunctions that have occurred when send-out was required is particularly problematic because the LNG provided by the Base Plant is FEI's gas supply resource of last resort, and as delays in send-out can have potentially significant implications for FEI's ability to meet firm demand.

E. FINANCIAL ANALYSIS

158.0 Reference: FINANCIAL ANALYSIS

Exhibit B-1, section 6.4.4, p. 166; Exhibit B-15, BCUC IR 44.1; Exhibit B-60, Section 6.1.2.2, p. 196-197; Order G-324-24 dated December 4, 2024

Application and Preliminary Stage Development Costs

On page 166 of the Application, FEI presents Table 6-5 showing total pre-tax Application and Preliminary Stage Development Costs of 2.146 million and annual amortization for a 3-year period of 0.127 million.

On page 197 of the Supplemental Evidence, FEI presents Table 6-3 showing total pre-tax Application and Preliminary Stage Development Costs of 6.491 million and annual amortization for a 3-year period of 0.976 million.

In response to BCUC IR 44.1, FEI stated:

> […] there is no difference in the annual delivery rate impact for amortization periods of 2 to 7 years when rounded to 3 decimal places. Given there is essentially no difference in terms of annual delivery rate impact when rounded to 3 decimal places, FEI ultimately considers that there is no basis on which to deviate from prior practice for this Project, and as such selected an amortization period of 3 years, which is consistent with recent BCUC approvals for FEI's CPCN applications

On page 197, FEI further stated:

> The total forecast pre-tax deferral costs are $6.491 million and include $4.945 million of Application costs, with $3.245 million of actual Application costs incurred from June 2020 to December 2023 and a forecast of $1.700 million from January 2024 to the end of the remaining regulatory process. […] The forecast Application costs from January 2024 to the end of the remaining regulatory process include the legal, consultant, and studies costs in 2024 and 2025 for the Supplemental Evidence, and assuming a written hearing process with an expert-led workshop when the regulatory process is restarted.

By Order G-324-24 dated December 4, 2024, the BCUC established a further regulatory timetable, which does not include an expert-led workshop.

158.1 Given the increased total forecasted Application and Preliminary Stage Development Costs, please provide an update to FEI's response to BCUC IR 44.1. In the response, please explain whether FEI continues to consider a 3-year amortization period for the Application and Preliminary Stage Development Costs deferral account to be appropriate.

Response:

Please refer to Table 1 below for the updated forecast of Application costs (in the same format as Table 6-3 of the Supplemental Evidence) based on the regulatory timetable established by Order G-324-24 which included two rounds of information request on the Supplemental Evidence and no expert-led workshop. The Application costs shown in Table 1 below also include actual costs incurred up to December 31, 2024 as presented in the response to BCOAPO IR5 4.1. FEI also notes that as discussed on page 197 of the Supplemental Evidence, there are no additional preliminary stage development costs incurred since December 2020.

Table 1: Updated Forecast of Application and Preliminary Stage Development Costs Deferral Account ($ millions)

Particular	Application (Actual: 2020-2024; Forecast 2025 Onwards)	Preliminary Stage Development (Actual: 2019-2020)	TOTAL
Pre-Tax Costs	4.445	1.546	5.991
WACC Return	0.485	(0.094)	0.391
Total Before Tax Offset	***4.930***	***1.452***	***6.382***
Tax Offset - Costs held in Deferral Account	(1.200)	(0.417)	(1.618)
Tax Offset - Capitalized Costs	-	(2.272)	(2.272)
Total	***3.730***	***(1.238)***	***2.492***
Annual Amortization for 3 years	1.243	(0.413)	0.831

With regard to the proposed amortization period for the Application and Preliminary Stage Development cost deferral account (based on the forecast presented in the Supplemental Evidence and updated in Table 1 above), FEI continues to consider three years to be reasonable. FEI considers three years to appropriately manage the delivery rate impact to customers while also aligning the amortization period with the expected in-service date of the TLSE Project.

Please refer to Table 2 below which summarizes the delivery rate impacts in 2026 (when compared to 2024 Approved delivery rates) for amortization periods ranging from one to seven years.

