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October 24, 2024

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Patrick Wruck, Commission Secretary

Dear Patrick Wruck:

Re: FortisBC Energy Inc. (FEI)

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

Supplemental Evidence

On December 29, 2020, FEI filed the above referenced Application in relation to the Tilbury Liquefied Natural Gas (LNG) Storage Expansion (TLSE) Project. In its decision of March 23, 2023 (Decision and Order G-62-23), the British Columbia Utilities Commission (BCUC) adjourned the proceeding, identified additional analysis it required before determining whether to grant a CPCN, and invited FEI to file further evidence (Supplemental Evidence).

FEI appreciates the opportunity to provide additional evidence in the context of this proceeding and has taken the time necessary to complete a significant amount of additional analysis that addresses the BCUC's comments. FEI hereby submits the public version of its Supplemental Evidence, dated October 24, 2024.

Request for Confidential Treatment of Certain Information

The Supplemental Evidence includes the following Appendices, which FEI is filing confidentially in accordance with Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents, as set out in Order G-72-23.

- Appendix D – CB&I Report
- Appendix E – WSP Report
- Appendix G – TLSE Detailed Cost Estimate Summary 3 BCF
- Appendix I – Validation Estimating Contingency Report
- Appendix J – Validation Estimating Escalation Report
- Appendix K – Financial Schedules (Preferred Alternative)

FEI respectfully requests that the BCUC hold the above listed documents confidential, and believes that such information should remain confidential in perpetuity. FEI outlines below the reasons for keeping the information confidential, and making it available only to those individuals who represent interveners and have signed undertakings.

Appendices D and E

Appendices D and E are engineering documents related to FEI's Base Plant. They should be kept confidential on the basis that they contain operationally sensitive information pertaining to FEI's assets. The disclosure of this information could impede FEI's ability to work safely and reliably operate its gas system assets and could risk the safety of both its workers and the public.

Appendices G, I, J and K

Appendices G, I, J and K include cost estimates, containing capital cost estimates for the TLSE Project. These appendices should be kept confidential on the basis that FEI may be going to the market to seek competitive bids for the materials and construction work for the Project. If the estimated costs for the material and construction work are disclosed, FEI reasonably expects that its negotiating position may be prejudiced. For instance, the bidding parties with knowledge about the estimated costs may use the estimate costs as a reference for their bidding.

Access to Confidential Application for Interveners

A number of representatives of interveners in the TLSE Project CPCN Application proceeding have already signed confidentiality undertakings. FEI is continuing to rely on those undertakings. That is, they would continue to entitle the signatories to access the Confidential Supplemental Evidence, as well as confidential information already in the evidentiary record that was previously provided to interveners. Should other individual representatives of those interveners require access to the Confidential Supplemental Evidence, FEI provided an Undertaking of Confidentiality in Appendix T-3 to the Application (Exhibit B-1-4). It would have to be executed before confidential information may be released to registered parties under the terms of the undertaking.

FEI requests that the BCUC provide it with the opportunity to file comments on any objections or concerns that it may have, should any other registered parties seek access to confidential information.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Registered Interveners

FORTISBC ENERGY INC.

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

Supplemental Evidence

October 24, 2024

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1. INTRODUCTION

1.1 INTRODUCTION

In December 2020, FortisBC Energy Inc. (FEI) applied for a Certificate of Public Convenience and Necessity (CPCN or Application) for approval of the Tilbury Liquefied Natural Gas (LNG) Storage Expansion Project (TLSE Project or the Project). The TLSE Project will enhance the resiliency of FEI's system by providing immediate backup gas supply to FEI customers, primarily in the Lower Mainland, in the event of a supply emergency, while also replacing the aging Tilbury Base Plant to maintain the essential gas supply and operational functions it has provided since 1971. The Project is therefore needed to:

- Mitigate the significant resiliency risk that hundreds of thousands of customers in the Lower Mainland will lose service for many weeks following a winter no-flow event[1] on the Westcoast Energy Inc. (WEI) T-South pipeline (T-South); and
- Ensure that FEI continues to have access to sufficient dependable peaking supply to be able to serve firm customers during normal operations.

In its decision of March 23, 2023 (Adjournment Decision),[2] the British Columbia Utilities Commission (BCUC) identified additional analysis required before determining whether to grant a CPCN. The BCUC acknowledged the need for resilient utility infrastructure and the importance of resiliency in the provision of safe and reliable service,[3] FEI's vulnerability to a supply interruption to the Lower Mainland (a no-flow event),[4] and that the TLSE Project will mitigate that risk.[5] However, the BCUC indicated that system vulnerabilities should be assessed holistically by comparing various resiliency options and prioritizing and planning against various outage scenarios, and then developing a comprehensive resiliency plan.[6] The BCUC also stated that it was unable to assess the cost effectiveness of the TLSE Project as a replacement for the Base

1 As in the Application, FEI uses the term "no-flow event" to describe a total cessation of physical gas flows to a portion of FEI's service area. A no-flow event can have many different causes and will depend on the pipeline or other asset.

2 Decision and Order G-62-23.

3 Adjournment Decision, p. 12: "The Panel accepts the need for resilient utility infrastructure and the importance of resiliency in the provision of safe and reliable service."

4 Adjournment Decision, p. 16: "The existing system currently has limited ability to mitigate a three day no-flow event. While it may be able to do so in July, it would be very challenged to do so in cooler months and not at all likely to be able to do so in a typical December or January."

5 Adjournment Decision, p. 16: "The Panel is satisfied with the evidence provided by FEI on the limitations of the system's ability to mitigate a 3 day no-flow event and finds that the TLSE Project will mitigate a 3-day no-flow event, provided the no-flow event does not occur simultaneously with the design peak day. In that latter circumstance, there would be insufficient regasification capacity. However, we accept FEI's assertion that even in this circumstance, the TLSE Project would provide FEI more time to conduct a more orderly shutdown than it otherwise would be able to conduct within the limits of the existing infrastructure."

6 Adjournment Decision, p. 12: "A robust resiliency plan should consider multiple credible threats to the FEI system, along with an assessment of the likelihood and consequence of each threat. Proposed solutions to mitigate those threats should consider the ability of a solution to mitigate one or more of the threats and a cost benefit analysis of that solution." The BCUC confirmed the need for holistic analysis in the FEI 2022 Long Term Gas Resource Plan (LTGRP) Decision: see Decision and Order G-78-24, p. 40.

Plant due to the lack of evidence regarding the TLSE Project as a "like-for-like" replacement of the Base Plant and the ability of the TLSE Project to replace the functions or capacity currently provided by the Base Plant with regard to dependable peaking supply.[7]

The BCUC invited FEI to provide more information about alternatives that would allow it to find "that the TLSE Project is the preferred alternative to address the need for resiliency more generally on FEI's system."[8] In particular, the BCUC sought additional information on the remaining life of the Base Plant,[9] identified specific Tilbury and non-Tilbury alternatives for further evaluation,[10] and invited further consideration of how potential future developments, such as changes in load, might impact the alternatives assessment.[11]

FEI appreciates the opportunity to provide additional evidence in the context of this proceeding and believes it has addressed the BCUC's comments. FEI has taken the necessary time to complete a significant amount of additional technical analysis, with the assistance of external experts, on matters including:

- A comprehensive and holistic 2024 Resiliency Plan (2024 Resiliency Plan), which includes FEI's risk exposure to widespread customer outages anywhere on its system due to supply disruptions;
- The condition of the now-53-year-old Tilbury Base Plant and independent engineering analysis on the potential for refurbishment;
- The availability of sufficient dependable peaking supply in the market to replace the supply functions of the Base Plant;
- Updated capital costs; and
- An expanded alternatives analysis which encompasses 13 Supplemental Alternatives, including continuing to rely on the existing Base Plant with no capital upgrades, new regasification only, new LNG facilities of various sizes and allocations between a resiliency reserve[12] and gas supply functions, and other non-Tilbury options that the BCUC had identified in its Adjournment Decision.

The 2024 Resiliency Plan confirms, through quantitative (probability x consequence) risk analysis, that a T-South winter no-flow event is, by far, FEI's single largest customer outage risk and should be mitigated. Irrespective of resiliency, new analysis has confirmed that the Base Plant has reached end-of-life, and a sizable capital investment is required simply to ensure that FEI can continue to dependably serve firm customers in cold periods as FEI has done for decades. While

[7] Adjournment Decision, p. 14.
[8] Adjournment Decision, p. 25.
[9] Adjournment Decision, pp. 14 and 51.
[10] Adjournment Decision, pp. 25-33.
[11] Adjournment Decision, pp. 39-40.
[12] As in the Application, FEI uses the term "resiliency reserve" to describe an amount of tank capacity that is set aside for use in a supply emergency only, i.e., it would not be used in the ordinary course of business for any other purpose such as gas supply.

FEI is relying on the facility continuing to function (albeit at reduced reliability) until construction of the TLSE Project is complete, there is no feasible option to extend the life of the Base Plant. FEI would be unable to replace in the market the peaking gas supply that Tilbury has provided since 1971.

FEI's additional analysis confirms that, as originally proposed in the Applicaton, FEI customers will obtain the greatest value from a new facility with 800 MMcf/d of regasification and a 3 Bcf tank that is allocated between a 2 Bcf "resiliency reserve" and a third Bcf for gas supply (Preferred Alternative). This is due in particular to a combination of: (1) the significant customer outage risk mitigation it provides in respect of a winter T-South no-flow event and other known vulnerabilities; (2) its peaking supply capabilities, which not only maintain FEI's Tilbury peaking supply but also give FEI the flexibility to avoid annual gas supply costs by displacing other resources in its portfolio; and (3) the very significant economies of scale associated with constructing a new LNG facility. FEI has used hypothetical adverse load loss sensitivities to demonstrate that any of the LNG facility alternatives, regardless of size, can be expected to remain fully utilized in the future; on-system LNG is a uniquely flexible asset in this regard.

FEI considers that this additional evidence reinforces that the Preferred Alternative is in the public interest and should be approved as proposed, along with the associated deferral account and depreciation rate approvals requested in Section 6 of the Application.

1.2 INITIAL COMMENT ON APPLICATION'S IMPORTANCE FOR PUBLIC SAFETY

Phrases like "adding resiliency" and "maintain peaking supply", and the associated technical discussion about probability adjusted risk and avoided gas supply costs, tend to understate the practical significance of this Application. The TLSE Project is, in essence, about ensuring that hundreds of thousands of customers have gas for heat in the winter in both normal operations and in the type of supply emergency that was already experienced in 2018 (2018 T-South Incident).[13] Since FEI filed this Application in 2020, FEI has experienced another supply disruption on T-South that necessitated reliance on Tilbury LNG, and a river flood that submerged one of the T-South pipelines.

FEI needs the Tilbury LNG facility to be able to serve firm customers – i.e., those customers who are relying on having gas service at all times – in cold winter periods in normal operations. The Base Plant facility, which houses the only regasification equipment at Tilbury and its only reserved peaking supply, has now reached end-of-life. It can no longer be counted on to reliably provide that peaking supply when it is needed. If unmitigated, thousands of firm customers in the Lower Mainland are at risk of being curtailed – having their gas turned off by FEI as a last resort to maintain system pressure – every winter in normal operations.[14] This is something that has never happened in FEI's decades of operation and it is vital that it does not happen now. Losing heat in the winter is a serious health risk, particularly for the vulnerable.[15] It is essential that, at an

13 See Application, Exhibit B-1-4, Section 3.4.2.2.
14 See Supplemental Evidence, Section 3.3.4.2.
15 See Supplemental Evidence, Section 3.2.2.3.

absolute minimum, FEI has continued access to enough peaking supply to meet firm load at all times of the year.

The 2024 Resiliency Plan, and the expert analysis that went into it, shows that a winter T-South no-flow event will, if it goes unmitigated, result in the entire Lower Mainland losing service for many weeks. That means no heat for well over half a million homes and businesses for many weeks, the effects of which would be significant, and could potentially include the deaths of vulnerable people or the suffering of serious health effects, the closing of businesses, the disruption of industrial production, and the failure of greenhouse crops. A winter T-South no-flow event, if unmitigated, is expected to cause cascading economic harm to the province.[16]

NERC noted recently that hundreds of people died as a result of an electric outage in Texas that left people without heat for only four days:[17]

> More than 4.5 million people in Texas lost power during the Event, and some went without power for as long as four days, while exposed to below-freezing temperatures for over six days. At least 210 people died during the Event, with most of the deaths connected to the power outages, of causes including hypothermia, carbon monoxide poisoning, and medical conditions exacerbated by freezing conditions. Among the deaths were a mother and her seven-year-old daughter, and an 11- year-old boy who died in his bed, who all died of carbon monoxide poisoning, and a 60-year-old disabled man who died of hypothermia. A grandmother and three children trying to keep warm using a wood-burning fireplace died in a house fire. In cities including Austin, Houston and San Antonio, over 14 million people were ordered to boil drinking and cooking water, and multiple cities ordered water conservation measures, due to broken pipes and power outages (which lowered water pressure). After the city of Denton, Texas, lost its gas supply, it was forced to cut power to nursing homes and water pumping stations. [Footnotes removed from original]

NERC determined that the February 2021 incident in Texas was precipitated by a cold weather event in which critical gas and electric infrastructure failed to operate due to lack of investment in resiliency (i.e., weather hardening to withstand cold weather conditions):[18]

> A confluence of two causes, both triggered by cold weather, led to the Event, part of a recurring pattern for the last ten years. First, generating units unprepared for cold weather failed in large numbers. Second, in the wake of massive natural gas production declines, and to a lesser extent, declines in natural gas processing, the natural gas fuel supply struggled to meet both residential heating load and

[16] See Supplemental Evidence, Section 3.2 for a discussion of consequences of a winter T-South no-flow event.

[17] FERC - NERC - Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States (2021), pp. 9-10: https://www.nerc.com/pa/rrm/ea/Documents/February_2021_Cold_Weather_Report.pdf. See also Supplemental Evidence, Section 3.2.2.3.

[18] FERC - NERC - Regional Entity Staff Report, pp. 11-12.

> generating unit demand for natural gas, exacerbated by the increasing reliance by generating units on natural gas. Natural gas pipeline capacity is for the most part designed, certificated and constructed to accommodate firm transportation commitments, while many natural gas-fired generating units rely on non-firm commodity and/or pipeline transportation contracts.

The energy systems were unable to meet firm peak winter demand and were forced to initiate the largest controlled firm load shedding event in US history, not only causing approximately 210 deaths, but also an estimated $80 to $130 billion in direct and indirect losses to the Texas economy.[19]

FEI is very cognizant that this Project involves significant capital costs and will increase customer bills. However, as demonstrated in Texas, the implications of not making an investment in a new facility to serve load in normal operations and a likely supply emergency are too significant to ignore.

1.3 EXECUTIVE SUMMARY AND ORGANIZATION OF THE EVIDENCE

The Supplemental Evidence is organized as follows.

1.3.1 Summary of the Process and Evidence to date, and FEI's Response to the Adjournment Decision (Section 2)

This section provides an overview of the proceeding to date, provides references to prior evidence, and explains how FEI has addressed the BCUC's Adjournment Decision commentary. Appendix A to this Supplemental Evidence provides references to key evidence in the record to date. Appendix B is a table of concordance, aligning the Adjournment Decision commentary with sections in this Supplemental Evidence.

1.3.2 Project Need (Section 3)

In this section, FEI provides the additional information on Project need identified in the Adjournment Decision as well as updated information given the passage of time since the Application was filed.

The Application described the Project need as enhancing the resiliency of FEI's system by providing immediate backup gas supply to FEI customers, primarily in the Lower Mainland, in the event of a supply emergency.[20] FEI further clarified the Project need as including the replacement of the existing Tilbury Base Plant in its Final Argument, as follows:[21]

> Although the TLSE Project is properly characterized as a resiliency project, it would be incorrect to conceptualize the full project cost as the cost of increasing

[19] FERC - NERC - Regional Entity Staff Report, pp. 9-10.
[20] Exhibit B-1-4, Application, p. 19.
[21] FEI Final Argument (Public Version), p. 9.

resiliency. As explained in Part Five, Section D, the TLSE Project also replaces the existing Tilbury Base Plant tank, which is now over 50 years old – well-beyond its expected service life. In the absence of the TLSE Project, FEI would still need to maintain the current gas supply and operational benefits provided by the Base Plant.

In response to the BCUC's findings and commentary in the Adjournment Decision, FEI has undertaken extensive additional analysis to support the Project need, including the comprehensive 2024 Resiliency Plan which is supported by the evidence of external experts. FEI has filed the 2024 Resiliency Plan concurrently with this Supplemental Evidence.

Based on the additional evidence, FEI confirms that the TLSE Project is needed to:

- mitigate the significant resiliency risk that hundreds of thousands of customers in the Lower Mainland will lose service for many weeks following a winter no-flow event on T-South; and
- ensure that FEI continues to have access to sufficient dependable peaking supply to be able to serve firm customers during normal operations.

The *status quo*, in the absence of significant capital investment, leaves customers exposed to loss of service in normal operations due to the Base Plant having reached end-of-life and no longer being a dependable source of critical peaking supply. In a widespread and lengthy gas outage, which will occur following a winter T-South no-flow event, British Columbians will be exposed to serious health and mortality risk and significant social and economic consequences. This would be, in FEI's view, an unacceptable basis for future system planning.

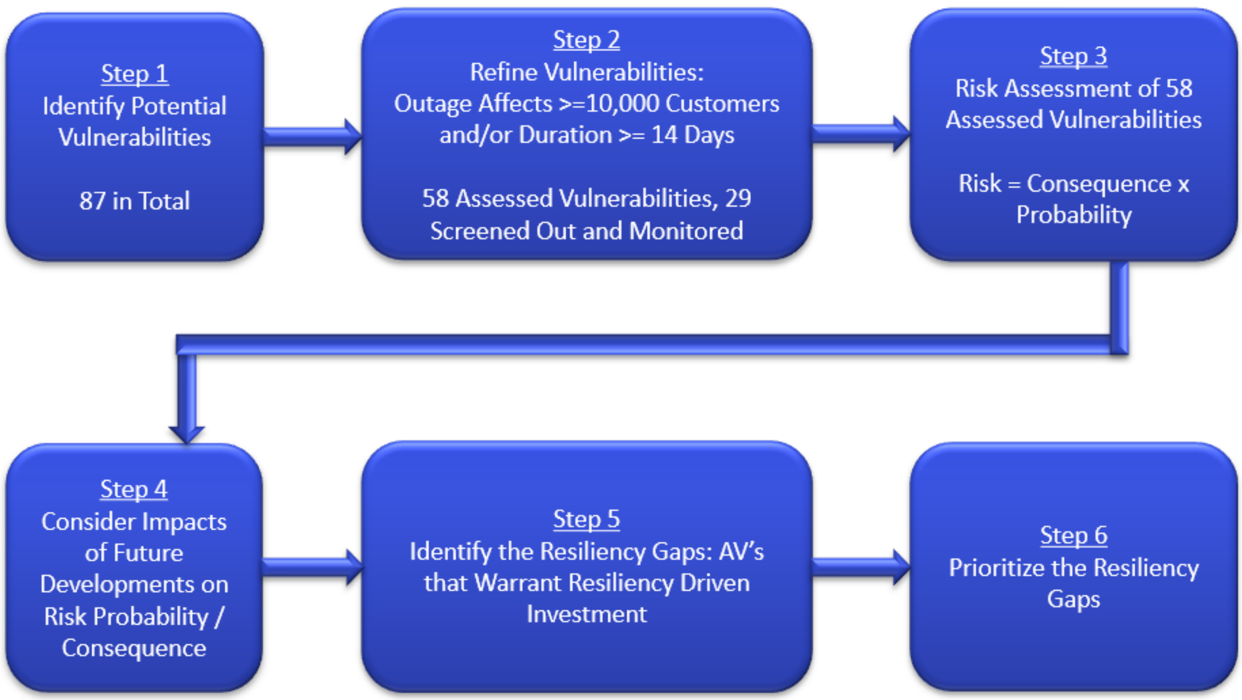
1.3.2.1 Mitigating FEI's Largest Customer Outage Risk (Section 3.2)

The 2024 Resiliency Plan includes a risk assessment prepared with the assistance of the expert consulting firm Exponent, Inc. (Exponent) that accounts for both probability and consequence. The risk assessment has reconfirmed that a total loss of T-South supply during winter is, and (unless mitigated) will remain, by far FEI's single greatest risk of a widespread and prolonged service disruption. The customer outage risk is so substantial that FEI needs to invest to mitigate the risk, wholly apart from the need to invest to continue dependably serving firm load in peak winter periods.

Section 3.2 is organized as follows:

- **2024 Resiliency Plan Is a Sound Basis for Determining Project Need (Section 3.2.1):** The 2024 Resiliency Plan is a holistic and comprehensive resiliency assessment. The analytical approach, which was developed with Exponent's advice, is depicted in the following flow chart and is explained in Section 3 of the 2024 Resiliency Plan.

Figure 1-1: Resiliency Plan Approach



The primary recommendation of the 2024 Resiliency Plan is:[22]

> FEI has confirmed the need for resiliency-driven investment to mitigate FEI's greatest customer outage risk that is due to a winter T-South no-flow event (Assessed Vulnerabilities (AV) 1, 2, 3 and 54), as well as risk associated with AV 18. New and larger on-system LNG at Tilbury will mitigate both risks.
>
> Four other AVs have been identified as warranting further investigation, but FEI is not recommending at this time any additional investment where the primary driver is resiliency.
>
> Based on FEI's current analysis, the AVs other than those noted above are already managed in a reasonable manner accounting for the magnitude of the risk of customer outages and the cost of mitigation, recognizing it is not feasible to fully mitigate every outage risk on a natural gas system.
>
> For all Assessed Vulnerabilities, FEI will consider further risk mitigation in sustainment capital planning, as assets come due for replacement, and in the context of potential projects that also have other non-resiliency drivers.

22 2024 Resiliency Plan, pp. 3-4.

- **Catastrophic Consequences of Winter T-South No-Flow Event (Section 3.2.2):** FEI used its standard hydraulic system modelling to determine the extent of the customer outages for each of the 58 AVs. A winter T-South no-flow event lasting only a matter of hours will, without question, have catastrophic consequences. By virtue of the regasification constraint at Tilbury, FEI's Lower Mainland gas system will fail on the first day of such an event regardless of AMI being in place,[23] and regardless of how much LNG is assumed to be present in the Base Plant or Tilbury 1A on the day the no-flow event occurs (see Table 1-1 below). In most scenarios, the depressurization will occur in an uncontrolled manner that entails public safety risks. The outage will last many weeks, even assuming that a material portion of customers are relighting their own appliances and that a full complement of technicians is available from the contracting community and other utilities to speed customer restoration.[24] It will cause billions of dollars of economic harm, and can be expected to result in adverse health impacts and deaths.

Table 1-1: Time to Failure Following T-South Winter No-flow Event – Status Quo (150 MMcf/d, Regardless of LNG Volumes Available)

Temperature Condition	Approximate Time Until Customers in the Lower Mainland Begin Losing Service[25]
-10.0°C (very cold Lower Mainland winter day)[26]	2 hours
-1.4°C (warmest Lower Mainland winter in 10 years) [27]	5 hours
+4.0°C (average Lower Mainland winter)[28]	7 hours

The Table 1-2 below summarizes **direct customer impacts** at average winter temperatures (+4°C) for the four anonymized segments of T-South.[29] The number of affected customers increases from the values shown as temperatures drop below

[23] As the BCUC has approved the AMI Project, the entirety of the analysis in this Supplementary Evidence and the 2024 Resiliency Plan assumes that residential and small commercial AMI is in place. The extent of the mitigation provided by AMI, in terms of reducing the extent and duration of an outage, was discussed in FEI's Rebuttal Evidence.

[24] The basis of the outage duration estimates was discussed in detail in FEI's Rebuttal Evidence.

[25] This represents the approximate duration of full firm load support from all on-system LNG and linepack from the CTS. The analysis also assumes that all interruptible customers are offline within 4 hours of the no-flow event.

[26] Due to the low probability of having multiple -10ºC days in a row in the Lower Mainland, the -10ºC temperature condition analysis assumes the following: the first day is -10ºC, the second and third days are -7ºC, the fourth day is -3ºC, and all subsequent days are 4ºC.

[27] The warmest winter in the last 10 years was found by determining the minimum daily average temperature for each year over a 10-year period from 2013-2022, then selecting the highest value. The analysis was based on data from the Vancouver International Airport (YVR).

[28] Defined as the average of the daily average temperatures for December, January, and February over a 10-year period from 2013-2022. The average winter day is based on data from YVR.

[29] See Section 3.2.2.1.1 of this Supplemental Evidence for a summary of the calculation parameters. The de-anonymized description of the four Assessed Vulnerabilities (AVs) comprising T-South are found in Appendices RP 4-01, 4-02 4-03 and 4-54 to the 2024 Resiliency Plan, which have been kept confidential for security reasons.

average, and the outage duration increases (other things equal) when the depressurization occurs in an uncontrolled manner.[30]

Table 1-2: Quantitative Metrics Related to Severity of a T-South No-Flow Event at Average Winter Temperatures by Incident Location

Type of Impact	Quantitative Metric	AV-1 Value	AV-2 Value	AV-3 Value	AV-54 Value
Direct customer service impact	Number of firm customers losing service on Day 1	640,100	600,400	640,400	600,400
Direct customer service impact	Total Outage Duration[31]	63.3 days	60.2 days	71.9 days	66.3 days
Direct customer service impact	Total firm customer-outage-days	24 million	21 million	32 million	28 million
Direct customer service impact	Firm customers losing service on Day 1 as a percentage of total FEI customers	60%	56%	60%	56%

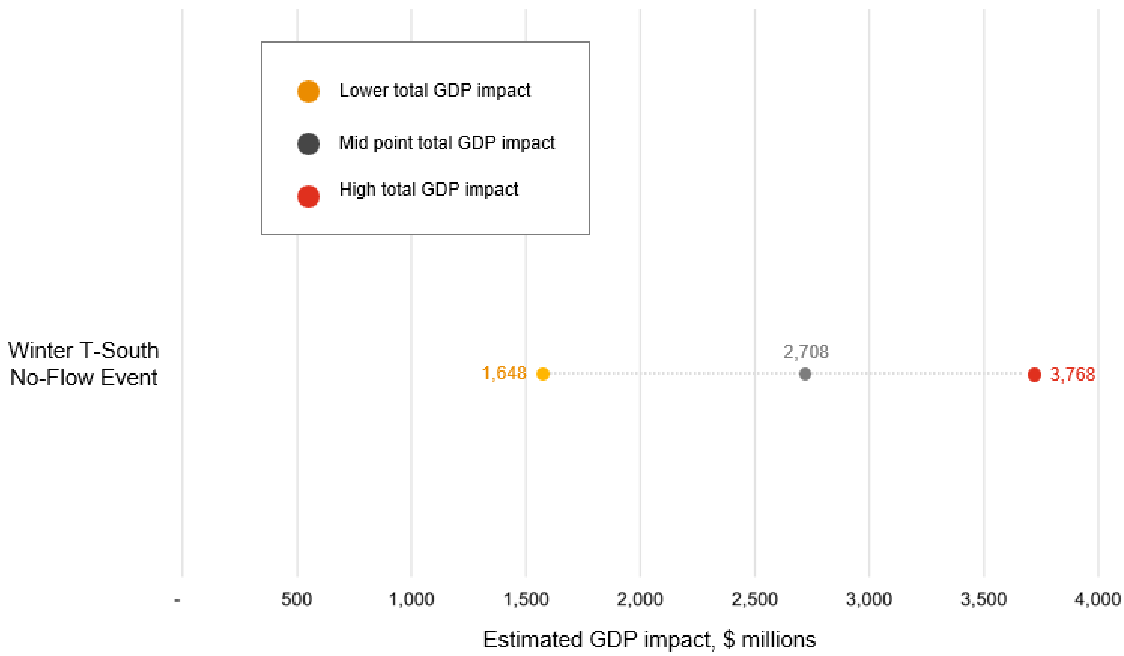
FEI retained PricewaterhouseCoopers (PwC) to provide independent analysis of **economic harm** to the Province (i.e., GDP loss). PwC estimated that a single incident anywhere on T-South, even at average winter temperature in the Lower Mainland (+4°C), would result in catastrophic economic harm well in excess of the cost of the Preferred Alternative (see Figure 1-2 below, which was prepared by PwC). PwC's analysis incorporated conservatism in a number of respects such that these GDP losses are likely understated.[32]

[30] An uncontrolled shutdown extends the outage duration as now any air entrained in the system must be purged prior to commencing relights.

[31] The Total Outage duration is defined as the estimated period (in days) starting on Day 1 of the customer outage to the day when service is finally restored to the last customer. Reported as the mean from Exponent's Monte Carlo analysis. Refer to Section 3.4.1.2 of the 2024 Resiliency Plan for additional information.

[32] See Section 3.2.2.2.1 of the Supplemental Evidence. See also e.g., Appendix RP 3 to the 2024 Resiliency Plan, PwC Report, Table 3 (pp. 8-9).

Figure 1-2: PwC Economic Harm Calculation for Winter T-South No-Flow Event (Low, Median, High)[33]



- **High Cumulative Probability of Winter T-South No-Flow Event (Section 3.2.3):** Exponent used engineering analysis to estimate the probability of failure for the 58 AVs. Exponent's winter-only probability calculations for T-South are summarized in the Table 1-3 below. Exponent calculated a very high cumulative probability of a winter no-flow event on the T-South system. These already-high cumulative probability results are still understated, since as they do not reflect the potential for cyberattacks or other malicious action.

[33] PwC's original economic harm report, filed with the Application, was based on a hypothetical major system wide disruption over a 120-day period at a time when such an outage is anticipated to have the maximum impact (peak demand during a cold winter period). The disruption in the original PwC report was assumed to affect the entire natural gas system, outages are immediate and impact 80-90 percent of demand, and there was limited time for preparation or mitigation measures. As such, it was necessary to interpolate to estimate losses with a winter T-South no-flow event. PwC's latest report, by contrast, is based on actual outage characteristics determined by system modelling in respect of each AV. The economic harm impacts shown in this figure are related only to a T-South no-flow incident occurring at average winter temperature, and which affects customers in the Lower Mainland region.

Table 1-3: Exponent's Calculated Cumulative Probability Range of T-South No-Flow Event in Winter34

Calculation Horizon	Basis for Horizon	Exponent's Calculated Cumulative Winter Only (90 Days) Probability
67 years	Expected Life of TLSE Project	95% - 100%
23 years	Adverse sensitivity included in response to BCUC commentary assumes no further use of Tilbury facility for resiliency or gas supply after 2050	65% - 97%

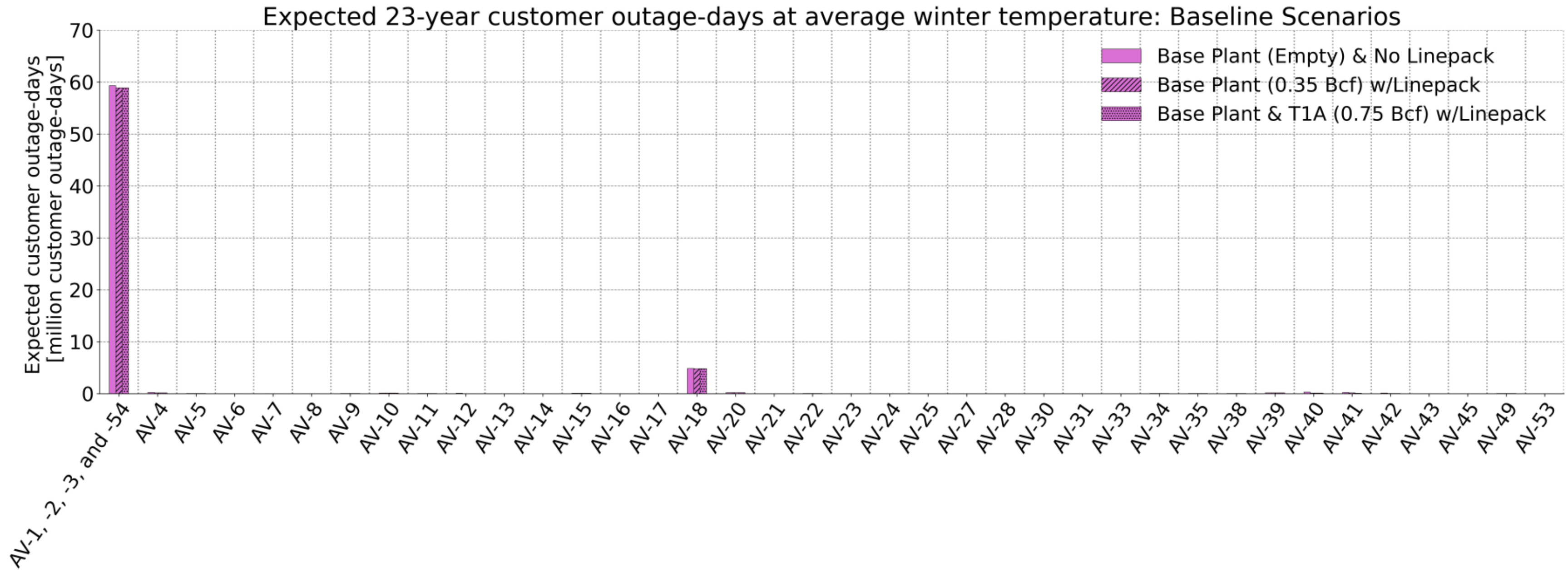
Just as the 2018 T-South Incident highlighted FEI's exposure to a T-South supply interruption, there have been two more concerning events on T-South since FEI filed this Application in 2020. FEI has experienced another supply disruption on T-South that necessitated reliance on Tilbury LNG and a river flood that submerged one of the T-South pipelines.

- **Exponent's Unmitigated Probability-Adjusted Risk Results (Section 3.2.4):** Exponent has calculated the winter-only risk for the 58 AVs over various time horizons (1 year, 23-years and 67-years), using various consequence measures (customers lost, customer-outage-days, and GDP losses). The same pattern shown in Figure 1-3 below is evident regardless of the time horizon or consequence metric: the probability-adjusted risk posed by a winter T-South no-flow event exceeds the risk associated with any other AV by a wide margin. For instance: (1) the expected annual winter-only loss associated with T-South is over eight times greater than the combined expected annual winter-only loss of all 54 of the other AVs; and (2) the expected 23-year winter-only GDP loss for T-South is approximately 14 times greater than the next largest loss (AV-18[35]).

[34] Reported as the lower bound and upper bound.

[35] AVs are anonymized for security reasons. The de-anonymized description of AV-18 is found in Confidential Appendix RP 4-18 to the 2024 Resiliency Plan.

Figure 1-3: Expected 23-year Winter-Only Customer Outage-Days for the Combination of AV-1, -2, -3, and -54[36] and for Other AVs for the Tilbury Baseline Scenarios[37]



Note: Vulnerabilities assessed by FEI and Exponent have been anonymized as "Assessed Vulnerability" numbers or "AV-#" throughout this evidence and the 2024 Resiliency Plan for security considerations. The de-anonymized information is confined to specific confidential appendices of the 2024 Resiliency Plan and expert reports.

Note: Exponent figures based on average winter temperatures exclude certain AVs where the system modelling ultimately determined that no losses would occur at average winter temperatures. See Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, para. 173.

[36] The de-anonymized description of AVs-1, 2, 3 and 54 are found in the associated AV-specific appendices to the 2024 Resiliency Plan, which has been kept confidential for security reasons.

[37] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, Figure 24.

- **Prioritizing Mitigation of T-South Risk Reflects Sound Risk Management Practices (Section 3.2.5):** Exponent recommends prioritizing mitigation of the highest risk customer outage vulnerability, which is T-South (AV's 1, 2, 3, and 54):[38] "Given the probability of failure in combination with the consequences associated with AV-1, -2, -3, and -54, Exponent would expect the risk on these AVs to be prioritized for mitigation." FEI concurs with this approach.

  The known consequences of a winter T-South no-flow event are sufficiently severe that, according to Exponent, established risk management principles would support a material investment to reduce the harm even at much lower probabilities than those calculated by Exponent. In this regard, Exponent's recommendation aligns with the views of all of the other independent experts that have previously provided evidence in this proceeding on this topic – JANA Corporation, Guidehouse and PwC.

1.3.2.2 Base Plant End-of-Life Jeopardizes Ability to Serve Customers in Normal Conditions (Section 3.3)

The Base Plant has played a critical role in FEI's supply portfolio since 1971, including providing critical peaking supply in cold winter periods. However, additional engineering analysis, and the Base Plant's deteriorating performance despite further investment, indicate that the Base Plant has reached end-of-life. There is no feasible option to extend the life of the Base Plant or replace its peaking supply in the market. A sizable capital investment is required, irrespective of resiliency considerations, to ensure that FEI can continue to serve firm load in normal operating conditions.

Section 3.3 is organized as follows:

- **Equipment is Obsolete, is Experiencing Increasing Failure Rates and is Increasingly Difficult to Maintain or Repair (Section 3.3.1):** The Base Plant houses the only regasification equipment at Tilbury. It is obsolete and is experiencing increasing rates of failure and reliability issues, which have rendered the facility unavailable when called upon. The facility is also increasingly difficult to maintain and repair, with repairs taking weeks to months to complete. FEI is already decommissioning the Base Plant liquefaction equipment.

- **Seismic, Environmental and Flooding Issues Are Inherent in Base Plant Design (Section 3.3.2):** The Base Plant was constructed to lower engineering and safety standards that were in place at the time of construction. Even if the regasification equipment was to be replaced, there are seismic, environmental and flooding issues inherent in the original Base Plant design. FEI now operates the tank well-below its design capabilities for seismic reasons (i.e., at 0.35 Bcf instead of 0.6 Bcf), and experts have recently advised against tank retrofits to restore those original capabilities.

[38] Appendix RP 2, Exponent Report, para. 245.

- **Long Replacement Project Lead Time Increases Risk (Section 3.3.3):** In light of the long lead time to permit and construct a new tank and regasification, investment decisions must be made well in advance. FEI already faces a number of years of continuing equipment deterioration while a replacement facility is built, and prolonging that time increases the potential for a permanent failure or further reduction to tank fill levels to occur before a solution is in place.

- **Losing Access to Tilbury Supply Would Challenge FEI's Ability to Meet Peak Load (Section 3.3.4):** Losing partial or full access to LNG at Tilbury, which would occur (e.g.) if the Base Plant regasification fails, would impair FEI's ability to provide uninterrupted service to customers in a typical winter. Even inferior fallback options for market-dependent peaking supply do not exist with today's highly constrained regional pipeline and storage infrastructure. In the absence of peaking supply from Tilbury, firm customers would face curtailments in normal operations unless and until sufficiently large third-party regional infrastructure upgrades were completed to make up the shortfall.

1.3.3 Expanded Alternatives Analysis (Section 4)

In the Application, FEI had considered a variety of ways to improve FEI's ability to withstand a winter T-South no-flow event.[39] In the Adjournment Decision, the BCUC indicated FEI should further consider:

- "…alternatives that offer different resiliency benefits from those that the TLSE Project purports to provide – whether such alternatives offer greater, lesser, or qualitatively different levels of resiliency benefits relative to TLSE.";[40]
- the possibility of using a portion of the Tilbury 1A tank for resiliency;[41]
- whether FEI could extend the life of the Base Plant;[42]
- three other non-Tilbury alternatives, and revisit the resiliency provided by a Southern Crossing Pipeline expansion;[43] and
- the potential for the transition towards a lower carbon future to affect the appropriate sizing of the TLSE Project.[44]

[39] Exhibit B-1-4, Application, Section 4. The first stage of that original alternatives analysis considered load management approaches, on- and off-system storage, and four different regional pipeline solutions. In the second stage of the original alternatives analysis, FEI assessed different tank sizing and regasification capacities that can support Lower Mainland load for at least three days during winter.

[40] Adjournment Decision, p. 25.

[41] Adjournment Decision, pp. 29.

[42] Adjournment Decision, p. 14.

[43] Adjournment Decision, pp. 25-30.

[44] Adjournment Decision, p. 52: "Further, if the throughput of natural gas is reduced due to a decrease in demand, the size of a tank and the amount of regasification required would likely be reduced." And p. 22: "The larger tank provides flexibility to accommodate future load growth that may occur. However, given the current emphasis on electrification and decarbonization in BC, it is unclear whether FEI will experience significant, or even any, future

The expanded alternatives analysis in Section 4 and Appendix C of this Supplemental Evidence includes the alternatives and considerations identified by the BCUC in the Adjournment Decision. Section 4 focuses primarily on those four Supplemental Alternatives that are both feasible and can avoid curtailments of firm load in normal operations, while providing varying amounts of resiliency. Appendix C includes the detailed analysis for every Supplemental Alternative.

Supplemental Alternative 9 is the Preferred Alternative, as it provides superior value to customers having regard to various considerations.

1.3.3.1 Summary of Supplemental Alternatives and Methodology to Select the Preferred Alternative (Section 4.2)

The 13 Supplemental Alternatives are described in summary form in Table 1-4 below. Expanded descriptions are included in Section 4.2 of this Supplemental Evidence, with full details of modelling parameters provided in Table C-1 in Section 2.1 of Appendix C.

Table 1-4: Summary of Supplemental Alternatives

Supp. Alt. #	Name
Alternatives Reliant on Existing Facilities[45]	
Alt 1	No Capital Upgrades with Optimized Liquefaction (No Resiliency Reserve)
Alt 2	New Regasification Only – 400 MMcf/d (No Resiliency Reserve)
Alt 3	New Regasification Only – 600 MMcf/d (No Resiliency Reserve)
New Facility with Gas Supply But No Resiliency Reserve[46]	
Alt 4	Like-for-Like (No Resiliency Reserve)
Alt 4A	New 1 Bcf Tank (No Resiliency Reserve) and 400 MMcf/d Regasification
New Facility with Resiliency Reserve But No Gas Supply[47]	
Alt 5	Like-for-Like (Full Resiliency Reserve)
Alt 6	New 1 Bcf Tank (Full Resiliency Reserve) and 800 MMcf/d Regasification
Alt 7	New 2 Bcf Tank (Full Resiliency Reserve) and 800 MMcf/d Regasification
New Facility with Both Resiliency Reserve and Gas Supply	
Alt 8	New 2 Bcf Tank (1.4 Bcf Resiliency Reserve) and 800 MMcf/d Regasification
Alt 9	New 3 Bcf Tank (2 Bcf Resiliency Reserve) and 800 MMcf/d Regasification (the Preferred Alternative)

natural gas load growth. The larger tank means greater risk of a stranded, or partially stranded, asset in the event that FEI's increased load does not emerge or decreases beyond the current load."

45 These alternatives include prolonged reliance on the Base Plant tank with no dependable resiliency reserve, declining reliability, and a high likelihood of relying on the market for some replacement gas supply.

46 These alternatives do not include a dependable resiliency reserve but provide different amounts of peaking gas supply and improved reliability.

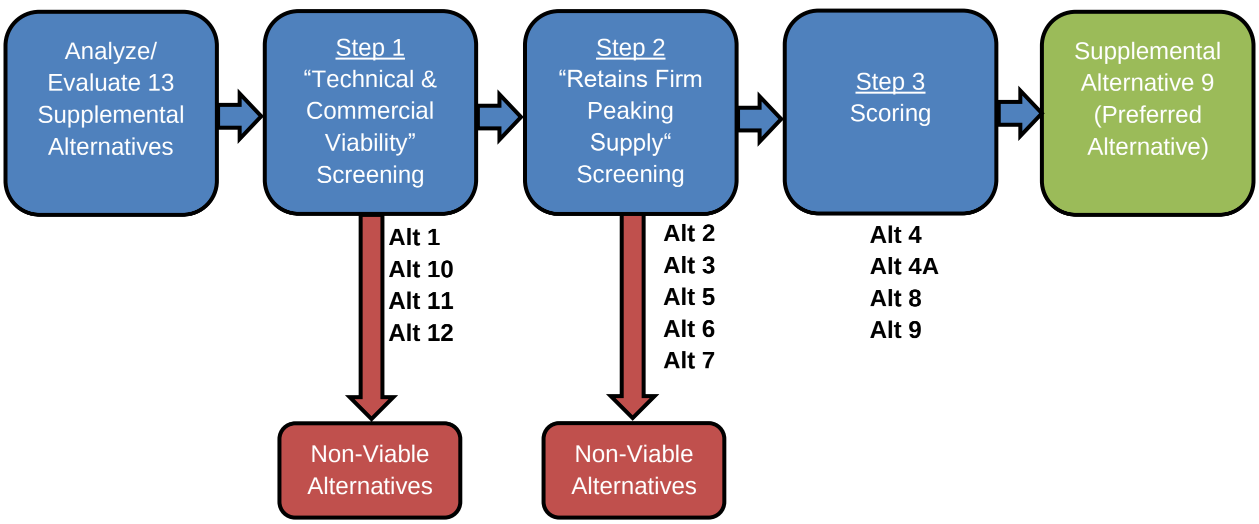
47 These alternatives include a full resiliency reserve but still rely on the market for replacement of the gas supply functions.

Supp. Alt. #	Name
Non-Tilbury Alternatives[48]	
Alt 10	Alt 1 plus Vancouver Island Transmission System (VITS) Reverse Flow
Alt 11	LNG from Woodfibre LNG
Alt 12	Floating LNG

FEI also evaluated sensitivities for Supplemental Alternatives 1, 2, 3, 4, 4A and 5 (referred to as **"contingent" scenarios**) to determine whether, optimistically assuming additional LNG volumes would be available at Tilbury on the day of a winter T-South no-flow event, would materially mitigate customer outage risk (they do not). Although FEI has provided these sensitivities in response to the Adjournment Decision, FEI remains of the view that resiliency planning should instead follow typical utility planning principles premised on sizing infrastructure and gas supply assets to be able to meet firm customer requirements consistently.[49]

FEI employed the following structured three step alternatives analysis process to ultimately identify Supplemental Alternative 9 as the Preferred Alternative.

Figure 1-4: Results from Structured Process to Identify the Preferred Alternative



1.3.3.2 Results of Step 1: FEI Eliminated Technically and Commercially Non-Viable Alternatives (Section 4.3)

In Step 1, FEI determined that all of the non-Tilbury LNG options involving the use of floating storage, Woodfibre LNG and upgrades to the Vancouver Island Transmission System (i.e., Supplemental Alternatives 10, 11 and 12) are not technically and commercially viable. Continuing

[48] FEI considers these alternatives to be non-viable approaches to providing winter resiliency and peaking gas supply.
[49] In Appendix C to this Supplemental Evidence, FEI explains why contingent modelling scenarios are not dependable and do not materially reduce risk.

to rely on the Tilbury Base Plant without capital upgrades was also ruled out because the Base Plant has reached end-of-life. Nine supplemental alternatives (2-9) passed the Step 1 screen.

1.3.3.3 Results of Step 2: FEI Eliminated Alternatives that Do Not Retain FEI's Existing On-System Firm Peaking Gas Supply (Section 4.4)

Five options that would fail to retain FEI's existing peaking supply are unacceptable because they would result in firm customers being curtailed (i.e., losing service) in peak winter periods under normal operating conditions. The four supplemental alternatives that passed this secondary screen – Supplemental Alternatives 4, 4A, 8, and 9 – would all involve a full replacement of the existing Base Plant with a new facility that will, at a minimum, restore the Base Plant's original design capabilities for gas supply (150 MMcf/d and 0.6 Bcf).

1.3.3.4 Results of Step 3 (Section 4.5)

In Step 3, FEI numerically scored Supplemental Alternatives 4, 4A, 8, and 9 (and, for information only, Supplemental Alternatives 2, 3, 5, 6, and 7[50]) having regard to the following criteria:[51]

- **Resiliency Benefit:** Considering the alternative's ability to mitigate the risk associated with a winter T-South no-flow event.
- **Gas Supply:** Considering the alternative's impact on the availability of dependable gas supply during peak demand.
- **Base Plant Challenges:** Considering the alternative's impact on the age-related Base Plant challenges (send-out reliability, seismic design, flooding, and tank venting).
- **Rate Impact:** Considering the alternative's levelized total rate impact due to both the capital costs on delivery rates and gas supply impacts/benefits on commodity rates.
- **Future Use:** Considering if the alternative would be useful or underutilized under two adverse future load sensitivities, in which FEI's Diversified Energy (Planning) Scenario is modified to assume higher rates of customer and load loss (2% and 5% annually) between the in-service date and 2050.

As summarized in Figure 1-5 and the bullets below, Supplemental Alternative 9 scored materially higher than the other Supplemental Alternatives. The scoring is relative to Supplemental Alternative 1 – No Capital Upgrades, which defines the financial outcome if the Application is not approved and no capital investment is made.

[50] Please refer to Appendix C to this Supplemental Evidence for the detailed analysis and scoring.
[51] Further discussion regarding the scoring of viable alternatives and associated weighting of the scoring criteria can be found in Section 4 of this Supplemental Evidence.

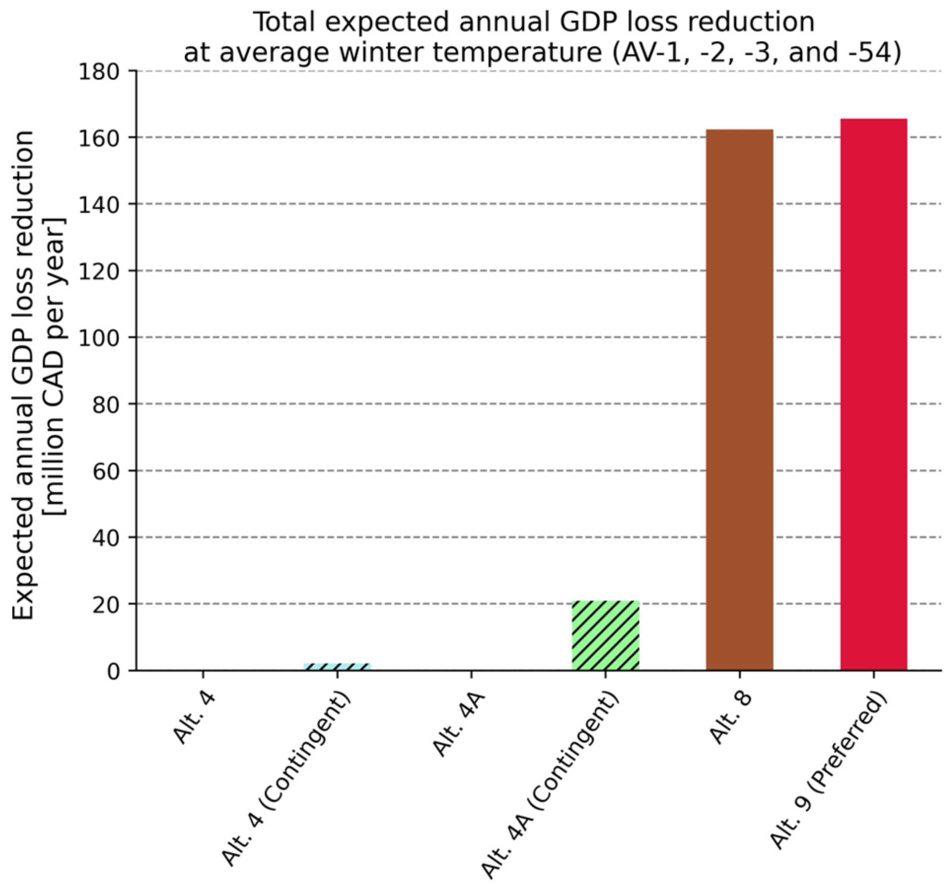
Figure 1-5: Step 3 Alternatives Evaluation Results

Evaluation Criterion	Criterion Weightin	Alternative 4	Alternative 4A	Alternative 8	Alternative 9
Resiliency Benefit	30%	No Impact	No Impact	Medium Positive Impact	High Positive Impact
Availability of Dependable Gas Supply During Peak Demand	20%	Medium Positive Impact	High Positive Impact	Medium Positive Impact	High Positive Impact
Resolves Age Related Base Plant Challenges	20%	High Positive Impact	High Positive Impact	High Positive Impact	High Positive Impact
Levelized Total Rate Impact	20%	Low Negative Impact	Low Negative Impact	Medium Negative Impact	Medium Negative Impact
Useful Under the Modified Diversified Energy (Planning) Scenario (mDEP) Between the In-Service Date and 2050	10%	No Impact	No Impact	No Impact	No Impact
	Total Weighted Score:	1.4	1.8	1.9	2.9
					Preferred

- **Step 3 "Resiliency Benefit" Scoring Criterion (Section 4.5.1):** Supplemental Alternative 9 is superior to any other alternative from a risk mitigation standpoint because, in addition to significantly increasing regasification capacity, it provides a large, dedicated resiliency reserve that provides a longer load support duration at a range of temperatures present during much of the winter.

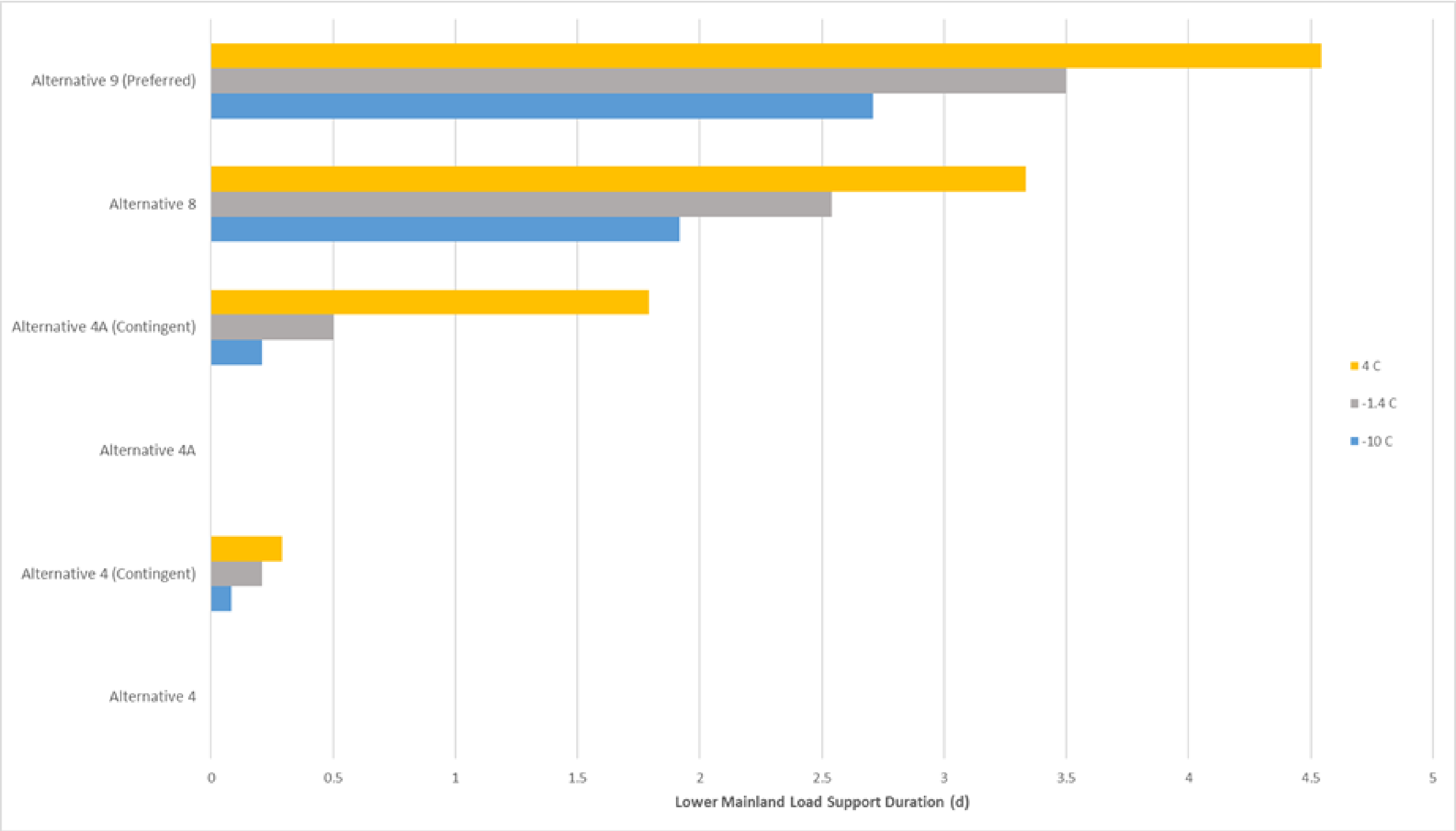
  As shown in Figure 1-6 below, at average winter temperatures (+4°C) only Supplemental Alternatives 8 and 9 provide a material improvement in risk mitigation relative to the existing Base Plant with no capital upgrades. This is true even accounting for the other alternatives' contingent scenarios, in which FEI is assumed to have access to non-dependable LNG supply on the day of a no-flow event.

Figure 1-6: T-South at Avg. Winter Temp – Expected Annual Loss Reduction



Supplemental Alternative 9 will provide superior risk mitigation relative to Supplemental Alternative 8 at below average winter temperatures that the Lower Mainland experiences during much of a typical winter. This can be seen, for instance, in Figure 1-7 below, which provides load support durations determined by transient modelling. Based on historical temperature data, nearly one-quarter of Lower Mainland winter days fall in the range of temperatures in which Supplemental Alternative 9 can bridge a three day no-flow event but Supplemental Alternative 8 could not (-6.8°C to +1.7°C).

Figure 1-7: Duration of Lower Mainland Load Support Provided by Supplemental Alternatives at Various Temperatures



- **Step 3 "Availability of Dependable Gas Supply During Peak Demand" Scoring Criterion (Section 4.5.2)**: Supplemental Alternatives 4A and 9 score higher on this criterion because, while Supplemental Alternatives 4 and 8 replace the existing Tilbury peaking gas (150 MMcf/d and 0.6 Bcf), FEI's requirements exceed that amount. FEI requires 200 MMcf/d and 1.0 Bcf of peaking supply. Supplemental Alternative 4A and 9 provide enough peaking supply to meet FEI's full requirements and thus optimize the gas supply portfolio.

- **Step 3 "Resolves Age-Related Base Plant Challenges" Scoring Criterion (Section 4.5.3):** Supplemental Alternatives 4, 4A, 8, and 9 all score highly because they all include the installation of a new tank and new regasification equipment built to current standards.

- **Step 3 "Levelized Total Rate Impact" Scoring Criterion (Section 4.5.4):** Supplemental Alternative 9 will provide an additional 0.4 Bcf of peaking gas supply relative to the smaller Supplemental Alternatives 4 and 8), which avoids the need for FEI to continue procuring peaking supply in the market. The avoided annual peaking gas costs, which would otherwise have to be incurred to obtain capacity on upgraded regional infrastructure, offset incremental capital costs to the point where the levelized total rate impact for Supplemental Alternative 9 is less than Supplemental Alternative 8.

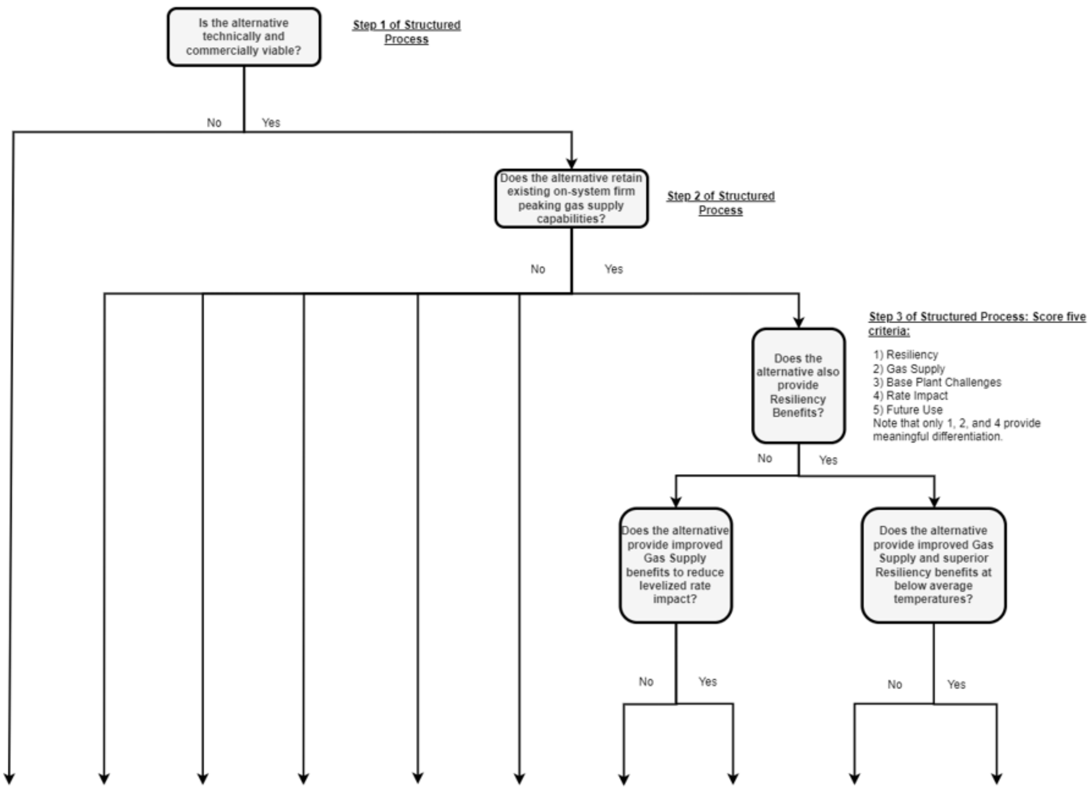
- **Step 3 "Future Use" Scoring Criterion (Section 4.5.5):** All of the viable alternatives (Supplemental Alternatives 4, 4A, 8, and 9) would be fully utilized for resiliency and/or gas supply in 2050 under two adverse load loss sensitivities. On-system LNG is a unique asset when it comes to the flexibility afforded in response to changing load:

    - The resiliency value (other things equal) increases if load declines because the same volume of LNG can support less load for longer. Exponent's calculations show that, since there is still residual risk with Supplemental Alternative 9 (the largest option) at current load, the additional risk mitigation that would be provided under a hypothetical reduced load scenario would be valuable for the remaining customers.

    - Alternatively, FEI (with input from the BCUC) could reallocate some of the resiliency reserve to gas supply to generate gas supply benefits for customers. FEI's overall energy requirements in 2050 under the adverse load loss sensitivities will still far exceed 3 Bcf. The inherent characteristics of on-system LNG (e.g., its value as a "backstop" for other resources, rapid send out, and the available mitigation opportunities) mean that, in a hypothetical declining load scenario, it would make more sense to optimize the portfolio by reducing other gas supply assets.

Figure 1-8 is an alternate presentation of the results of the structured three-step alternative analysis process.

Figure 1-8: Step 3 – Scoring Results



	Alternative 1	Alternative 2	Alternative 3	Alternative 5	Alternative 6	Alternative 7	Alternative 4	Alternative 4A	Alternative 8	Preferred (Alternative 9)
Viability:	Not Viable	Not Viable	Not Viable	Not Viable	Not Viable	Not Viable	Viable	Viable	Viable	Viable
Levelized Total Rate Impact (%):	1.8%	3.3%	3.4%	4.4%	4.9%	5.6%	3.2%	3.0%	4.4%	4.2%
Levelized Total Rate Impact - Incremental to Alt 1 (%):	NA	1.57%	1.66%	2.68%	3.2%	3.84%	1.44%	1.27%	2.60%	2.45%
67-Year Expected GDP Loss Reduction ($millions):	0	0	0	139.5	2,152.9	11,092.7	0	0	10,877.1	11,092.7
Expected Annual COD - Cold Weather (-1.4C):	NA	NA	NA	NA	NA	1,250,000	NA	NA	2,900,000	1,250,000
Scoring Results	NA	0.1	0.1	0.4	0.0	1.5	1.4	1.8	1.9	2.9

FEI's strong view is that Supplemental Alternative 9 will provide the best value in meeting the Project objectives by providing the optimum peaking gas supply and providing material customer outage risk reduction. Comparing the 67-year expected GDP loss reduction and the levelized total rate impact of Supplemental Alternative 4A to Supplemental Alternatives 8 and 9 leads to the following conclusions:

- For an additional 1.3 percent and 1.2 percent levelized total rate impact, Supplemental Alternatives 8 and 9 would both provide significant loss reduction against a T-South no-flow event when compared to Supplemental Alternative 4A, which would optimize peaking supply only. This is true for direct customer impacts (customer outage-days) and GDP impacts.

- The increase in levelized total rate impact between Supplemental Alternative 4A (which would optimize gas supply only) and Supplemental Alternatives 8 and 9 (which would have varying amounts of gas supply plus resiliency reserves) is small compared to the significant loss reduction that would be provided by Supplemental Alternatives 8 and 9.
- Supplemental Alternatives 8 and 9 would provide similar levels of risk mitigation against a T-South winter no-flow event at average winter temperature. However, Supplemental Alternative 9 will provide superior risk mitigation at temperatures below the average winter temperature (i.e., the expected annual customer outage-day loss at -1.4°C is lower under Supplemental Alternative 9 than under Supplemental Alternative 8) for a lower levelized total rate impact. Based on historical temperature data, nearly one-quarter of Lower Mainland winter days fall in the range (-6.8°C to +1.7°C) in which Supplemental Alternative 9 can bridge the regulatory shutdown period but Supplemental Alternative 8 could not. This shows the benefit of the Supplemental Alternative 9's incremental resiliency reserve (i.e., an additional 0.6 Bcf relative to Supplemental Alternative 8) and incremental gas supply capabilities (i.e., an additional 0.4 Bcf), which come at a relatively small incremental cost.

1.3.3.5 Additional Information on the Preferred Alternative's Resiliency Benefits (Section 4.7)

Supplemental Alternative 9 (the Preferred Alternative) will provide significant resiliency benefits relative to today, over and above what are accounted for in the Step 3 "Resiliency Benefit" criterion. These benefits include: providing the potential option of a staged shutdown that maintains service to some portion of FEI's customers; avoiding uncontrolled depressurization and the attendant safety risks; providing valuable time for customers, governments and social / health services to prepare for an outage; mitigating the calculated customer outage risk for 13 other customer outage vulnerabilities across FEI's system; and, backstopping off-system storage supply in the event of a disruption at those facilities.

1.3.4 Project Description (Section 5)

This section updates certain information contained in Section 5 of the Application. The description of the TLSE Project has not changed since the filing of the Application, as the preferred alternative continues to be to replace the existing Base Plant with 3 Bcf of storage and 800 MMcf/d of regasification capacity. However, since the Application was filed, geotechnical requirements have changed due to changes in seismic design standards. FEI has updated the AACE Class 3 cost estimate with new contingency and escalation reports and has updated the Project schedule to reflect an updated in-service date at the end of 2030.

1.3.5 Financial Analysis for Preferred Alternative (Section 6)

This section provides the updated financial analysis for the Preferred Alternative (Supplemental Alternative 9), a new LNG facility with 3 Bcf of LNG storage capacity and 800 MMcf/d of regasification. At a high level, the financial analysis includes an updated AACE Class 3 capital cost estimate, delivery rate impact and total rate impact analyses. FEI has made changes to the analysis to address specific commentary in the Adjournment Decision, and to better reflect the overall customer bill impact.

- **Updated TLSE Project Cost Estimate (Section 6.1):** FEI has updated the AACE Class 3 cost estimate, including to account for industry-wide inflationary pressures, a larger contingency, and P70-based escalation (in the Application, FEI used a P50). The updated total cost estimate for the TLSE Project is $1,143.889 million in as-spent dollars, including AFUDC.
- **Updated Financial Analysis – 67-year Analysis Period (Section 6.2):** FEI has undertaken its primary financial evaluation of the Preferred Alternative in a similar manner as in the Application. The exception is that FEI has now also recognized offsetting reductions in the cost of gas due to the Preferred Alternative's incremental gas supply benefits (avoided costs) relative to Supplemental Alternative 1 – No Capital Upgrades.
- **Updated Rate Impact for the Preferred Alternative (Section 6.3):** The Preferred Alternative results in a levelized total rate (i.e., bill) impact of approximately $21 per year over the 67-year analysis period relative to Supplemental Alternative 1. FEI's bill impact analysis reflects the incremental delivery rate impact associated with the Project, partially offset by gas supply benefits (reflected in a lower cost of gas rate) when compared to current 2024 Approved rates.
- **FEI Performed a Sensitivity with a Shorter (27-year) Amortization Period to Address BCUC Commentary (Section 6.4):** In recognition of the BCUC's commentary in the Adjournment Decision, FEI has also provided sensitivities based on a shorter amortization period (i.e., full depreciation by 2050). However, FEI considers this period is too short, given the ongoing usefulness of the Preferred Alternative.

1.3.6 Environmental and Archaeological (Section 7)

This section provides an update of the Environmental Assessment for the Tilbury Phase 2 LNG Expansion Project (Phase 2) which has involved additional environmental and archaeological activities. Based on the additional assessments undertaken, FEI's assessment of the pre-mitigation potential environmental and archaeological impacts of the Project have downgraded. FEI expects to mitigate potential impacts to negligible levels through additional assessments, permitting, and standard protection and mitigation measures.

1.3.7 Consultation and Engagement (Section 8)

This section provides an update on consultation and engagement with Indigenous groups, the public, government and other stakeholders. These activities are consistent with the BCUC's CPCN Guidelines, are in alignment with other FEI applications approved by the BCUC, and reflect the TLSE Project's current stage of development.

1.3.8 BC Energy Objectives and Long-Term Gas Resource Plan (Section 9)

This section discusses the factors that section 46(3.1) of the *Utilities Commission Act* states the BCUC must consider when determining whether to issue a CPCN. The applicable of British Columbia's energy objectives support the TLSE Project. FEI anticipates the Project will deliver socio-economic benefits. Otherwise, British Columbia's energy objectives are generally neutral in relation to the Project. Further, this Application considers and is consistent with the outcome of the 2022 LTGRP proceeding, which identified the need for FEI to revise and resubmit its resiliency plan. FEI has performed that work, and the 2024 Resiliency Plan provides the basis for this Application.

1.4 PROPOSED REGULATORY REVIEW PROCESS

Due to the technical nature, size of the evidentiary record, and multiple layers of confidentiality, FEI considers that a written hearing process which includes a technical workshop on Exponent's risk and consequence determination method and two rounds of information requests (IRs) from the BCUC and interveners will provide for an appropriate and efficient review of the Supplemental Evidence.

FEI proposes the regulatory timetable set out in Table 1-5 below for reviewing the Supplemental Evidence and relevant portions of the 2024 Resiliency Plan. FEI notes that interveners have already registered and have actively participated in the proceeding to date, which has involved a workshop, multiple rounds of IRs, and intervener evidence and rebuttal evidence over the course of multiple years until the adjournment. Existing interveners are receiving prompt notice of this evidence filing.

The proposed regulatory timetable contemplates that the BCUC issue a procedural order related to this submission by the week of November 25, 2024. A draft procedural order is attached as Appendix M-1 to the Supplemental Evidence.

Table 1-5: Proposed Regulatory Timetable

ACTION	DATE (2024)
FEI provides notice of Supplemental Evidence and procedural order to registered Interveners	Friday, December 6
FEI provides confirmation of notice requirements	Friday, December 13
ACTION	**DATE (2025)**
Technical Workshop on Exponent's Risk and Consequence Determination Method	Wednesday, January 29
BCUC Information Request (IR) No. 1	Thursday, February 20
Intervener IR No. 1	Thursday, February 27
FEI responses to IR No. 1	Thursday, April 3

ACTION	DATE (2025)
BCUC IR No. 2	Thursday, April 17
Intervener IR No. 2	Thursday, April 24
FEI responses to IR No. 2	Thursday, May 15
Letters of comment deadline	Thursday, May 22
FEI final argument	Thursday, June 12
Intervener final argument	Thursday, July 3
FEI reply argument	Thursday, July 24

2. SUMMARY OF THE PROCESS AND EVIDENCE TO DATE, AND FEI'S RESPONSE TO THE ADJOURNMENT DECISION

The purpose of this Supplementary Evidence is to respond to the BCUC's findings in the Adjournment Decision and to update the evidence where needed given the passage of time since the Application was filed. There is a significant body of evidence already filed in this proceeding, and the prior evidence remains important. Accordingly, FEI has sought to avoid unduly repeating previous evidence.

The following sections summarize the regulatory process undertaken to-date, provide references to the previously filed evidence, and identifies where in the Supplemental Evidence FEI has addressed the BCUC's findings from the Adjournment Decision.

2.1 THE REGULATORY PROCESS TO-DATE

FEI filed the Application on December 29, 2020. The proceeding commenced with a workshop in March 2021 and was adjourned approximately two years later, pending the filing of additional evidence. The regulatory process to-date is summarized in the following table.

Table 2-1: Summary of Regulatory Process

Steps	Date
FEI filed Application	December 29, 2020
Workshop	March 11, 2021
In-camera Technical Session	April 7, 2021
BCUC & Intervener Information Request (IR) No. 1	June 17 & July 9, 2021
FEI Response to IR No. 1	September 8, 2021
BCUC & Intervener IR No. 2	October 6, 2021
FEI Response to IR No. 2	November 10, 2021
BCUC Panel IR No. 1	January 25, 2022
FEI Response to BCUC Panel IR No. 1	March 1, 2022
Intervener Evidence Written & Oral	March 15 & April 6, 2022
IR No. 1 on Intervener Written & Oral Evidence	April 21 & May 2, 2022
Intervener Response to IR No. 1 on Written & Oral Evidence	May 11 & May 30, 2022
FEI Rebuttal Evidence	June 2, 2022
IR No. 1 on FEI Rebuttal Evidence	June 23, 2022
FEI Response to IR No. 1 on Rebuttal Evidence	July 14, 2022
BCUC & Intervener IRs on Exhibit A2-1	August 25 & September 1, 2022
FEI Response to IRs on Exhibit A2-1	September 16, 2022
FEI Written Final Argument	October 24, 2022
Intervener Oral & Written Argument	November 3 or 4 & November 24, 2022
FEI Written Reply Argument	December 12, 2022
BCUC Adjournment Decision	March 23, 2023

2.2 REFERENCES TO PREVIOUSLY FILED EVIDENCE

FEI has already filed a significant amount of evidence in this proceeding, including the Application, responses to five rounds of IRs, and rebuttal evidence. While FEI has avoided repeating that information within the Supplemental Evidence, it remains important. Appendix A identifies key topics discussed in previous evidence, with citations to the applicable evidence. FEI's previously filed written Final and Reply Arguments also include extensive citations to the relevant evidence.

2.3 FEI HAS ADDRESSED THE ADJOURNMENT DECISION FINDINGS

FEI has addressed the BCUC's findings regarding further evidence needed to evaluate the TLSE Project and the need for a comprehensive Resiliency Plan. The following table, which summarizes the more detailed Table of Concordance provided in Appendix B, identifies the BCUC's findings and commentary in the Adjournment Decision and where these points are addressed in the Supplemental Evidence.

Table 2-2: Summary of Where FEI Addresses Adjournment Decision Findings

Adjournment Decision Finding	Where Finding is Addressed
Need for comprehensive Resiliency Plan (p. 12)	FEI has prepared a comprehensive Resiliency Plan, filed concurrently with this Supplemental Evidence (2024 Resiliency Plan). As part of the 2024 Resiliency Plan, FEI examined the entire regional system for single point of failure risk and performed a detailed assessment of 58 AVs (see Section 5 of the 2024 Resiliency Plan).
Consequence of T-South no-flow event (p. 11)	FEI has used its system modelling to determine how many customers would lose service following a no-flow event, and how long those customers are likely to be without service. PwC has performed an economic impacts analysis. (See Section 5 of the 2024 Resiliency Plan and Section 3.2.2 of this Supplemental Evidence)
Probability of T-South no-flow event (time of year) (p. 9)	Exponent has reviewed conditions specific to each AV and determined the probability of a no-flow event occurring during the three winter months. (See Section 5 of the 2024 Resiliency Plan and Section 3.2.3 of this Supplemental Evidence)
Probability of T-South no-flow event (time horizon) (pp. 8-9)	The 67-year expected life of the TLSE Project is an appropriate time scale for assessing risk and rate impacts, given FEI's expectation that the facility will remain useful. Exponent has nevertheless also calculated the probability for failure over a 23-year time horizon. The cumulative probability of a winter no-flow event on T-South is still significant over 23 years. (See Section 5 of the 2024 Resiliency Plan and Section 3.2.4 of this Supplemental Evidence)

Adjournment Decision Finding	Where Finding is Addressed
Duration of T-South no-flow event (residual risk with TLSE Project) **(pp. 9, 11, 16)**	Exponent has considered the potential duration of a no-flow event having regard to the potential causes it identified. Exponent also prepared a Monte Carlo analysis to account for the potential for different no-flow event durations. Exponent determined that the TLSE Project significantly reduces the risk associated with a T-South no-flow event, both in terms of reducing probability of a customer outage and the consequences of any customer outage. (See Section 5.1 of the 2024 Resiliency Plan)
Other causes of customer outages **(p. 17)**	The 2024 Resiliency Plan evaluated 58 AVs, including a number in the Lower Mainland. The TLSE Project addresses the AVs that give rise to the largest risks. (See Section 7 of the 2024 Resiliency Plan)
Future developments (impact on probability and consequence of T-South no-flow event) (pp. 8-9)	FEI has assessed the impact of future developments on consequence (e.g., impact of electrification of Lower Mainland gas load) and probability (e.g., climate change increasing potential of no-flow events). (See Section 6 of the 2024 Resiliency Plan) (Section 4.5.5 of this Supplemental Evidence provides adverse load loss sensitivities) (Section 5.2 of the 2024 Resiliency Plan addresses the Federal Government's assessment of increasing cyber risk for utilities)
Gas supply benefits **(p. 14)**	The TLSE Project, by replacing the end-of-life Base Plant that is no longer able to reliably perform its critical gas supply function, will ensure that FEI is able to continue serving peak winter loads as it has for decades. As part of the Supplemental Alternatives analysis, FEI assessed the financial value for customers of LNG located in the Lower Mainland based on the avoided cost of acquiring peaking supply on upgraded regional infrastructure. (See Section 4.5.4 of this Supplemental Evidence)
Other potential alternatives to the TLSE Project **(pp. 25-32)**	FEI has evaluated all of the alternatives identified by the BCUC, including options that provide varying levels of customer outage risk mitigation and peaking gas supply. (See Section 4.2 of this Supplemental Evidence)
Stranded asset risk **(p. 53)**	FEI discusses the future use for the TLSE Project. FEI started with its accepted planning scenario from the 2022 LTGRP, the Diversified Energy Planning (DEP) Scenario, modified into two hypothetical adverse load sensitivities to reflect hypothetical customer losses in the Lower Mainland of 2 percent and 5 percent per year until 2050. (See Section 4.5.5 of this Supplemental Evidence)

The following table provides references to where the 2024 Resiliency Plan addresses the BCUC Panel's specific comments in the Adjournment Decision on the expected content of a comprehensive resiliency plan.

Table 2-3: Summary of Where FEI Addresses the BCUC's Commentary on Resiliency Plan Content

Adjournment Decision Commentary	Where Commentary is Addressed in 2024 Resiliency Plan
Identification of vulnerabilities (p. 51)	FEI identified 87 system outage vulnerabilities through a holistic review. Exponent quantified the risk associated with the 58 AVs. (See Section 4.1 of the 2024 Resiliency Plan)
Current risk assessment / resiliency gap analysis (p. 51)	FEI identified 87 system outage vulnerabilities through a holistic review. Exponent's quantitative risk analysis of the 58 AVs accounts for available supply assets, infrastructure (including AMI), and personnel. (See Section 5 of the 2024 Resiliency Plan)
Current risk assessment / gap analysis (consequences / probability) (pp. 11, 51)	Exponent has quantified risk for all 58 AVs based on probability x consequence, as follows: • a variety of modes of failure were considered, as applicable; • Exponent only considered the risk during a three-month winter period; • Exponent used hydraulic modelling that accounts for available alternative supply and uses average winter temperatures in the relevant area to determine customer outage breadth; • customer outage duration is based on the BCUC-approved System Preservation and Restoration Plan[52]; and • Exponent used a Monte Carlo analysis to address uncertainty in the duration of the no-flow event. (See Section 3 and Appendix RP 3 to the 2024 Resiliency Plan (PwC Report))
Impact of potential future developments on risk (pp. 52-53)	FEI has assessed the impact of future developments on consequence (e.g., impact of electrification of Lower Mainland gas load) and probability (e.g., climate change increasing potential of no-flow events). (See Section 6 of the 2024 Resiliency Plan) (Section 5.2 of the 2024 Resiliency Plan addresses the Federal Government's assessment of increasing cyber risk for utilities)
Options to address risks (p. 51)	Based on the risk assessments of the 58 AVs, FEI is only recommending resiliency-specific investments to address a no-flow event on T-South at this time. (See Section 7.1 of the 2024 Resiliency Plan)

52 These assumptions were discussed in detail in FEI's Rebuttal Evidence to RCIA (Exhibit B-46).

3. PROJECT NEED

3.1 INTRODUCTION

In this section, FEI provides the additional information on Project need identified in the Adjournment Decision as well as updated information given the passage of time since the Application was filed.

The Application described the Project need as enhancing the resiliency of FEI's system by providing immediate backup gas supply to FEI customers, primarily in the Lower Mainland, in the event of a supply emergency.[53]

FEI further clarified the Project need as including the replacement of the existing Tilbury Base Plant, stating in its Final Submissions:[54]

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

In the Adjournment Decision, the BCUC accepted the need for resilient utility infrastructure and the importance of resiliency in the provision of safe and reliable service. However, the BCUC stated that resiliency objectives are best assessed on a holistic level by comparing various resiliency options and prioritizing and planning against various outage scenarios, and then developing a comprehensive resiliency plan.[55] Regarding the need to replace the Base Plant, the BCUC stated that it was unable to assess the cost effectiveness of the TLSE Project as a replacement for the Base Plant due to the lack of evidence regarding the TLSE Project as a "like-for-like" replacement of the Base Plant and the ability of the TLSE Project to replace the functions or capacity currently provided by the Base Plant with regard to peaking supply.[56]

Accordingly, and in response to the BCUC's findings and commentary in the Adjournment Decision, FEI has undertaken extensive additional analysis to support the Project need, including the comprehensive 2024 Resiliency Plan which is supported by the evidence of external experts.

Based on the additional evidence, FEI confirms that the TLSE Project is needed to:

[53] Exhibit B-1-4, p. 19.
[54] FEI Final Argument (Public Version), p. 9.
[55] Adjournment Decision, p. 12.
[56] Adjournment Decision, p. 14.

- mitigate the significant resiliency risk that hundreds of thousands of customers in the Lower Mainland will lose service for many weeks following a winter no-flow event on T-South; and
- ensure that FEI continues to have access to sufficient dependable peaking supply to be able to serve firm customers during normal operations.

The status quo, in the absence of significant capital investment, leaves customers exposed to loss of service in normal operations due to the Base Plant having reached end-of-life and no longer being able to reliably provide critical peaking supply. In a widespread and lengthy gas outage, which will occur following a winter T-South no-flow event, British Columbians are left exposed to serious health and mortality risk and significant social and economic consequences. This would be, in FEI's view, an unacceptable basis for future system planning.

Section 3 is organized around the following points:

- **Section 3.2 – Mitigating FEI's Largest Customer Outage Risk:** The 2024 Resiliency Plan analysis confirms that a winter T-South no-flow event is FEI's single largest customer outage risk, and that the risk is too significant to leave unmitigated.
  - **Section 3.2.1 – 2024 Resiliency Plan Is a Sound Basis for Determining Project Need:** The 2024 Resiliency Plan, filed in tandem with this Supplemental Evidence, provides a sound basis for the BCUC to conclude that FEI is appropriately targeting its resiliency investments towards its highest risk. It is a holistic and comprehensive resiliency assessment, undertaken with considerable input from independent experts, and reflects the BCUC's guidance and direction in the Adjournment Decision.
  - **Section 3.2.2 – Catastrophic Consequences of T-South Winter No-flow Event:** FEI used its standard hydraulic system modelling to determine the extent of the customer outages for each Assessed Vulnerability. A winter no-flow event on T-South lasting only a matter of hours will, without question, have catastrophic consequences. By virtue of the regasification constraint at Tilbury, FEI's Lower Mainland gas system will fail on Day 1 regardless of how much LNG is assumed to be present in the Base Plant or Tilbury 1A on the day the no-flow event occurs. The outage will last many weeks. It will cause billions of dollars of economic harm, and can be expected to result in adverse health impacts and death for vulnerable populations.
  - **Section 3.2.3 – High Cumulative Probability of T-South Winter No-flow Event:** Exponent calculated a very high cumulative probability of a winter no-flow event on the T-South system. This is true regardless of whether the time horizon is the 67-year expected service life of the TLSE Project or the 23-year shortened life (i.e., to 2050) that FEI included as a sensitivity to be responsive to the Adjournment Decision. The already high results are still understated as they do not reflect the

potential for cyberattacks or other malicous action. There have been two more near-miss events on T-South since FEI filed the Application in 2020.

- **Section 3.2.4 – Exponent's Unmitigated Probability-Adjusted Risk Results:** Exponent has used a consistent methodology to quantify risk for all AVs, having regard to both probability and consequences. The probability-adjusted risk posed by a T-South winter no-flow event exceeds the risk associated with any other AV by a wide margin, regardless of the consequence measures or time horizon used.

- **Section 3.2.5 – Prioritizing Mitigation of T-South Risk Reflects Sound Risk Management Practices:** Exponent recommends prioritizing mitigation of the highest risk customer outage vulnerability, which is T-South. The known consequences of a T-South winter no-flow event are so severe that, according to Exponent (and consistent with prior expert evidence in this proceeding), established risk management principles would support a material investment to reduce the harm even at much lower probabilities than those calculated by Exponent.

- **Section 3.3 – Ensuring Sufficient Peaking Supply to Maintain Service in Normal Operations:** The Tilbury Base Plant has played a critical role in normal operations since 1971, including providing critical winter peaking supply, and support during less severe supply constraints and system work to sustain service to customers. However, it is clear based on additional operating experience and engineering studies since filing the Application that, despite FEI's investment in the Base Plant in recent years, the Base Plant has reached end-of-life. Continuing to operate this critical supply portfolio asset longer than is necessary to construct a replacement facility would jeopardize FEI's ability to meet peak loads in normal operations. There is no feasible option to extend the life of the Base Plant or replace its peaking supply in the market.

    - **Section 3.3.1 – Equipment is Obsolete, is Experiencing Increasing Failure Rates and is Increasingly Difficult to Maintain or Repair:** The Base Plant houses the only regasification equipment at Tilbury. It is obsolete and is experiencing increasing rates of failure and reliability issues, which have rendered the facility unavailable when called upon. The facility is also increasingly difficult to maintain and repair, with repairs taking weeks to months to complete. FEI is already decommissioning the Base Plant liquefaction equipment. The declining regasification equipment reliability is a matter of significant concern to FEI, since the equipment is only called on to function at times where the supply is necessary to meet customer demand and avoid curtailments.

    - **Section 3.3.2 – Seismic, Environmental and Flooding Issues Are Inherent in Base Plant Design:** The Base Plant was constructed to lower engineering and safety standards that were in place at the time of construction. Even if the regasification equipment was to be replaced, there are seismic, environmental and flooding issues inherent in the original Base Plant design. FEI now operates the tank well-below its design capabilities for seismic reasons, and experts have recently advised against tank retrofits to restore those original capabilities.