Table 2: Comparison of Delivery Rate Impact and Residential Bill Impact for Amortization Periods from One to Seven Years

	Amortization Period						
	1 Year	2 Years	3 Years	4 Years	5 Years	6 Years	7 Years
Incremental Delivery Margin in 2026 ($ millions)	3.520	1.867	1.315	1.040	0.874	0.764	0.685
Delivery Rate Impact in 2026 compared to 2024 Approved (%)	0.31%	0.16%	0.12%	0.09%	0.08%	0.07%	0.06%
Estimated Bill Impact to Avg. RS 1 Customer in 2026 ($)	1.58	0.84	0.59	0.47	0.39	0.34	0.31

Based on the delivery rate impacts for amortization periods ranging from one to seven years as shown in Table 2 above, FEI notes the following:

- The delivery rate impact and the resulting bill impact to the average residential customer from a one-year amortization period is significantly higher than the other options, thus it was rejected;

- The difference in the delivery rate impact (or bill impact) between two-year and seven-year amortization periods is small, ranging from 0.16 percent to 0.06 percent; and
- Although a seven-year amortization period would align with the construction period of the TLSE Project, FEI believes this is unnecessarily long given the relatively small deferral account balance.

In summary, FEI continues to consider a three-year amortization period to be appropriate and to provide a reasonable level of rate smoothing. FEI does not consider it necessary to amortize the Application and Preliminary Stage Development Cost deferral account over a longer period of time than three years since the additional degree of rate smoothing is minor beyond three years and longer amortization periods could give rise to intergenerational inequity issues.

158.2 Please provide an updated Table 6-3 in the Supplemental Application showing the revised forecast pre-tax deferral cost to be recorded in the Application and Preliminary Stage Development Costs deferral account.

Response:

Please refer to the response to BCUC IR6 158.1.

159.0 Reference: FINANCIAL ANALYSIS

Exhibit B-1-4 (Updated Application), Section 6.4.5, p. 167; Exhibit B-15, BCUC IR 45.1; Exhibit B-60, Section 6.1.2, Table 6-1, p. 195

TLSE Foreign Exchange Mark to Market Valuation Deferral Account

On page 167 of the Updated Application, FEI states "The deferral account treatment of the mark-to-market adjustments related to the foreign exchange rate hedging for the Project will have no impact on customer rates. […] The forward contracts will provide cost certainty as they lock in the foreign exchange rate for USD denominated cost components obtained by FEI for this Project."

In response to BCUC IR 45.1, FEI provides the expected portion of the estimated Project costs that may include USD payments, including the foreign exchange rate that was used to prepare the Project cost estimate and the source of this foreign exchange rate forecast.

On page 195 of the Supplemental Evidence, FEI presents Table 6-1 showing a breakdown of the TLSE project cost estimate, with a total of $1,143.889 million in as-spent dollars.

159.1 Please provide an update to FEI's response to BCUC IR 45.1 with the updated project cost estimate as presented in the Supplemental Evidence.

<u>Response:</u>

Please refer to Table 1 below for an update to the response to BCUC IR1 45.1. As shown in Table 1, based on the updated TLSE Project cost estimate of $1,140 million (i.e., Table 6-4 of the Supplemental Evidence, sum of Line 1 Total Additions to Plant of $1,118 million and Line 2 Base Plant Demolition Costs of $22.724 million), approximately 27.4 percent of the Project costs are expected to include payments in US dollars.

Table 1: Expected Portion of the Estimated TLSE Project Costs (as Presented in Supplemental Evidence) that May Include USD Payments

Partcular	Total As-spent ($ millions)	Portion USD ($ millions)	Exchange Rate (USD/CAD)	Source
LNG Tank	$ 572.204	$ 196.266	0.744	Horton CBI, Limited
Regasification Equipment	214.547	62.219	0.708	Linde
Ground Improvement	95.484	-		
Auxiliary System	236.005	54.281	0.735	Clough Enercore
Subtotal Addition to Plant	$ 1,118.238	$ 312.765		
Base Plant Demolition	22.724	-		
Subtotal Project Capital Cost	$ 1,140.962	$ 312.765		
Project Capital Cost in USD (%)		**27.4%**		