- **Section 3.3.3 – Long Replacement Project Lead Time Increases Risk:** In light of the long lead time to permit and construct a new tank and regasification equipment, investment decisions must be made well in advance. FEI already faces a number of years of continuing equipment deterioration while a replacement facility is built, and prolonging that time increases the potential for a permanent failure or further reduction to tank fill levels to occur before a solution is in place.
- **Section 3.3.4 – Losing Access to Tilbury Supply Would Challenge FEI's Ability to Meet Peak Load:** Losing partial or full access to LNG at Tilbury, which would occur, for example, if the Base Plant regasification fails, would impair FEI's ability to provide uninterrupted service to customers in a typical winter. Even inferior fallback options for market-dependent peaking supply do not exist with today's highly constrained regional pipeline and storage infrastructure. In the absence of peaking supply from Tilbury, firm customers would face curtailments in normal operations unless and until regional upgrades could be completed to make up the shortfall.

3.2 LOSS OF T-SOUTH SUPPLY IN WINTER IS, BY FAR, FEI'S GREATEST RESILIENCY RISK AND SHOULD BE MITIGATED

As described below, the 2024 Resiliency Plan, with its probability x consequence analysis that reflects actual location-specific causes of supply disruptions, confirms that a total loss of T-South supply during winter is FEI's single greatest customer outage risk by a large margin. FEI's Lower Mainland gas system will fail on Day 1, resulting in hundreds of thousands of customers losing service for many weeks, regardless of how much LNG is assumed to be present in the Base Plant or Tilbury 1A on the day the no-flow event occurs. Exponent calculated a high cumulative probability of a T-South winter no-flow event. Exponent endorsed targeting the T-South risk for mitigation, and suggested that established risk management principles would support a material investment to reduce catastrophic harm even at much lower probabilities.

3.2.1 2024 Resiliency Plan Is a Sound Basis for Determining Project Need

This section provides a high-level summary of the approach and content of the 2024 Resiliency Plan, with a focus on the considerable input of independent experts and how it provides the type of holistic assessment suggested in the Adjournment Decision. The 2024 Resiliency Plan reflects substantial analysis and provides a sound basis for the BCUC to conclude that FEI is appropriately targeting its resiliency investments towards its highest risk.

The primary recommendation of the 2024 Resiliency Plan is:[57]

> *FEI has confirmed the need for resiliency-driven investment to mitigate FEI's greatest customer outage risk that is due to a winter T-South no-flow event (Assessed Vulnerabilities (AV) 1, 2, 3 and 54), as well as risk associated with AV 18. New and larger on-system LNG at Tilbury will mitigate both risks.*
>
> *Four other AVs have been identified as warranting further investigation, but FEI is not recommending at this time any additional investment where the primary driver is resiliency. Based on FEI's current analysis, the AVs other than those noted above are already managed in a reasonable manner accounting for the magnitude of the risk of customer outages and the cost of mitigation, recognizing it is not feasible to fully mitigate every outage risk on a natural gas system.*
>
> *For all Assessed Vulnerabilities, FEI will consider further risk mitigation in sustainment capital planning, as assets come due for replacement, and in the context of potential projects that also have other non-resiliency drivers.*

The 2024 Resiliency Plan provides a more comprehensive explanation of the approach and results. Section 2 and Appendix B to this Supplemental Evidence provide tables of concordance summarizing how FEI has addressed the BCUC's commentary regarding: (1) further evidence needed to evaluate the TLSE Project; and (2) specific content of FEI's holistic resiliency plan.

[57] 2024 Resiliency Plan, Section 1.3.

3.2.1.1 Summary of 2024 Resiliency Plan Approach and Content

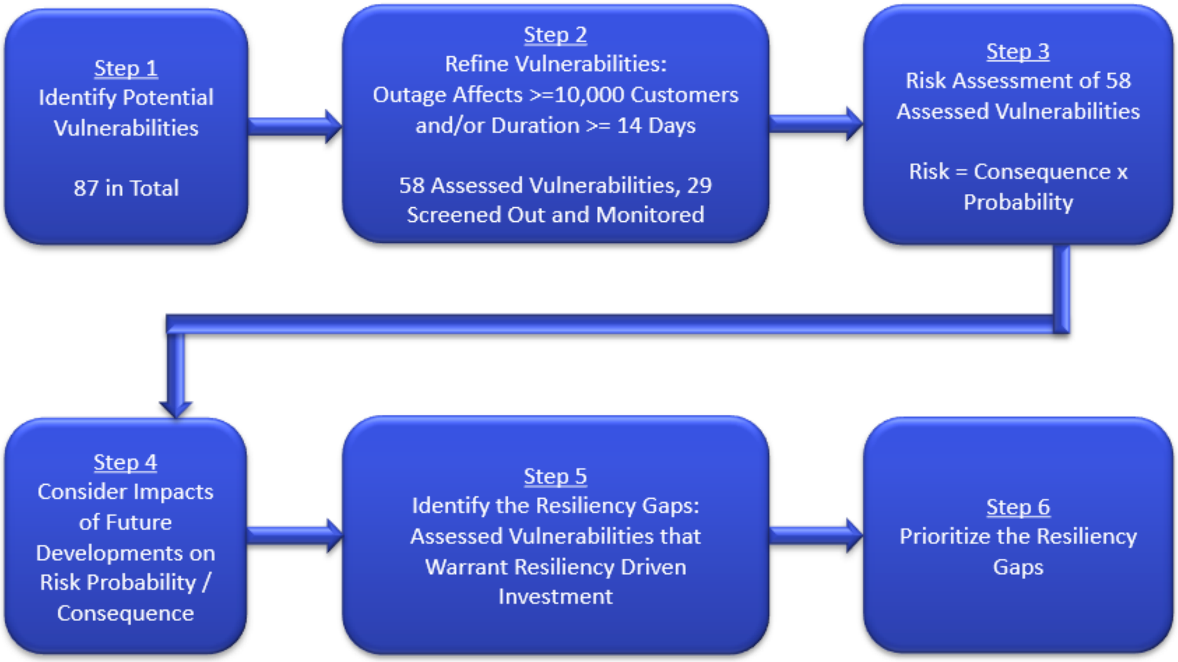
The 2024 Resiliency Plan is the output of a structured process developed with input from Exponent. Exponent's assessment of the process is: "…Exponent agrees with FEI's Resiliency Risk Assessment Plan and its methodology for identifying, assessing, and quantifying system risk."[58] Among other things, the 2024 Resiliency Plan incorporates:

- a holistic scan of vulnerabilities, both on FEI's system and upstream of FEI's system, that can interrupt supply and expose FEI to a material customer outage (87 potential resiliency vulnerabilities);
- a consequence and probability-based risk assessment of the 58 AVs associated with the most significant potential customer outages;
- discussion of cyber-related risk for energy infrastructure, sourced from government publications, which would be incremental to the quantified assessed risk for AVs;
- consideration of whether the risk assessment might change in the future having regard to future developments such as aging infrastructure, climate change impact on natural hazards, changes in load or anticipated projects in the region or on FEI's own system;
- identification of the vulnerabilities for which the assessed risk is sufficiently great to warrant resiliency-driven investment;
- identification of the vulnerabilities for which the assessed risk warrants further investigation to determine if a resiliency-driven investment is required;
- identification of potential resiliency investments to mitigate unacceptable risks; and
- prioritization of the AVs that warrant resiliency-driven investment.

Section 3 of the 2024 Resiliency Plan sets out the analytical process that FEI followed in developing the Plan, which is depicted in Figure 3-1 below. Sections 4 to 8 of the 2024 Resiliency Plan present the results of each analytical step.

[58] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, para. 47.

Figure 3-1: Approach to the 2024 Resiliency Plan



In **Step 1**, FEI used its standard system modelling techniques to identify the off-system supply vulnerabilities and vulnerabilities on FEI's own system where an interruption in gas flows could result in material customer outages. The modelling allowed FEI to determine where the system would depressurize following a no-flow event and determine the number of customers that would experience an outage. At this initial stage of identifying potential vulnerabilities for assessment, FEI conducted its modelling at design temperatures (i.e., the coldest expected weather condition), so as to be as inclusive as possible. See Section 3.2 of the 2024 Resiliency Plan.

In **Step 2**, FEI focused its review on vulnerabilities where a no-flow event would impact at least 10,000 customers or otherwise could cause a lesser number of customers to experience an outage of at least 14 days. As described in Section 3.3.2 of the 2024 Resiliency Plan, the objective in selecting screens was to balance two competing considerations: (i) ensuring that the Plan considered FEI's most significant potential outages; and (ii) avoiding unnecessary complexity and delay associated with assessing smaller outages that are inherent in the gas system configuration and adequately addressed in the ordinary course of business through FEI's sustainment capital planning and an effective Emergency Response Plan. Exponent endorsed the screening approach.[59]

[59] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, p. 2: "FEI has undertaken a two-step consequence-based screening to identify vulnerabilities with the potential to result in significant customer outages that were then subject to further detailed quantification. Exponent considers FEI's overall approach for its 2024 Resiliency Plan to identify and screen system vulnerabilities (for subsequent detailed assessment and quantification) to be reasonable and along the lines of good industry risk assessment practices."

Step 3, described in Section 3.4 of the 2024 Resiliency Plan, entailed quantitative risk analysis of the 58 AVs that passed these initial screens. Exponent identified potential causes of failure and conducted a quantitative risk analysis accounting for both probability and consequence. The objective of the risk analysis was to identify where significant investments to mitigate the risk are potentially required. Exponent summarized:

> Exponent has performed quantitative risk analyses to determine the 90-day winter-only annual rates of failure, as well as the probability of failure in 23 and 67 years, for pipelines, compressor stations, control stations, valve assemblies, and bridges carrying pipelines on FEI's transmission system that are vulnerabilities with the potential to result in significant customer outages. Exponent's analysis typically makes use of the principles of performance-based engineering, which is a sophisticated and well recognized method of quantitative risk analysis. The frequency of hazards of a particular intensity are determined, in conjunction with developing relationships between the hazard intensity and the probability of unwanted outcomes (e.g., pipe rupture). These relationships are integrated to determine annual rates of the unwanted outcome, which can be used to determine the probability of occurrence over some time period. There is uncertainty in the assets characteristics and hazards; thus, lower and upper bounds were determined. The performance-based engineering methodology is described in more detail in Section 4.2.[60]
>
> …
>
> Exponent has calculated the overall risk based on the consequences of a failure at average winter temperatures in terms of gross domestic product ("GDP") loss, customer outage days ("CODs"), and customer outages based on input parameters related to the number of customers impacted, outage durations, existing gas supply sources for resiliency, and the system configuration provided by FEI, and based on economic losses estimated by PwC. This analysis was conducted for three baseline scenarios using the Monte Carlo simulation of the impact of a failure on each AV, as described in Section 6 of this report.[61]

Step 4 considered qualitatively how future events or developments may impact the current risk assessment for the AVs. FEI considered developments (including those identified in the Adjournment Decision) that could affect the probability of failure and the potential consequences.

The **Steps 5 and 6** identification and prioritization of resiliency gaps (i.e., AVs that warrant resiliency-driven investment) were informed by Exponent's advice on risk management approaches. As discussed in Section 3.2.5 of this Supplemental Evidence, Exponent recommended prioritizing the highest risk AVs. Exponent also advised that it is reasonable to

60 Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, para. 8.
61 Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, para. 13.

perform mitigation activities for foreseeable events when consequences are known to be severe, even at lower probabilities.[62]

3.2.1.2 External Experts Had Significant Input on the Plan

The 2024 Resiliency Plan reflects input and analysis from independent experts. In particular, FEI has relied on experts in the following areas:

- The overall design of the structured process for developing the 2024 Resiliency Plan (Exponent);
- Appropriate criteria for identifying vulnerabilities for detailed analysis as AVs in the Plan (Exponent);
- Estimating the economic (GDP) consequences associated with a customer outage for the AVs (PwC);
- Estimating the probability of failure (Exponent, based on its own analysis of external risks and some prior engineering analysis of FEI's transmission system undertaken by JANA in the ordinary course of business);[63]
- The calculation of risk based on probability and consequences (Exponent); and
- The recommended approach to risk management in terms of prioritizing risk-mitigation investment in light of catastrophic and non-catastrophic risks (Exponent, which re-affirmed previously filed advice from Guidehouse, JANA, and PwC).

FEI expands on the roles of the respective independent experts in Section 3.1 of the 2024 Resiliency Plan.

3.2.1.3 Exponent's Risk Methodology Accounts for Various Time Horizons, Various Consequence Metrics and Uncertainty

Exponent describes its approach to calculating risk in Section 6 of the Exponent Report:[64]

> The risk associated with each AV is quantified by the expected annual winter-only loss, which is the product of combining annual winter failure rates of gas infrastructure, as determined by Exponent and JANA considering a variety of external and internal hazards, and the associated consequence. FEI identified three consequence metrics as part of its analysis: (1) gross domestic product ("GDP") loss; (2) customer outage-days ("CODs"); and (3) customer outages. These are standard consequence metrics for risk assessments. For each AV, the results of the risk assessment are therefore reported in terms of: (1) expected annual winter-only GDP loss; (2) expected annual winter-only CODs; (3) and

62 Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, paras. 42 and 46.
63 This engineering work by JANA is distinct from the JANA "white paper" filed in the TLSE Project CPCN proceeding assessing cumulative probability of rupture for T-South based on industry rupture rates.
64 Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, para. 155.

> expected annual winter-only customer outages. The expected 23-year and 67-year winter-only GDP loss, CODs, and customer outages are also provided. All hazards (non-earthquake, earthquake, and internal mechanisms) are considered in this analysis.

The time horizons reflect the expected life of the TLSE Project (67 years), and a 2050 adverse sensitivity (23 years) to address the BCUC's comments in the Adjournment Decision.

Exponent accounted for uncertainty in probability and consequences of failure using Monte Carlo analysis:[65]

> When an annual winter-only failure rate is multiplied by the consequences of said failure (in terms of GDP loss, customer outage-days, or customer outages), the result is the expected annual loss, which is a measure of the risk associated with an AV. The expected annual loss accounts for both the likelihood of a failure occurring as well as the magnitude of its consequences. Expected loss values can provide a basis for developing mitigation strategies or prioritizing interventions within the system of pipelines, compressor stations, control stations, and valve assemblies.

> The probability of an asset failing due to a particular hazard is uncertain, i.e., is not known exactly. The consequence given that a failure occurs – that is, the conditional consequence or conditional loss – is also uncertain. Additionally, the losses that follow a failure are conditional on the influence that parallel segments, regulatory shutdowns, and other mitigation measures (e.g., the Tilbury Alternatives or FEI's Mount Hayes LNG facility) have in bridging gaps in supply. To account for uncertainties in both probabilities of failure and consequences of failure, Exponent has performed a Monte Carlo analysis to determine the expected GDP loss, expected CODs, and expected customer outages for each AV.

3.2.2 Catastrophic Consequences of T-South Winter No-Flow Event

FEI used its standard hydraulic system modelling to determine the extent of the customer outages for each AV. The 2024 Resiliency Plan analysis confirmed that the loss of T-South supply lasting only a matter of hours, even under average winter conditions,[66] will without question have catastrophic consequences. By virtue of the regasification constraint at Tilbury, FEI's Lower Mainland gas system will fail on Day 1 regardless of how much LNG is assumed to be present in the Base Plant or Tilbury 1A on the day the no-flow event occurs. The outage will last many weeks. It will cause billions of dollars of economic harm and can be expected to result in adverse health impacts and deaths in vulnerable populations. FEI discusses each type of expected consequence below.

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[65] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, para. 160.

[66] Defined as the average of the daily average temperatures for December, January, and February over a 10-year period from 2013-2022. The average winter day is based on data from the Vancouver International Airport (YVR).

3.2.2.1 Direct Customer Impact: Widespread and Lengthy Loss of Gas Service in Lower Mainland and Potentially Vancouver Island and the Interior

As discussed below, at average winter temperatures of +4°C, between 600,000 and 640,000 customers will lose service on Day 1 of a T-South no-flow event, with the number in that range depending on the location of the disruption on T-South. With this number of customer outages, and assuming FEI's Advanced Metering Infrastructure (AMI) is in place, it will take FEI between 8 and 10 weeks to restore service. The number of customers losing service on Day 1 will be higher than the numbers noted above in below-average winter temperatures, which (all else equal) has the effect of further extending customer service restoration time.[67] [68]

3.2.2.1.1 QUANTITATIVE METRICS REGARDING SEVERITY OF DIRECT CUSTOMER IMPACTS

The 2024 Resiliency Plan presents various metrics to assess the severity of direct customer impacts associated with a no-flow event and facilitates comparisons among all AVs. The following table provides the quantitative metrics for a T-South winter no-flow event at average winter temperatures. The 2024 Resiliency Plan evaluates T-South in four segments, which are anonymized as AV-1, AV-2, AV-3 and AV-54, recognizing that the impacts can differ depending on where on T-South the disruption occurs.[69] The impacts are severe for all segments, even at average winter temperatures.

At below average winter temperatures, the number of affected customers can increase markedly. Near the upper end of potential consequences, under design day conditions, a prolonged failure in one T-South AV (and at a different failure location than assumed in the 2024 Resiliency Plan) would result in approximately 955,000 customer outages.

Table 3-1: Quantitative Metrics Related to Severity of a T-South No-Flow Event at Average Winter Temperatures by Incident Location

Type of Impact	Quantitative Metric	AV-1 Value	AV-2 Value	AV-3 Value	AV-54 Value
Direct customer service impact	Number of firm customers losing service on Day 1	640,100	600,400	640,400	600,400
Direct customer service impact	Total Outage Duration[70]	63.3 days	60.2 days	71.9 days	66.3 days
Direct customer service impact	Total firm customer-outage-days	24 million	21 million	32 million	28 million

[67] The reported customer outage numbers are from the risk assessment performed as part of the 2024 Resiliency Plan. As noted in the 2024 Resiliency Plan, the four AVs which represent T-South are based on specific failure locations and temperature conditions.

[68] The stated customer outage numbers are based on the duration of the T-South no-flow event being shorter than the duration that FEI's Mt. Hayes LNG Facility can support the Vancouver Island Transmission System (VITS). Under average winter conditions, Mt. Hayes can support the VITS for approximately 13 days. If the no-flow duration were to exceed the Mt. Hayes supply duration, then an additional 159,500 customers would lose service within FEI's VITS.

[69] These segments have been anonymized for security reasons using AV designations from the 2024 Resiliency Plan. Each of these AVs has a separate Confidential Appendix in the 2024 Resiliency Plan with restricted access.

[70] The Total Outage duration is defined as the estimated period (in days) starting on Day 1 of the customer outage to the day when service is finally restored to the last customer. Reported as the mean from Exponent's Monte Carlo analysis. Refer to Section 3.4.1.2 of the 2024 Resiliency Plan for additional information.

Type of Impact	Quantitative Metric	AV-1 Value	AV-2 Value	AV-3 Value	AV-54 Value
Direct customer service impact	Firm customers losing service on Day 1 as a percentage of total FEI customers	60%	56%	60%	56%

FEI summarizes below how these values were calculated:

- **FEI's Standard System Modelling Shows Number of Customers Losing Service:** FEI used its standard steady state hydraulic modelling (which evaluates system pressure in response to fixed supply and demand conditions) to determine the extent of a customer outage following a no-flow event at average winter temperatures for all of the AVs.
- **FEI Assumed a Failure Occurred at the Downstream End of a Pipeline Segment:** The approach taken in the 2024 Resiliency Plan was to base consequences on the assumption that a pipeline failure occurred at the far downstream end of an AV's pipeline segment. This was done for consistency and to facilitate analysis. However, this approach has the effect of under-reporting consequences if a pipeline fails anywhere else on the segment. In many cases (e.g., sparsely populated rural areas and/or a short AV pipeline segment), the difference in customer outages may be relatively small, regardless of where on the AV segment the failure is assumed to occur. However, along with the temperature condition at the time of the failure event, the failure location makes a significant difference for some AVs. Notably, a prolonged failure further upstream on AV-1 and at design day conditions results in approximately 955,000 customers losing service.
- **Purging, Regasification and Relight Times Are Based on System Preservation and Restoration Plan:** FEI's Rebuttal Evidence discussed in detail the timeline for restoring service to customers once gas flows resume on FEI's system.[71] It was based on FEI's BCUC-approved System Preservation and Restoration Plan and forms the basis of the current calculations.
- **Exponent's Monte Carlo Analysis Accounted for Uncertainty in Length of No-Flow Event:** Exponent's overall risk assessment used Monte Carlo analysis to capture the uncertainty in how long a no-flow event will last, given the various potential causes and uncertainties. Given how little load support is provided by Tilbury at present, for all practical purposes any T-South no-flow event in winter would result in the type of widespread customer outages described earlier in this section. However, Exponent's use of Monte Carlo analysis in its risk calculations becomes more important in the context of assessing project alternatives. It addresses the BCUC's Adjournment Decision commentary about whether a no-flow event could exceed the duration of support provided by the TLSE Project. Exponent's overall risk calculations are adjusted for this.

[71] Exhibit B-46-1, Rebuttal Evidence to RCIA, Figures 3 and 4 (pp. 21-22).

3.2.2.1.2 ALL LOWER MAINLAND CUSTOMERS WILL LOSE SERVICE ON DAY 1 DUE TO REGASIFICATION CONSTRAINT AT TILBURY

FEI's system modelling shows that, at minimum, a T-South no-flow event at average Lower Mainland winter temperatures (+4°C) will result in approximately 600,000 Lower Mainland customers losing service on Day 1. The modelling also reconfirmed that Tilbury's limited regasification capacity, and not the amount of LNG present, is currently the governing constraint on Tilbury's ability to support load following a winter no-flow event. In other words, the system will fail in the same short amount of time regardless of whether Tilbury 1A is full or effectively empty on the day the no-flow event occurs. These points are further discussed below.

Detailed Transient System Modelling Results

FEI used its transient hydraulic modelling tool to determine the length of time that the Tilbury Base Plant (assuming it functions as intended despite its condition) and the Supplemental Alternatives (further described in Section 4 of this Supplemental Evidence) can support the Lower Mainland following a T-South no-flow event.

FEI's transient system modelling shows the relationship between gas supply and the pressure in FEI's transmission system. An unmitigated supply disruption will result in a supply/demand imbalance which causes the pressure to drop on FEI's system. FEI's transmission system must operate above a minimum pressure to serve customers. If the pressure drops below this minimum threshold, then customers in the affected area lose service. This relationship between gas supply and pressure allows FEI to model the impact that a supply disruption has on system pressure over time and, by extension, how quickly customers will lose service.

The following table summarizes how long the existing Tilbury LNG facilities, in combination with FEI's other existing capabilities, will be able to sustain the Lower Mainland load following a winter no-flow event. FEI has consistently modelled three temperatures that are reflective of local conditions, since FEI's load increases as temperatures decrease. The modelling shows that all firm customers will lose service on Day 1. Given how fast the system depressurizes, FEI expects that the system will likely depressurize in an uncontrolled manner, creating safety risks and service restoration challenges.[72]

[72] For a discussion of the implications of an uncontrolled shut-down, please see Exhibit B-46-1, Rebuttal Evidence to RCIA, pp. 8-9, and Exhibit B-50, RCIA IR3 43.1.

Table 3-2: Time to Failure Following T-South Winter No-Flow Event – Status Quo (150 MMcf/d, Regardless of Available LNG volumes)

Temperature Condition	Approximate Time Until Customers in the Lower Mainland Begin Losing Service[73]	Expectation of Controlled or Uncontrolled Shut Down
-10°C (very cold Lower Mainland winter day)[74]	2 hours	AV-1: Uncontrolled AV-2: Uncontrolled AV-3: Uncontrolled AV-54: Uncontrolled
-1.4°C (warmest winter in 10 years)[75]	5 hours	AV-1: Uncontrolled AV-2: Uncontrolled AV-3: Uncontrolled AV-54: Uncontrolled
+4.0°C (average Lower Mainland winter)[76]	7 hours	AV-1: Controlled AV-2: Controlled AV-3: Uncontrolled AV-54: Uncontrolled

Figures 3-2 to 3-4 below are the graphical outputs of the transient modelling results for the temperature scenarios in Table 3-2 above.

Each graphical presentation of FEI's transient modelling throughout the Supplemental Evidence contains the following information:

- The gas supply entering the CTS from T-South, which is represented by the grey dotted line titled "Huntingdon InFlow";
- The gas pressure in the CTS, which is represented by the solid orange line titled "Fraser Inlet Pressure"; and
- The gas supply entering the CTS from the Tilbury Facility for the alternative being modelled, which is represented by the solid yellow line titled "Tilbury Facility InFlow".

Each graphical presentation of FEI's transient modelling throughout the Supplemental Evidence follows the timeline described below. Each event in the timeline is indicated by a red circle in the graph:

[73] This represents the approximate duration of full firm load support from on-system LNG and linepack from the CTS. The analysis also assumes that all interruptible customers are offline within 4 hours of the no-flow event, except for the -10°C analysis, wherein interruptible customers would already be offline due to the cold temperature condition.

[74] Due to the low probability of having multiple -10°C days in a row in the Lower Mainland, the -10°C temperature condition analysis assumes the following: the first day is -10°C, the second and third days are -7°C, the fourth day is -3°C, and all subsequent days are +4°C.

[75] The warmest winter in the last 10 years was found by determining the minimum daily average temperature for each year over a 10-year period from 2013-2022, then selecting the highest value. The analysis was based on data from YVR.

[76] Defined as the average of the daily average temperatures for December, January, and February over a 10-year period from 2013-2022. The average winter day is based on data from YVR.

- At 12:00 AM:
  - A no-flow event occurs off-system on the T-South pipeline.
  - FEI is made aware of the event and begins preparing Tilbury for sendout.
- At 2:00 AM:
  - Gas supply to the CTS ceases (i.e., between 12:00 AM and 2:00 AM it is assumed that the CTS receives gas supply via T-South linepack). This can be seen in the transient modelling graphs by observing the Huntingdon InFlow (grey dotted line) decreasing to zero.
  - LNG sendout from the Tilbury Facility begins. This can be seen in the transient modelling graphs by observing the Tilbury Facility InFlow (solid yellow line) increasing from zero.
- At 4:00 AM:
  - Interruptible customers are offline.[77]

The final event in the timeline is the point at which the CTS pressure (solid orange line) drops below the minimum pressure threshold and customer outages start to occur.[78] The time at which this event occurs varies based on the following parameters:

- The temperature condition at which the supply disruption is assumed to occur (i.e., the temperature condition drives the demand on the system, which impacts the rate at which the system pressure drops under the upset condition); and
- The design parameters (i.e., storage volume and regasification capacity) of the on-system LNG facility that is intended to mitigate the supply disruption (i.e., the Supplemental Alternatives).

The constraining design parameter of a given Tilbury Facility can be determined by observing the status of the LNG sendout (yellow solid line) at the time when customer outages begin. For example, if the LNG sendout goes to zero before customer outages occur, it indicates that the tank volume is the constraining factor. If customer outages occur before the LNG sendout goes to zero (indicating there is still volume left in the tank), it indicates that the regasification capacity is the constraint. The latter is true in the *status quo* modelling, indicating that the 150 MMcf/d regasification capacity at Tilbury is currently the governing limitation.

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77 Under normal operating conditions, if the Lower Mainland temperature is -10°C, interruptible customers would be offline. Therefore, the graphs showing modelling results for the -10°C temperature condition do not show interruptible customers going offline at 4:00 AM, as they would not be online due to the cold temperature condition.

78 The CTS pressure that indicates when customer outages have started varies based on the temperature condition used in the analysis. FEI undertook a detailed iterative study to estimate the threshold pressure at each temperature condition.

The mitigation provided by the Preferred Alternative or other Supplemental Alternatives can be viewed as the delay (relative to the *status quo*) in the time it takes for the CTS pressure to decay to the point where customers lose service.

Figure 3-2: Impact to Lower Mainland at -10°C due to Loss of T-South Supply, with Mitigation from Existing Tilbury Facilities (150 MMcf/d Regas and at Least 0.35 Bcf LNG)

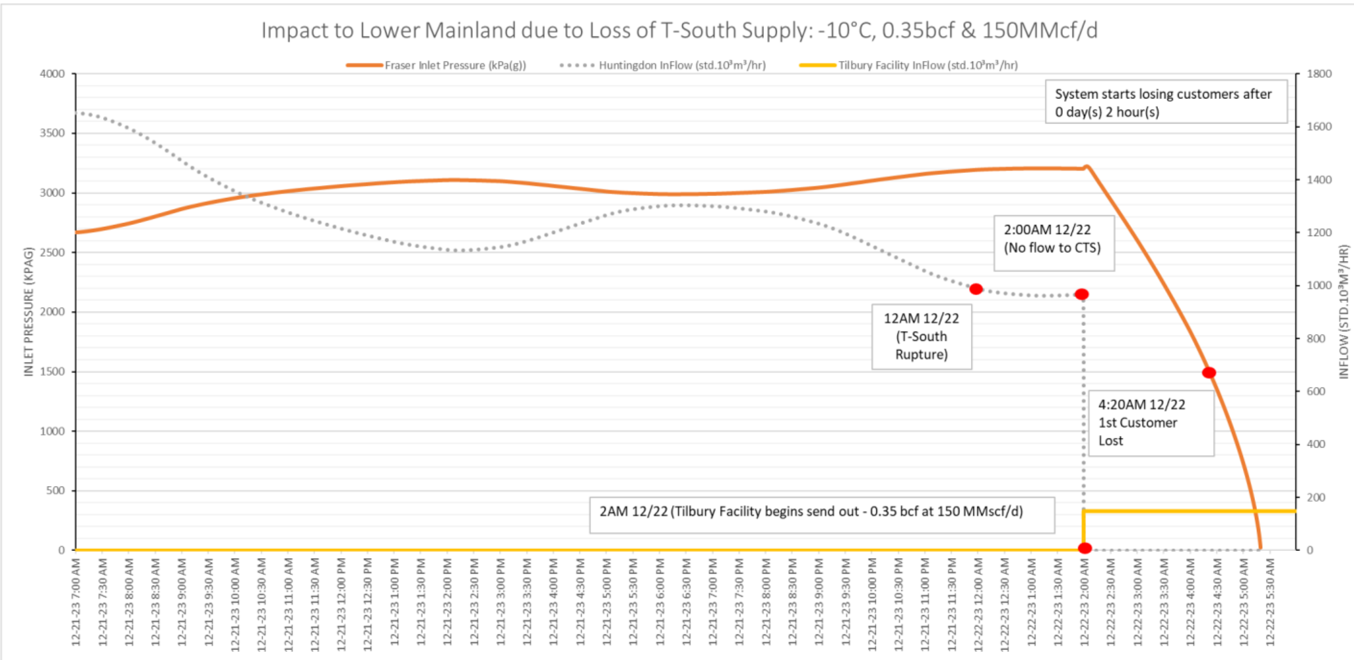


Figure 3-3: Impact to Lower Mainland at -1.4°C due to Loss of T-South Supply, with Mitigation from Existing Tilbury Facilities (150 MMcf/d Regas and at Least 0.35 Bcf LNG)

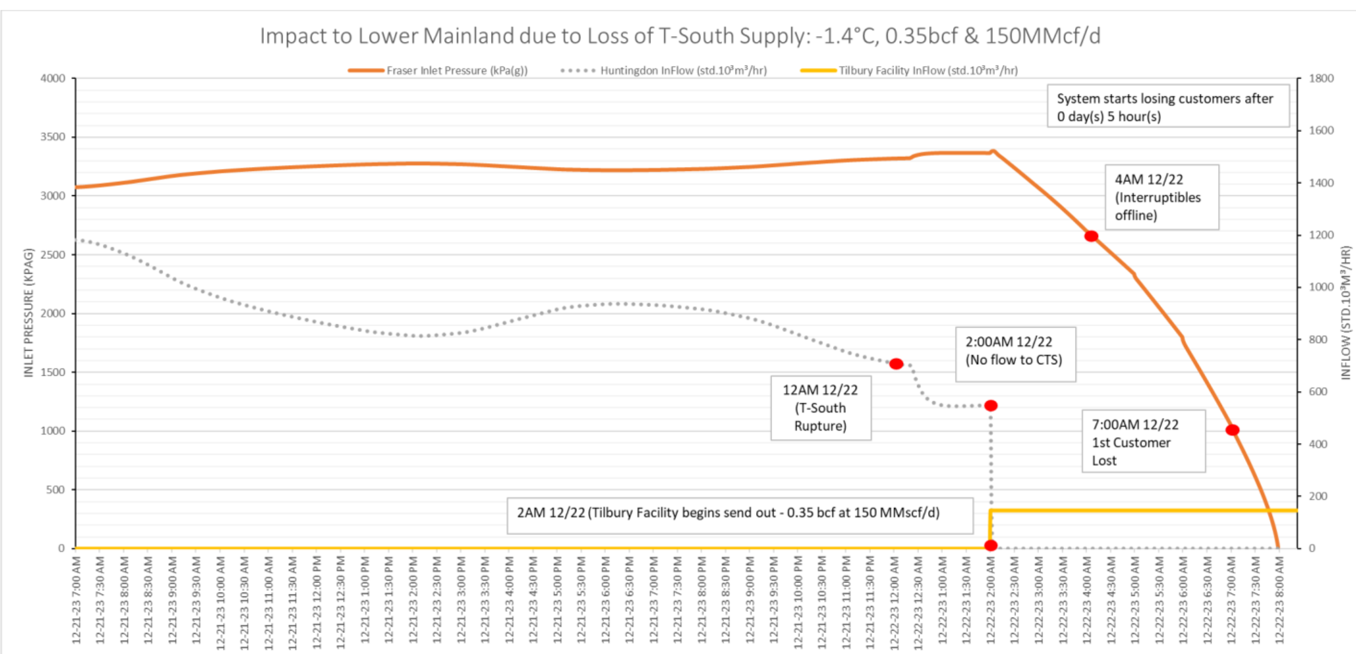
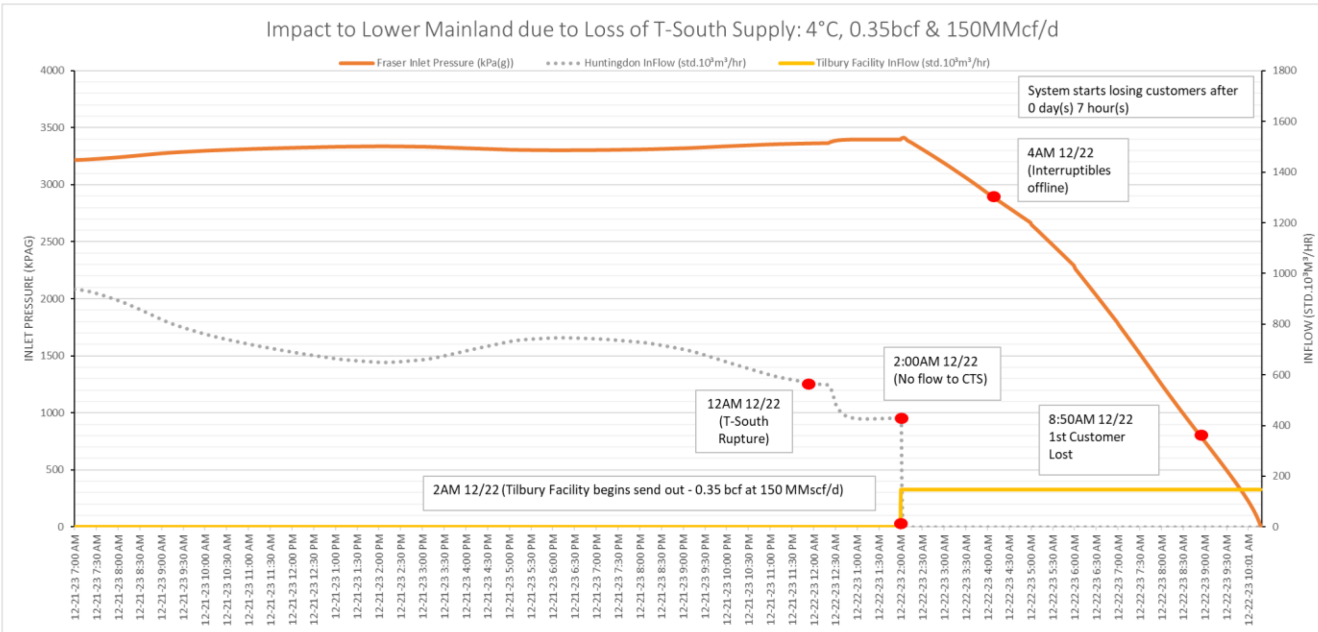


Figure 3-4: Impact to Lower Mainland at +4°C due to Loss of T-South Supply, with Mitigation from Existing Tilbury Facilities (150 MMcf/d Regas and at Least 0.35 Bcf LNG)

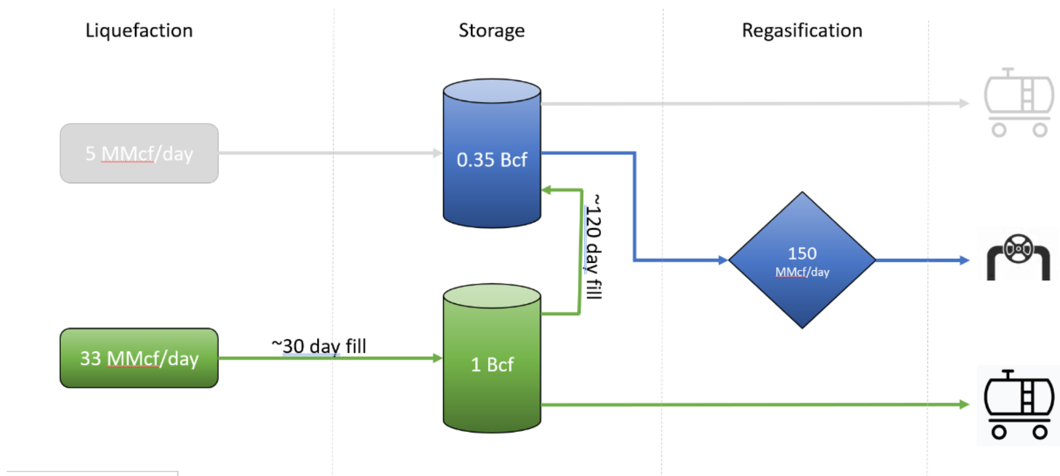


Regasification Constraint Means a Day 1 Full Customer Outage Will Occur Regardless of Assumed LNG Volume

As FEI described in the Application, the rapid depressurization of the Lower Mainland system occurs because LNG from Tilbury is the only potential source of supply in winter, and Tilbury is too small to support the daily Lower Mainland load in winter. The governing resiliency limitation at Tilbury is the current regasification capacity of 150 MMcf/d, all of which is part of the Base Plant (see facility schematic in Figure 3-5 below).

The modelling confirms that, by virtue of the regasification constraint, Lower Mainland customers will lose service in the same short amount of time regardless of whether Tilbury 1A is full or effectively empty on the day the no-flow event occurs. In other words, the results do not improve even in the best-case assumption that there is 1.35 Bcf available at Tilbury (i.e., 1.0 Bcf at Tilbury 1A plus 0.35 Bcf in the Base Plant) when the no-flow event occurs.

Figure 3-5: Tilbury Base Plant and Tilbury 1A Facilities – 2024 Configuration[79]



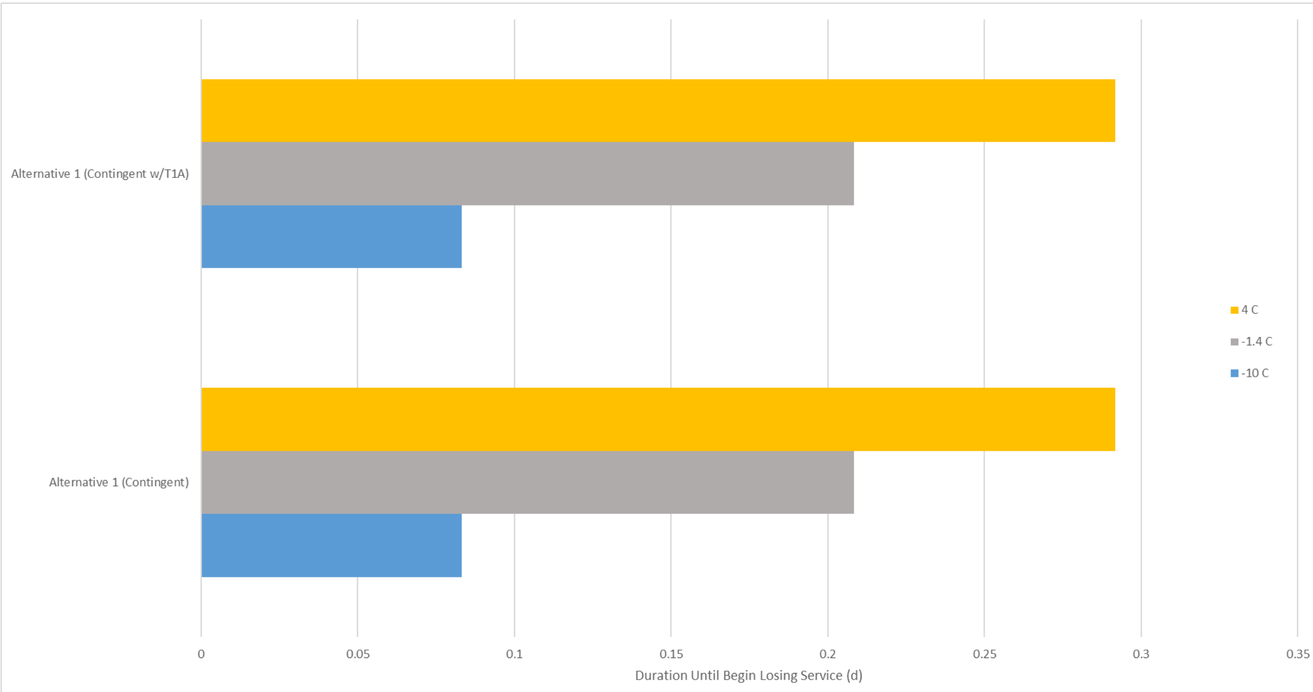
A regasification capacity of 150 MMcf/d means that the amount of gas FEI can re-inject in the Lower Mainland system each day is limited to 150 MMcf (or 0.15 Bcf). This regasification capacity is only a fraction of the daily Lower Mainland load in a typical winter. In such circumstances, the amount of gas liquefied, or LNG stored, is a moot point from a resiliency standpoint. Regardless of how much LNG is assumed to be on-hand at Tilbury at the time of a no-flow event, the system quickly depressurizes because FEI cannot regasify the LNG fast enough keep up with the Day 1 demand.

Figure 3-6 below compares the load support duration at various winter temperatures in the Lower Mainland assuming 150 MMcf/d of existing regasification, but changing the assumptions about the available LNG so as to simulate different volumes being present in Tilbury 1A on the day of the no-flow event (0.75 Bcf, labelled as "Alternative 1 (Contingent w/T1A)") and 0.35 Bcf (labelled as "Alternative 1 (Contingent)"[80]). Note that none of the LNG at Tilbury is set aside as a designated "resiliency reserve"; rather, it is dedicated to other purposes, such that it may or may not be present on the day of a no-flow event. Even with more available LNG, the durations remain identical for a given temperature condition. The only time the regasification constraint would not determine the load support duration is if the temperature was high enough that daily load declines markedly, which would typically only occur in summer months.

[79] The figure shows the reduced operating level of the Base Plant tank due to seismic reasons.

[80] This labelling reflects the fact that Supplemental Alternative 1, discussed in Section 4 of the Supplemental Evidence, contemplates a continuation of the status quo by virtue of not performing any capital upgrades. The label "Contingent" denotes that none of the LNG at Tilbury is set aside as a designated "resiliency reserve"; rather, it is dedicated to other purposes, such that it may or may not be present on the day of a no-flow event.

Figure 3-6: Duration of Lower Mainland Load Support Provided by Tilbury Does Not Change Under Different LNG Volume Assumptions



Although the governing constraint at Tilbury is the regasification capacity, the Base Plant tank is also undersized based on current load for both resiliency and gas supply. The limited LNG storage would quickly become the resiliency constraint if the regasification capacity was increased significantly without increasing the amount of LNG storage. This is discussed further in the context of Supplemental Alternatives 2 and 3 (see Section 4.4.1 and Appendix C of this Supplemental Evidence), both of which involve adding regasification capacity while retaining the Base Plant tank. Neither of those alternatives are effective at avoiding a Lower Mainland-wide customer outage following a winter T-South no-flow event, even at average winter temperatures.

3.2.2.1.3 RESTORING SERVICE AFTER T-SOUTH GAS FLOW RESUMES WILL TAKE WEEKS

FEI's Rebuttal Evidence explained the service restoration process and timeline in detail. This section summarizes how the process and timeline applies to the four Avs that comprise T-South (AV-1, AV-2, AV-3 and AV-54).

The number of customers losing service due to a T-South no-flow event depends on both the location of the failure as well as the temperature condition at which the failure occurs. Under average winter conditions and even with AMI in place,[81] it would take between 57 and 70 days – an average of approximately 9 weeks – to restore service to all affected customers following the prompt resumption of flows on T-South. For simplicity, the durations presented here are based

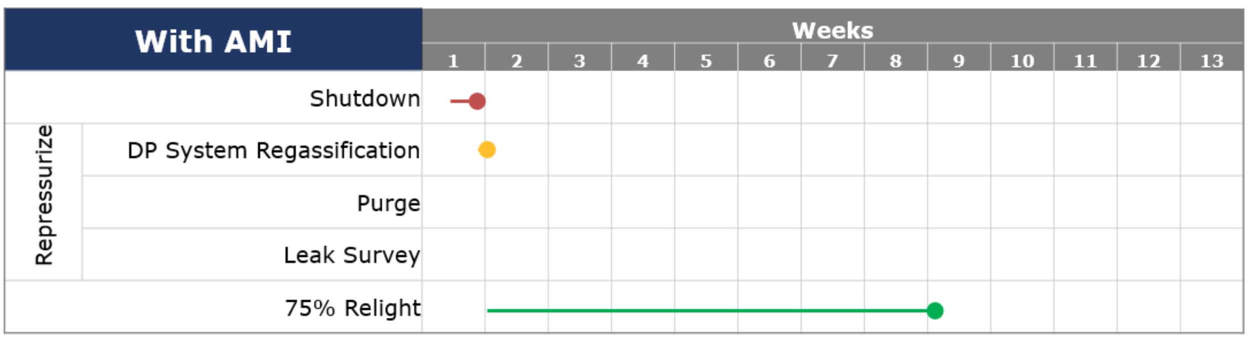
[81] As the BCUC has approved the AMI Project, the entirety of the analysis in this Supplemental Evidence and the 2024 Resiliency Plan assumes that residential and small commercial AMI is in place. The extent of the mitigation provided by AMI, in terms of reducing the extent and duration of an outage, is discussed in FEI's Rebuttal Evidence.

on an assumed 3-day no-flow event that does not delay restoration efforts. Exponent's Monte Carlo-based risk analysis accounts for the uncertainty in the no-flow duration, such that its risk calculations consider scenarios where the duration to restore service exceeds this range.

The duration is approximately 57 days if the location of the failure on T-South is such that (a) the Lower Mainland alone is affected and (b) FEI is able to initiate a controlled shutdown before the system depressurized in an uncontrolled manner, thereby saving some restoration time (AV-2). The 70-day duration is applicable where the failure location is such that additional customers lose service, and the system is shutdown in an uncontrolled manner (AV-3). The remaining two T-South AVs (AV-1 and AV-54) result in durations of 61 days and 66 days, respectively.

Figure 3-7 below shows the contributors to the 57-day timeline for AV-2, which is the bottom end of the time range.

Figure 3-7: Timeline for AV-2 Customer Service Restoration (with AMI)



With respect to the various stages of the AV-2 timelines:

- **Shutdown:** FEI would first need to visit approximately 50,000 large commercial and industrial premises over approximately 3-4 days to manually turn off meter valves. AMI avoids the need to do this for hundreds of thousands of residential and small customer premises, such that the shut-down timeline would otherwise be much longer.[82]
- **Regasification, purge and leak surveys:** The time for these steps differs significantly depending on whether FEI has enough time to react to prevent an uncontrolled depressurization. Figure 3-7 above reflects the favourable situation where FEI has enough time to execute a controlled shutdown. Provided that FEI has enough time to assess the situation, the ability with AMI to close customer valves remotely can allow FEI to maintain pressure in portions of the system.[83] Purging and extensive leak surveys will be largely

[82] Exhibit B-46-1, Rebuttal Evidence to RCIA, pp. 23-24.

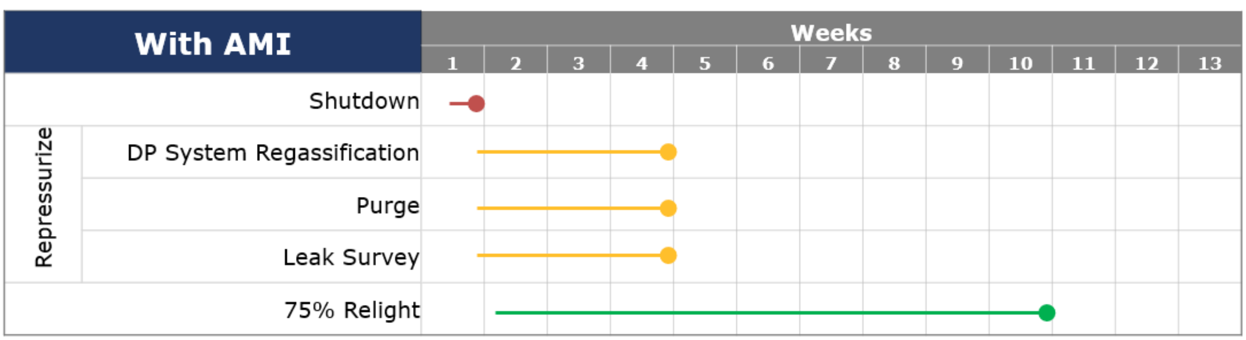
[83] This is not universally true across all portions of the system because customers with manual meters would continue to consume gas. However, the assumption for AV-2 is that, since the failure location is reasonably far from the demand centre and does not disrupt FEI's Kingsvale Supply from reaching the Lower Mainland, there would be sufficient time for FEI to close the manual meter valves before an uncontrolled shutdown occurs. Refer to FEI's 2024 Resiliency Plan for assumptions on controlled vs. uncontrolled shutdowns.

unnecessary in those areas, and thus the time required for these activities is avoided and the overall restoration timeline is lower relative to an uncontrolled shutdown.

- **Relighting customer appliances:** Most of the restoration time is spent manually relighting customer appliances. FEI's Rebuttal Evidence, and the two timelines shown in this section (Figures 3-7 and 3-8), reflect a number of favourable assumptions that (other things being equal) may tend to understate the total restoration duration. For example, it contemplates only relighting essential appliances within a premises to save time and assumes that 25 percent of customers relight their own appliances. It also assumes that FEI has full access not only to its own workforce, but also to the entire Lower Mainland gas contracting community and a large complement of mutual aid personnel from other utilities in the region. To the extent that any of these additional personnel fail to materialize, the duration of the relight process could be materially longer.

Figure 3-8 below shows the timeline for restoring service to customers following a no-flow event on AV-3 at average winter temperatures (+4°C). The restoration timeline shown in Figure 3-8 is longer than the above timeline primarily because, due to the AV-3 failure location, FEI expects that it will be unable to initiate a controlled shutdown before the system depressurizes in an uncontrolled manner. Additionally, AV-3 results in approximately 40,000 more customer outages than AV-2.

Figure 3-8: Timeline for AV-3 Service Restoration (with AMI)



With respect to the various stages of the AV-3 restoration timeline:

- **Shutdown**: The shutdown stage in the uncontrolled scenario is the same as for the controlled scenario (i.e., AMI will be used to shut down the majority of meter valves; however, approximately 50,000 meters will need to be closed manually).
- **Regasification, purge and leak surveys:** As AV-3 is expected to result in an uncontrolled shutdown, this stage of the timeline is significantly longer than the Figure 3-7 timeline (wherein the shutdown is controlled). In an uncontrolled shutdown, purging will be required and thus the overall timeline will be longer. At present, there would be very little time for FEI to react to an AV-3 event before the system depressurizes in an uncontrolled manner. While in theory FEI could immediately shut all residential and small commercial customer meter valves remotely, at present FEI would be unlikely to have the necessary information

to make that decision until it is too late. The timeline of the 2018 Incident[84] illustrated how long it can take before FEI has actionable information from Westcoast Energy. Disconnecting customers at the first notice of an incident based on limited information would give rise to the risk of causing unnecessary outages based on incomplete information. Further, even if all AMI valves were instantly shut off, the remaining 50,000 valves requiring manual shutoff would lead to an uncontrolled shutdown.

- **Relighting customer appliances:** One key difference in the relight stage for a controlled shutdown vs. an uncontrolled shutdown is that, in an uncontrolled shutdown, the relight rate is slightly lower than for a controlled shutdown. Due to the purging that is required in an uncontrolled shutdown, resources that could otherwise be relighting customers must be allocated to purging the distribution system. The result is a lower average relight rate for an uncontrolled shutdown when compared to a controlled shutdown. Further, the relight times for AV-3 shown in Figure 3-8 above could be materially understated for the same reasons stated above regarding AV-2.

In response to the suggestion from REL Engineering (REL) (retained by RCIA) that the overall duration to restore service to customers could be reduced, FEI explained in its Rebuttal Evidence that the potential for variances in the time to fully restore service to customers is asymmetrical:[85]

> FEI recognizes that an actual event would vary somewhat from the assumptions used; however, the potential for time variances is asymmetrical. That is, although unforeseen events (e.g., identification of major leaks, bad weather, competing demands limiting mutual aid assistance) could cause significant delays in the restoration work, it is much less likely that opportunities for time savings would meaningfully shorten the time required. FEI has performed its own sensitivity testing of the working model (refer to the response to Q36) to test the assumptions and does not foresee any realistic scenario where there could be time savings of the magnitude hypothesized by REL.[86]

FEI believes that the timelines above are unlikely to be materially shorter than shown and could be materially longer.

3.2.2.1.4 A T-SOUTH WINTER NO-FLOW EVENT WILL ALSO CAUSE A LARGE OUTAGE IN THE INTERIOR IN SOME CASES

A disruption on T-South can also result in a large outage in the Interior, depending on where the incident occurs on T-South. AV-1 is the segment of T-South that, if disrupted, results in an outage in both the Lower Mainland and Interior. The result will be that, at average winter temperatures, approximately 640,000 customers will lose service for almost 9 weeks after accounting for AMI and assuming a controlled shutdown can take place. FEI's comments above regarding the potential for service restoration to take longer than estimated apply here as well.

[84] Exhibit B-1-4, Application, p. 41.
[85] Exhibit B-46-1, Rebuttal Evidence to RCIA, p. 19.
[86] Exhibit B-46-1, Rebuttal Evidence to RCIA, p. 19.

As previously explained, the modelling assumes that a failure occurs at the downstream end of an AV, which has the effect of understating the number of customers effected if the failure occurs further upstream. AV-1 is an instance where the location can make a material difference. For instance, changing the AV-1 failure location and assuming design day conditions, a prolonged failure on AV-1 would result in approximately 955,000 customer outages.

3.2.2.2 Economic Harm: New Outage-Specific PwC Analysis Confirms Severe GDP Impacts

As part of preparing the 2024 Resiliency Plan, FEI retained PwC to estimate the economic impacts of a winter outage for all of the AVs based on their specific circumstances. PwC's 2024 report is Appendix RP 3 to the 2024 Resiliency Plan. It confirms severe GDP impacts associated with a T-South winter no-flow event.

The Application included another PwC report (Original PwC Report), in which PwC modelled three hypothetical outage scenarios using different assumptions regarding (among other things) temperature, outage area, economic activity, and customer numbers. The Original PwC Report was prepared for another purpose, and the hypothetical scenarios were intended to book-end economic harm from a widespread customer outage. On one end of the spectrum was a localized outage, while on the other end of the spectrum was an outage affecting the entire province including areas beyond FEI's own service territory. Neither of these book-ends matched the specific outage characteristics that FEI would experience following a T-South no-flow event, making it necessary to interpolate. Thus, as part of preparing the 2024 Resiliency Plan, FEI retained PwC to estimate the economic impacts of a winter outage for all of the AVs based on their specific circumstances.[87]

PwC has used AV-specific inputs obtained from FEI, including the number of affected customers, load profile, outage area-specific GDP and the applicable average winter temperatures. PwC also conducted interviews with FEI customers in various economic sectors to understand the impact a gas disruption would have on the customers' businesses, including their preparedness in the event of a loss of gas service due to a no-flow event.[88]

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. Figure 3-9 below was prepared by PwC at FEI's request and shows the estimated range of economic harm that would result from a single winter T-South no-flow event.[89]

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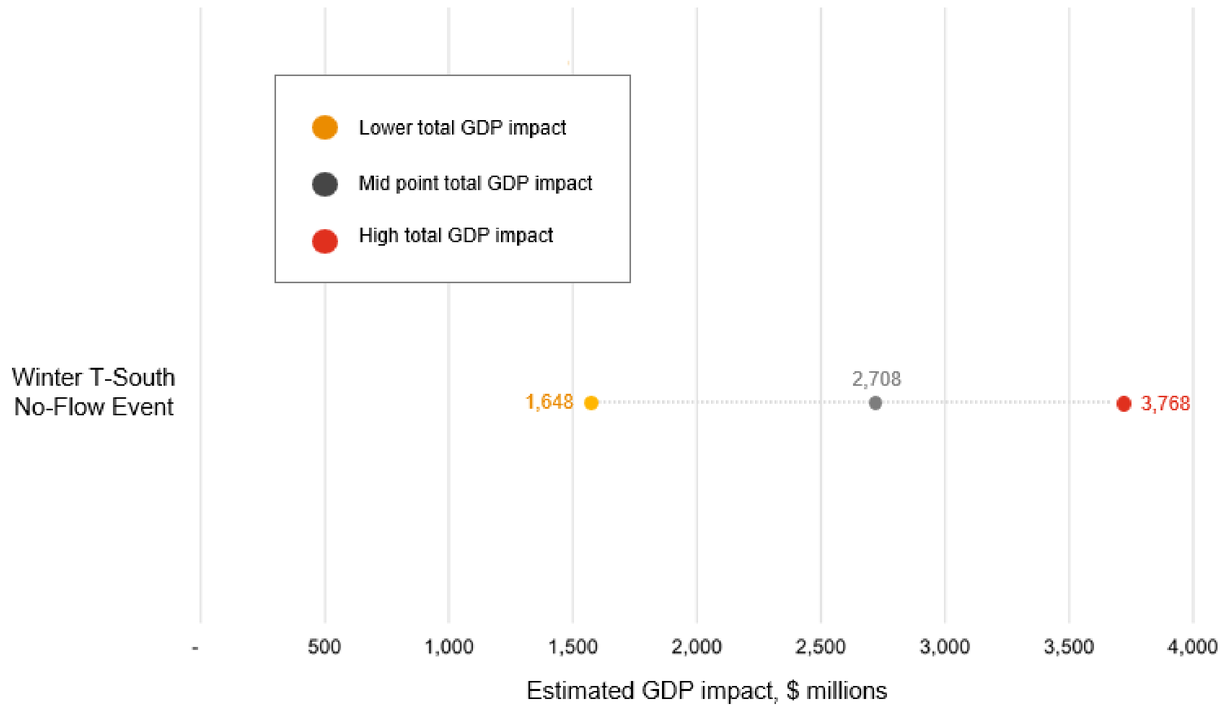
[87] Appendix RP 3 to the 2024 Resiliency Plan, PwC Report, Section 1.5.
[88] Appendix RP 3 to the 2024 Resiliency Plan, PwC Report, Section 2 (pp. 4-9).
[89] See Appendix RP 3 to the 2024 Resiliency Plan, PwC Report, Figure 5 (p. 10) for summary of the highest estimated economic impacts.

Figure 3-9: PwC Economic Harm Calculation for Winter T-South No-Flow Event (Low, Median, High)



3.2.2.2.1 PWC ECONOMIC IMPACT CALCULATIONS MAY BE SIGNIFICANTLY UNDERSTATED

PwC's calculations of economic harm, although already significant, are potentially understated. For instance, PwC assumed there are no impacts from economic sectors where they lacked certain data. PwC also excluded the impact of consequential outages on the Lower Mainland electric system. Technical discussions between FEI and BC Hydro following the 2018 T-South Incident concluded that a widespread gas outage could require rotating electric feeder outages (i.e., brown outs).[90] PwC provided a qualitative evaluation of how the loss of electric service would affect the GDP impact results:[91]

> Natural gas supply outages in B.C. may also place **a strain on the electrical grid** as many households and businesses may seek to substitute the energy provided by gas to that from electricity. At peak hourly demand, B.C. consumes 65 TJ of natural gas, compared to only 37 TJ of electricity, so the ability of the electrical grid to make up for the loss of natural gas is likely to be limited, and attempts to do so may lead to infrastructure damage or the need for mitigation actions such as managed power brownouts to protect the grid. In Appendix 4 we have reviewed literature on other utility outage events with a focus on electrical outages to give

[90] Exhibit B-22-1, RCIA IR1 10.1.2.
[91] Appendix RP 3 to the 2024 Resiliency Plan, PwC Report, p. 14.

> insights into the possible consequences of any knock-on effects on the grid. In summary our literature review suggest that:
>
> - Economic impacts estimated from full power blackouts tend to be more acute than those estimated in this report for a natural gas outage. The natural gas outage scenarios in this report estimate an impact in the region of 5% to 20% of GDP for the duration of the outage; in the case of a complete loss of electricity, the literature provides examples where economic losses can be in the 25% to 50% range, or higher in some cases.
>
> [Emphasis in original and references omitted]

3.2.2.3 Serious Public Health, Mortality and Safety Implications of Uncontrolled Shut-Down and Prolonged Winter Outage

A winter outage in the Lower Mainland can also reasonably be expected to have a negative impact on public health and safety, despite extensive emergency planning by FEI, municipal, regional and provincial agencies. While it would be very difficult to quantify health and safety impacts, it is possible to describe potential impacts qualitatively.

3.2.2.3.1 UNCONTROLLED DEPRESSURIZATION CREATES HAZARDOUS CONDITIONS

An uncontrolled depressurization of the gas system, which is a most likely outcome at present, can present hazardous conditions for the public, including the risk of fire and explosions.[92]

3.2.2.3.2 LOSS OF HEAT IN WINTER LINKED TO POOR HEALTH AND MORTALITY

There is a known link between cold residences and workplaces and incidence of poor health and mortality. PwC stated, for example:[93]

> **Health and safety** may also be impacted, as cold residences and workplaces would likely lead to an increase in the incidence of poor health such as respiratory illnesses. There is extensive evidence of the link between temperature and poor health. For example, mortality rates in Canada are 11% higher in winter than in summer on a like-for-like basis, with death rates amongst the elderly rising by 1-2% for every 1°C drop in external temperature. This statistic does not incorporate any loss of heating capacity; thus, it is reasonable to assume that with loss of some heating capacity excess deaths would be higher than a typical winter.
>
> Linked to the above point, whilst main hospitals are required to have at least three days of backup heating on-site (often in the form of fuel oil), this is often not the case at smaller medical facilities such as **family doctors' offices,** which may close in the event of a natural gas outage. [Emphasis in original and references omitted]

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92 Exhibit B-46-1, Rebuttal Evidence to RCIA, pp. 8-9; Exhibit B-50, RCIA IR3 43.1.

93 Appendix RP 3 to the 2024 Resiliency Plan, PwC Report, p. 14.

Vulnerable populations (e.g., residents of long-term care facilities and nursing homes, individuals with disabilities, and persons requiring home-health services) are at elevated risk.

NERC noted recently that hundreds of people died as a result of an electric outage in Texas that left people without heat for only four days (vs. a 9-week outage following a T-South no-flow event):

> More than 4.5 million people in Texas lost power during the Event, and some went without power for as long as four days, while exposed to below-freezing temperatures for over six days. At least 210 people died during the Event, with most of the deaths connected to the power outages, of causes including hypothermia, carbon monoxide poisoning, and medical conditions exacerbated by freezing conditions. Among the deaths were a mother and her seven-year-old daughter, and an 11- year-old boy who died in his bed, who all died of carbon monoxide poisoning, and a 60-year-old disabled man who died of hypothermia. A grandmother and three children trying to keep warm using a wood-burning fireplace died in a house fire. In cities including Austin, Houston and San Antonio, over 14 million people were ordered to boil drinking and cooking water, and multiple cities ordered water conservation measures, due to broken pipes and power outages (which lowered water pressure). After the city of Denton, Texas, lost its gas supply, it was forced to cut power to nursing homes and water pumping stations.[94]

As Exponent discusses in its report,[95] measures intended to protect vulnerable populations require time to properly implement. Providers of services to vulnerable populations would benefit from having more than a few hours to plan for a pending outage. Examples include: relocating vulnerable members of the population; setting up warming shelters for evacuated individuals who cannot shelter in place at home; supplying government buildings, emergency centres, hospitals, and long-term facilities with electricity-, gasoline- or propane-powered heaters, backup generators, and sufficient supply of fuel; pre-positioning medical personnel and supplies at shelter locations; and establishing out-of-hospital care centres to respond to cold weather related conditions (e.g., hypothermia).

Natural gas outages may place strain on the Lower Mainland electrical grid as gas users may seek to substitute the energy provided by gas with electricity. PwC explained:[96]

> Natural gas supply outages in B.C. may also place **a strain on the electrical grid** as many households and businesses may seek to substitute the energy provided by gas to that from electricity. At peak hourly demand, B.C. consumes 65 TJ of natural gas, compared to only 37 TJ of electricity, so the ability of the electrical grid to make up for the loss of natural gas is likely to be limited, and attempts to do so

94 https://www.nerc.com/pa/rrm/ea/Documents/February_2021_Cold_Weather_Report.pdf.
95 Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, paras. 248-250.
96 Appendix RP 3 to the 2024 Resiliency Plan, PwC Report, p. 14.

> may lead to infrastructure damage or the need for mitigation actions such as managed power brownouts to protect the grid.

In the event of consequential outages on the electric system, adverse health impacts can increase significantly. Loss of heat becomes a more widespread issue. There can be logistical challenges for communities with municipal and regional emergency support services, which frequently establish warming and reception centres in extreme cold weather conditions. These centres often rely on energy such as natural gas to provide emergencies services, like heating and cooking, to displaced and vulnerable people. Additionally, backup generation capacity at facilities, such as hospitals, police stations, fire halls, and schools are temporary and based on the availability of fuels, and have limited ability to bridge outages.

PwC explained that such non-GDP impacts can be conceptualized as "consumer surplus" effects and that PwC would expect them to be material:[97]

> The literature also measures "consumer surplus" effects on residential customers associated with electrical outages, which can be defined as effects on consumer wellbeing that are not measured by GDP such as inconvenience, health impacts, leisure and other factors. At a high level, studies have placed this cost at around US$1,750 per household for a one-month blackout. This cost would equate to US$3.5 billion if applied to the 2 million households in B.C. While our study has not measured consumer surplus effects of a natural gas outage, we would also expect these to be material given the impacts on health, education, reduced ability to heat homes and other disruptions that residents would likely experience.

3.2.3 High Cumulative Probability of T-South Winter No-Flow Event

The 2024 Resiliency Plan reflects Exponent's independent expert assessment of the probability of failure for the AVs based on various integrity-related (internal) and external causes. Exponent calculated a very high cumulative probability of a winter no-flow event on the T-South system. This is true regardless of whether the time horizon is the 67-year expected service life of the TLSE Project or the 23-year shortened life (i.e., to 2050) that FEI included as a sensitivity to be responsive to the Adjournment Decision. The 23-year winter-only lower and upper bound failure probabilities of a T-South failure are 65 percent and 97 percent, respectively. These already-high cumulative probability results are still understated as they do not reflect the potential for cyberattacks or other malicous action. Just as the 2018 T-South Incident highlighted FEI's exposure to a T-South supply interruption, there have been two more near-miss events on T-South since FEI filed this Application in 2020.

[97] Appendix RP 3 to the 2024 Resiliency Plan, PwC Report, pp. 14-15.

3.2.3.1 Exponent's Calculated Cumulative Probabilities

FEI instructed Exponent to perform cumulative probability calculations for a winter-only disruption on all AVs based on two horizons:

1. The 67-year expected life of the TLSE Project, which FEI regards as the appropriate horizon; and

2. A 23-year sensitivity based on an assumed facility retirement in 2050, which FEI included to address the BCUC's commentary regarding the energy transition potentially shortening the useful life of a new LNG facility.

FEI explains in Section 4.5.5 of this Supplemental Evidence why it regards 23 years as being too short.[98] However, the cumulative probability is very high regardless, as shown in the table below.

Table 3-3: Exponent's Calculated Cumulative Probability of T-South No-Flow Event in Winter[99]

Calculation Horizon	Basis for Horizon	Exponent's Calculated Cumulative Winter Only (90 Days) Probability
67 years	Expected Life of TLSE Project	95% - 100%
23 years	Hypothetical adverse sensitivity assumes no further use of Tilbury facility for resiliency or gas supply after 2050	65% - 97%

The Exponent Report explains these results.[100] A key factor driving the high probability of failure is the length of the T-South pipeline. Due to its length, T-South has increased exposure to all hazards. One cause of failure (also referred to as a "mode of failure"), that drives the high probability of a winter T-South outage, is the internal per kilometre rupture and ignited rupture rates when applied to a very lengthy pipeline like T-South. As occurred in the 2018 T-South Incident, rupture or ignited rupture of one of the two T-South lines could be expected to prompt a regulatory / precautionary shut-down of the other line in the same right-of-way, resulting in a no-flow event. In the 2018 T-South Incident, the regulatory shut-down/no-flow event lasted 2 days, followed by a long period of reduced flow. At present, Tilbury, regardless of the potential volumes in the Base Plant and Tilbury 1A, could not support Lower Mainland load for a single day in winter, such that the regulatory shutdown would cause Lower Mainland customers to lose service very quickly.

3.2.3.1.1 EXPONENT'S APPROACH TO CALCULATING CUMULATIVE PROBABILITY

Exponent's calculated overall cumulative probability of a winter T-South no-flow event reflects:

[98] If FEI's load declines in the future, FEI would expect to optimize the size of its resiliency reserve and allocate more of the tank to gas supply. The unique attributes of on-system LNG make it possible to optimize the gas supply portfolio by shedding other contracted elements of the gas supply portfolio, and generate gas supply mitigation revenue in the normal course.

[99] Reported as the lower bound and upper bound.

[100] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, para. 138.

- The combination of the annual failure rate associated with all of the modes of failure on the T-South system capable of being assigned a failure rate (cyberattacks and sabotage are not included, such that the cumulative probabilities are understated);
- The annual failure rate is translated into a winter-only rate by pro-rating to 90 days; and
- The winter-only annual failure rate is translated to a cumulative probability over a defined period. Exponent was instructed to assume 67 years (coinciding with the expected service life of the TLSE Project) and a 23-year shortened life sensitivity to 2050.

The cumulative probability calculations for a T-South no-flow event combine engineering work undertaken previously by JANA for integrity projects and new work undertaken by Exponent. The Exponent Report provides more information on the basis for Exponent's probability calculations.[101]

3.2.3.2 Two Incidents Since the 2018 T-South Incident Highlight FEI's Exposure to Upstream Supply Disruptions

Two incidents have occurred since the 2018 T-South Incident that highlight FEI's risk exposure associated with being dependent on T-South for much of its supply. Given the recency of these events, this is new information in this proceeding.

3.2.3.2.1 THE 2023 T-SOUTH "SWAMP GAS" INCIDENT

On January 31, 2023, Westcoast identified a potential leak on its T-South system NPS 36[102] pipeline, and as a result, shut in the pipeline as a precaution to investigate. The shut-in resulted in flows on the T-South system being reduced to approximately 65 percent of firm service. The proximity between the incident and FEI's system meant that, had the triggering incident resulted in a no-flow event, the majority of the T-South linepack would not be accessible to FEI customers in the Lower Mainland. Instead, T-South linepack would be limited to the volume of gas stored in the relatively short pipeline segment between the incident location and FEI's system. Less linepack results in a shorter support duration, which in turn results in FEI having less time to react to the incident.

Westcoast shut in its NPS 36 T-South pipeline due to safety concerns related to gas "bubbling" that was observed in the vicinity of their pipeline. With only limited field resources in the area, Enbridge accepted assistance from FEI to investigate the potential leak. FEI provided leak surveyors and equipment to investigate the gas emissions, and several samples were taken, analyzed, and eventually determined to be swamp gas.[103] Once the pipeline integrity was confirmed, Enbridge resumed full service of the Westcoast T-South system, restoring full capacity and supply to FEI's CTS approximately 24 hours after the initial shut in.

[101] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, Section 4.2 (pp. 23-28).

[102] NPS refers to the nominal pipe size outside diameter, measured in inches.

[103] Swamp gas is a naturally occurring gas (composed primarily of methane) that results from the anaerobic decomposition of organic matter in moisture-laden ground conditions.

As a result of the incident, FEI experienced an unexpected reduction of gas supply to its downstream CTS over approximately a 24-hour period. FEI relied on its Mt. Hayes and Tilbury facilities to make up for the supply shortfall, which limited the amount of Sumas supply FEI had to purchase on the day when the incident occurred. In addition, the actual temperature on January 31, 2023 was warmer than previously forecast. Had the weather been colder, FEI would have used more LNG supply and risked not having sufficient peaking supply for the rest of the winter.

FEI notes that, despite the triggering event ultimately being a false alarm, it still took 24 hours to restore full capacity and supply to the CTS after the initial shut in. Once AMI is in place, FEI would theoretically have the ability to shut off all residential and small commercial customers in the Lower Mainland so as to avoid a worst-case uncontrolled shut-down. However, doing so without the benefit of full information risks unnecessarily causing hundreds of thousands of customers to lose service for many weeks. Having enough on-system LNG on hand to support the Lower Mainland load while FEI assesses the situation avoids the potential for false alarms to trigger an unnecessary shut-down.

3.2.3.2.2 THE NOVEMBER 2021 FLOOD

In 2021, a flooding river left a portion of the T-South pipeline submerged and undercut. Enbridge restricted the flow on T-South, resulting in FEI losing 175 TJ of supply for the Lower Mainland.[104] FEI relied on market area storage and on-system LNG to make up for the T-South supply loss. As the figure below shows, the pipeline was at risk. Exponent has identified a number of locations on T-South that are susceptible to natural hazards and has factored those into its risk assessment.

[104] 175 TJ is approximately 30 percent of the supply required on November 16, 2021.

Figure 3-10: T-South Pipe Partially Submerged in Coquihalla River

3.2.4 Exponent's Unmitigated Probability-Adjusted Risk Results

The following figures from the Exponent Report show probability-adjusted risk for all AVs (the T-South AVs 1, 2, 3 and 54 are shown combined) using standard consequence measures and the 67-year and 23-year horizons.[105] The probability-adjusted risk associated with a winter no-flow event on T-South is very significant and exceeds the risk associated with any other AV by a wide margin, regardless of the consequence measure or time horizon. For instance:

- The expected 23-year winter-only GDP loss for T-South is approximately 14 times greater than the next largest loss (AV-18);
- The expected annual winter-only loss associated with T-South is over eight times greater than the combined expected annual winter-only loss of all other AVs;[106] and

[105] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, Figures 23-28 (pp. 93-98).
[106] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, para. 245.

- If the next largest AV (i.e., AV-18) is excluded, the expected annual winter-only loss on the combined AV-1, -2, -3, and -54 (i.e., T-South) is more than 30 times the <u>combined</u> expected loss on the remaining AVs.

These results do not capture cybersecurity risk, nor do they reflect the potential health and safety impacts, such as any increased incidence of poor health or mortality associated with cold residences and workplaces. They also do not account for the potential for an unexpected shift of space and water heating from natural gas to electricity during winter conditions to cause an electric system outage. While these factors are not readily quantifiable, they are real and suggest that the calculated risk is understated.

Figure 3-11: Expected 23-year Winter-only GDP Loss for the Combination of AV-1, -2, -3, and -54 and for Other AVs for the Tilbury Baseline Scenarios

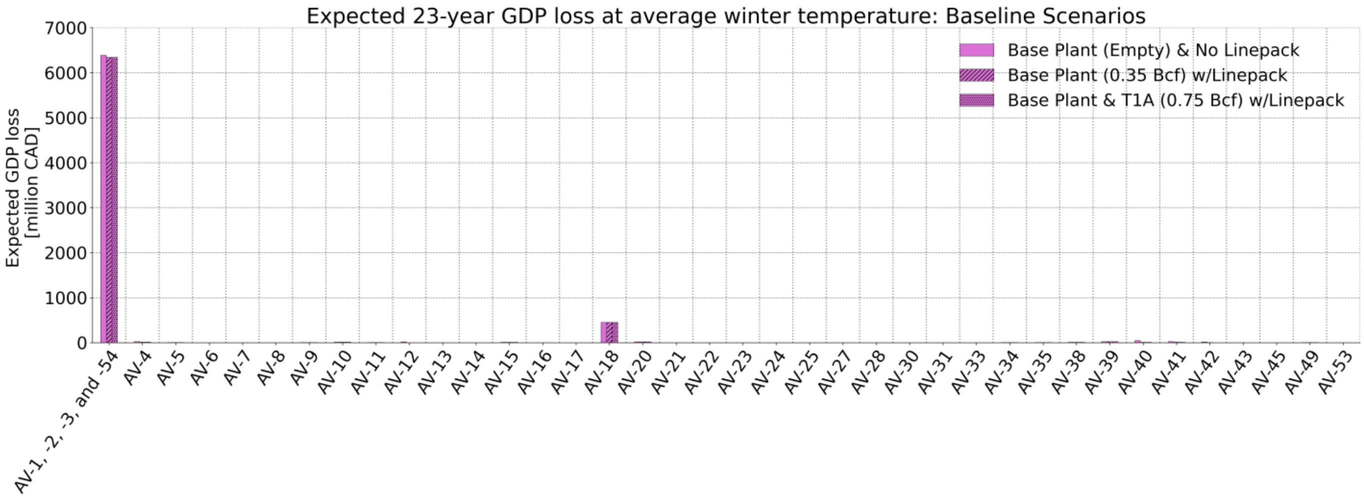


Figure 3-12: Expected 23-year Winter-only Customer Outage-days for the Combination of AV-1, -2, -3, and -54 and for Other AVs for the Tilbury Baseline Scenarios

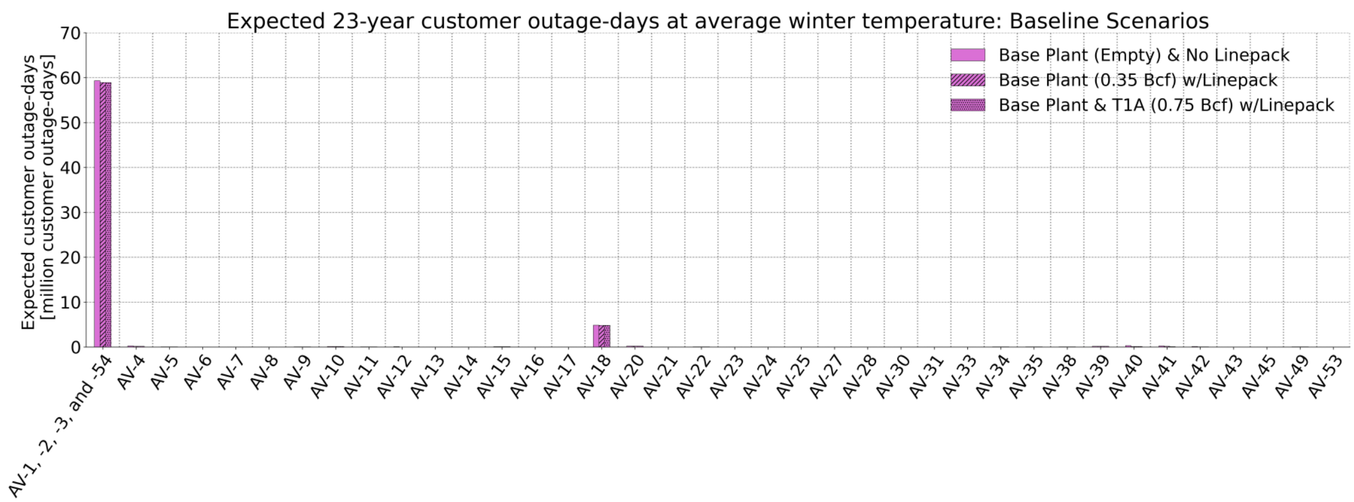


Figure 3-13: Expected 23-year Winter-only Customer Outages for the Combination of AV-1, -2, -3, and -54 and for Other AVs for the Tilbury Baseline Scenarios

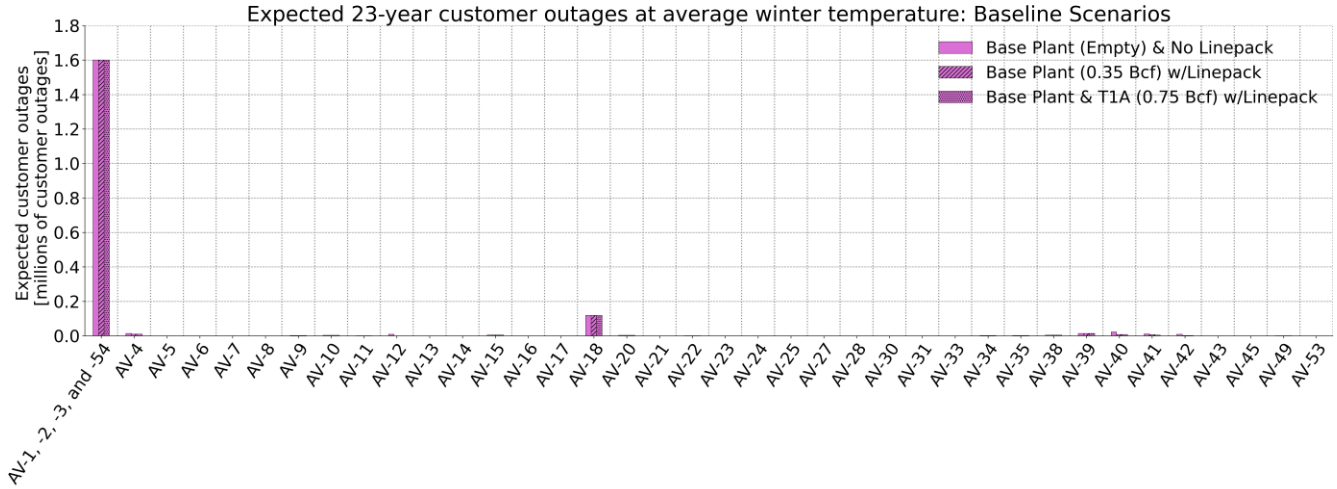


Figure 3-14: Expected 67-year Winter-only GDP Loss for the Combination of AV-1, -2, -3, and -54 and for Other AVs for the Tilbury Baseline Scenarios

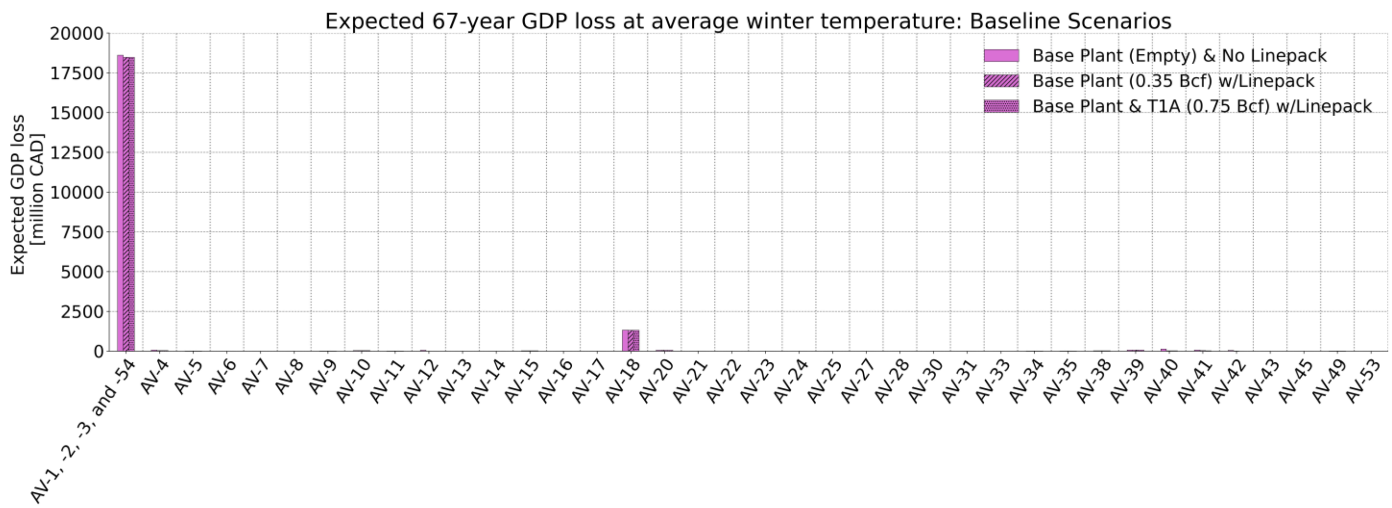


Figure 3-15: Expected 67-year Winter-only Customer Outage-days for the Combination of AV-1, -2, -3, and -54 and for Other AVs for the Tilbury Baseline Scenarios

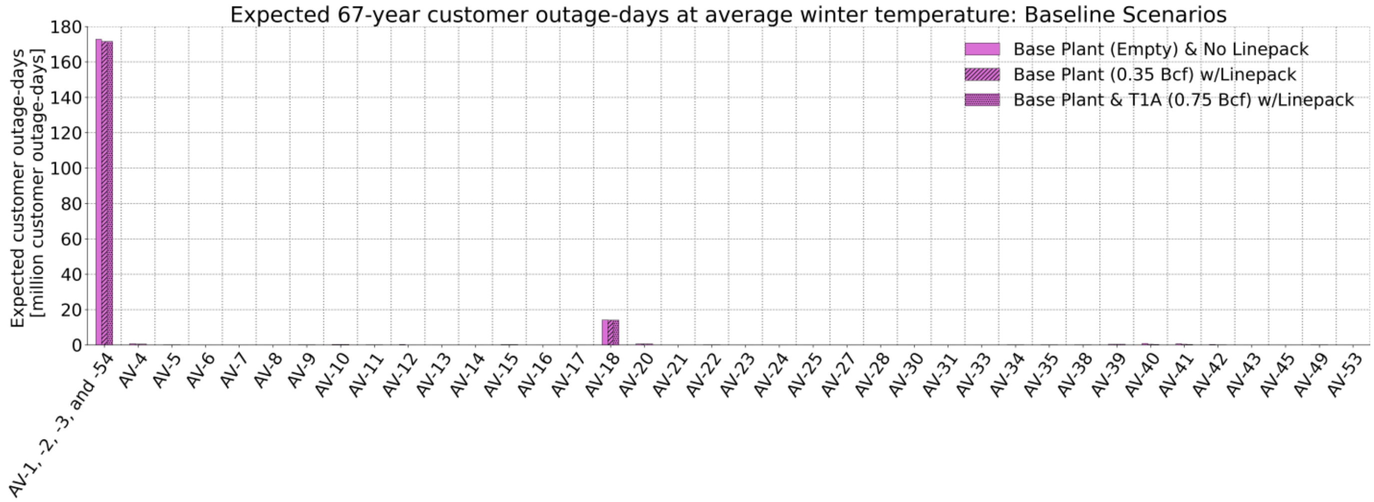
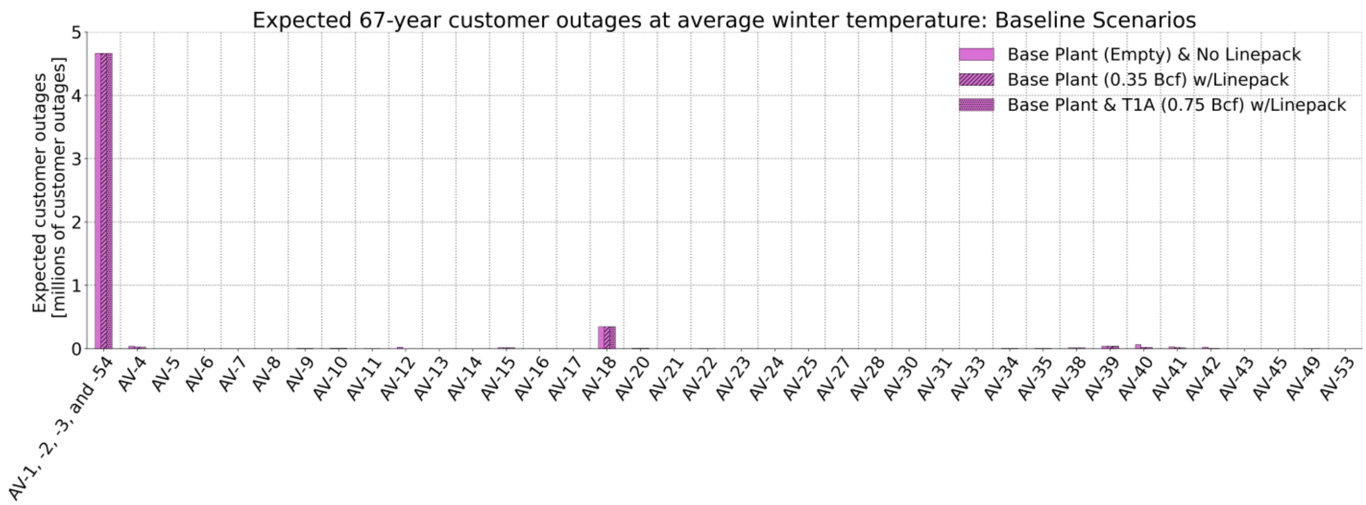


Figure 3-16: Expected 67-year Winter-only Customer Outages for the Combination of AV-1, -2, -3, and -54 and for Other AVs for the Tilbury Baseline Scenarios



3.2.5 Prioritizing Mitigation of T-South Risk Reflects Sound Risk Management Practices

Exponent discussed risk management considerations in Section 10 of its report. Its expert advice regarding standard risk management practices supports FEI's decision to invest in mitigating FEI's largest outage risk – the risk associated with a winter no-flow event on T-South or unexpected supply loss due to extreme weather events.