The USD/CAD exchange rates used by the consultants that developed the individual components of the cost estimates remain unchanged from the original cost estimate filed in 2020. FEI notes that the current exchange rate is at approximately 0.72 (average between April 9, 2025 and May

9, 2025)[13] which is similar to the exchange rates used by the consultants as part of the updated TLSE Project cost estimate. FEI also clarifies that, until final contracts with contractors are executed, FEI is unable to confirm whether these expenditures will be invoiced in USD or CAD. These payments could include amounts invoiced directly to FEI in USD, or amounts incurred in USD by the contractor, converted to CAD, and invoiced to FEI in CAD.

159.2 Please confirm, or explain otherwise, that FEI has forward contracts to lock in the foreign exchange rate for all USD denominated cost components of the Project as presented above.

159.2.1 If not confirmed, please explain whether, and if so how, FEI proposes to mitigate any project cost difference arising from foreign exchange volatility. Please provide a rate impact analysis with the proposed mitigation strategy.

Response:

Not confirmed. As the TLSE Project has not yet been approved by the BCUC, FEI has not yet entered into forward contracts to lock in exchange rates. As part of this proceeding, FEI is seeking approval of the TLSE Foreign Exchange Mark to Market deferral account to capture the mark-to-market valuation of any foreign currency forward contracts entered into related to construction of the TLSE Project. As further noted in the response to CEC IR1 61.4, foreign exchange will be managed via FEI financial instruments to provide the most advantageous result for the Project, and therefore customers, given the specific situation. The nominated currencies in service and supply contracts will be the subject of negotiation with suppliers.

FEI notes that any change in Project costs arising from variations in the exchange rate would be treated the same as other changes to Project costs, with FEI managing budget variations through contingency.

FEI does not consider changes in the CAD/USD exchange rates to represent a significant risk to the TLSE Project. As noted in the response to BCUC IR6 159.1, FEI expects only 27.4 percent of the total Project capital costs to include USD payments. Therefore, even under an extreme scenario where the USD/CAD exchange rate shifts downward by 10 basis points (i.e., from the current level of approximately 0.72 CAD to USD as discussed in the response to BCUC IR6 159.1 to approximately 0.62 CAD to USD), the TLSE Project cost would increase by approximately $49 million (CAD). This cost increase equates to an increase of approximately 4.32 percent to the total Project capital cost. Variances between the forecast and actual Project costs are expected, and, consistent with FEI's other major projects, there may be decreases in other actual costs which

[13] Bank of Canada: Daily exchange rates: Lookup tool (https://www.bankofcanada.ca/rates/exchange/daily-exchange-rates-lookup/?rangeType=dates&rangeValue=1.w&lP=lookup_daily_exchange_rates_2017.php&sR=2017-01-01&se=FXUSDCAD&dF=2025-04-09&dT=2025-05-09).

offset cost increases, or FEI would seek to manage/mitigate the cost increase through the use of the Project contingency.

F. CONSULTATION AND ENGAGEMENT

160.0 Reference: CONSULTATION AND ENGAGEMENT

Exhibit B-60, Section 8, Exhibit B-63, BCUC IRs 137.1, 137.2, 137.3, 137.4, 138.2

Consultation and Engagement Update

160.1 Please provide an update on any consultation activities with Indigenous groups relevant to the TLSE Project since the filing of FEI's responses to IR 5, including the outcomes from these activities.

Response:

Since filing its responses to BCUC IR5, FEI has continued consultation and engagement with Indigenous groups relevant to the TLSE Project. No new issues specific to the TLSE Project have been raised during this time. FEI has continued to respond to comments and/or information requests received through the ongoing environmental assessment process for the Tilbury Phase 2 LNG Expansion Project. Comments have come from the following Indigenous groups:

- Musqueam Indian Band;
- Quw'utsun Nation (Cowichan Tribes, Halalt First Nation, Lyackson First Nation, Stz'uminus First Nation, Penelakut Tribe);
- Tsawwassen First Nation;
- Tsleil-Waututh Nation; and
- Snuneymuxw First Nation.