3.2.5.1 Exponent Recommends Targeting Resiliency Investment at Largest Risks

Exponent recommended prioritizing mitigation of the highest risk AVs, and T-South in particular:

> It is a good industry practice for a Resiliency Risk Assessment Plan to address the System Level Risks in a Top Down manner. In order to conserve and prioritize allocation of risk assessment effort resources to the most critical areas, a good risk assessment often begins with a prioritized screening of high-interest vulnerabilities. Such an effort to identify high-interest vulnerabilities and performance of a prioritized screening allows the identification of areas where subsequent and detailed risk assessment efforts should be focused.[107]
>
> …
>
> Per general good industry practices, subsequent to a proactive risk assessment evaluation, the high-risk scenarios should be reduced to acceptable levels.[108]
>
> ….
>
> As shown in Chapter 7, AV-1 has the highest associated risk at the status quo, i.e., with the Tilbury Baseline Scenarios, followed by AV-54, AV-3, and AV-2. When considered in combination, AV-1, -2, -3, and -54 have the highest associated risk at the status quo. The risk of AV-1 alone and the risk of AV-1, -2, -3, and -54 in combination are significantly higher than the risk associated with the other AVs included in this study: the expected annual winter-only loss on the combined AV-1, -2, -3, and -54 is more than eight times the combined expected annual winter-only loss of all other AVs in the status quo scenario. Therefore, prioritizing these AVs for mitigation would be reasonable. In general, mitigating assets in descending order of risk – that is, mitigating the highest-risk assets first – is considered an effective approach to reducing risk. Given the probability of failure in combination with the consequences associated with AV-1, -2, -3, and -54, Exponent would expect the risk on these AVs to be prioritized for mitigation.[109]

[107] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, para. 42.
[108] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, para. 244.
[109] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, para. 245.

> Further, regarding T-South, Exponent stated: "…that there are numerous hazards that can lead to such outages [outages with substantial (multi-billion CAD) losses], and that mitigation scenarios are hugely beneficial in reducing the risk."[110]

3.2.5.2 Mitigating the Known Catastrophic Consequences Would Reflect Sound Risk Management Even at Lower Calculated Probabilities

Exponent expressed the opinion that the known consequences of a winter T-South no-flow event are sufficiently severe that established risk management principles would support investment to reduce the harm even at much lower probabilities than those calculated by Exponent.

In respect of the T-South AVs, Exponent stated:[111]

> While there is uncertainty in the determination of failure probabilities, based on its analysis, Exponent does not consider the hazards and subsequent consequences that can impact FEI's system and the customers it serves to be "low probability" with respect to certain AVs (-1, -2, -3, -18, and -54). There is significant benefit to mitigating the consequences of a failure – this would be true even if the hazards were considered to be low probability. Scenario-based analysis considers the expected impacts of a failure, independent of the likelihood of the failure. PwC's consequence analysis indicates that there are significant losses if certain AVs fail (the scenario), and Exponent's analysis indicates that this loss can be largely mitigated if it stems from certain hazards. <u>It is well established that scenario-based analysis is a valid approach for making mitigation decisions when the consequences of a loss are substantial, independent of the likelihood of the failure. Additionally, it is common and most productive to address the largest risk first and those with the highest benefit relative to mitigation cost first.</u> Further discussion is provided in Section 10 of this report. [Emphasis added.]

Exponent also stated:

> The analysis performed in this report has revealed that there are a number of AVs that have failure modes with relatively high probabilities of occurrence, e.g., non-earthquake induced landslides on AV-1. As results have been bounded, it is possible that the hazard-specific failure rate for an AV is towards the lower end of the bounds. However, based on its analysis, Exponent does not consider the hazards present on FEI's system to be "low probability." Furthermore, AVs are typically subjected to multiple hazards, and the cumulative rate of failure of an AV (i.e., the rate of failure considering all applicable hazards) will naturally be higher than the rate of failure due to any one of the applicable hazards. When the rates of failure for different AVs are considered collectively, the cumulative rate of failure of the combination of AVs may be even higher – as is the case for the combination

[110] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, para. 243.
[111] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, para. 22.

> of AV-1, AV-2, AV-3, and AV-54. Thus, there is reason to perform mitigation activities, as it is foreseeable that a failure could occur, and the consequences of a failure are substantial. This holds true even in cases where the rate of failure of an AV is low. [112] [Emphasis added.]

Exponent has referenced academic literature and provided industry examples in support of this view in Section 10 of its report, including the following:

> There is large uncertainty in predicting low-probability, high-consequence events because observations of such events are very sparse, and the observational time span is typically not long enough. Therefore, the distributions fitted to the observed data tend to fit the central tendencies of the data, but may underestimate the rare tail events, whereas distributions fitted to the extreme tail events must contend with a very small number of available observations. The large uncertainty in the occurrence of the tail events may lead to hazard and risk estimates that are highly sensitive to the distribution parameters and modeling assumptions.[113]
> …
>
> Standard probabilistic risk assessment may underestimate the impacts of rare events because of the difficulty to estimate their probabilities and quantify their impacts, and the sensitivity of the risk to the variables of the hazard and modeling decisions. In addition, some studies suggest that risk analysis based on fat-tailed power laws may still underestimate rare risk events. Specifically, the presence of outliers (defined as extreme events which may be significantly larger than the predictions of power-law distributions) has been documented. Those are events that are sometimes referred to as Black Swans or Dragon Kings, and have been identified in nuclear accident datasets, and the magnitude-frequency distribution of earthquakes in localized regions in southern California.[114] [Emphasis added and references omitted.]

Exponent's recommendations regarding the approach to high consequence events is aligned with those of the three other experts who provided evidence on this point – JANA, PwC and Guidehouse. JANA stated, for instance:[115]

> When we land in Quadrant IV [limited knowledge, unpredictable timing and location of event, high consequences], what we must do is 1.) Accept that we cannot predict what will happen, or when; 2.) Reject all narratives and projections that try to tell us what will happen and when; and 3) Work towards mitigating the consequence of such an occurrence.

Please refer to Section 3.7 of the 2024 Resiliency Plan for a summary of the other experts' views.

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112 Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, para. 231.
113 Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, para. 234.
114 Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, para. 239.
115 Exhibit B-32, BCOAPO IR2 2.3.

3.3 BASE PLANT END-OF-LIFE JEOPARDIZES ABILITY TO SERVE CUSTOMERS IN NORMAL CONDITIONS

The Base Plant has played a critical role in FEI's supply portfolio since 1971, including providing peaking supply in normal operations. FEI, like other utilities throughout western North America, relies on on-system LNG because it has a shorter response time than off-system capacity resources and deliverability does not depend on third-party infrastructure. FEI has also relied on it during less severe supply disruptions and constraints, and for routine operations support, to sustain service to customers.[116]

The Adjournment Decision sought additional information on the remaining life of the Base Plant,[117] which FEI provides below. Additional engineering analysis on the Base Plant, and its recent deteriorating performance despite further investment, indicate that the Base Plant has reached end-of-life. Continuing to operate this critical supply portfolio asset longer than the time it takes to construct a replacement facility would jeopardize FEI's ability to meet peak loads in normal operations. There is no feasible option to extend the life of the Base Plant or replace its peaking supply in the market. A sizable capital investment is required, irrespective of resiliency considerations.

3.3.1 Equipment Is Obsolete, Is Experiencing Increasing Failure Rates and Is Increasingly Difficult to Maintain or Repair

The Base Plant houses the only regasification capacity at Tilbury (there is no regasification equipment in Tilbury 1A). It is connected to the Base Plant storage tank and FEI's transmission system through interconnection piping.[118] The Base Plant equipment is only called on to function at times where the supply is necessary to meet customer demand, such that its reliability is critically important to avoid curtailment of firm load. As discussed below, despite investment in recent years, the Base Plant equipment has been experiencing unpredictable failures consistent with equipment that is end of life. The regasification equipment is obsolete, has been experiencing increasing rates of failure and reliability issues, and is difficult to maintain or repair, as further explained below. Its deteriorating condition is compromising both existing peaking gas supply and resiliency. FEI is already decommissioning the Base Plant liquefaction equipment.

[116] Please refer to Section 4.4.1.5.4 of the Application. Additionally, Tilbury provides operations support for unplanned activities. For example, both Tilbury and Mt. Hayes were used to send out gas on January 24, 2024 in response to an East Kootenay Exchange (EKE) compressor outage. FEI's LNG facilities helped make up supply that was lost due to this unforeseen compressor outage given FEI could not source more gas from Trans Canada pipeline.

[117] Adjournment Decision, p. 14. "FEI states that "even with significant additional capital investment, the extent of additional operational life that FEI would be able to achieve is unclear". Given this uncertainty regarding the cost of extending the life of the existing tank and the amount of extended life that can be achieved, the Panel is unable to assess the cost effectiveness of the TLSE Project as a replacement for the Base Plant." See also p. 51.

[118] FEI constructed the interconnection piping in response to the 2018 T-South Incident and the subsequent 12 to 18 months of supply concern from T-South (pressure restriction on the failed line to enable subsequent integrity work). The interconnect enables FEI to access the Tilbury 1A storage and liquefaction capacity (when capacity is available) at the time of an emergency. Additionally, as explained in the Application, FEI determined that utilizing Tilbury 1A liquefaction capacity to fill the Base Plant tank would be more efficient and cost effective.

3.3.1.1 Regasification Equipment Technical and Reliability Concerns

The Base Plant regasification equipment is comprised primarily of send-out pumps (pumps that move the LNG from the tank to the vaporizers), vaporizers (units that convert the liquid to a gas) and ancillary equipment such as power supply and utilities. The discussion below focusses on the issues with these two primary components (i.e., send-out pumps and vaporizers).

3.3.1.1.1 SEND OUT PUMPS ARE EXPERIENCING ABOVE NORMAL FAILURE RATES

The send-out pumps and motors are a key component of the regasification system and have been experiencing unplanned outages more frequently.

The Base Plant is designed with four send-out pumps; however, currently only the “A”, “B” and “C” pumps can run in parallel. The “D” pump does not have the same performance curve, and therefore it does not function as a spare for the other three pumps. Each send-out pump consists of a motor and a pump with common suction piping, all of which is tied to a common pipe. These pumps pull LNG from the Base Plant tank, and push it into the vaporizers, where it is gasified and pushed into the distribution gas pipeline. Functioning send-out pumps are essential to the Base Plant being able to send out gas into the system.

FEI is currently working to upgrade pump “D” so that it can run in parallel with the other three pumps and function as a standby spare with roughly 90 percent of the capacity of the other three pumps. This upgrade is expected to be completed in the fall/winter of 2025. Currently there is no redundancy, which elevates reliability risk. For example, without the partial redundancy provided by the fourth send-out pump, the loss of a single pump would reduce the send-out capacity provided by the Base Plant from 150 MMcf/d to approximately 100 MMcf/d, and even lower if multiple failures occur simultaneously.

The three functioning send-out pumps (Pumps “A”, “B” and “C”) suffer from various failure modes, including process seal failures, freezing in place during cool down, and high vibrations due to their long narrow shafts and lack of pump bearings. A more modern pump of similar capacity would benefit from a shorter, wider shaft, higher efficiency impellers achieved through modern manufacturing processes, and modern process seal technology.

The three functioning send-out pumps have experienced a higher-than-normal failure rate over the past three years, including the following failures:

- **August 2020:** Pump “C” was removed, as it was seized. The pump was repaired and reinstalled.
- **November 2021:** Pump “A” seized during cool down. The pump was warmed up, and subsequently cooled down again. The pump unseized and was restarted.
- **December 2022:** The Pump “A” motor experienced high vibrations and subsequent arcing of the windings. As a result, FEI overhauled the pump motor, including rewinding the stator and machining the shaft.

- **August 2023:** Pump "B" had a seal failure which was repaired by the Original Equipment Manufacturer (OEM).
- **November 2023:**
  - Pump "A" had a higher-than-normal oil leak into the pump. In order to remain operational, the oiler required top up approximately every 4 hours to keep the pump running. This has subsequently been repaired.
  - Pump "B" had high bearing temperatures. The pump could only be operated for 15 minutes before it had to be shut down. Repairs to this pump have been completed.
  - Pump "C" seized on cool down due to a faulty temperature probe indicating a temperature higher than actual. In particular, the pump cooled down too quickly, resulting in the pump freezing in place. The pump worked normally after warming and cooling down again.

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.

3.3.1.1.2 VAPOURIZERS ARE INCREASINGLY UNRELIABLE AND INCLUDE OBSOLETE TECHNOLOGY THAT CANNOT BE REPLACED

There are four 50 MMcf/d vapourizers at the Base Plant, including three operating vapourizers and one spare vapourizer (i.e., a maximum of three can operate at any one time – 3 x 50 MMcf/d = 150 MMcf/d). While FEI cycles through the vapourizers, and plans maintenance cycles accordingly, the vaporizers have nonetheless become appreciably unreliable. There are several concerns regarding the condition of the vapourizers and FEI's ability to continue maintaining them.

- Over the past five years it has become common to take multiple attempts to start the vapourizers when there is a demand for regasification. At times, this has delayed the ability to send out by up to 4 to 8 hours. FEI has identified a few potential causes for this lack of reliability and has taken steps to try to address them (e.g., upgrading the ignitors, electrodes, transformers, and bench testing them annually). FEI will continue to monitor these steps taken to improve the reliability of the vapourizers.
- Three of the four vaporizers are manufactured from carbon steel and suffer from corrosion in the water/glycol bath. FEI monitors the corrosion and completes spot repairs over time. As the corrosion continues and affects more of the vapourizer metal, FEI expects more unplanned repairs. The corrosion is affecting many aspects of the vapourizers. For instance:
  - In the most recent inspection, three of the four vapourizers had significant coating failures on the bath walls and floor, which requires removal via blasting, followed by recoating;

- Seven of the 16 wall and floor supports on Vapourizers “A” and “C” have broken and have been weld repaired;
- The walls of all four vapourizers are bowed out of shape due to thermal cycling;
- The corner vertical seam on one vapourizer has cracked, requiring a 4-foot vertical weld repair; and
- The outlet nozzle on one vapourizer has corroded through to atmosphere and currently contains a temporary patch. Two of the other vapourizers have outlet nozzles that are nearly corroded through. A permanent weld repair is required on these three vapourizers at the next thorough inspection.

The issues outlined above are indicative of the types of failures that can be expected as the vaporizers are operated well-beyond their design life. As they age, the vaporizers will very likely see increased rates of these types of issues. Even with ongoing monitoring, predicting when a failure might occur is difficult and it is inevitable that reliability will decrease over time.

The existing vapourizers are tuned each year to ensure an adequate fuel-to-air ratio. Whereas modern vapourizers are tuned via control valve positioners and Programmable Logic Controllers (PLCs), the existing vapourizers require tuning via a mechanical linkage connecting the air and fuel inlet valves. The mechanical linkage makes tuning the vapourizers difficult as very small changes to the linkage orientation (e.g., loosening joints or changing valve friction while stroking) have adverse effects on the combustion efficiency.

The following photos show examples of corrosion. As noted above, as the vaporizers age, FEI expects the frequency of these incidents to increase as the cumulative corrosion increases and distortion of the bath walls continues. As the frequency of failures increases so too does the need to replace the vapourizers to improve reliability.

Figure 3-17: Severe Corrosion in Vaporizer Stack A

Figure 3-18: Typical Coating Failure on Floor of Vaporizer Bath

Figure 3-19: Example of Coating Failure on Walls of Vaporizer

Figure 3-20: Discoloration and Bowing of the Bath Walls

3.3.1.1.3 PLANNED AND UNPLANNED MAINTENANCE RESULTS IN EXTENDED DOWNTIME

The problem of more frequent failures of the send-out pumps is compounded by the challenges with performing emergency repairs or maintenance quickly.

The Base Plant has limited isolation valves, making it difficult to complete emergency repairs and maintenance tasks quickly. When compared to a modern plant, the Base Plant has large sections of piping and equipment which must be warmed up to achieve a safe isolation on any piece of equipment. This warming up and subsequent cooling down adds 6-10 days to the repair duration. The lengthy time to conduct repairs applies to nearly all of the regasification system, but especially to the pumps, motors, piping and valves that interconnect the tanks with the regasification equipment. Further, if a failure or breakdown occurs during or just prior to a resiliency event, this effectively renders the Base Plant useless for the event given the antiquated design and challenges in completing repairs in a timely manner. FEI provides examples of the impact of limited isolation valves below:

- In the case of the send-out systems, the limited isolation valves result in long timeframes and significant costs to complete emergency maintenance or repairs. In the absence of isolation valves, performing maintenance on any of the pumps or motors (including bearing, seal, wear ring replacements or impeller/inducer inspection/repairs), necessitates first warming the entire send-out system and the interconnected piping, requiring purging of LNG gas vapours. Cooling down the interconnect and send-out systems following maintenance requires bringing in a liquid nitrogen injection truck at an average cost of $150,000.[119] The full cycle to warm up the equipment and then cool it back down to put it back into service can take up to 10 days, (excluding the time to repair the damaged equipment, which may take longer than 10 days, depending on the repair scope).
- Inadequate isolation points for each valve make it difficult for FEI to remove and recertify the Base Plant's 44 Pressure Safety Valves (PSVs) that form part of the regasification system without venting natural gas to atmosphere. FEI removes and recertifies the PSVs approximately every 24 months (and no longer than every 30 months), as per CSA Z276. This work is necessary to avoid failures and the risks of leaks, which can cause the Base Plant to be out of service for 10 days. A typical new facility includes two isolation valves immediately upstream of each PSV being removed, allowing for quick isolation, and minimal venting.

FEI has evaluated the potential to install additional isolation valves to reduce the down time required for maintenance activities on the regasification system. Given the age of the Base Plant, the piping around the send-out system does not have sufficient room to allow installation of any additional valving. Retrofitting the system would require reconfiguring the regasification piping and surrounding infrastructure. Given the space limitations and the challenges with the inherent design, this would require a very substantial outage and is not a practical solution.

3.3.1.2 Base Plant Liquefaction Equipment is Being Decommissioned

The Base Plant was constructed in 1971 with 5 MMcf/d of liquefaction capacity. The equipment is obsolete, and its reliability declined appreciably over the past decade. In order to address the issue, FEI interconnected the Base Plant and Tilbury 1A tanks so that FEI can use 5 MMcf/d of

119 The cost depends on a number of variables including weather conditions and duration.

Tilbury 1A liquefaction to fill the Base Plant tank.[120] Sustaining the obsolete Base Plant liquefaction equipment is no longer practical, and FEI recently ceased to use the equipment altogether.

In 2022, FEI began the process of decommissioning the Base Plant liquefaction equipment and laying it up for safe long-term storage and eventual demolition. This development has not eroded FEI's gas supply and resiliency, given FEI's ability to rely on Tilbury 1A liquefaction. However, the deterioration of the Base Plant liquefaction equipment is symptomatic of the age of the Base Plant.

3.3.2 Seismic, Environmental and Flooding Issues Are Inherent in the Base Plant Design

As described below, the Base Plant was constructed to lower engineering and safety standards that were in place at the time of construction. Even if the regasification equipment was to be replaced, there are seismic, environmental and flooding issues inherent in the original Base Plant design. FEI now operates the tank well-below its design capabilities for seismic reasons, and experts have advised against tank retrofits to restore those original capabilities.

3.3.2.1 The Base Plant Tank Was Designed to Lower Seismic Standards and Issues Cannot Be Solved with Retrofits

The Base Plant tank was constructed beginning in 1969, at a time when seismic standards were much lower than today. Over time, changes in standards have prompted improvements, as well as multiple reductions in the tank fill elevation to mitigate identified seismic risks. This section discusses the latest seismic studies that caused FEI to operate the tank at 0.35 Bcf, and the new engineering advice against attempting tank retrofits to restore its design capabilities.

3.3.2.1.1 RECENT SEISMIC ASSESSMENTS HAVE PROMPTED REDUCED LNG FILL ELEVATION

At the time of construction in 1969, 1,600 timber piles were installed under the tank in order to improve the ground it was located on and guard against unwanted movements and displacements during a seismic event. The tank was constructed as a single wall vessel and an earthen dike was constructed to act as secondary containment for the LNG in the event of a breach of the tank. Since that time, understanding of seismic risk has advanced, resulting in more stringent design requirements and prompting actions by FEI.

- **1981:** A new study was completed based on the 1978 version of the CSA Z276 standard for LNG facilities. As a result of this study, in 1983 additional ground improvements were completed around the tank to help mitigate soil liquefaction during seismic events. In addition, the earthen dike was abandoned and a new concrete containment wall was built around the tank.
- **1996:** A further code review was completed based on the CSA Z276-1994 standard. As a result of this review, the maximum liquid level in the tank was reduced to 26 metres (or 95

[120] See Exhibit B-1-4, p. 62 for further discussion.

percent of the tank level) to prevent spillage and protect the integrity of the tank during a seismic event.

- **2018:** FEI operated the tank at the reduced 95 percent level until 2018 when further studies were initiated to check the tank performance against the 2015 version of the CSA Z276 standard and to review the performance of the tank related to any potential breach (in particular the fire suppression system). Those reviews identified the following:
  - The firewater foam system was inadequate to combat a fire within the containment walls from a full breach of the tank.
  - The original ground improvements completed at the time of the tank construction and subsequently in 1983 would be inadequate based on current day code to prevent large differential settlements between the tank and the connecting piping and equipment. As a result, even with operating the tank at the reduced liquid levels there remains a loss of containment risk in the event of a seismic event.
- **2020 / 2023:** In light of the findings in the 2018 reports, FEI completed updated studies in 2020 and 2023 (by CB&I, an industry expert in the design and construction of tanks) to assess the performance of the Base Plant tank against current engineering standards for seismic design. Similar to the situation in 1996, when FEI reduced the fill level of the tank to 95 percent to reflect then current day seismic standards, these engineering studies based in current standards have prompted FEI to operate the Base Plant tank at 58 percent capacity.
  - CB&I issued its first report in 2020 (2020 CB&I Report), noting that a fill elevation in the tank of 16 metres (versus design level of 26 metres) is required to limit stresses to acceptable levels for the inner tank, prevent the ring wall foundation from unloading, and to comply with current day seismic requirements.[121] A 16 metre fill elevation equates to 58 percent capacity, or 0.35 Bcf.
  - A further study completed in 2023, also by CB&I, included a more detailed assessment of the tank (utilizing finite element analysis). This study confirmed that operating the tank above 16 metres could cause the tank's ring wall to unload under the CSA Z276-2015 geotechnical and seismic standards.[122] The report also noted that based on even more recent code changes, as well as improved understanding of how the ground at the Tilbury site would act during a seismic

[121] Confidential Appendix D, p. 3: "CB&I is in the process of performing a more rigorous evaluation of the single-containment BPT. In 2020, CB&I performed a review of the BPT using current-day seismic levels and code requirements which indicated that it should only be operated at a capacity of ~59% (16 m product height) of the original tank design capacity."

[122] Confidential Appendix D, p. 6: "Under the 16.0 meters of product with 100% horizontal SSE and 40% vertical SSE, the bearing pressures beneath the ringwall based on the ANSYS analysis and original seismic spectra are comparable with hand calculations. In this condition, the foundation is on the verge of unloading as previously stated in 246376-000-PS-RP-00001."

> event, that unloading of the foundation may occur even at the 16 metre liquid elevation.[123]

Improved understanding of how the tank would react, combined with the tank's old single wall technology (meaning any breach of the tank would result in LNG being discharged into the environment), has led FEI to continue to operate the tank at a fill elevation of 16 metres (equivalent of 0.35 Bcf) as initially recommended in the 2020 CB&I Report.

FEI would need to perform further risk / engineering evaluation before considering operating the tank at design volumes with additional risk mitigation measures. However, CB&I has suggested that it expects further analysis could instead result in further reductions in the recommended fill elevation (i.e., the tank capacity could be reduced below 0.35 Bcf):

> The preliminary evaluation considering the 2023 WSP response spectra indicates that unloading of the ring wall is likely, even at the 16.0 m product level. As discussed in 246376-000-PS-RP-00001, unloading of the foundation is not covered by the API Standards <u>and is expected to worsen the results from the Standards-based hand calculations</u>. An FEA would be required to determine the full extent of the impact of the 2023 WSP response spectra.[124] [Emphasis added.]

3.3.2.1.2 RETROFITTING TO RESTORE THE TANK DESIGN CAPACITY IS NOT FEASIBLE

FEI retained CB&I and WSP (previously Golder, an expert in geotechnical matters) in 2023 to assess the feasibility of refurbishing the Base Plant tank to withstand minimum seismic requirements and return it to its original design capacity of 0.6 Bcf. CB&I's 2023 review focused on the tank itself, while WSP focused on the foundations. Those reports show that refurbishment of the Base Plant tank would be impractical and risky, such that FEI has concluded tank refurbishment is not feasible.

<u>2023 CB&I Report Recommended Against Attempting to Remediate the Deficiencies in the Tank Itself</u>

CB&I's 2023 report (2023 CB&I Report) is included in Confidential Appendix D. The section on Remediation Methodology describes what refurbishment would involve, as well as the associated risks. CB&I's key findings include:

- Numerous elements of the tank would not comply with the most recent edition of API 620, Design and Construction of Low-Pressure Storage Tanks.
- One of the keys to restoring the Base Plant tank to its design capacity is its foundations. The only way to resolve one of the key failure modes (unloading of the foundation) is to

[123] Confidential Appendix D, p. 8: "The preliminary evaluation considering the 2023 WSP response spectra indicates that unloading of the ring wall is likely, even at the 16.0 m product level. As discussed in 246376-000-PS-RP-00001, unloading of the foundation is not covered by the API Standards and is expected to worsen the results from the Standards-based hand calculations. An FEA would be required to determine the full extent of the impact of the 2023 WSP response spectra."

[124] Confidential Appendix D, p. 8.

replace the existing foundation with one designed to accommodate the higher loads. CB&I did not comment on how to replace the foundation, as FEI retained WSP for that purpose.

- The existing tank also has deficiencies with the anchor straps holding the inner tank, the compressive strength of the outer tank concrete wall and the outer tank anchor strap attachments.

The above is not an exhaustive list of components that would require upgrading.

CB&I identified a potential scenario to repair the tank components (not the foundations) but noted it would involve significant risk. It recommended against undertaking the repairs. CB&I stated the following in the 2023 CB&I Report (Section 2.0 (Contractor Opinion)):

> CB&I believe that performing the modifications and repairs is possibly achievable, however, the repairs and modification process is fraught with significant risk. Safety and environmental risks aside, the consequences of noted, but not limited to risks would likely jeopardise the intended purpose of the repairs / modification, which is to bring the tank up to current day standards and seismic conditions and provide full capacity utilization. Moreover, even if possible, and in the unlikely event that all risks are mitigated to inconsequentiality, after the tank modifications are carried out the tank may still not be up to current day standards for siting of a single containment tank at this location (to be determined by Owner / Regulator / Permit issuer).
>
> It should be noted that the following discussion about refurbishment of the Base Plant Tank assumes that all tank components are in as-new condition. Components being in as-new condition is unlikely given that tank was placed into service ~52 years ago, circa 1971. Any component/s that are discovered to have deteriorated will need to be repaired or replaced accordingly. Any deteriorated components that are not discovered may potentially affect the BPT longevity and operability of the tank. Further, after any potential remediation CB&I would not warrant the tank or operability due to remediated condition or pre-existing or latent unknown conditions in the existing structure.
>
> With the risks of the repair and unknowns CB&I would suggest that this path not be followed. [Emphasis added]

WSP 2023 Report Confirmed That the Base Plant Tank Will Fail Under Current Seismic Loads Without Ground Improvements

WSP's 2023 report on the foundation (2023 WSP Report) is included as Confidential Appendix E. Even if all the tank repairs identified by CB&I could be completed as planned, the foundation would have to be replaced or the tank would still fail under seismic loading derived from recent codes and standards. The potential options that WSP identified would not be cost-effective or feasible.

WSP found that based on previous reports and engineering efforts, the ground below the existing timber piles supporting the Base Plant tank would likely experience soil liquefaction and as a result, post-earthquake differential settlements of between 400 and 600 millimetres.

WSP considered two potential options to address this differential settlement: (1) completing ground improvements with the Base Plant tank remaining in place; or (2) completing ground improvements with the Base Plant tank being decommissioned, removed and then replaced after ground improvements were complete. WSP found that with Option 1 (leaving the Base Plant tank in place), some soil improvements could be affected around the perimeter of the tank; however, it would not be possible to improve the ground directly below the timber piles. As a result, Option 1 would not mitigate soil liquefaction potential under the tank.

With respect to WSP's second option, even if it were possible to safely remove and reinstall the Base Plant tank, this option still presents risks because the existing condition of the timber piles is unknown. This could be mitigated by installing new stone columns instead; however, this installation would still present significant challenges in working around the existing timber foundations. FEI does not consider decommissioning, temporarily removing, and then reinstalling the Base Plant tank to be a cost effective or feasible solution given its age and the complexity and risk that would be involved with this approach. The re-installed tank would still need to be operated at its reduced capacity, and the Base Plant would still be exposed to the other challenges outlined above.

FEI will continue to operate the tank at its reduced capacity of 0.35 Bcf with ongoing evaluation to determine if further derating is necessary depending on the tank condition and any future changes to seismic codes.

3.3.2.2 The Base Plant Tank's Design Entails Higher Environmental Risk

From an environmental perspective, the Base Plant tank design does not meet current design expectations as it relates to emissions.

The Base Plant tank was constructed with one boil off gas compressor to manage pressure build up within the tank (boil off gases). In addition, the tank was designed to operate under a very narrow pressure range. Under normal operations, this compressor manages the pressure in the tank within the design ranges and captures the boil off gases and sends them back to the pipeline. However, even under minor upset conditions or during periods of maintenance for the compressor, the pressure can build up in the tank beyond the design range and is released to atmosphere through a vent at the top of the tank. This design configuration was common practice for tanks built in the 1970s; however, current day standards require multiple boil off gas compressors (to provide redundancy), and include a wider range of design pressures to avoid venting boil off gases to atmosphere.

Similarly, in the event of a breach of the tank, the current standard is to have full secondary containment built within the tank itself, unlike the Base Plant tank which has open air secondary containment. If a leak were to occur from the Base Plant tank, the LNG would collect within the open-air secondary containment and would vent to atmosphere as it changes from a liquid to a gas. Conversely, a new TLSE Project tank would have full secondary containment (as does the existing Tilbury 1A tank), preventing methane venting to atmosphere in the event of a breach.

3.3.2.3 Plant Was Built at an Elevation that is Susceptible to Flooding

The Base Plant was constructed at an elevation that makes it susceptible to significant damage and service disruption in the event of any flooding. Retrofits to address this risk are not practical.

Flood modeling completed in this section of the Fraser River indicates that the Base Plant's elevation makes it susceptible to flooding. Specifically, if a flood event were to occur, there is a very high risk that the Base Plant control room and other process buildings would be damaged. This includes the electrical transformer and its connections to the process equipment. When constructing the new Tilbury 1A facility, the City of Delta required FEI to raise the elevation of the site by 3 to 3.5 metres to ensure that in the event of a flood the new equipment would remain operational.

The damage from a flood affecting the control room and process equipment would likely interrupt FEI's ability to rely on the Base Plant for months to allow for damage assessment and delivery of replacement parts for the distributed control system (DCS), uninterrupted power supply (UPS) and motor control center (MCC). During that period, FEI would have no ability to send out gas from Tilbury since the Base Plant houses the only regasification equipment at Tilbury.

It would not be possible to raise the elevation of the ground under the Base Plant; therefore, the Base Plant equipment would remain susceptible to damage from flooding. Moreover, trying to raise the aging equipment would be complex, risky and very costly. Keeping the Base Plant operational during the work would also be impractical. It would require constructing new temporary facilities at a different location to maintain the functionality of the plant. The existing facilities would then need to be removed, the elevation in that area raised to the new height, and then the existing facilities would need to be reinstalled. The temporary facilities could then be removed.

3.3.3 Long Replacement Project Lead Time Increases Risk

In light of the long lead time to permit and construct a new tank and regasification, investment decisions must be made well in advance. FEI already faces a number of years of continuing equipment deterioration due to the lead time for the TLSE Project. Prolonging that time increases the potential for a permanent failure or further reduction to tank fill levels to occur before a solution is in place.

FEI estimates that it would take 6 to 8 years to permit and construct a new tank and regasification equipment after deciding to build a new facility. FEI's 6- to 8-year estimate of the potential lead time is based on its experience. The execution phase for the TLSE Project is estimated to be 5 years from project approval. Following approvals of a Base Plant replacement project, it would take over 4 years to engineer, procure and construct a 0.6 Bcf tank and 4 x 50 MMcfd vaporization. This is contingent on regulatory approvals, market conditions and other external factors.

3.3.4 Losing Access to Tilbury Supply Would Challenge FEI's Ability to Meet Peak Load

FEI's supply portolio (i.e., the BCUC-accepted Annual Contracting Plan (ACP)) has, since 1971 when the Base Plant was commissioned, included 0.6 Bcf of energy (storage) and 150 MMcf/d of capacity (regasification) from Tilbury in its planning to meet customer demand. FEI explains below why losing access to some or all of the peaking capacity and energy currently provided by Tilbury, which would occur, for example, if the Base Plant regasification fails, would impair FEI's ability to provide uninterrupted service to customers in winter. With today's highly constrained regional pipeline and storage infrastructure, even inferior fall-back options for market-dependent peaking supply no longer exist. FEI could not replace 150 MMcf/d and 0.6 Bcf of peaking supply in the market. FEI does not have control over regional infrastructure expansions, and if those expansions were to occur in the future they would entail very significant annual gas supply costs for FEI customers.

3.3.4.1 On-System LNG Is a Critical Part of FEI's Gas Supply Portfolio

On-system LNG has played an important, long-standing role in FEI's overall supply portfolio (as it does for utilities throughout the Pacific Northwest), providing critical dependable peaking supply on cold winter days, while also backstopping other resources within the portfolio.

3.3.4.1.1 TILBURY LNG PROVIDES PEAKING SUPPLY IN FEI'S ANNUAL CONTRACTING PLAN

FEI described how it designs its gas portfolio in the Application.[125] That evidence is summarized below.

FEI's gas supply strategy has been to rely on physical assets (i.e., pipeline capacity and regional storage capacity) to procure supply with limited exposure to market risks such as counterparty default risk and commodity price spikes on high demand days. The physical supply available at Sumas is the Station 2 gas delivered through T-South, and the costs of Sumas winter supply are much higher than the costs of holding T-South plus Station 2 commodity. FEI currently sources the majority of its gas supply from Station 2 and AECO, and only includes limited Sumas supply as contingency resources in the ACP portfolio.

As the figure below illustrates,[126] FEI's resource portfolio includes pipeline, market area storage and on-system LNG storage for peaking. Each asset or resource, with different supply durations (i.e., energy) and daily deliverability (i.e., capacity), provides supply at different times of the year to meet seasonal gas demand while having different attributes. Each year, FEI conducts a portfolio optimization exercise using standard gas portfolio planning software to seek an optimal

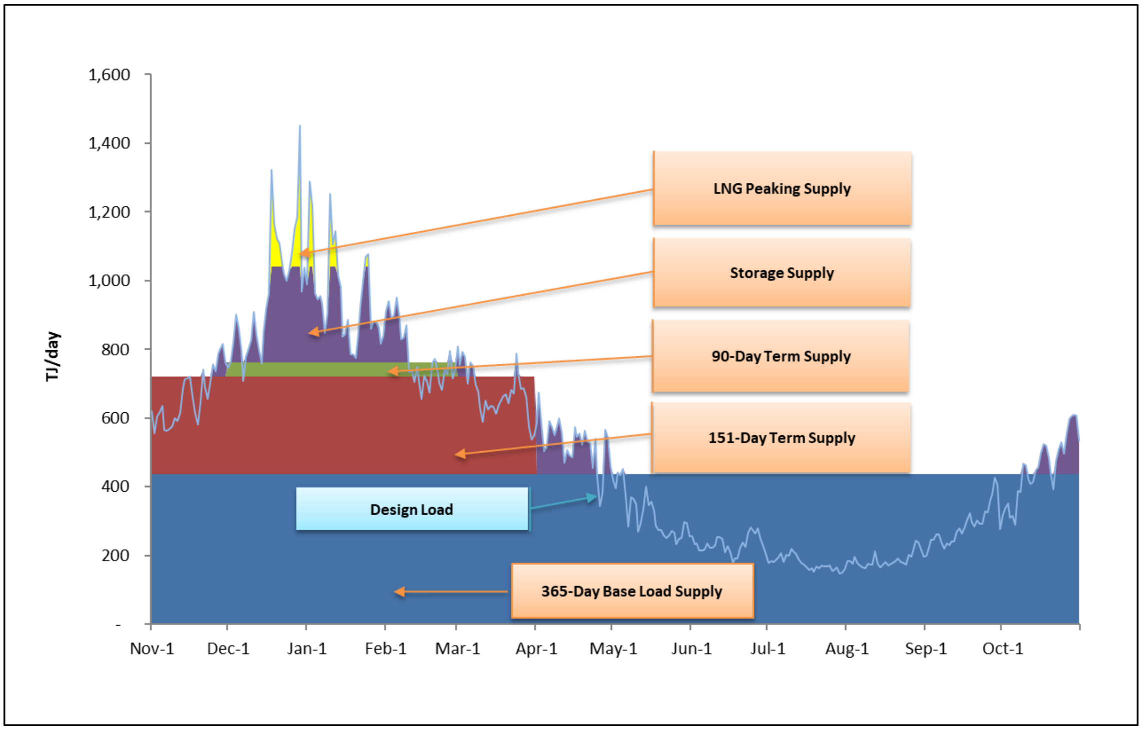
[125] Exhibit B-1-4, Application, pp. 30-31 and 79-80.
[126] The specific volumes are commercially sensitive but are available in Figure 3-4 from the 2023/24 Annual Contracting Plan.

portfolio to meet requirements based on updated inputs (i.e., forecast demand). The ACP sets out the annual requirements of each type of supply resource to optimally match FEI's load profile. In general:

- Since **pipeline capacity** must generally be purchased for longer durations (typically, 365 or 151 days), FEI tends to use pipeline supply for loads that require service year-round and the majority of the winter. FEI's pipeline capacity holdings are comprised of many individual contracts with different volumes and renewal dates, which gives FEI significant flexibility to recontract or de-contract resources as load changes over time.
- **Market area storage** provides supplemental supply during the cold winter periods (i.e., 10 to 60 days of demand). FEI employs the same contracting strategy as with pipelines, entering into multiple storage agreements with different volumes and renewal dates. These assets are also used to balance the system by injecting and withdrawing gas to and from storage throughout the year.
- **On-system LNG peaking supply** is typically reserved for peak day (i.e., 1-10 days of demand) and cold winter days because it provides additional capacity (i.e., daily deliverability, determined by regasification output) on system which reduces the needs for pipeline supply during cold winter days. This capacity is backed by energy (i.e., LNG in storage) with the on-system energy from LNG being a small, but crucial, supply to meet overall energy requirements in peak periods. Tilbury LNG has been a critical peaking supply asset to serve Lower Mainland gas customers since it was built in 1971.

As shown in the Figure 3-21 below, FEI develops a mix of resources in the gas supply portfolio to meet forecast demand. Through the development of the ACP, FEI contracts for resources to meet daily demand, taking into consideration security, diversity and reliability of supply while minimizing the overall cost of the portfolio. FEI's ability to meet the objectives within the ACP is advanced by continuing to have access to, and flexibility around, each of the three resource types listed above.

Figure 3-21: 2024/25 Design and Peak Day Load vs. Recommended Supply Portfolio



3.3.4.1.2 ON-SYSTEM LNG'S UNIQUE ATTRIBUTES

On-system LNG has several unique attributes that make it a critical part of FEI's supply portfolio, as well as the supply portfolios of other regional utilities.

- On-system LNG provides not only energy (peaking supply, measured in Bcf of LNG) but also supplemental capacity (measured in MMcf/d and determined by regasification output) which does not require upstream pipeline capacity that comes with annual tolls when the capacity is only required for a short duration. Holding pipeline capacity that is only required during a few cold winter days each year necessitates significant mitigation activities during the remainder of the year to attempt to offset fixed demand costs. FEI's gas supply portfolio is already subject to considerable cost mitigation risk given the load profile of the customer base (i.e., RS 1 has an approximately 30 percent load factor, meaning the profile is very "peaky"). Further, as discussed below, additional pipeline and regional storage capacity are no longer available given that facilities are fully contracted.
- On-system LNG allows FEI to access energy on short notice, responding to rapid weather changes or urgent operational needs. By contrast, upstream pipeline supply requires scheduling 24-48 hours in advance due to commercial transactions or business rules on pipelines, and storage supply requires scheduling and may be constrained by the operating conditions of storage and the associated pipelines.
- On-system LNG storage is commercially valuable because the gas distribution utility (in this case, FEI) has full control of the supply without relying on counterparties and third-

party assets (e.g., T-South) for delivery during cold weather when marketplace conditions are volatile. In FEI's experience, transacting commercial deals to receive a significant amount of supply required on cold days is not only costly but also risky given the market that FEI operates within. The key risks are:

1. The difficulty of securing these types of deal structures with a long-term commitment given the constrained regional gas supply resources (i.e., term of the deal); and
2. Execution failure, in which parties are not able to deliver their commitments.[127]

- On-system LNG resources can backstop other supply resources that may be subject to planned maintenance or unplanned outages. It is not uncommon to have multiple operational issues during cold weather events. For example, during a recent cold snap in January 2024 in the Pacific Northwest region, both TransCanada (i.e., Foothills) and an outage at the Jackson Prairie Storage (JPS) facility required additional natural gas to be sent out from Tilbury and Mt. Hayes during the cold event. Because of the unexpected JPS outage, mutual aid across the pacific Northwest was activated, and FEI, given the on-system LNG resources, was able to send out extra supply from the Mt. Hayes LNG facility and Tilbury to help maintain the pressure on the T-South system so gas could flow south. This ensures that downstream utilities received enough supply to meet their load requirements. On-system LNG provides additional supply and operational flexibility to the regional gas system.

For many years, through FEI's ACPs, FEI has received the BCUC's support for the strategy of holding on-system LNG and other physical assets to ensure reliable supply – which is critical during cold and extreme weather events when there is considerable market uncertainty.

This approach of using on-system physical assets to de-risk and optimize the portfolio is common in the Pacific Northwest region. As shown in Figure 3-22 below, there are a number of LNG facilities[128] in the region, including FEI's Mt. Hayes facility and Tilbury, with all but one owned by local distribution companies (LDC).[129] These other LNG facilities are designed to serve the last measure of demand on the very coldest days of the year, and LDCs typically reserve LNG capacity to serve their gas and/or electric customers. Mr. Raymond Mason, an expert in the regional gas supply market who FEI retained to opine on the role of on-system LNG storage in a supply portfolio, explains:[130]

> LNG peak-shaving plants ensure that adequate supplies of natural gas are readily available when demand is at its peak. Throughout North America, natural gas transmission pipeline operators and/or utilities, use these facilities to liquefy natural

[127] In the early 2000s, FEI experienced a counterparty failing to deliver gas during a cold weather event, which was transacted through a commercial arrangement. FEI used LNG from Tilbury to replace the lost supply.
[128] Northwest Gas Association 2022 Outlook, p. 16: 054dfe_207b3155de904ebb8d4513ef2790cfb9.pdf (nwga.org).
[129] i.e., NW Natural, Puget Sound Energy, Intermountain Gas and FEI.
[130] Appendix F, Raymond Mason Report, pp. 19-20.

> gas for storage. When demand is lower (i.e., typically in the summer), the operator can liquefy natural gas for above ground storage and then regasify the LNG when demand is high.
>
> These facilities typically provide reliable supply in areas where pipeline/distribution capacity limitations and/or weather conditions tend to cause supply and demand discrepancies. [Footnote omitted]

Figure 3-22, which is reproduced from Mr. Mason's report, shows where LNG facilities are located.[131]

Figure 3-22: LNG Peak Shaving Facilities in Western Canada and the United States

3.3.4.2 FEI's Peaking Supply Requirements Already Exceed Tilbury's Capabilities

As discussed below, the 150 MMcf/d regasification (i.e., daily deliverability) and 0.6 Bcf at Tilbury reflected in FEI's ACPs are already insufficient based on current peak load. In recent years, the BCUC-accepted ACPs have augmented the Tilbury peaking supply with temporary and suboptimal measures. FEI's portfolio optimization suggests that FEI requires 200 MMcf/d x 5 days (1.0 Bcf) of peaking supply.

3.3.4.2.1 PEAK LOADS HAVE INCREASED SINCE 1971, AND MATERIALLY IN RECENT YEARS

The original design capacity of the Base Plant when it was constructed in 1971 was 150 MMcf/d of regasification and 0.6 Bcf, which means the Base Plant was designed to provide 150 MMcf/d (i.e., 0.15 Bcf/d) of daily deliverability for 4 days (150 MMcf/d x 4d = 0.6 Bcf). Over the past five decades, FEI's customer demand has increased significantly. The number of gas customers in the Lower Mainland has increased from approximately 200,000 in 1971 to 630,000 in 2023. Since 2016/2017 alone, FEI's peak day demand has increased by 125 MMcf/d,[132] which is attributed to: (1) customer growth; and (2) Transportation Service customers (i.e., RS 23 and 25) returning to

[131] Appendix F, Raymond Mason Report, p. 20.
[132] RS 1 to 7 customers.

bundled service (i.e., RS 3 and 5). The demand growth has increased the need for gas supply resources within the portfolio. FEI's peaking capacity requirements now exceed 150 MMcf/d regasification capacity of the Base Plant, while the energy requirements now exceed 0.6 Bcf.

3.3.4.2.2 PEAK LOADS NOW EXCEED EVEN THE TEMPORARY AND SUBOPTIMAL MEASURES FEI HAS BEEN USING TO AUGMENT THE UNDERSIZED BASE PLANT

In recent years, the Annual Contracting Plans have augmented the 150 MMcf/d and 0.6 Bcf of Tilbury peaking supply with additional pipeline capacity on T-South. This was the only resource FEI was able to contract in a constrained market to meet the growing demand. This has been effective, though sub-optimal from a gas supply planning perspective; however, load growth is now exceeding the capacity of FEI's additional T-South holdings as well.

As discussed in the ACPs, relying on additional capacity on T-South for peaking supply is sub-optimal because it results in lower asset utilization (i.e., pipeline capacity is only being used on a few days each year). It requires FEI to mitigate unused capacity during most of the year, increasing portfolio cost risk for customers.

Operating the Base Plant at the reduced tank capacity of 0.35 Bcf for seismic reasons (discussed in Section 3.3.2 above) has only exacerbated the situation. FEI has had to start relying on 0.25 Bcf of peaking energy from Tilbury 1A just to restore the ACP requirement for LNG and serve customers during peak winter periods. For example, FEI needed to draw on this energy from Tilbury 1A during the 2021/2022 winter, when BC experienced prolonged cold weather. This is a temporary and limited solution.

- Tilbury 1A was built pursuant to Direction No. 5 to the BCUC on the basis that it is to be used for serving natural gas to the transportation sector to reduce GHG emissions by using cleaner fuels. Using Tilbury 1A tank volumes for peaking supply is only possible at present because LNG sales growth has been slower than anticipated to date; however, the recent provincial and federal approvals of the Tilbury Jetty are a significant development because delays in the jetty approval had represented a significant sales constraint. FEI now expects RS 46 LNG sales to increase significantly and sell out Tilbury 1A as early as 2028;
- As noted in Section 3.3.2 above, CB&I has suggested that it expects further analysis could result in further reductions in the recommended fill elevation (i.e., the tank capacity could be reduced below 0.35 Bcf); and
- As explained in further detail below, there is no further pipeline capacity available to serve as a substitute for this peaking energy.

3.3.4.3 FEI Could Not Replace Existing Dependable Tilbury Peaking Supply

As discussed below, FEI's assessment, which is supported by the report of Mr. Mason, is that fully-contracted regional infrastructure would preclude replacing Tilbury's existing peaking capabilities with high-capacity long-term commercial contracts for peaking supply arrangements. In the absence of on-system LNG at Tilbury, FEI's ability to secure replacement peaking supply would depend on regional pipeline or storage infrastructure being upgraded beyond any currently planned expansions. FEI would not control the timing or size of any upgrades, it would take years to construct an expansion, and the costs for customers would be significant. In the absence of adequate regional expansions, FEI's firm customers would likely face curtailments in normal operations.

3.3.4.3.1 HIGH-CAPACITY LONG-TERM CONTRACTS ON REGIONAL INFRASTRUCTURE ARE NO LONGER AVAILABLE

As noted above, FEI requires 200 MMcf/d x 5 days (1.0 Bcf) of peaking supply and the majority of that is provided by Tilbury LNG. Current gas supply resources in the Pacific Northwest region, including pipeline capacity on the major regional pipelines and regional storage facilities, are fully contracted.[133] As described below, the regional demands on the infrastructure are increasing, notably due to natural gas power production in the Pacific Northwest and the pending completion of Woodfibre LNG. The fully-contracted state of regional infrastructure also means that some of FEI's existing holdings are exposed to non-renewal risk.

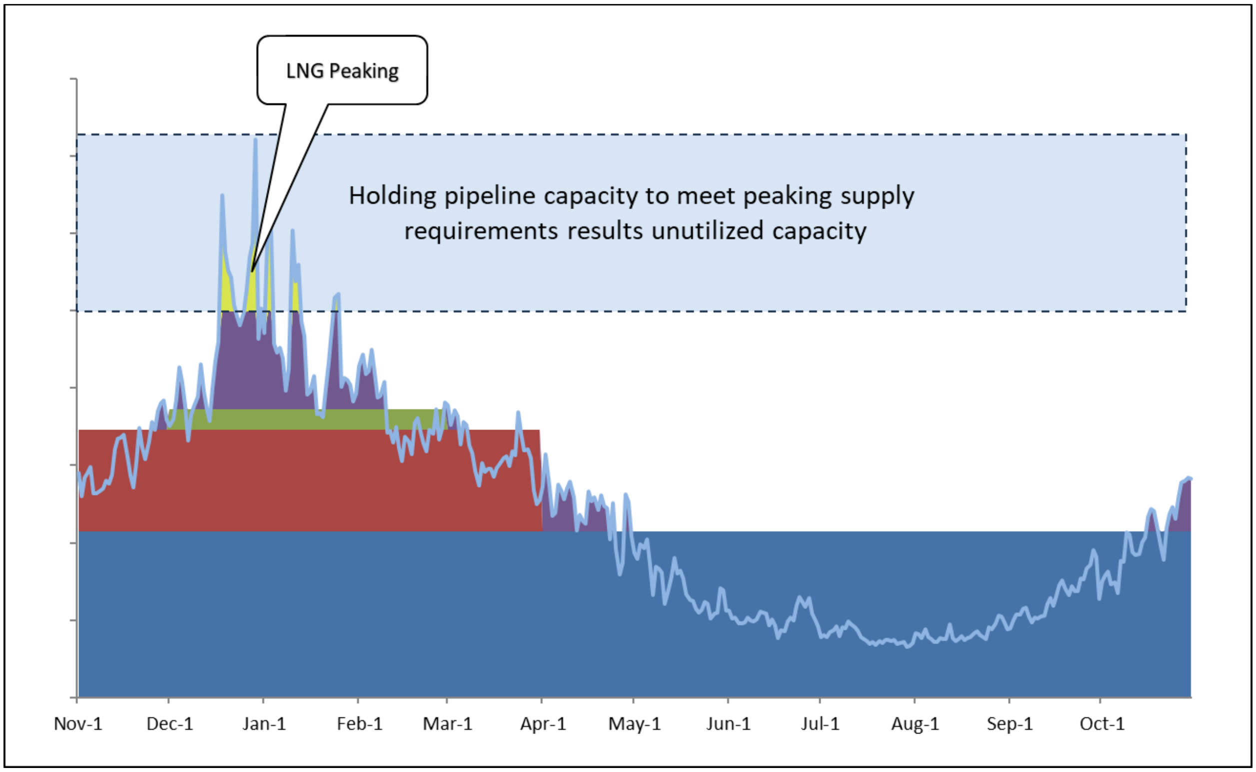
Pipeline is 365 Days and Storage Also Requires US Pipeline Capacity

At a high level, when FEI refers to acquiring regional pipeline or storage capacity, it means:

- Meeting FEI's peaking supply requirements with pipeline capacity would mean securing daily 200 MMcf/d for 365 days per year, and then looking to mitigate (i.e., resell) unused capacity during the remainder of the year when peak loads do not occur. Pipeline capacity held for peaking supply is not required for most of the year (see illustrative Figure 3-23 below).

[133] Appendix F, Raymond Mason Report, pp. 15 and 34.

Figure 3-23: Holding Pipeline Capacity to Meet Peak Demand Results in Under-utilization



- Replacing Tilbury peaking supply with off-system storage would require off-system storage itself (either at JPS or Mist), plus additional capacity on US pipeline infrastructure between the facility and FEI's system to facilitate storage injection and withdraw. That pipeline capacity, assuming it could be obtained, would be sold on a 365-day basis and would have to be mitigated in a similar fashion.

These approaches have been considered as one of the Supplemental Alternatives evaluated in Section 4 of this Supplemental Evidence (Supplemental Alternative 1 – No Capital Upgrades). FEI determined that option was not viable given the issues outlined below.

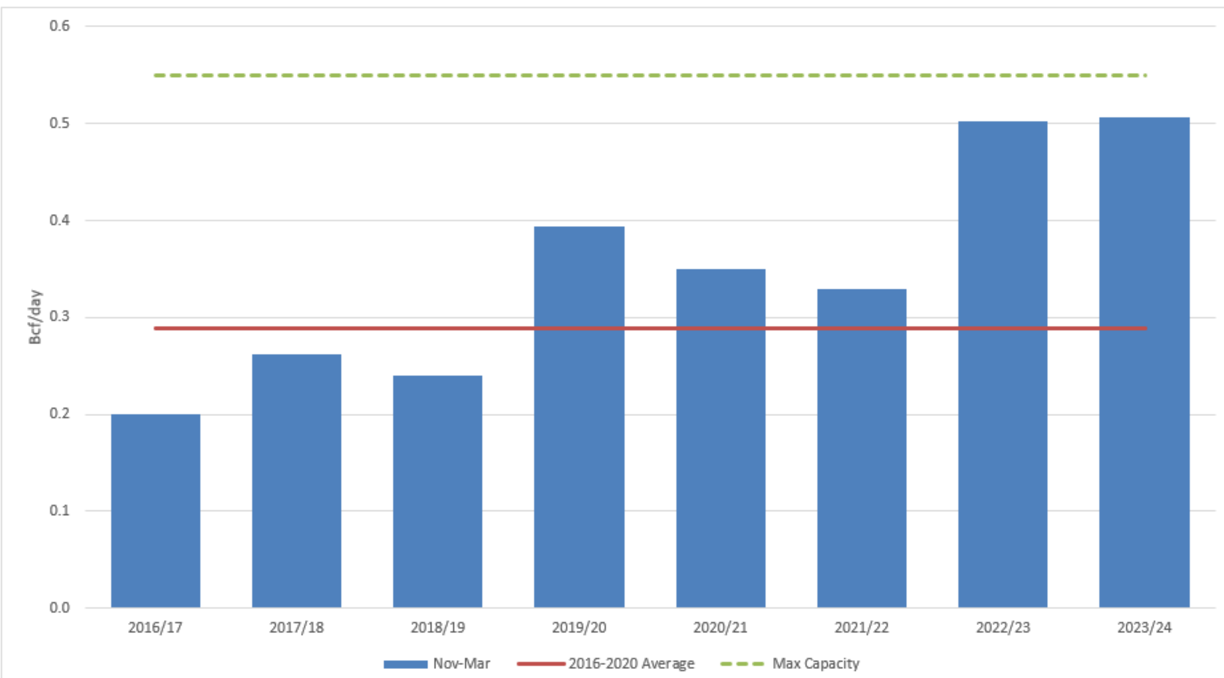
Increasing Gas-Fired Power Production Competes for Capacity

As detailed in the 2024/25 Annual Contracting Plan, increased reliance on natural gas-fired power generation in both the I-5 Corridor and the broader Western energy markets has developed into a gas supply portfolio risk in the past few years. Government policies aimed at reducing GHG emissions have incentivized development of renewable resources, including hydroelectric, solar and wind, to offset the loss of supply from the coal-fired generation retirements across western North America. However, because renewable resources generally provide intermittent generation (i.e., not firm, dependable generation), natural gas power plants are increasingly needed to meet the region's electricity demand.

Over the past decade, FEI has monitored the daily demand from the natural gas-fired generators that are directly tied to Williams' Northwest Pipeline, which is illustrated in Figure 3-24 below.

Historically, these gas-fired generators would typically purchase their gas supply at the Huntingdon/Sumas market and would only run on colder-than-normal days during the winter with the ability to shut off when no longer needed to meet demand on peak (cold) days. This practice has fundamentally changed. Figure 3-24 shows that for the past two winter seasons, demand from these natural gas-fired generators averaged 220 MMcf/d higher than the 5-year average between 2016 and 2020, and that they operated at or near maximum capacity on a daily basis throughout the entire winter period. The incremental 220 MMcf/d coming from the natural gas-fired generation is approximately 33 Bcf over a 151-day winter season. This is a larger volume than what Jackson Prairie (25 Bcf) or Mist (19 Bcf) storage facilities could offer on their own. These developments have not only put a strain on peaking resources, but also on baseload and storage resources during the winter period. The issue has been compounded by the lack of development of additional infrastructure to meet this incremental demand.

Figure 3-24: Natural Gas for Power Generation on Northwest Pipeline (Winter Averages in Bcf/Day)



FEI does not expect the reliance on natural gas power generation to change any time soon. A recent North American Electric Reliability Corporation (NERC) report concluded that Western North America is currently at an elevated risk of having insufficient capacity available and energy from resources during extreme and prolonged weather events.[134] Around the same time that this report was released, an assessment from the Western Electricity Coordinating Council (WECC) concluded that Western North America was not prepared to meet the rapidly increasing demand

[134] NERC (December 2023). “2023 Long-Term Reliability Assessment.”

in the region over the next 10 years.[135] Currently, the only additions of new capacity are from renewable resources, which, as noted-above, are intermittent sources of energy.

Woodfibre LNG Completion Will Remove 15 Percent of T-South Capacity

In addition to increased daily demand from the natural gas-fired generators since FEI filed the Application, development of the Woodfibre LNG facility has progressed and will significantly impact the regional market when it comes online.

In November 2021, Woodfibre LNG Ltd. (Woodfibre) signalled its intent[136] to construct an LNG export terminal, with a capacity of 2.1 MTPA (approximately 275 MMcf/d) located near Squamish. Woodfibre has since commenced construction on its facilities and FEI is constructing the infrastructure to bring gas to Woodfibre. Woodfibre has already contracted approximately 15 percent of the existing T-South capacity to supply its facilities, and for the moment is reselling it. However, when the Woodfibre LNG facility commences operations, the capacity will no longer be available to the market. This will represent a very significant tightening of the market.

The expected loss of Woodfibre capacity has led to proposals for pipeline expansions to help solve existing market dynamics. In particular, Enbridge Inc. (Enbridge) conducted an "open season" in Q2 2022 to develop an expansion of T-South, specifically to replace the capacity that will no longer be available to the market when Woodfibre enters service. In November 2022, after this open season was over-subscribed, Enbridge announced that it is moving ahead with plans to expand T-South with up to 300 MMcf/d of additional capacity (i.e., T-South Sunrise Expansion).[137] Since the open season, Enbridge has provided two updates regarding Sunrise's capital cost. The first update occurred during the open season process, with the capital cost estimated at $3.6 billion. Subsequently, the capital cost estimate was revised to $4 billion. These cost increases reflect a refinement of the scope of the project and a more detailed build-up of project requirements.

The T-South Sunrise Expansion does not add capacity beyond what will be lost to Woodfibre LNG, and it could thus not serve as a replacement for peaking supply from Tilbury. Moreover, the regional gas supply markets (i.e., Huntingdon/Sumas) are expected to remain high and volatile during winter seasons. As noted by Mr. Mason:[138]

> …even assuming the proposed WEI Sunrise Expansion Program is successfully implemented and constructed, this project would only replace Woodfibre LNG supplies, leaving the conditions at the Huntingdon/Sumas market in a similar

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[135] Western Energy Electricity Coordinating Council (November 2023). "Western Assessment of Resource Adequacy."

[136] Woodfibre announced the award of an Engineering, Procurement, Fabrication, and Construction contract for the construction of the facility to McDermott International. Woodfibre LNG had announced that pre-installation work beginning in 2022 and provided a Notice to Proceed in April 2022 to McDermott International, which has led to major construction starting in September 2023. This Notice to Proceed is effectively an FID in signaling that Woodfibre will move forward with the project.

[137] https://www.enbridge.com/projects-and-infrastructure/projects/sunrise-expansion-program.

[138] Appendix F, Raymond Mason Report, p. 49.

supply/demand and pricing position as today (i.e., 300-400 MMcf/d of market absorption potential).

FEI remains concerned that, in the absence of a further regional infrastructure expansion beyond the T-South Sunrise Expansion, infrastructure constraints will drive high Sumas prices with significant price volatility.

Over the last two years, FEI conducted a comprehensive evaluation of potential alternative pipeline routes. The findings suggest that collaborating with other regional market participants on an integrated solution could be beneficial for the region and FEI's customers. However, no further upgrades are imminent, and any upgrade would come with increased annual costs for FEI customers. The current tolls FEI must pay on regional infrastructure for existing and incremental capacity will increase regardless of who triggers an upgrade, due to the rolled-in tolling of federally regulated transmission pipelines in Canada. The tolls are cost of service based, such that once the upgrades are completed, the associated cost will be recovered from all shippers. Since FEI holds the most firm-service capacity on T-South, the cost increases to FEI's supply portfolio will be significant when the system undergoes major expansions.

FEI's Existing Regional Supply Assets Are Exposed to Non-Renewal Risk

In addition to the above considerations, FEI's Annual Contracting Plan includes resources that do not have renewal rights within the existing contracts with counterparties and are at risk of not being renewed because of the market conditions throughout the region. The loss of access to Tilbury would exacerbate an already significant gas supply issue for FEI.

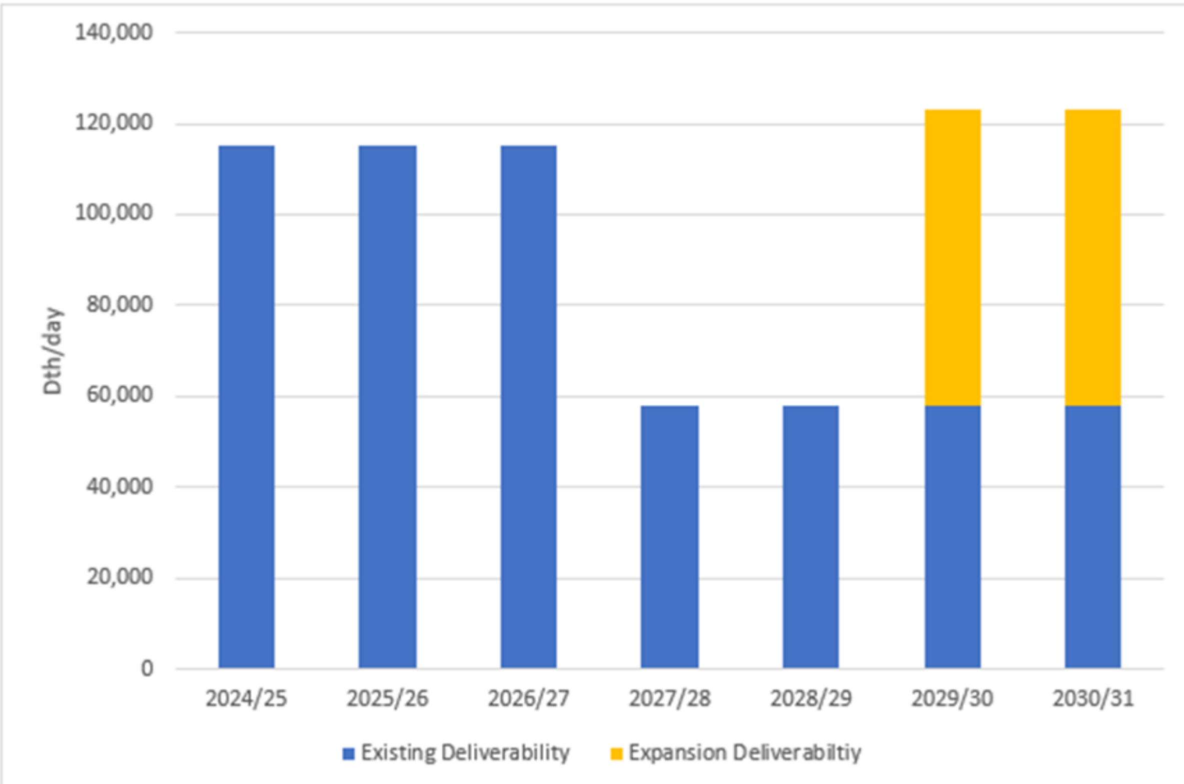
For instance, FEI currently holds approximately 3 Bcf of storage and approximately 110 MMcf/d of deliverability from the Mist facility. However, Northwest Natural, the owner of Mist and a large utility in the Pacific Northwest, has already indicated in public documents that it is intending to place greater reliance on Mist capacity for its own purposes as part of its own response to regional market forces described above (the Mist facility is on-system storage for Northwest Natural). Once the Woodfibre facility is in-service, the regional gas flow and prices for all customers that rely on the Huntingdon/Sumas market hub may be impacted, as the hub is expected to become more volatile in the absence of new infrastructure. Northwest Natural has indicated that their strategy to reduce this Huntingdon/Sumas supply exposure for its utility customers is to recall Mist storage capacity for its own use. Northwest Natural's 2022 Integrated Resource Plan (IRP) discussed customer exposure to the Huntingdon/Sumas market, and how this exposure will be "further exacerbated in 2027 when the Woodfibre LNG facility is expected to come online."[139]

FEI has had ongoing discussions with Northwest Natural to understand the materiality of the expected capacity being recalled in the near future. The exact amount to be recalled is subject to change based on updates to NW Natural's IRP and/or changes to the expected in-service date of the Woodfibre facility. However, based on the most recent discussions, FEI expects that as much as 50 percent of FEI's currently contracted capacity could be recalled by winter 2027/2028. The

[139] 2022 NW Natural Integrated Resource Plan (September 2022), "Exposure to Sumas", p. 209 online at: https://edocs.puc.state.or.us/efdocs/HAA/lc79haa174551.pdf.

results of this for FEI's holdings are shown in Figure 3-25 below. FEI filed an application with the BCUC in respect of underwriting an expansion of the Mist facility to restore those amounts, which was recently approved. The effect of that expansion is shown in the yellow bars in Figure 3-25).

Figure 3-25: FEI's Mist Recall (Storage Deliverability)[140]



FEI continues to be exposed to non-renewal rights on some of its other existing regional supply resources. The recall of FEI's capacity in the Mist facility due to the requirements of its owner is a demonstration of how difficult it would be to secure alternative storage in the event that on-system LNG at Tilbury were to cease to be available.

3.3.4.3.2 FEI COULD NOT REPLACE TILBURY PEAKING SUPPLY WITH SHORT-TERM AD HOC COMMERCIAL AGREEMENTS

As discussed below, adopting a strategy of replacing this dependable peaking supply on an *ad hoc* basis without long-term contracts would be very detrimental to customers. First, under current market conditions, it would not be realistic to expect that FEI could replace that much peaking supply at the Sumas market; significant curtailments of firm load in normal operations are a likely outcome. To the extent that some *ad hoc* contracts were available, FEI would be exposed to non-delivery risk and very significant prices.

[140] 1 Dth = 1 Mcf = 0.001 MMcf.

Mr. Mason, an expert in the regional gas market, offered the following assessment which aligns with FEI's experience discussed in this section:[141]

> In my opinion, FEI would not be able to contract for peaking capacity resources that I would consider dependable, beyond those that are currently committed, as an alternative to on-system LNG storage. The deployment duration and dispatch capability of a resource remain the main criteria for security of supply from a peaking capacity resource. Due to the nature of the regional demands of FEI's customers, third-party off-system storage and companies offering peaking gas supply arrangements, are constrained by the ability to transport the underlying supply of natural gas, as well as the potential for unplanned outages. Furthermore, based on the results of my market research evaluating third-party arrangements, the costs for peaking resources are extremely expensive, do not support a consistent long term supply resource, and would require a portfolio of participants to be able to meet FEI winter demand. To put this in perspective, FEI would be competing/accessing the Huntingdon/Sumas gas supply market, on the coldest days of the winter, for significant volumes historically destined to the PNW (rapidly escalating pricing throughout daily trading hours). These factors, when taken together, are not conducive to contract for dependable peaking supply resources.
>
> In the absence of readily available dependable peaking resources (including sufficient existing on-system storage), FEI would need to make significant investments (including capital investments and/or contractual capacity commitments) to meet its peaking capacity needs. The types of investments could include expanding mainline transportation, and the associated interconnected off-system storage facilities, and/or developing on-system peak shaving LNG.

The Amount of Capacity that Tilbury Provides is Too Great to Replace Through Ad Hoc Commercial Arrangements

It would not be realistic to assume FEI could replace the existing Tilbury peaking supply with commercial deals on a short-term, *ad hoc* basis to meet peak day demand.

The existing 150 MMcf/d capacity at Tilbury represents approximately 8 percent[142] of the current firm service WEI T-South capacity, which is a large amount from a market perspective.

The winter flow on T-South is already at its maximum capacity, and replacing the peaking supply provided by the Base Plant means parties who hold existing T-South capacity will have to sell their capacity to FEI or sell the delivered Station 2 supply at Sumas in the form of commercial arrangements such as call options. Brokering out physical assets to the secondary market would only be transacted if it involves limited risk. FEI holds more than one third of the T-South capacity, and other utilities in the region are facing the same challenges during cold winter periods.

[141] Appendix F, Raymond Mason Report, p. 4.
[142] MMcf/d / 1,800 MMcf/d (i.e., 1,800 MMcf/d is Westcoast Energy firm service to Huntington or Sumas).

On a short-term basis, it may be possible to transact a peaking call option to receive some volume of gas delivered at Huntingdon; however, this is not dependable over the long term and would still leave FEI well-short of being able to meet its full peak day requirements. Moreover, peaking call options of this nature would require FEI to pay a call option premium upfront (i.e., demand charge) to have the rights to purchase the gas at prevailing Sumas prices. FEI would have to pay Sumas daily prices which have been volatile and expensive during peak periods. Further, when significant physical disruptions occur on regional infrastructure, commercial counterparties may not be able to deliver on commercial arrangements.

Counterparties May Not Provide Gas When Called Upon

FEI has relatively few commercial contracts included in the current portfolio. FEI's gas supply strategy has long been to rely on long-term firm services through contracting pipeline and storage capacities to meet customer demand. In addition to exposing FEI to non-renewal risk and potential cost escalation, commercial contracts hold the potential for non-performance.

Commercial peaking deals are associated with volatile commodity prices and physical delivery on peak day. Unlike long-term contracts with storage and pipeline owners directly, the counterparties on short-commercial transactions may or may not hold physical capacity on regional infrastructure. If the counterparty failed to provide the gas when called, it would be challenging for FEI to replace the required volume on a cold/peak day when other market competitors could be seeking gas at the same time.

To mitigate this non-performance risk, FEI contracts for the underlying firm service with the pipeline and/or storage resource. Given the current resource constraints in the region, transacting commercial deals without holding the underlying firm resources to provide large amount of peaking supply is not prudent or practical.

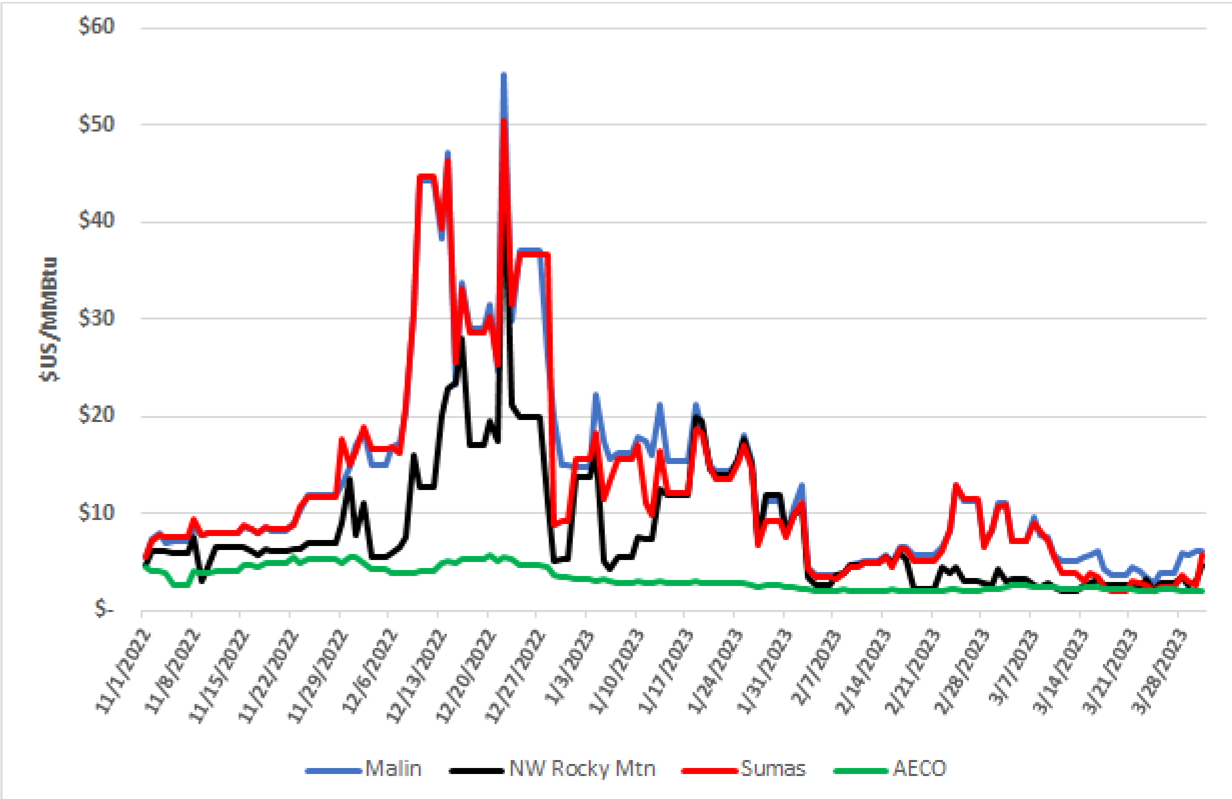
Further, FEI notes that over time there is considerable turnover in the counterparties that participate in the Sumas marketplace, which highlight some of the challenges associated with the Sumas market.

Any Gas Successfully Procured on the Spot Market Will Be Very Costly

To the extent that FEI was successful in partially replacing the lost on-system peaking gas supply from Tilbury with *ad hoc* contractual arrangements on the day, FEI customers would be very exposed to price risk.

The lack of existing regional infrastructure already results in extreme price volatility and price spikes during peak demand, including increased power demand. These periods of pricing volatility usually occur when increased demand in the Pacific Northwest region and the western US exceeds the delivery capacity of pipelines into the region, which causes prices to increase significantly above other market prices. In recent years this has become more pronounced. It was evident during the winter months of 2022/23, for instance, as is illustrated in the following figure.

Figure 3-26: Regional Settled Daily Prices for Winter 2022/23



As Figure 3-26 above shows, during winter 2022/23 the prices at Sumas, Malin and Rockies, which are market hubs for the Pacific Northwest region and the western US, became disconnected from AECO/NIT, the main market hub for western Canada. The price spikes at the market hubs were due to cold weather in the Pacific Northwest region at the same time as frigid temperatures for much of the US midcontinent, which increased natural gas demand, including increased natural gas demand for power generation. These periods of pricing volatility usually occur when increased demand in the region exceeds the delivery capacity of pipelines into the region.

Table 3-4 below illustrates the magnitude of potential costs customers could face by relying on the Sumas market on a spot (non-firm) basis. The table provides the total cost that FEI would have incurred assuming that it had been necessary for FEI to procure its peaking supply from the Sumas market during the 2022/23 winter. This illustrative calculation <u>assumes</u> that the supply would have actually been available in the market on the cold days, which would be in considerable doubt given the large volumes required. It is also understated because it does not account for the upward price impacts that could be expected from FEI trying to buy such large volumes in an already tight market, as discussed below.

Table 3-4: Illustrative Commodity Costs to Replace 150 MMcf/d and 0.6 Bcf Peaking Supply at Winter 2022/23 Sumas Prices[143]

		Sumas Peaking Supply Commodity Costs (150 MMcf/d x 4 days = 0.6 Bcf)				Annual Costs	Annual Costs
		Day 1	Day 2	Day 3	Day 4	4 Days	4 Days
		150000 Mcf	150000 Mcf	150000 Mcf	150000 Mcf	(US$/year)	(CAD$/year)
Sumas Daily Price* (US$/Mcf)	$10	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$6,000,000	$8,108,108
	$20	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$12,000,000	$16,216,216
	$30	$4,500,000	$4,500,000	$4,500,000	$4,500,000	$18,000,000	$24,324,324
	$40	$6,000,000	$6,000,000	$6,000,000	$6,000,000	$24,000,000	$32,432,432
	$50	$7,500,000	$7,500,000	$7,500,000	$7,500,000	$30,000,000	$40,540,541

* 1 Mcf = 1 MMBtu

These historical market prices occurred in an environment when FEI has had limited need to participate in buying Sumas gas during winter periods due to the buying strategies within the ACP. That would no longer be possible if FEI were to cease to have access to on-system LNG at Tilbury. FEI is one of the major market participants in the local gas markets, such that any significant changes FEI makes in its supply portfolio can be expected to have an impact on the local price setting during high demand periods. Telegraphing to the market that FEI was facing having to replace the existing 150 MMcf/d of LNG supply from Tilbury with commercial arrangements – an amount representing approximately 8 percent of the daily capacity of T-South – could be expected to put upward pressure on the monthly and daily prices that FEI's customers would have to pay. That is, the daily Sumas price shown above would have been higher if FEI was participating in the Sumas trading, as the market would be further constrained.

3.3.4.4 FEI Customers Would Face Curtailments Pending a Third Party Upgrading Regional Infrastructure Sufficiently

A strategy of relying on uncertain regional infrastructure expansions to replace FEI's existing critical on-system peaking supply would contradict the strategy that has been inherent in FEI's Annual Contracting Plans for many years. It would be very detrimental to customers, as it would involve the likelihood that FEI would have to curtail firm load in peak winter periods.

FEI would not control the timing or size of any upgrades. FEI does not own T-South or the regional storage facilities and is no longer pursuing the RGSD Project as an FEI project.

Even once triggered, it would take years to develop a pipeline or regional storage expansion. In the meantime (i.e., between the time when FEI loses access to Tilbury and completion of the regional infrastructure upgrades), FEI would be reliant on short-term contractual arrangements with the attendant availability, pricing and counterparty risks outlined above.[144]

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[143] The table illustrates potential commodity costs of Sumas peaking supply, which does not include the call option premium if FEI were to transact for firm supply to be delivered at the Sumas/Huntingdon area.

[144] To be conservative, FEI did not include the costs for these short-term contractual gas supply contracts in its financial analyses for any of the alternatives analyzed.

Mr. Mason highlighted the timing risk in his Report:[145]

> In the absence of readily available dependable peaking resources (including sufficient existing on-system storage), FEI would need to make significant investments (including capital investments and/or contractual capacity commitments) to meet its peaking capacity needs. The types of investments could include expanding mainline transportation, and the associated interconnected off-system storage facilities, and/or developing on-system peak shaving LNG. Building these types of resources takes time, especially capital projects that require consultation with multiple parties throughout the planning and construction phases. For example, increasing WEI mainline capacity and associated interconnected off-system storage facility (i.e., Aitken Creek) would likely require longer development periods than increasing off-system storage displacement in the Pacific Northwest and/or increasing on-system peak shaving LNG.
>
> In my opinion, the development of a proprietary on-system asset, such as the proposed TLSE Project, has advantages over the alternative infrastructure investments when it comes to designing a gas supply portfolio. Constructing a mainline transportation resource, for the purposes of meeting winter demand, would also result in inefficient utilization due to underutilized capacity in non-winter months. Any investments considered by FEI should consider the assets' long-term utilization parameters and the timing in which the resource could be deployed.

As discussed in Section 4 of this Supplemental Evidence, FEI has screened out Supplemental Alternatives that do not maintain FEI's existing peaking gas capabilities in light of the risks associated with procuring replacement peaking supply in the spot market or as part of undefined regional infrastructure upgrades. The options ruled out on this basis include those Supplemental Alternatives that continue to rely on the aging Base Plant (Supplemental Alternatives 1-3), as well as those that replace the Base Plant but allocate the entirety of the tank to a resiliency reserve (Supplemental Alternatives 5-7).[146]

3.3.4.5 Relying on Upgraded Regional Infrastructure for Peaking Supply Would Involve Significant Gas Supply Costs for FEI Customers

If and when those regional infrastructure upgrades were to occur and FEI was able to secure replacement capacity on that infrastructure, customers would face a significant annual cost recovered through cost of gas.

Any regional pipeline or storage expansions capable of replacing or supplementing FEI's existing on-system peaking supply would involve the owners of that infrastructure incurring significant capital costs. These capital costs get reflected in higher tolls or demand charges, which are

[145] Appendix F, Raymond Mason Report, pp. 4-5.

[146] Although FEI screened out these alternatives, FEI nonetheless completed a financial evaluation that accounts for the expected gas supply costs associated with holding capacity on expanded regional infrastructure at some point in the future.

passed along to FEI customers through cost of gas. The cost of JPS or Mist expansions are borne by the party that triggers them, and the higher tolls are passed on to FEI customers through cost of gas. In the case of pipeline expansions, due to rolled-in tolling design FEI would pay higher tolls than today for <u>all</u> of its capacity (existing holdings plus new incremental holdings). That means FEI's existing capacity holdings on the regional infrastructure would also become more expensive for customers.

As part of the alternatives analysis in Section 4, FEI has estimated the annual gas supply costs that FEI customers would incur for peaking supply in a scenario where regional infrastructure was upgraded at a future date. The feasible Supplemental Alternatives avoid these costs to varying degrees, representing a direct supply benefit for customers. Any such supply benefit is accounted for as a reduction in the levelized customer bill impacts in the financial analysis for the feasible Supplemental Alternatives.

3.4 CONCLUSION

The need to mitigate the significant resiliency risk facing FEI's customers and ensure that FEI continues to have access to sufficient dependable peaking supply is clear. FEI must now invest in solutions to address these needs as continuing to rely on the *status quo* will only further expose FEI's customers to these risks and is therefore unacceptable.

The customer outage risk assessment undertaken by Exponent as part of the 2024 Resiliency Plan has re-confirmed that a winter T-South no-flow event presents a very significant risk to FEI customers and BC generally. There is a high probability that hundreds of thousands of customers will, at some point, experience a lengthy loss of gas supply during winter that will expose vulnerable populations to serious health and mortality risks and have widespread social and economic consequences for British Columbians. This risk is too significant to leave unmitigated.

Further, based on the additional time that has elapsed since the Application proceeding and the additional work performed by FEI, it is clear that the 53-year-old Base Plant needs to be replaced irrespective of resiliency. The Tilbury Base Plant has reached end-of-life and is unable to reliably perform its critical gas supply function. A strategy of prolonged reliance on the the Base Plant for critical peaking supply, given its age-related issues and the absence of any feasible contingency plan for peaking supply, leaves firm customers at serious risk of losing service in normal operations. Allowing this to occur would contradict the gas supply planning approach that has been in place for decades.

Section 4 explains why this need is best addressed with a larger facility that will both provide a designated resiliency reserve and meet FEI's full peaking supply requirements.

4. EXPANDED ALTERNATIVES ANALYSIS

4.1 INTRODUCTION

This section addresses FEI's expanded alternatives analysis. FEI describes the 13 options considered as part of the expanded analysis (Supplemental Alternatives), the process used to screen and assess them, and the overall evaluation results. Appendix C to this Supplemental Evidence provides the detailed supporting information and analysis on each of the options.

In the Application, FEI considered a variety of ways to improve its ability to withstand a winter T-South no-flow event. The first stage of that original alternatives analysis considered load management approaches, on- and off-system storage, and four different regional pipeline solutions. In the second stage of that original alternatives analysis, FEI assessed different tank sizing and regasification capacities that can support Lower Mainland load for at least three days during winter.[147]

In the Adjournment Decision, the BCUC identified a need for FEI to further consider:

- "…alternatives that offer different resiliency benefits from those that the TLSE Project purports to provide – whether such alternatives offer greater, lesser, or qualitatively different levels of resiliency benefits relative to TLSE";[148]
- the possibility of using a portion of the Tilbury 1A tank for resiliency;[149]
- whether FEI could extend the life of the Base Plant;[150]
- three other non-Tilbury alternatives, and revisit the resiliency provided by a Southern Crossing Pipeline expansion;[151] and
- the potential for the transition towards a lower carbon future to affect the appropriate sizing of the TLSE Project.[152]

The expanded alternatives analysis includes all of the alternatives and considerations identified by the BCUC in the Adjournment Decision.[153]

FEI's expanded alternatives analysis confirms that, among the viable options, Supplemental Alternative 9 (replacing the Base Plant with 800 MMcf/d new regasification and 3 Bcf tank with 2

147 Exhibit B-1-4, Application, Section 4.
148 Adjournment Decision, p. 25.
149 Adjournment Decision, p. 29.
150 Adjournment Decision, p. 14.
151 Adjournment Decision, pp. 25-31.
152 Adjournment Decision, p. 52. "Further, if the throughput of natural gas is reduced due to a decrease in demand, the size of a tank and the amount of regasification required would likely be reduced." And p. 22: "The larger tank provides flexibility to accommodate future load growth that may occur. However, given the current emphasis on electrification and decarbonization in BC, it is unclear whether FEI will experience significant, or even any, future natural gas load growth. The larger tank means greater risk of a stranded, or partially stranded, asset in the event that FEI's increased load does not emerge or decreases beyond the current load."
153 Adjournment Decision, Section 4.

Bcf set aside as a "resiliency reserve") is the Preferred Alternative. Supplemental Alternative 9 delivers on the Project objectives in a way that provides superior customer value. In particular, Supplemental Alternative 9: (1) significantly mitigates FEI's largest customer outage risk; (2) meets FEI's full peaking supply requirements in an optimal manner from a gas supply portfolio design perspective; (3) fully addresses age-related Base Plant challenges; (4) compares favourably to smaller replacement facilities in terms of levelized total rate impact; and (5) is expected to be fully utilized throughout its expected service life.

The section is organized as follows:

- **Section 4.2 – Summary of Supplemental Alternatives and Methodology to Select the Preferred Alternative:** FEI describes the 13 Supplemental Alternatives, the structured three-step process, and the scoring approach that FEI used to evaluate the Supplemental Alternatives and select the Preferred Alternative.
- **Section 4.3 – Results of Step 1: FEI Eliminated Technically and Commercially Non-Viable Alternatives:** FEI screened out four Supplemental Alternatives as non-viable, including continuing to rely on the end-of-life Tilbury Base Plant with no capital upgrades, as well as non-Tilbury options.
- **Section 4.4 – Results of Step 2: FEI Eliminated Alternatives that Do Not Retain FEI's Existing On-System Firm Peaking Gas Supply:** Five options that would fail to retain FEI's existing peaking supply are unacceptable because they would result in firm customers losing service in peak winter periods under normal operating conditions. The four Supplemental Alternatives that passed this secondary screen – Supplemental Alternatives 4, 4A, 8, and 9 – would all involve a full replacement of the existing Base Plant with a new facility that will, at a minimum, restore the Base Plant's original design capabilities for gas supply.
- **Section 4.5 – Step 3:** FEI describes the scoring criteria applied to the Supplemental Alternatives
  - **Section 4.5.1 Step 3 "Resiliency Benefit" Scoring Criterion:** Only two Supplemental Alternatives – those with 800 MMcf/d of regasification and a resiliency reserve of 1 Bcf or more (Supplemental Alternatives 8 and 9) – would materially improve FEI's ability to withstand a winter T-South no-flow event at average winter temperatures. Supplemental Alternative 9 will provide considerably more outage risk mitigation than any other option. Smaller replacement facilities, for all practical purposes, would only serve a gas supply function.
  - **Section 4.5.2 – Step 3 "Availability of Dependable Gas Supply During Peak Demand" Scoring Criterion:** Only Supplemental Alternatives 4A and 9 would provide the optimum amount of peaking gas supply (i.e., sufficient peaking supply to meet FEI's entire requirements, such that it both replaces the supply provided by Tilbury and avoids having to augment it with year-round pipeline capacity). The

former is sized solely for optimum gas supply, while Supplemental Alternative 9 is a larger facility that combines that optimum gas supply with resiliency.

- **Section 4.5.3 – Step 3 "Resolves Age-Related Base Plant Challenges" Scoring Criterion:** Supplemental Alternatives 4, 4A, 8, and 9 would all involve the installation of a new tank and new regasification equipment built to current standards, such that FEI assigned a "High Positive Impact" score to each of these options.

- **Section 4.5.4 – Step 3 "Levelized Total Rate Impact" Scoring Criterion:** FEI considered the combined impact of capital and operating costs and the cost of procuring the necessary peaking supply (200 MMcf/d and 1.0 Bcf), since there is no zero-cost option available for customers when it comes to peaking gas supply. The relative levelized total rate impact for the Supplemental Alternatives is significantly influenced by: (1) economies of scale in the construction of the facility; and (2) the extent to which an alternative allocates a portion of the tank to peaking gas supply, thereby avoiding the cost of using longer duration off-system storage or pipeline capacity for peaking supply if / when regional infrastructure is upgraded sufficiently. Supplemental Alternative 4A, which is sized based on the optimal amount of peaking gas supply only[154], would have the lowest levelized rate impact among Supplemental Alternatives 4, 4A, 8, and 9. The Preferred Alternative's levelized rate impact will fall between Supplemental Alternatives 4, 4A and 8, which translates to much more risk reduction per dollar of rate impact than any of those other options.

- **Section 4.5.5 – Step 3 "Future Use" Scoring Criterion:** In response to BCUC commentary in the Adjournment Decision, FEI assessed the risk that the Supplemental Alternatives would be underutilized in the future under hypothetical load loss sensitivities. The hypothetical sensitivities illustrate how all of the viable options (Supplemental Alternatives 4, 4A, 8, and 9) would be fully utilized for resiliency and/or gas supply in 2050. On-system LNG is a unique asset when it comes to the flexibility afforded in response to changing load.

- **Section 4.6 – Summary of Alternatives Analysis Results**

- **Section 4.7 – Additional Information on the Preferred Alternative's Resiliency Benefits:** Supplemental Alternative 9 (the Preferred Alternative) will provide significant resiliency benefits over and above what are accounted for in the Step 3 "Resiliency Benefit" criterion. These benefits include: (1) providing the potential option of a staged shutdown that maintains service to some portion of FEI's customers; (2) avoiding uncontrolled depressurization and the attendant safety risks; (3) providing valuable time for customers, governments and social / health services to prepare for an outage; (4)

[154] It provides sufficient peaking supply to meet FEI's entire requirements, such that it both replaces the supply provided by Tilbury and avoids having to augment it with year-round pipeline capacity.

mitigating the calculated customer outage risk for 13 other customer outage vulnerabilities across FEI's system; and (5) backstopping off-system storage supply in the event of a disruption at those facilities.

4.2 SUMMARY OF SUPPLEMENTAL ALTERNATIVES AND METHODOLOGY TO SELECT THE PREFERRED ALTERNATIVE

This section summarizes the Supplemental Alternatives and FEI's three-step assessment process. FEI selected the Preferred Alternative based on considerations of technical and commercial viability, the ability to retain existing firm peaking supply, the ability to mitigate customer outage risk, age related Base Plant challenges, levelized total rate impact, and future use.

4.2.1 FEI Considered 13 Supplemental Alternatives, Contingent Scenarios, Plus a Southern Crossing Extension

Table 4-1 below provides summary descriptions of each of the Supplemental Alternatives, which include the options identified in the Adjournment Decision. More detailed descriptions of each Supplemental Alternative are included in Table C-1 in Appendix C, Section 2.1.

All of the Supplemental Alternatives listed in the table below reflect a **planning view**, which means that they treat stored LNG as being available on a dependable basis for a single planned purpose, since it will not be dependable for any purpose if it is allocated to (or planned for) multiple purposes. This is the typical basis of utility planning, and FEI considers it should be used for the reasons described in Section 4 of Appendix C to this Supplemental Evidence.

However, in response to the BCUC's commentary in the Adjournment Decision, FEI also investigated **"contingent" scenarios** for viable Supplemental Alternatives that would involve either only replacing the regasification equipment or a new facility with a tank less than 2 Bcf (i.e., Supplemental Alternatives 1, 2, 3, 4, 4A, and 5). In general, the contingent scenarios for a given alternative consider the case where some volume of LNG that is not set aside as a "resiliency reserve" is available on the day of a no-flow event. In other words, some volume of LNG from Tilbury 1A or the Base Plant (as applicable) that was intended to be used for RS 46 LNG sales or gas supply remains in the tank on the day of the no-flow event and is then used for resiliency instead of its intended purpose. While FEI does not endorse using this approach for planning purposes (because FEI cannot rely on these LNG volumes being present on Day 1 of a no-flow event), the scenarios address comments in the Adjournment Decision about the potential resiliency value of such volumes. Each contingent scenario is explained in the Appendix C sections addressing Supplemental Alternatives 1, 2, 3, 4, 4A, and 5.

1 **Table 4-1: Summary of Supplemental Alternatives**

Supp Alt #	Name	Description
Alternatives Reliant on Existing Facilities[155]		
Alt 1	No Capital Upgrades with Optimized Liquefaction (No Resiliency Reserve)	Run the Base Plant until it is no longer usable with no resiliency reserve.
Alt 2	New Regasification Only – 400 MMcf/d (No Resiliency Reserve)	Replace the Base Plant regasification with 400 MMcf/d of new capacity, but continue to rely on a non-refurbished Base Plant tank until it is no longer usable. There is no resiliency reserve.
Alt 3	New Regasification Only – 600 MMcf/d (No Resiliency Reserve)	Replace Base Plant regasification with 600 MMcf/d of new capacity but continue to rely on a non-refurbished Base Plant tank until it is no longer usable. There is no resiliency reserve.
New Facility with Gas Supply But No Resiliency Reserve[156]		
Alt 4	Like-for-Like (No Resiliency Reserve)	Replace the Base Plant like-for-like to restore the 1971 design capacity (150 MMcf/d regasification and 0.6 Bcf tank) and continue using Tilbury as a supply peaking resource, without a resiliency reserve.
Alt 4A	New 1 Bcf Tank (No Resiliency Reserve) and 400 MMcf/d Regasification	Replace the Base Plant with the smallest new facility capable of providing FEI's optimum peaking gas supply, including a 1 Bcf tank and 200 MMcf/d regasification (with an additional 200 MMcf/d for redundancy). Continue using it as a supply peaking resource, without a resiliency reserve.
New Facility with Resiliency Reserve But No Gas Supply[157]		
Alt 5	Like-for-Like (Full Resiliency Reserve)	Replace the Base Plant like-for-like to restore the 1971 design capacity (150 MMcf/d regasification and 0.6 Bcf tank) and allocate the entire tank as a resiliency reserve.
Alt 6	New 1 Bcf Tank (Full Resiliency Reserve) and 800 MMcf/d Regasification	Replace the Base Plant with a 1.0 Bcf tank and 800 MMcf/d regasification. Allocate the entire tank as a resiliency reserve.
Alt 7	New 2 Bcf Tank (Full Resiliency Reserve) and 800 MMcf/d Regasification	Replace the Base Plant with a 2.0 Bcf tank and 800 MMcf/d regasification. Allocate the entire tank as a resiliency reserve.
New Facility with Both Resiliency Reserve and Replacement of Gas Supply		
Alt 8	New 2 Bcf Tank (1.4 Bcf Resiliency Reserve) and 800 MMcf/d Regasification	Construct the smallest facility that allows FEI to both avoid curtailments of firm peak load in normal operations and provide a certain level of resiliency reserve. This includes replacing the Base Plant with a 2 Bcf tank and 800 MMcf/d regasification, of which 1.4 Bcf is allocated as a resiliency reserve, and 0.6 Bcf is allocated to replace the existing gas supply functions at Tilbury.

155 These alternatives include prolonged reliance on the Base Plant tank with no dependable resiliency reserve, declining reliability, and a high likelihood of relying on the market for some replacement gas supply.

156 These alternatives do not include a dependable resiliency reserve but provide different amounts of peaking gas supply and improved reliability.

157 These alternatives include a full resiliency reserve but still rely on the market for replacement of the gas supply functions.

Supp Alt #	Name	Description
Alt 9	New 3 Bcf Tank (2 Bcf Resiliency Reserve) and 800 MMcf/d Regasification	Construct a facility that both significantly mitigates FEI's largest customer outage risks and meets FEI's required peaking gas supply in an optimal manner (since it no longer requires relying on year-round pipeline capacity to provide short-term peaking supply). Replace the Base Plant with a 3 Bcf tank and 800 MMcf/d regasification and allocate 2 Bcf as a resiliency reserve, and 1 Bcf to gas supply.
Non-Tilbury Alternatives[158]		
Alt 10	Alt 1 plus VITS Reverse Flow	FEI would retain the existing Tilbury facilities with no capital upgrades (i.e., Supplemental Alternative 1). FEI would also construct the necessary facilities to allow significant reverse flows on the Vancouver Island Transmission System (VITS) at all times during the year, such that the combined daily delivery is at least 550 MMcf/d.
Alt 11	LNG from Woodfibre LNG	Use the existing Tilbury facilities with no capital upgrades (i.e., Supplemental Alternative 1). FEI would also contract with Woodfibre LNG for a long-term firm supply of LNG.
Alt 12	Floating LNG	Purchase a vessel to provide floating LNG storage. Acquire a water lot that would allow for permanent mooring. Add more regasification capacity, either as an integrated component of the LNG storage vessel or on the adjacent shoreline. Construct onshore facilities, including a jetty and interconnecting pipe.

In response to the BCUC's commentary in the Adjournment Decision, Appendix C to this Supplemental Evidence also addresses a Southern Crossing Pipeline extension (e.g., the RGSD Project). The RGSD Project was one of the alternatives that FEI originally evaluated in the TLSE Application. FEI has recently determined not to pursue RGSD on its own, although FEI has not foreclosed participating with others in a similar pipeline project. Regardless, FEI explained in the Application why it regarded a Southern Crossing Pipeline extension as complementary to, rather than a substitute for, on-system LNG when it comes to mitigating the risk associated with a winter T-South no-flow event. That conclusion is unchanged following FEI's additional analysis. FEI's transient modelling shows that in the winter months the Lower Mainland system will depressurize before any supply could be obtained from a Southern Crossing Pipeline extension, regardless of size or end-point.

4.2.2 FEI Employed a Structured Process to Identify the Preferred Alternative

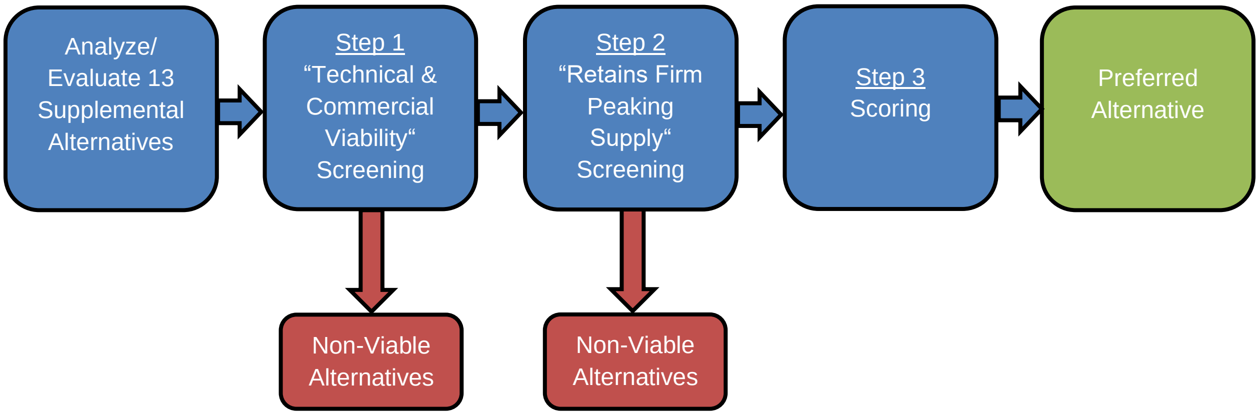
FEI employed a structured process to evaluate the 13 Supplemental Alternatives and identify a preferred alternative. It is depicted in Figure 4-1 and further described below.

To inform the steps in the process, FEI conducted extensive analysis and evaluation of the Supplemental Alternatives with respect to technical and commercial viability, resiliency, gas supply, reliability, levelized total rate impact, and future use. This involved conducting both internal and external studies and analyses to understand the performance of the Supplemental Alternatives (e.g., risk analysis, gas supply market studies, capital cost estimates, and levelized

[158] FEI considers these alternatives to be non-viable approaches to providing winter resiliency and peaking gas supply.

total rate impact analysis). Appendix C to this Supplemental Evidence provides the full results of the scoring analysis for all viable Supplemental Alternatives that passed Step 1.

Figure 4-1: Three-Step Process to Identify the Preferred Alternative



Step 1: Screen out alternatives that are not technically or commercially viable.

Step 2: Screen out alternatives that would not retain FEI's existing on-system firm peaking gas supply capabilities.

Step 3: Score the remaining[159] Supplemental Alternatives to select a preferred alternative, having regard to resiliency, gas supply, age-related Base Plant challenges, levelized total rate impact, and future use.

4.2.2.1 Step 1 Methodology: Screening of Technically and Commercially Non-Viable Alternatives

Step 1 in the structured process was to screen out Supplemental Alternatives that, after evaluation, are determined to be technically or commercially non-viable. FEI considered the balance of technical and commercial challenges associated with an alternative and then considered viability holistically.

4.2.2.2 Step 2 Methodology: Screening of Alternatives That Would Not Retain FEI's Existing On-System Firm Peaking Gas Supply Capabilities

In Step 2, FEI screened out Supplemental Alternatives that would not retain FEI's existing on-system firm peaking gas supply capabilities of 0.6 Bcf[160] of LNG and 150 MMcf/d of regasification capacity.

FEI's gas supply and system planning has always been based on being able to meet firm load at all times, and this remains the appropriate basis for planning. As discussed in Section 3.3.4 of this Supplemental Evidence, since 1971 FEI has been relying on on-system LNG in its BCUC-

[159] For completeness, FEI has still scored any alternatives screened out at Step 2. See Appendix C for this analysis.
[160] Consisting of 0.35 Bcf from the Tilbury Base Plant plus 0.25 Bcf from Tilbury 1A.

approved Annual Contracting Plans (ACP) to serve customers during periods of peak demand. This approach to supply portfolio design has recognized the important attributes of on-system LNG, including: providing supplemental capacity (i.e., MMcf/d versus only energy measured in Bcf); providing deliverability on short notice; being within FEI's full control; and the ability to backstop other resources.

As discussed in Section 3.3.4.2, FEI's current requirements for peaking supply are well in excess of what the Base Plant can provide, and there are no available substitutes in the market to replace the capacity and energy provided by it. In those circumstances, losing access to the 0.6 Bcf / 150 MMcf/d peaking supply in the ACP would mean likely curtailments for firm customers in normal operations during the coldest times of the year.

In practice, there are two potential ways that a Supplemental Alternative might fail to retain FEI's existing on-system firm peaking gas supply capabilities:

1. the Supplemental Alternative removes FEI's existing on-system peaking resource without replacement; or

2. the Supplemental Alternative relies on a resource that is expected to be unavailable in the future due to market conditions (e.g., no capacity available on pipelines or regional storage) or aging FEI infrastructure.

FEI considers that any alternative that fails to retain FEI's existing on-system peaking resources is not viable, because of the high risk of FEI not being able to meet firm load. However, FEI has analyzed and scored these options in Appendix C to this Supplemental Evidence so as to provide the BCUC with complete information.

4.2.2.3 Step 3 Methodology: Scoring of Viable Alternatives

Step 3 involves scoring the viable Supplemental Alternatives (i.e., those that are technically and commercially viable and that, at minimum, retain FEI's existing firm peaking supply capabilities) against a set of weighted criteria to determine the preferred alternative. Step 3 consists of the following three elements, which are explained in the following sections:

1. Scoring System and Approach;

2. Evaluation Criteria; and

3. Evaluation Criteria Weighting.

4.2.2.3.1 SCORING SYSTEM AND APPROACH IN STEP 3

FEI's approach to scoring the Supplemental Alternatives in Step 3 was to assess the impact the alternative would have on the given evaluation criterion relative to retaining the end-of-life Base Plant in its current state with no capital upgrades (Supplemental Alternative 1).

As an alternative may have a positive, negative, or no impact on a given criterion, FEI used the scoring system shown in the table below.

Table 4-2: Supplemental Alternative Scoring System

Score	Corresponding Numerical Score (un-weighted)
High Negative Impact	-5
Medium Negative Impact	-3
Low Negative Impact	-1
No Impact	0
Low Positive Impact	1
Medium Positive Impact	3
High Positive Impact	5

After FEI assigned a score to a Supplemental Alternative for a given criterion, the corresponding un-weighted numerical score was multiplied by the criterion's weighting (discussed below) to determine the weighted numerical score. The weighted numerical scores from each criterion were then summed to determine the total weighted numerical score for each alternative. The Supplemental Alternative with the highest weighted numerical score is the preferred alternative.

4.2.2.3.2 EVALUATION CRITERIA, METRICS AND SCORING GUIDELINES IN STEP 3

The Step 3 evaluation criteria used for scoring is presented below.

Table 4-3: Supplemental Alternative Evaluation Criteria

Category	Evaluation Criterion	Evaluation Criterion Description
Resiliency	Resiliency Benefit	The ability to mitigate the risk associated with a winter T-South no-flow event.
Gas Supply	Availability of Dependable Gas Supply During Peak Demand	The impact on the availability of dependable gas supply during peak demand.
Base Plant Challenges	Resolves Age Related Base Plant Challenges	The impact on the age-related Base Plant challenges (send-out reliability, seismic design, flooding, and tank venting).
Rate Impact	Levelized Total Rate Impact	The levelized total rate impact due to both the capital costs on delivery rates and gas supply impacts/benefits on commodity rates.
Future Use	Useful Under the Modified Diversified Energy (Planning) Scenario (mDEP 2% and 5%) Between the In-Service Date and 2050	Considers if the alternative is useful or underutilized under two adverse future load sensitivities, in which FEI's Diversified Energy (Planning) Scenario is modified to assume higher rates of customer and load loss (2% and 5% annually) between the in-service date and 2050.

Due to the broad similarities in the viable alternatives (i.e., all involve on-system LNG at Tilbury), some criteria that FEI typically considers, such as constructability,[161] have been excluded from this evaluation. Environmental considerations are reflected in “Base Plant Challenges”, since the primary environmental considerations that assist in distinguishing amongst the viable options are related to the increased environmental standards required for newer construction including (but not limited to) fully enclosed secondary containment and improved tank venting configurations.[162]

For each criterion, FEI identified a metric for evaluating the alternatives, as well as scoring guidelines to ensure consistent scoring across the alternatives:

1. **Resiliency Benefit**
    - **Evaluation Metric:** The level of risk mitigation provided by the alternative against a winter T-South no-flow event as determined via a quantitative risk assessment performed by Exponent (i.e., risk without the alternative – risk with the alternative).
    - **Scoring Guidelines:** Relative comparison of the level of risk mitigation each alternative provides.
2. **Availability of Dependable Gas Supply During Peak Demand**
    - **Evaluation Metric:** Qualitative evaluation of the alternative’s impact on the availability of dependable gas supply during peak demand conditions.
    - **Scoring Guidelines:** Relative comparison of the impact the alternative has to the availability of dependable gas supply.
3. **Resolves Age Related Base Plant Challenges**
    - **Evaluation Metric:** Qualitative evaluation of the alternative’s impact on the age-related Base Plant challenges discussed in Section 3 of this Supplemental Evidence (i.e., send-out reliability, seismic design, flooding, and tank venting).
    - **Scoring Guidelines:** Relative comparison of the impact the viable alternative has on the age-related Base Plant challenges.
4. **Levelized Total Rate Impact**
    - **Evaluation Metric:** The levelized total rate impact of the viable alternative (delivery rate impacts associated with the capital costs of the Project net of gas supply benefits or costs).

[161] In the Application, FEI assessed that all of the options involving a new facility at Tilbury up to 3 Bcf were constructable.

[162] See Section 3.3 of this Supplemental Evidence for a discussion of environmental considerations inherent in the Base Plant design.

- **Scoring Guidelines:** Comparison of levelized total rate impact between each supplemental alternative relative to Supplemental Alternative 1 - No Capital Upgrades.

5. **Useful Under the Modified Diversified Energy (Planning) Scenario (mDEP 2% and 5%) Between the In-Service Date and 2050**

- **Evaluation Metric:** Qualitative evaluation to assess if the viable alternative will be useful for resiliency and/or FEI's gas supply portfolio (to serve load or generate mitigation revenue), and its potential to be underutilized between the in-service date and 2050 based on two adverse future load sensitivities referred to as "mDEP 2% and 5%". These sensitivities start with FEI's 2022 LTGRP Diversified Energy (Planning) Scenario (DEP Scenario), with modifications to assume higher rates of customer and load loss (2% and 5% annually) between the in-service date and 2050.

- **Scoring Guidelines:** Relative comparison of each alternative's usefulness/underutilization between the in-service date and 2050 based on FEI's modified DEP Scenario adverse future load sensitivities (mDEP 2% and 5%).

- To inform the alternative evaluation and to establish usefulness versus underutilization, FEI applied the following guidelines:

    1. An alternative remains useful and not underutilized for resiliency if, over the course of the evaluation period (i.e., from the in-service date to 2050), the load support duration provided by the resiliency reserve does not exceed what is reasonably required to avoid an outage.

    2. An alternative remains useful and not underutilized for gas supply if, over the course of the evaluation period (i.e., from the in-service date to 2050), the gas supply allocation is less than the volume that can be utilized for FEI gas supply and/or be monetized via FEI's ordinary course gas supply mitigation activities.

4.2.2.3.3 EVALUATION CRITERIA WEIGHTING IN STEP 3

As shown in Table 4-4 below, FEI assigned a weighting to each evaluation criterion.

Table 4-4: Step 3 Evaluation Criteria Weighting

Category	Evaluation Criterion	Weighting
Resiliency	Resiliency Benefit	30%
Gas Supply	Availability of Dependable Gas Supply During Peak Demand	20%

Category	Evaluation Criterion	Weighting
Base Plant Challenges	Resolves Age Related Base Plant Challenges	20%
Rate Impact	Levelized Total Rate Impact	20%
Future Use	Used and Useful Under the Modified Diversified Energy (Planning) Scenario (mDEP 2% and 5%) Between the In-Service Date and 2050	10%

To determine the weighting of each criterion, FEI Subject Matter Leads (SMLs) conducted a qualitative review considering the relative importance of each criterion. All of the criteria included in the evaluation process are important to FEI, such that the assigned weightings only indicate relative importance. FEI provides the following rationale for the assigned weightings:

- **Resiliency** is assigned the most weight as FEI is currently exposed to a significant customer outage risk that FEI believes should be mitigated. As discussed in Section 3 of this Supplemental Evidence, the consequences are catastrophic and the cumulative probability calculated by Exponent is high. The known consequences of a winter T-South no-flow event are so severe that, according to Exponent (and consistent with prior expert evidence in this proceeding), established risk management principles would support a material investment to reduce the harm even at much lower probabilities than those calculated by Exponent.
- **Gas Supply, Base Plant Challenges, and Levelized Total Rate Impact** are weighted equally in the Step 3 scoring. Consideration of gas supply at Step 2 means that all of the alternatives being scored in Step 3 provide, at minimum, sufficient dependable peaking supply to allow FEI to continue meeting its peak firm load. Once that minimum standard is met, FEI considered it appropriate to give equal weight to differences in gas supply, levelized total rate impact and the extent to which an alternative addresses the Base Plant's inherent challenges (reliability, seismic, flooding and venting).
- **Future Use** is given relatively less weight due to the known current needs and the uncertainty surrounding the long-term implications of the energy transition.

FEI describes below the results of applying the three-step process. The structured process confirmed Supplemental Alternative 9, which is the originally proposed 3 Bcf tank (2 Bcf resiliency reserve, 1 Bcf gas supply) with 800 MMcf/d regasification capacity, as the preferred alternative.

4.3 RESULTS OF STEP 1: FEI ELIMINATED TECHNICALLY AND COMMERCIALLY NON-VIABLE ALTERNATIVES

FEI investigated all 13 Supplemental Alternatives to assess technical and commercial viability, as defined in Section 4.2.1 above. Through this step, FEI determined that Supplemental Alternatives 1, 10, 11, and 12 are not viable.

The following table provides a high-level summary of why each Supplemental Alternative was found to be non-viable. A more detailed discussion of these Supplemental Alternatives and why they were found to be non-viable is provided in Appendix C to this Supplemental Evidence.

Table 4-5: Summary of Non-Viable Alternatives

No.	Description	Summary of Why Non-Viable	Reference
Alt 1	No Capital Upgrades with Optimized Liquefaction (No Resiliency Reserve)	Supplemental Alternative 1 is technically non-viable due to the age-related challenges associated with the Tilbury Base Plant. As discussed in Section 3, the Tilbury Base Plant has reached its end of life and can no longer reliably perform its intended function. As a result, continuing to rely on the Base Plant without capital upgrades is not technically viable.	Section 3.3 and Appendix C, Section 5.1.1
Alt 10	Alt 1 plus VITS Reverse Flow	Even with significant upgrades, a hydraulic constraint exists which limits the amount of reverse flow that is possible through the VITS. Also significantly more costly compared to Tilbury-based alternatives, given this alternative would involve looping significant portions of FEI's VITS and completing multiple compressor station upgrades.	Appendix C, Section 5.5.1
Alt 11	LNG from Woodfibre	Inconsistent with Woodfibre's (WFLNG) business model and LNG markets. WFLNG's business model requires that any LNG storage WFLNG has on the site be inventoried to ensure the next customer vessel can be filled on schedule. Further, even assuming FEI were able to contract for LNG supply from WFLNG, FEI would then need significant new infrastructure to make use of the LNG. Neither of the two infrastructure options are viable.	Appendix C, Section 5.5.2
Alt 12	Floating LNG	There are no appropriate sites. All options also have issues with technical feasibility either due to the tie-in point pressure rating and pipeline capacity, or execution difficulties caused by the location of the tie-in point in the Fraser River, difficulty and uncertainty of additional regulatory approvals associated with a water-based option, and high probability of an Environmental Assessment given the size of the storage capacity or based on a discretionary mandate by the Province.	Appendix C, Section 5.5.3

4.4 RESULTS OF STEP 2: FEI ELIMINATED ALTERNATIVES THAT DO NOT RETAIN FEI'S EXISTING ON-SYSTEM FIRM PEAKING GAS SUPPLY

In Step 2, FEI evaluated the technically and commercially viable Supplemental Alternatives and eliminated those that would not retain FEI's existing on-system firm gas supply capabilities of 0.6 Bcf of on-system storage and 150 MMcf/d of regasification capacity, as loss of the existing firm gas supply capabilities creates a high risk of material firm load curtailments in normal operations during peak winter periods. Table 4-6 below summarizes the results of the Step 2 screening. Further detail is provided in the sections below.

Table 4-6: Summary of Step 2 Screen

Supp Alt #	Name	On-System Gas Supply Modelling Parameters[163] To 2030	On-System Gas Supply Modelling Parameters[163] After 2030	Retains FEI's Existing On-System Firm Peaking Gas Supply Capabilities?
Alt 2	New Regasification Only - 400 (No Resiliency Reserve)	0.6 Bcf 400 MMcf/d	< 0.6 Bcf 400 MMcf/d	✗
Alt 3	New Regasification Only - 600 (No Resiliency Reserve)	0.6 Bcf 600 MMcf/d	< 0.6 Bcf 600 MMcf/d	✗
Alt 4	Like-for-Like (No Resiliency Reserve)	0.6 Bcf 150 MMcf/d	0.6 Bcf 150 MMcf/d	✓
Alt 4A	New 1 Bcf Tank (No Resiliency Reserve) and 400 Regasification	1 Bcf 400 MMcf/d	1 Bcf 400 MMcf/d	✓
Alt 5	Like-for-Like (Full Resiliency Reserve)	0 Bcf 150 MMcf/d	0 Bcf 150 MMcf/d	✗
Alt 6	New 1 Bcf Tank (Full Resiliency Reserve) and 800 Regasification	0 Bcf 800 MMcf/d	0 Bcf 800 MMcf/d	✗
Alt 7	New 2 Bcf Tank (Full Resiliency Reserve) and 800 Regasification	0 Bcf 800 MMcf/d	0 Bcf 800 MMcf/d	✗
Alt 8	New 2 Bcf Tank (1.4 Bcf Resiliency Reserve) and 800 Regasification	0.6 Bcf 800 MMcf/d	0.6 Bcf 800 MMcf/d	✓
Alt 9	New 3 Bcf Tank (2 Bcf Resiliency Reserve) and 800 Regasification	1.0 Bcf 800 MMcf/d	1.0 Bcf 800 MMcf/d	✓

4.4.1 Aging Base Plant Tank and Expected Increase in RS 46 Sales Make Supplemental Alternatives 2 & 3 Non-Viable

Supplemental Alternatives 2 and 3 would replace the regasification equipment at Tilbury that has reached end-of-life, and would thus solve one potential cause of losing the Tilbury Base Plant as a peaking resource. However, Supplemental Alternatives 2 and 3 would still leave FEI without full

[163] The modelling parameters for each supplemental alternative are discussed in greater detail in Appendix C to this Supplemental Evidence.

access to the dependable peaking supply from the storage that is currently in FEI's ACP. FEI would be at risk of no longer being able to meet firm peak load in normal operations.

There are three interrelated reasons why this is the case:

1. As discussed in Section 3.3.2.1 of this Supplemental Evidence, seismic challenges are inherent in the original Base Plant design. FEI now operates the tank well-below its design capabilities for seismic reasons (at a reduced volume of 0.35 Bcf), and experts have advised against tank retrofits to restore it to 0.6 Bcf. If the operating level of tank were further reduced due to the seismic design challenges, then other things being equal FEI would be left with less than 0.6 Bcf of on-system firm peaking supply.

2. 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. Therefore, the 0.25 Bcf of LNG from Tilbury 1A that FEI currently relies on for peaking supply will no longer be available.

3. As discussed in Section 3.3.4.3 of this Supplemental Evidence, there is no back-up option for dependable peaking supply if the 150 MMcf/d and 0.6 Bcf provided by Tilbury is no longer available. Relying on the market for all of FEI's peaking supply would be a significant deviation from FEI's longstanding practice of relying on on-system resources in the BCUC-approved ACP, and would not be viable in the current market context. Regional infrastructure is fully-contracted, such that any access to long-term replacement peaking supply would depend on regional infrastructure upgrades. FEI would not control the timing or size of any upgrades, it would take years to construct an expansion, and the impact on gas supply (storage and transportation) costs for customers would be significant. Upstream resources are not as dependable as on-system LNG.

   In the meantime, FEI would be faced with the highly undesirable position of relying on the Sumas market for short-term, non-dependable supply contracts with significant price exposure. There is no certainty that FEI would be able to buy at Sumas. This is supported by Mr. Mason, an expert in the regional gas market, who concluded: "In my opinion, FEI would not be able to contract for peaking capacity resources that I would consider dependable, beyond those that are currently committed, as an alternative to on-system LNG storage."[164] Considering that T-South capacity is fully contracted during winter, FEI would be attempting to buy the required supply, most likely at a premium price, from parties who hold T-South capacity to deliver gas at Sumas/Huntingdon. FEI customers would bear additional supply costs assuming FEI was able to transact the deal on the day. If unable to transact the deal, then FEI would be unable to serve all customers and would have to start curtailing.

[164] Appendix F, Raymond Mason Report, pp. 4 and 22.

4.4.2 Absence of a Gas Supply Reserve Make Supplemental Alternatives 5, 6, and 7 Non-Viable

Supplemental Alternatives 5, 6, and 7 would replace the existing Tilbury Base Plant with a new storage tank and regasification. However, these supplemental alternatives would not allocate any of the new storage volume to gas supply. In each case, the entirety of the tank would be allocated to a resiliency reserve, leaving FEI without its existing 0.6 Bcf and 150 MMcf/d of on-system peaking resources.

As a result, these options would potentially reduce the risk exposure to a T-South winter no-flow event and would address reliability considerations and age-related issues with the Base Plant. However, these alternatives create an unacceptable risk to FEI's ability to continue serving firm load during peak winter periods in normal operations. As discussed in the previous section above and Section 3.3.4 of this Supplemental Evidence, making up the lost supply on the spot market or through regional resources would not be viable.

4.4.3 Four Supplemental Alternatives Remain for Step 3 Evaluation

Supplemental Alternatives 4, 4A, 8, and 9 are the four alternatives that are technically and commercially viable and retain FEI's existing on-system firm peaking supply.

Table 4-7: Supplemental Alternatives that Passed Step 2

New Facility with Gas Supply But No Resiliency Reserve[165]		
Alt 4	Like-for-Like (No Resiliency Reserve)	Replace the Base Plant like-for-like to restore the 1971 design capacity (150 MMcf/d regasification and 0.6 Bcf tank) and continue using Tilbury as a supply peaking resource, without a resiliency reserve.
Alt 4A	New 1 Bcf Tank (No Resiliency Reserve) and 400 MMcf/d Regasification	Replace the Base Plant with the smallest new facility capable of providing FEI's optimum peaking gas supply, including a 1 Bcf tank and 200 MMcf/d regasification (with an additional 200 MMcf/d for redundancy). Continue using it as a supply peaking resource, without a resiliency reserve.
New Facility with Both Resiliency Reserve and Replacement of Gas Supply		
Alt 8	New 2 Bcf Tank (1.4 Bcf Resiliency Reserve) and 800 MMcf/d Regasification	Construct the smallest facility that allows FEI to both avoid curtailments of firm peak load in normal operations (albeit in a suboptimal manner, since it still requires relying on pipeline capacity to provide short-term peaking supply) and provide a certain level of resiliency reserve. This includes replacing the Base Plant with a 2 Bcf tank and 800 MMcf/d regasification, of which 1.4 Bcf is allocated as a resiliency reserve, and 0.6 Bcf is allocated to replace the existing gas supply functions at Tilbury.

[165] These alternatives do not include a dependable resiliency reserve but provide different amounts of peaking gas supply and improved reliability.

New Facility with Both Resiliency Reserve and Replacement of Gas Supply		
Alt 9	New 3 Bcf Tank (2 Bcf Resiliency Reserve) and 800 MMcf/d Regasification	Construct a facility that both significantly mitigates FEI's largest customer outage risks and meets FEI's required peaking gas supply in an optimal manner (since it no longer requires relying on pipeline capacity to provide short-term peaking supply). Replace the Base Plant with a 3 Bcf tank and 800 MMcf/d regasification and allocate 2 Bcf as a resiliency reserve, and 1 Bcf to gas supply.

4.5 RESULTS OF STEP 3 ALTERNATIVES ANALYSIS

This section sets out the results of the Step 3 analysis, focusing on the four options that passed Step 2 (Supplemental Alternatives 4, 4A, 8 and 9). Please see Appendix C for the Step 3 results for Supplemental Alternatives that did not pass the Step 2 screen.

4.5.1 Resiliency Benefit Scoring Criterion

The "Resiliency Benefit" criterion considers an alternative's ability to mitigate the risk associated with a winter T-South no-flow event, which is FEI's largest customer outage risk exposure. As described below, the evaluation is based on multiple quantitative analyses performed by Exponent that consider various winter temperature conditions and the results of FEI's system modelling. On this criterion, Supplemental Alternatives 4 and 4A scored the lowest ("No Impact"), while Supplemental Alternatives 8 and 9 scored as "Medium Positive Impact" and "High Positive Impact", respectively. Supplemental Alternative 9 is therefore superior when it comes to mitigating the customer outage risk posed by a T-South winter no-flow event. In particular:

- Supplemental Alternatives 4 and 4A would provide no risk mitigation on a planning basis as they do not include a resiliency reserve.
- While Supplemental Alternatives 8 and 9 would provide similar and significant risk mitigation under average winter temperatures (refer to Figure 4-2 below), the larger resiliency reserve provided by Supplemental Alternative 9 (2.0 Bcf vs. 1.4 Bcf) will make it far superior at below average temperatures prevalent for significant portions of a typical winter.
- The longer load support duration provided by Supplemental Alternative 9 relative to Supplemental Alternative 8 means that there would be a greater likelihood that any Lower Mainland shutdown would occur in a controlled, versus uncontrolled, manner. This is particularly true when the temperature is between -6.8°C to +1.7°C, as in that temperature range Supplemental Alternative 9 will be able to provide at least a 3-day[166] support duration but Supplemental Alternative 8 would not. Refer to Section 3.2.2 of this Supplemental Evidence for details on why a controlled shutdown is preferred over an uncontrolled shutdown.

[166] Per FEI's 2024 Resiliency Plan, three days is enough time to implement a controlled shutdown.

The resiliency benefits provided by Supplemental Alternative 9 will extend beyond the risk mitigation discussed in this section. The risk mitigation calculations presented in this section relate specifically to mitigation of FEI's largest risk (i.e., T-South winter outage risk) which is how the "Resiliency Benefit" criterion in Step 3 is defined. Supplemental Alternative 9 will provide additional quantifiable risk mitigation for other Assessed Vulnerabilities and off-system storage disruptions. The cumulative risk reduction benefits of Supplemental Alternative 9, accounting for all Assessed Vulnerabilities, are discussed in greater detail in Section 4.7 below.

4.5.1.1 Exponent Accounted for Load Support Duration and Uncertainty in Duration of No-Flow Period

The assessment under the Resiliency Benefit criterion is based on risk calculations performed by Exponent in respect of a winter T-South no-flow event.[167] Exponent performed three analyses to determine the risk mitigation provided by the Supplemental Alternatives at different temperature conditions that can occur in a typical Lower Mainland winter:

1. Risk reduction provided by Supplemental Alternatives 4, 4A, 8 and 9 at average winter temperatures in the Lower Mainland (+4°C) against a T-South winter no-flow event.
2. Expected annual customer-outage-day risk under Supplemental Alternatives 8 and 9 at a fixed temperature of -1.4°C.
3. Load support duration provided by Supplemental Alternatives 8 and 9 at variable colder temperatures (i.e., support duration as a function of temperature), including identifying the temperature range in which the alternatives provide different levels of risk mitigation in the context of a 3-day regulatory shutdown. The analysis also considers the load support duration as a function of temperature with respect to historical temperature data and in the context of a 3-day regulatory shutdown (i.e., based on historical temperature data, it identifies the portion of winter days in which Supplemental Alternative 9 can bridge a 3-day regulatory shutdown but Supplemental Alternative 8 cannot).

Exponent's calculated risk reduction reflects the results of FEI's transient modelling, which determines the length of time the Supplemental Alternatives could support the Lower Mainland in the event of a loss of supply from T-South. Exponent's Monte Carlo-based risk analysis accounts for multiple modes of failure and the potential for no-flow events of varying durations, (i.e., the risk mitigation shown in all of Exponent's risk mitigation figures accounts for the possibility that the no-flow duration may exceed the duration of support provided by Supplemental Alternative 9). Exponent provides a detailed description of its Monte Carlo-based risk analysis in Appendix RP-2 to the 2024 Resiliency Plan, Exponent Report, Appendix U.

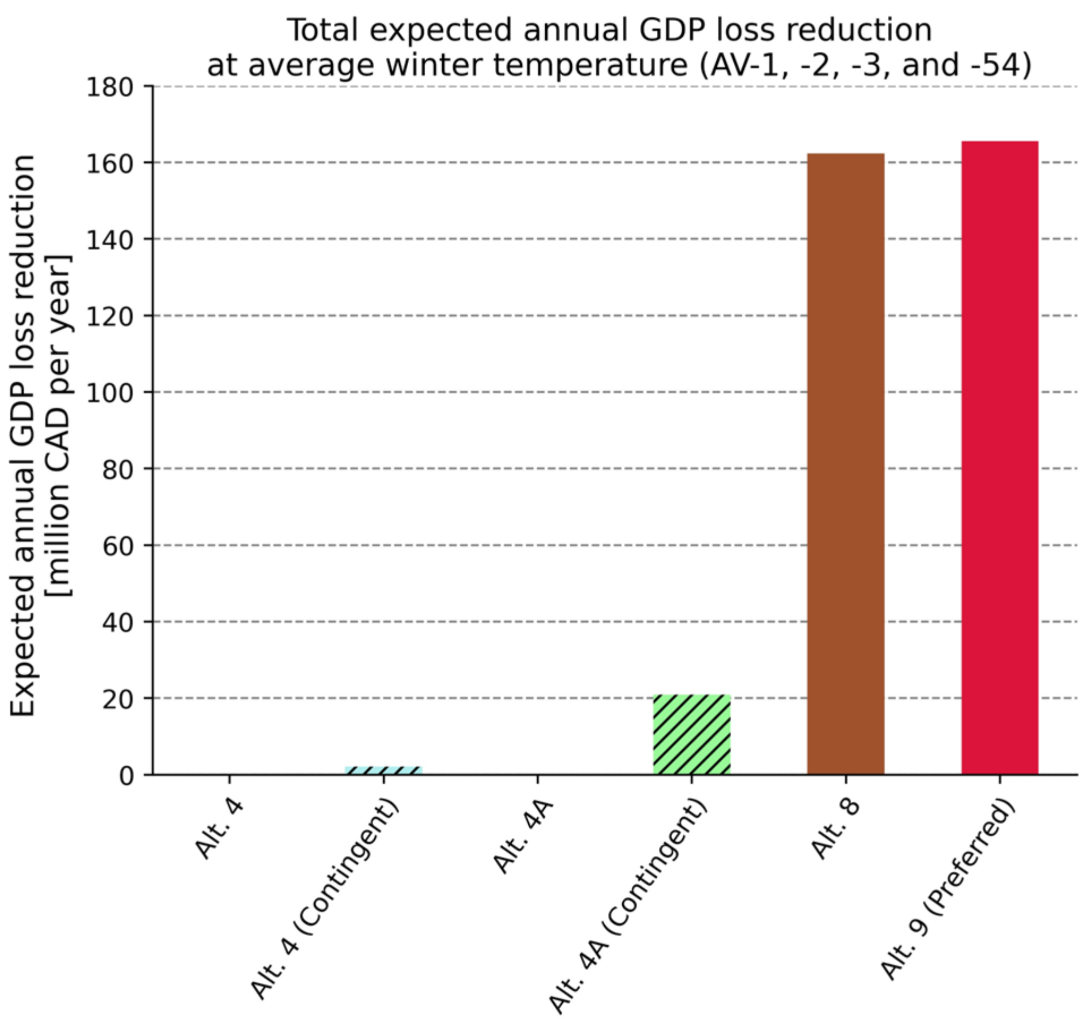
[167] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report.

4.5.1.2 Exponent's Risk Mitigation Results – Average Winter Temperature (+4°C)

This section addresses the results of Exponent's analysis at average winter temperature in the Lower Mainland (+4°C).

Figure 4-2 below summarizes the annual expected GDP loss reduction associated with each of Supplemental Alternatives 4, 4A, 8 and 9, relative to Supplemental Alternative 1 (Planning) scenario that involves no capital upgrades.[168] The pattern is similar regardless of the time horizon or whether the consequence metric used is cumulative GDP loss reduction or customer-outage-days.

Figure 4-2: T-South at Average Winter – Expected Annual Loss Reduction



[168] Refer to Section 2.5 of Appendix C to this Supplemental Evidence for a detailed discussion on the resiliency performance of all Supplemental Alternatives.

Supplemental Alternatives 4 and 4A received a score of “No Impact” for the Resiliency Benefit criterion because they would not improve the current poor ability to mitigate FEI’s largest resiliency risk even at average winter temperature in the Lower Mainland. As shown in the figure:

- Supplemental Alternative 4 (Planning) and Supplemental Alternative 4A (Planning) would provide no additional risk mitigation against a winter T-South no-flow event when compared to FEI’s current capabilities (represented by Supplemental Alternative 1). This is because, like Supplemental Alternative 1, Supplemental Alternatives 4 and 4A would not have a dedicated resiliency reserve, and therefore could not support the Lower Mainland for any duration during a winter T-South no-flow event.
- Supplemental Alternative 4’s performance would not improve under a favourable “contingent” scenario. In particular, Supplemental Alternative 4 (Contingent), which assumes that 0.6 Bcf of LNG is available on the day of a no-flow event, would not mitigate additional risk (relative to Supplemental Alternative 1 (Contingent)) because the like-for-like replacement of the existing Base Plant does not address the governing constraint – limited regasification capacity of only 150 MMcf/d.
- Supplemental Alternative 4A (Contingent), which assumes that 1.0 Bcf of LNG is available despite the tank’s use for peaking supply, would provide improved risk mitigation; however, the improvement would not be material. As shown in Figure 4-2 above, the loss reduction provided by Supplemental Alternative 4A (Contingent) would surpass that provided by Supplemental Alternative 4 (Contingent), but is significantly less than what would be provided by the larger supplemental alternatives (i.e., Supplemental Alternatives 8 and 9). As the basis for scoring this criterion is a relative comparison of the level of risk mitigation each supplemental alternative provides (refer to Section 4.2.2.3.2), the improvement in risk mitigation that would be provided by Supplemental Alternative 4A (Contingent) is too small to warrant a positive score. As such, even when considering the favourable contingent scenario for Supplemental Alternative 4A, the score for the Resiliency Benefit criterion remains “No Impact”.

At average Lower Mainland winter conditions (+4°C), Supplemental Alternatives 8 and 9 would both provide significant risk mitigation. The figure above shows the risk mitigation as a reduction in annual expected GDP losses, totalling approximately $160 million per year. Over a long period of time, those avoided expected GDP losses are very significant. The same is true when considering customer-outage-days and customer outages.

Section 4.7 below provides additional Exponent risk calculation results for Supplemental Alternative 9, including for various consequence measures and cumulative risk calculations over 67-year and 23-year horizons. Please refer to Appendix C for a detailed review and discussion of the risk mitigation benefit, if any, provided by each supplemental alternative at average winter conditions.

4.5.1.3 Exponent's Cold Weather Analysis Results – Fixed Temperature (-1.4°C)

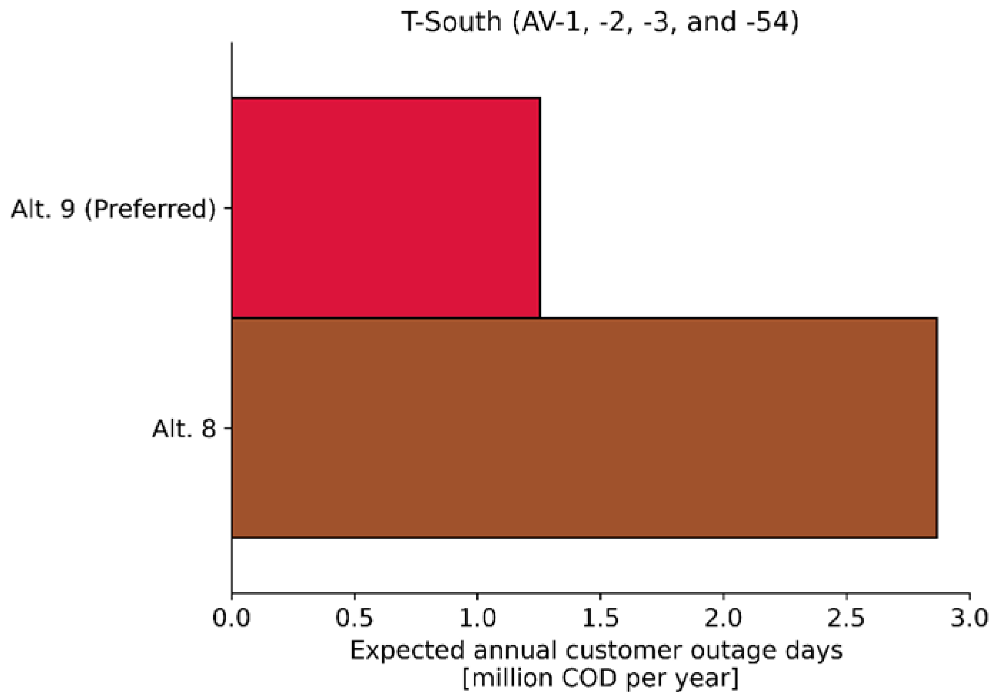
FEI requested that Exponent conduct additional analysis for the two options – Supplemental Alternatives 8 and 9 – that had demonstrated material risk reductions at average winter temperatures. The purpose of the analysis was to understand their relative effectiveness in mitigating risk in colder conditions that are present for periods of the winter.[169] Under this analysis, Supplemental Alternative 9 will provide superior risk mitigation under colder conditions when compared to Supplemental Alternative 8.

As the intent was to understand the difference between the two Supplemental Alternatives under cold weather, as opposed to the total expected risk under colder conditions, this analysis was simplified to only focus on T-South, and only on customers impacted in the Lower Mainland. Excluding customers outside of the Lower Mainland will result in the total expected risk at colder temperatures being under-reported in this secondary analysis; however, the risk to the Lower Mainland is FEI's largest outage risk and the simplification allows for a meaningful comparison of expected Lower Mainland risk between the supplemental alternatives.

Figure 4-3 below shows the results from Exponent's expected annual risk calculations at -1.4°C, with direct customer impact expressed in terms of customer-outage-days. The expected risk under Supplemental Alternative 8 is significantly higher than Supplemental Alternative 9. This shows that the latter provides superior risk mitigation at -1.4°C when compared to Supplemental Alternative 8.

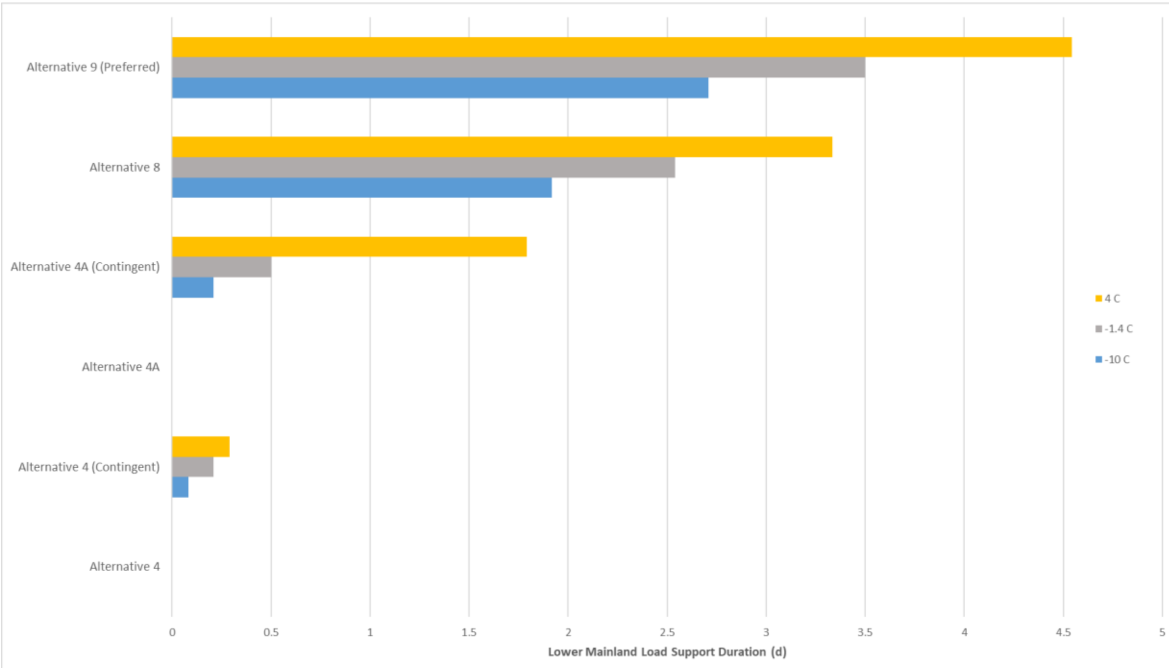
[169] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, Section 9 and Report Appendix U, Section U.6.1.

Figure 4-3: Expected Annual Winter-only Customer Outage-days Loss for Different Supplemental Alternatives for T-South (AV-1, -2, -3, and -54) at -1.4°C



The risk results shown above align with the expected load support duration for each of Supplemental Alternatives 8 and 9. Supplemental Alternative 9 provides a 3-day support duration at -1.4°C whereas the support duration provided by Supplemental Alternative 8 would be approximately a full day shorter (see Figure 4-4 below). With a load support duration of less than three days, Supplemental Alternative 8 would be less likely to bridge a no-flow event prompted by, for example, a precautionary regulatory shutdown following an integrity incident on one of the T-South pipelines. The residual risk for Supplemental Alternative 9 is due to possible failure modes that can result in an outage duration exceeding the duration of support provided to FEI's entire Lower Mainland load. In this situation, the Supplemental Alternative 9 tank allows FEI to enact a controlled shutdown, which reduces the number of customer outage days.

Figure 4-4: Lower Mainland Support Duration Provided by Supplemental Alternatives at Various Temperatures



4.5.1.4 Exponent's Cold Weather Analysis Results – Variable Temperature

Exponent also performed a variable temperature analysis showing the relationship between below average winter temperatures and risk mitigation. The result, described below, is that nearly a quarter of winter days fall in the range in which Supplemental Alternative 9 can support the Lower Mainland load for at least three days but Supplemental Alternative 8 could not. The material difference in load support duration at a given temperature has significant consequences for the GDP losses and customer-outage-days. A likely outcome of a T-South failure is that only one of the two pipelines is physically damaged, and the adjacent undamaged line is shut-in as a precaution by the regulator (i.e., a regulatory shutdown). The regulatory shutdown could reasonably be expected to last three days.

FEI provided Exponent with the Lower Mainland load support duration for each of Supplemental Alternatives 8 and 9 at -10°C, -1.4°C, and +4°C as follows.[170]

[170] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, Section 9 and Report Appendix U.6.2.

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

	Load support duration [days]	
Temperature [degrees Celsius, ℃]	**Alternative 8**	**Alternative 9 (Preferred)**
4	3.33	4.54
-1.4	2.54	3.5
-10	1.92	2.71

Using this data, Exponent determined the load support duration for Supplemental Alternatives 8 and 9 as a function of temperature. The key finding from this analysis was that Supplemental Alternative 9 is superior to Supplemental Alternative 8 throughout a temperature range of approximately -6.8°C to +1.7°C. Above +1.7°C, Supplemental Alternatives 8 and 9 both provide at least a 3-day support duration. This translates to similar amounts of risk mitigation because they can both bridge a regulatory shutdown of an undamaged T-South pipe for up to 3 days. However, between -6.8°C and +1.7°C, only Supplemental Alternative 9 will provide 3 days of load support. Thus, in this temperature range Supplemental Alternative 9 will provide a superior resiliency benefit.

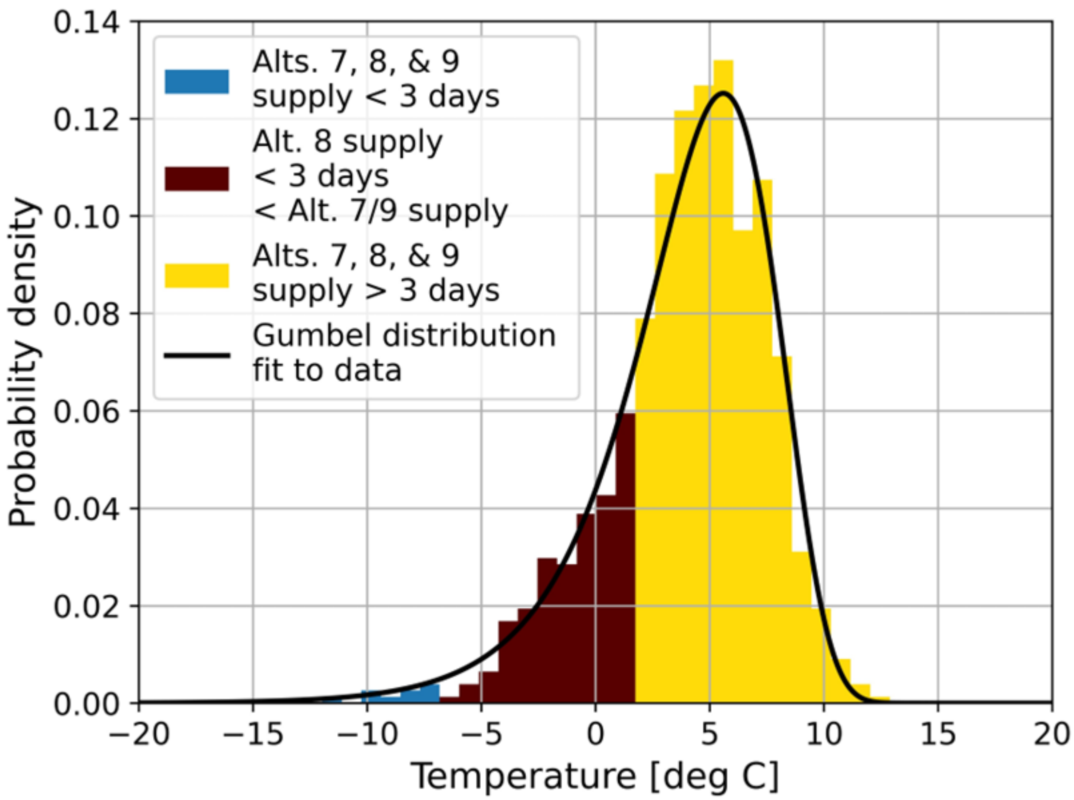
Exponent then considered the load support duration as a function of temperature with respect to historical daily average temperature data. Figure 74 from the Exponent Report,[171] included below as Figure 4-5, presents the results from this analysis in the context of exceeding an assumed 3-day regulatory shutdown. In the figure, the temperature range at which the load support duration exceeds the assumed regulatory shutdown period for Supplemental Alternative 9, but not Supplemental Alternative 8, is highlighted in burgundy in the figure, being -6.8°C to +1.7°C. And the temperature range at which neither Supplemental Alternative 8 nor 9 would meet the 3-day regulatory shutdown period is the blue at the left hand side of the distribution when temperatues are lower than -6.8°C and for which the probability density is very low.

Exponent explained the significance of the results as follows:[172]

> This review of the temperature data and supply duration for each temperature reveals the substantial benefit of using Alternative 7 or 9 (Preferred) over Alternative 8, as nearly a quarter of winter days fall in the range in which Alternatives 7 and 9 (Preferred) can bridge the regulatory shutdown period but Alternative 8 cannot. This has significant consequences for the GDP losses and CODs for failures of a single pipeline on AV-1, -2, -3, and -54 [i.e., the four segments comprising T-South].

[171] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, para. 228.
[172] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, para. 229.

Figure 4-5: Distribution of Average Daily Winter (December through February) Temperature in the Lower Mainland (Vancouver Airport) between January 2013 and December 2022



4.5.1.5 Supplemental Alternative 9 Best Mitigates Risk

Supplemental Alternative 9 will provide a significant reduction in customer outage risk that is superior to either Supplemental Alternatives 4, 4A, or 8 because it will increase both the regasification capacity and the storage at Tilbury to the point where it can support FEI's load for much longer than can be supported today.

- **The benefit of more regasification capacity:** Supplemental Alternatives 8 and 9 provide 800 MMcf/d of regasification capacity, thereby addressing the existing governing regasification constraint at Tilbury. The present regasification constraint guarantees a Day 1 widespread customer outage even at average winter temperatures. The proposed regasification capacity of Supplemental Alternative 9 (and Supplemental Alternative 8) is sufficient to support the Lower Mainland daily load in all but the coldest of conditions that occur relatively infrequently for only short durations. Supplemental Alternative 4 would not address the constraint, and Supplemental Alternative 4A, while increasing the regasification capacity and thus providing some improvement, would not fully address the constraint. This is because at average winter conditions (+4°C) the 400 MMcf/d regasification capacity would remain undersized for the Lower Mainland demand.

- **The benefit of having a resiliency reserve over and above gas supply:** Supplemental Alternative 9 sets aside 2 Bcf in the 3 Bcf tank as a resiliency reserve, such that this will be the minimum amount available for resiliency when a T-South no-flow event occurs. Once the regasification constraint is addressed, the additional LNG allows FEI to serve the daily load for multiple days, with the specific duration of that support depending on the system load, which is primarily driven by temperature. The longer Tilbury can serve the winter load, the greater the potential to bridge a no-flow event and avoid depressurization and customer outages. Exponent observed that more than 1 Bcf is required to make a material risk reduction:[173]

  > The on-system LNG of a Tilbury Alternative plays an important role in determining the reduction in losses compared to the status quo configuration (Alternative 1 (Planning)). When the Tilbury Facility has limited on-system LNG (1 Bcf or less), relatively few hazards are mitigated by its presence because there is not enough volume to bridge the regulatory shutdown period or shorter repair durations for AVs with higher loads, such as AV-1, AV-2, AV-3, AV-54, and AV-18.

  While Supplemental Alternative 8 would have a 1.4 Bcf resiliency reserve, which would be an improvement relative to the existing Base Plant, the additional 0.6 Bcf of LNG provided by Supplemental Alternative 9 makes a difference to the level of risk mitigation provided (particularly at temperatures below the average Lower Mainland winter temperature).

- **A precautionary shut down of the unaffected adjacent T-South pipeline is a likely trigger of a no-flow event:** Exponent's risk assessment evaluates a T-South failure assuming a range of no-flow durations and failure modes (i.e., hazards). In Exponent's analysis, in instances where there are parallel pipelines (as is the case for T-South), the analysis considers the probability of each hazard causing simultaneous failure of both pipelines. As many of the hazards considered have a low probability of simultaneous failure, a likely outcome of a T-South failure is that only one line is physically damaged and the adjacent undamaged line is shut-in as a precaution by the regulator (i.e., a regulatory shutdown). As such, FEI can mitigate significant risk by being able to continue supporting load until the federal regulator allows Westcoast to resume flowing gas on the unaffected pipeline. Exponent explained:[174]

  > Larger on-system LNG volumes (such as 2 Bcf) provide enough backup supply to bridge the three-day regulatory shutdown period on AVs-1, 2, 3, 54, and 18, which are AVs with parallel pipeline segments. Bridging the regulatory shutdown period significantly reduces losses on these AVs, except for cases in which the two parallel pipeline segments fail simultaneously.

[173] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, para. 192.
[174] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, para. 192.

Supplemental Alternative 9, by virtue of the amount of regasification capacity and LNG resiliency reserve, is likely to achieve this outcome. Supplemental Alternative 8 would likely achieve this outcome at average winter temperatures, but not if the temperature dropped to +1.7°C or below.

- **Lower Mainland outages expected to occur in an uncontrolled manner today will be controlled:** At minimum, even if a no-flow event exceeds the duration of load support and an outage occurs, Supplemental Alternative 9 will provide an adequate response time in most temperature conditions to ensure a controlled shutdown of the Lower Mainland system. An uncontrolled shutdown extends the time to restore service to customers relative to a controlled shutdown. As such, a controlled shutdown reduces the number of customer outage days and GDP losses (please also refer to Section 3.2.2 of this Supplemental Evidence). Supplemental Alternative 9 is likely to provide the amount of time necessary for FEI to arrange for a controlled shutdown. Supplemental Alternative 8 would not be able to achieve this outcome when the temperature is +1.7°C or below, which represents a significant portion of the winter.

4.5.2 Availability of Dependable Gas Supply During Peak Demand Scoring Criterion

With respect to the criterion "Availability of Dependable Gas Supply During Peak Demand", FEI has scored Supplemental Alternatives 4 and 8 as "Medium Positive Impact", and Supplemental Alternatives 4A and 9 as "High Positive Impact". The difference is attributable to the incremental gas supply that Supplemental Alternatives 4A and 9 provide relative to today.

Supplemental Alternative 4 ("Medium Positive"): With a 0.6 Bcf gas supply reserve and 150 MMcf/d of send-out, Supplemental Alternative 4 would retain FEI's existing firm peaking gas supply capabilities that have long been included in the ACP. Further, it would improve FEI's gas supply capabilities relative to Supplemental Alternative 1 by:

1. Resolving the age-related challenges associated with the end-of-life Tilbury Base Plant by replacing it with a new facility, which increases the availability of dependable gas supply; and
2. Providing a new tank that effectively provides the amount of LNG that FEI has long included in its ACP, allowing FEI to discontinue the stop-gap measure of relying on 0.25 Bcf from Tilbury 1A (i.e., LNG that is intended for RS 46 sales) to compensate for the Base Plant tank being operated at 0.35 Bcf for seismic reasons.

Supplemental Alternative 4A ("High Positive"): Supplemental Alternative 4A, with a gas supply reserve of 1.0 Bcf paired with 200 MMcf/d[175] of send out, was designed to meet FEI's full peaking

[175] Supplemental Alternative 4A includes 400 MMcf/d of send out capacity, however for gas supply planning purposes only 200 MMcf/d is required.

supply requirement in an optimal manner without adding resiliency.[176] It would provide the benefits outlined above for Supplemental Alternative 4. The additional 0.4 Bcf dedicated to gas supply, paired with the additional 50 MMcf/d of send-out, would provide FEI considerable flexibility for gas supply planning and winter operation, and potentially displace other less optimal gas portfolio assets. Without those additional peaking supply capabilities, FEI would need to continue to incur millions of dollars of costs each year to maintain its existing year-round pipeline capacity that FEI relies on as a sub-optimal source of peaking supply. Section 4.5.4.1.2 below quantifies the avoided gas supply costs associated with Supplemental Alternative 4A.

Supplemental Alternative 8 ("Medium Positive"): Supplemental Alternative 8 increases the send-out capacity relative to Supplemental Alternative 4 (800 MMcf/d vs. only 150 MMcf/d). However, this alternative would only allocate 0.6 Bcf of the 2.0 Bcf tank to gas supply, such that it provides the same energy as Supplemental Alternative 4. The additional regasification would provide some additional operational flexibility, but the extent of the benefit would be constrained due to the limited gas supply reserve of only 0.6 Bcf. Like other storage assets, both daily send-out capacity and total storage supply are needed to make the asset useful in FEI's gas supply portfolio.

LNG peaking is the last resource in the portfolio to provide up to 10 days[177] of peaking supply during winter season. The LNG send-out is only called when additional supply is required on cold winter days. Due to the unpredictability of cold weather events, having additional send-out capacity provides optionality to increase peak day LNG supply in the planning model as well as the operational flexibility to call on LNG send out. Unless there was enough LNG reserve to cover the whole winter period, the increased daily send-out capacity provides limited benefits because one-day send-out could deplete the whole LNG reserve and leave a shortage of peaking supply for the remainder of winter. For instance, sending out at that maximum rate of 800 MMcf/d would consume 0.6 Bcf (i.e., 600 MMcf) in less than a day. As such, FEI has not differentiated between Supplemental Alternatives 4 and 8 for the "Availability of Dependable Gas Supply During Peak Demand" criterion, and both are scored as "Medium Positive".

Supplemental Alternative 9 ("High Positive"): Supplemental Alternative 9 was sized for optimal gas supply and optimal outage risk mitigation. With a gas supply reserve of 1.0 Bcf paired with 800 MMcf/d of send out, Supplemental Alternative 9 will provide the same gas supply benefits as Supplemental Alternative 4A.[178] That is, Supplemental Alternative 9 offers incremental benefits beyond those offered by Supplemental Alternatives 4 and 8. The additional 0.4 Bcf that is dedicated to gas supply, paired with 200 MMcf/d of send-out, will provide FEI with considerable flexibility for gas supply planning and winter operation, and potentially displace or secure other

[176] Section 3.3.4 discusses FEI's peaking supply requirements and how resources are optimized to meet those requirements.

[177] FEI includes the maximum peak day send out and the total LNG reserve in it planning model but not all LNG send out is at the maximum send out capacity.

[178] Supplemental Alternative 9 includes 800 MMcf/d of send out capacity, however for gas supply planning purposes only 200 MMcf/d is required.

higher cost gas portfolio assets. Section 4.5.4.1.2 of this Supplemental Evidence quantifies the avoided gas supply costs associated with Supplemental Alternative 9.

4.5.3 Resolves Age-Related Base Plant Challenges Scoring Criterion

The key consideration for the "Resolves Age-Related Base Plant Challenges" criterion is whether the alternative addresses the issues related to the end-of-life Base Plant (outlined in Section 3.3 of this Supplemental Evidence) that are preventing the Base Plant from reliably performing its critical gas supply function. These challenges include unreliable and obsolete regasification equipment that is difficult to repair, the seismic design challenges that have caused FEI to operate the tank at only 59 percent of its design capabilities, the flooding risk, and the environmental challenges associated with how the Tilbury Base Plant tank vents to atmosphere. As Supplemental Alternatives 4, 4A, 8, and 9 all include the installation of a new tank and new regasification equipment built to current standards, each alternative received the same score. A "High Positive Impact" score was selected as the alternatives would be resolving all age-related challenges associated with the Base Plant.

4.5.4 Levelized Total Rate Impact Scoring Criterion

The levelized total rate impact criterion compares the incremental levelized total rate impact over a 67-year period between each supplemental alternative. Alternatives with a higher levelized total rate impact over the 67-year analysis period will score lower (i.e., worse) than those alternatives with a lower levelized total rate impact. The levelized total rate impact includes:

- The impact to FEI's delivery rates due to the capital and operating costs of each alternative; and
- The impact to FEI's cost of gas rates (which include both commodity and midstream costs) due to the incremental gas supply costs/benefits to FEI's customers resulting from each alternative (which are discussed in Section 4.5.4.1.2 below).

The 67-year analysis period is used for the financial analysis to cover the expected useful life of the assets pertaining to all alternatives, which is 60 years for an LNG storage tank, plus seven prior years from 2024 to 2030 (assuming all alternatives are placed in-service by 2030).

Table 4-9 provides the financial results for the four feasible supplemental alternatives (Supplemental Alternatives 4, 4A, 8, and 9) based on the capital and operating cost estimates, as well as the estimate of gas supply costs/savings of each alternative over the 67-year analysis period. Although this section focuses on the results of Supplemental Alternatives 4, 4A, 8 and 9, FEI has also undertaken the financial analysis for the remaining Supplemental Alternatives (i.e., Supplemental Alternative 1, 2, 3, 5, 6, and 7)[179] in Appendix C to this Supplemental Evidence.

[179] No financial analysis was completed for Supplemental Alternatives 10, 11, and 12.

Table 4-9: Summary of Capital Costs, Cost of Service, Gas Supply Costs/Savings, and Levelized Total Rate Impacts for Feasible Supplemental Alternatives

	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

Based on the results of the levelized total rate impact analysis, Supplemental Alternatives 4 and 4A received a score of "Low Negative Impact", while Supplemental Alternatives 8 and 9 received a score of "Medium Negative Impact".

4.5.4.1 Key Observations from the Financial Analysis Results for the Four Feasible Supplemental Alternatives (4, 4A, 8 and 9)

Based on the financial results for Supplemental Alternatives 4, 4A, 8, and 9 from Table 4-9 above, the levelized total rate impact to FEI's customers between each alternative over the life of the assets (i.e., 67 years) is significantly influenced by two factors:

- The strong economies of scale in the construction capital costs of the facility; and
- The extent to which an alternative is capable of providing the necessary peaking supply to avoid curtailments during normal operations, being 200 MMcf/d and 1.0 Bcf (i.e., 5 days x 200 MMcf/d) as discussed in Section 3.3.4.2, thereby avoiding the need for FEI to incur annual gas supply costs for holding less efficient peaking supply on expanded off-system storage or regional pipeline infrastructure (assuming that is even available).

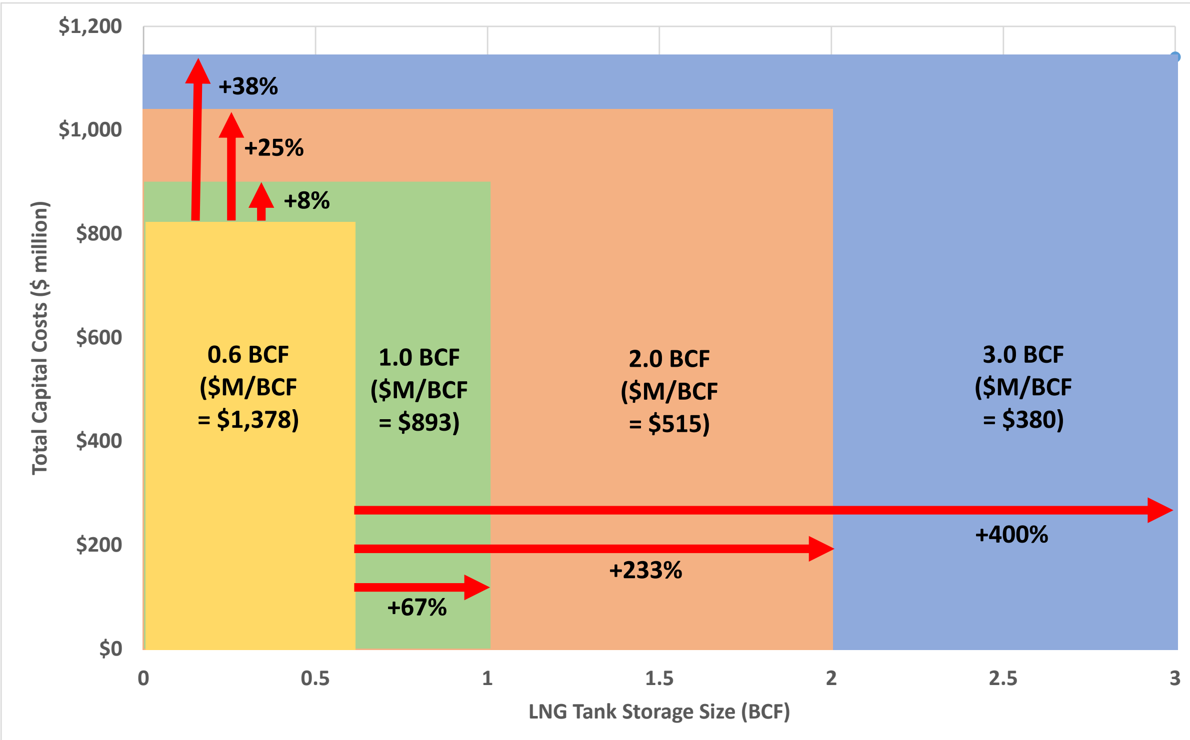
These factors are further discussed below.

4.5.4.1.1 BENEFITS FROM SIGNIFICANT ECONOMIES OF SCALE

As previously discussed in Section 4.4.1.2 of the Application,[180] LNG storage infrastructure is characterized by significant economies of scale, where the capital cost per unit of storage decreases as the size of the LNG storage increases. Figure 4-6 below provides a graphical illustration of the strength of the economies of scale for new facilities at Tilbury ranging from a like-for-like replacement (0.6 Bcf / 150 MMcf/d) up to a 3 Bcf / 800 MMcf/d replacement. The costs shown are based on updated estimates.

[180] Exhibit B-1-4, Application, p. 107.

Figure 4-6: Graphical Illustration of Economies of Scale by Tank Capacity (from 0.6 Bcf to 3.0 Bcf)



The capital cost per Bcf comparison demonstrates that:

- When comparing against a 0.6 Bcf and 150 MMcf/d facility that would offer no resiliency benefits (Supplemental Alternative 4), Supplemental Alternative 9 (3.0 Bcf and 800 MMcf/d) provides five times the storage (+400 percent) and over five times the regasification capacity (+433 percent) for approximately $314 million more (or 38 percent more) in capital cost. The unit cost for Supplemental Alternative 9 with a 3.0 Bcf tank (including ground improvement, auxiliary systems, and regasification) is approximately $998 million per Bcf lower than the unit cost for Supplemental Alternative 4.
- When comparing against a 1.0 Bcf and 400 MMcf/d facility that would offer no resiliency benefits (Supplemental Alternative 4A), Supplemental Alternative 9 (3.0 Bcf and 800 MMcf/d) provides three times the storage (+200 percent) and two times the regasification capacity (+100 percent) for approximately $248 million more (or 28 percent more) in capital cost. The unit cost for Supplemental Alternative 9 with a 3.0 Bcf tank (including ground improvement, auxiliary systems, and regasification) is approximately $513 million per Bcf lower than the unit cost for Supplemental Alternative 4A.
- When compared to a 2 Bcf tank with the equivalent regasification capacity (Supplemental Alternative 8), Supplemental Alternative 9 (3.0 Bcf and 800 MMcf/d) provides 50 percent more storage for an additional capital cost of only 11 percent (approximately $111 million). The unit cost for Supplemental Alternative 9 with a 3 Bcf tank (including ground

improvement, auxiliary systems, and regasification) is therefore approximately $135 million less per Bcf than the unit cost of a 2 Bcf tank.

Thus, the economies of scale significantly favour Supplemental Alternative 9.

4.5.4.1.2 SIGNIFICANT GAS SUPPLY BENEFITS

As explained in Section 3.3.4.2 of the Supplemental Evidence, FEI's current peaking supply requirements are 1.0 Bcf paired with 200 MMcf/d. A supplemental alternative must achieve this level of peaking supply to avoid curtailments of firm customers under normal operations. This could be achieved through: (a) on-system LNG; (b) the regional gas supply market, with reliance on future large regional infrastructure expansions; or (c) a combination of both. Where an alternative involves FEI relying on the market, the annual peaking supply costs would be paid by FEI's customers through the cost of gas, and these annual costs are reflected in the levelized total rate impact calculation. Having on-system LNG for peaking gas supply would either partially or fully avoid the annual market-based gas supply costs, which represents a benefit for customers.

This section explains how FEI calculated annual market-based gas supply costs / avoided costs in respect of the various supplemental alternatives. FEI considers there are three separate phases of gas supply costs/savings over the 67-year analysis period:

- From the present to when, absent capital upgrades, LNG from Tilbury would no longer be available either due to the existing Tilbury Base Plant no longer being usable or due to an inability to continue using LNG from Tilbury 1A to supplement the Base Plant's reduced capacity (assumed to be **present to 2030**);
- The period between when, absent capital upgrades, Tilbury LNG is no longer available and when a sufficiently large regional infrastructure expansion could replace the lost LNG (assumed to be **between 2030 and 2035**); and
- The period thereafter, when relying on expanded regional infrastructure would cause FEI to incur higher annual tolls / charges on all capacity held on that infrastructure (assumed to be **2035 and onwards**).

Annual Gas Supply Costs up to 2030

Since FEI requires 200 MMcf/d and 1.0 Bcf of peaking gas supply, the existing Tilbury Base Plant is already undersized. To make up this level of peaking gas supply, the current ACP includes 150 MMcf/d and 0.6 Bcf of LNG from Tilbury, plus 50 MMcf/d of year-round pipeline capacity on T-South, which FEI then must try to resell (mitigate) during most of the year.[181] FEI estimates the annual costs it incurs at present for holding the 50 MMcf/d of pipeline capacity on T-South year-round are approximately $7 million, net of mitigation of the unused capacity.

In the baseline scenario where there are no capital upgrades (i.e., Supplemental Alternative 1), FEI could, if required, continue to hold 50 MMcf/d of pipeline capacity on T-South indefinitely

[181] FEI's 2024/25 ACP provides a detailed discussion of T-South holdings.

because it has rollover rights. However, FEI's ability to continue relying on the 0.6 Bcf / 150 MMcf/d of LNG peaking supply in the ACP is time limited due to the following:

- The Base Plant has already reached end-of-life (as discussed in Section 3).
- As discussed in Section 4.4.1 above, FEI is unlikely to be able to continue relying on the Tilbury 1A tank to augment FEI's peaking energy given the recent regulatory approval of the Tilbury Jetty and the anticipated deliveries to service the Port of Vancouver.

FEI has assumed that the end date for the existing Base Plant is 2030, which FEI believes is reasonable based on its deteriorating condition. As such, for the purposes of the financial analysis, FEI assumes that it would continue to incur approximately $7 million annually (net of mitigation) for holding the 50 MMcf/d of pipeline capacity on T-South until 2030 for all supplemental alternatives (including those alternatives that would have new storage and/or regasification equipment since any new assets pertaining to each alternative would not be in-service before 2030).

Annual Gas Supply Costs between 2030 and 2035

As explained in Section 3.3.4.3, the regional infrastructure is already fully contracted which precludes replacing Tilbury's existing peaking capabilities with long-term commercial contracts. Once the Base Plant ceases to operate in the baseline scenario (i.e., Supplemental Alternative 1), firm customers would face curtailments in normal operations absent the completion of a regional infrastructure upgrade that is sufficiently large to replace the lost peaking supply from Tilbury. FEI believes there is no possibility of this occurring by 2030. Currently, the only planned regional infrastructure upgrade that FEI is aware of is the T-South Sunrise Expansion which will only offset the capacity of Woodfibre LNG and does not provide any added capacity to the region.[182] FEI is also not aware of any other potential for regional market area storage upgrades, other than the North Mist Expansion Project which is anticipated to complete in 2029. Any subsequent expansion at Mist, if possible, would take multiple years to develop post 2029. Therefore, FEI considers 2035 is a reasonable assumption for regional infrastructure upgrades.

As such, in the baseline scenario there would be a period where FEI is curtailing customers instead of incurring annual peaking supply costs.

FEI's financial analysis therefore had to make assumptions as to if and when regional infrastructure might be expanded sufficiently to meet peaking supply requirements so that FEI could cease having to curtail customers in the normal course. FEI assumed this would occur in 2035, as previously described.

As such, for the baseline scenario (i.e., Supplemental Alternative 1), FEI continue to incur millions of dollars annually (net of mitigation) to hold the existing 50 MMcf/d of pipeline capacity, but

[182] See Section 3.3.4.3.1.3 of the Supplemental Evidence.

otherwise will likely to have to curtail firm loads in normal operations until another expansion in regional pipeline or storage facility becomes available for FEI to contract.

- **Annual cost of holding existing 50 MMcf/d of pipeline capacity increases with 2028 Sunrise Expansion:** Since the currently planned T-South Sunrise Expansion is expected to result in tolls of $0.95/GJ, which is a significant increase (46 percent) over current embedded tolls on T-South, FEI assumes it would incur those $0.95/GJ tolls to continue to hold 50 MMcf/d of pipeline capacity that it currently uses to supplement Tilbury LNG in the ACP. Paying the higher toll on 50 MMcf/d represents approximately $17 million per year of annual peaking supply costs, before mitigation. Assuming FEI's current ability to mitigate that pipeline capacity, the post mitigation cost remains at approximately $7 million annually.
- **Curtailments of up to 150 MMcf/d get reflected as gas cost savings:** Since there is no possibility for FEI to replace the lost peaking capacity from the existing Tilbury Base Plant once it ceases operation, assumed to be 2030, the financial analysis assumes no costs to replace the lost 0.6 Bcf and 150 MMcf/d of peaking gas supply for those supplemental alternatives that do not provide new replacement for Tilbury LNG (i.e., those without a new LNG storage tank and no allocation for gas supply). However, as discussed above, FEI expects it would have to curtail customers to reduce demand by up to 150 MMcf/d until another regional expansion becomes available.

In comparison to the baseline scenario (i.e., Supplemental Alternative 1), Supplemental Alternatives 4 and 8 provide at least 150 MMcf/d of regasification, thereby avoiding curtailments. However, both of these alternatives would only provide 0.6 Bcf of LNG storage, therefore, FEI would still have to incur the estimated $7 million post mitigation gas supply costs to augment the remaining 0.4 Bcf of peaking supply in order to meet the requirement of having an optimized portfolio of 200 MMcf/d and 1.0 Bcf of peaking supply. This results in no avoided costs for Supplemental Alternatives 4 and 8 from 2030 to 2035.