In addition, FEI met with the Musqueam Indian Band, Tsawwassen First Nation, Tsleil-Waututh Nation, Leq'á:mel First Nation (a Stó:lō Nation member community) and Snuneymuxw First Nation. These meetings provided opportunities to discuss interests and issues raised during the application development and review phase, as well as to offer technical clarifications regarding the information, assessments and studies supporting the Tilbury Phase 2 LNG Expansion Project environmental assessment application.

At a high level, the comments, information requests and meetings covered issues which are subject to ongoing discussion, including potential environmental impacts, safety, economic opportunities, engagement and technical comments regarding the environmental assessment. As described in the response to BCUC IR5 137.4, a complete record of comments and/or information requests received from Indigenous groups to date, as well as FEI's responses, will be posted on the BC EAO's EPIC website[14] once the comment period for Indigenous groups is complete.

FEI also provides an updated Engagement Log as Attachment 160.1. As noted in the response to BCUC IR5 137.2, because FEI has synchronized engagement activities between this CPCN

[14] https://projects.eao.gov.bc.ca/p/5df7f1bfb7434b002164961c/project-details.

proceeding and the EA process for the Tilbury Phase 2 LNG Expansion Project, consultation activities that are specific to the TLSE Project alone are often intermingled with other aspects of the Tilbury Phase 2 LNG Expansion Project and developments at Tilbury generally. In preparing the updated Indigenous Engagement Log, FEI has narrowed the consultation activities to those relevant to the TLSE Project to the extent practicable.

FEI will continue engagement with potentially affected Indigenous groups as development of the TLSE Project progresses, which includes engagement activities outlined in the Application, Supplemental Evidence and in the response to BCUC IR5 137.4.

160.2 Please provide an update on any consultation and engagement activities with the public, government or other stakeholders relevant to the TLSE Project since the filing of FEI's responses to IR 5, including the outcomes from these activities.

Response:

As noted in the response to BCUC IR5 138.2, because FEI has synchronized engagement activities for the TLSE Project and the broader environmental assessment process for the Tilbury Phase 2 LNG Expansion Project, consultation activities that are specific to the TLSE Project are often intermingled with other aspects of the Tilbury Phase 2 LNG Expansion Project and Tilbury development overall. There are also several BC EAO comment processes occurring simultaneously as part of the environmental assessment, including with government stakeholders, through the Technical Advisory Committee (TAC), and the public through defined comment periods. FEI provides an update regarding each of these consultation and engagement activities below.

Technical Advisory Committee (TAC)

Since filing the responses to BCUC IR5, FEI has continued consultation and engagement activities with government stakeholders through the TAC. Engagement and consultation activities have focused on responding to outstanding comments and/or information requests. Of the 684 comments and/or information requests that were submitted by TAC members, only 24 new comments were made since BCUC IR5 was filed – none of which raised new issues or concerns regarding the TLSE Project.

As described in the response to BCUC IR5 137.4, a complete record of each comment and/or information request received from TAC to date, as well as FEI's responses, will be posted on the BC EAO's EPIC website[15] once the comment period is complete. FEI will continue engaging with the TAC as development of the TLSE Project progresses.

[15] https://projects.eao.gov.bc.ca/p/5df7f1bfb7434b002164961c/project-details.

EA Public Comment Period

Since filing the responses to IR5, the Public Comment Period in the current phase of the environmental assessment process for the Tilbury Phase 2 LNG Expansion Project closed. On April 10, 2025, FEI submitted its Public Engagement Report[16] which provides a summary of engagement that took place during the Public Comment Period and FEI's responses to public comments.

A second Public Comment Period will be held following the completion of the environmental assessment Effects Assessment and Recommendations Phase currently anticipated to conclude in 2026. FEI will continue engagement with the public and stakeholders throughout the development of the TLSE Project.

---

16 Tilbury Phase 2 LNG Expansion Project Public Engagement Report (gov.bc.ca).

Attachment 143.6

FILED CONFIDENTIALLY

Attachment 160.1

REFER TO LIVE SPREADSHEET

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)