Supplemental Alternatives 4A and 9, which would have 1 Bcf of LNG storage and at least 200 MMcf/d of regasification at Tilbury for peaking gas supply purposes, would avoid the estimated $7 million tolls from the regional market.

Annual Gas Supply Costs for 2035 and Beyond

FEI has assumed for the purposes of this analysis that the period of curtailment following the failure of the Base Plant would end when construction of a regional infrastructure (pipeline or storage) expansion is large enough to meet FEI's full requirements of 1.0 Bcf and 200 MMcf/d. Table 4-10 below provides the alternative resource capacity required to provide the equivalent of 1 Bcf and 200 MMcf/d of on-system LNG.

Table 4-10: Alternative Resource Capacity Required to Replace 1 Bcf / 200 MMcf/d of On-System Peaking Supply

	Annual Capcity (Bcf)	Daily Deliverability (MMcfd)
TLSE Peaking Supply	**200*5/1000 =1 Bcf**	**200 MMcfd**
1) Off-system Storage	200*10/1000 = 2 Bcf	200 MMcfd
2) T-South Expansion (Sunrise 300 MMcfd)	200 *365/1000 = 73 Bcf	200 MMcfd
3) T-South Expansion (Potential)	200 *365/1000 = 73 Bcf	200 MMcfd

FEI assumes the earliest upgrade in regional infrastructure (either a regional storage or pipeline expansion) could be in 2035 (given the T-South Sunrise Expansion is expected to complete in 2028 and FEI is not aware of any other potential for regional market area storage upgrades, other than the North Mist Expansion Project which is anticipated to complete in 2029). As such, for the purposes of the financial analysis, FEI would begin to incur higher tolls in 2035 (whether it is from new regional storage or pipeline expansion) under the baseline scenario (i.e., Supplemental Alternative 1) as well as any other Supplemental Alternatives (i.e., 2, 3, 5, 6, and 7) that do not have on-system LNG storage for peaking gas supply. In contrast, for those Supplemental Alternatives that have on-system LNG storage either fully or partially allocated for gas supply (i.e., 4, 4A, 8, and 9), the higher tolls in 2035 would effectively be gas supply costs savings or avoided costs reflected in the calculation of the levelized total rate impact and to the benefit of FEI's customers.

The annual costs of holding capacity on regional infrastructure will increase significantly with upgrades. These capital costs get reflected in higher tolls or demand charges, which are passed along to FEI customers through Storage and Transportation charges. Specifically:

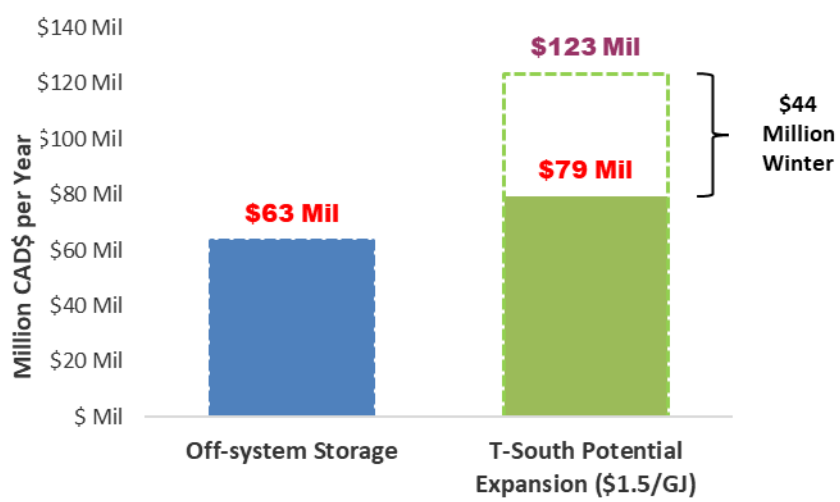
- For access to regional storage like JPS and Mist, FEI pays the storage demand charges, plus pipeline tolls on Northwest Pipeline for capacity to deliver the volumes to FEI's system. The cost of JPS or Mist expansions are borne by the party that requires the incremental capacity, in this case FEI. The same is true for expansions on Northwest Pipeline. The higher storage demand charge, and associated transportation charge, are passed on to FEI customers through Storage and Transportation charges.

- In the case of a T-South expansion, due to rolled-in tolling design, FEI would pay higher tolls than today for all of its capacity (existing holdings plus new incremental holdings), which means that FEI's existing capacity holdings on the regional infrastructure would also become more expensive for customers.

As the cost of holding capacity on regional infrastructure is a function of the expected tolls and charges, the costs will be higher than they are today by virtue of the capital costs of upgrades being reflected in the tolls and charges. Therefore, as discussed below, FEI used information from currently proposed pipeline and storage expansions to derive the cost estimates for peaking resources on expanded regional pipeline or storage infrastructure. The underlying market conditions and alternatives employed are similar as that used in the confidential section 71 application recently approved by Order G-241-24.

Assuming regional storage expansion or regional pipeline infrastructure would be upgraded sufficiently by 2035, Figure 4-7 below shows the estimated annual costs for holding peaking gas supply of 1.0 Bcf and 200 MMcf/d could range from $63 million to $79 million (net of mitigation), depending on if the regional infrastructure upgrade is storage or pipeline. For the purposes of the financial analysis and comparing between all supplemental alternatives, FEI conservatively used the lower annual cost of storage shown in Figure 4-7 below for gas supply costs/savings. Using the higher pipeline costs would have the effect of improving the levelized total rate impact of those supplemental alternatives that meet all of FEI's peaking gas supply requirements (Supplemental Alternatives 4A and 9) relative to those options that do not (i.e., 1, 2, 3, 4, 5, 6, 7, and 8).

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



The estimated annual costs of holding peaking gas supply of 1 Bcf and 200 MMcf/d from a regional storage or pipeline expansion are based on the following assumptions:

- **Expected Regional Storage Cost Increase (Basis for Financial Calculations):** The cost of using regional storage involves: (1) a storage demand charge; and (2) the associated transportation charge:
    - The assumed storage demand charge is based on a Mist storage expansion project which FEI is currently involved with. FEI's current ACP portfolio includes approximately 115 MMcf/d of Mist storage, out of which up to 50 percent capacity will be recalled by the storage owner NW Natural. FEI is currently participating in an expansion project in order to maintain the same level of Mist capacity in future ACP portfolios. This expansion project does not have additional capacity to replace the required Tilbury send out. FEI is uncertain if another expansion would be feasible at the current Mist facility. Recent study of this incremental project at Mist indicates the transportations charge of moving the Mist supply will be significantly

higher. FEI has used existing tolls for the transportation charges in these avoided cost calculations. In addition, FEI has used the storage demand charge from the North Mist Expansion Project.

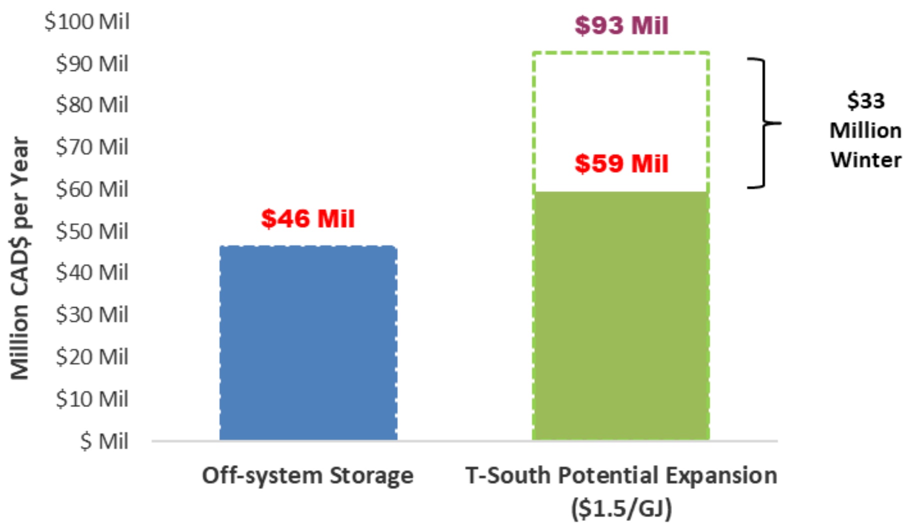
- The associated transportation charge is the cost of obtaining pipeline capacity on Northwest Pipeline (NWP) to deliver gas (by displacement) to FEI's service territory. The expected regional storage cost increase shown in Figure 4-7 above includes transportation charge based on current NWP tolls. However, the regional storage facilities (JPS and Mist) are in the US, and future expansion of either storage facility will also require an expansion on the NWP system because existing transportation capacity required to access these locations is fully contracted and utilized during the winter period. Therefore, if an expansion was required, the costs to upgrade the NWP system would have to be paid by the expansion shippers (i.e., FEI) to NWP. As such, the expansion costs to FEI would be even higher than the current NWP tolls used in FEI's calculation.

- **Expected T-South Toll Increases (Not Used in Financial Analysis):** The T-South toll for the Huntingdon delivery area is currently $0.65/GJ, however:
  - As noted above, the currently planned 2028 T-South Sunrise Expansion is expected to result in tolls of $0.95/GJ, which is a significant increase (46 percent) over the current embedded tolls on T-South.
  - Given the 2028 T-South Sunrise Expansion is only offsetting the incremental demand in the region when Woodfibre LNG comes into service, it would not provide added capacity for replacing the required on-system peaking supply from Tilbury. As such, FEI expects the next expansion after the 2028 T-South Sunrise Expansion will be much more costly, resulting in a further increase from the expected tolls of $0.95/GJ in 2028. FEI's internal hydraulic modeling suggests that a future post-Sunrise expansion of T-South that would provide sufficient capacity and energy to replace FEI's peaking supply would require approximately 200 km of looping. Based on the capital cost of the T-South Sunrise Expansion, FEI estimates that the T-South Long-Haul toll could increase to approximately $1.50/GJ (i.e., a 58 percent increase over the expected toll of $0.95/GJ by 2028) which FEI would have to pay year-round.
  - FEI would expect to continue to seek mitigation for its gas supply costs by selling underutilized pipeline capacity into the market in non-peak times. Based on the observed T-South values between January 2016 and March 2023, FEI assumes a mitigation value of $1.62/GJ for the expected T-South toll increase shown in Figure 4-7 above. FEI also assumed that it would be able to mitigate the T-South capacity at this value for 120 days based on mitigation during the winter period.

Using the same methodology as outlined above and assuming sufficient regional infrastructure upgrades at that time, FEI also estimated the annual gas supply costs to replace the existing 0.6

Bcf and 150 MMcf/d of peaking supply from the existing Tilbury Base Plant by 2035 for the financial analysis of Supplemental Alternatives 4 and 8, both of which would maintain the existing 0.6 Bcf and 150 MMcf/d of regasification. These amounts are shown in Figure 4-8 below, which range from $46 million to $59 million (post mitigation), depending on whether the regional infrastructure upgrade is from a storage facility or pipeline. Similar to the discussion above, FEI used the lower bound of $46 million for the gas supply cost calculations for these two alternatives.

Figure 4-8: Annual Cost (Post Mitigation) of Using Expanded Regional Infrastructure to Supply Equivalent of 0.6 Bcf, 150 MMcf/d



Avoided Costs of Holding Capacity on Expanded Regional Infrastructure

In general, for those supplemental alternatives that do not have on-system LNG storage for peaking gas supply, such as the baseline scenario (i.e., Supplemental Alternative 1), FEI would be relying on a combination of curtailment and regional market supply to meet the peaking gas requirement of 1.0 Bcf and 200 MMcf/d of regasification, thus there would be annual gas supply costs reflected in customers' rates as cost of gas and included in the calculation of total levelized rate impact over the 67-year analysis period. In contrast, for those supplemental alternatives that have on-system LNG storage either fully or partially allocated for gas supply (i.e., 4, 4A, 8, and 9), the annual gas supply costs from off-system regional market would effectively become savings or avoided costs reflected in the calculation of the levelized total rate impact and to the benefit of FEI's customers.

Table 4-11 below summarizes the annual gas supply costs for the baseline scenario (Supplemental Alternative 1) as well as the feasible alternatives that passed the Step 1 and Step 2 screens discussed in Sections 4.3 and 4.4 above (Supplemental Alternatives 4, 4A, 8, and 9). The incremental costs/savings from the baseline scenario (i.e., the avoided costs of holding capacity on expanded regional infrastructure), which are used for the financial analysis are also shown in the table below. Although this section focuses on the results of Supplemental

Alternatives 4, 4A, 8 and 9, FEI has also provided the annual gas supply costs and incremental costs/savings for the remaining supplemental alternatives (i.e., Supplemental Alternative 2, 3, 5, 6, and 7)[183] in Appendix C to this Supplemental Evidence.

As noted above, for the purposes of the financial analysis for all supplemental alternatives, FEI conservatively used the lower annual cost of storage shown in Figures 4-7 and 4-8 above for gas supply costs/savings. Using the higher pipeline costs would have the effect of improving the levelized total rate impact of those supplemental alternatives that meet all of FEI's peaking gas supply requirements (Supplemental Alternatives 4A and 9) relative to those options that do not (Supplemental Alternatives 4 and 8).

Table 4-11: Avoided Annual Gas Supply Costs for Supplemental Alternatives 4, 4A, 8, and 9 ($ millions)

Supplemental Alternatives	Description	Annual Gas Supply Costs ($millions) Present to 2030	2030 to 2035	2035 onwards	Incremental to Baseline / (Avoided Costs) ($ millions) Present to 2030	2030 to 2035	2035 onwards
1	No Capital Upgrades (Continue to rely on existing Base Plant until it fails. No on-system peaking gas supply thereafter and no resiliency reserve)	7.0	7.0	63.0			
4	Like-for-Like Replacement for 0.6 Bcf and 150 MMcf/d (No Resiliency Reserve)	7.0	7.0	17.0	-	-	(46.0)
4A	New 1 Bcf Tank and 400 MMcf/d Regasification (No resiliency reserve)	7.0	-	-	-	(7.0)	(63.0)
8	New 2 Bcf Tank and 800 MMcf/d Regasification (1.4 Bcf resiliency reserve and 0.6 Bcf for peaking gas supply)	7.0	7.0	17.0	-	-	(46.0)
9	New 3 Bcf Tank and 800 MMcf/d Regasification (2 Bcf resiliency reserve and 1 Bcf for peaking gas supply)	7.0	-	-	-	(7.0)	(63.0)

Table 4-11 above demonstrates that having new on-system storage and added regasification at Tilbury would provide significant benefit in terms of avoided gas supply costs from the regional market (assuming expanded regional infrastructure is available in the future).

In summary, Supplemental Alternatives 4 and 8 would partially avoid annual peaking gas supply costs:

- Both of these alternatives would avoid curtailment of firm customers compared to Supplemental Alternative 1 as they can provide more than 150 MMcf/d of regasification. However, both alternatives would still leave FEI with a shortage of energy for peaking supply (i.e., there is still only 0.6 Bcf allocated to gas supply, whereas FEI requires 1 Bcf). As such, from 2030 to 2035, FEI would still incur gas supply costs, estimated to be approximately $7 million post mitigation as discussed above from the regional market to augment the remaining 0.4 Bcf of peaking supply in order to meet the requirement of

[183] The financial analysis was not completed for non-viable Alternatives 10, 11, and 12.

having an optimized portfolio of 200 MMcf/d and 1.0 Bcf of peaking supply. This results in no avoided costs for Supplemental Alternatives 4 and 8 from 2030 to 2035.

- For 2035 and onwards, given both Supplemental Alternatives 4 and 8 would include on-system LNG storage with gas supply allocation of 0.6 Bcf and 150 MMcf/d, FEI's customers would avoid annual gas supply costs from the expanded regional infrastructure for the equivalent amount of supply that could range from $46 million to $59 million as shown in Figure 4-8 above (conservatively using the lower end of $46 million for the purpose of the financial analysis).
- However, since both of these alternatives would only have 0.6 Bcf for gas supply purposes, they still require FEI to hold peaking gas supply capacity from regional infrastructure from 2035 onwards for the remaining 0.4 Bcf in order to meet the optimized portfolio requirement. As such, the avoided gas supply costs for Supplemental Alternatives 4 and 8 would be less than the avoided gas supply costs for Supplemental Alternative 4A and 9 as shown in Table 4-11 above.

In contrast, Supplemental Alternatives 4A and 9 would avoid all annual peaking gas supply costs:

- Since Supplemental Alternatives 4A and 9 would have 1 Bcf and at least 200 MMcf/d of regasification at Tilbury for peaking gas supply purposes, there is no need to incur additional gas supply costs, thereby avoiding the tolls from the regional market estimated to be approximately $7 million from 2030 to 2035.
- As reflected in the financial analysis, the additional 50 MMcf/d and 0.4 Bcf provided by Alternatives 4A and 9 creates the flexibility to shed other supply resources in the ACP, all else equal.
- For 2035 and onwards, given Supplemental Alternatives 4A and 9 include on-system LNG storage with gas supply allocation that already meet the optimized portfolio of 1.0 Bcf and more than 200 MMcf/d of regasification, FEI's customers would avoid annual gas supply costs from the expanded regional infrastructure for the equivalent amount of supply that could range from $63 million to $79 million[184] as shown in Figure 4-7 above (conservatively using the lower end of $63 million for the purposes of the financial analysis).

[184] In September 2021, in the response to BCUC IR1 46.2 (Exhibit B-15), FEI estimated that the financial value to customers of the "third Bcf" (i.e., the storage available in a 3 Bcf tank over and above the 2 Bcf retained as a resiliency reserve) combined with the proposed regasification capacity was approximately $30 million per year. FEI estimated this value based on the T-South market value in 2021 net of winter mitigation revenue, which was close to the 2021 T-South toll for 365 days a year. That is, by having 1 Bcf of LNG available, FEI would be avoiding $30 million in annual pipeline tolls. FEI explained that this calculation understated the benefits by virtue of being based on the assumption that FEI was only avoiding the T-South embedded toll, whereas in reality FEI would need to pay a premium. As discussed in Section 3.3.2.3. of this Supplemental Evidence, there have been several market changes since 2021 including: (1) Woodfibre making a final investment decision; (2) WEI's new T-South expansion project (i.e., the T-South Sunrise Expansion) was fully contracted; and (3) the winter of 2022/23 showed market participants that the costs for energy in western North America are high due to, for instance, gas-fired electricity demand and coal plant retirements. FEI's Supplemental Evidence financial analysis reflects these significant market developments.

4.5.4.2 Summary of Levelized Total Rate Impact Results for the Four Feasible Supplemental Alternatives (4, 4A, 8 and 9)

In summary, for the criterion of comparing the Levelized Total Rate Impact over the expected life of the assets of each feasible Supplemental Alternative (4, 4A, 8, and 9), the results confirm that it makes financial sense for customers to build for more gas supply capabilities than currently provided by Tilbury in order to meet FEI's full peaking supply requirements of 200 MMcf/d and 1.0 Bcf. Although Supplemental Alternative 4A would have the lowest levelized total rate impact out of the four feasible supplemental alternatives, it would only be sized for meeting FEI's peaking supply requirements in an optimal manner, whereas Supplemental Alternative 9 will be able to provide the required peaking supply in an optimal manner while also significantly mitigating customer outage risk.

The results of the financial analysis indicate the following:

- **Supplemental Alternative 4** would be the smallest facility (offering the same peaking gas supply capabilities installed in 1971 with no resiliency reserve), and yet would not have the lowest total rate impact. It would have a lower capital cost; however, it would necessitate FEI continuing to supplement its undersized LNG peaking supply with an additional 50 MMcf/d and 0.4 Bcf from the market at a cost of $7 million to $17 million annually.
- **Supplemental Alternative 4A** would have the lowest levelized total rate impact of the four alternatives because it is sized to provide the optimum amount of peaking gas supply, without mitigating FEI's largest customer outage risk. It would have a higher capital cost than Supplemental Alternative 4 because it is a larger facility; however, its larger gas supply reserve and expanded regasification capacity would avoid Supplemental Alternative 4's annual gas supply costs.
- **Supplemental Alternative 8** would have the highest levelized total rate impact of any of the four alternatives, despite its 2 Bcf tank being one-third smaller than that of Supplemental Alternative 9. Its levelized total rate impact would be highest because: (1) the difference in capital cost between a 2 Bcf tank and a 3 Bcf tank is relatively small due to economies of scale; and (2) as with Supplemental Alternative 4, Supplemental Alternative 8 would require FEI to continue to acquire an additional 50 MMcf/d and 0.4 Bcf of peaking resources from the market at a cost of $7 million to $17 million annually.
- **Supplemental Alternative 9**, the largest facility, will optimize the gas portfolio like Supplemental Alternative 4A, while also optimizing the risk mitigation against a winter T-South no-flow event. The levelized total rate impact is higher than Supplemental Alternatives 4 and 4A (which do not provide resiliency), but lower than Supplemental Alternative 8 (which would provide less resiliency and less gas supply). As explained in Section 4.5.4.1.1, the economies of scale are very significant up to a 3 Bcf tank, and FEI would avoid the need to incur annual peaking supply costs in the market to provide the required supply.

Table 4-12 below also provides the risk reduction per dollar of rate impact between Supplemental Alternatives 4, 4A, 8, and 9 based on the risk reduction values from Exponent's analysis at average winter conditions.[185]

Table 4-12: Risk Reduction per Dollar of Rate Impact

Parameter	Supplemental Alternative 4	Supplemental Alternative 4A	Supplemental Alternative 8	Supplemental Alternative 9
(1) 67-Year Expected GDP Loss Reduction ($millions)	-	-	10,877	11,093
(2) Total PV of Cost of Service ($millions)	424	375	768	723
Ratio (1)/(2)	-	-	14.2	15.3

As demonstrated in the table above, Supplemental Alternative 9 offers a lower cost than Supplemental Alternative 8, and greater risk reduction per dollar spent than Supplemental Alternatives 4, 4A, or 8.[186]

4.5.5 Future Use Scoring Criterion

In the Adjournment Decision, the BCUC identified a need for FEI to further consider the potential for the transition towards a lower carbon future to affect the appropriate sizing of the TLSE Project.[187] FEI's "Future Use" criterion evaluates the degree to which an alternative will be useful for FEI's own resiliency and gas supply portfolio (i.e., to serve load or generate mitigation revenue), and its potential to be underutilized.

FEI acknowledges the uncertainty in forecasting future load over a long period of time. To that end, as discussed in this section, FEI has assessed the future use for the viable Supplemental Alternatives (4, 4A, 8 and 9) using two hypothetical adverse load sensitivities that modify FEI's DEP Scenario from the 2022 LTGRP. Specifically, these sensitivities reflect significant hypothetical customer losses in the Lower Mainland of 2 percent and 5 percent per year between 2030 and 2050 (the "modified DEP" sensitivities are abbreviated as mDEP 2% and 5%).

Even under the most adverse hypothetical sensitivity (mDEP 5%), FEI would still be serving hundreds of thousands of customers in the Lower Mainland in 2050. Customers in the Lower Mainland and FEI's other service areas would still need peaking supply. The Lower Mainland would (absent mitigation) still be exposed to a significant customer outage – with all of the

[185] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, Section 8.3, Table 9.

[186] The resiliency performance of Supplemental Alternative 9 at temperatures below the average winter temperature is not captured in Table 4-12. At colder temperatures, specifically between to -6.8°C to +1.7°C, the difference in the value ratio for Supplemental Alternatives 8 and 9 is expected to be much larger.

[187] Adjournment Decision, p. 52. "Further, if the throughput of natural gas is reduced due to a decrease in demand, the size of a tank and the amount of regasification required would likely be reduced." And p. 22: "The larger tank provides flexibility to accommodate future load growth that may occur. However, given the current emphasis on electrification and decarbonization in BC, it is unclear whether FEI will experience significant, or even any, future natural gas load growth. The larger tank means greater risk of a stranded, or partially stranded, asset in the event that FEI's increased load does not emerge or decreases beyond the current load."

associated social, human health and economic consequences – following a no-flow event on T-South.

The hypothetical adverse load loss sensitivities illustrate how an on-system LNG facility is a unique asset when it comes to the flexibility afforded in response to changing load. There would be a spectrum of choices available to FEI in terms of how to reallocate the tank as between a resiliency reserve and gas supply:

- One end of the spectrum would be to maximize resiliency, for instance by maintaining the same resiliency reserve to achieve progressively more customer outage risk reduction. The resiliency value of on-system LNG increases if load declines (other things equal) because the facility will support less load for a longer period of time following a no-flow event. There is still residual risk with any of the Supplemental Alternatives at the current load. FEI's system modelling and Exponent's risk calculations indicate that a longer load support duration under hypothetical reduced load sensitivities would be valuable for the remaining customers in 2050.
- On the other end of the spectrum, for Supplemental Alternatives that provide a resiliency reserve from the outset, FEI could progressively reallocate some of the resiliency reserve to gas supply. FEI could maintain a consistent level of risk mitigation over time, while realizing additional gas supply benefits for all FEI customers. FEI reoptimizes its ACP portfolio annually based on the available supply options. The additional LNG available for gas supply could provide optionality in future gas supply portfolio by either replacing other gas supply resources or displacing other peaking supply[188] that is exposed to potential commodity price spikes on cold days.

In either case, customers receive value from the TLSE Project. As a result, all four of the viable Supplemental Alternatives (4, 4A, 8 and 9) received the same score, "No impact", reflecting that stranding risk does not increase relative to retaining the existing Base Plant with no capital upgrades (Supplemental Alternative 1), which is not viable.

4.5.5.1 Defining Usefulness vs. Underutilization: Whether the Alternative Provides Excessive Resiliency or Gas Supply

FEI considered two illustrative "book-end" approaches to reallocating the TLSE Project's capabilities in the face of hypothetical declining load – resiliency maximization and resiliency retention. The focus of the future use analysis was to determine whether, under either "bookend" approach, FEI's customers would be faced with underutilized resiliency capability or underutilized gas supply capability in 2050 based on the mDEP (2% and 5%) adverse sensitivities.

[188] FEI's gas supply portfolio includes commercial arrangements (i.e., peaking call options), which are priced based off a daily index. Gas prices generally increase when the region experiences a cold weather event. Having additional on-system LNG allows gas supply to displace the peaking supply received from the market and reduce the costs to customers.

- For the **resiliency maximizing strategy**, FEI determined the load support duration under average winter conditions using the 2050 Year mDEP (2% and 5%) load scenario and maintaining the current resiliency and gas supply allocations defined for each alternative; and
- For the **resiliency retention strategy**, FEI determined the resiliency reserve volume required such that, using the 2050 Year mDEP (2% and 5%) load scenario, the alternative would provide the same support duration as under current year load. As this would result in a lower resiliency reserve volume, and thus a larger gas supply reserve volume, this approach assessed if a Supplemental Alternative would be underutilized for gas supply.

FEI and Exponent modelled Supplemental Alternatives 8 and 9, since they would be the largest facilities and any smaller facilities would necessarily be useful if the largest facilities are useful. Alternatives 4 and 4a were not included in this analysis because they are significantly smaller than 8 and 9. If the larger alternatives prove to be useful under a future scenario, then both the smaller alternatives would also be useful. The system results of each "bookend" strategy are set out in Sections 4.5.5.3 and 4.5.5.4 below.

4.5.5.2 Approach and Inputs for mDEP Hypothetical Adverse Sensitivities

FEI's hypothetical adverse sensitivities modified FEI's DEP Scenario from the 2022 LTGRP in the manner described below to estimate the customer numbers, and annual and peak load from 2024 to 2050. FEI then used the results from these hypothetical mDEP sensitivities in transient modelling, as described in Section 3, to determine how many days of load support a 2 Bcf and 1.4 Bcf resiliency reserve would provide in 2050. This also informed how much of the 2 Bcf and 1.4 Bcf resiliency reserves could be re-allocated to FEI's gas supply portfolio.

4.5.5.2.1 2050 Customer Count in Hypothetical Adverse Scenarios

Starting with the DEP Scenario, which includes FEI's core customers in Rate Schedules (RS) 1 to 5 and 7 in the Lower Mainland, FEI adjusted the customer count for these hypothetical adverse sensitivities as follows:

- FEI adjusted the customer count downward by 40,000 which is the approximate number of customers (categorized as Lower Mainland in the DEP Scenario) that FEI serves who are east of FEI's interconnection with T-South (Huntingdon). FEI made this adjustment because gas resiliency at Tilbury would not directly benefit these customers because FEI cannot flow gas eastward into T-South at Huntingdon.
- FEI assumed that new residential and commercial customers would continue to connect to FEI's gas distribution system until the year 2030. After 2030, commencing in 2031, FEI assumed it would stop adding new customers and residential and commercial customers would begin to decrease by either 2 percent or 5 percent per year. The 2 percent decline assumption (mDEP 2%) is a modification from the DEP Scenario, but is in line with the estimated demolition rate provided in FEI's 2022 LTGRP (Appendix C-1 to the 2022

LTGRP, page 34). FEI considers the 5 percent assumption (mDEP 5%) to be an extreme hypothetical sensitivity.

- FEI did not adjust the number of industrial customers, which account for approximately 0.1 percent of FEI's customers and approximately 30 percent of FEI's load.
- FEI did not include volumes of gas associated with RS 23 or 25 in the Lower Mainland. The results are therefore understated given that RS 23 and 25 are firm delivery; however, they buy their gas from a third party where FEI takes possession at its interconnections with upstream pipelines.

Figure 4-9 below shows the 2050 customer results of the hypothetical sensitivity using a 2 percent annual decrease in customers (mDEP 2%). FEI would still be serving approximately 400,000 customers in the Lower Mainland in 2050.

Figure 4-9: Lower Mainland 2050 Customers at 2 Percent Customer Decrease Per Year (mDEP 2% Adverse Sensitivity)

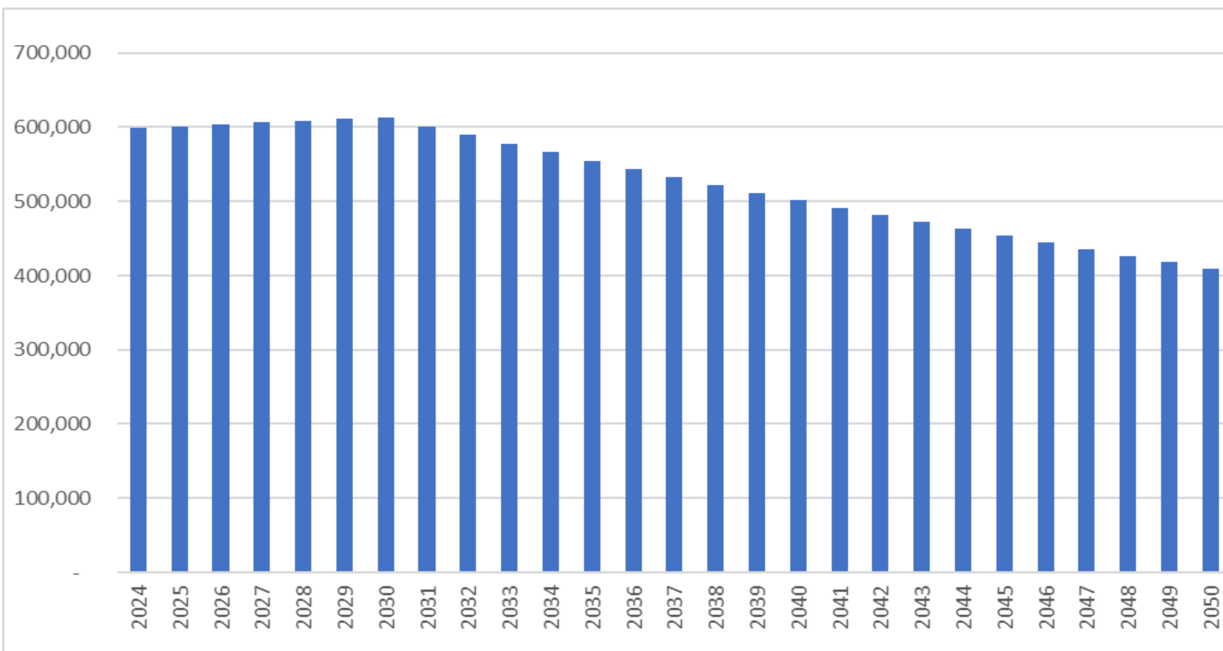
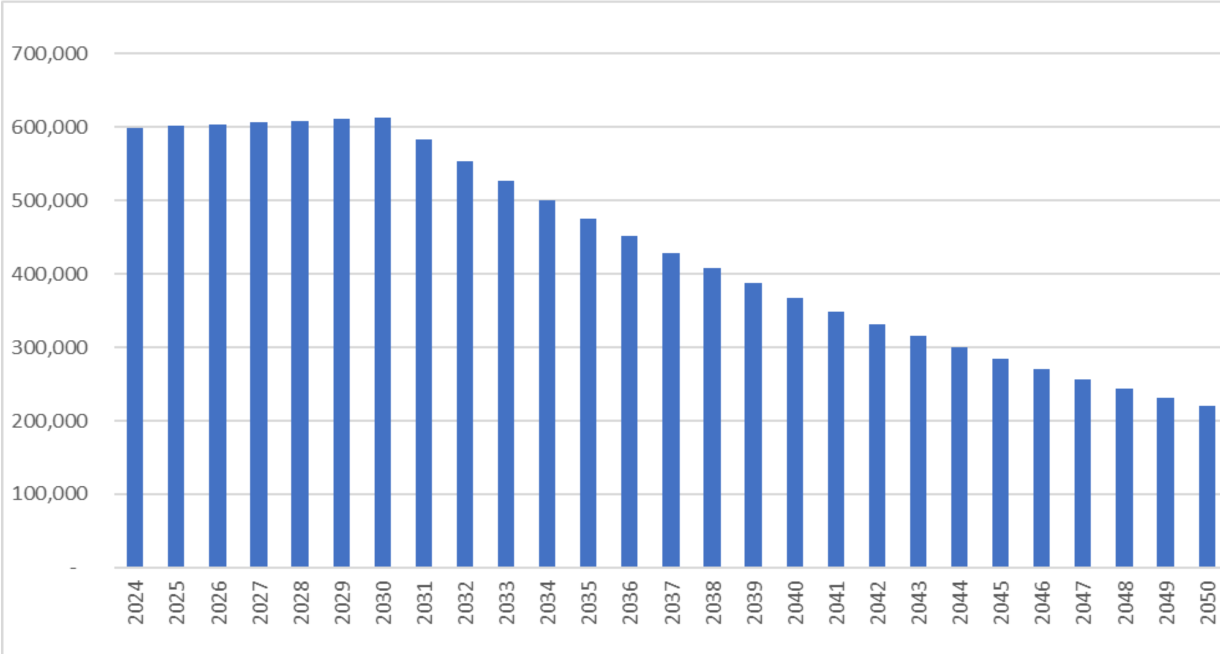


Figure 4-10 below shows that, even hypothetically assuming an extreme 5 percent customer decrease per year starting in 2031, FEI would still be serving approximately 220,000 customers in the Lower Mainland in 2050.

Figure 4-10: Lower Mainland 2050 Customers at 5 Percent Customer Decrease Per Year (mDEP 5% Adverse Sensitivity)

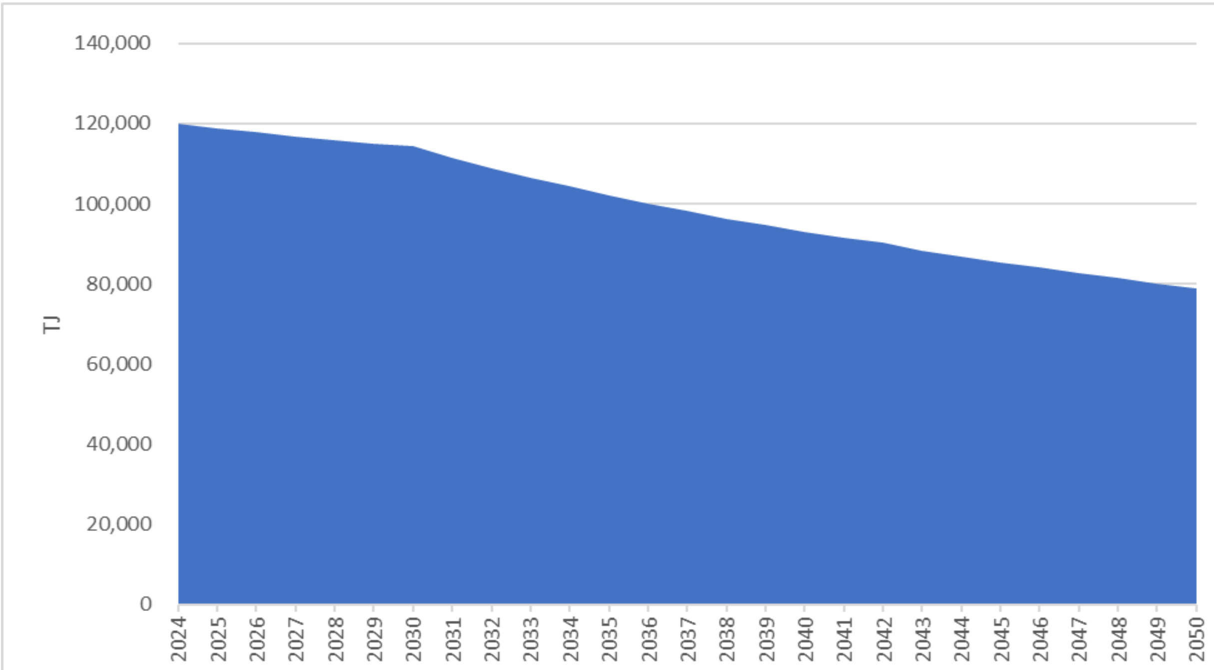


4.5.5.2.2 2050 ANNUAL LOAD IN HYPOTHETICAL ADVERSE SENSITIVITIES

FEI's two hypothetical adverse mDEP (2% and 5%) sensitivities use the use per customer (UPC) included in the DEP Scenario, which includes UPCs to 2042. FEI trended UPC to 2050 using the prior 10 years of forecast UPC from the DEP Scenario (2033 – 2042) and then multiplied the UPCs by the number of customers as discussed above, resulting in an estimated Lower Mainland load to 2050.

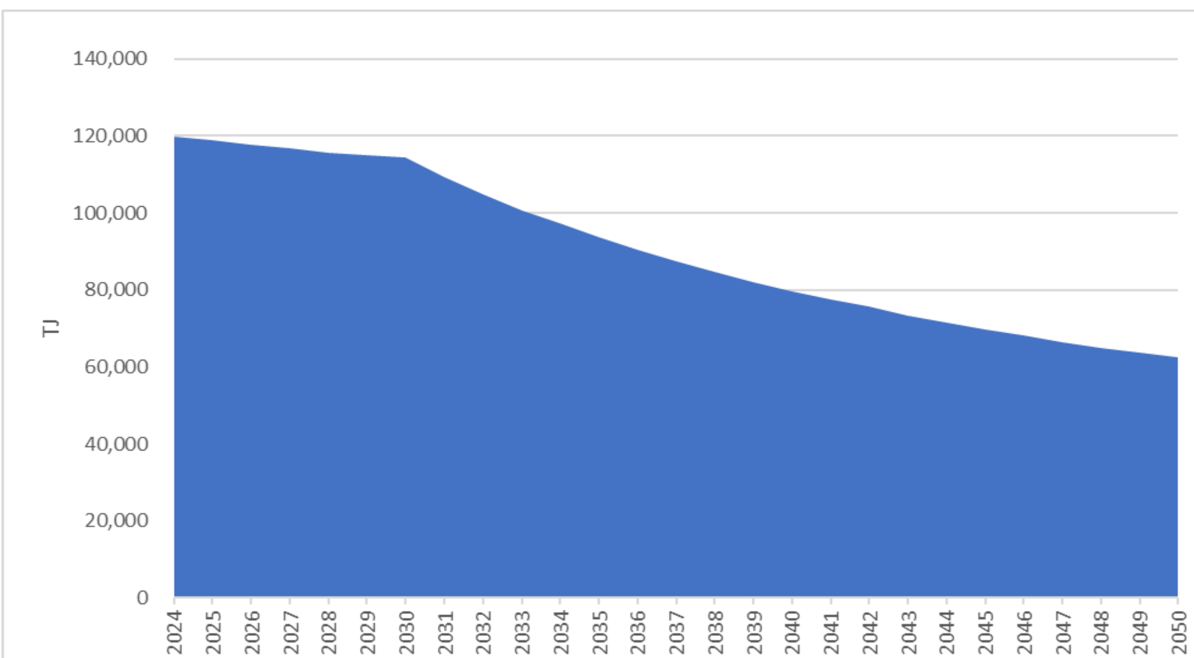
As shown in Figure 4-11 below, FEI's load in the Lower Mainland would still be substantial at 80 PJ under the mDEP 2% sensitivity.

Figure 4-11: Lower Mainland 2050 Gas Load at 2 Percent Customer Decrease Per Year (mDEP 2% Adverse Sensitivity)



When FEI uses a 5 percent customer decrease per year starting in 2031 (mDEP 5%), the Lower Mainland load would be approximately 60 PJ per year, or approximately half of the 2024 level.

Figure 4-12: Lower Mainland 2050 Gas Load at 5 Percent Customer Decrease Per Year (mDEP 5% Adverse Sensitivity)



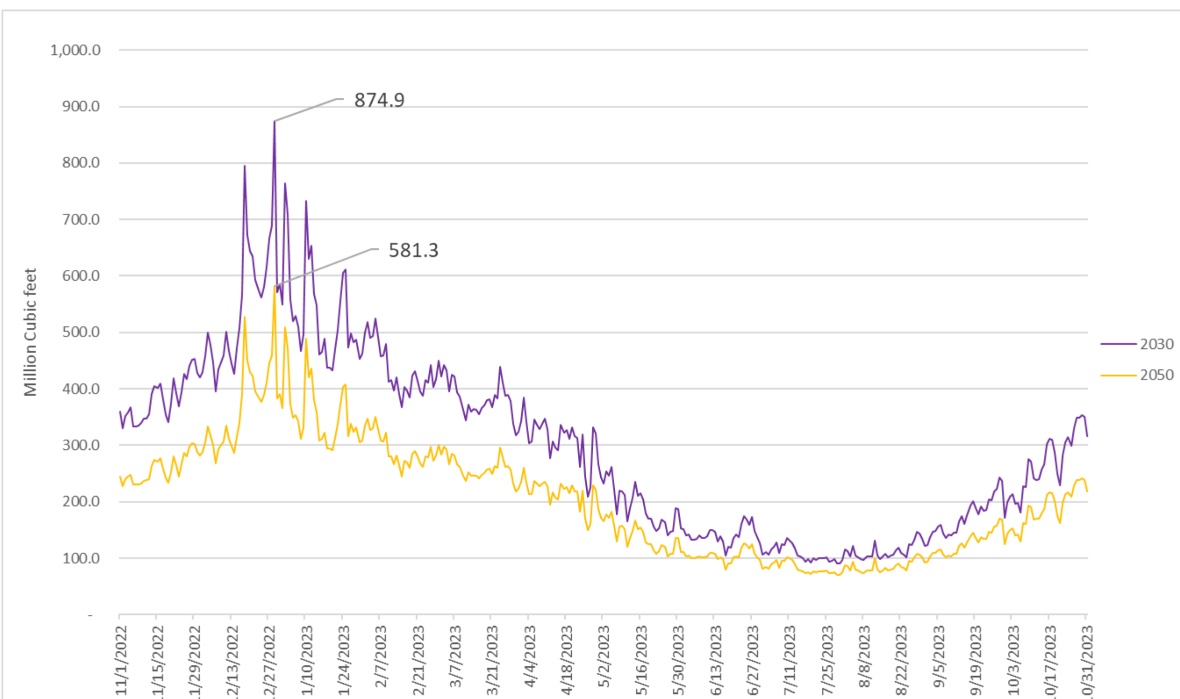
4.5.5.2.3 2050 PEAK DEMAND IN HYPOTHETICAL ADVERSE SENSITIVITIES

FEI used the same transient modelling process described in Section 3 of this Supplemental Evidence to determine how long a 2 Bcf resiliency reserve at Tilbury would last following a winter T-South no-flow event in a hypothetical future where there are fewer customers and lower load in the Lower Mainland. As the risk being addressed is a winter no-flow event, the transient modelling requires a load duration curve for mDEP 2% and 5% that shows FEI's load profile throughout the year. FEI prepared the load duration curve in the manner described below.

FEI started with the Lower Mainland's year 2041 load duration curve (LDC) developed for FEI's 2024/25 ACP so that FEI could consider what resources it may require in the future by matching resources with the characteristics of FEI's demand. FEI further trended the LDC from 2042 to 2050. As with the UPCs described above, FEI trended each day's demand to 2050 using the prior 10 years of forecast (2032 to 2041). In order to apply the LDC (trended to 2050), which does not account for a per year loss in residential and commercial customers from 2031 onward, FEI used the trended LDC to proportion the annual load, as determined above, across 365 days.

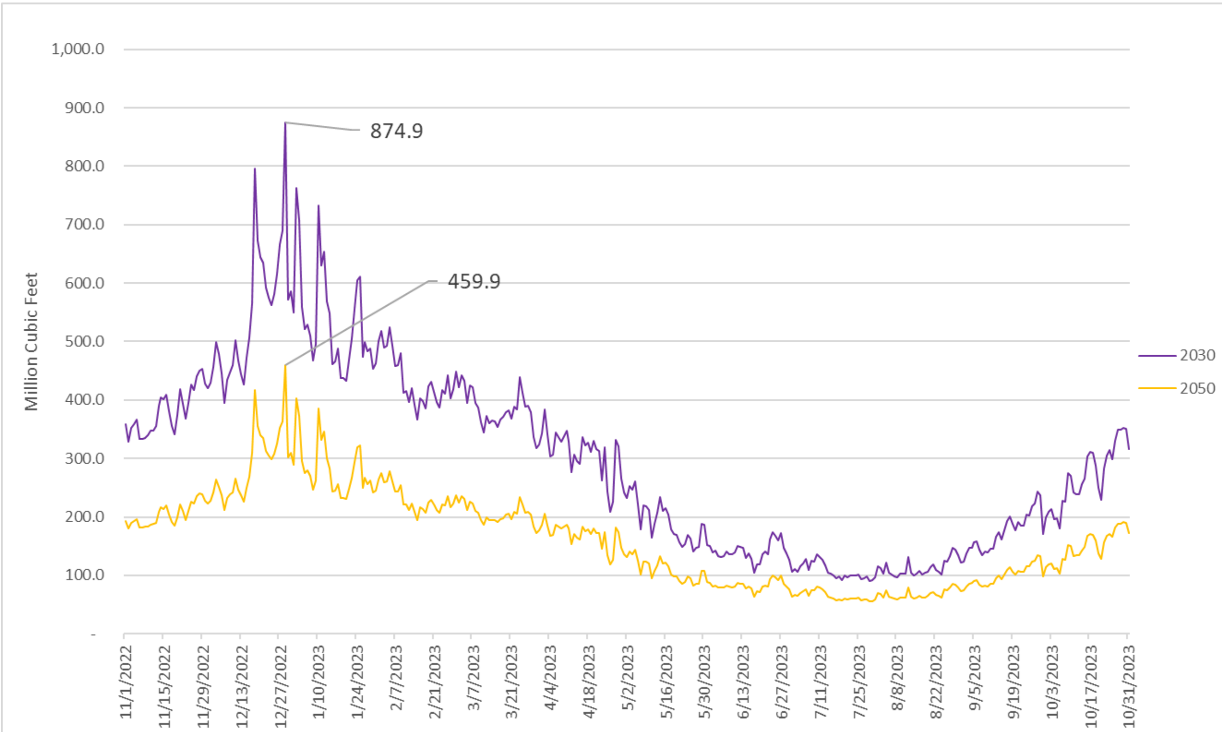
Figure 4-13 shows the load duration curve over the gas year for 2030 and 2050 under the mDEP 2% sensitivity. The peak day demand for the mDEP 2% sensitivity would be 874.9 MMcf/d in 2030 and 581.3 MMcf/d in 2050.

Figure 4-13: Lower Mainland Load Duration Curve 2030 & 2050 Showing Peak Day Demand Assuming 2% Per Year Customer Decrease (mDEP 2% Adverse Sensitivity)



Assuming a 5 percent per year decrease in customers (mDEP 5%), which FEI considers to be an extremely adverse hypothetical sensitivity, the peak day demand would fall to 459.9 MMcf/d in 2050.

Figure 4-14: Load Duration Curve 2030 & 2050 Showing Peak Day Demand Assuming 5% Per Year Customer Decrease (mDEP 5% Adverse Sensitivity)



4.5.5.3 Option of Maximizing Resiliency in 2050 Would Still Be Providing Significant Risk Mitigation Under Adverse Sensitivities

As noted previously, there is a spectrum of potential approaches that FEI could take over time in response to changing load. The resiliency maximization approach is one potential strategy that represents a "bookend" on the spectrum. Under this strategy, each Supplemental Alternative would provide a longer load support duration in 2050 under the two adverse load loss sensitivities when compared to the current load. However, none of the Supplemental Alternatives would be underutilized for resiliency under a resiliency maximization strategy. As discussed below, the load support duration for the largest facility under the most adverse load loss sensitivity would be akin to what is provided by Mt. Hayes on Vancouver Island today (assuming it has LNG volumes available for resiliency in the event of a supply outage). This translates into a meaningful and valuable customer outage risk reduction in 2050.

4.5.5.3.1 FEI USED TRANSIENT MODELLING TO DETERMINE HOW LONG THE SAME RESILIENCY RESERVE WOULD SUPPORT LOAD IN 2050

FEI undertook the same type of transient modelling described in Section 3 of this Supplemental Evidence to determine the load support duration for the Lower Mainland at average winter temperatures (+4°C), assuming 2 Bcf and 1.4 Bcf resiliency reserves at Tilbury (i.e., Supplemental Alternatives 9 and 8, respectively) with consideration for the lower number of customers and the estimated change in peak load. FEI focused on these two alternatives as they have the largest resiliency reserves and longest load support durations.

The table below sets out the assumed number of customers in 2050, the estimated annual demand, the estimated daily demand under average winter conditions (+4°C), and the duration of load support that a 2 Bcf and 1.4 Bcf resiliency reserve at Tilbury would provide to the Lower Mainland under the two hypothetical mDEP (2% and 5%) sensitivities.[189] As shown in the table, the load support duration increases as customers and load decrease. That is, with sufficient regasification capacity in place from the outset, the same volume of LNG would be expected (other things being equal) to serve reduced load for a longer period of time following a winter no-flow event.

Table 4-13: Resiliency Reserve Support Under Two Hypothetical Customer Loss Sensitivities

Parameter	2050 mDEP (2%)	2050 mDEP (5%)
Lower Mainland Customers	409,831	220,395
Annual Throughput (TJ)	78,847	62,380
Lower Mainland Load +4°C (MMcf/d)	406	321
Supplemental Alternative 8 Lower Mainland Support Duration +4°C	7 days and 19 hours	9 days and 20 hours
Supplemental Alternative 9 Lower Mainland Support Duration +4°C	10 days and 20 hours	13 days and 14 hours

The transient modelling outputs for Supplemental Alternative 9, which is the largest facility among all viable alternatives, are shown in Figures 4-15 and 4-16 below.

189 To perform this analysis FEI had to reduce the number of customers within its system planning models. FEI assumed that the change in customers, related to these two hypothetical sensitivities, occurred proportionately across its system in the Lower Mainland.

Figure 4-15: Impact to Lower Mainland due to Loss of T-South Supply with 2% per Year Customer Loss (mDEP 2% Adverse Sensitivity)

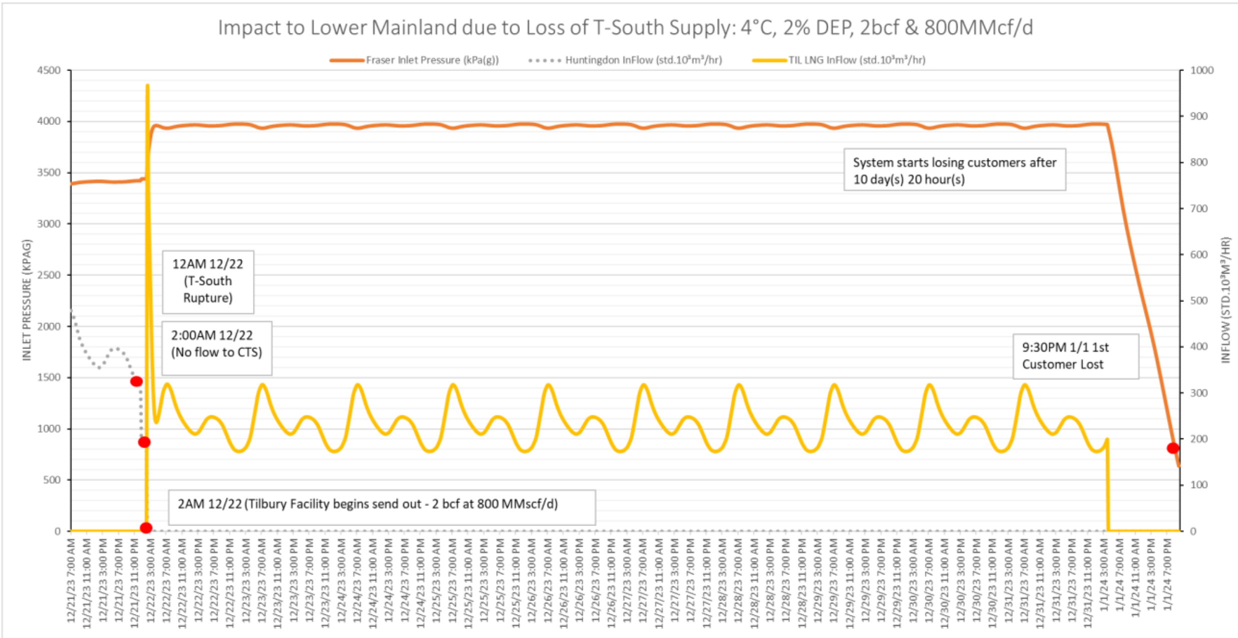
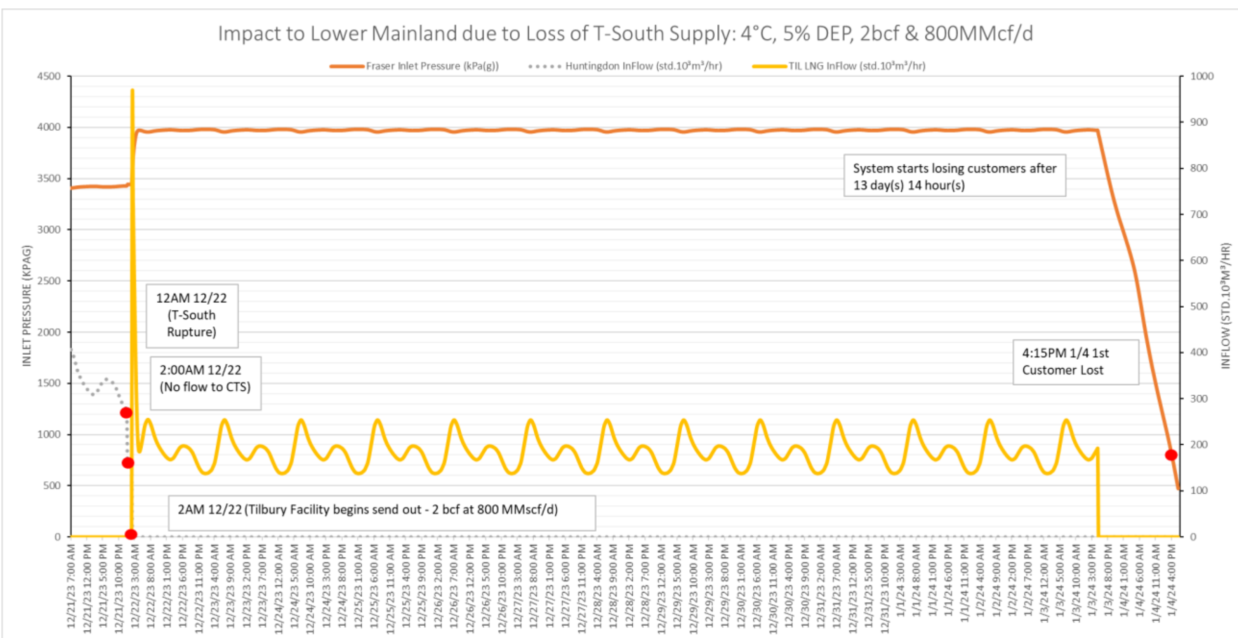


Figure 4-16: Impact to Lower Mainland due to Loss of T-South Supply with 5% per Year Customer Loss (mDEP 2% Adverse Sensitivity)



As long as there is sufficient regasification capacity, under average winter conditions, 2 Bcf of LNG earmarked for resiliency will initially (i.e., upon commissioning) allow FEI to maintain service to 100 percent of firm Lower Mainland customers for approximately 4.5 days. If the peak load in the Lower Mainland were to decline, as calculated with the 5 percent customer reductions sensitivity (mDEP 5%), the same 2 Bcf resiliency reserve could support the load for approximately 13.5 days.

As discussed in the Exponent Report, there are various modes of failure that could result in a no-flow event longer than 4.5 days.[190] Some of those modes of failure (e.g., flooding) are events that could increase in likelihood with climate change. Continuing to have access to the same resiliency reserve decreases the potential for catastrophic social, health and economic harm to result from those modes of failure.

By 2050, the support duration provided by Supplemental Alternatives 8 and 9 under the mDEP (2% and 5%) adverse load sensitivities would increase to be more in line with the support currently provided by Mt. Hayes LNG to Vancouver Island customers. The longest load support duration under the most adverse hypothetical sensitivity (mDEP 5%) is 13 days and 14 hours, associated with Supplemental Alternative 9. This duration is useful given the range of no-flow events considered in the 2024 Resiliency Plan (i.e., the load support duration does not increase to the level of surpassing the no-flow durations considered in the analysis).

While customers and load/peak load decrease, there would still be 220,000 – 410,000 customers left in the Lower Mainland in 2050 under the hypothetical adverse sensitivities (respectively, mDEP 5% and 2%). All of these customers would lose service if a T-South no-flow event occurred. In the intervening years between when the TLSE Project is constructed and 2050, the Project would be providing resiliency support for hundreds of thousands of customers in the Lower Mainland. These customers would all be exposed to the significant social, health and economic impacts.

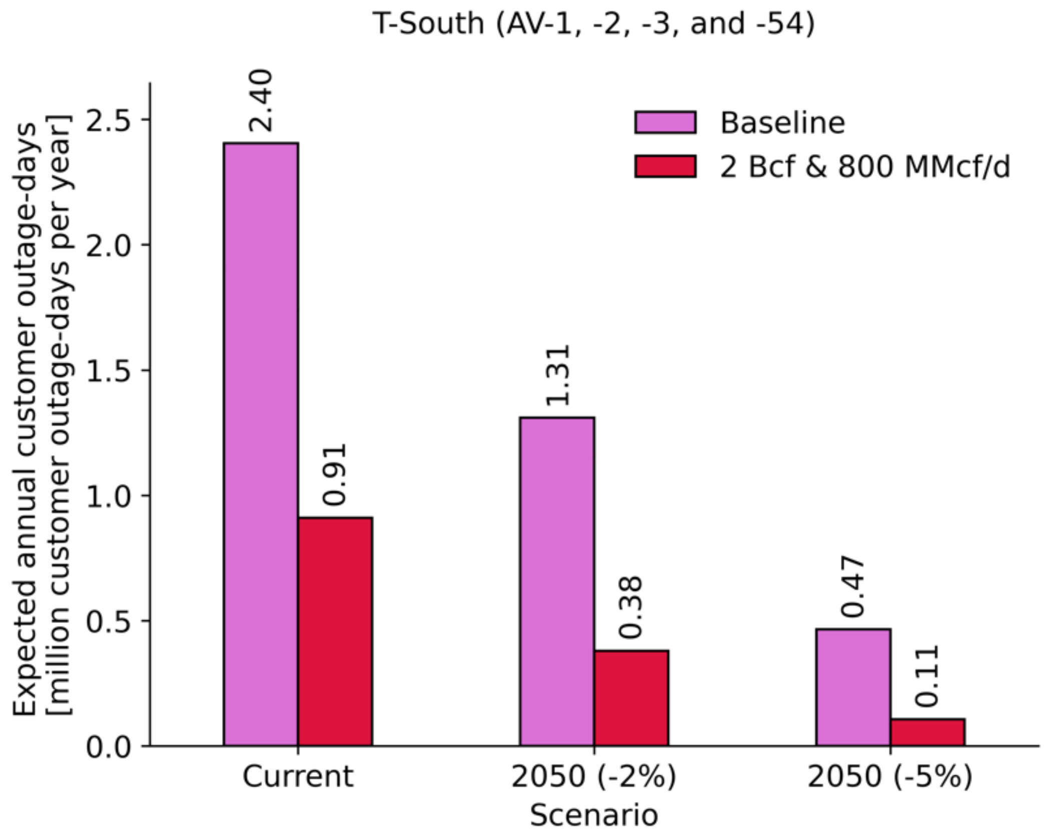
4.5.5.3.2 EXPONENT'S 2050 RISK CALCULATIONS SHOW SIGNIFICANT RISK MITIGATION

Exponent calculated the risk mitigation provided in 2050, measured by customer outage-days, using the parameters of the two hypothetical sensitivities (mDEP 2% and 5%). As shown in the following figure, the risk mitigation benefit for customers is material relative to the baseline.[191] For this purpose, the baseline represents the scenario where there is no available LNG volume at Tilbury for resiliency use and no linepack. To simplify the analysis, FEI instructed Exponent to consider only the impact to the Lower Mainland due to a T-South failure (i.e., customers that would be impacted by a T-South failure in other regions such as Vancouver Island and the Interior are not included in this specific analysis).

[190] Refer to Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, Report Appendix U, Table U.3 for the no-flow durations considered in the 2024 Resiliency Plan.

[191] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, Report Appendix X, Figure X.4.

Figure 4-17: Expected Annual Customer Outage-Days With and Without Mitigation from TLSE Project – Current and Hypothetical Future Adverse Load Sensitivities (mDEP 2% and 5%)



4.5.5.4 Resiliency Retention Strategy – Reallocating Part of Resiliency Reserve to Gas Supply Would Avoid More Gas Supply Costs in 2050

As discussed above, if load declines, FEI could elect to retain the initial level of resiliency and reallocate some of the resiliency reserve to gas supply. The allocation of more of the tank to the gas supply portfolio would create opportunities for FEI to optimize its gas supply portfolio for the benefit of customers. These benefits could come from substituting LNG for other resources or generating mitigation revenue by making peaking supply available in the market.

FEI also used transient modelling to determine what size of Tilbury resiliency reserve would be required in 2050 under the adverse load loss scenarios to maintain the same support duration of 4.5 days (at average winter temperatures) for the approximately 600,000 customers currently in the Lower Mainland. Table 4-14 shows the results, along with how much LNG would then be available for gas supply if that approach was taken.

Table 4-14: LNG Volume Required Under the 2050 mDEP (2% and 5%) Load – Resiliency Retention Approach (i.e., Maintain Equivalent Support Duration as Current Year)

Parameter	Alternative 8	Alternative 9
Support Duration Under Current Load +4°C	3 days and 8 hours	4 days and 13 hours
Current Load Resiliency Reserve Volume	1.4 Bcf	2.0 Bcf
Current Load Gas Supply Volume	0.6 Bcf	1.0 Bcf
Target Support Duration Under 2050 mDEP (2%) Load Sensitivity +4°C	3 days and 8 hours	4 days and 13 hours
2050 mDEP (2%) Load Sensitivity – Required Resiliency Reserve to Achieve Target Support	0.53 Bcf	0.76 Bcf
2050 mDEP (2%) Load Sensitivity – Resulting Gas Supply Volume	1.47 Bcf	2.24 Bcf
Target Support Duration Under 2050 mDEP (5%) Load Sensitivity +4°C	3 days and 8 hours	4 days and 13 hours
2050 mDEP (5%) Load Sensitivity– Required Resiliency Reserve to Achieve Target Support	0.39 Bcf	0.58 Bcf
2050 mDEP (5%) Load Sensitivity– Resulting Gas Supply Volume	1.61 Bcf	2.42 Bcf

The largest gas supply allocation under the most adverse hypothetical sensitivity (mDEP 5%) is 2.42 Bcf and is associated with Supplemental Alternative 9. As explained below, the gas supply volume is considered useful because FEI has opportunities to optimize its portfolio by substituting this volume for other contracted resources in FEI's supply portfolio, or at a minimum by selling peaking supply in the market to generate mitigation revenue. The volume is less than the established market demand volume of 3 to 4 Bcf.[192] Given that the 2.42 Bcf available for gas supply in Supplemental Alternative 9 will be useful in the future, the smaller Supplemental Alternatives would also be useful.

4.5.5.4.1 ON-SYSTEM LNG CAN SUBSTITUTE FOR OTHER SUPPLY RESOURCES DURING ANNUAL SUPPLY PORTFOLIO OPTIMIZATION

FEI conducts portfolio optimization annually to provide an outlook for future resource requirements. Maximizing the utilization of the TLSE Project would provide FEI with valuable supply portfolio flexibility, allowing it to adjust other elements of its supply portfolio to meet the shifting load profile, and is supported by the expert evidence of Raymond Mason.

The objective of the portfolio optimization process is to develop a cost-effective portfolio to meet FEI's design load, which helps FEI to contract supply, transportation and storage capacities with the resources available in the region. The outcomes of the portfolio optimization help FEI to adjust the resource mix by including new resources or de-contracting resources that are no longer required. One of the key objectives of the portfolio is to have flexibility in the resource mix and contract terms over time. For example, some of FEI's storage service agreements have short

[192] Refer to Appendix F, Raymond Mason Report, pp. 6 and 36.

terms, which require FEI to negotiate renewals after a few years. The flexibility in resource mix and contract terms facilitates adjusting the resources over time to match changing customer demand and/or the resources available in the marketplace.

For context, 1 Bcf could compensate for approximately 20 percent of FEI's current off-system storage holdings. As noted in Table 4-14 above, the largest gas supply allocation under the most adverse hypothetical sensitivity (mDEP 5%) is 2.42 Bcf and is associated with the Supplemental Alternative 9. FEI expects it will be able to make use of the remainder under even the largest of the Supplemental Alternatives for gas supply portfolio purposes by adjusting other resources holdings as they come up for renewal given the different contract terms within the portfolio.

Mr. Mason also noted the potential for resource substitution within the gas supply portfolio if the demand profiles of FEI's customers were to shift over time (i.e., lowering annual demand while maintaining the need for winter supply).[193] Resource substitution within FEI's portfolio can be attractive because of the favourable attributes of on-system LNG in normal operations, described by Mr. Mason as follows:[194]

> On-system peaking resource(s) must be able to provide (at a minimum) continuous availability to bridge any gaps in winter weather events. As such, in anticipation of a forecasted weather event, a peaking resource can remain idle (i.e., operational ready to deploy gas supply) while actual weather unfolds and can typically be ramped up within hours. This operational flexibility enhances the assets value compared to an alternate resource that requires 24-hours notice to be deployed (e.g., off-system storage and mainline transportation) or if there is an unplanned operational mainline transportation disruption. For example, when a utility elects to nominate an off-system resource and the weather forecast doesn't materialize as expected, it will be left with excess gas that will require mitigation. After mitigation, the off-system resource will be depleted should future weather events or unplanned outages occur. This contrasts with an on-system peaking resource which can be deployed when access to gas supplies from mainline transportation or off-system storage faces an unplanned outage.

Mr. Mason also observed that the TLSE Project "would provide FEI with operational backup for disruption…to existing off-system storage and/or mainline transmission."[195]

4.5.5.4.2 GAS SUPPLY MITIGATION OPPORTUNITIES TO GENERATE VALUE FOR CUSTOMERS

At minimum, FEI could generate mitigation revenue for customers to offset gas supply costs.

FEI routinely realizes gas supply mitigation revenues for customers from gas supply portfolio elements that it does not require on any given day, and its approach to the TLSE Project would be no different. Peaking capacity is scarce and valuable in the Pacific Northwest market, where

[193] Appendix F, Raymond Mason Report, pp. 5 and 35.
[194] Appendix F, Raymond Mason Report, p. 17.
[195] Appendix F, Raymond Mason Report, pp. 5 and 35.

energy demand has grown, and utilities are making significant long-term investments in natural gas-fired generation.

Mr. Mason summarized this opportunity as follows:[196]

> The proposed TLSE Project's proximity to a larger US export market could also be a benefit to FEI's customers. In particular, peer utilities in the US, servicing a growing gas-powered electricity and industrial demand are, and will be for the foreseeable future, evaluating the cost/benefit of limiting pricing exposure to Huntingdon/Sumas, in response to growing peaking demand, by either: (a) sourcing peaking services like what the proposed TLSE Project could provide; or (b) committing to long-term mainline transportation.

Mr. Mason has undertaken an analysis of the financial value of LNG storage in the Lower Mainland from the perspective of mitigation (i.e., FEI selling peaking capacity into the market to entities throughout the Pacific Northwest region). Mr. Mason's opinion is that LNG storage in the Lower Mainland will continue to have financial value regardless of how FEI's own customer demand evolves:[197]

> Assuming that the TLSE Project is constructed, and FEI were to have spare capacity that is not required to meet customer demand or resiliency, FEI would be able to generate revenues to offset the cost of service of the facility by selling its excess supply into the market. Based on my assessment of the available supply and demand in the Huntingdon/Sumas natural gas market, and assuming current market conditions persist, I expect the daily market can reasonably absorb 300-400 MMcf/d of natural gas across multiple days (e.g., 10 days) during winter without influencing daily prices in a manner that could limit monetization values (i.e., materially decreasing the revenues generated through mitigation into the market).

Mr. Mason explains why, in his view, peaking resources will remain important throughout the Pacific Northwest region, such that there will be a market for any LNG that is surplus to FEI's requirements.[198] The volume is less than the established market demand volume of 3 to 4 Bcf.[199]

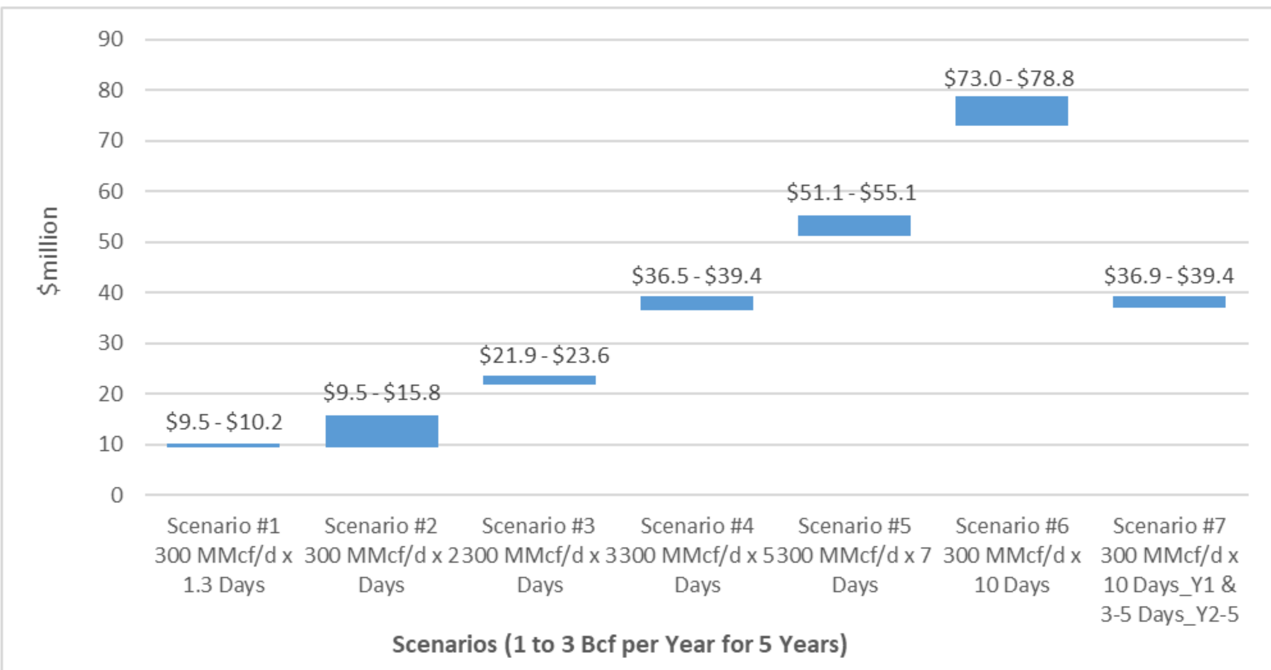
Mr. Mason provides estimates of the potential gas supply mitigation value of various assumed LNG volumes at Tilbury using forward prices, while acknowledging that some assumptions must be made about market conditions in the future. The analysis supports FEI's belief that, at minimum, LNG surplus to FEI's own requirements could generate significant gas supply mitigation revenue to benefit customers.

[196] Appendix F, Raymond Mason Report, p. 5.
[197] Appendix F, Raymond Mason Report, pp. 6 and 36.
[198] Appendix F, Raymond Mason Report, pp. 36-43.
[199] Appendix F, Raymond Mason Report, pp. 6 and 36.

Mr. Mason's calculations assume 300 MMcf/d of regasification to reflect a reasonable proxy for what the market could absorb on a given day, and various LNG volumes, e.g., 0.9 Bcf (3 days x 300 MMcf/d), 1.5 Bcf (5 days x 300 MMcf/d, and 3 Bcf (10 days x 300 MMcf/d). They are presented before adding a standing demand charge, which would be a significant additional revenue stream if FEI was able to commit to providing any of that capacity on a firm basis.

The figure below, using data from the Raymond Mason Report, shows annual and five-year cumulative values for the various mitigation scenarios.[200] The highest mitigation values ($73.0 million to $78.8 million) are predicated on selling 3 Bcf over 10 peak days in the winter, each year. In practice, FEI expects to retain some of the LNG for resiliency and gas supply, so there is a low likelihood of needing to mitigate 3 Bcf.[201] However, even the results for 1.5 Bcf (300 MMcf/d over 5 days) suggest a high mitigation value for customers: $36.5 million to $39.4 million over five years, before accounting for any revenue from a standing demand charge.

Figure 4-18: Gas Supply Cost Mitigation Scenarios – Selling Peaking Supply in the Market – 5-Year Cumulative Value



Mr. Mason estimates that FEI could generate the following range of additional incremental value through an annual standing demand charge: $5.2 million to $7.0 million for every 50 MMcf/d.[202]

[200] Based on forward markets dated February 29, 2024.

[201] Achieving the $73.0 million to $78.0 million would also require that FEI has full access to the existing liquefaction at Tilbury each year so that FEI can completely refill the 3 Bcf tank after emptying it in year one. The lower Scenario #7 results in Figure 4-18 are applicable if FEI is assumed to be limited to the 5 MMcf/d liquefaction currently allocated to the Base Plant (the rest being allocated to Tilbury 1A), which slows the pace of refilling the tank once sold. The smaller volume scenarios are not subject to the liquefaction constraint.

[202] Appendix F, Raymond Mason Report, pp. 7 and 58 and Report Appendix C, pp. 10-11.

4.6 SUMMARY OF ALTERNATIVES ANALYSIS RESULTS

Figure 4-19 and Table 4-15 below summarize the results from each step of the alternative selection process that led to Supplemental Alternative 9 being confirmed as the Preferred Alternative. The results from each step are discussed in the following sections.

Figure 4-19: Results from Structured Process to Identify the Preferred Alternative

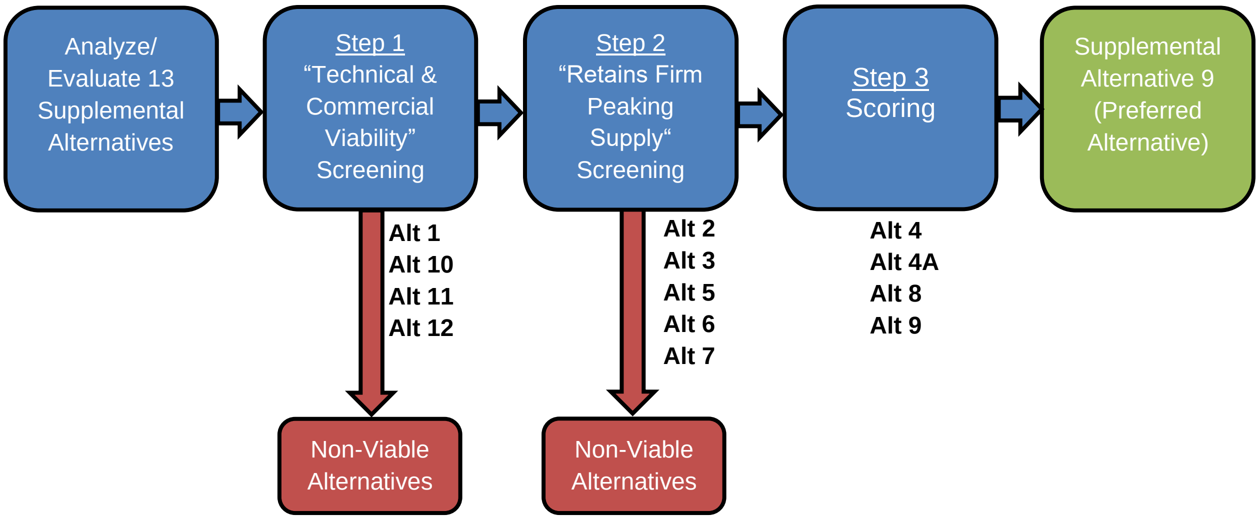


Table 4-15: Results from Three-Step Process to Identify the Preferred Alternative

SUMMARY OF RESULTS				
Supp. Alt. #	**Name**	**Step 1 Results**	**Step 2 Results**	**Step 3 Overall Score**
Alternatives Reliant on Existing Facilities[203]				
Alt. 1	No Capital Upgrades with Optimized Liquefaction (No Resiliency Reserve)	×	N/A	N/A
Alt. 2	New Regasification Only - 400 MMcf/d (No Resiliency Reserve)	✓	×	N/A
Alt. 3	New Regasification Only - 600 MMcf/d (No Resiliency Reserve)	✓	×	N/A
New Facility with Gas Supply But No Resiliency Reserve[204]				
Alt. 4	Like-for-Like (No Resiliency Reserve)	✓	✓	**1.4**
Alt. 4A	New 1 Bcf Tank (No Resiliency Reserve) and 400 MMcf/d Regasification	✓	✓	**1.8**

[203] These alternatives include prolonged reliance on the Base Plant tank with no dependable resiliency reserve, declining reliability, and a high likelihood of relying on the market for some replacement gas supply.

[204] These alternatives do not include a dependable resiliency reserve but provide different amounts of peaking gas supply and improved reliability.

SUMMARY OF RESULTS				
Supp. Alt. #	**Name**	**Step 1 Results**	**Step 2 Results**	**Step 3 Overall Score**
New Facility with Resiliency Reserve But No Gas Supply[205]				
Alt. 5	Like-for-Like (Full Resiliency Reserve)	✓	✗	N/A
Alt. 6	New 1 Bcf Tank (Full Resiliency Reserve) and 800 MMcf/d Regasification	✓	✗	N/A
Alt. 7	New 2 Bcf Tank (Full Resiliency Reserve) and 800 MMcf/d Regasification	✓	✗	N/A
New Facility with Both Resiliency Reserve and Gas Supply				
Alt. 8	New 2 Bcf Tank (1.4 Bcf Resiliency Reserve) and 800 MMcf/d Regasification	✓	✓	**1.9**
Alt. 9	New 3 Bcf Tank (2 Bcf Resiliency Reserve) and 800 MMcf/d Regasification (the Preferred Alternative)	✓	✓	**2.9 (Preferred)**
Non-Tilbury Alternatives[206]				
Alt. 10	Alt 1 plus VITS Reverse Flow	✗	N/A	N/A
Alt. 11	LNG from Woodfibre	✗	N/A	N/A
Alt. 12	Floating LNG	✗	N/A	N/A

Table 4-16 below summarizes the Step 3 evaluation scoring results for the alternatives that passed the Step 1 and Step 2 screening (Supplemental Alternatives 4, 4A, 8 and 9). The scoring is relative to the existing Base Plant with no capital upgrades (Supplemental Alternative 1) given that there are no zero-cost alternatives.

Supplemental Alternative 9 (New 3.0 Bcf Tank with 2.0 Bcf Resiliency Reserve and 800 MMcf/d Regasification) scored the highest and was therefore confirmed as the Preferred Alternative.

[205] These alternatives include a full resiliency reserve but still rely on the market for replacement of the gas supply functions.

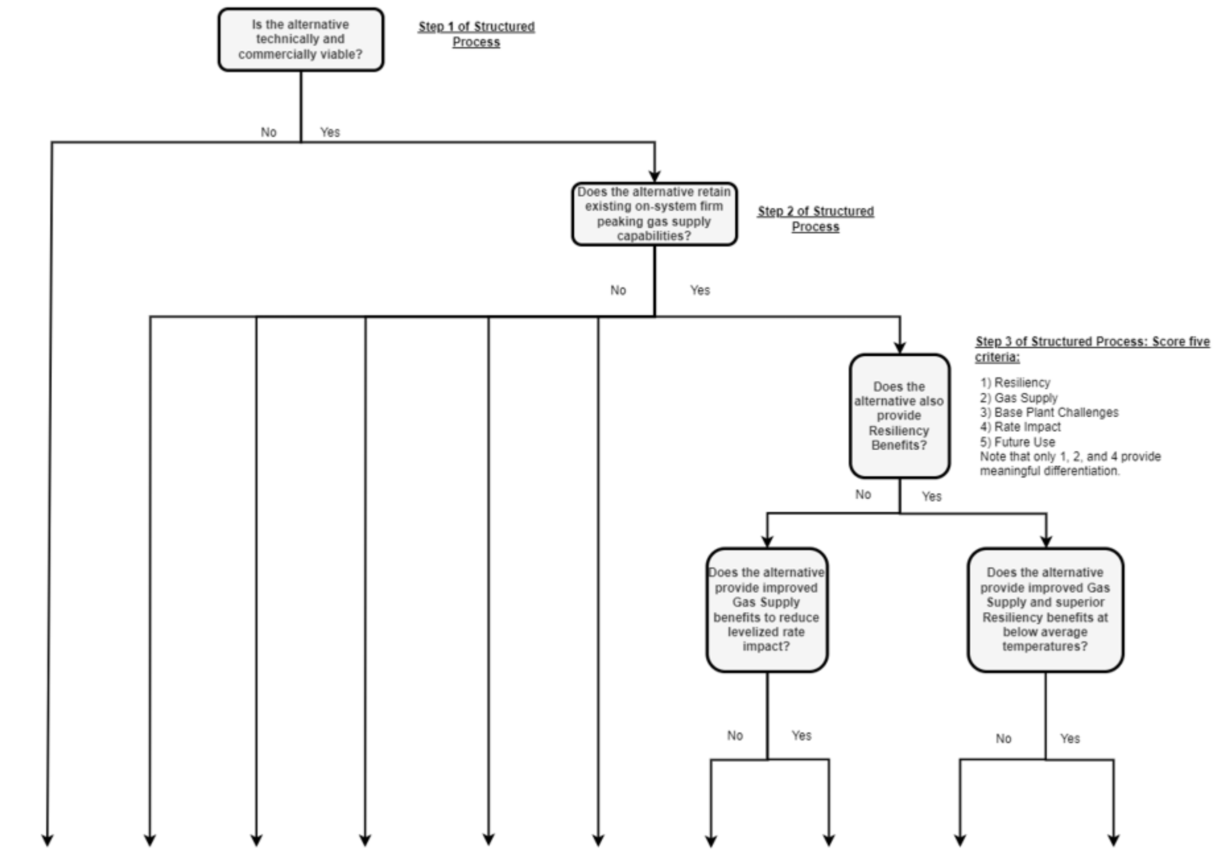
[206] FEI considers these alternatives to be non-viable approaches to providing winter resiliency and peaking gas supply.

Table 4-16: Step 3 Scoring Results

Evaluation Criterion	Criterion Weightin	Alternative 4	Alternative 4A	Alternative 8	Alternative 9
Resiliency Benefit	30%	No Impact	No Impact	Medium Positive Impact	High Positive Impact
Availability of Dependable Gas Supply During Peak Demand	20%	Medium Positive Impact	High Positive Impact	Medium Positive Impact	High Positive Impact
Resolves Age Related Base Plant Challenges	20%	High Positive Impact	High Positive Impact	High Positive Impact	High Positive Impact
Levelized Total Rate Impact	20%	Low Negative Impact	Low Negative Impact	Medium Negative Impact	Medium Negative Impact
Useful Under the Modified Diversified Energy (Planning) Scenario (mDEP) Between the In-Service Date and 2050	10%	No Impact	No Impact	No Impact	No Impact
	Total Weighted Score:	1.4	1.8	1.9	2.9
					Preferred

Figure 4-20 is an alternate presentation of the results of the structured alternatives analysis process.

Figure 4-20: Step 3 Scoring Results



	Alternative 1	Alternative 2	Alternative 3	Alternative 5	Alternative 6	Alternative 7	Alternative 4	Alternative 4A	Alternative 8	Preferred (Alternative 9)
Viability:	Not Viable	Not Viable	Not Viable	Not Viable	Not Viable	Not Viable	Viable	Viable	Viable	Viable
Levelized Total Rate Impact (%):	1.8%	3.3%	3.4%	4.4%	4.9%	5.6%	3.2%	3.0%	4.4%	4.2%
Levelized Total Rate Impact - Incremental to Alt 1 (%):	NA	1.57%	1.66%	2.68%	3.2%	3.84%	1.44%	1.27%	2.60%	2.45%
67-Year Expected GDP Loss Reduction ($millions):	0	0	0	139.5	2,152.9	11,092.7	0	0	10,877.1	11,092.7
Expected Annual COD - Cold Weather (-1.4C):	NA	NA	NA	NA	NA	1,250,000	NA	NA	2,900,000	1,250,000
Scoring Results	NA	0.1	0.1	0.4	0.0	1.5	1.4	1.8	1.9	2.9

FEI's strong view is that Supplemental Alternative 9 will provide the best value in meeting the Project objectives by providing the optimum peaking gas supply and providing material customer outage risk reduction. Comparing the 67-year expected GDP loss reduction and the levelized total rate impact of Supplemental Alternative 4A to Supplemental Alternatives 8 and 9 leads to the following conclusions:

- For an additional 1.3 percent and 1.2 percent levelized total rate impact, Supplemental Alternatives 8 and 9 would both provide significant loss reduction against a T-South no-flow event when compared to Supplemental Alternative 4A, which would optimize peaking supply only. This is true for direct customer impacts (customer outage-days) and GDP impacts.

- The increase in levelized total rate impact between Supplemental Alternative 4A (which would optimize gas supply only) and Supplemental Alternatives 8 and 9 (which would have varying amounts of gas supply plus resiliency reserves) is small compared to the significant loss reduction that would be provided by Supplemental Alternatives 8 and 9.
- Supplemental Alternatives 8 and 9 would provide similar levels of risk mitigation against a T-South winter no-flow event at average winter temperature. However, as discussed in Section 4.5.1.5 and summarized in Figure 4-3 above (see "Expected Annual COD – Cold Weather (-1.4°C)"), Supplemental Alternative 9 will provide superior risk mitigation at temperatures below the average winter temperature (i.e., the expected annual customer outage-day loss at -1.4°C is lower under Supplemental Alternative 9 than under Supplemental Alternative 8) for a lower levelized total rate impact. As discussed in Section 4.5.1.5, based on historical temperature data, nearly one-quarter of Lower Mainland winter days fall in the range (-6.8°C to +1.7°C) in which Supplemental Alternative 9 can bridge the regulatory shutdown period but Supplemental Alternative 8 could not. This shows the benefit of the Supplemental Alternative 9's incremental resiliency reserve (i.e., an additional 0.6 Bcf relative to Supplemental Alternative 8) and incremental gas supply capabilities (i.e., an additional 0.4 Bcf), which come at a relatively small incremental cost.

4.7 ADDITIONAL INFORMATION ON THE PREFERRED ALTERNATIVE'S RESILIENCY BENEFITS

The Resiliency Benefit criterion in the structured alternatives analysis focuses on Exponent's calculated annual risk reduction in respect of a winter T-South no-flow event only. While that evaluation provides a common basis for alternatives evaluation in respect of FEI's single largest customer outage risk exposure, it understates the resiliency benefits from Supplemental Alternative 9 (Preferred Alternative). This section provides additional information on those considerable resiliency benefits, in particular:

- The Preferred Alternative provides very significant cumulative risk mitigation in respect of a winter T-South no-flow event over 67-years (the expected life of the Project) and 23-year time horizons (the adverse sensitivity used to address BCUC commentary);[207]
- The Preferred Alternative introduces the potential for FEI to undertake a staged shutdown to maintain service to some portion of FEI's customers for longer. This makes it much more likely that many customers will remain uninterrupted, while having the knock-on benefit of shortening the outage duration for curtailed customers.
- In a worst-case scenario where a winter T-South no-flow event is longer than the Preferred Alternative's load support duration, the Preferred Alternative will still (1) avoid the uncontrolled depressurization and the attendant safety risks expected today; and (2) provide valuable time for customers, governments and social / health services to prepare.
- The Preferred Alternative will mitigate the calculated customer outage risk for 13 other customer outage vulnerabilities across FEI's system.
- In a circumstance where access to off-system storage is temporarily impaired for operational reasons during cold periods, the Preferred Alternative can be used to backstop off-system storage supply and limit the service impact on FEI's customers.

4.7.1 Cumulative Risk Reduction in Respect of a Winter T-South No-Flow Event

Exponent's risk calculations show that the Preferred Alternative provides very significant cumulative risk mitigation in respect of a winter T-South no-flow event over 67-years (the expected life of the Project) and 23-year time horizons (the shorter adverse sensitivity used to address BCUC commentary).

The following figures prepared by Exponent show the overall winter risk mitigation provided by the Preferred Alternative in respect of T-South <u>only</u>. Exponent's calculations are based on average Lower Mainland winter temperatures (+4°C) and the assumption that the existing Base Plant with no capital upgrades (mirroring the Supplemental Alternative 1 scenarios) and the Preferred Alternative will operate to the extent of their capabilities until the LNG is exhausted. The figures express risk mitigation in terms of reductions in customer-outage-days, customer outages

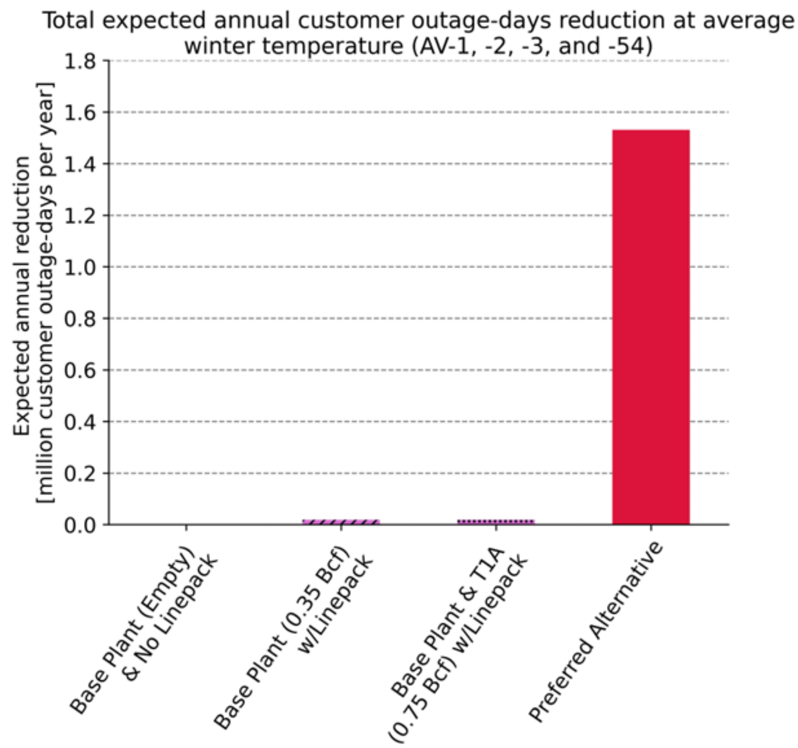
[207] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, pp. 119 - 122.

and expected GDP losses ($), respectively. The same pattern is evident regardless of the consequence measure used.

4.7.1.1 Annual Winter Risk Mitigation (T-South Only)

The following figures show the winter mitigation in relation to T-South only for a time horizon of one year.[208]

Figure 4-21: Preferred Alternative Annual T-South-Only Expected Customer Outage Days Reduction[209]



[208] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, Figures 61, 67 and 55, respectively.

[209] Figures 4-21 to 4-29 are at average winter temperature and compared to the three baseline (status quo) scenarios provided to Exponent.

Figure 4-22: Preferred Alternative Annual T-South-Only Expected Customer Outages Reduction

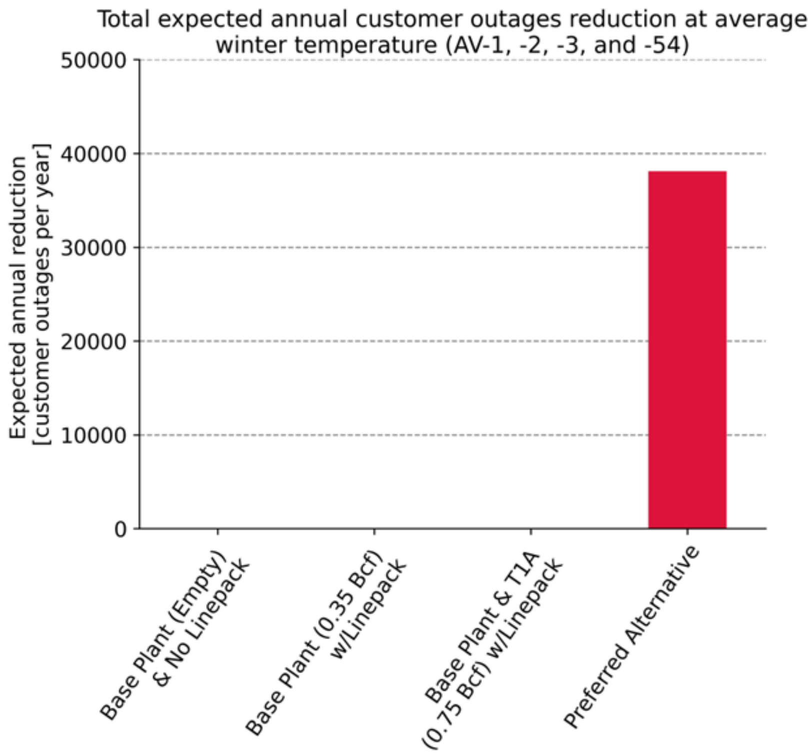
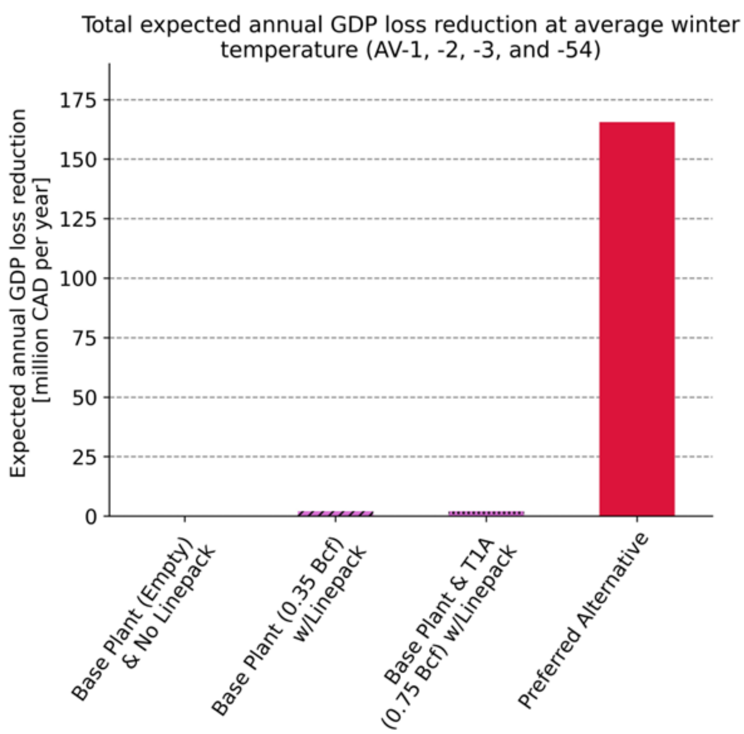


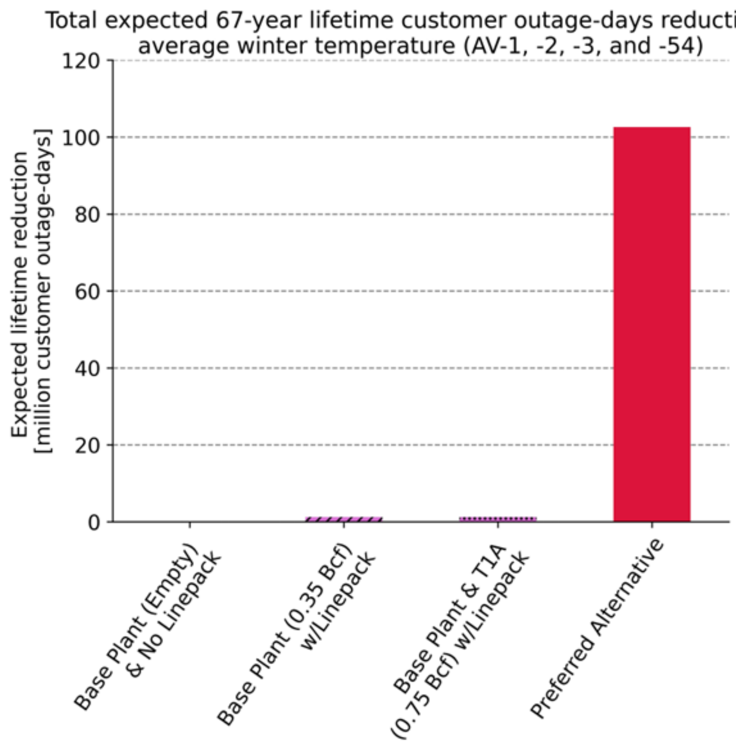
Figure 4-23: Preferred Alternative Annual T-South-Only Expected GDP Loss Reduction



4.7.1.2 Cumulative Winter Risk Mitigation 67 Years (T-South Only)

The following figures show the cumulative winter mitigation in relation to T-South only over 67 years.[210] FEI considers that this is the appropriate horizon over which to assess risk, as it is the expected life of the TLSE Project and FEI expects to continue using it throughout that period for the reasons stated in Section 6 of this Supplemental Evidence.

Figure 4-24: Preferred Alternative 67-Year T-South-Only Expected Customer Outage Days Reduction



[210] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, Figures 65, 71 and 59, respectively.

Figure 4-25: Preferred Alternative 67-Year T-South-Only Expected Customer Outages Reduction

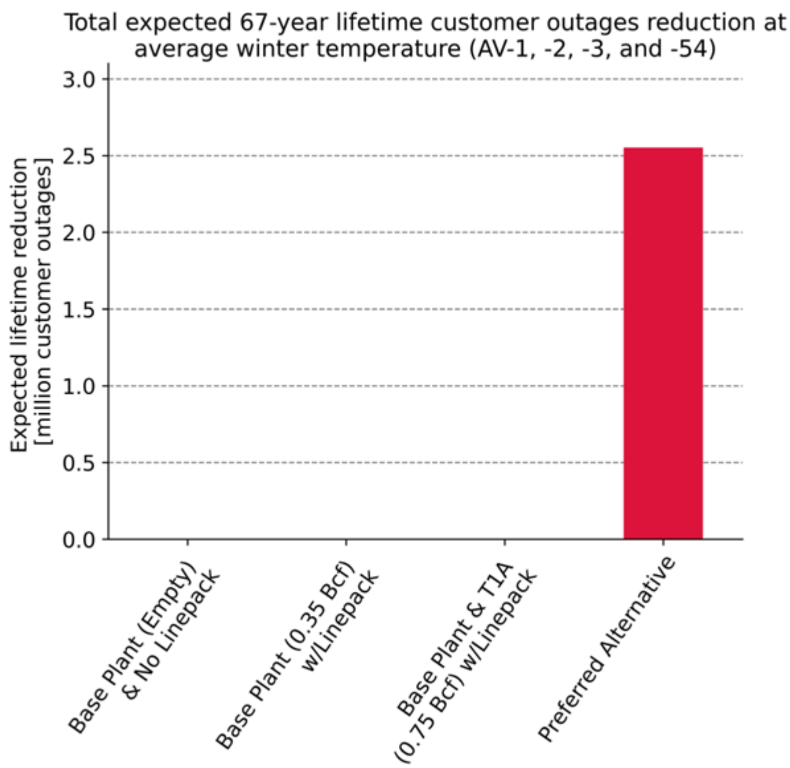
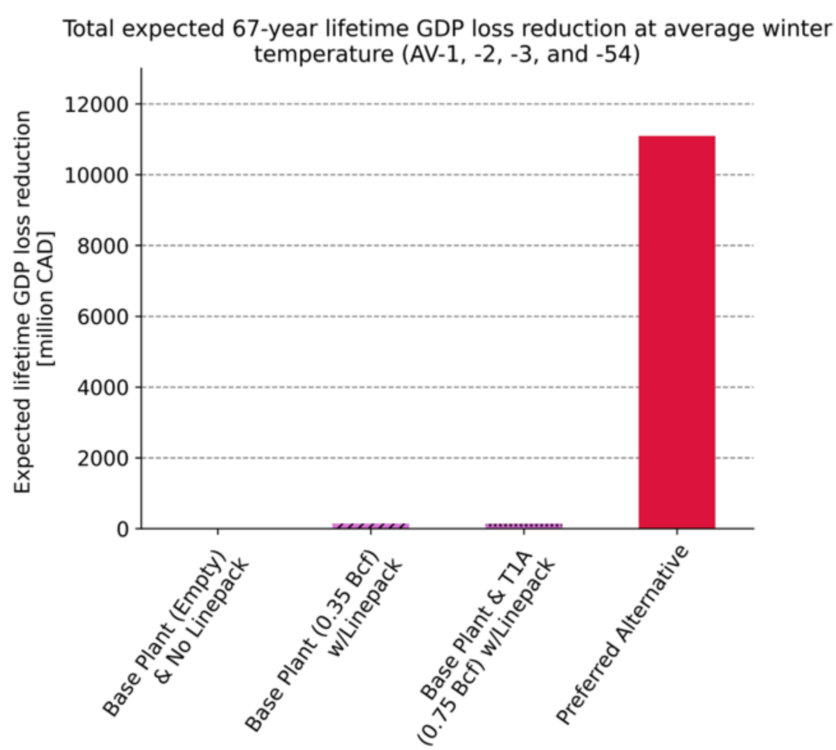


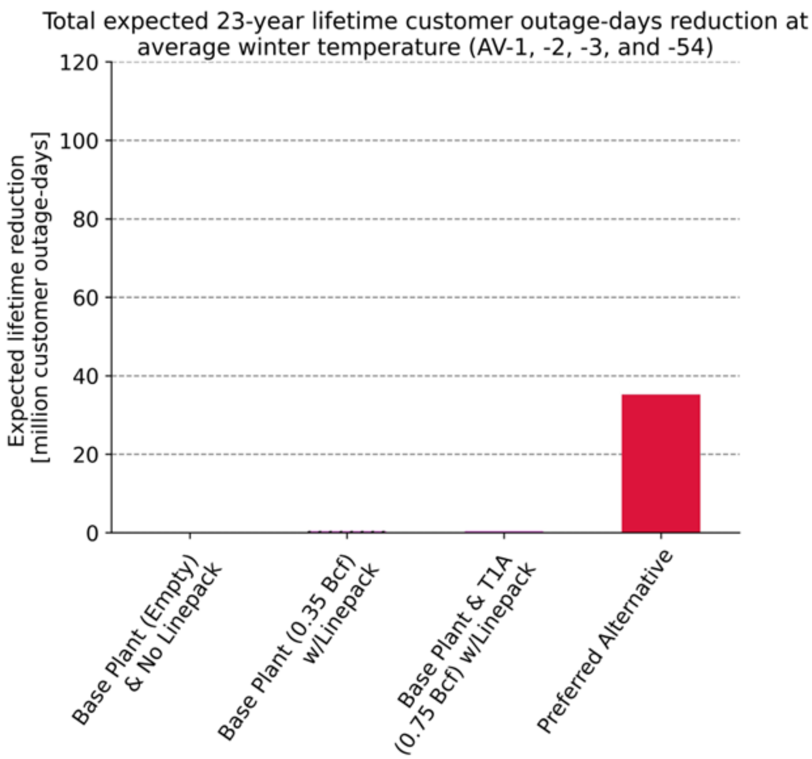
Figure 4-26: Preferred Alternative 67-Year T-South-Only Expected GDP Loss Reduction



4.7.1.3 Cumulative Winter Risk Mitigation 23 Years (T-South Only)

The following figures show the cumulative winter mitigation in relation to T-South only over 23 years.[211] FEI asked Exponent to prepare a sensitivity based on 23 years, as the BCUC had raised the issue of the usefulness of the Preferred Alternative beyond 2050. FEI regards this period as far too short as it expects to continue using the facility throughout its expected service life for the reasons stated in Sections 6.2.2 and 6.4 of this Supplemental Evidence.

Figure 4-27: Preferred Alternative 23-Year T-South-Only Expected Customer Outage Days Reduction



[211] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, Report Appendix, Figures 63, 69 and 57, respectively.

Figure 4-28: Preferred Alternative 23-Year T-South-Only Expected Customer Outages Reduction

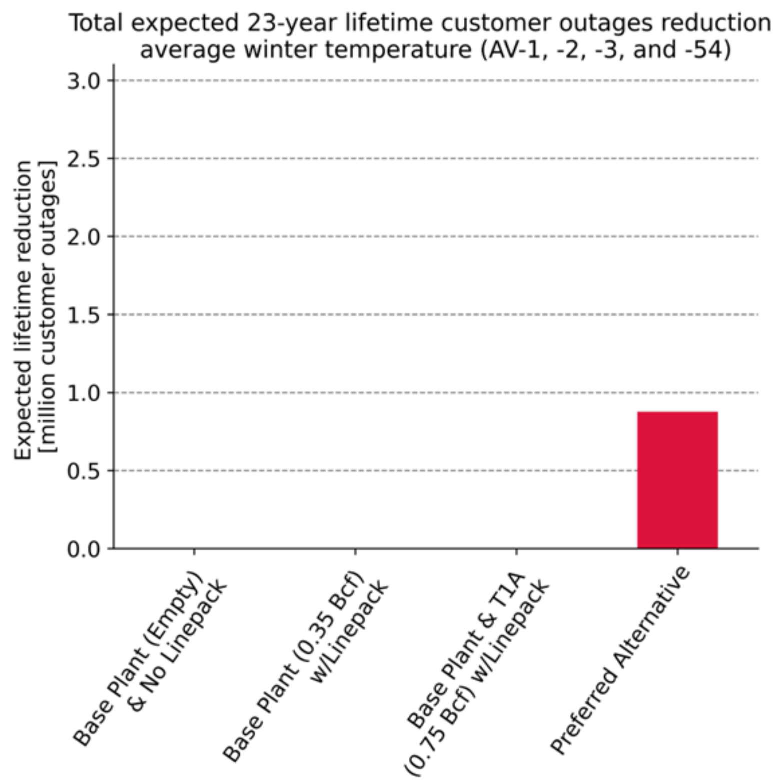
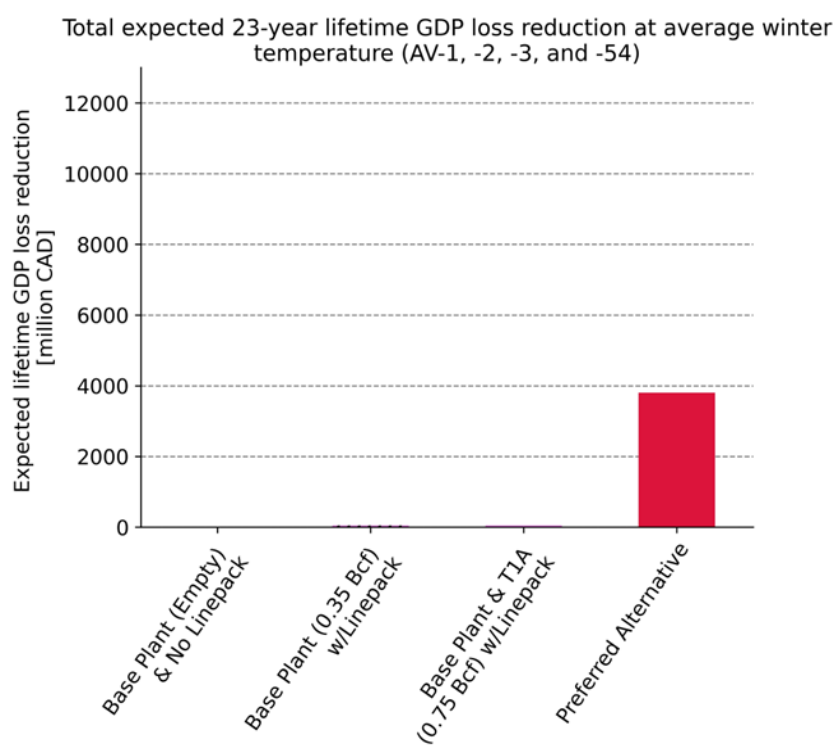


Figure 4-29: Preferred Alternative 23-Year T-South-Only Expected GDP Loss Reduction



4.7.2 Preferred Alternative Offers Potential for Staged Shutdown to Maintain Service to Some Customers

Currently, the system will depressurize before FEI has time to assess and respond to a winter T-South no-flow event. The Preferred Alternative will give FEI time to assess conditions and the flexibility to adjust its curtailment response based on its real-time expectations about when the no-flow event will be resolved. This time and flexibility makes it far more likely that at least some portion of FEI's customers would continue to receive uninterrupted service during a no-flow event. Having fewer depressurized sections of the system to restore has the knock-on benefit of shortening the overall outage duration for curtailed customers.

In this section, FEI presents transient modelling load support duration results for multiple no-flow / FEI response scenarios to illustrate the extent of the flexible risk mitigation provided by the TLSE Project.

4.7.2.1 Response Options Available to FEI With Preferred Alternative

The following table outlines, in broad terms, the response options that will be available once the Preferred Alternative is in place.

Table 4-17: FEI's Response Options to No-Flow Event with Preferred Alternative

Potential Response Options to a No-flow Event	Circumstances When Option Used
Continue to serve all firm load for as long as possible (the basis for the Resiliency Benefit criterion in Section 4.2.2.3.2 above). In this option FEI's deployment of the asset would entail sending out at a flow rate that matches or exceeds system demand and thus maintains or increases the pressure in the system.	When FEI is confident that the no-flow event will be rectified before the available LNG is depleted.
Once the issue is understood, begin to curtail firm loads progressively according to FEI's System Preservation and Restoration (P&R) Plan to reduce demand and thus extend the duration of support for the remaining customers. FEI's deployment of the asset in this option would be the same as described above. However, in this option system demand has been decreased through curtailment and therefore the send out flow rate required to maintain or increase the system pressure is also decreased, and thus the duration of support for the non-curtailed customers is extended.	When FEI is not confident that the no-flow event will be rectified before the available LNG is depleted.

4.7.2.2 Option to Maintain Service to All Firm Customers When FEI Confident Supply Will Resume Before Tank is Empty

The Preferred Alternative will enable FEI to continue to support all firm load without forced curtailments if FEI is confident that a no-flow event would be resolved before the tank was emptied. This is the scenario that was the focus of FEI's evidence in the TLSE Project CPCN proceeding to date, and the analysis remains valid.

FEI used its transient modelling to determine the length of time the Preferred Alternative could support the entire Lower Mainland load under a variety of winter temperature conditions in the event of a loss of supply from T-South. Table 4-18 below summarizes this analysis.

Table 4-18: Preferred Alternative Support of Lower Mainland Under Various Winter Temperatures

Temperature Condition (°C)	Existing Tilbury Base Plant (assuming full to 0.35 Bcf)[212]	Preferred Alternative – 2 Bcf resiliency reserve & 800 MMcf/d (Minimum 2 Bcf available in 3 Bcf tank on first day of no-flow event)
-10.0 (very cold winter day)[213]	2 hours	2 days and 17 hours
-1.4 (warmest winter in last 10 years)[214]	5 hours	3 days and 12 hours
+4.0 (average Lower Mainland winter)[215]	7 hours	4 days and 13 hours

Figures 4-30 and 4-32 below are the outputs of FEI's transient system modelling for column three in Table 4-18 above (i.e., the modelling results at various temperatures for a 2.0 Bcf resiliency reserve and 800 MMcf/d of regasification). The figures show that in each temperature scenario the current regasification constraint has been addressed, such that the overall load support duration is defined by the amount of LNG present. Please refer to Section 3.2.2.1.2 of this Supplemental Evidence for an explanation of the various components of these transient modelling graphs.

[212] Although there is no resiliency reserve at present that would provide dependable resiliency, FEI has assumed that at least 0.35 Bcf of LNG is available on the day of the no-flow event (i.e., FEI assumed that the Base Plant is full based on current operating levels, meaning that FEI has used no supply to serve peak load). In the alternatives analysis, this is referred to as Alternative 1 (Contingent)).

[213] Due to the low probability of having multiple -10°C days in a row in the Lower Mainland, the -10°C temperature condition analysis assumes the following: the first day is -10°C, the second and third days are -7°C, the fourth day is -3°C, and all subsequent days are +4°C.

[214] The warmest winter in the last 10 years was found by determining the minimum daily average temperature for each year over a 10-year period from 2013-2022, then selecting the highest value. The analysis was based on data from YVR.

[215] Defined as the average of the daily average temperatures for December, January, and February over a 10-year period from 2013-2022. The average winter day is based on data from YVR.

Figure 4-30: Impact to Lower Mainland Due to T-South No-Flow Event with 2 Bcf Resiliency Reserve and 800 MMcf/d Regasification at -10°C

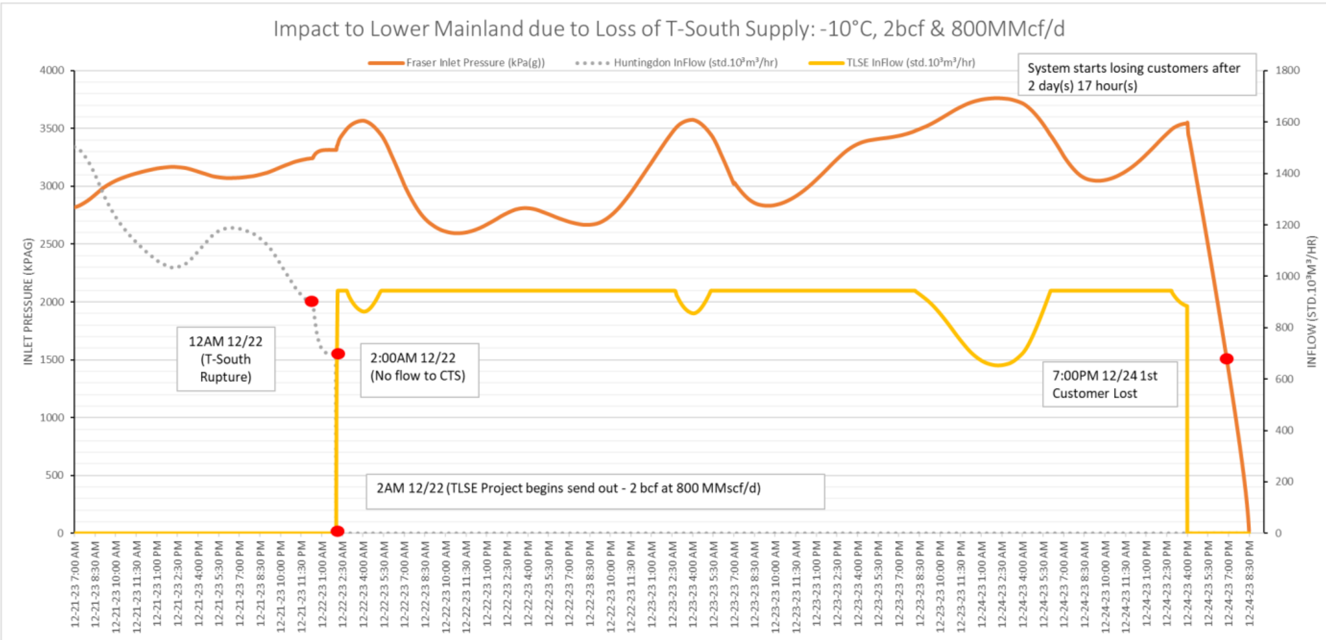


Figure 4-31: Impact to Lower Mainland Due to T-South No-Flow Event with 2 Bcf Resiliency Reserve and 800 MMcf/d Regasification at -1.4°C

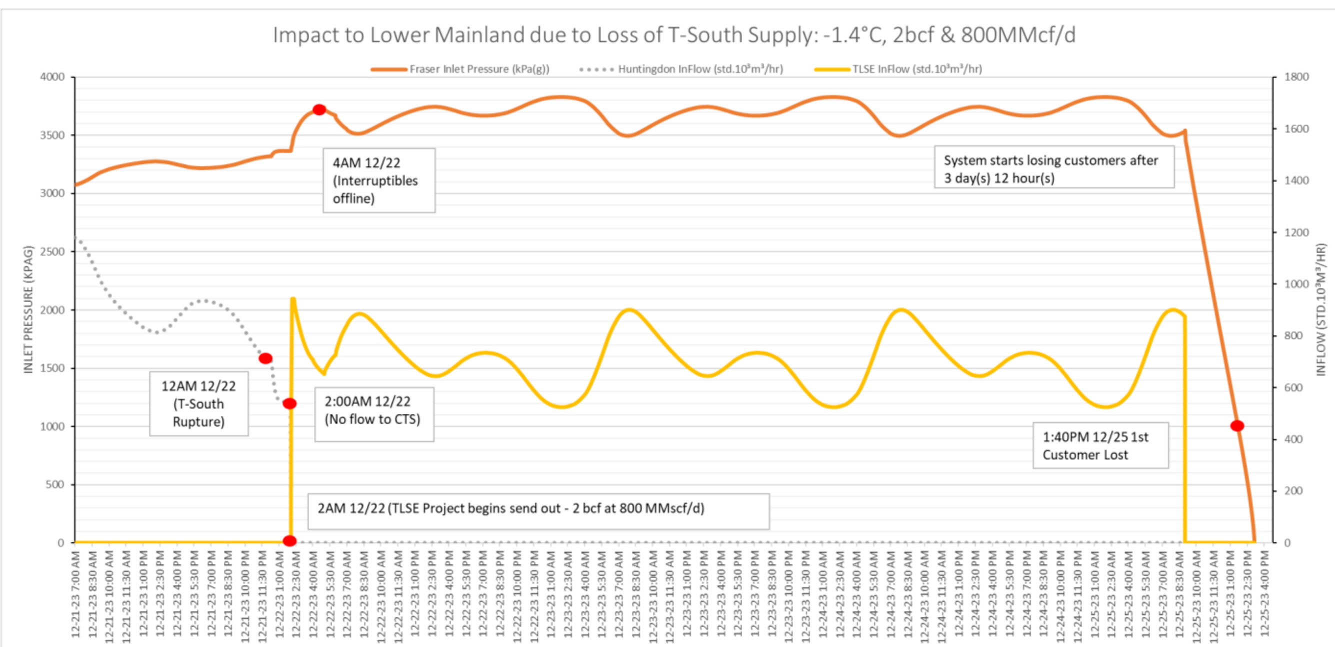
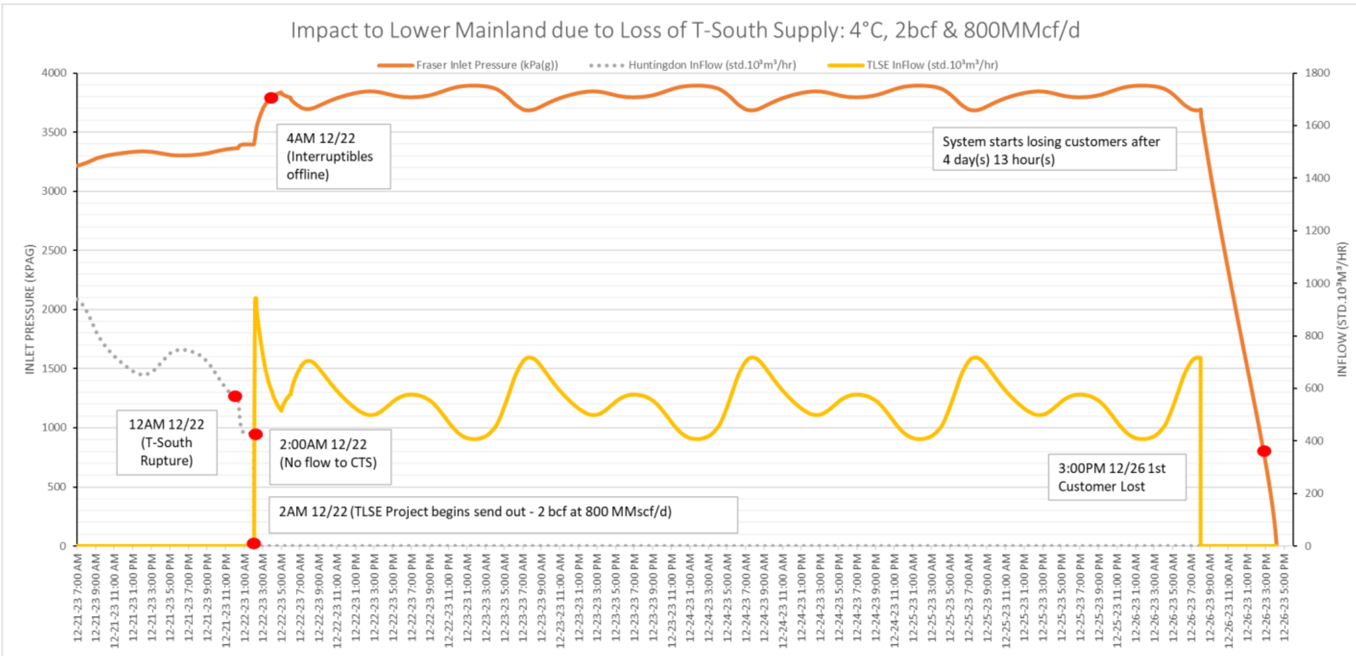


Figure 4-32: Impact to Lower Mainland Due to T-South No Flow Event with 2 Bcf Resiliency Reserve and 800 MMcf/d Regasification) at Average Winter Conditions (+4°C)



4.7.2.3 Option to Initiate Staged Shutdown When Supply Resumption Date Unknown

The Preferred Alternative also provides FEI with the flexibility to perform a staged shutdown to extend the duration of load support for remaining customers, which is unlikely to be an option currently in winter because of how quickly the system will currently depressurize. This flexibility will be a significant benefit when responding to a no-flow event. A staged shutdown can reduce the number of customers who experience an outage. It can also shorten the time to restore service to all customers because there are fewer customers to relight.

As described in the Application,[216] in circumstances where FEI is not confident that the no-flow event will be resolved before stored LNG is exhausted and FEI has time to respond, it will begin a staged shutdown of the system in a manner consistent with the BCUC-approved Gas Supply Shortfall System Preservation and Service Restoration Plan (P&R Plan).[217] By pre-emptively shutting down customers while the Preferred Alternative's tank still has volume, FEI can reduce the system demand. This reduces the rate at which the tank storage is depleted and increases the tank supply duration for the remaining online customers (i.e., customers that were not shutdown pre-emptively).

[216] Exhibit B-1-4, Application, pp. 23-24; Exhibit B-46-1, Rebuttal Evidence to RCIA.

[217] The P&R Plan is confidential and security sensitive. However, in broad terms, contemplates initially shedding larger customers and then successively isolating portions of the Lower Mainland to maintain system pressure. Decisions on whether to curtail are made in real time, with reference to the most up-to-date information on when the no flow event is expected to be resolved.

At present, even under average winter temperatures (+4°C), FEI expects that a T-South failure on certain segments of T-South will cause the system to depressurize too quickly for FEI to employ a staged shutdown. The Preferred Alternative, in contrast, will provide sufficient regasification capacity and a resiliency reserve (i.e., guaranteed supply) to provide FEI with enough time to make the decision as to whether to initiate a staged shutdown.

FEI used its transient system modelling to determine the length of time the Preferred Alternative could support portions of the Lower Mainland under various illustrative staged shutdown scenarios. The results of these illustrative scenarios are presented in Table 4-19 below.

Table 4-19: Preferred Alternative (2 Bcf Resiliency Reserve & 800 MMcf/d) Lower Mainland Support Durations Under Various Staged Shutdown Scenarios

Temperature Condition (°C)	Lower Mainland Support Duration				
	Without Staged Shutdown	**Example 1:** 20% Customer Shutdown After 24 hrs	**Example 2:** 20% Customer Shutdown After 24 hrs Additional 20% Customer Shutdown After 48 hrs	**Example 3:** 20% Customer Shutdown After 24 hrs Additional 20% Customer Shutdown After 48 hrs Additional 20% Customer Shutdown After 72 hrs	**Example 4:** 40% Customer Shutdown After 24 hrs Additional 20% Customer Shutdown After 48 hrs
-10.0C (very cold winter day)[218]	2 days and 17 hrs	3 days and 5 hours	3 days and 8 hours	3 days and 11 hours	4 days and 3 hours
-1.4°C (warmest winter in 10 years)[219]	3 days and 12 hours	4 days and 5 hours	4 days and 9 hours	5 days and 3 hours	5 days and 17 hours
+4.0°C (average Lower Mainland winter)[220]	4 days and 13 hours	5 days and 6 hours	5 days and 17 hours	6 days and 20 hours	7 days and 11 hours

Given these results, there are a variety of scenarios where FEI could significantly reduce the scale and duration of a customer outage by performing a partial staged shutdown; for instance, where a no-flow event occurring at -1.4°C ends up lasting 4 days. Without a staged shutdown, 100

[218] Due to the low probability of having multiple -10°C days in a row in the Lower Mainland, the -10°C temperature condition analysis assumes the following: the first day is -10°C, the second and third days are -7°C, the fourth day is -3C, and all subsequent days are 4°C.

[219] The warmest winter in the last 10 years was found by determining the minimum daily average temperature for each year over a 10-year period from 2013-2022, then selecting the highest value. The analysis was based on data from YVR.

[220] Defined as the average of the daily average temperatures for December, January, and February over a 10-year period from 2013-2022. The average winter day is based on data from YVR.

percent of Lower Mainland customers would lose service after the support duration (an estimated 3 days and 12 hours). However, if FEI executed a staged shutdown, then approximately 80 percent of Lower Mainland customers would retain service throughout the entirety of the event. While 20 percent of Lower Mainland customers would still lose service, the staged shutdown approach significantly reduces the overall consequence of the no-flow event. Restoring service to 20 percent of the Lower Mainland would take far less time than a Lower Mainland-wide customer outage.

4.7.3 Preferred Alternative Has Resiliency Value Even Where T-South No-Flow Event Is Too Long to Bridge

In a worst-case scenario where a T-South no-flow event is longer than the Preferred Alternative's load support duration, the Preferred Alternative will still: (1) avoid the uncontrolled depressurization and the attendant safety risks expected today; and (2) provide valuable time for customers, governments and social / health services to prepare.

4.7.3.1 Preferred Alternative, at Minimum, Prevents Uncontrolled Shutdown

FEI described in its prior evidence[221] the difference between a controlled and uncontrolled shutdown, emphasizing the safety and service restoration issues associated with an uncontrolled shutdown. A controlled shutdown requires time to implement,[222] and FEI lacks the necessary time at present to respond to a T-South winter no-flow event. At minimum, even if a no-flow event exceeds the duration of load support, the Preferred Alternative will provide adequate response time in most temperature conditions to ensure a controlled shutdown.

To summarize FEI's prior evidence, an uncontrolled shutdown occurs when the gas distribution system is naturally lost due to a collapse of system pressure and gas supply. An uncontrolled shutdown is a serious scenario both in terms of service disruptions to customers as well as the potential for safety concerns.

- From a safety perspective, the uncontrolled drop in system gas pressure can introduce the possibility of air being drawn into the distribution system. This is a potentially hazardous situation as the gas-air mixture can result in fire or explosion risks. Entrained air can also blow out the flames in customer appliances or equipment, resulting in improper operation.
- From an outage duration perspective, any air within the gas distribution system must be purged and the segment re-pressurized with gas prior to relighting any customers. This purge and regasification/re-pressurization process extends the duration of the customer outage when compared to a controlled shutdown.

In a controlled shutdown, which will be possible with the Preferred Alternative, gas pressure in the system is maintained. This reduces the possibility of air being drawn into the system. As such,

221 Exhibit B-46-1, Rebuttal Evidence to RCIA, p. 9.
222 Exhibit B-1-4, Application, p. 24.

notwithstanding a third-party line hit, in a controlled shutdown the safety hazard due to entrained air is less likely to occur. Additionally, the extended outage duration associated with the need for purging and repressurizing due to entrained air is avoided.

4.7.3.2 Preferred Alternative, at Minimum, Provides Valuable Preparation Time for Customers, Governments and Health / Social Services

In a worst case scenario where the Preferred Alternative only delays a widespread customer outage, this still provides valuable preparation time for customers, governments and health / social services that can reduce harm.

Exponent addressed this in Section 11 of its Report:[223]

> There can be significant downtime following a pipeline rupture or failure at a compressor station, control station, or valve assembly, as demonstrated by a review of outage durations in Appendix T. In certain situations, a backup source of gas may not provide sufficient load support to an AV to avoid an outage: for example, if the time required to repair a ruptured pipe exceeds the load support duration provided by the backup source. However, even when an outage eventually occurs, having a backup supply of gas for three, five, or more days may allow several emergency preparedness strategies to be implemented for protecting individuals, communicating critical information to the public, and sustaining medical services in the event of a winter failure. This chapter summarizes some of the key preparedness measures that a backup supply of gas might enable.
>
> The following preparedness measures assume a certain degree of planning prior to the disruption of gas service, including: the identification of regions with high population density; the identification of areas with high concentrations of vulnerable populations such as children, individuals with disabilities, and residents of long-term care facilities; and the creation of evacuation plans for those regions. It is also assumed that a communications system is available for timely dissemination of relevant information to the public. Examples of preparedness measures in the days ahead of the gas outage include:
>
> a. Relocating vulnerable members of the population, such as residents of long-term care facilities and nursing homes, individuals with disabilities, and persons requiring home-health services.
>
> b. Setting up warming shelters for evacuated individuals and those who cannot shelter at home. The warming shelters may be equipped with heaters that run on electricity, gasoline or propane, and stockpiled

[223] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, paras. 247-250.

with blankets, cots, water, and ready-to-eat meals, or self-heating meals.

c. Supporting sheltering-in-place for capable individuals, if possible, by distributing heaters that run on other fuel sources than natural gas, and providing timely communication of the imminent disruption event, and safe practices for sheltering-in-place. For example, individuals should be advised on protecting themselves from cold-related injuries, preparing heating alternatives, and avoiding carbon monoxide poisoning. Timely dissemination of information should include plans to alert individuals with sensory or cognitive disabilities.

d. Supplying all essential facilities such as government buildings, emergency centers, hospitals and long-term care facilities with electricity-, gasoline- or propane-powered heaters, backup generators, and a sufficient supply of fuel.

e. Bolstering hospital staffing in preparation of the increased demands, and stockpiling medical equipment needed to treat cold weather-related conditions in hospitals and emergency centers.

f. Setting up the necessary backup systems for hospitals to run the chillers, which keep the hospital servers and equipment running, and keep medications accessible by maintaining functioning computer systems. Temperature management of hospital facilities may also be critical for proper storage of medications. It may become necessary to temporarily relocate critical patients to other hospitals.

g. Developing a strategy for the management and possible relocation of incarcerated persons.

h. Managing traffic to support evacuation efforts, and possibly implementing contraflow strategies, wherein all highway lanes are temporarily converted to outbound lanes for maximizing traffic flow. There may be a need to set up shelters along the designated evacuation routes and running special-service public transit to transport individuals to sheltering locations. Designating refuges of last resort may also be necessary for individuals which were unable to reach the warming shelters.

i. Pre-positioning medical personnel and supplies at shelter locations and establishing out-of-hospital care centers to respond to cold weather-related conditions such as frostbites and hypothermia.

j. Identifying and pre-staging big kitchen locations for creating meals and feeding the sheltered population.

> While additional days of backup gas supply may not always prevent an outage following a failure along a pipeline or at a station, they may provide enough time to mitigate the impacts of an outage on affected customers, including in particular the most vulnerable community members.

These benefits are not reflected in Exponent's risk calculations, but they are significant and very real. NERC noted recently that hundreds of people died as a result of an electric outage in Texas that left people without heat for only four days, in part due to "hypothermia, carbon monoxide poisoning, and medical conditions exacerbated by freezing conditions."[224] Minimizing the risk of these outcomes would require advance preparation and outreach by various agencies.

4.7.4 Preferred Alternative Mitigates Risk of 13 Other Assessed Vulnerabilities

The Preferred Alternative will mitigate the calculated winter-only customer outage risk for 13 other customer outage vulnerabilities (referred to in the 2024 Resiliency Plan as Assessed Vulnerabilities or AVs) across FEI's system. The subsections below provide Exponent's calculations for the 13 other AVs only, and on a combined basis with the T-South risk to give an overall total risk reduction.

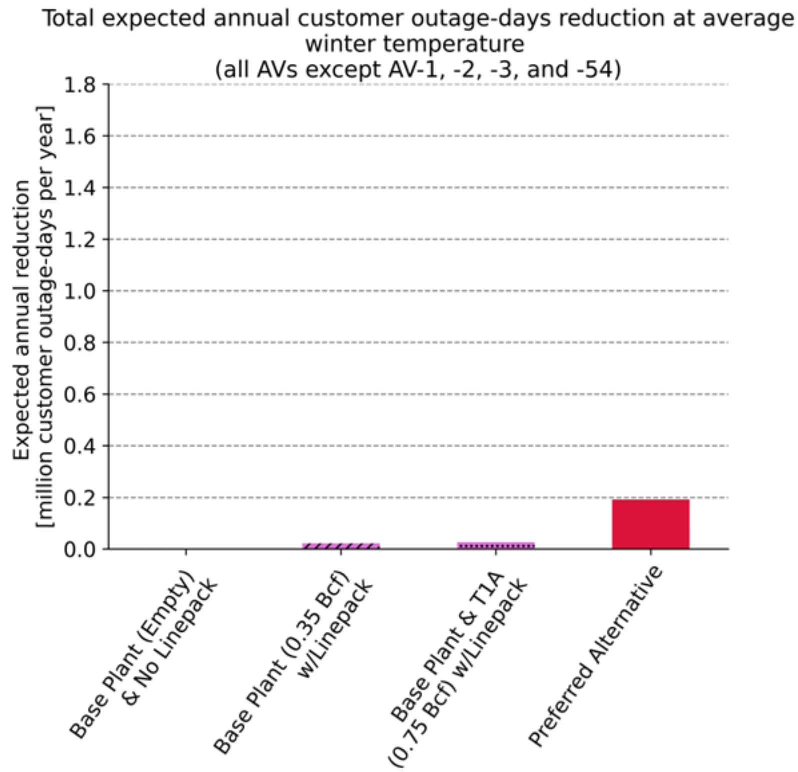
4.7.4.1 Risk Reduction for 13 Non-T-South Assessed Vulnerabilities Only

Figure 4-33 below is from Exponent's report and shows the annual winter-only risk mitigation provided by the Preferred Alternative relative to the status quo for non-T-South AVs. Please refer to the Exponent Report for Exponent's equivalent figures for horizons of 23 and 67-years.[225] A similar pattern exists, although the mitigation values are a lot higher, when the risk mitigation is considered on a cumulative basis over 23 and 67 years.

[224] https://www.nerc.com/pa/rrm/ea/Documents/February_2021_Cold_Weather_Report.pdf.

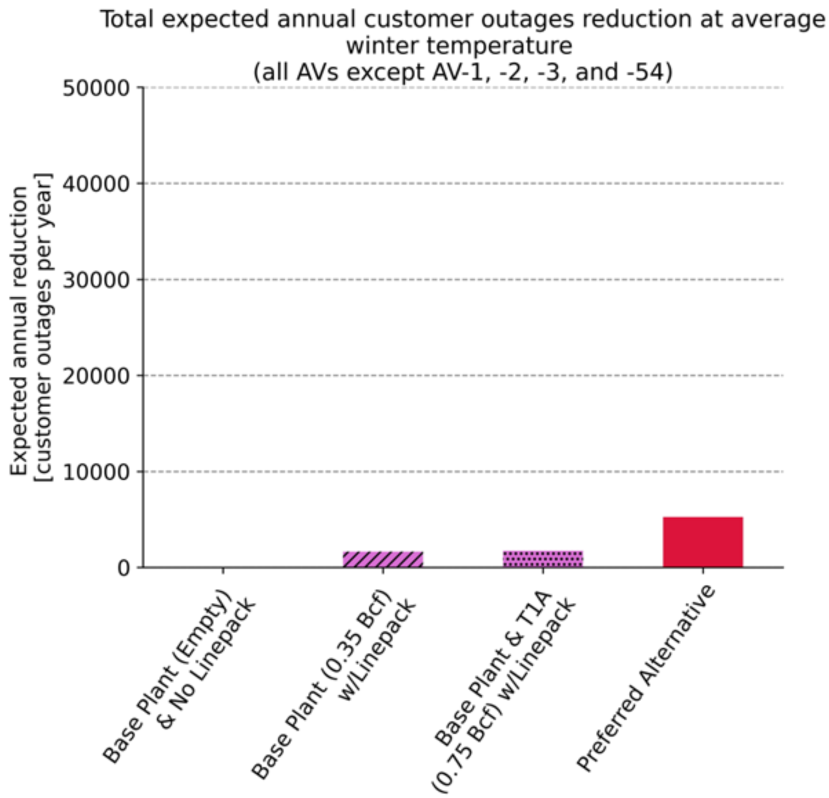
[225] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, Figures 62, 68 and 56, respectively.

Figure 4-33: Annual Winter Only Expected Customer Outage Days Reduction – All AVs Except T-South[226]



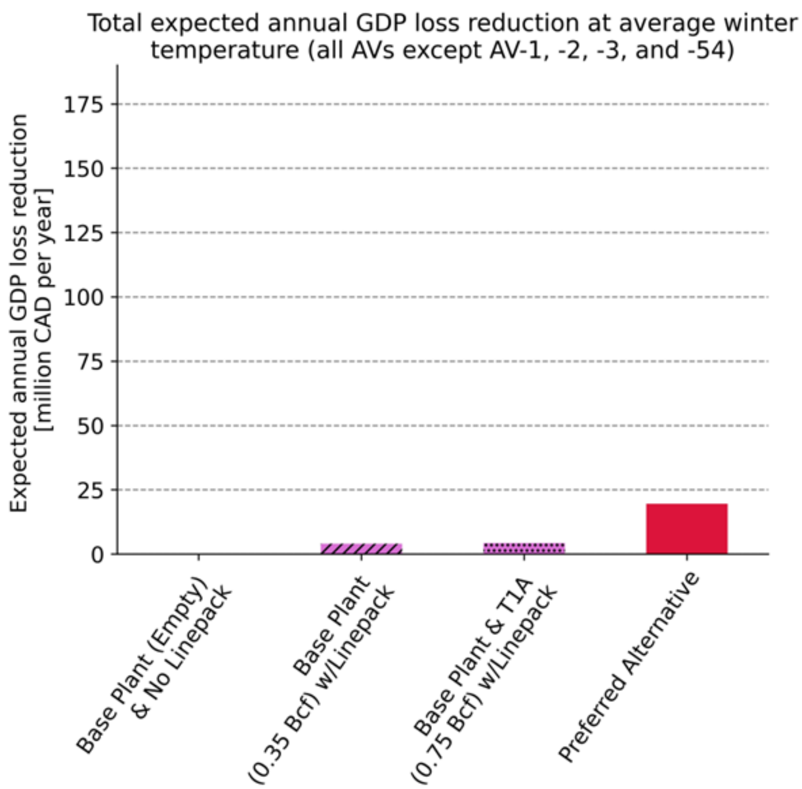
[226] At average winter temperature and compared to the three baseline (status quo) scenarios provided to Exponent.

Figure 4-34: Annual Winter Only Expected Customer Outages Reduction – All AVs Except T-South[227]



[227] At average winter temperature and compared to the three baseline (status quo) scenarios provided to Exponent.

Figure 4-35: Annual Winter-Only Expected GDP Loss Reduction – All AVs Except T-South[228]



The risk mitigation evident in Exponent's figures above for these non-T-South AVs is due to the load support duration provided by the Preferred Alternative. The following table summarizes the estimated length of time the Preferred Alternative would support these non-T-South AVs under average winter conditions for the areas impacted by the AVs.[229]

Table 4-20: Preferred Alternative Support Durations Under Average Winter Conditions for Non-T-South AVs Only[230]

Assessed Vulnerability	Mitigation Type[1]	Load Support Duration from Preferred Alternative
AV-4	Direct & Displacement	13.3 days
AV-12	Direct	19.1 days
AV-13	Direct	58.8 days
AV-14	Direct	95.2 days
AV-16	Direct	52.6 days
AV-17	Direct	19.1 days

[228] At average winter temperature and compared to the three baseline (status quo) scenarios provided to Exponent.
[229] The average winter temperature in the Lower Mainland and the relevant parts of Vancouver Island is +4°C, but the average winter temperature in various parts of the Interior is much colder.
[230] FEI did not conduct transient modelling to determine the support duration for all AVs. For these AVs, the tank support durations are estimated by dividing the tank volume by the AVs' daily flow rate. This method does not account for linepack; therefore, some durations may be under reported.

Assessed Vulnerability	Mitigation Type[1]	Load Support Duration from Preferred Alternative
AV-18	Direct	4.9 days
AV-20	Direct	4.5 days
AV-23	Direct & Displacement	13.3 days
AV-30	Direct	19.1 days
AV-40	Direct & Displacement	16.9 days
AV-41	Direct & Displacement	13.5 days
AV-42	Direct & Displacement	16.9 days

Note to Table:

[1] *Direct mitigation and mitigation displacement provide the equivalent benefit for customers. The only difference is the source of the physical gas molecules.*

Table 4-20 above identifies two categories of mitigation, direct and by displacement, although the effect from a customer perspective is the same in both instances.

- **Direct mitigation** involves instances where the re-gasified LNG from Tilbury physically flows to the region of the system that is experiencing the supply shortfall. An example of direct mitigation is the support provided by the Preferred Alternative to the Lower Mainland following a T-South winter no-flow event.
- **Mitigation by displacement** refers to instances where the LNG supports the region at risk indirectly. As FEI discussed in the TLSE Workshop and prior written evidence,[231] the storage provided by the TLSE Project would also allow FEI to meet Interior customer demand for the vast majority of the year even if one of the gas transmission lines in the Interior was disrupted. For example, if there was reduced capacity or a no-flow event on the TC Energy pipeline that provides supply for the ITS at Yahk, the TLSE Project could also help FEI manage such an event. FEI could divert supply from the T-South system into the ITS to replace the lost capacity from TC Energy, and then use the TLSE storage and regasification to back-fill the reduced supply into the LML which would have previously been supplied from the T-South system.

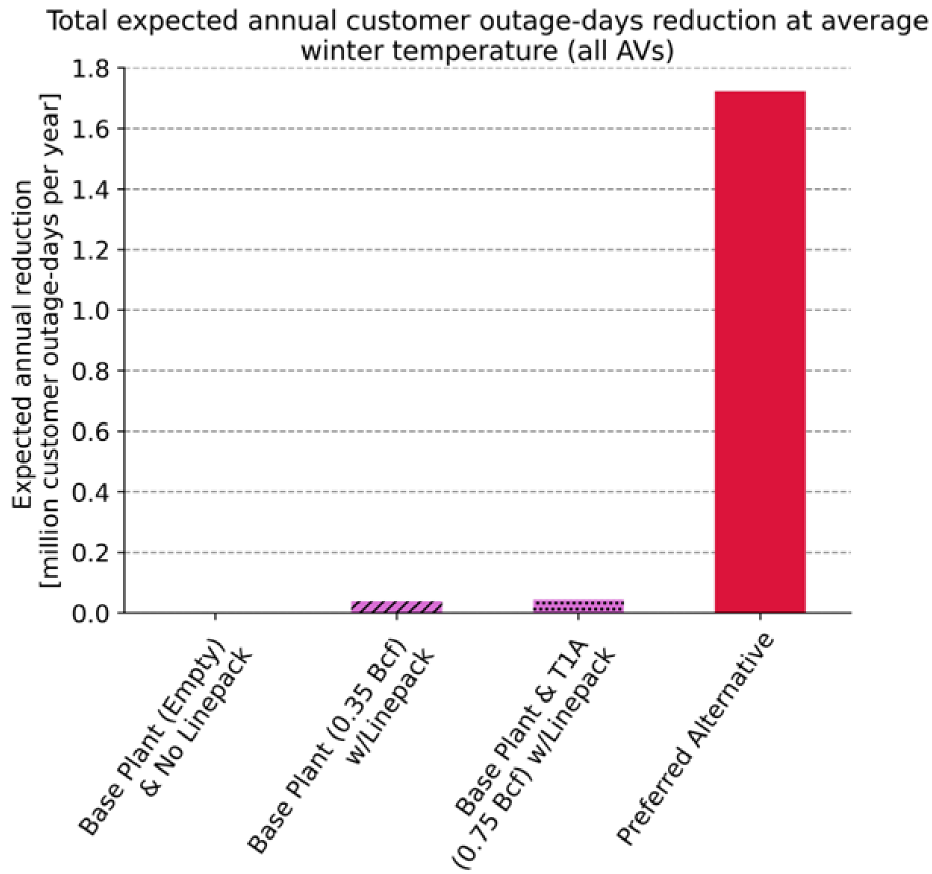
4.7.4.2 Total Combined Risk Reduction for All Assessed Vulnerabilities

The following Exponent figures show their overall risk mitigation results for the Preferred Alternative at average winter temperatures, accounting for T-South, plus all other AVs.[232] The figures express risk mitigation in terms of, respectively, customer-outage-days, customer outages and expected GDP losses ($). The figures show the winter mitigation for a time horizon of only one year. A similar pattern exists, although the mitigation values are much higher, when the risk mitigation is considered on a cumulative basis over 23 and 67 years.

[231] Transcript Volume 1, Web-Based Workshop March 11, 2021, pp. 187-188; Exhibit B-17, BCOAPO IR1 5.1.

[232] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, Figures 47, 48 and 46, respectively.

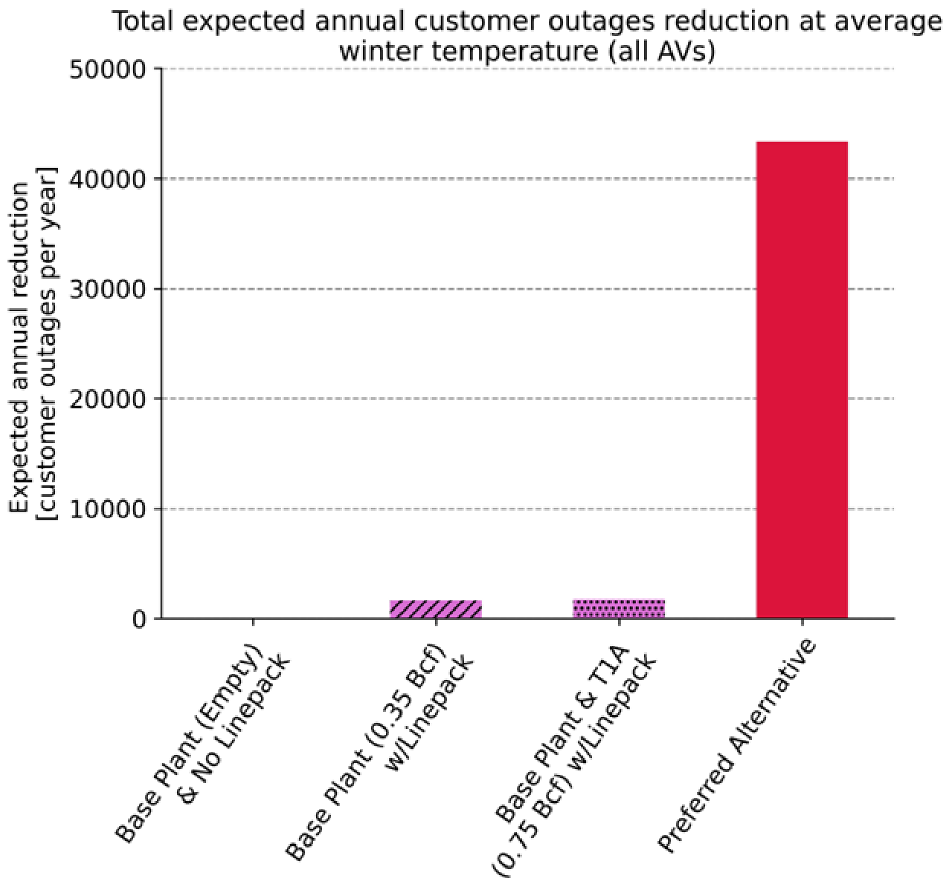
1 **Figure 4-36: Total (All AVs) Expected Annual Winter-Only Customer Outage Days Reduction[233]**



2

[233] At average winter temperature and compared to the three baseline (status quo) scenarios provided to Exponent.

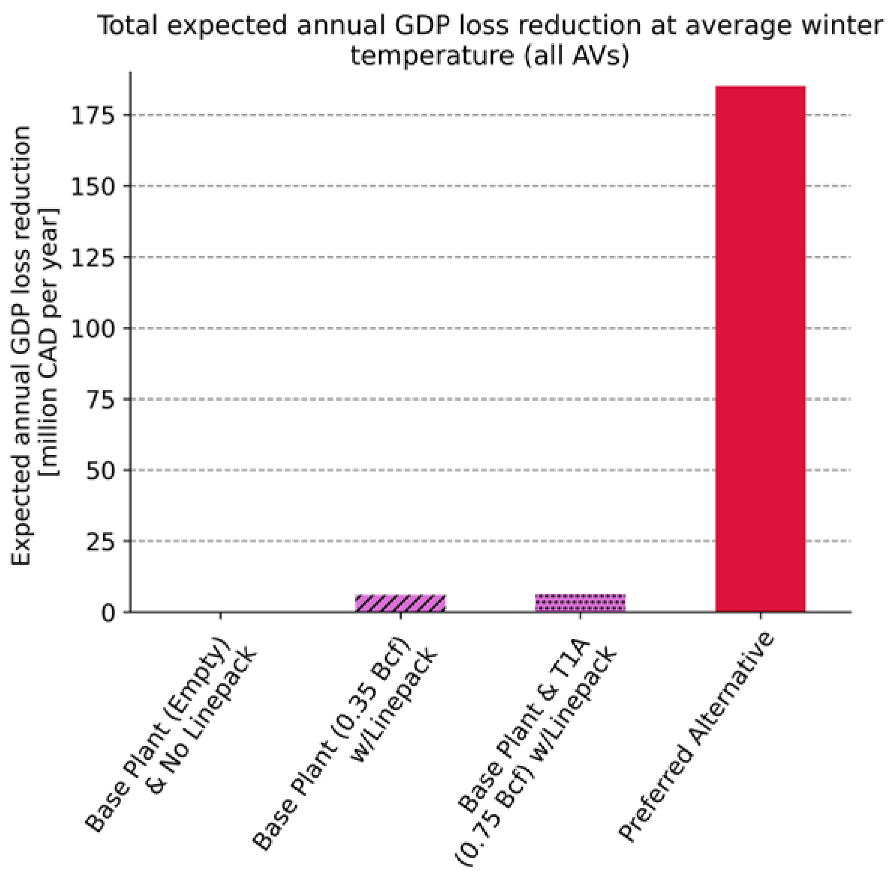
1 **Figure 4-37: Total (All AVs) Expected Annual Winter-Only Customer Outages Reduction**[234]



2

[234] At average winter temperature and compared to the three baseline (status quo) scenarios provided to Exponent.

Figure 4-38: Total (All AVs) Expected Annual Winter-Only GDP Loss Reduction[235]



4.7.5 Preferred Alternative Protects Customers from Off-System Storage Disruptions

FEI contracts storage capacity at JPS and Mist to provide seasonal supply during the winter period. Both are AVs in FEI's 2024 Resiliency Plan. Under normal operating conditions, FEI receives storage supply at Huntingdon through gas displacement which works essentially as an exchange of third-party T-South supply with FEI's off-system storage supply. However, the displacement service is not available during major disruptions which limit the withdraw from off-system storage. Operational issues can occur for a variety of reasons along the supply chain which result in supply shortfall and restricted capacity. For example:

- During a recent cold snap in the Pacific Northwest region during January 2024, both TransCanada (i.e., Foothills) and an outage at the JPS facility required additional natural gas to be sent out from Tilbury and Mt. Hayes during the cold event.
- The January 2023 T-South "swamp gas" incident discussed in Section 3.2.3.2.1 of this Supplemental Evidence resulted in FEI experiencing an unexpected reduction of gas

[235] At average winter temperature and compared to the three baseline (status quo) scenarios provided to Exponent.

supply to its downstream system over approximately a 24-hour period. FEI relied on the Mt. Hayes and Tilbury facilities to make up for the supply shortfall.

If operational issues occur on the cold winter days, it would be very challenging for FEI to replace a significant amount of storage supply in the market within a few hours. Under these circumstances, TLSE Project LNG can be used to backstop storage supply to meet FEI's customer demand and limit the impact on customers.

4.8 CONCLUSION

FEI's expanded alternatives analysis provides a sound basis for selecting Supplemental Alternative 9 as the Preferred Alternative. An alternative must, at a minimum, be commercially and technical viable and allow FEI to continue meeting its firm load to avoid firm customer curtailments in normal operations. The analysis confirms that, among the viable options, Supplemental Alternative 9 delivers on the Project objectives in a way that provides superior customer value. In particular, Supplemental Alternative 9 will:

- Maintain and expand FEI's on-system firm peaking supply;
- Significantly mitigate FEI's largest customer outage risks associated with T-South, plus other AVs and off -system storage disruptions;
- Fully address end-of-life issues with the existing Tilbury Base Plant which has reached end-of-life and is experiencing age-related challenges;
- Compare favourably to smaller replacement facilities in terms of levelized total rate impact; and
- Be fully utilized throughout its expected service life.

As FEI has demonstrated in this section, it is in customers' best interest to replace the Base Plant and size the new facility based on near and mid-term load requirements, rather than under-sizing the TLSE Project for resiliency and gas supply in anticipation of uncertain adverse long-term future load scenarios. FEI will retain the flexibility to determine, in the future, how much of the tank should be set aside as a "resiliency reserve", and how much can be made available to optimize the gas supply portfolio. FEI's adverse load loss sensitivities (mDEP 2% and 5%) show that customers can expect to continue benefitting from the Preferred Alternative over time.

5. PROJECT DESCRIPTION

5.1 INTRODUCTION

In this section, FEI provides an update on the Project description, including the approach for calculating the updated Project cost estimate and the updated Project schedule.

The scope of the TLSE Project has not changed, and much of the information contained in Section 5 of the Application remains current and applicable. There have been no changes made to the key Project components, how they advance the Project objectives,[236] FEI's assessment of resources to complete the Project,[237] the risk management approach taken[238] or FEI's assessment of the key regulatory permits and approvals.[239] FEI has undertaken the necessary work to reflect new geotechnical standards, and to update the cost estimate and schedule, as further described below.

5.2 PROJECT COMPONENTS REMAIN THE SAME

The Project components remain the same. As discussed in Section 4 of this Supplemental Evidence, the preferred alternative (Supplemental Alternative 9) continues to be to replace the existing Base Plant with 3 Bcf of storage and 800 MMcf/d of regasification capacity. The tank will be allocated between a 2 Bcf resiliency reserve and 1 Bcf allocated to gas supply as a peaking resource.

Table 5-1 below provides an overview of the Project components and how each component serves the Project objectives described in Section 3 of the Supplemental Evidence.

[236] Discussed in Section 3 of the Supplemental Evidence and Exhibit B-1-4, Application, Section 5.2.
[237] Discussed in Exhibit B-1-4, Application, Section 5.6.
[238] Discussed in Exhibit B-1-4, Application, Section 5.7.
[239] Discussed in Exhibit B-1-4, Application, Section 5.8.

Table 5-1: Overview of Project Components

Key Project Component	How Component Serves Project Objective
Regasification capacity of 800 MMcf/day.[240]	800 MMcf/day of regasification capacity serves a gas supply and resiliency function: • The current regasification equipment is end-of-life. It is obsolete, experiencing increasing rates of failure and reliability issues, and is difficult to maintain or repair. • FEI's peaking supply requirements (200 MMcf/d) exceed the current regasification capacity at Tilbury (150 MMcf/d). The increased regasification allows FEI to inject sufficient natural gas from Tilbury into the Lower Mainland system each day to ensure that it is able to meet peak load consistently as it has for decades. • The current regasification capacity is far too small to be able to prevent a Day 1 system depressurization following a T-South winter no-flow event. • The proposed equipment will provide quicker response time than the present configuration. The response time will be two hours (between notification from FEI Gas Control to gas delivered to the system). This is beneficial for both gas supply and resiliency.
LNG storage Tank of 3 Bcf (142,400 m^3).	The Base Plant was constructed to lower engineering and safety standards that were in place at the time of construction. There are seismic, environmental and flooding issues inherent in the original Base Plant design. External experts have advised against refurbishment. The new LNG tank will be designed according to current design standards to provide safe and reliable operations. A 3 Bcf tank provides a 2 Bcf resiliency reserve and 1 Bcf allocated to gas supply as a peaking resource: • The resiliency reserve provides sufficient LNG supply to serve FEI's Lower Mainland average winter load for approximately 4.5 days if a T-South no-flow event were to occur. This, in combination with the increased regasification capacity, provides significant customer outage risk mitigation. • The 1 Bcf gas supply allocation will ensure that FEI has sufficient peaking resources to serve firm demand during peak periods, and allow FEI to optimize its gas supply portfolio.
Addition or modification of any necessary auxiliary systems including power supply, utility pipe racks, in-tank pumps, piping, cable trays, instrument air compressors, boil-off gas compressors, connectivity to Tilbury 1A LNG storage tank, and connections to the sendout gas pipeline.	These systems are required to provide the necessary power, control, monitoring, and interconnection systems to safely and reliably operate the facility.

[240] 4x200 MMcf/d. Each unit is capable of an output range of 50 to 200 MMcf/d (i.e., 50 MMcf/d is the lowest capacity at which a vapourizer can operate).

Key Project Component	How Component Serves Project Objective
Demolition of above-ground portion of the Tilbury Base Plant LNG storage tank and liquefaction facilities (Base Plant).	As explained in Section 3 of this Supplemental Evidence, the Base Plant has reached end-of-life and needs to be replaced as part of the Project.

5.3 GEOTECHNICAL REQUIREMENTS HAVE CHANGED DUE TO SEISMIC DESIGN STANDARD CHANGES

The geotechnical requirements for the Preferred Alternative have changed due to changes in the seismic design standards since the Application was filed.

The 2020 geotechnical costs, linked to design based on an earlier version of the CSA Z276 code, are no longer valid due to significant changes in seismic hazard and design criteria according to the latest code CSA Z276: 2022 (April 2023 version). The geotechnical costs from 2020 have been re-evaluated using new construction rates from 2023. To improve the accuracy of the cost estimate, WSP reviewed the design assumptions and consulted with a specialty ground improvement contractor to ensure the design requirements could be met.

Detailed geotechnical work will be carried out prior to commencing detailed design to ensure the proposed ground improvements will meet the limits of the ground settlement specified by the tank vendor.

5.4 APPROACH TO UPDATED TLSE PROJECT COST ESTIMATE

As discussed in Section 6.1 of this Supplemental Evidence, FEI has updated the AACE Class 3 Project cost estimate to account for industry-wide inflationary pressures, a larger contingency, and P70-based escalation (vs. P50 previously). The updated total cost estimate of the TLSE Project is $1,143.899 million in as-spent dollars, including AFUDC.

5.4.1 Project Cost Estimate Updated Based on AACE with New Contingency and Escalation Reports

Consistent with the original estimate completed in 2020, FEI, in conjunction with Linde, Horton CB&I (HCBI), WSP (previously Golder), and Solaris Management Consultants Inc. (SMCI), updated the Project capital cost estimate using AACE International Recommended Practices 18R-97 and 97R-18 as guides. Please refer to Section 6 and Confidential Appendix G to this Supplemental Evidence for the updated summary of the total base capital cost estimate for the Project, and Confidential Appendices I and J for the Validation Estimating Contingency Report and Escalation Report, respectively.

Please refer to the Application, Section 5.4.1 for an overview of the external experts, their credentials, experience and their scope of work for the estimate.

5.4.2 Basis of Estimate Remains the Same Except for Timing

Please refer to Section 5.4.2 of the Application for more information on the basis of estimate. Aside from a shift in the construction dates, the basis of estimate remains the same.

5.4.3 Risk Analysis Reviewed

The risk assessment process for the Project has not changed. As noted in the Validation Estimating Contingency Report:[241]

> The risk analysis workshops to obtain team inputs were held in 2020. No new workshops were held for this update; however, the systemic and project-specific risks were reviewed with project management in October 2023. Systemic risk inputs were only changed slightly and project-specific risk quantification values were updated as appropriate (e.g., for changes between 2020 and 2023).

FEI has set contingency and escalation amounts in addition to the Project base cost estimate to achieve a P50 confidence level (with a P70 level for escalation risk) to address foreseeable risks and changes in market conditions over time. Contingency and escalation amounts included in the Project cost are discussed further in Section 6 of this Supplemental Evidence.

5.5 UPDATED TLSE PROJECT SCHEDULE

FEI has updated the detailed Project schedule to reflect the passage of time since the Adjournment Decision, during which FEI was preparing a comprehensive resiliency plan and addressing the BCUC's commentary from the Adjournment Decision through this Supplemental Evidence. The overall schedule has been delayed approximately four years from what was presented in the Application (filed in 2020), such that the in-service date is now at the end of 2030, rather than the end of 2026. The current Project schedule was created by FEI, with input from its consultants, to ensure that all activity durations are based on reasonable assumptions and agreed upon by experts with experience scheduling projects of this nature.

As in the Application, the Project construction is divided into the following five main sub-projects:

- Ground Improvement and Early Works;
- Regasification Package;
- Auxiliary Systems (Utility Pipe Rack and Equipment);
- 3 Bcf LNG Storage Tank; and
- Base Plant Demolition.

[241] Supplemental Evidence, Confidential Appendix I, p. 3.

Each sub-project will have its own activities, including pre-construction, construction, and post-construction. Sub-projects will be planned and coordinated to optimize limited space on site and to ensure a streamlined process.

The Project schedule assumes a BCUC approval of the CPCN by Q2 2025, with the execution phase beginning in Q4 2026.

Table 5-2 below is a summary of the Project schedule and key milestones, with a comparison to the schedule and milestones from the Application (see Table 5-9 of the Application). The basis of estimate and detailed Project schedule is included as Appendix H.

Table 5-2: TLSE Project Schedule and Milestones

Activity	Dates from Application	Revised Dates
Environmental Assessment (EA)		
Submit EA Final Application	Jan-22	Jun-25
Phase 2 EA Certificate - Provincial/Federal	Jul-22	Mar-26
Contractor Selection and Award		
Award Engineering Procure Construct (EPC) and Engineering Contract(s)	Jul-22	Jun-26
Permitting		
BC FLNRORD (HCA Inspection Permit)	Jun-23	May-27
BCOGC Permits	Jun-23	Aug-27
Boundary Bay Airport - Email Notification	Jul-23	May-27
Ministry of Transportation and Infrastructure (Highway Use Permit)	Aug-23	May-27
BC 1 Call registration	Jan-24	Aug-27
Port of Vancouver (Notice of Shipping)	Jan-24	May-27
NavCanada (Land Use Program - Tower Care)	Jan-24	Oct-27
Transport Canada (Aeronautical Clearance Permit)	Jan-24	Oct-27
City of Delta Permits	May-24	Jun-27
WorkSafeBC - Worker Compensation Act/OHS Regulation	Jul-24	Aug-27
Technical Safety BC - Safety Standards Act Permits	Dec-24	Jun-27
Metro Vancouver Permits	Jan-25	Jan-28
Construction		
Start of Ground Improvement Work in Regasification and Auxiliary Piping Area	Jan-23	Oct-26
Ground Improvement in Tank Area Start of Construction	Mar-23	Feb-27
First Regasification Units Construction Complete (Phase 1)	Jul-24	Aug-28
Balance of Regasification Units Construction Completion (Phase 2)	Apr-25	Jun-29
Auxiliary System Construction Completion	Sep-26	Oct-30
LNG Storage Tank Expansion Completion	Sep-26	Oct-30
Project Technical Close-out (new)		Dec-30

There have been several schedule adjustments, mostly in the timing of permits based on FEI's current understanding of permitting timelines; however, the overall schedule has been delayed approximately four years from the original schedule in the Application (in service at the end of 2030 rather than the end of 2026).

5.6 CONCLUSION

The scope of the TLSE Project has not changed, and much of the information in the Application remains current and applicable. FEI has undertaken the necessary work to reflect new geotechnical standards and to update the cost estimate and Project schedule.

6. FINANCIAL ANALYSIS FOR PREFERRED ALTERNATIVE

This section provides the updated financial analysis for the Preferred Alternative, a new LNG facility with 3 Bcf of LNG storage capacity and 800 MMcf/d of regasification. FEI has made changes to the analysis to address specific commentary in the Adjournment Decision, and to better reflect the overall customer bill impact.

The section is organized as follows:

- **Section 6.1 – Updated TLSE Project Cost Estimate:** FEI updated the AACE Class 3 cost estimate, including to account for industry-wide inflationary pressures, a larger contingency, and P70-based escalation. The updated total cost estimate for the TLSE Project is $1,143.889 million in as-spent dollars, including AFUDC.
- **Section 6.2 – Updated Financial Analysis:** FEI has undertaken its primary financial evaluation of the Preferred Alternative in a similar manner as in the Application, with the exception that FEI has now also recognized offsetting reductions in the cost of gas due to the Preferred Alternative's incremental gas supply benefits (avoided costs) relative to Supplemental Alternative 1.
- **Section 6.3 – Updated Rate Impact for the Preferred Alternative:** The Preferred Alternative results in a levelized total rate impact of approximately $21 per year over the 67-year analysis period relative to Supplemental Alternative 1. FEI's bill impact analysis reflects the incremental delivery rate impact associated with the Project, partially offset by gas supply benefits (reflected in a lower cost of gas rate) when compared to current 2024 Approved rates.
- **Section 6.4 – FEI Performed a Sensitivity with a Shorter (27-year) Amortization Period to Address BCUC Commentary:** In recognition of the BCUC's commentary in the Adjournment Decision, FEI has also provided sensitivities based on a shorter amortization period (i.e., full depreciation by 2050).

6.1 UPDATED TLSE PROJECT COST ESTIMATE

As discussed below, FEI updated the AACE Class 3 cost estimate. The updated cost estimate incorporates industry-wide inflationary pressures, a larger contingency, and P70-based escalation (compared to the P50-based escalation used in the Application). The updated total cost estimate is $1,143.889 million in as-spent dollars, including AFUDC.

6.1.1 Approach to Updated Project Costs Estimate, Contingency and Escalation

Consistent with the original estimate completed in 2020, FEI, in conjunction with Linde, HCBI, WSP (previously Golder), and SMCI, updated the Project capital cost estimate using AACE International Recommended Practices 18R-97 and 97R-18 as guides.

The design and quantities remain largely unchanged. With the exception of the ground improvement work, the updated AACE Class 3 cost estimate is based on quantities that were developed using the designs and material take-offs completed as part of the original estimate in 2020. The changes in the ground improvement work are due to a change to the seismic standards.

The updated base capital cost estimate is $731.067 million in 2023 dollars (before contingency, deferred costs and financing costs), which is an approximate 38 percent increase from the original base capital cost estimate of $529.103 million. The difference between the original and the updated base capital cost estimate is primarily due to inflationary increases in material and equipment costs and, to a lesser extent, increased labour costs consistent with the increases experienced across the industry since 2020 when the original estimate was completed. Please refer to Confidential Appendix G to this Supplemental Evidence for the updated summary of the total base capital cost estimate for the Project.

FEI also re-engaged Validation Estimating to update the quantitative analysis on Project specific risks and systemic risks used to determine the appropriate level of contingency, as well as to update the escalation risk analysis used to determine the appropriate level of escalation funding.

- **Updated contingency:** For the updated contingency, based on the updated quantitative risk analysis, a total capital budget at a P50 confidence level was recommended by Validation Estimating, resulting in a contingency estimate of $135.800 million in 2023 dollars, which is approximately 19 percent of the updated base capital cost estimate. No specific management reserve was recommended by Validation Estimating. Please refer to Confidential Appendix I to this Supplemental Evidence for the updated Validation Estimating Contingency Report.
- **Updated escalation, now based on P70:** The original escalation was performed based on a P50 confidence level. For the updated escalation, based on the updated escalation risk analysis completed by Validation Estimating, FEI is now applying a P70 escalation value of $154.460 million. Validation Estimating recommended a higher (P70) confidence level for escalation in consideration that the scale of the TLSE Project could put significant demands on local markets that would generate localized escalation. Further, the current base price forecast by S&P Global (formerly IHS Markit) is showing a trend of low prices through 2026, likely reflecting a combination of reduced steel prices and reduced industry capital spending in BC. However, from a pricing risk perspective, a low base forecast means the risk is high should there be a resurgence of inflation and/or competing capital spending, thus emphasizing the need to consider a higher confidence level (e.g., P70) when budgeting for escalation. Please refer to Confidential Appendix J to this Supplemental Evidence for the Validation Estimating Escalation Report.

6.1.2 Summary of Updated Project Cost Estimate

Table 6-1 below summarizes the updated total Project capital cost estimate in both 2023 and as-spent dollars. The updated capital cost estimate for the Preferred Alternative meets the criteria for an AACE Class 3 cost estimate.

Table 6-1: Breakdown of the TLSE Project Cost Estimate ($ millions)

	2023 $	As-Spent $
LNG Tank (3 BCF)	359.749	423.480
Regasification Equipment	141.483	166.547
Ground Improvement	60.944	71.740
Auxiliary System	153.964	181.239
Base Plant Demolition	14.927	17.571
Subtotal Capital Cost	731.067	860.578
Contingency	135.800	160.749
Subtotal Project Capital Costs w/ Contingency	866.867	1,021.327
CPCN Application	4.945	4.945
CPCN Preliminary Stage Development	1.546	1.546
Subtotal w/ Deferral Costs	873.358	1,027.818
AFUDC	-	120.096
Tax Offset	-	(4.025)
TOTAL Project Cost	***873.358***	***1,143.889***

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

- An updated capital cost estimate of $731.067 million in 2023 dollars developed by FEI, in conjunction with Linde, HCBI, WSP, and SMCI. The capital cost estimate includes:
  - $688.321 million of base capital costs comprised of a new 3 Bcf LNG storage tank, 800 MMcf/d of regasification equipment, ground improvement work including installation of stone columns necessary for the new LNG storage tank, new auxiliary system, and base plant demolition. Please refer to Section 5.3 of the Application for a detailed description of each component of the Project; and
  - $42.746 million of pre-construction capitalized development costs, which include actuals of $28.347 million from 2020 to 2023, and a forecast of $14.399 million from 2024 to 2025.
- A contingency estimate of $135.800 million in 2023 dollars (approximately 18 percent of the base cost estimate of $731.067 million in 2023 dollars), as discussed in Section 6.1.1 above, provides a total capital budget at a P50 confidence level.
- A P70 escalation value of $154.460 million as discussed in Section 6.1.1 above for the Project over the period from 2024 to 2030 applied to both the base capital cost and contingency.[242] The escalation is used to convert the Project capital cost, including contingency, from 2023 dollars to as-spent dollars (i.e., from $866.867 million in 2023 dollars to $1,021.327 million in as-spent dollars).

[242] No escalation has been applied on actual costs incurred by FEI prior to December 2023.

- Estimated $6.491 million of total deferred costs, which includes $4.945 million of Application Costs and $1.546 million of Preliminary Stage Development Costs. Please refer to Section 6.1.2.2 of this Supplemental Evidence for further discussion.
- Financing costs based on FEI's 2024 approved AFUDC rate of 6.24 percent, equivalent to FEI's after-tax weighted average cost of capital (WACC).[243]

6.1.2.1 Updated Project In-Service Years by Asset Components

The TLSE Project is expected to complete in multiple phases from 2025 to 2030. Table 6-2 below provides the estimated amount of the Project costs (i.e., $1,143.889 million) to be complete (deferral) or in-service (capital costs) each year between 2025 and 2030. Consistent with FEI's treatment of major project capital costs, including CPCNs, once the assets are placed into service, the associated capital cost will be added to FEI's rate base on January 1 of the following year. For Project deferral costs, please refer to Section 6.1.2.2 below for the proposed treatment.

Table 6-2: Breakdown of Project Capital Costs by In-Service Year (2025-2030)

	Project complete and in-service each year, incl. Project Deferral ($ millions) (To be transferred to Rate Base January 1 of each following year)						
As-Spent $, incl. AFUDC and Tax Offset	2025	2026	2027	2028	2029	2030	TOTAL
LNG Tank (3.0 BCF)	-	-	-	-	-	572.204	572.204
Regasification Equipment	-	-	-	111.627	102.920	-	214.547
Ground Improvement	-	-	95.484	-	-	-	95.484
Auxiliary System	-	-	-	129.432	48.509	58.063	236.005
Total Charged to Gas Plant in Service	-		95.484	241.058	151.429	630.267	1,118.238
Base Plant Demolition	-	-	-	-	22.724	-	22.724
Project Deferral Costs	2.927	-	-	-	-	-	2.927
Total Project Costs	2.927	-	95.484	241.058	174.153	630.267	1,143.889
Annual Project % In-Service	0.3%	0.0%	8.3%	21.1%	15.2%	55.1%	100.0%

6.1.2.2 Updated Application and Preliminary Stage Development Costs

Consistent with the request in the Application (as discussed in Section 6.4.4 of the Application), FEI is seeking approval under sections 59 to 61 of the UCA for deferral treatment of the Application and Preliminary Stage Development Costs. The Application Costs incurred by FEI include BCUC costs and BCUC-approved intervener costs for the regulatory process, as well as FEI's external legal, consultant, and studies costs for the preparation of the Application, including this Supplemental Evidence, and review as required to complete the regulatory process. The Preliminary Stage Development Costs are related to expenses incurred for engaging third-party consultants for feasibility evaluation, preliminary development, and assessment of potential design and alternatives as required to complete this Application.

[243] As approved for 2024 by Order G-41-24. The actual AFUDC will be calculated based on the approved AFUDC rate at the time of construction.

Table 6-3 below provides an updated forecast of the Application and Preliminary Stage Development Costs. 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 actual Application costs up to December 2023 include the costs to prepare the Application and the subsequent regulatory process. The regulatory process thus far has spanned from December 2020 to March 2023, when it was adjourned by Order G-62-23. The actual Application costs also include the additional legal, consultant, and studies costs incurred by FEI for the preparation of the Supplemental Evidence (i.e., from April 2023 to December 2023). 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.
- $1.546 million of actual Preliminary Stage Development Costs from 2019 to 2020 for the preparation of the TLSE Project and Application. There are no additional preliminary stage development costs incurred by FEI since the Application was filed in December 2020.

Table 6-3: Forecast Application and Preliminary Stage Development Costs Deferral Account ($ millions)[244,245]

Particular	Application (Actual: 2020-2023; Forecast 2024 Onwards)	Preliminary Stage Development (Actual: 2019-2020)	TOTAL
Pre-Tax Costs	4.945	1.546	6.491
WACC Return	0.555	(0.094)	0.461
Total Before Tax Offset	***5.500***	***1.452***	***6.952***
Tax Offset - Costs held in Deferral Account	(1.335)	(0.417)	(1.753)
Tax Offset - Capitalized Costs	-	(2.272)	(2.272)
Total	***4.165***	***(1.238)***	***2.927***
Annual Amortization for 3 years	1.388	(0.413)	0.976

The actual Application and Preliminary Stage Development Costs will be recorded in the proposed non-rate base deferral account, i.e., the Application and Preliminary Stage Development Costs deferral account, attracting FEI's WACC until it enters rate base. Consistent with FEI's previous CPCN applications, FEI proposes to transfer the balance in the deferral account to rate base on January 1 of the year following BCUC approval of the Application. Consistent with FEI's request

244 Income tax offset on the deferred costs (i.e., $1.753 million) equals to the sum of $4.945 million for the Application costs and $1.546 million for the development costs times the income tax rate of 27 percent.

245 Income tax offset on the capitalized costs is related to the pre-construction development costs that were capitalized but are eligible for deduction for tax purposes. The amount (i.e., $2.272 million) is equal to the capitalized costs of $8.416 million times the income tax rate of 27 percent.

in Section 6.4.4 of the Application, FEI is proposing an amortization period of three years for the deferral account.

6.2 UPDATED FINANCIAL ANALYSIS – 67 YEAR ANALYSIS PERIOD

FEI has updated the financial evaluation of the Preferred Alternative based on the updated capital cost estimate shown above in Section 6.1.2 over a 67-year analysis period. This is a similar approach used in the Application, with the exception that FEI has now also recognized offsetting reductions in the cost of service due to the Preferred Alternative's incremental gas supply benefits (avoided costs) relative to Supplemental Alternative 1. Please refer to Section 6.2.3 below for further explanation on the gas supply benefits in the financial evaluation.

FEI has treated Supplemental Alternative 1 as the Base Case Scenario (i.e., all financial results are assessed as incremental to the Base Case Scenario) for the purpose of the financial evaluation. As explained in Section 4 and Appendix C of this Supplemental Evidence, FEI has ruled out Supplemental Alternative 1 because adequate peaking supply is not currently available, and off-system resources are not a replacement for on-system LNG[246]; nevertheless, off-system peaking supply was considered as an alternative to capital infrastructure investment and can serve as a reasonable financial comparator for the TLSE Project alternatives. FEI assumed for this financial analysis that there would be another upgrade to the regional infrastructure by 2035 (with associated costs and an increase in tolls) to continue to serve FEI peak load under the Base Case Scenario.

6.2.1 Summary of Results – 67-Year Analysis Period

Table 6-4 below provides the present value (PV) of the incremental revenue requirement and the levelized total rate impact to FEI's non-bypass customers over a 67-year analysis period. Details of the financial evaluation of the Preferred Alternative are provided in the Financial Schedules included in Confidential Appendix K to this Supplemental Evidence.

As shown in Table 6-4 below, the PV of the incremental revenue requirement due to the Preferred Alternative is approximately $723.267 million over the 67-year analysis period, which includes approximately $1,240.821 million of PV delivery margin impact related to the capital cost of the Project that is partially offset by approximately $517.554 million related to the avoided cost of gas provided by the additional 1 Bcf of LNG storage reserved for gas supply (compared to the Base Case Scenario, as discussed in Section 4.5.4.1.2 of this Supplemental Evidence).

The levelized total rate impact of the Preferred Alternative over the 67-year analysis period, including both the delivery rate impact and the cost of gas savings, is 2.45 percent, which is equivalent to $0.228 per GJ. For clarity, the new assets associated with the Project will be included in FEI's rate base when construction completes, with the capital costs recovered through FEI's delivery rates. The avoided gas supply costs, in contrast, will be a benefit to FEI's cost of gas which is not part of FEI's delivery rates. As such, in order to evaluate the Preferred Alternative,

246 See discussion in Section 3.3.4 of this Supplemental Evidence.

taking into account both the impacts due to the capital cost and the gas supply benefits, FEI presents a levelized total rate impact (which is the levelized total bill impact) over the 67-year period in Table 6-4 below. If presented separately, the levelized delivery rate impact due to the Project is 6.90 percent and the levelized cost of gas impact due to the gas supply benefits are savings of 4.49 percent.[247]

Table 6-4: Financial Analysis of the Project – 67-year Analysis Period

Line	Particular	TOTAL	(Confidential Appendix K, Financial Schedule)
1	Total Charged to Gas Plant in Service ($ millions)	1,118.238	Schedule 6; Line 65
2	Base Plant Demolition Costs ($ millions)	22.724	Schedule 6; Sum of Line 62 (2025 to 2029)
3	Total Project Deferral Cost, Net of Tax ($ millions)	2.927	Schedule 9; Line 6 + Line 15
4	***Total Project Cost ($ millions)***	**1,143.889**	**Sum of Line 1 to Line 3**
5			
6	Incremental Delivery Margin in 2035 ($ millions)	118.671	Schedule 1; Line 12 (2035)
7	Incremental Cost of Gas Benefits in 2035 ($ millions)	(63.000)	Schedule 1; Line 2 (2035)
8	***Net Incremental Revenue Requirement in 2035 ($ millions)***	**55.671**	**Line 6 + Line 7**
9			
10	PV of Incremental Delivery Margin 67 years ($ million)	1,240.821	Schedule 10; Line 22
11	PV of Incremental Cost of Gas Benefits 67 years ($ million)	(517.554)	Schedule 10; Line 32 - Line 22
12	***Net PV of Incremental Revenue Requirement 67 years ($ million)***	**723.267**	**Line 10 + Line 11**
13			
14	Delivery Rate Impact in 2035 (%)	10.40%	Schedule 10; Line 25 (2035)
15	Total Rate Impact (incl. Cost of Gas) in 2035 (%)	2.97%	Schedule 10; Line 35 (2035)
16			
17	***Levelized Total Rate Impact (Incl. Cost of Gas) 67 years (%)***	**2.45%**	**Schedule 10; Line 39**
18	***Levelized Total Rate Impact (Incl. Cost of Gas) 67 years ($/GJ)***	**0.228**	**Schedule 10; Line 46**

6.2.2 Basis for 67-Year Analysis Period

The 67-year analysis period is based on a 60-year post-Project analysis period plus seven prior years from 2024 to 2030 (with all new assets to be placed in-service by 2030 as shown in Table 6-2 above).

As discussed in Section 6.4.1 of the Application, the 60-year post-Project analysis period was chosen based on the average service life for a new 3 Bcf LNG tank, as recommended by Concentric Advisors, ULC (Concentric), who completed FEI's most recent Depreciation Study (2022) which was filed as part of FortisBC's 2025-2027 Rate Setting Framework Application.[248] As discussed in Section 4.5.5 of the Supplemental Evidence, FEI expects the Preferred Alternative will continue to be used and useful through the energy transition and, as such, the 60-

[247] The levelized delivery rate impact of 6.90 percent is calculated based on a PV of incremental revenue requirement over a 67-year period of $1,240.821 million related to the capital cost and divided by the PV of FEI's 2024 approved delivery margin over a 67-year period of $17.984 billion (see Confidential Appendix K to this Supplemental Evidence, Schedule 10, Line 29). The levelized cost of gas impact of 4.49 percent is calculated based on a PV of incremental cost of gas benefits over a 67-year period of $517.554 million divided by the PV of FEI's 2024 approved cost of gas over a 67-year period of $11.527 billion (see Confidential Appendix K to this Supplemental Evidence, Schedule 10, Line 38 – Line 28). The total levelized rate impact (delivery and cost of gas) of 2.45 percent is calculated based on the total PV of revenue requirement of $723.267 million divided by the total PV of FEI's 2024 approved revenue requirement of $29.511 billion (i.e., sum of $17.984 billion and $11.527 billion).

[248] Filed for BCUC review on April 8, 2024.

year post-Project analysis period (based on the expected average service life of the LNG storage tank) remains appropriate. As part of this Supplemental Evidence, FEI continues to seek approval of a depreciation rate of 1.67 percent and a net salvage rate of 0.67 percent (equivalent to 60 years) for the new 3 Bcf LNG tank.

Please refer to Section 6.4 of the Supplemental Evidence for a financial evaluation based on a shorter post-Project analysis period in response to the BCUC commentary from the Adjournment Decision.

6.2.3 Importance of Recognizing Avoided Gas Supply Costs

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.

These avoided costs are related to the “third Bcf” allocated for planning purposes to gas supply (i.e., not the 2 Bcf resiliency reserve) and the associated increased regasification capacity. As highlighted in Section 4.5.4.1.2 of this Supplemental Evidence, FEI has estimated the avoided costs to be approximately $7 million (post mitigation) between 2030 and 2035. The avoided costs are based on the assumptions that peaking gas supply ceases to be available from Tilbury (when the existing Base Plant ceases operation due to its age and Tilbury 1A is fully subscribed through RS 46) and that third party regional pipeline or storage upgrades will not be completed until at least 2035. From 2035 onwards, FEI estimated the avoided costs to be between approximately $63 million and $79 million annually, as shown in Figure 4-7 of this Supplemental Evidence, reflecting the gas supply costs that FEI would incur by relying on regional infrastructure under the Base Case Scenario (i.e., Supplemental Alternative 1). For the financial analysis, FEI has used the lower bound of gas supply costs of $63 million.

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.

6.2.4 Assumptions Used

With the exception of the gas supply benefits discussed above, FEI applied the same assumptions to the financial evaluation in this Supplemental Evidence as was used in the Application; however, FEI updated the assumptions from 2020 dollars to 2023 dollars.

The assumptions applied to the financial analysis are summarized below:

- **Inflation:** 2 percent annually for incremental O&M, property tax, and future capital replacement costs during the post-Project analysis period starting from 2031 (i.e., since the new LNG tank is scheduled to be in-service in 2030, the first full year of the new LNG tank in-service will be 2031). This is consistent with the Bank of Canada inflation target of 2 percent which Canada is expected to return to in 2025.[249]
- **Incremental O&M:** An estimate of incremental O&M costs resulting from the TLSE Project of approximately $5.729 million in 2023 dollars ($6.953 million in 2031 dollars[250]). These costs are comprised of:
  - approximately $8.818 million in 2023 dollars ($10.585 million in 2031 dollars) of new O&M costs, including electricity costs, associated with the new 3 Bcf LNG tank, the new 800 MMcf/d regasification equipment, and auxiliary systems;
  - offset by O&M savings, including electricity costs, of approximately $3.089 million in 2023 dollars ($3.631 million in 2031 dollars) due to the demolition of the Tilbury Base Plant.

  The O&M estimates for the new tank, regasification equipment, and auxiliary systems are based on the escalated estimates from 2019 developed by Partners in Performance (PiP), as presented in Confidential Appendix N of the Application. As part of this Supplemental Evidence, FEI updated the maintenance, utilities, chemicals and reagents, and insurance costs, as well as the cross-charge expenses, to 2023 dollars using actual CPI inflation from 2019 to 2023. FEI also updated the labour costs to 2023 dollars based on FEI's actual increase in costs for the relevant roles. For electricity costs, FEI updated the calculation based on BC Hydro's RS 1830 for transmission service customers, which was recently approved by the BCUC and will be transitioning from RS 1823 over a three-year period from 2024 to 2026.[251] FEI assumed a 2 percent general electricity rate increase for 2026 and beyond.

  The offsetting savings reflect the average of historical O&M costs for the Tilbury Base Plant over the most recent 10-year period from 2014 to 2023. These costs will no longer be incurred once the Tilbury Base Plant is decommissioned.
- **Property Tax:** Incremental property tax as a result of the new 3 Bcf tank based on the 2023 tax rate. The incremental property tax is assumed to occur in phases based on percentage completion of the LNG tank construction between 2025 and 2030.
- **Incremental Sustainment Capital for Mechanical Equipment:** FEI continued to use an average of 1 percent per year of the revised mechanical equipment capital expenditures (LNG tank, regasification equipment, auxiliary equipment) in this Supplemental Evidence as an estimate of incremental sustainment capital due to the Project. As explained in

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249 Bank of Canada Monetary Policy Report – April 2024 (https://www.bankofcanada.ca/2024/04/mpr-2024-04-10/#:~:text=The%20Bank%20projects%20that%20inflation,April%201%20to%20March%2031).

250 Based on 2 percent annual inflation for all O&M costs, except electricity. Since the new LNG tank is scheduled to be in-service in 2030, the first full year of the new LNG tank in-service will be 2031.

251 Order G-353-23; three-year transition from RS 1823 to 1830 from BC Hydro's Fiscal 2025 to Fiscal 2027 (i.e., April 2024 to April 2026).

Section 6.3 of the Application, this assumption was developed by PiP based on the industry benchmark of similar operations and interviews with third party industry experts.[252] This benchmark applies to the capital cost of the mechanical equipment only, which does not include other indirect costs such as mobilization, engineering, contingency, etc.

- **Future capital replacement:** The average service life for the regasification equipment and auxiliary system is 41 years, which is shorter than the 60-year post-Project period used for the financial analysis. As such, FEI's financial analysis includes future replacement of the regasification and auxiliary systems at the end of their average service life at 41 years. The future replacement costs are based on the 2023 estimate plus an annual escalation of 2 percent. Consistent with the assumption made in the financial evaluation completed in 2020 as part of the Application, the future capital replacement does not include the replacement of ground improvement work related to stone columns. FEI does not expect the stone columns will need to be replaced within the 60-year post-Project period.

For clarity, FEI is not seeking approval of the incremental sustainment capital, incremental O&M, or the future capital replacements as part of this proceeding. These costs are included as a proxy to ensure a fulsome analysis of the financial impact of the TLSE Project over the expected life of the new assets. If these requirements materialize in the future, FEI will seek approval from the BCUC, as required, for these incremental costs in future applications such as FEI's revenue requirement applications.

6.3 UPDATED RATE IMPACT FOR THE PREFERRED ALTERNATIVE

The incremental delivery rate impact from 2026 to 2031 includes the amortization from the Application and Preliminary Stage Development Costs deferral account between 2026 and 2028, as discussed in Section 6.1.2.2 above, and the incremental impact of the capital costs which will enter FEI's rate base in phases between 2028 and 2031, as shown in Table 6-2 above.

The updated incremental delivery rate impact due to the Project is summarized as follows:

- Based on the updated capital cost estimate in Section 6.1.2 above, the Preferred Alternative will result in a cumulative incremental delivery rate impact of 11.03 percent by 2031 when compared to FEI's 2024 approved delivery rates.
- The year-over-year increase in delivery rate is shown in Table 6-5 below, with an average incremental delivery rate impact per year of approximately 1.78 percent over the six-year period from 2026 to 2031 when compared to FEI's 2024 approved delivery rates.

[252] Exhibit B-1-4, Application, Confidential Appendix N.

Table 6-5: Summary of Delivery Rate Impact for the TLSE Project

	2026	2027	2028	2029	2030	2031
Annual Delivery Margin, Incremental to 2026 Approved, Non-Bypass ($ millions)	1.328	1.456	13.834	33.280	54.792	125.920
% Increase to 2026 Approved Delivery Margin, Non-bypass	***0.12%***	***0.13%***	***1.21%***	***2.92%***	***4.80%***	***11.03%***
Incremental % Delivery Rate Impact (Year-over-Year)	***0.12%***	***0.01%***	***1.08%***	***1.68%***	***1.83%***	***5.95%***

However, when accounting for the cost of gas savings starting from 2031 (as discussed in Section 6.2.3 above) in addition to the incremental delivery rate impact from 2026 to 2031, the levelized total rate impact (levelized total bill impact) over the 67-year analysis period due to the Project is 2.45 percent or $0.228 per GJ. For the typical residential customer with an average annual consumption of 90 GJ, this is equivalent to a bill impact of approximately $20.55 per year over the 67-year analysis period.

6.4 FEI PERFORMED A SENSITIVITY WITH A SHORTER (27-YEAR) AMORTIZATION PERIOD TO ADDRESS BCUC COMMENTARY

Regarding the rate impact analysis time horizon, the BCUC stated in the Adjournment Decision:[253]

> However, the cost justification for the larger [3 Bcf vs 2 Bcf] tank is based on forecasts over 67 years at a time when the future of natural gas and the pipeline system is uncertain. The Panel reviews these uncertainties in Section 5.2.1 of this Decision." Page 40: "Because of these concerns we are unable to find a 60-year life to be appropriate for the purpose of amortization. Given the uncertainties around the useful life, a shorter amortization period may be more appropriate.

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[254]. The 27-year analysis period, with all new assets being fully depreciated by 2050, aligns with BC's target of net-zero by 2050[255] and the timeframe suggested by the BCUC in the Adjournment Decision.[256]

Table 6-6 below provides the financial analysis with a shorter analysis period of 27 years compared to the proposed 67-year analysis period. As a result of higher depreciation rates for all

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253 Adjournment Decision, p. 21.

254 The 27-year period includes the Project period from 2024 to 2030 and the post-Project period by assuming all assets will be fully depreciated by 2050.

255 cleanbc_roadmap_2030.pdf (gov.bc.ca).

256 Adjournment Decision, pp. 39-41.

new assets related to the Project (i.e., in order to be fully depreciated by 2050), the levelized total rate impact would be 3.56 percent, which is approximately 1.11 percent higher than the levelized total rate impact of 2.45 percent if the new assets are depreciated over a 60-year period (i.e., a 67-year analysis period when including the seven prior years starting from 2024). For a typical residential customer with an average annual consumption of 90 GJ, this is equivalent to a levelized total bill impact of approximately $29.88 per year if the assets are to be fully depreciated by 2050, which is approximately $9.34 per year higher than the $20.55 per year shown in Section 6.3 above.

FEI notes that using a shorter amortization period might entail additional costs for managing external financial reporting.[257] These additional costs are unknown and therefore have been excluded from the financial analysis presented in Table 6-6 below.

Table 6-6: Financial Analysis of the Project over 27 Years Compared to 67 Years (20 Years vs. 60 Years Expected Service Life)

Line	Particular	TOTAL (20-years)	TOTAL (60-years)	Difference
1	Total Charged to Gas Plant in Service ($ millions)	1,118.238	1,118.238	-
2	Base Plant Demolition Costs ($ millions)	22.724	22.724	-
3	Total Project Deferral Cost, Net of Tax ($ millions)	2.927	2.927	-
4	***Total Project Cost ($ millions)***	**1,143.889**	**1,143.889**	**-**
5				
6	Incremental Delivery Margin in 2035 ($ millions)	163.014	118.671	44.344
7	Incremental Cost of Gas Benefits in 2035 ($ millions)	(63.000)	(63.000)	-
8	***Net Incremental Revenue Requirement in 2035 ($ millions)***	**100.014**	**55.671**	**44.344**
9				
10	PV of Incremental Delivery Margin over analysis period ($ million)	1,199.226	1,240.821	(41.595)
11	PV of Incremental Cost of Gas Benefits over analysis period ($ million)	(337.830)	(517.554)	179.724
12	***Net PV of Incremental Revenue Requirement over analysis period ($ million)***	**861.396**	**723.267**	**138.128**
13				
14	Delivery Rate Impact in 2035 (%)	14.28%	10.40%	3.89%
15	Total Rate Impact (incl. Cost of Gas) in 2035 (%)	5.34%	2.97%	2.37%
16				
17	***Levelized Total Rate Impact over analysis period (%)***	**3.56%**	**2.45%**	**1.11%**
18	***Levelized Total Rate Impact over analysis period ($/GJ)***	**0.332**	**0.228**	**0.104**

Considering the likelihood that the assets will remain used and useful for the full 60-year expected service life, as discussed in Section 4.5.5 of this Supplemental Evidence, FEI considers it reasonable to depreciate the assets over their 60-year useful life.

6.5 CONCLUSION

FEI's updated financial analysis and incremental rate impact for the Preferred Alternative account for the BCUC's commentary in the Adjournment Decision. FEI updated the capital cost estimate, the contingency, and used a P70 escalation. FEI has accounted for the incremental gas supply benefits associated with avoiding the cost of holding capacity on expanded regional infrastructure,

[257] See Exhibit B-39, BCUC Panel IR1 6.9.1.

which would be necessary under the Base Case Scenario once the Base Plant ceases operation. Although FEI has provided the BCUC-suggested sensitivity based on the assets being fully depreciated by 2050, this period is too short in light of the ongoing resiliency and gas supply benefits discussed in Section 4.5.5 of this Supplemental Evidence.

7. ENVIRONMENT AND ARCHAEOLOGY

Although there has been no change to the TLSE Project scope or footprint, over the past three years, FEI has been advancing the Environmental Assessment (EA) for the Tilbury Phase 2 LNG Expansion Project (Phase 2), which includes components of the TLSE Project. This has involved additional environmental and archaeological activities, including a Stage 2 Preliminary Site Investigation (PSI), Limited Detailed Site Investigation (DSI) and removal of soil stockpiles, discarded rail ties, etc., and completion of an Archaeological Impact Assessment (AIA) for the site. These additional steps have provided FEI the opportunity to further understand the environmental and archaeological risks of the Project, as described below.

Based on the additional assessments undertaken, and prior to FEI's planned mitigation activities, FEI's assessment of the potential impacts of the project have changed.

This section is organized around the following points:

- **Section 7.1 – Environmental Assessment:** The potential environmental impacts of the TLSE Project, which were described as "moderate" in the Application, have been downgraded to "low to moderate".
- **Section 7.2 – Archaeological Assessment:** The potential archaeological impacts of the TLSE Project, which were described as "moderate" in the Application, have been downgraded to "low".

FEI expects to mitigate potential impacts through additional assessments, permitting, and standard protection and mitigation measures so there would be negligible environmental and archaeological effects from the Project.

7.1 ENVIRONMENTAL ASSESSMENT

Technical Data Reports (TDRs) for biophysical receptors identified in the Environmental Overview Assessment (EOA) for the Tilbury site were conducted in preparing the Phase 2 EA application. These reports included a Terrestrial Biophysical TDR (including wildlife and wildlife habitat surveys, vegetation and invasive species surveys and wetlands characterization) and an Aquatic Biophysical TDR (including fish and fish habitat surveys). The findings from these reports support the previous filing's "low" risk rating for the following biophysical receptors:

- Surface water quality and quantity;
- Fish and fish habitat;
- Vegetation and wetlands;
- Wildlife and wildlife habitat; and
- Land use.

Biophysical receptors identified as having additional risk in Section 7.2.1.3 of the Application (i.e., the atmospheric and contaminated soils and ground water receptors) were also further investigated for the Phase 2 EA application. The results of this further investigation are as follows:

- The risk rating of the atmospheric biophysical receptor has not changed, as risks associated with Metro Vancouver permitting are still considered "medium to high".
- For the contaminated soil and/or groundwater biophysical receptor, a Stage 1 and Stage 2 PSI were completed to further understand the potential contamination at the site. These investigations concluded that seven of the eight areas of potential environmental concern (APECs) outlined in the EOA did not show contamination. One APEC, APEC 1 – former sawmill site, was identified to have contaminated soil. A Limited DSI was conducted for APEC – 1 to further delineate the extent of soil contamination, and remediation works are scheduled for the near future. Therefore, the risk rating for the contaminated soils and groundwater biophysical receptor has been downgraded from "medium to high" to "negligible to low".

As described in the Application, FEI will follow best management practices and mitigation measures applicable to the Tilbury site during construction and will obtain all required environmental permits and approvals as required.

7.2 ARCHAEOLOGICAL ASSESSMENT

An AIA was completed for the site in 2021. This work was conducted under *Heritage Conservation Act* Permit #2020-137 and the following Cultural Heritage Investigation permits were obtained:

- Katzie Development Limited Partnership Archaeological/Heritage Permit 2020-03;
- Seyem' Qwantlen Land Development Ltd. Heritage Investigation Permit SQ 2022-63;
- Stó:lō Research and Resource Management Centre Heritage Investigation Permit 2019-225;
- xʷməθkʷəy̓əm (Musqueam Indian Band) Heritage Investigation Permit MIB-2019-163-AIA;
- Sḵwx̱wú7mesh Úxwumixw (Squamish Nation) Archaeological Investigation Permit 20-0131; and
- səlilwətaɬ (Tsleil-Waututh Nation) Cultural Heritage Investigation Permit 2019-149-1.

The objectives of the AIA were as follows:

- Identify the location and extent of archaeological sites that may be affected by the Project;
- Assess the heritage significance of any identified archaeological sites;
- Evaluate the nature and magnitude of direct and indirect impacts of the Project on archaeological sites; and

- Formulate management options for avoiding or mitigating Project impacts to archaeological sites.

During the AIA, 186 test pits were started with four being terminated early due to encountering inactive utilities and two locations not being excavated due to overlaps with known buried utilities. Work was conducted with in-field assistance from representatives from Seyem' Qwantlen, Sḵwx̱wú7mesh Úxwumixw, and Katzie Development Limited Partnership. Due to concerns regarding the COVID-19 pandemic, several Nations did not attend field work, but remote monitoring was provided by representatives from səlilwətaɬ, Katzie Development Limited Partnership, xʷməθkʷəy̓əm. Daily post-fieldwork summaries were also provided to Cowichan Tribes, Katzie Development Limited Partnership, Lyackson First Nation, xʷməθkʷəy̓əm, Sḵwx̱wú7mesh Úxwumixw, səlilwətaɬ, and Tsawwassen First Nation.

No archaeological materials or features were identified as part of the AIA. Recommendations resulting from the AIA included the following:

- No further archaeological work for the Project footprint, provided that it is not altered to include areas that were not assessed during this AIA;
- No further archaeological work for the FEI property (Project area); and
- Project-specific Archaeological Chance Find Management Procedure is to be available to contractors prior to undertaking ground-altering activities.

In 2022, a project-specific Archaeological Chance Find Management Procedure was developed for the Project site, with input from Nations who requested to participate.

With the recommendations from the AIA and development of the Archaeological Chance Find Management Procedure, the risk of archaeological impact has been downgraded from "moderate to low" to "low".

7.3 CONCLUSION

Over the past three years, FEI has undertaken additional environmental and archaeological activities, including a Stage 2 Preliminary Site Investigation, Limited Detailed Site Investigation, and completion of an Archaeological Impact Assessment for the site. Based on the additional assessments undertaken, FEI has downgraded the potential environmental impacts of the TLSE Project from "moderate" to "low to moderate" and has downgraded the potential archaeological impacts from "moderate" to "low". FEI expects to mitigate potential impacts through additional assessments, permitting, and standard protection and mitigation measures.

8. CONSULTATION AND ENGAGEMENT

8.1 INTRODUCTION

This section provides an update on consultation and engagement with Indigenous groups, the public, government and other stakeholders. These activities are integral components of FEI's project development process and meet the requirements of the the BCUC's CPCN Guidelines.

This section is organized around the following points:

- **Section 8.2 – FEI Has Continued to Engage with Indigenous Groups:** FEI has undertaken, and will continue to undertake, significant engagement with Indigenous groups regarding the TLSE Project, including through the ongoing Environmental Assessment process. FEI has also entered into capacity funding and other agreements which have enabled Indigenous groups to meaningfully participate and contribute to these concurrent regulatory processes. FEI's engagement is sufficient, reflecting the TLSE Project's current stage of development.
- **Section 8.3 – FEI Has Continued to Engage with the Public, Governments and Stakeholders:** FEI is committed to meaningful, proactive and ongoing engagement with the public, governments and other stakeholders regarding the TLSE Project through, in particular, the ongoing Environmental Assessment process. FEI's engagement approach has focused on sharing project information through various activities and public communications channels, which have provided stakeholders with the opportunity to provide feedback. FEI's engagement is sufficient, reflecting the TLSE Project's current stage of development.

8.2 FEI HAS CONTINUED TO ENGAGE WITH INDIGENOUS GROUPS

The Application and evidence presented throughout the regulatory proceeding demonstrates that consultation and engagement with Indigenous groups has been meaningful, timely and sufficient to date, given the nature of the approvals sought. These consultation and engagement activities remain consistent with the BCUC's CPCN Guidelines, are in alignment with other FEI applications approved by the BCUC, and reflect the TLSE Project's current stage of development.

FEI has continued to engage with Indigenous groups regarding the TLSE Project, responding to all issues, concerns and opportunities as they are raised.

8.2.1 Summary of FEI's Approach to Engagement with Indigenous Groups

As discussed in the Application and other evidence in this proceeding,[258] FEI's engagement with Indigenous groups with respect to the TLSE Project is taking place through this CPCN Application and the Environmental Assessment (EA) process for the FortisBC Holdings Inc. and FortisBC

[258] See e.g., Exhibit B-1-4, Application, Section 8; Exhibit B-44, Rebuttal Evidence to TWN.

Energy Inc. (collectively, FortisBC) Tilbury Phase 2 LNG Expansion Project (Tilbury Phase 2 Expansion Project), which includes components of the TLSE Project.[259] As these regulatory processes remain underway concurrently, and in recognition of the resource constraints facing many Indigenous groups, FEI sought to limit consultation fatigue by synchronizing engagement activities between these regulatory processes where possible. FEI applies comments received from Indigenous groups through this synchronized process to all applicable aspects of the developments at Tilbury, including the TLSE Project, to ensure they are appropriately captured and addressed.

Engagement with Indigenous groups with respect to the TLSE Project has continued to be guided by FEI's Statement of Indigenous Principles (Appendix R-1 to the Application) and FEI's Engagement Plan (Appendix Q-2 to the Application). FEI's engagement through the EA process has been robust, and consistent with the BC Environmental Assessment Office's (BC EAO) framework for consensus-seeking with Indigenous groups, as outlined in the Assessment Plan for the Tilbury Phase 2 Expansion Project.[260]

8.2.2 Indigenous Groups Identified for TLSE Project

As set out in the Application, FEI identified the following 21 potentially affected Indigenous groups to engage with specifically in respect of the TLSE Project.

Table 8-1: Indigenous Groups Potentially Affected by the TLSE Project

Indigenous Groups		
Cowichan Tribes	Musqueam Indian Band	Soowahlie First Nation
Halalt First Nation	Penelakut Tribe	Squamish First Nation
Katzie First Nation	Seabird Island Band	Stó:lö Nation
Kwantlen First Nation	Semiahmoo First Nation	Stó:lö Tribal Council
Lake Cowichan First Nation	Shxw'ōwhámél First Nation	Stz'uminus First Nation
Lyackson First Nation	Skawahlook First Nation	Tsawwassen First Nation
Métis Nation British Columbia	Snuneymuxw First Nation	Tsleil-Waututh Nation

FEI also continues to engage with the following 22 additional Indigenous groups that have been identified as potentially affected Indigenous Nations by the BC EAO as part of the ongoing EA process for the Tilbury Phase 2 Expansion Project.[261]

[259] Components of the TLSE Project scope (e.g., the TLSE tank) forming part of the Tilbury Phase 2 Expansion Project is a function of the law governing the scope of environmental assessments under the *Environmental Assessment Act*, S.B,C. 2018, c. 51 (BC EAA) and the *Impact Assessment Act*, S.C. 2019, c. 28, s. 1 (IAA).

[260] Tilbury Phase 2 Expansion Project, Schedule B – Assessment Plan: https://projects.eao.gov.bc.ca/api/public/document/62c75af8e04a3a00225b7d84/download/Tilbury%20LNG%20Phase%202%20-%20Assessment%20Plan%20-%20Rev1%20-%20June%2013%202022%20%28EPIC%20Posting%29.pdf.

[261] Tilbury Phase 2 Expansion Project, Schedule B – Assessment Plan, Sections 2.0 – 2.3 Consultation with Indigenous Nations: https://projects.eao.gov.bc.ca/api/public/document/62c75af8e04a3a00225b7d84/download/Tilbury%20LNG%20P

Table 8-2: Indigenous Groups Identified as Potentially Affected by the BC EAO

Indigenous Groups		
Aitchelitz First Nation	Pauquachin First Nation	Tsartlip Indian Band
Chawathil First Nation	Popkum First Nation	Tsawout First Nation
Cheam First Nation	Semá:th (Sumas) First Nation	Tseycum First Nation
Leq'á:mel First Nation	Shxwhá:y Village	Tzeachten First Nation
Kwaw-Kwaw-Apilt First Nation	Skowkale First Nation	Yakweakwioose First Nation
Kwikwetlem First Nation	Skwah First Nation	Yale First Nation
Malahat First Nation	Sq'éwlets (Scowlitz) First Nation	
Matsqui First Nation	Squiala First Nation	

8.2.3 TLSE Project-Specific Engagement with Indigenous groups

FEI's engagement with potentially affected Indigenous groups has continued to be meaningful, timely and sufficient to date, consistent with the BCUC CPCN Guidelines, and reflects the TLSE Project's current stage of development. In particular, FEI has focused its engagement activities on ensuring that Indigenous groups:

- Are kept informed about the TLSE Project and have access to Project-related information as it becomes available;
- Are able to provide feedback, including opportunities to identify issues and concerns regarding the TLSE Project; and
- Have opportunities to describe how the TLSE Project may interact with their Indigenous interests.

FEI has provided these Indigenous groups with updates regarding the TLSE Project as new information arises, and has also addressed issues, concerns and opportunities through the following engagement activities, in particular:

- **Regular Meetings with Indigenous Groups:** FEI has continued to discuss the TLSE Project through regular project meetings with Indigenous groups. A summary of the issues, concerns and opportunities discussed with Indigenous groups since FEI's last evidentiary update regarding Indigenous engagement is provided in Section 8.2.4 below.
- **Tilbury Site Tours:** Since November 2021, FEI has held 16 site tours with Indigenous groups regarding the Tilbury Phase 2 Expansion Project. These tours provide Indigenous groups the opportunity to ask questions about the TLSE Project and to identify areas of concern, interest or opportunity relating to the Project.

hase%202%20-%20Assessment%20Plan%20-%20Rev1%20-%20June%2013%202022%20%28EPIC%20Posting%29.pdf.

- **Updates Regarding the CPCN Application:** FEI sent a notification letter to the 21 potentially affected Indigenous groups (see Table 8-1 above) providing an update regarding the TLSE Project, including the status of the Project and this Application before the BCUC. Indigenous groups were offered an opportunity to ask questions and seek additional information. A copy of this letter is included as Appendix L to the Supplemental Evidence. FEI received two responses: (1) on December 20, 2023, TWN confirmed receipt of the letter; and (2) on January 3, 2024, Lyackson First Nation sought clarification regarding the full name of FEI, which FEI provided in response on January 10, 2024.
- **TWN Final Argument:** In November 2022, TWN filed its Final Argument in this proceeding advising the BCUC that they do not oppose the TLSE Project and are not seeking to delay the Project from moving forward. TWN has not indicated that this position has changed since this filing.[262]

8.2.4 FEI Has Responded to Issues, Concerns and Opportunities Raised by Indigenous Groups

FEI has continued to respond to and address concerns raised by Indigenous groups regarding the TLSE Project. Since November 2021, when FEI provided its last evidentiary update in this proceeding regarding its engagement activities, FEI received inquiries regarding the following:

- The potential environmental impacts of the TLSE Project; including cumulative effects, greenhouse gas (GHG) emissions and marine impacts; and
- Business opportunities related to the TLSE Project.

8.2.4.1 Potential Environmental Impacts

FEI has continued to discuss concerns raised by some Indigenous groups regarding cumulative effects of increased development on and near Tilbury Island, especially as it relates to GHG emissions and increased shipping on the Fraser River related to waterborne delivery of Project materials. In response to the concern regarding increased shipping on the Fraser River, FEI has removed all waterborne delivery of Project materials. FEI has also engaged Indigenous groups regarding air quality, human health and GHG emissions through BC EAO-led workshops and regular project meetings.

Some Indigenous groups also remain concerned about up-stream emissions from the production of LNG, and downstream emissions from LNG's use as a marine fuel. While these concerns are largely related to issues beyond the scope of the TLSE Project, FEI continues to work closely with these Indigenous groups to incorporate their concerns in a manner consistent with the CPCN Guidelines and the EAO effects assessment methodology.

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[262] See TWN Final Argument: https://docs.bcuc.com/documents/arguments/2022/doc_68841_2022-11-21-twn-final-argument.pdf.

8.2.4.2 Business Opportunities

FEI has continued to discuss business opportunities on the TLSE Project with Indigenous groups. In particular, FEI has held multiple meetings with Indigenous groups and provided information via email to address concerns or further discuss opportunities. Specific areas of interest have included:

- Potential contracting opportunities;
- Job training and mentoring opportunities, including Indigenous monitoring;
- Post-secondary opportunities, and future opportunities for youth in archaeological programming, environmental stewardship, and fish habitat programs; and
- Requests for equitable access to business opportunities, particularly for Indigenous groups that are not in immediate proximity to the TLSE Project site.

In November 2022, FEI held an in-person business-to-business session with local Indigenous affiliated and member-owned businesses. In October 2023, FEI also facilitated a business-to-business session with Musqueam Indian Band to discuss procurement opportunities for Musqueam affiliate and member-owned businesses. These sessions included a presentation on the Tilbury development, including TLSE-specific project components, and an opportunity to network with attendees. FEI will continue to engage Indigenous groups regarding business opportunities as the Project progresses, through various methods and forums.

In addition, during an April 2022 Process Planning workshop led by the BC EAO, Seabird Island Band inquired about Project safety and response procedures at the Tilbury Project site, in the case of an emergency. FEI responded by providing additional information regarding Project safety and associated response procedures. FEI has not received any further response on the matter and, therefore, considers this concern to be addressed.

8.2.5 Agreements with Indigenous Groups

Given the scope of the Project, which requires an EA and significant participation from Indigenous groups, FEI has finalized funding agreements with 15 Indigenous groups that support their capacity to actively participate in and engage regarding the Tilbury Phase 2 Expansion Project, including the TLSE Project. FEI has offered a capacity funding agreement to one additional Indigenous group that is not yet finalized. FEI continues regular dialogue with Indigenous groups to discuss capacity constraints and advance agreement-specific deliverables.

In addition to the funding agreements described above, FEI has executed project agreements with the following two Indigenous groups:

- Musqueam Indian Band (August 2022);[263] and

[263] See Exhibit A2-1 and Exhibit B-54-1, BCUC IR4 114.1.

- Snuneymuxw First Nation (January 2023).[264]

Both agreements reflect FortisBC's collective efforts to build strong relationships with Indigenous groups regarding the TLSE Project and other Tilbury Projects, to meaningfully engage with potentially affected Indigenous groups and to seek their free, prior, and informed consent. These agreements demonstrate the value of meaningful engagement undertaken in close collaboration and the spirit of reconciliation for customers of a regulated utility.

8.2.6 Engagement with Indigenous Groups Will Continue

FEI will continue engaging with potentially affected Indigenous groups as development of the TLSE Project progresses, including engagement through the ongoing EA process, and other future permitting processes. In particular, FEI will continue to work collaboratively with Indigenous groups to address existing concerns, address new questions that arise through future engagement, and identify opportunities for Indigenous groups and their members where possible. FEI will also continue to provide updates to Indigenous groups regarding the Application, including notifying these groups about the filing of this Supplemental Evidence.

8.3 FEI HAS CONTINUED TO ENGAGE WITH THE PUBLIC, GOVERNMENTS, AND STAKEHOLDERS

FEI is committed to meaningful engagement with the communities it serves, particularly where its major projects are taking place. Since its last evidentiary update, FEI has continued to actively engage with the public, including its customers, residents, businesses and landowners located near the facility and surrounding area, governments and other stakeholders regarding the TLSE Project using a variety of engagement methods and, in particular, through the ongoing EA process.

As discussed further in the sections below, FEI's engagement with the public, governments and other stakeholders has been meaningful, timely and sufficient to date, given the nature of the approvals sought. These consultation and engagement activities remain consistent with the BCUC's CPCN Guidelines, are in alignment with other FEI applications approved by the BCUC, and reflect the TLSE Project's current stage of development.

8.3.1 Summary of FEI's Approach to Engagement with the Public, Government and Other Stakeholders

FEI's engagement efforts are designed to ensure that the public, governments, and other stakeholders are kept informed about the Project, have access to relevant information, and are provided with multiple opportunities to provide feedback throughout project development. This

[264] Snuneymuxw First Nation and FortisBC Holdings Inc. sign agreement for Tilbury LNG projects, strengthening long-standing relationship (Jan. 27, 2023): https://www.fortisbc.com/news-events/media-centre-details/2023/01/27/snuneymuxw-first-nation-and-fortisbc-holdings-inc.-sign-agreement-for-tilbury-lng-projects-strengthening-long-standing-relationship.

engagement approach supports FEI's goal of understanding public interests and incorporating feedback into the Project design. Since FEI's last evidentiary update, it has continued to create opportunities for stakeholders to learn more about the TLSE Project, to ask questions, and to provide feedback, including identifying issues, concerns and opportunities, as applicable.

FEI has also, and will continue to, maintain the positive relationships developed during engagement to date, particularly with those located closest to the TLSE Project, and with those who have demonstrated a high level of interest. These engagement activities remain consistent with the communication and consultation objectives identified in Section 8.3.2 of the Application.

Further, as described in Section 8.2.1 above, FEI sought to limit consultation fatigue of stakeholders by synchronizing engagement activities where possible between the concurrent regulatory processes. FEI applies comments received from stakeholders through this synchronized process to all applicable aspects of the developments at Tilbury, including the TLSE Project, to ensure they are appropriately captured and addressed.

8.3.2 Engagement with the Public and Other Stakeholders

FEI has continued to engage with the public and other stakeholders through several engagement activities:

- **Site Tours & LNG Demonstrations:** Since November 2021, FEI has held 76 site tours with stakeholders and governments. These tours have provided opportunities for interested stakeholders to ask questions regarding the TLSE Project, and for FEI to educate interested groups on the day-to-day operations of FEI's existing LNG storage facility. FEI has also provided multiple opportunities for stakeholders to view live demonstrations of LNG during FEI-led site tours, and upon request.
- **Meetings & Presentations:** Since November 2021, FEI has held 41 project meetings and presentations with interested members of the public and stakeholders. These meetings have taken place in both a virtual and in-person format to ensure project information is accessible for interested groups.
- **Broad Digital & Customer Communications:** FEI has established and maintained various communication channels, including a project-specific website on TalkingEnergy.ca, where educational materials such as videos and articles have been posted to help the public understand LNG and learn more about the TLSE Project. FEI has also shared these materials on social media and on FortisBC websites to further engage the public. For example, in August 2023, FEI posted an article on Talking Energy focusing on how the TLSE Project will improve the resilience of FEI's gas system.[265]
- **Community Events:** FEI actively participates in local community events held throughout the year, providing many opportunities for the public to ask question and learn about the TLSE Project, in addition to general information about FortisBC and its operations.

[265] https://talkingenergy.ca/stories/tilbury-expansion-ensuring-energy-there-when-you-need-it.

- **EA Open Houses:** In March 2022, FEI participated in two virtual open houses hosted by the BC EAO as part of the prescribed 45-day public comment period during the Process Planning phase of the EA. These open houses allowed FEI to continue to understand key issues, engage with the public and propose further mitigations, where necessary.

Government representatives also participated in a number of the activities summarized above. FEI addresses government-specific engagement below.

8.3.3 Engagement with Government

FEI has engaged directly with nearby local, provincial, and federal government agencies to share updates and seek feedback regarding the TLSE Project. In particular, FEI meets regularly with the City of Delta to provide updates related to the Tilbury LNG facility, including with respect to the TLSE Project, and provides advance notice to government officials of FEI related activities taking place in their communities. FEI has also provided ongoing updates to the nearby City of Richmond. Further, FEI has engaged local government staff, first responders, and other stakeholders in full-scale emergency exercises at the Tilbury LNG facility, fostering collaboration and preparedness, in addition to providing specific LNG training for firefighters.

Finally, as part of the ongoing EA process for the Tilbury Phase 2 Expansion Project, which includes components of the TLSE Project, FEI has maintained regular engagement with government and government agencies through the Technical Advisory Committee (TAC). The TAC's role as part of the EA process is to advise the BC EAO and participating Indigenous Nations on technical matters related to the assessment; and to review FortisBC's application for an EA certificate.[266] The TAC includes participating Indigenous Nations, local governments, provincial, and federal agencies. Since its last evidentiary update, FEI has engaged with government representatives through more than 910 interactions, including 45 site tours, 22 project meetings, and over 840 individual engagements by email or phone.

8.3.4 FEI Has Responded to Issues, Concerns and Opportunities Raised by the Public, Governments and Other Stakeholders

The following sub-sections describe the inquiries, including issues, concerns and opportunities, regarding the TLSE Project that FEI has received from the public, governments and other stakeholders since its last evidentiary update. In general, FEI has continued to reach a wide cross-section of stakeholders through diverse channels, consistent with the communication and consultation objectives identified in Section 8.3.2 of the Application.

8.3.4.1 Inquiries from the Public and Other Stakeholders

Since the last evidentiary update regarding its public engagement activities, FEI has received inquiries from interested members of the public and other stakeholders through various

[266] Tilbury Phase 2 Expansion Project, Technical Advisory Committee Terms of Reference, June 2022: https://projects.eao.gov.bc.ca/api/public/document/629a5bd4eedf690022c8657b/download/TAC%20Terms%20of%20Reference_TilburyLNG_Final.pdf.

communication channels, including by email and through project meetings and site tours. These inquiries have generally focused on aspects of project development, economic opportunities, environmental impacts, as well as issues that are beyond the Project scope. The primary interests raised are specifically related to:

- The purpose and need for the proposed Project;
- Rate impacts associated with the proposed Project;
- GHG emissions associated with LNG for export and marine fuelling; and
- Contracting and workforce opportunities associated with the TLSE Project.

FEI has responded directly to public and other stakeholder inquiries by providing further information regarding the purpose of the TLSE Project, associated rate impacts, as well as the projected economic benefits associated with Project construction. Where applicable, FEI has also provided additional information regarding how potential environmental impacts, such as GHG emissions, are assessed through the ongoing parallel EA process for the Tilbury Phase 2 Expansion.

FEI has committed to providing further information regarding the TLSE Project when it becomes available, to address questions on topics such as the construction schedule, workforce impacts, and job opportunities as development of the Project progresses. FEI has received positive feedback regarding site tours and presentations and will continue to use these engagement methods to respond to issues raised by stakeholders and members of the public.

FEI also recognizes that multiple stakeholder groups and members of the public have concerns regarding issues that are beyond the Project scope (e.g., marine shipping regulations and upstream natural gas extraction). FEI has, to the best of its ability, provided interested parties with supplemental information regarding these issues. One representative also inquired about visual effects of LNG facilities once in operation.

8.3.4.2 Inquiries from Governments

FEI has continued to engage with government representatives to address outstanding concerns, issues and inquiries relating to:

- Project construction and LNG facility operation;
- Traffic impacts;
- Environmental impacts;
- Safety; and
- Issues beyond the Project scope.

FEI addresses each of these inquiries, as well as FEI's response, further below.

8.3.4.2.1 PROJECT CONSTRUCTION AND LNG FACILITY OPERATION

During a process planning workshop as part of the ongoing EA process, FEI received an inquiry regarding hydro-testing during construction of the TLSE Project. In particular, FEI was asked about the use of surface water for the hydro testing of tanks and raised concerns regarding water contamination. In response, FEI confirmed that water from the Fraser River would be used for hydro testing, but that the water would be treated prior to discharge.

The City of Richmond inquired about the technical equipment at the Tilbury LNG facility, as well as the associated energy usage and GHG emissions with the use of a hot oil heater at the LNG facility.

8.3.4.2.2 ENVIRONMENTAL IMPACTS

Interest in and concerns regarding environmental impacts were raised by multiple government representatives during regular project engagement. Questions and discussion during regular project meetings generally focused on FEI's decarbonization goals, upstream GHG emissions and how GHG emissions are being examined in the EA process.

Environment and Climate Change Canada inquired about whether FEI is considering mitigations to reduce interactions with migratory birds. FEI stated that there has not been a completed assessment to identify a need for mitigations. Further, if a need for mitigations is identified, they will be implemented by FEI.

Finally, the City of Vancouver asked FEI whether the potential difference in GHG emissions depending on the use of barges or trucks to deliver Project materials would be assessed. FEI confirmed that GHG emissions will be included in the assessment during the EA process.

8.3.4.2.3 ISSUES OUTSIDE OF THE PROJECT SCOPE

One local government inquired about the use of renewable natural gas (RNG) as a fuel for customers. FEI re-iterated that its focus is exploring opportunities to use RNG in its operations at the Tilbury facility, including the TLSE Project, as a means to manage the facility's GHG emissions and meet the Project's net-zero planning requirements.

8.3.4.2.4 OTHER ISSUES

During a project update meeting, one local government asked questions about the emergency response procedures of the Tilbury LNG facility, and if alternatives to the project's location at the existing facility had been considered. FEI provided information about the safety protocols for the facility, including engagement undertaken with local first responders to participate in LNG training and emergency planning exercises. FEI also noted that the CPCN Application and EA draft application have more detailed information on alternatives that have been considered for the TLSE Project.

FEI received one question from a local government representative related to traffic impacts, and what plans are in place to assess truck traffic resulting from construction of the Project. FEI identified trucking routes and potential loads during those transfer windows. FEI confirmed that traffic routes are assessed in incremental change and the cumulative effects assessment notes increased congestion if multiple projects will be occurring during the same time.

8.3.5 Engagement with the Public, Governments and Other Stakeholders Will Continue

FEI is dedicated to maintaining and strengthening positive relationships with the public, governments and other stakeholders through an open and transparent engagement process throughout the duration of the Project. Please refer to the Section 8.3.10 of the Application which discusses FEI's approach to continued engagement. This approach, and the associated areas of focus, remain relevant. In particular, FEI will continue to provide regular updates as this proceeding advances, and through subsequent stages of project development, such as BCER permitting.

FEI will also continue to actively engage with the public, governments and other stakeholders regarding the TLSE Project through the remainder of the EA process. FEI currently anticipates submitting the Draft Application as part of the EA process in Q3 2024. After the Draft Application has been submitted, a public comment period will open which will include further opportunities for engagement such as both in-person and virtual open houses.

Finally, FEI will explore further opportunities to host live LNG demonstrations to educate stakeholders and help the public better understand the properties of LNG, including continuing to seek participation from municipal staff and local stakeholders in future emergency preparedness exercises.

8.4 CONCLUSION

FEI has actively engaged with Indigenous groups, the public, governments and other stakeholders regarding the TLSE Project through open, transparent and timely engagement methods that has resulted in meaningful two-way dialogue. FEI has made best efforts to ensure Indigenous groups and stakeholders are informed and engaged about the Project holistically and to allow for synchronized engagement activities with the parallel Provincial EA and Federal IA processes, which provide significant engagement opportunities.

To date, FEI has identified and responded to concerns raised by Indigenous groups, the public, and stakeholders. FEI's consultation and engagement has been sufficient, reflecting the TLSE Project's stage of development and meeting the requirements of the the BCUC's CPCN Guidelines. FEI will continue to engage directly with Indigenous groups, stakeholders and government to address outstanding issues on the Project, to incorporate feedback into Project mitigations, and to share relevant Project updates through the engagement activities outlined in the Application and in this Supplemental Evidence.

9. BC ENERGY OBJECTIVES AND LONG TERM GAS RESOURCE PLAN

9.1 INTRODUCTION

This section discusses the factors that the BCUC must consider pursuant to section 46(3.1) of the *Utilities Commission Act* (UCA) when determining whether to issue a CPCN:

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

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

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

Sections 6 and 19 of the *Clean Energy Act* (CEA), as referred to in subsection (c) above, do not apply to FEI. FEI addresses the other two requirements below.

9.2 BRITISH COLUMBIA'S ENERGY OBJECTIVES

The applicable of British Columbia's energy objectives support the TLSE Project. FEI anticipates positive socio-economic benefits to the area as a result of the Project. Otherwise, British Columbia's energy objectives are generally neutral in relation to the Project. Some objectives do not apply to FEI. Other objectives either do not apply to the TLSE Project, or are not in conflict with the Project, as the Project is designed to allow FEI to continue meeting winter peak demand and provide energy resiliency in the Lower Mainland. There is currently no feasible alternative peak resource available to serve this load or provide the necessary resiliency.

Section 3 of the Supplemental Evidence discusses the Project drivers. The Project is a critical asset within FEI's gas supply portfolio (i.e., FEI's ACP). Since 1971, FEI's gas supply portfolio has included on-system LNG storage and regasification capacity at Tilbury in its planning to meet customer demand. Losing access to some or all of the peaking capacity and energy currently provided by Tilbury would impair FEI's ability to provide uninterrupted service to customers in winter. Adding on-system LNG is also the only way to materially reduce the customer outage risk associated with a winter no-flow event on T-South.

Table 9-1 below sets out each of British Columbia's energy objectives and their applicability to the Project.

1

Table 9-1: British Columbia's Energy Objectives[267]

Item	Objective	Comments
(a)	to achieve electricity self-sufficiency;	The Project does not affect the generation or acquisition of electricity or otherwise impact the Province's achievement of electricity self-sufficiency.
(b)	to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%;	FEI is implementing its accepted 2024-2027 DSM Expenditures Plan, which includes the Lower Mainland, to take demand-side measures and conserve energy. The peak load served by the Project is net of demand side measure savings (and the 66 percent reduction in demand applies to BC Hydro and is not applicable to FEI).
(c)	by 2030, to ensure that 100% of the electricity generated in British Columbia and supplied to the integrated grid is generated from clean or renewable resources, and to ensure that the infrastructure necessary to transmit that electricity is built;	The Project does not affect the generation or supply of electricity.
(d)	to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;	The Project does not impact FEI's ability to deliver renewable and low carbon gas supplies to its customers or utilize other innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources. The Project replaces existing storage and regassification capacity while also mitigating exposure to significant resiliency risks for which there are no other more reasonable alternatives.
(e)	to ensure the authority's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the *BC Hydro Public Power Legacy and Heritage Contract Act* continue to accrue to the authority's ratepayers;	This objective applies to BC Hydro and is not applicable to FEI.
(f)	to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America;	This objective applies to BC Hydro and is not applicable to FEI.
(f.1)	to ensure that changes to the authority's rates (i) are reasonably predictable, and (ii) are reasonably consistent from year to year;	This objective applies to BC Hydro and is not applicable to FEI.
(f.2)	to ensure that increases to the authority's rates do not exceed cumulative inflation;	This objective applies to BC Hydro and is not applicable to FEI.

[267] As set out in section 2 of the CEA, as amended on February 15, 2024.

Item	Objective	Comments
(g)	to reduce BC greenhouse gas emissions: (i) by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007, (ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007, (iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007, (iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and (v) by such other amounts as determined under the *Climate Change Accountability Act*;	The Project does not conflict with the reduction of greenhouse gas emissions in BC. The Project is designed to support energy system resiliency and peak energy demand requirements in the Lower Mainland during cold winter conditions and there is currently no feasible alternative peak resource available to serve this load. The "resiliency reserve" is stored, unused, until it is required in a supply emergency. Further, the Project's allocation to the gas supply portfolio will facilitate customers' continued use of renewable natural gas even during peak demand conditions, as the renewable natural gas is blended on FEI's system and allocated to FEI's Sales customers, to reduce emissions in BC.
(g.1)	to ensure that the authority holds rights to a sufficient amount of clean or renewable electricity to enable British Columbia to meet the objective set out in paragraph (g);	This objective applies to BC Hydro and is not applicable to FEI.
(h)	to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;	The Project is designed to meet energy system resiliency and peak demand and will not prevent the switch to other energy sources that can decrease greenhouse gas emissions, such as electricity or renewable natural gas. The Project does not affect customer use of renewable natural gas, which is blended on FEI's system and allocated to FEI's Sales customers, to reduce emissions in BC.
(i)	to encourage communities to reduce greenhouse gas emissions and use energy efficiently;	The Project is designed to meet energy system resiliency and peak demand and will not prevent communities from reducing greenhouse gas emissions or using energy efficiently.
(j)	to reduce waste by encouraging the use of waste heat, biogas, and biomass;	The Project does not affect customer use of renewable natural gas, which is blended on FEI's system and allocated to FEI's Sales customers, to reduce emissions in BC.

Item	Objective	Comments
(k)	to encourage economic development and the creation and retention of jobs;	The Project will benefit the local economy during the construction phase by creating jobs in BC through FEI's contractors, and result in the procurement of goods and services from locally owned and operated vendors and subcontractors (i.e., the use of local hotels and restaurants for employees working on the construction sites). FEI is committed to working with Indigenous groups, community leaders and local organizations, developing the local workforce, supporting local businesses, and connecting them to Project opportunities. The Project will also ensure adequate capacity is available to support economic activity and growth in the region. The British Columbia energy objective related to retention of jobs is also served by reducing the potential for a T-South no-flow event to cause a widespread and lengthy outage in the Lower Mainland, British Columbia's most important economic region. A loss or disruption of gas supply would impact many hundreds of thousands of natural gas customers who use gas in their homes and businesses, plus those who indirectly rely on natural gas for access to goods or services. The PwC Report[268] provides additional analysis of the potential GDP implications of an outage.
(l)	to foster the development of first nation and rural communities through the use and development of clean or renewable resources;	The Project does not affect the development of clean or renewable resources.
(m)	to maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia;	The Project does not affect BC's generation and transmission assets.
(n)	to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia;	The Project does not affect the generation or export of electricity.
(o)	to achieve British Columbia's energy objectives without the use of nuclear power;	The Project does not affect the generation of electricity.

[268] Appendix RP 3 to the 2024 Resiliency Plan, PwC Report.

Section 4 of the CEA indicates that the objectives in section 2(f.2) and (g) of the CEA have priority, as follows:

> 4 The energy objectives set out in section 2 (f.2) and (g) of the Act have priority over the other energy objectives set out in that section.

The objective in section 2(f.2) applies only to BC Hydro and is therefore not applicable to the Project. As noted in Table 9-1 above, the Project does not conflict with the objective in section 2(g) to reduce GHG emissions, as it is designed to strengthen long term energy system resiliency and serve peak demand through the winter for which there is no available alternative, and will facilitate FEI's customers' use of renewable natural gas – even during these peak periods. Since the Project is not in conflict with this objective, the priority to be given to it has no bearing on the Project.

In summary, a consideration of British Columbia's energy objectives supports the Project, and FEI anticipates positive socio-economic benefits to the area as a result of the Project. A consideration of the remaining objectives is neutral in relation to the Project.

9.3 LONG TERM GAS RESOURCE PLAN

This Application considers and is consistent with the outcome of the 2022 LTGRP proceeding, which identified the need for FEI to revise and resubmit its resiliency plan. FEI has performed that work, and the 2024 Resiliency Plan provides the basis for this Supplemental Evidence. Further, Section 6.3.2 of the 2022 LTGRP explains the vital role of the existing Tilbury Base Plant in providing gas supply throughout the year and, in particular, during peak demand events[269] and that this type of critical service is difficult to replace with market alternatives.

The need for the TLSE Project as a resiliency measure was considered at length in the 2022 LTGRP proceeding,[270] supported by the initial version of FEI's Resiliency Plan. This initial version of the plan was appended to the 2022 LTGRP and included in the LTGRP Action Plan.[271]

The BCUC Panel for the 2022 LTGRP agreed with the findings in the Adjournment Decision[272] that additional analysis and information about FEI's overall risk exposure was needed for the BCUC to complete its review of the Resiliency Plan and make any decisions regarding the infrastructure needed to implement it.[273] While the Panel in the 2022 LTGRP rejected the initial version of the Resiliency Plan as presented in the 2022 LTGRP, it noted that:

[269] 2022 LTGRP, Exhibit B-1, Section 6.3.2, pp. 6-25.

[270] 2022 LTGRP, Exhibit B-1: Section 7.5 discusses gas system resiliency; Section 10, Action Item 6 discusses inclusion of the TLSE Project as part of the Resiliency Plan in the actions FEI intends to pursue, numerous information requests in the LTGRP regulatory proceeding discussed the TLSE Project and the resiliency plan. 2022 LTGRP, Decision and Order G-78-24, Section 3.5, pp. 38-40, discusses the TLSE Project and FEI's initial resiliency plan.

[271] 2022 LTGRP, Exhibit B-1, Section 10, Action Plan Item 6, p. 10-5.

[272] The Adjournment Decision was made after the 2022 LTGRP was submitted, but prior to the 2022 LTGRP Decision and Order G-78-24.

[273] 2022 LTGRP Decision and Order G-78-24, p. 40.

> …FEI has committed to preparing a new resiliency plan that will include a more comprehensive and robust analysis, and intends to include the latest version of its resiliency plan in future long-term gas resource plans for BCUC review. The Panel considers this commitment to be reasonable and appropriate.

The 2024 Resiliency Plan filed concurrently with this Supplementary Evidence completes FEI's commitment made during the 2022 LTGRP to revise its resiliency plan and is resubmitting that part of the 2022 LTGRP that was rejected as set out in section 44.1(7) of the UCA.

As discussed in Section 3 of this Supplemental Evidence, the 2024 Resiliency Plan confirms that a winter no-flow event on T-South is the largest customer outage risk by a wide margin. The risk is significant and should be mitigated with the addition of on-system LNG.

9.4 CONCLUSION

The TLSE Project is consistent with the applicable of British Columbia's energy objectives set out in Section 2 of the *Clean Energy Act.* FEI's 2024 Resiliency Plan, which is filed concurrently with this Supplemental Evidence, completes FEI's commitment made during the 2022 LTGRP (and confirmed by the BCUC Panel in the 2022 LTGRP Decision), and confirms the resiliency need for the TLSE Project.

10. CONCLUSION

A total loss of supply to the Lower Mainland during winter is, and will remain, FEI's largest customer outage risk by an order of magnitude. The consequences of a winter no-flow event, lasting only a matter of hours on T-South, are known, and if left unmitigated, will be catastrophic. It will, without question, result in at least 600,000 customers losing service within a day of the event. Service would not be fully restored to those customers for many weeks. A lengthy loss of gas supply during winter will expose vulnerable populations to serious health and mortality risks and have widespread social and economic consequences for British Columbians. Exponent has calculated a high cumulative probability of a winter no-flow event, even assuming a 23-year evaluation horizon sensitivity that is less than half of the expected service life of the TLSE Project. Since the 2018 T-South Incident there have been two incidents on T-South that highlight FEI's risk exposure to upstream supply disruptions given its heavy reliance on T-South.

It is also now even more clear that the 53-year-old Base Plant needs to be replaced soon irrespective of resiliency. The Base Plant has reached end-of-life and is unable to reliably perform its critical gas supply function. A strategy of prolonged reliance on the Base Plant for critical peaking supply would leave firm customers at serious risk of losing service in normal operations, given the Base Plant's age-related issues and the absence of any feasible contingency plan for peaking supply. Allowing this to occur would contradict the gas supply planning approach that has been in place for decades.

Replacing the Base Plant with a facility that will both meet FEI's gas supply requirements and mitigate a known catastrophic risk associated with the loss of gas supply to the Lower Mainland is appropriate and necessary. FEI's analysis, presented in this Supplemental Evidence, shows that FEI customers will obtain much greater value from the Preferred Alternative (Supplemental Alternative 9) than any other viable alternative.

FEI respectfully submits that the TLSE Project is in the public interest and should be approved as proposed, along with the associated deferral account and depreciation rate approvals requested in Section 6 of the Application.

Appendix A

REFERENCES TO PREVIOUS FEI EVIDENCE BY TOPIC

No.	Application Topic	Reference to Evidence
Project Need and Justification		
1.	Customers recognize the importance of resiliency.	• Exhibit B-15, BCUC IR1 7.1 and Attachment 7.1.
2.	Limited gas distribution infrastructure in the Pacific Northwest region has left FEI heavily reliant on a single upstream supply source (the T-South system).	• Exhibit B-1-4, Application, Section 3.4.2.1, pp. 37-39 • Exhibit B-1-4, Application, Appendix A (Guidehouse Report on Natural Gas System Resiliency), pp. 29 to 38. • Transcript Vol 1, p. 41, l. 7 to p. 42, l. 23. • Transcript Vol 1, p. 122, l. 7 to p. 123, l. 9.
3.	The 2018 T-South Incident resulted in a no-flow event lasting approximately two days, during which the Lower Mainland system was at material risk of hydraulic collapse.	• Exhibit B-1-4, Application, Section 3.4.2.2, pp. 39 to 50.
4.	T-South and other natural gas systems in North America have experienced major service disruptions and near misses.	• Exhibit B-1-4, Application, Appendix B (PwC – The Case for Improved System Resiliency), p. 17. • Exhibit B-15, BCUC IR1 3.1.
5.	FEI's Lower Mainland system only avoided a widespread and prolonged outage due to the 2018 T-South Incident because of warm weather conditions and a favourable pipeline rupture location.	• Exhibit B-1-4, Application, pp. 45-46 and 52. • Transcript Vol 1, p. 73, l. 9 to p. 74, l. 8.
6.	Contractual rights to additional gas supply and capacity on the T-South system are of no assistance to FEI during a no-flow event on T-South.	• Exhibit B-1-4, Application, p. 22 and Appendix A (Guidehouse Report on Natural Gas System Resiliency), pp. 18 to 23. • Exhibit B-24, Sentinel IR1 55. • Transcript Vol 1, p. 31, ll. 10 to 18.

No.	Application Topic	Reference to Evidence
7.	Other potential supply sources, including market area storage (Mist and JPS), mutual aid, and the Mt. Hayes LNG facility cannot be relied on during a winter no-flow event on T-South.	*Market Area Storage* • Exhibit B-1-4, Application, pp. 69 to 73. • Exhibit B-1-4, Application, Appendix A (Guidehouse Report on Natural Gas System Resiliency), p. 14. • Exhibit B-15, BCUC IR1 16.14, 16.16 and 46.1. • Exhibit B-19, CEC IR1 25.1 and 25.2. • Transcript Vol 1, p. 43, ll. 5 to 21. • Transcript Vol 1, p. 52, ll. 2 to 20. • Transcript Vol 1, p. 61, l. 17 to p. 62, l. 13. • Transcript Vol 1, p. 133, ll. 3 to 12. *Mutual Aid* • Exhibit B-1-4, Application, p. 52. • Exhibit B-15, BCUC IR1 4.2 and Attachment 4.2. • Exhibit B-26, BCUC IR2 74.1. • Transcript Vol 1, p. 155, l. 26 to p. 156, l. 11. *Mt Hayes LNG* • Exhibit B-15, BCUC IR1 11.8. • Transcript Vol 1, p. 149, l. 22 to p. 150, l. 1. • Transcript Vol 1, p. 174, ll. 16-26. • Transcript Vol 1, p. 175, ll. 7-11.
8.	FEI's ability for FEI's Lower Mainland system to withstand a no-flow event requires both dependable "energy" (regasification) and "capacity" (storage).	• Exhibit B-1-4, Application, p. 65 (Figure 3-14). • Exhibit B-1-4, Application, Appendix C (2020/21 ACP Compliance Report), p. 15. • Exhibit B-26, BCUC IR2 76.1 and 78.1.

No.	Application Topic	Reference to Evidence
9.	Restoring service to hundreds of thousands of customers after a winter no-flow event would take almost 9 weeks reflecting AMI, FEI's BCUC-approved P&R Plan, regulations, standards and the experience of other utilities.	• Exhibit B-46, Rebuttal Evidence to RCIA. • Transcript Vol 1, p. 137, l. 17 to p. 138, l. 23.
10.	Where the consequence of events are unacceptably severe, an appropriate risk management approach is to mitigate the consequences to tolerable levels irrespective of the calculated probabilities of the triggering event.	• Exhibit B-18, BCSEA IR1 2.1. • Exhibit B-28, RCIA IR2 31.2. • Exhibit B-32, BCOAPO IR2 2.3. • Exhibit B-39, BCUC Panel IR1 4.1.
11.	The existing Base Plant is well-over its average service life and needs to be replaced.	• Exhibit B-15, BCUC IR1 16.21, 16.22 and 40.1. • Exhibit B-22, RCIA IR1 18.1.
12.	The BCUC directed FEI to describe the utility's plans to address resiliency in the short, medium and long terms in response to the 2018 T-South Incident.	• BCUC Letter L-31-20, dated June 5, 2020. • Exhibit B-1-4, Application, Appendix C (2020/21 ACP Compliance Report).
Description of Alternatives		
13.	The optimal resiliency portfolio should align with the optimal gas supply portfolio.	• Exhibit B-4, Workshop Presentation, slide 35. • Transcript Vol 1, p. 30, l. 7 to p. 31, l. 18. • Transcript Vol 1, p. 164, l. 26 to p. 166, l. 1.
14.	On-system storage is the only dependable, practical and effective source of supply to avoid or reduce the impact of a widespread and prolonged outage as a result of a T-South no-flow event occurring during the winter.	• Exhibit B-1-4, Application, pp. 77-92. • Exhibit B-1-4, Application, Appendix A (Guidehouse Report on Natural Gas System Resiliency), p. 46. • Transcript Vol 1, p. 114, l. 11 to p. 115, l. 5. • Transcript Vol 1, p. 140, ll. 16-21.

No.	Application Topic	Reference to Evidence
15.	Regional pipeline alternatives would not prevent a widespread outage in the Lower Mainland.	• Exhibit B-1-4, Application, pp. 84 to 92. • Exhibit B-4, Workshop Presentation, slide 33. • Exhibit B-15, BCUC IR1 16.3, 16.5, 16.6 and 16.9. • Transcript Vol 1, p. 116, l. 6 to p. 117, l. 14. • Transcript Vol 1, p. 132, l. 23 to p. 133, l.2.
16.	There are significant advantages to locating on-system storage at the existing Tilbury facility, relative to other locations.	• Exhibit B-15, BCUC IR1 16.18 and 24.3. • Exhibit B-24, Sentinel IR1 77. • Exhibit B-4, Workshop Presentation, slide 46. • Transcript Vol 1, p. 48, ll. 2-9. • Transcript Vol 1, p. 171, l. 25 to p. 172, l. 9. • Transcript Vol 1, p. 186, l. 23 to p. 188, l. 12.
17.	It is impractical and insufficient to add regasification capacity without also replacing the Base Plant tank.	• Exhibit B-1-4, Application, pp. 57 and 65. • Exhibit B-26, BCUC IR2 78.1. • Transcript Vol 1, p. 18, ll. 13-16.
18.	FEI has properly sized the TLSE Project to prepare for, withstand and recover from a high impact event.	• Exhibit B-1-4, Application, Appendix A (Guidehouse Report on Natural Gas System Resiliency), pp. 49 to 50. • Exhibit B-5, Guidehouse Workshop Presentation, slide 21.
19.	Proposed 800 MMcf/d of regasification capacity provides resiliency, reliability and optionality, as well as being cost-effective.	• Exhibit B-1-4, Application, Appendix A, (Guidehouse Report on Natural Gas System Resiliency), p. 48. • Exhibit B-1-4, Application, pp. 116 to 118. • Exhibit B-15, BCUC IR1 19.3 to 19.6. • Transcript Vol 1, p. 18, l. 20 to p. 19, l. 1.

No.	Application Topic	Reference to Evidence
20.	A 3 Bcf tank is the best way to avoid or mitigate a widespread outage following a T-South no-flow event, and provides a variety of ancillary benefits unavailable with a smaller tank.	• Exhibit B-1-4, Application, pp. 103 to 116. • Exhibit B-4, Workshop Presentation, slides 39, 41. • Exhibit B-18, BCSEA IR1 4.1. • Transcript Vol 1, p. 182, l. 1 to p. 183, l. 15.
21.	Inherent economies of scale, as well as other environmental, reliability and operational benefits of a 3 Bcf storage tank are preferrable to keeping the existing Base Plant tank in-service.	• Exhibit B-1-4, Application, pp. 99 to 100 and 107 to 108. • Exhibit B-15, BCUC IR1 16.21, 16.22 and 16.27. • Exhibit B-28, RCIA IR2 37.3.
22.	New facility sizing should account for gas supply benefits, as a larger facility can avoid the cost of acquiring other supply resources.	• Exhibit B-1-4, Application, Appendix C (2020/21 ACP Compliance Report), pp. 14 to 15. • Exhibit B-4, Workshop Presentation, slide 42. • Exhibit B-15, BCUC IR1 22.7, 46.1 and 46.2. • Transcript Vol 1, p. 182, l. 1 to p. 183, l. 15 (preliminary $30 million/year avoided cost estimate).
23.	TLSE Project enables a controlled shutdown if a no-flow event(s) exceeds the capacity of the storage tank.	• Exhibit B-26, BCUC IR2 88.1.2.
No.	**FEI Evidence**	**Topic**
Project Description		
24.	The TLSE Project will meet or exceed all safety standards.	• Exhibit B-1-4, Application, pp. 121 to 133. • Exhibit B-15, BCUC IR1 25.1. • Exhibit B-18, BCSEA IR1 4.6.
Environmental and Archaeological Impacts		
25.	The TLSE Project will be constructed on an existing brownfield site and the potential adverse environmental and archaeological impacts can be mitigated.	• Exhibit B-1-4, Application, pp. 169 to 182, Appendices O and P. • Exhibit B-44, Rebuttal Evidence to TWN, p. 22.

No.	Application Topic	Reference to Evidence
26.	The components of the TLSE Project are subject to additional regulatory scrutiny through the environmental assessment process for the Tilbury Phase 2 LNG Expansion Project.	• Exhibit B-44, Rebuttal Evidence to TWN, pp. 5-13, 14 to 16 and 23 to 24.
	Indigenous and Stakeholder Engagement	
27.	FEI has engaged with stakeholders regarding developments at Tilbury since 2012 and continues to do so consistent with the requirements of the BCUC's CPCN Guidelines.	• Exhibit B-1-4, Application, pp. 183 to 196.
28.	Engagement activities regarding the TLSE Project have been synchronized with the environmental assessment process for the Tilbury Phase 2 LNG Expansion Project.	• Exhibit B-1-4, Application, pp. 184 to 185 and Appendix Q-2 (Engagement Plan). • Exhibit B-18, BCSEA IR1 3.4.
29.	Consultation and engagement with Indigenous groups has been meaningful, timely and sufficient consistent with the requirements of the BCUC's CPCN Guidelines, and will continue.	• Exhibit B-1-4, Application, pp. 196 to 205. • Exhibit B-15, BCUC IR1 58.1 and 58.2. • Exhibit B-26, BCUC IR1 102.1. • Exhibit B-44, Rebuttal Evidence to TWN, pp. 13 to 14, 18 and 19 to 20.
30.	Collaboration and partnership with the Musqueam Indian Band embodies the spirit of reconciliation and demonstrates FEI's commitment to robust engagement.	• Exhibit A2-1, Press Release - Musqueam Indian Band and FortisBC Holdings Inc. sign Tilbury LNG Projects Agreement. • Exhibit B-54, BCUC IR4 114 and 115 series, and Attachment 114.1. • Exhibit C8-1, Musqueam Indian Band – Request to Intervene.
No.	**FEI Evidence**	**Topic**
	British Columbia Energy Objectives	
31.	The TLSE Project will encourage economic development and the creation and retention of jobs.	• Exhibit A2-1, Press Release - Musqueam Indian Band and FortisBC Holdings Inc. sign Tilbury LNG Projects Agreement. • Exhibit B-1-4, Application, pp. 206 to 207.

No.	Application Topic	Reference to Evidence
32.	The TLSE Project enables greater system resiliency and is not expected to contribute to greenhouse gas emissions.	• Exhibit B-15, BCUC IR1 63.1. • Exhibit B-30, BCSEA IR2 11.1. • Exhibit B-44, Rebuttal Evidence to TWN, p. 24.

Appendix B

CONCORDANCE WITH BCUC ADJOURNMENT DECISION COMMENTARY

Appendix B

Concordance with BCUC Adjournment Decision Commentary

This Appendix summarizes how FEI has addressed the BCUC's commentary in the TLSE Project CPCN Adjournment Decision. Table B-1 addresses the BCUC's comments regarding further evidence needed to evaluate the TLSE Project. Table B-2 addresses the BCUC's comments on the specific content of FEI's holistic resiliency plan.

Table B-1: How and Where FEI Addresses the Adjournment Decision

BCUC Commentary Topic	TLSE Adjournment Decision Commentary	Where Commentary is Addressed
Need for comprehensive Resiliency Plan	"The Panel considers resiliency objectives are best assessed on a holistic level by comparing various resiliency options and prioritizing and planning against various outage scenarios, and then developing a comprehensive resiliency plan. Ideally, this planning would be completed in the context of the development of a Long Term Gas Resource Plan (LTGRP). A robust resiliency plan should consider multiple credible threats to the FEI system, along with an assessment of the likelihood and consequence of each threat. Proposed solutions to mitigate those threats should consider the ability of a solution to mitigate one or more of the threats and a cost benefit analysis of that solution. The Panel considers that the assessment of resiliency through such a plan is needed before concurring with FEI that "storage is the only practical and effective way to bridge a winter no-flow event on the T-South system." (p. 12) "The need for this Project as set out in the Application does not benefit from such a resiliency plan. Instead, FEI singles out one specific outage scenario on the T-South System as the basis for this resiliency Project without a fulsome analysis of the likelihood of that scenario or whether there are any other scenarios of similar or greater likelihood." (p. 12)	The 2024 Resiliency Plan considers: • 58 Assessed Vulnerabilities that have the potential to lead to material customer outages; and • Quantitative consequence and probability-based risk analysis based on engineering analysis and system modelling. (See 2024 Resiliency Plan, Section 5) FEI has considered a number of Supplemental Alternatives to mitigate the risks of a winter no-flow event on T-South to varying degrees. FEI is not proposing to address any other Assessed Vulnerabilities at this time. (See Supplemental Evidence, Section 4)

BCUC Commentary Topic	TLSE Adjournment Decision Commentary	Where Commentary is Addressed
Consequence of T-South no-flow event	"However, we do find that the consequence of a no-flow event is proportional to the duration of the no-flow event. Further, the consequence is higher during colder months. A five day no-flow event coinciding with a particularly cold spell in January has significantly greater consequence than a one day no-flow event in July. Rupture location and availability of alternative supply options also affect the consequence of a no-flow event, but we have no evidence of the specific risk related to these factors." (p. 11)	For each of the 58 Assessed Vulnerabilities: • FEI has modelled system pressure and impacts at multiple temperatures; • FEI's system modelling assumes that all available sources of alternative supply are being used and that non-firm interruptible load has already been curtailed; • Exponent's quantitative risk analysis is based on a three-month winter period only, and uses average Jan-Feb temperatures for the relevant areas (e.g., +4ºC for the Lower Mainland); and • Exponent has considered the potential duration of a no-flow event given the vulnerability-specific causes of failure it identified (i.e., hazards). Exponent included those considerations in its Monte Carlo analysis. (See 2024 Resiliency Plan, Section 5)
Probability of T-South no flow event (time of year)	"Further, there is no evidence in the proceeding that a rupture is more likely to occur at any particular time of the year or in any season or within a specific location on the T-South System, …. The Panel also considers that it may well be the case that the probability of a no-flow event caused by weather risk is somewhat elevated in the winter, but there is no evidence on the record to support that conjecture." (p. 9)	Exponent has reviewed the hazards specific to each Assessed Vulnerability and determined which could occur during the winter period. Exponent has not assumed that integrity related rupture risk is elevated in winter, as most hazards considered in Exponent's analysis are not seasonal. (See 2024 Resiliency Plan, Section 5 and Appendix RP 2, Exponent Report, Section 4.6 (paras. 126-127))

BCUC Commentary Topic	TLSE Adjournment Decision Commentary	Where Commentary is Addressed
Probability of T-South no flow event (time horizon)	"An additional consideration is the time scale over which the risk of a no-flow event is considered. FEI states that over the service life of the TLSE Project, a multi-day no-flow event is likely. While we would not go so far as to characterize a no-flow event as likely, we do agree that the longer the service life the greater the probability of a no-flow event – it is a truism that as the period under examination increases, the probability of the event happening during the period increases towards 100 percent. Conversely, the shorter the service life, the less likely the occurrence of a no-flow event."	FEI continues to believe that the 67-year expected life of the TLSE Project is an appropriate time scale for assessing risk and rate impacts. FEI has provided additional evidence in support of this view including: • The long-term usefulness of the facility for providing gas supply and resiliency to FEI customers based on adverse load loss sensitivities; and • The mitigation revenues that could potentially be achieved to the extent that FEI no longer requires the full facility for its own gas supply or resiliency purposes. (See Supplemental Evidence, Sections 4.5.5, 4.7; Appendix F, Raymond Mason Report, pp. 36-53) FEI asked Exponent to calculate cumulative probabilities over a 23-year time scale. The cumulative probability of a winter no-flow event on T-South is still significant over 23 years. (See Supplemental Evidence, Section 4.7.1; 2024 Resiliency Plan, Section 5)

BCUC Commentary Topic	TLSE Adjournment Decision Commentary	Where Commentary is Addressed
Duration of T-South no flow event (Residual risk with TLSE Project)	"The Panel recognizes that the proposed TLSE Project would improve resiliency, but only in certain circumstances. It will not mitigate all resiliency risks, and indeed, FEI may never be able to mitigate all resiliency risks. There may be circumstances where FEI still needs to initiate a widespread controlled shutdown, even with the TLSE Project in place – for example, a no-flow event lasting longer than 3 days in winter." (p. 16) "…nor is there conclusive evidence of the duration of the ensuing no-flow event. However, in FEI's view there would be a higher likelihood of inclement weather or snow making access to a rupture site more challenging, and, therefore, increasing the time to investigate, repair, and determine if and when service on one or both pipelines could be restored." (p. 9) "JANA's evidence is that 27 out of 30 reported pipeline ruptures and 22 of 23 ignited ruptures resulted in an outage of more than three days. Based on this evidence we find an event of more than three days more likely than an event of 3 days or less. In this regard, we also note FEI and JANA's submissions that even a precautionary shutdown of one of the two pipelines due to a rupture in the other pipeline would likely result in the adjacent line being out for a period of two days or longer [Emphasis added]." (p. 9) "Further, as discussed in Section 2.1 of this Decision, we have no evidence concerning the specific probabilities associated with outage duration, time of year or rupture location." (p. 11)	The TLSE Project significantly reduces the risk associated with a T-South no-flow event, both in terms of: (i) reducing probability of a customer outage; and (ii) the consequences of any customer outage (customers lost, customer-outage-days, economic, safety risks associated with uncontrolled depressurization). (See Supplemental Evidence, Section 4.7) Exponent considered the potential duration of a no-flow event, having regard to the potential hazards it identified for each Assessed Vulnerability. Exponent also prepared a Monte Carlo analysis to account for the potential for different no-flow event durations. (See 2024 Resiliency Plan, Section 3.4.1.2.1 and Appendix RP 2, Exponent Report, Section 6.5)
Other causes of Lower Mainland outage	"Additionally, uncontrolled shutdowns could still potentially occur, for instance if there was an earthquake that ruptured the pipeline in Delta running to/from Tilbury. This underlines the importance of developing different use cases representing catastrophic failures and approaches to mitigating those failures identified and the cost of those approaches considered in order to properly assess resiliency needs." (p. 16)	The 2024 Resiliency Plan evaluated 58 Assessed Vulnerabilities, including a number in the Lower Mainland. The TLSE Project addresses the Assessed Vulnerabilities determined by Exponent to give rise to the largest risks. (See Resiliency Plan, Section 5 and Appendix RP 2, Exponent Report, Section 7.3)

BCUC Commentary Topic	TLSE Adjournment Decision Commentary	Where Commentary is Addressed
Future Developments (Impact on Probability and Consequence of T-South no flow event)	"The Panel agrees with FEI that there is a potential for a multi day no-flow event on the T-South System. The T-South Incident in 2018 demonstrates this potential and also illustrates some of the potential consequences of such an event. There is, however, uncertainty whether the risk of no-flow events on the T-South System may increase or decrease in the future. Factors that could contribute to increasing the probability of a no-flow event include the aging of the T-south pipeline, increased severity or extreme weather events and the potential for increased cyber and physical security incursions. With regards to extreme weather events, we note the significant physical exposure the pipeline faced during the floods of 2021 when water erosion left significant portions of the pipeline exposed – although that did not lead to a no-flow event. On the other hand, there are factors that reduce the probability of a no-flow event, including the development of enhanced integrity management practices and technology and improved cyber security practices and potential actions taken by the utility to replace aging sections of the pipeline." (pp. 7-8)	FEI has considered hypothetical load loss sensitivities to demonstrate the continued usefulness of the TLSE Project in the event of significant future load loss. (See Supplemental Evidence, Section 4.5.5) The 2024 Resiliency Plan presents FEI's assessment of future developments on probability (e.g., climate change increasing potential of no flow events). (See Resiliency Plan, Section 6). The Federal Government's assessment of increasing cyber risk for utilities is addressed in the 2024 Resiliency Plan, Section 5.2.
Ancillary (supply) benefits	"FEI's analysis of ancillary benefits, as discussed further in Section 3.3 of the Decision, does not assess the ability of the TLSE Project to replace the functions or capacity currently provided by the Base Plant with regards to peaking supply." (p. 14)	The TLSE Project replaces the current functions of the Base Plant, and provides additional flexibility to use the facility to avoid investments in other gas supply resources. FEI assessed the financial value for customers in terms of avoided supply costs of LNG located in the Lower Mainland. This assessment shows that the avoided supply cost benefit is much higher than originally estimated. (See Supplemental Evidence, Section 4.5.4.1.2)

BCUC Commentary Topic	TLSE Adjournment Decision Commentary	Where Commentary is Addressed
Other Potential Alternatives to TLSE Project	The BCUC identified various potential options that could potentially provide differing levels of mitigation. (pp. 26-33)	FEI has evaluated various Supplemental Alternatives, including all of the alternatives identified by the BCUC. (See Supplemental Evidence, Section 4 and Appendix C)
Stranding risk of the TLSE Project	"We acknowledge the difficulty of navigating a path to clean gas given these new technologies and business practices that must be considered. However, we share the Commercial Energy Consumers Association of British Columbia's concerns that "a higher level of confidence in terms of the risk being assessed and the expected life for the assets to be used and useful" is necessary to assess whether further resiliency investments are in the public convenience and necessity. In light of the current uncertainty with respect to the continued role of the natural gas system in British Columbia, we find insufficient evidence to conclude that the risk of stranding of the Project is acceptable, especially considering its expected life. FEI is invited to file further evidence that addresses the Panel's concerns about the stranding risk of the TLSE Project." (p. ii)	FEI has considered hypothetical load loss sensitivities to demonstrate the continued usefulness of the TLSE Project in the event of significant future load loss. (See Supplemental Evidence, Section 4.5.5)

Table B-2: How and Where FEI Addresses BCUC Commentary on Resiliency Plan Content

BCUC Commentary Topic	BCUC Decision Commentary (Page references are to Adjournment Decision unless indicated.)	How and Where BCUC Commentary is Addressed
Loss of resiliency from PGR Project	"The Panel is concerned with the loss of resiliency [from PGR Project] and FEI's lack of a firm plan to replace the lost resiliency. Given this apparent existing non-systemic approach to addressing resiliency of its system, the Panel considers it necessary for FEI to address resiliency in a more comprehensive and holistic manner." (PGR Decision, p. 9)	The 2024 Resiliency Plan provides a holistic risk assessment of FEI's 58 most material vulnerabilities. Based on that risk analysis, at this time FEI is not recommending a resiliency-driven project to address the loss of resiliency from the PGR Project. Resiliency would continue to be considered in the course of typical planning. (See 2024 Resiliency Plan, Section 4.3.2.1)

BCUC Commentary Topic	BCUC Decision Commentary (Page references are to Adjournment Decision unless indicated.)	How and Where BCUC Commentary is Addressed
Identification of vulnerabilities	“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?” (p. i)	FEI identified 87 system outage vulnerabilities through a holistic review. Exponent quantified the risk associated with the 58 Assessed Vulnerabilities. (See 2024 Resiliency Plan, Section 3) FEI also addresses future risk, considering factors that affect both probability and consequences. (See 2024 Resiliency Plan, Section 3.4)
Current risk assessment / resiliency gap analysis	“What assets provide resiliency in FEI’s current system and what and where are the gaps in resiliency?” (p. i)	FEI identified 87 system outage vulnerabilities through a holistic review. Exponent’s quantitative risk analysis of the 58 Assessed Vulnerabilities accounts for available supply assets, infrastructure (including AMI), and personnel. (See 2024 Resiliency Plan, Section 3.6)

BCUC Commentary Topic	BCUC Decision Commentary (Page references are to Adjournment Decision unless indicated.)	How and Where BCUC Commentary is Addressed
Current risk assessment / gap analysis (consequences/probability)	"Typically, a probability/consequence analysis involves multiplying probabilities and consequences. However, in this instance a quantification of probability multiplied by consequence would likely be impossible, since there are a number of factors affecting consequence (e.g. outage duration, time of year, rupture location, availability of alternate supply options), some of which could be estimated but others of which are uncertain. Further, as discussed in Section 2.1 of this Decision, we have no evidence concerning the specific probabilities associated with outage duration, time of year or rupture location. However, we do find that the consequence of a no-flow event is proportional to the duration of the no-flow event. Further, the consequence is higher during colder months. A five day no-flow event coinciding with a particularly cold spell in January has significantly greater consequence than a one day no-flow event in July. Rupture location and availability of alternative supply options also affect the consequence of a no-flow event, but we have no evidence of the specific risk related to these factors." (p. 11)	Exponent has quantified risk for all 58 of the Assessed Vulnerabilities based on probability x consequence. The analysis addresses the variables that the BCUC identified, including: • Exponent has accounted for a variety of modes of failure (hazards) as applicable; • The risk analysis only accounts for a three-month winter period; • The customer outage breadth and timing is based on hydraulic modelling that accounts for available alternative supply and uses average winter temperatures in the relevant area (e.g., +4ºC for the Lower Mainland); • Customer outage duration is based on the BCUC-approved System Preservation and Restoration Plan;[1] • Exponent used a Monte Carlo analysis to address uncertainty in the duration of the no-flow event; (See 2024 Resiliency Plan and Appendix RP 2, Exponent Report, Sections 6 and 7)
Impact of potential future developments on risk	"The impact, if any, of the loss of contracted storage on resilience." (p. i)	The Plan provides a future risk assessment that includes discussion of the impact of losing market storage on system resilience. (See 2024 Resiliency Plan, Section 4.2)

[1] These assumptions were discussed extensively in FEI's Rebuttal Evidence to RCIA in this proceeding.

BCUC Commentary Topic	BCUC Decision Commentary (Page references are to Adjournment Decision unless indicated.)	How and Where BCUC Commentary is Addressed
Impact of potential future developments on risk	"How do FEI's other planned projects address or mitigate these gaps – e.g. AMI, RGSD - and what is the relationship and extent of overlap between those planned projects and the TLSE Project?" (p. i)	The risk analysis contained in the 2024 Resiliency Plan assumes the AMI Project is in place. A Southern Crossing Pipeline expansion (e.g., RGSD) is considered as a TLSE Project alternative. FEI explains that RGSD on its own would not be able to prevent a system collapse in the Lower Mainland following a T-South no-flow event because FEI would not be able to access the supply quickly enough. (See 2024 Resiliency Plan, Section 3.5.2 and Supplemental Evidence, Appendix C)
Options to address risks	"What steps can be taken to fill those gaps in the short, medium and long term and what are the costs associated with these options? This should include analysis of some of the alternatives discussed in the proceeding, including: o Additional regasification and liquefaction at Tilbury; o Assessment of the remaining life of the existing Base Plant" (p. i)	Based on the risk assessments of the 58 Assessed Vulnerabilities, at this time FEI is only recommending the TLSE Project. It addresses FEI's largest customer outage risks. (See 2024 Resiliency Plan, Section 5.1) FEI evaluated additional alternatives to the TLSE Project, including all of those that the BCUC identified in the Adjournment Decision. (See Supplementary Evidence, Section 4 and Appendix C).

1

Appendix C

DETAILED ANALYSIS OF SUPPLEMENTAL ALTERNATIVES

Appendix C

Detailed Analysis of Supplemental Alternatives

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List of Appendices

Appendix C-1 Floating LNG Storage Concept Analysis

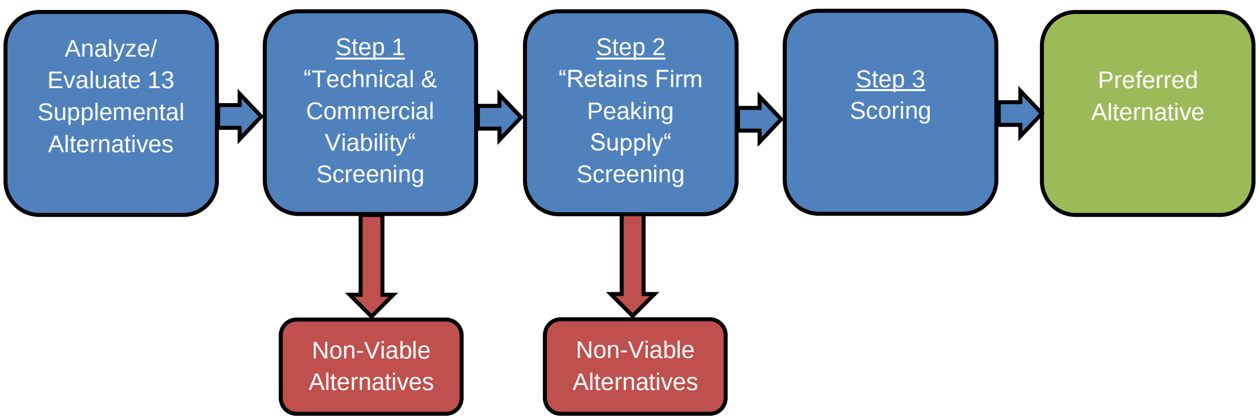
Index of Tables and Figures

1. INTRODUCTION

This Appendix provides supporting detail for the alternatives analysis described in Section 4 of the Supplemental Evidence. FEI used the information in this Appendix throughout the structured three-step alternatives analysis process described in Section 4.2.2 of the Supplemental Evidence and depicted in Figure C-1 below.

In order to ensure that the BCUC has complete information, this Appendix includes a full analysis and Step 3 scoring for all Supplemental Alternatives that are technically and commercially viable (i.e., passed Step 1), even if they fail the Step 2 screen by jeopardizing FEI's ability to maintain service in normal operations. As such, Supplemental Alternatives 2, 3, 4, 4A, 5, 6, 7, 8 and 9 were scored relative to the existing Tilbury Base Plant with no capital upgrades (Supplemental Alternative 1), having regard to resiliency, gas supply, age-related Base Plant challenges, levelized total rate impact, and future use. This analysis confirms that Supplemental Alternative 9 provides superior overall customer value and is the Preferred Alternative.

Figure C-1: Structured Process to Identify the Preferred Alternative



Appendix C is organized as follows:

- **Section 2 – Description of Alternatives and Summary of Results:** This section provides more detailed alternative and contingent scenario descriptions and modelling parameters. It also summarizes the Step 1 and Step 2 screening results, and the Step 3 scoring results for all Supplemental Alternatives that are technically and commercially viable. FEI evaluated every alternative that passed the Step 1 viability screening, despite Supplemental Alternatives 2, 3, 5, 6, and 7 risking FEI's existing ability to serve firm customers in normal operations. Expanding the scoring to include other alternatives that failed the Step 2 screen only reinforces that Supplemental Alternative 9 is the preferred alternative.
- **Section 3 – Financial Impacts for All Supplemental Alternatives:** This section provides the financial impacts for Supplemental Alternatives 1 to 9 and the contingent scenarios, as well as additional information regarding the associated inputs. The financial impacts

are based on updated capital cost estimates and consistent financial assumptions regarding gas supply requirements, availability in the market and associated costs.

- **Section 4 – Development of Planning and Contingent Scenarios to Address BCUC Commentary:** FEI developed both "planning" and "contingent" scenarios for certain Supplemental Alternatives.
  - The planning scenarios assume dependable LNG supply for resiliency, predicated on setting aside a "resiliency reserve".
  - The contingent scenarios are included to address commentary from the BCUC in the Adjournment Decision. These contingent scenarios are sensitivities that assume a specified amount of non-dependable LNG (i.e., LNG allocated for gas supply or LNG sales) is present on the day of a winter T-South no-flow event.

  The planning scenarios, with their focus on dependable resiliency reserves, reflect typical utility planning principles that FEI believes should be applied. Proceeding on the expectation that unreserved LNG volumes would *necessarily* be present at Tilbury and available for resiliency is risky as these volumes are used for other purposes in normal operations. However, Exponent's analysis confirms that none of the contingent scenarios would materially improve FEI's ability to withstand a winter T-South no-flow event.

- **Section 5 – Detailed Information Supporting Assessment of the Supplemental Alternatives:** FEI provides an alternative-by-alternative detailed discussion for every Supplemental Alternative, including those located at Tilbury, non-Tilbury alternatives raised by the BCUC in the Adjournment Decision, as well as a Southern Crossing Pipeline (SCP) extension.

2. DESCRIPTION OF ALTERNATIVES AND SUMMARY OF RESULTS

This section provides more detailed alternative and contingent scenario descriptions and modelling parameters. It also summarizes the Step 1 and Step 2 screening results, and the Step 3 scoring results for all Supplemental Alternatives that are technically and commercially viable.

2.1 ALTERNATIVE AND CONTINGENT SCENARIO DESCRIPTIONS AND MODELLING PARAMETERS

The following table sets out the names and descriptions for all 13 Supplemental Alternatives, plus the “contingent” scenarios for Supplemental Alternatives 1, 2, 3, 4, 4A, and 5.

The base (i.e., non-contingent) alternatives reflect planning principles, meaning they reflect dependable resources that are allocated for specific purposes. In contrast, the contingent scenarios for a given alternative consider the case where some volume of LNG that is not set aside as a “resiliency reserve” is available on the day of a no-flow event. In other words, some volume of LNG from Tilbury 1A or the Base Plant (as applicable) that was intended to be used for Rate Schedule (RS) 46 sales or gas supply remains in the tank on the day of the no-flow event and is used for resiliency instead of its intended purpose. FEI does not endorse using a contingent approach for planning purposes because: (a) FEI cannot rely on these LNG volumes being present on the day of a winter T-South no-flow event; and (b) the use of peaking supply for resiliency leaves FEI very exposed to firm load curtailments during a subsequent typical cold weather event. FEI has included these contingent scenarios to address the BCUC’s commentary in the Adjournment Decision about the potential resiliency value of such volumes. The concept of the “planning” and “contingent” scenarios is discussed further in Section 4 of this Appendix.

Table C-1: Supplemental Alternatives and Descriptions

Supp. Alt. #	Name	Description
Alternatives Reliant on Existing Facilities[1]		
Alt 1	No Capital Upgrades with Optimized Liquefaction (No Resiliency Reserve)	Run the Base Plant until it is no longer usable with no resiliency reserve. For peaking supply, FEI would continue to rely on the existing, non-refurbished Base Plant (i.e., 150 MMcf/d regasification and reduced tank capabilities of 0.35 Bcf) which has reached its end of life, augmented by 0.25 Bcf from Tilbury 1A to restore the original Base Plant design capabilities reflected in the Annual Contracting Plan (ACP).[2] FEI would need to continue relying on 50 MMcf/d of year-round pipeline capacity to achieve the required peaking supply (1 Bcf and 200 MMcf/d[3]). This option would result in FEI ultimately losing its LNG peaking supply (150 MMcf/d and 0.6 Bcf), and dependable peaking supply on regional infrastructure would be unavailable. Firm customers would thereafter begin to be curtailed in normal operations by up to 150 MMcf/d. FEI considers 2030 to be a reasonable estimate for when this period of curtailment would begin. Although it is uncertain if and when this period of curtailment would end, in order to provide a consistent basis for the financial analysis FEI assumed that the period of curtailment would end in 2035 with the construction of regional infrastructure upgrades. **Contingent Scenarios:** FEI also considered two contingent scenarios for Supplemental Alternative 1 wherein LNG volume from the Base Plant (0.35 Bcf) (Alternative 1 Contingent) and Tilbury 1A (0.4 Bcf)[4] (Alternative 1 Contingent with T1A) is present on the day of a no-flow event and available for outage risk mitigation, despite its intended purpose of gas supply and RS 46 sales, respectively. This would leave FEI without peaking supply for the rest of the winter, thus exposing FEI customers to curtailments in normal operations.

[1] These alternatives include prolonged reliance on the Base Plant tank with no dependable resiliency reserve, declining reliability, and a high likelihood of relying on the market for some replacement gas supply.

[2] As discussed in Section 3.3.2.1 of the Supplemental Evidence, the Base Plant has been operating at a reduced tank capacity of 0.35 Bcf for seismic reasons and has been relying on 0.25 Bcf of peaking energy from Tilbury 1A to restore the ACP requirement. However, FEI does not expect to be able to continue relying on the 0.25 Bcf from Tilbury 1A, as discussed in Section 4.4.1 of the Supplemental Evidence.

[3] The optimized gas supply portfolio is discussed in Section 3.3.4.1 of the Supplemental Evidence.

[4] Section 4.2.2 in this Appendix discusses the basis for using 0.4 Bcf as a contingent volume in Tilbury 1A.

Supp. Alt. #	Name	Description
Alt 2	New Regasification Only – 400 MMcf/d (No Resiliency Reserve)	Replace the Base Plant regasification with 400 MMcf/d of new capacity, but continue to rely on a non-refurbished Base Plant tank until it is no longer usable. There is no resiliency reserve. For peaking supply, FEI would continue to rely on the existing, non-refurbished Base Plant (i.e., reduced tank capabilities of 0.35 Bcf) which has reached its end of life, augmented by 0.25 Bcf from Tilbury 1A to restore the original Base Plant design capabilities reflected in the ACP.[5] Despite the new regasification of 400 MMcf/d, FEI would need to continue relying on 50 MMcf/d of year-round pipeline capacity to achieve the required peaking supply (1 Bcf and 200 MMcf/d) due to insufficient storage. This option would result in FEI ultimately having insufficient peaking supply, and firm customers would thereafter begin to be curtailed in normal operations by up to 150 MMcf/d. FEI considers 2030 to be a reasonable estimate for when this period of curtailment would begin; the new regasification will be of limited use after that point given there would be insufficient available LNG in storage at Tilbury beyond 2030. Dependable peaking supply on regional infrastructure would be unavailable. Although it is uncertain if and when this period of curtailments would end, in order to provide a consistent basis for the financial analysis FEI assumed that the period of curtailment would end in 2035 with the construction of regional infrastructure upgrades. **Contingent Scenarios:** FEI also considered two contingent scenarios for Supplemental Alternative 2 wherein LNG volume from the Base Plant (0.35 Bcf) (Alternative 2 Contingent) and Tilbury 1A (0.4 Bcf) (Alternative 2 Contingent with T1A) is present on the day of a no-flow event and available for outage risk mitigation, despite its intended purpose of gas supply and RS 46 sales respectively. This would leave FEI without peaking supply for the rest of the winter, thus exposing FEI customers to curtailments in normal operations.

[5] As discussed in Section 3.3.2.1 of the Supplemental Evidence, the Base Plant has been operating at a reduced tank capacity of 0.35 Bcf for seismic reasons and has been relying on 0.25 Bcf of peaking energy from Tilbury 1A to restore the ACP requirement. However, FEI does not expect to be able to continue relying on the 0.25 Bcf from Tilbury 1A, as discussed in Section 4.4.1 of the Supplemental Evidence.

Supp. Alt. #	Name	Description
Alt 3	New Regasification Only - 600 MMcf/d (No Resiliency Reserve)	Replace Base Plant regasification with 600 MMcf/d of new capacity but continue to rely on a non-refurbished Base Plant tank until it is no longer usable. There is no resiliency reserve. For peaking supply, FEI would continue to rely on the existing, non-refurbished Base Plant (i.e., reduced tank capabilities of 0.35 Bcf) which has reached its end of life, augmented by 0.25 Bcf from Tilbury 1A to restore the original Base Plant design capabilities reflected in the ACP.[6] Despite the new regasification of 600 MMcf/d, FEI would need to continue relying on 50 MMcf/d of year-round pipeline capacity to achieve the required peaking supply (1 Bcf and 200 MMcf/d) due to insufficient storage. This option would result in FEI ultimately having insufficient peaking supply, and firm customers would thereafter begin to be curtailed in normal operations by up to 150 MMcf/d. FEI considers 2030 to be a reasonable estimate for when this period of curtailments would begin; the new regasification will be of limited use after that point given there would be insufficient available LNG in storage at Tilbury beyond 2030. FEI would be unable to procure dependable replacement peaking supply on regional infrastructure. Although it is uncertain if and when this period of curtailment would end, in order to provide a consistent basis for the financial analysis FEI assumed that the period of curtailment would end in 2035 with the construction of regional infrastructure upgrades. **Contingent Scenarios:** FEI also considered two contingent scenarios for Supplemental Alternative 3 wherein LNG volume from the Base Plant (0.35 Bcf) (Alternative 3 Contingent) and Tilbury 1A (0.4 Bcf) (Alternative 3 Contingent with T1A) is present on the day of a no-flow event and available for outage risk mitigation, despite its intended purpose of gas supply and RS 46 sales respectively. This would leave FEI without peaking supply for the rest of the winter, thus exposing FEI customers to curtailments in normal operations.

6 As discussed in Section 3.3.2.1 of the Supplemental Evidence, the Base Plant has been operating at a reduced tank capacity of 0.35 Bcf for seismic reasons and has been relying on 0.25 Bcf of peaking energy from Tilbury 1A to restore the ACP requirement. However, FEI does not expect to be able to continue relying on the 0.25 Bcf from Tilbury 1A, as discussed in Section 4.4.1 of the Supplemental Evidence.

Supp. Alt. #	Name	Description
New Facility with Gas Supply But No Resiliency Reserve[7]		
Alt 4	Like-for-Like (No Resiliency Reserve)	Replace the Base Plant like-for-like to restore the 1971 design capacity (150 MMcf/d regasification and 0.6 Bcf tank) and continue using Tilbury as a supply peaking resource, without a resiliency reserve. FEI would continue to rely on 50 MMcf/d of year-round pipeline capacity to achieve required peaking supply (1 Bcf and 200 MMcf/d), which is suboptimal from a portfolio design standpoint. **Contingent Scenario:** FEI also considered a contingent scenario for Supplemental Alternative 4 wherein 0.6 Bcf of LNG volume is present on the day of a no-flow event and available for outage risk mitigation, despite its intended purpose for gas supply. This would leave FEI without peaking supply for the rest of the winter, thus exposing FEI customers to curtailments in normal operations.
Alt 4A	New 1 Bcf Tank (No Resiliency Reserve) and 400 MMcf/d Regasification	Replace the Base Plant with the smallest new facility capable of providing FEI's optimum peaking gas supply, including a 1 Bcf tank and 200 MMcf/d regasification (with an additional 200 MMcf/d for redundancy). Continue using it as a supply peaking resource, without a resiliency reserve. The facility provides sufficient capability to meet FEI's required peaking supply and therefore does not require FEI to augment with regional market resources. This is optimal from a gas supply portfolio design perspective. **Contingent Scenario:** FEI also considered a contingent scenario for Supplemental Alternative 4A wherein 1.0 Bcf of LNG volume is present on the day of a no-flow event and available for outage risk mitigation, despite its intended purpose for gas supply. This would leave FEI without peaking supply for the rest of the winter, thus exposing FEI customers to curtailments in normal operations.

7 These alternatives do not include a dependable resiliency reserve but provide different amounts of peaking gas supply and improved reliability.

Supp. Alt. #	Name	Description
New Facility with Resiliency Reserve But No Gas Supply[8]		
Alt 5	Like-for-Like (Full Resiliency Reserve)	Replace the Base Plant like-for-like to restore the 1971 design capacity (150 MMcf/d regasification and 0.6 Bcf tank) and allocate the entire tank as a resiliency reserve. FEI would continue to hold the existing 50 MMcf/d of sub-optimal year-round pipeline capacity for peaking supply. However, this option would result in FEI losing its LNG peaking supply (150 MMcf/d and 0.6 Bcf) upon commissioning of the new facility, and firm customers would thereafter begin to be curtailed in normal operations by up to 150 MMcf/d due to an inability to procure dependable replacement peaking supply on regional infrastructure. Although it is uncertain if and when this period of curtailment would end, in order to provide a consistent basis for the financial analysis FEI assumed that the period of curtailment would end in 2035 with the construction of regional infrastructure upgrades. **Contingent Scenario:** FEI also considered a contingent scenario for Supplemental Alternative 5 wherein 0.4 Bcf of LNG volume from Tilbury 1A is also present on the day of a no-flow event and available for outage risk mitigation, despite its intended purpose of being set aside for RS 46 sales.
Alt 6	New 1 Bcf Tank (Full Resiliency Reserve) and 800 MMcf/d Regasification	Replace the Base Plant with a 1.0 Bcf tank and 800 MMcf/d regasification. Allocate the entire tank as a resiliency reserve. FEI would continue to hold the existing 50 MMcf/d of sub-optimal year-round pipeline capacity for peaking supply. However, this option would result in FEI losing its LNG peaking supply (150 MMcf/d and 0.6 Bcf) upon commissioning of the new facility, and firm customers would thereafter begin to be curtailed in normal operations by up to 150 MMcf/d due to an inability to procure dependable replacement peaking supply on regional infrastructure. Although it is uncertain if and when this period of curtailment would end, in order to provide a consistent basis for the financial analysis FEI assumed that the period of curtailment would end in 2035 with the construction of regional infrastructure upgrades.
Alt 7	New 2 Bcf Tank (Full Resiliency Reserve) and 800 MMcf/d Regasification	Replace the Base Plant with a 2.0 Bcf tank and 800 MMcf/d regasification. Allocate the entire tank as a resiliency reserve. FEI would continue to hold the existing 50 MMcf/d of sub-optimal year-round pipeline capacity for peaking supply. However, this option would result in FEI losing its LNG peaking supply (150 MMcf/d and 0.6 Bcf) upon commissioning of the new facility, and firm customers would thereafter begin to be curtailed in normal operations by up to 150 MMcf/d due to an inability to procure dependable replacement peaking supply on regional infrastructure. Although it is uncertain if and when this period of curtailment would end, in order to provide a consistent basis for the financial analysis FEI assumed that the period of curtailment would end in 2035 with the construction of regional infrastructure upgrades.

[8] These alternatives include a full resiliency reserve but still rely on the market for replacement of the gas supply functions.

Supp. Alt. #	Name	Description
New Facility with Both Resiliency Reserve and Replacement of Gas Supply		
Alt 8	New 2 Bcf Tank (1.4 Bcf Resiliency Reserve) and 800 MMcf/d Regasification	Construct the smallest facility that allows FEI to both avoid curtailments of firm peak load in normal operations and provide a certain level of resiliency reserve. This includes replacing the Base Plant with a 2 Bcf tank and 800 MMcf/d regasification, of which 1.4 Bcf is allocated as a resiliency reserve, and 0.6 Bcf is allocated to replace the existing gas supply functions at Tilbury. FEI would continue to rely on 50 MMcf/d of year-round pipeline capacity to achieve required peaking supply (1 Bcf and 200 MMcf/d), which is suboptimal from a portfolio design standpoint.
Alt 9	New 3 Bcf Tank (2 Bcf Resiliency Reserve) and 800 MMcf/d Regasification	Construct a facility that both significantly mitigates FEI's largest customer outage risks and meets FEI's required peaking gas supply in an optimal manner. Replace the Base Plant with a 3 Bcf tank and 800 MMcf/d regasification and allocate 2 Bcf as a resiliency reserve, and 1 Bcf to gas supply. The facility provides sufficient capability to meet FEI's required peaking supply and therefore does not require FEI to augment with regional market resources. This is optimal from a gas supply portfolio design perspective.
Non-Tilbury Alternatives[9]		
Alt 10	Alt 1 plus VITS Reverse Flow	FEI would retain the existing Tilbury facilities with no capital upgrades (i.e., Supplemental Alternative 1). FEI would also construct the necessary facilities to allow significant reverse flows on the Vancouver Island Transmission System (VITS) at all times during the year, such that the combined daily delivery is at least 550 MMcf/d.
Alt 11	LNG from Woodfibre LNG	Use the existing Tilbury facilities with no capital upgrades (i.e., Supplemental Alternative 1). FEI would also contract with Woodfibre LNG for a long-term firm supply of LNG and FEI would either: • Custom build a vessel for transporting LNG up the Fraser River to Tilbury, construct a facility at Tilbury for offloading the LNG from the vessel, and add more regasification capacity at Tilbury to address the existing regasification constraint; or • Acquire property rights from Woodfibre LNG on which FEI constructs a regasification facility at Woodfibre, plus FEI constructs facilities to permit reversing the flow of the VITS.
Alt 12	Floating LNG	Purchase a vessel to provide floating LNG storage. Acquire a water lot that would allow for permanent mooring. Add more regasification capacity, either as an integrated component of the LNG storage vessel or on the adjacent shoreline. Construct onshore facilities, including a jetty and interconnecting pipe.

9 FEI considers these alternatives to be non-viable approaches to providing winter resiliency and peaking gas supply.

2.2 STEP 1 RESULTS: NON-TILBURY ALTERNATIVES AND "NO CAPITAL UPGRADES" ARE TECHNICALLY AND COMMERCIALLY NON-VIABLE

The BCUC stated in the Adjournment Decision that it required further information about the remaining life of the Base Plant, specific non-Tilbury alternatives (constructing facilities to permit reverse-flow on the VITS, LNG from Woodfibre LNG, and floating LNG storage), and a Southern Crossing Pipeline extension. The following table summarizes why each of these Supplemental Alternatives was found to be non-viable at Step 1. More detailed discussion of each alternative is provided in Section 5 of this Appendix.

Table C-2: Summary of Non-Viable Alternatives

No.	Description	Rationale
Alt 1	No Capital Upgrades with Optimized Liquefaction (No Resiliency Reserve)	Supplemental Alternative 1 is not technically viable because the Base Plant has reached end-of-life and can no longer reliably perform its intended function without capital upgrades. Please refer to Section 3.3 of the Supplemental Evidence for more details on the Base Plant.
Alt 10	Alt 1 plus VITS Reverse Flow	Supplemental Alternative 10 would have a significant scope of work compared to Tilbury-based alternatives that provide a similar resiliency benefit. For example, this alternative would involve looping significant portions of FEI's VITS and completing multiple compressor station upgrades. Further, a hydraulic constraint exists which limits the amount of reverse flow that is possible on the VITS during winter.
Alt 11	LNG from Woodfibre	Supplemental Alternative 11 would be inconsistent with Woodfibre LNG's business model and LNG markets. Any LNG storage that Woodfibre has on the site is inventoried to ensure the next customer vessel can be filled on schedule. Further, even if LNG from Woodfibre were available, the reverse flow constraint identified in Supplemental Alternative 10 applies to Supplemental Alternative 11 as well.
Alt 12	Floating LNG	There are no viable sites for floating LNG. All options also have issues with technical feasibility, either due to the tie-in point pressure rating and pipeline capacity or execution difficulties caused by the location of the tie-in point in the Fraser River.
n/a	Southern Crossing Extension (e.g., RGSD Project)	FEI has re-confirmed that a Southern Crossing Pipeline extension, regardless of size or end point, would not be able to provide supply fast enough to prevent a Lower Mainland outage on a similar scale to what would occur today following a winter T-South no-flow event. FEI notes that although a future Southern Crossing Pipeline extension remains possible, FEI is no longer pursuing RGSD as an FEI project.

2.3 STEP 2 RESULTS: SUPPLEMENTAL ALTERNATIVES 2, 3, 5, 6, AND 7 DO NOT RETAIN FEI'S EXISTING ON-SYSTEM FIRM PEAKING GAS SUPPLY

In Section 4.2.2.2 of the Supplemental Evidence, FEI outlines and explains the rationale for the Step 2 screen. Step 2 screens out supplemental alternatives that do not, at minimum, retain FEI's existing on-system peaking resources of 0.6 Bcf and 150 MMcf/d. The intent is to ensure that FEI remains able to serve firm load dependably in cold weather without curtailments. Based on this

Step 2 screen, Supplemental Alternatives 2, 3, 5, 6, and 7 were screened out. The results are summarized in Table C-3 below. Please refer to Section 4.4 of the Supplemental Evidence and Section 5 of this Appendix for more details.

Table C-3: Summary of Step 2 Screen Results

Supp Alt #	Name	On-System Gas Supply Modelling Parameters[10]		Retains FEI's Existing On-System Firm Peaking Gas Supply Capabilities?
		To 2030	After 2030	
Alt 2	New Regasification Only - 400 MMcf/d (No Resiliency Reserve)	0.6 Bcf 400 MMcf/d	< 0.6 Bcf 400 MMcf/d	✗
Alt 3	New Regasification Only - 600 MMcf/d (No Resiliency Reserve)	0.6 Bcf 600 MMcf/d	< 0.6 Bcf 600 MMcf/d	✗
Alt 4	Like-for-Like (No Resiliency Reserve)	0.6 Bcf 150 MMcf/d	0.6 Bcf 150 MMcf/d	✓
Alt 4A	New 1 Bcf Tank (No Resiliency Reserve) and 400 MMcf/d Regasification	1 Bcf 400 MMcf/d	1 Bcf 400 MMcf/d	✓
Alt 5	Like-for-Like (Full Resiliency Reserve)	0 Bcf 150 MMcf/d	0 Bcf 150 MMcf/d	✗
Alt 6	New 1 Bcf Tank (Full Resiliency Reserve) and 800 MMcf/d Regasification	0 Bcf 800 MMcf/d	0 Bcf 800 MMcf/d	✗
Alt 7	New 2 Bcf Tank (Full Resiliency Reserve) and 800 MMcf/d Regasification	0 Bcf 800 MMcf/d	0 Bcf 800 MMcf/d	✗
Alt 8	New 2 Bcf Tank (1.4 Bcf Resiliency Reserve) and 800 MMcf/d Regasification	0.6 Bcf 800 MMcf/d	0.6 Bcf 800 MMcf/d	✓
Alt 9	New 3 Bcf Tank (2 Bcf Resiliency Reserve) and 800 MMcf/d Regasification	1 Bcf 800 MMcf/d	1 Bcf 800 MMcf/d	✓

2.4 STEP 3 RESULTS FOR SUPPLEMENTAL ALTERNATIVES 2 TO 9

In Section 4.2.2.3 of the Supplemental Evidence, FEI describes Step 3 of the structured alternative analysis process. As part of Step 3, FEI scored all alternatives relative to the existing Tilbury Base Plant with no capital upgrades (Supplemental Alternative 1) against five criteria. The discussion in Section 4 of the Supplemental Evidence focuses on how the criteria apply to Supplemental Alternatives 4, 4A, 8, and 9, since these are the only Supplemental Alternatives that passed both the Step 1 and Step 2 screens. However, as explained above, as part of this

[10] The modelling parameters for each Supplemental Alternative are discussed in greater detail in Section 4 of this Appendix.

Appendix FEI also assessed and scored the five alternatives screened out at Step 2 (Supplemental Alternatives 2, 3, 5, 6 and 7) to be fully responsive to the Adjournment Decision.

Figure C-2 below presents scoring results for all technically and commercially viable supplemental alternatives (i.e., those that passed the Step 1 screening). In Figure C-2, Supplemental Alternatives that did not pass the Step 2 screen are identified by a red filled “No Impact” score for the “Availability of Dependable Gas Supply During Peak Demand” criterion. FEI has scored Step 3 on a relative basis; therefore, “No Impact” means that the option does not improve on the adverse service implications of continuing to rely on the existing Tilbury Base Plant with no capital upgrades (Supplemental Alternative 1). As Figure C-2 demonstrates, when the additional Supplemental Alternatives are considered, Supplemental Alternative 9 remains the Preferred Alternative.

1 **Figure C-2: Scoring Results for Technically and Commercially Viable Supplemental Alternatives**

Evaluation Criterion	Criterion Weighting	Alternative 2	Alternative 3	Alternative 4	Alternative 4A	Alternative 5	Alternative 6	Alternative 7	Alternative 8	Alternative 9
Resiliency Benefit	30%	No Impact	No Impact	No Impact	No Impact	No Impact	No Impact	High Positive Impact	Medium Positive Impact	High Positive Impact
Availability of Dependable Gas Supply During Peak Demand	20%	No Impact	No Impact	Medium Positive Impact	High Positive Impact	No Impact	No Impact	No Impact	Medium Positive Impact	High Positive Impact
Resolves Age Related Base Plant Challenges	20%	Medium Positive Impact	Medium Positive Impact	High Positive Impact	High Positive Impact	High Positive Impact	High Positive Impact	High Positive Impact	High Positive Impact	High Positive Impact
Levelized Total Rate Impact	20%	Low Negative Impact	Low Negative Impact	Low Negative Impact	Low Negative Impact	Medium Negative Impact	High Negative Impact	High Negative Impact	Medium Negative Impact	Medium Negative Impact
Useful Under the Modified Diversified Energy (Planning) Scenario (mDEP) Between the In-Service Date and 2050	10%	Medium Negative Impact	Medium Negative Impact	No Impact	No Impact	No Impact	No Impact	No Impact	No Impact	No Impact
	Total Weighted Score:	0.1	0.1	1.4	1.8	0.4	0.0	1.5	1.9	2.9
										Preferred

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2.5 RESILIENCY BENEFIT ASSESSMENT SUMMARY

This section presents the results from Exponent's analysis of how effective each technically and commercially viable Supplemental Alternative (i.e., Supplemental Alternatives 2 to 9) is at mitigating the risk from a winter T-South no-flow event.

Exponent used the same approach to determining risk and risk reduction across all alternatives. FEI summarized the approach in Section 3.2 of the Supplemental Evidence, and Exponent also describes its approach in its report.[11] At a high-level, Exponent: (1) determined the *status quo* risk associated with a winter T-South no-flow event relying on the existing Tilbury Base Plant with no capital upgrades (represented by Supplemental Alternative 1 (Planning)); and then (2) compared this *status quo* risk to the risk of a winter T-South no-flow event assuming each Supplemental Alternative is in place. The amount of risk mitigation provided by an alternative is then the difference between the *status quo* risk and the risk with the alternative in place.

FEI summarizes the results as follows:

- Most of the Supplemental Alternatives would not materially improve FEI's current ability to withstand a winter T-South no-flow event. In other words, the Lower Mainland system would still depressurize, and all customers would still lose service, on the day of a T-South no-flow event at average winter temperatures;
- Even the contingent scenarios do not result in a significant improvement; and
- Supplemental Alternatives 7, 8 and 9 offer significantly greater risk mitigation relative to the other alternatives.

Exponent's risk reduction results are reflective of the importance of regasification capacity and storage volume in determining the support duration, and that certain hazards are likely to cause a failure of only a single T-South pipeline, leading to a regulatory shutdown of the intact pipeline.

2.5.1 Results of Exponent's Risk Assessment for Technically and Commercially Viable Alternatives

Table C-4 below summarizes the resiliency modelling parameters for each Supplemental Alternative and identifies the alternatives that, based on Exponent's risk calculations, materially improve FEI's resiliency against a winter T-South no-flow event. The resiliency modelling parameters are the send-out capacity and volume of LNG that is used for resiliency. As will be discussed in Section 2.5.2 of this Appendix, the resiliency modelling parameters, combined with the system demand, determine how long a Supplemental Alternative can support the entirety of FEI's Lower Mainland load, which in turn dictates the level of risk mitigation. FEI used the amount of risk reduction provided by an alternative against a T-South no-flow event at average winter

[11] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report.

conditions, as calculated by Exponent, to establish whether the alternative materially improves resiliency.

Table C-4: Supplemental Alternatives that Materially Improve Resiliency at Average Winter Temperatures (+4°C)

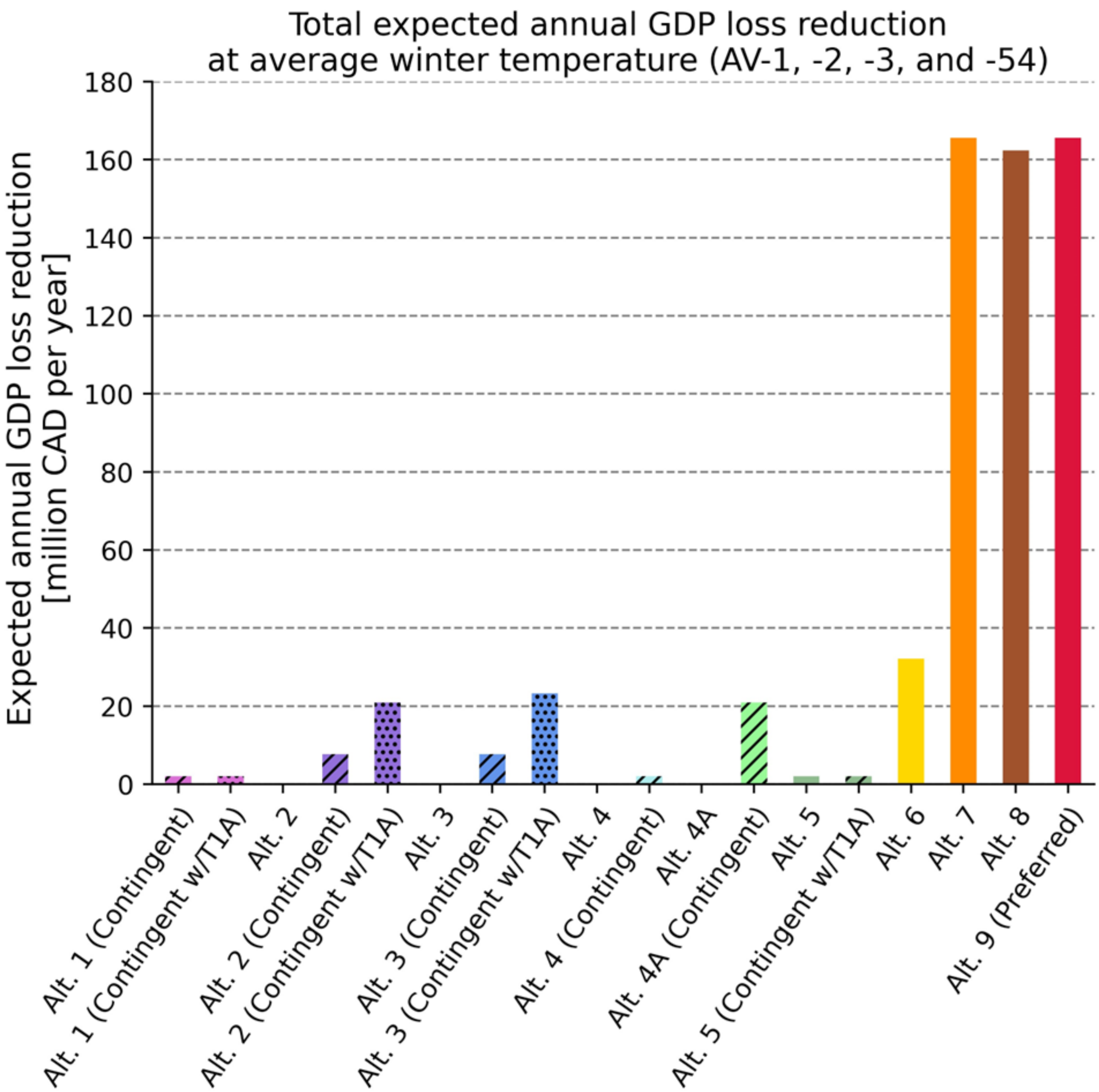
Supp Alt #	Name	Resiliency Modelling Parameters	Material Resiliency Improvement?
Alternative 1	No Capital Upgrades with Optimized Liquefaction (No Resiliency Reserve)	0 Bcf 150 MMcf/d	✗
Alternative 1 Contingent		0.35 Bcf 150 MMcf/d	✗
Alternative 1 Contingent w/T1A		0.75 Bcf 150 MMcf/d	✗
Alternative 2	New Regasification Only – 400 MMcf/d (No Resiliency Reserve)	0 Bcf 400 MMcf/d	✗
Alternative 2 Contingent		0.35 Bcf 400 MMcf/d	✗
Alternative 2 Contingent w/T1A		0.75 Bcf 400 MMcf/d	✗
Alternative 3	New Regasification Only – 600 MMcf/d (No Resiliency Reserve)	0 Bcf 600 MMcf/d	✗
Alternative 3 Contingent		0.35 Bcf 600 MMcf/d	✗
Alternative 3 Contingent w/T1A		0.75 Bcf 600 MMcf/d	✗
Alternative 4	Like-for-Like (No Resiliency Reserve)	0 Bcf 150 MMcf/d	✗
Alternative 4 Contingent		0.6 Bcf 150 MMcf/d	✗
Alternative 4A	New 1 Bcf Tank (No Resiliency Reserve) and 400 MMcf/d Regasification	0 Bcf 400 MMcf/d	✗
Alternative 4A Contingent		1 Bcf 400 MMcf/d	✗
Alternative 5	Like-for-Like (Full Resiliency Reserve)	0.6 Bcf 150 MMcf/d	✗
Alternative 5 Contingent w/T1A		1 Bcf 150 MMcf/d	✗
Alternative 6	New 1 Bcf Tank (Full Resiliency Reserve) and 800 MMcf/d Regasification	1 Bcf 800 MMcf/d	✗
Alternative 7	New 2 Bcf Tank (Full Resiliency Reserve) and 800 MMcf/d Regasification	2 Bcf 800 MMcf/d	✓

Supp Alt #	Name	Resiliency Modelling Parameters	Material Resiliency Improvement?
Alternative 8	New 2 Bcf Tank (1.4 Bcf Resiliency Reserve) and 800 MMcf/d Regasification	1.4 Bcf 800 MMcf/d	✓
Alternative 9	New 3 Bcf Tank (2 Bcf Resiliency Reserve) and 800 MMcf/d Regasification	2 Bcf 800 MMcf/d	✓

The results in Table C-4 were determined based on Exponent's risk analysis. Figure C-3 below, prepared by Exponent, summarizes the annual expected loss reduction associated with each Supplemental Alternative relative to the existing Base Plant with no capital upgrades (the Supplemental Alternative 1 (Planning) scenario).[12] Exponent also prepared figures based on customer outages and customer-outage-days consequence metrics, and the pattern is the same. Exponent's calculations show that, even at average winter temperatures, the calculated risk for most Supplemental Alternatives remains similar to the existing Base Plant with no capital upgrades. Even the contingent scenarios do not significantly improve risk mitigation. Supplemental Alternatives 7, 8 and 9 offer significantly greater risk mitigation relative to the others. For example, Supplemental Alternative 9 provides over 4 times more risk mitigation than Supplemental Alternative 6.

[12] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, Figure 41.

Figure C-3: T-South at Avg. Winter – Expected Annual Loss Reduction



The choice of time horizon does not affect the relativities among the various Supplemental Alternatives. This can be seen in the expected 23- and 67-year GDP loss results included below.[13]

[13] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, Figures 42 and 43.

Figure C-4: T-South at Avg. Winter – Expected 23-Year Loss Reduction

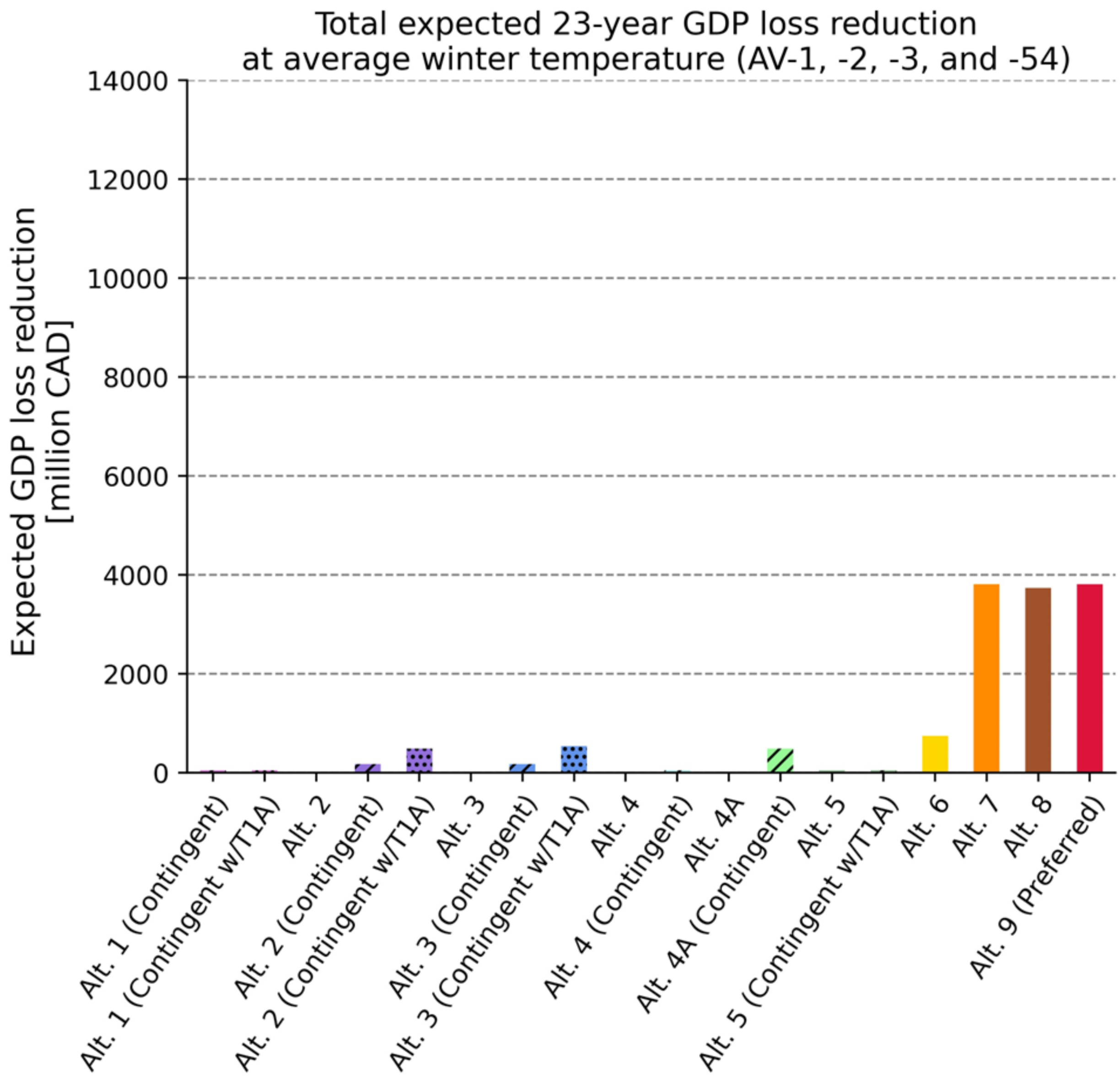
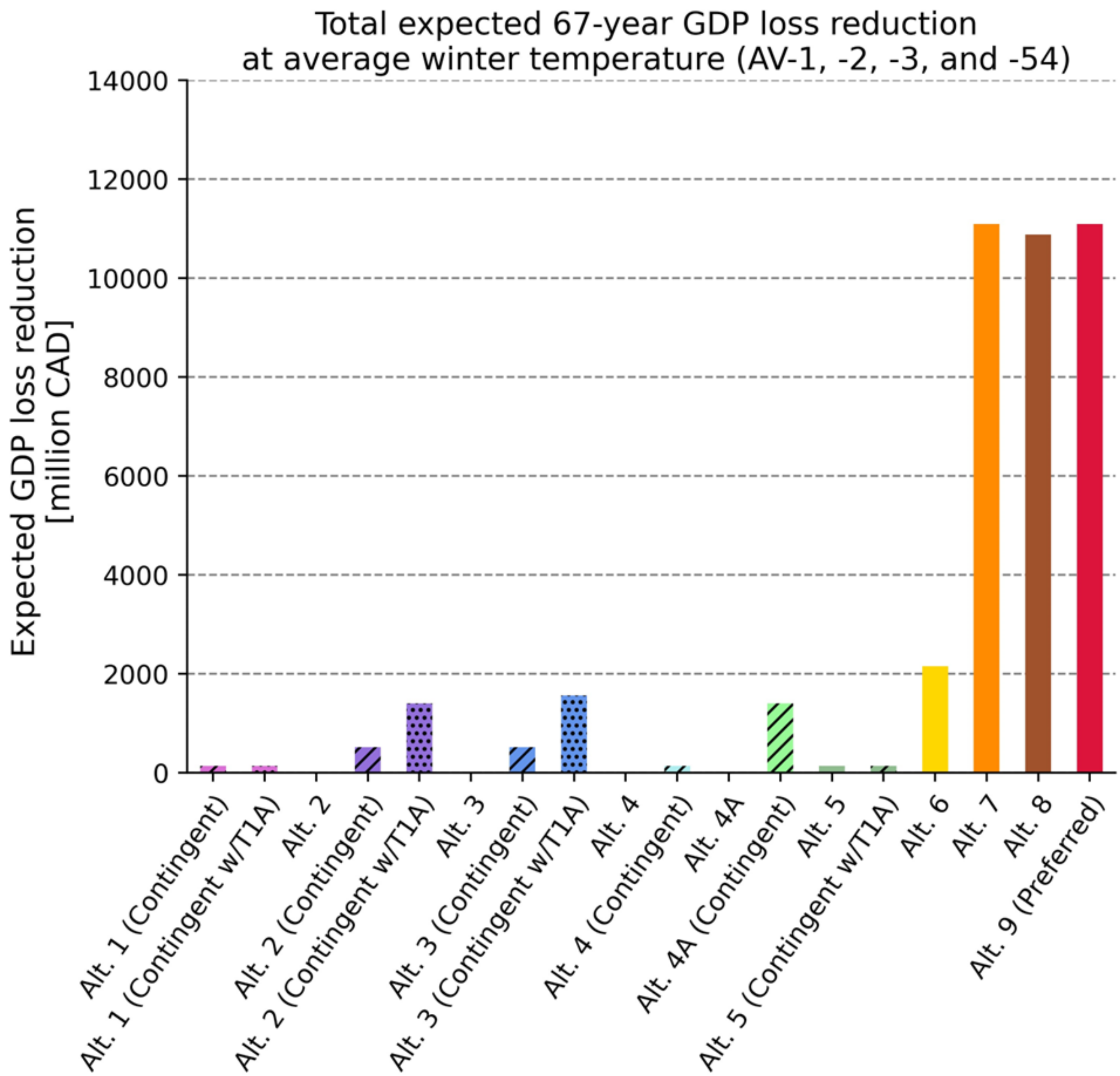


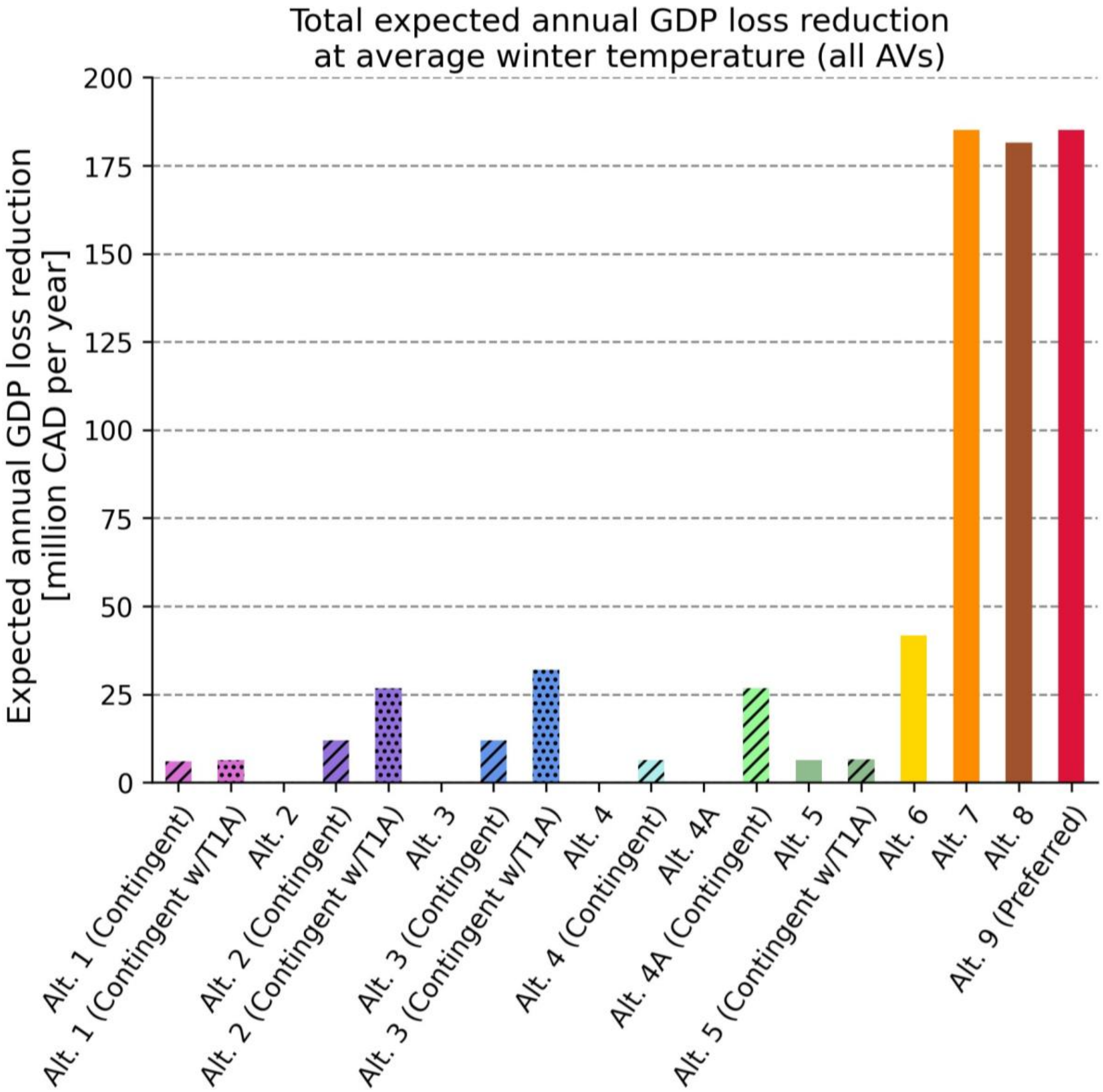
Figure C-5: T-South at Avg. Winter – Expected 67-Year Loss Reduction



The above figures show risk mitigation for T-South related risks only (AVs 1, 2, 3 and 54), since that is the measure used for the "Resiliency Benefits" criterion in the alternatives analysis. However, Exponent also calculated the risk mitigation for each Supplemental Alternative on a combined basis for all Assessed Vulnerabilities. The corresponding figures for all Assessed Vulnerabilities are provided below as Figures C-6 to C-8.[14] When these figures are compared to the corresponding T-South-only figures above, they show that the larger Supplemental Alternatives provide more risk mitigation in respect of non-T-South AVs than the smaller Supplemental Alternatives.

[14] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, Figures 38-40.

Figure C-6: All AVs at Avg. Winter – Expected Annual Loss Reduction



1 **Figure C-7: All AVs at Avg. Winter – Expected 23-Year Loss Reduction**

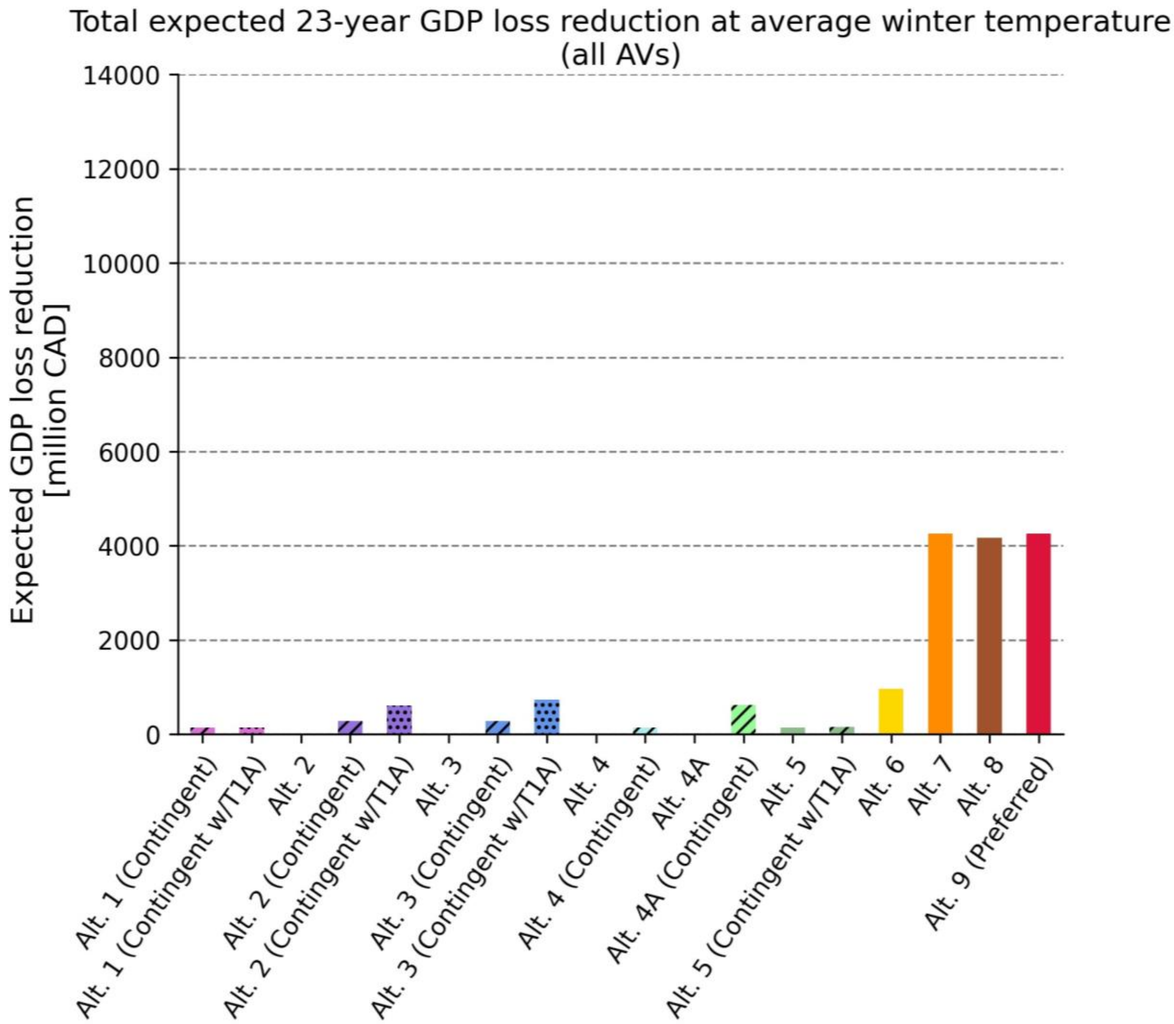


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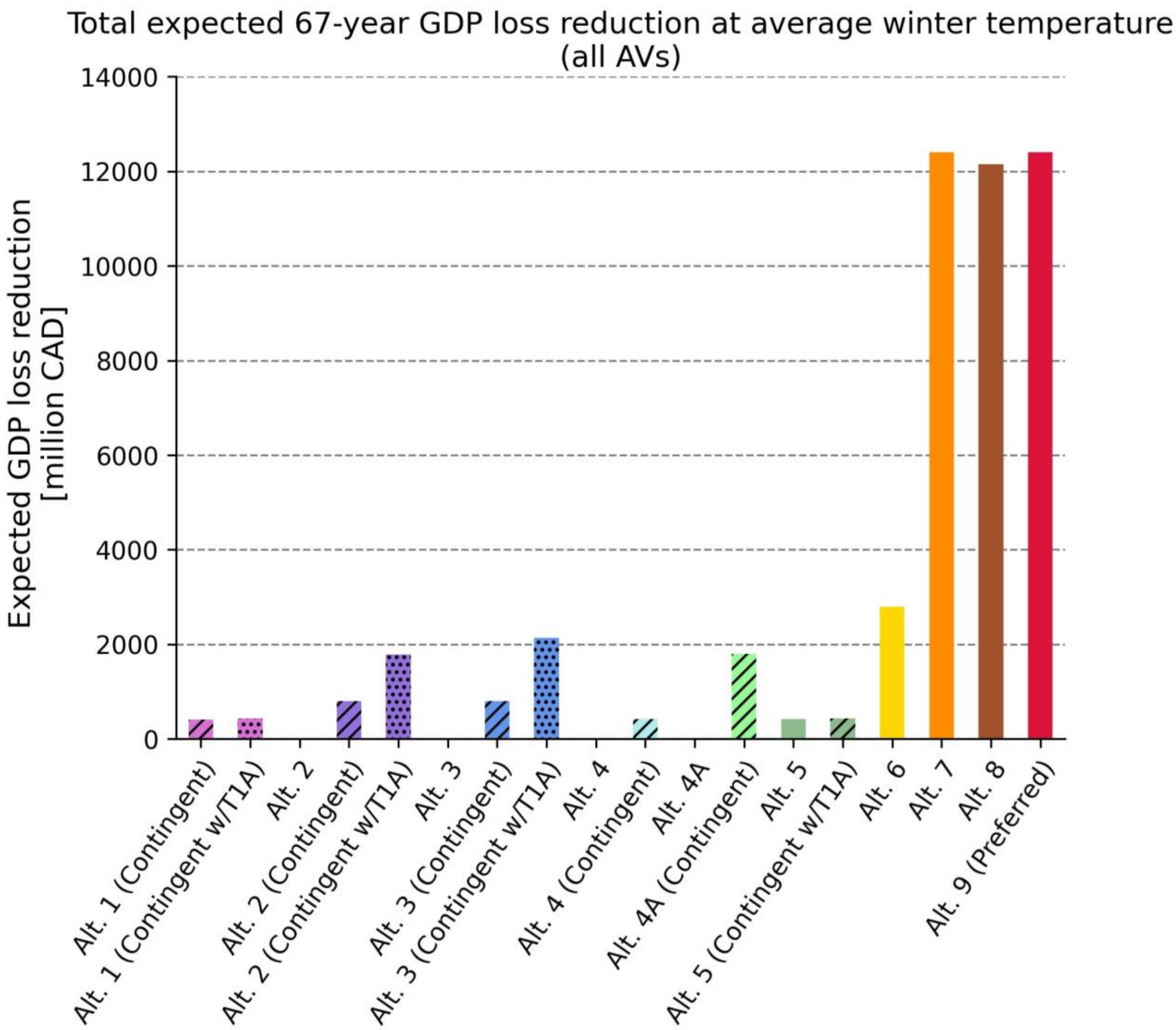
Figure C-8: All AVs at Avg. Winter – Expected 67-Year Loss Reduction



2.5.2 Understanding the Results of Exponent's Risk Mitigation Calculations

Exponent's risk reduction results shown in the above figures are reflective of the importance of regasification capacity and storage volume in determining the support duration, and that certain hazards are likely to cause a failure of only a single T-South pipeline, leading to a regulatory shutdown of the intact pipeline. The implications of those considerations for the risk mitigation results are discussed below.

1. **The Risk Mitigation Provided by a Supplemental Alternative is Dictated by its Support Duration:**

   An alternative's load support duration (i.e., the duration the entire Lower Mainland system can be supported by the alternative until customer outages occur) influences the level of risk mitigation provided. For example, if the load support duration exceeds a given no-flow duration, then the Lower Mainland component of the risk will have been mitigated.

2. Regasification Capacity and Storage Volume Dictate Support Duration: The support duration is, in turn, a function of the regasification capacity, the available volume of LNG, and the system demand. FEI explains in Section 3.2.2 of the Supplemental Evidence, for instance, how the constraint in regasification is presently limiting the Tilbury support duration to less than 1 day, even at average winter temperatures.

3. A 3-Day Support Duration is Necessary to Provide Significant Risk Mitigation: Supplemental Alternatives that only marginally extend the load support duration are unlikely to significantly mitigate risk, as many modes of failure on T-South are expected to result in a no-flow event lasting approximately 3 days.

Exponent's risk assessment evaluates a T-South failure assuming a range of no-flow durations and failure modes (i.e., hazards). In instances where there are parallel pipelines (as is the case for T-South), Exponent's analysis considers the probability of each hazard causing simultaneous failure of both pipelines. As many of the hazards considered have a low probability of simultaneous failure, a likely outcome of a T-South failure is that only one line is physically damaged and the adjacent undamaged line is shut-in as a precaution by the regulator (i.e., a regulatory shutdown). For example, the duration of the no-flow event during the 2018 T-South Incident was determined by the duration of the regulatory shutdown.

Exponent's calculations assume a regulatory shutdown will be resolved in 3 days; thus, alternatives that provide at least 3 days of support are able to bridge the regulatory shutdown and mitigate the risk for this specific failure scenario. This results in a significant risk reduction, given that a regulatory shut-down is a likely outcome of a T-South failure. Exponent explained:[15]

> The on-system LNG of a Tilbury Alternative plays an important role in determining the reduction in losses compared to the status quo configuration (Alternative 1 (Planning)). When the Tilbury Facility has limited on-system LNG (1 Bcf or less), relatively few hazards are mitigated by its presence because there is not enough volume to bridge the regulatory shutdown period or shorter repair durations for AVs with higher loads, such as AV-1, AV-2, AV-3, AV-54, and AV-18. Larger on-system LNG volumes (such as 2 Bcf) provide enough backup supply to bridge the three-day regulatory shutdown period on AVs-1, 2, 3, 54, and 18, which are AVs with parallel pipeline segments. <u>Bridging the regulatory shutdown period significantly reduces losses on these AVs</u>, except for cases in which the two parallel pipeline segments fail simultaneously. [Emphasis added]

[15] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, para. 192.

The assumption of a 3-day regulatory shutdown is considered reasonable given that the regulatory shutdown during the 2018 T-South Incident was two days, and that was in favourable conditions that facilitated crews reaching and assessing the condition of the adjacent pipe. The 2018 T-South Incident timeline and the favourable conditions that influenced it are discussed in the Application and several responses to information requests.[16] FEI considers it reasonable to assume that the regulator will perform its safety assessment with due haste, as it will recognize that an unnecessarily prolonged precautionary shut-down of the unaffected line will have significant consequences for all downstream gas users.

4. Increased Regasification is Required to Increase the Load Support Duration and Improve Resiliency Against a Winter T-South No-Flow Event:

Regardless of the volume of LNG available at Tilbury, 150 MMcf/d of regasification (i.e., the existing capacity at the Tilbury Base Plant) is insufficient to meet the daily winter system demand (see further discussion in Section 3.3.4.2 of the Supplemental Evidence). At average winter temperatures the system demand greatly exceeds 150 MMcf/d, resulting in a supply/demand imbalance that causes the system to fail on the day of a winter T-South no-flow event. Thus, alternatives that do not increase the regasification capacity above 150 MMcf/d would not increase the load support duration. In other words, they would not provide risk mitigation relative to the existing Base Plant with no capital upgrades in the event of a T-South winter no-flow event at average winter temperatures.

Supplemental Alternatives 1, 4 and 5, all of which have 150 MMcf/d of regasification capacity, fall in this category.

5. Increasing Regasification Alone Will Not Materially Increase the Load Support Duration or Improve Resiliency Against a Winter T-South No-Flow Event – More than 1 Bcf is Required:

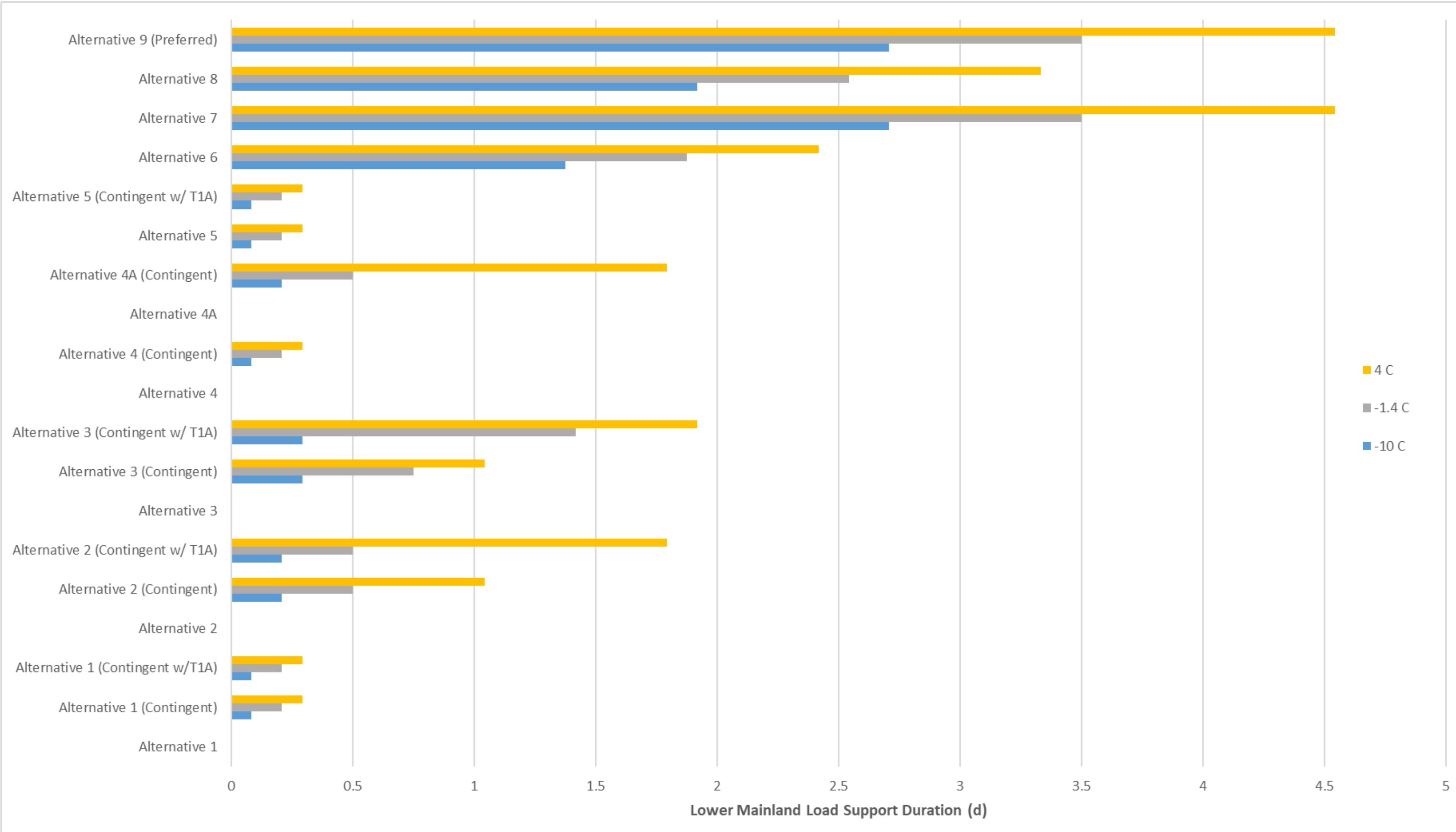
Supplemental Alternatives 2 and 3 (which were screened out at Step 2 due to their inability to preserve FEI's peaking supply) would only increase regasification capacity, without expanding the tank. However, an adequate volume of LNG must also be available to materially improve resiliency, since a higher rate of regasification will empty the tank faster. Exponent observed that more than 1 Bcf is required to make a material risk reduction:[17]

> When the Tilbury Facility has limited on-system LNG (1 Bcf or less), relatively few hazards are mitigated by its presence because there is not enough volume to bridge the regulatory shutdown period or shorter repair durations for AVs with higher loads, such as AV-1, AV-2, AV-3, AV-54, and AV-18.

[16] Exhibit B-1-4, Application, p. 52 and Exhibit B-15, BCUC IR1 1.1 to 1.4.
[17] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, para. 192.

Figure C-9 below summarizes the Lower Mainland support duration provided by each Supplemental Alternative at various winter temperatures (the average Lower Mainland winter temperature of +4°C, -1.4°C, and -10°C) as determined by FEI's transient system modelling. The relationship between an alternative's load support duration and the extent of the risk mitigation calculated by Exponent is evident when reviewing this figure in conjunction with Exponent's figures above.

1 **Figure C-9: Duration of Lower Mainland Load Support Provided by Supplemental Alternatives**



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Based on the points above, FEI concludes the following:

1. **Supplemental Alternatives 1, 4, and 5** would not materially improve FEI's ability to withstand a winter T-South no-flow event relative to the existing Base Plant with no capital upgrades (Supplemental Alternative 1 (Planning)) because they would not increase regasification above the existing capacity of 150 MMcf/d. The load support duration would remain far too short. Additionally, Supplemental Alternatives 1 and 4 do not contemplate a dedicated resiliency reserve, thus from a planning perspective there would be no LNG volume available for resiliency.

2. **Supplemental Alternatives 2, 3, 4A, and 6** would provide increased regasification capacity and would, therefore, improve resiliency (for Supplemental Alternatives 2, 3 and 4A, this is only true when one considers the contingent scenarios). However, the improvement would not be material. In the case of Supplemental Alternatives 3 and 6, which would provide at least 600 MMcf/d of regasification, this is due to the limited LNG volume available (i.e., the high rate of regasification quickly consumes the available LNG, resulting in depressurization). In the case of Supplemental Alternative 2, which would provide 400 MMcf/d of regasification capacity, this is due to the limited LNG volume available and insufficient regasification capacity (i.e., even if the available volume of LNG was increased, there would not be a material resiliency improvement). In the case of Supplemental Alternative 4A, this is due to insufficient regasification capacity. Even if the regasification constraint were fully resolved, the limited LNG volume available would prevent Supplemental Alternative 4A (Contingent) from providing a material resiliency improvement. As a result, Supplemental Alternatives 2, 3, 4A, and 6 would not materially improve resiliency.

3. **Supplemental Alternatives 7, 8, and 9** would add significant levels of both regasification and storage volume, such that they are able to provide, for example, at least a 3-day support duration under average winter conditions of +4°C. Thus, they would provide significant and material risk mitigation at average winter conditions. As set out in Section 4.5.1 of the Supplemental Evidence, these alternatives provide differing levels of risk mitigation at colder winter temperatures. In particular, Supplemental Alternative 8 would be unable to provide 3 days of load support at colder temperatures that are present during large portions of the winter.

3. FINANCIAL IMPACTS FOR ALL SUPPLEMENTAL ALTERNATIVES

Section 4.5.4 of the Supplemental Evidence discusses the methodology for determining levelized rate impacts, one of the five criteria used in the Step 3 scoring analysis, and evaluates the levelized rate impacts of the four Supplemental Alternatives that passed both Step 1 and Step 2 screens (i.e., Supplemental Alternatives 4, 4A, 8 and 9). In order to provide the BCUC with full information, this section of Appendix C provides the financial impacts for Supplemental Alternatives 1 to 9 and contingent scenarios, as well as additional information regarding the associated inputs. The financial impacts are based on updated capital cost estimates and consistent financial assumptions regarding gas supply requirements, availability in the market, and associated costs.

3.1 FINANCIAL ANALYSIS RESULTS

Table C-5 below summarizes, for Supplemental Alternatives 1 to 9 and the associated contingent scenarios, the following information: (1) construction capital cost; (2) total capital cost (including sustainment); (3) present value (PV) of the cost of service, which is borne by customers through delivery charges; (4) PV of the cost of gas, which is borne by customers through Cost of Gas charges; (5) PV of the revenue requirement, which is the sum of the aforementioned cost of service and cost of gas; (6) the PV of FEI's current revenue requirement; (7) the levelized total rate impact; (8) the incremental levelized total rate impact when compared to Supplemental Alternative 1; and (9) the payback period. The information is based on a 67-year analysis period, for the reasons described in Section 6.2.2 of the Supplemental Evidence.

Table C-5: Costs and Rate Impacts of the Supplemental Alternatives

Alternative	Construction Capital Cost ($MM)	Total Capital Cost incl. Sustainment ($MM)	PV Cost of Service ($MM)	PV Cost of Gas ($MM)	Total PV of Revenue Requirement ($MM)	PV of 2024 Revenue Requirement ($MM)	Levelized Total Rate Impact (%)	Incremental to Alt 1 - Base Case (%)	Payback Period (Years)
	(A)	(B)	(C)	(D)	(E) = (C) + (D)	(F)	(G) = (E) / (F)	(H) = (G) - Base Case(G)	(I)
Alt 1 (Base Case)	-	-	-	517.6	517.6	29,510.5	1.8%	0.00%	-
Alt 1 (Contingent)	-	-	-	517.6	517.6	29,510.5	1.8%	0.00%	-
Alt 1 (Contingent w/T1A)	-	-	-	517.6	517.6	29,510.5	1.8%	0.00%	-
Alt 2	391.5	1,290.7	464.2	517.6	981.7	29,510.5	3.3%	1.57%	-
Alt 2 (Contingent)	391.5	1,290.7	464.2	517.6	981.7	29,510.5	3.3%	1.57%	-
Alt 2 (Contingent w/T1A)	391.5	1,290.7	464.2	517.6	981.7	29,510.5	3.3%	1.57%	-
Alt 3	435.0	1,467.9	490.0	517.6	1,007.5	29,510.5	3.4%	1.66%	-
Alt 3 (Contingent)	435.0	1,467.9	490.0	517.6	1,007.5	29,510.5	3.4%	1.66%	-
Alt 3 (Contingent w/T1A)	435.0	1,467.9	490.0	517.6	1,007.5	29,510.5	3.4%	1.66%	-
Alt 4	826.9	1,887.9	790.0	151.2	941.2	29,510.5	3.2%	1.44%	22
Alt 4A	893.2	2,022.7	892.6	-	892.6	29,510.5	3.0%	1.27%	18
Alt 4 (Contingent)	826.9	1,887.9	790.0	151.2	941.2	29,510.5	3.2%	1.44%	-
Alt 5	826.9	1,887.9	790.0	517.6	1,307.6	29,510.5	4.4%	2.68%	-
Alt 5 (Contingent w/T1A)	826.9	1,887.9	790.0	517.6	1,307.6	29,510.5	4.4%	2.68%	-
Alt 6	933.5	2,224.0	943.1	517.6	1,460.7	29,510.5	4.9%	3.20%	-
Alt 7	1,030.3	2,276.9	1,134.0	517.6	1,651.5	29,510.5	5.6%	3.84%	-
Alt 8	1,030.3	2,276.9	1,134.0	151.2	1,285.2	29,510.5	4.4%	2.60%	27
Alt 9 (Preferred)	1,141.0	2,370.0	1,240.8	-	1,240.8	29,510.5	4.2%	2.45%	22

FEI highlights two points:

- The various Supplemental Alternatives can have an impact on the delivery rates through the capital costs, or an impact on the cost of gas related to the costs/savings for gas supply resources, or both. As such, focusing on only one of these components in isolation can distort the overall impacts for customers. As explained in Section 6.2.1 of the Supplemental Evidence, the levelized total rate impact used to compare among various alternatives includes both the impacts due to the capital costs and gas supply costs/savings over the 67-year period; and
- The Contingent scenarios, which are sensitivities assuming a different amount of LNG is present on the day of a no-flow event, show the same financial results as compared to their associated Planning Alternative (e.g., Supplemental Alternative 2 (Contingent) and (Contingent w/T1A) would have the same costs and rate impacts as Supplemental Alternative 2 (Planning)). This is because the Contingent scenarios do not change the underlying planning for the utility; rather, they just take advantage of the resources that are in place and may be available at the time of a no-flow event on T-South to determine how non-dependable resources could affect resiliency. FEI discusses the Contingent scenarios in the Section 4 of this Appendix.

3.2 FINANCIAL ANALYSIS ASSUMPTIONS: BASE COST ESTIMATES

As discussed in Section 6 of the Supplemental Evidence, FEI, in conjunction with Linde, Horton CB&I (HCBI), Golder, and Solaris Management Consultants Inc. (SMCI), updated the AACE Class 3 Project capital cost estimate for Supplemental Alternative 9 as well as Supplemental Alternatives 7 and 8 using AACE International Recommended Practices 18R-97 and 97R-18 as guides. These estimates were originally prepared in 2020 and updated in 2023.

In 2023, FEI retained these external experts to additionally prepare AACE Class 4 cost estimates for the new Supplemental Alternatives. Solaris prepared the Class 4 Ground Improvement cost with inputs from WSP and FEI. Linde and Solaris prepared the Class 4 Regasification Package cost estimate. HCBI prepared Class 4 LNG Storage Tank cost estimates and factored it for both 0.6 Bcf and 1 Bcf Tank sizes. Solaris prepared Class 4 estimates for both Base Plant Demolition and Auxiliary Systems.

3.3 FINANCIAL ANALYSIS ASSUMPTIONS: PEAKING SUPPLY COSTS / BENEFITS REFLECTED IN LEVELIZED TOTAL RATE IMPACT

FEI used the approach described in Section 4.5.4 of the Supplemental Evidence to determine the annual gas supply costs or benefits (avoided costs) for Supplemental Alternatives 1 to 9. In summary:

- Supplemental Alternative 1 – No Capital Upgrade serves as the baseline in the analysis. It would entail several years when FEI would face curtailments of up to 150 MMcf/d for a period of time (2030-2035) due to an inability to obtain sufficient peaking supply to replace the loss of access to Tilbury LNG. It would also entail significant annual peaking gas supply costs throughout the entire assessment period. The annual costs increase over time as tolls / charges on regional infrastructure increase to reflect expansions;

- The same is true for Supplemental Alternatives 2, 3, 5, 6 and 7, all of which would depend on procuring capacity on regional infrastructure to provide sufficient peaking supply to avoid firm curtailments in normal operations. Supplemental Alternatives 2 and 3, which only replace the regasification equipment, rely on the market because they face the loss of access to sufficient stored energy at Tilbury by 2030. Supplemental Alternatives 5, 6 and 7 depend on the market because the new facility would be set aside in its entirety as a resiliency reserve. The annual gas costs are the same as for the baseline.
- Supplemental Alternatives 4, 4A, 8 and 9 avoid the above-described annual costs to varying degrees. Supplemental Alternatives 4 and 8 still require supplementing LNG with 50 MMcf/d on regional infrastructure. Supplemental Alternatives 4A and 9 avoid the need to incur any annual peaking gas costs for market resources, since they meet FEI's full requirements; and
- FEI conservatively used the (lower) annual cost of storage for gas supply costs/savings. Using the higher pipeline costs would have the effect of improving the levelized total rate impact of the Supplemental Alternatives that meet all of FEI's peaking gas supply requirements (i.e., Supplemental Alternatives 4A and 9).

Table C-6 provides the annual gas supply costs/benefits for each Supplemental Alternative.

1 **Table C-6: Avoided Gas Supply Market Resources Included in Financial Analysis**

Supplemental Alternatives	Description	Annual Gas Supply Costs ($millions) Present to 2030	2030 to 2035	2035 onwards	Incremental to Baseline / (Avoided Costs) ($ millions) Present to 2030	2030 to 2035	2035 onwards
1	No Capital Upgrades (Continue to rely on existing Base Plant until it fails. No on-system peaking gas supply thereafter and no resiliency reserve)	7.0	7.0	63.0			
2	New Regasification Only - 400 MMcf/d (Continue to rely on existing Base Plant until it fails. No on-system peaking gas supply thereafter and no resiliency reserve)	7.0	7.0	63.0	-	-	-
3	New Regasification Only - 600 MMcf/d (Continue to rely on existing Base Plant until it fails. No on-system peaking gas supply thereafter and no resiliency reserve)	7.0	7.0	63.0	-	-	-
4	Like-for-Like Replacement for 0.6 Bcf and 150 MMcf/d (No Resiliency Reserve)	7.0	7.0	17.0	-	-	(46.0)
4A	New 1 Bcf Tank and 400 MMcf/d Regasification (No resiliency reserve)	7.0	-	-	-	(7.0)	(63.0)
5	Like-for-Like Replacement for 0.6 Bcf and 150 MMcf/d (Full resiliency reserve and no allocation for peaking gas supply)	7.0	7.0	63.0	-	-	-
6	New 1 Bcf Tank and 800 MMcf/d Regasification (Full resiliency reserve and no allocation for peaking gas supply)	7.0	7.0	63.0	-	-	-
7	New 2 Bcf Tank and 800 MMcf/d Regasification (Full resiliency reserve and no allocation for peaking gas supply)	7.0	7.0	63.0	-	-	-
8	New 2 Bcf Tank and 800 MMcf/d Regasification (1.4 Bcf resiliency reserve and 0.6 Bcf for peaking gas supply)	7.0	7.0	17.0	-	-	(46.0)
9	New 3 Bcf Tank and 800 MMcf/d Regasification (2 Bcf resiliency reserve and 1 Bcf for peaking gas supply)	7.0	-	-	-	(7.0)	(63.0)

2

4. DEVELOPMENT OF PLANNING AND CONTINGENT MODELLING SCENARIOS TO ADDRESS ADJOURNMENT DECISION

The alternatives analysis provided in the Application took a typical utility reliability planning approach that is premised on sizing infrastructure and gas supply assets to be able to meet firm customer requirements consistently. On a planning basis, it is not possible to treat a resource as being dependable for two different purposes. That is, Tilbury 1A must be available on a dependable basis for RS 46 LNG sales (the purpose for which it was constructed pursuant to Direction No. 5 to the BCUC), making it non-dependable for resiliency. FEI's Annual Contracting Plan treats a certain amount of LNG as dependable in the gas supply portfolio, making that same volume non-dependable for resiliency. The focus on dependability requires basing the resiliency analysis on a "resiliency reserve" that is dedicated to resiliency. In the absence of a resiliency reserve, the dependable LNG for resiliency is zero.

The BCUC stated in the Adjournment Decision:[18]

> We appreciate that the primary purpose of Tilbury Tank 1A is to serve FEI's existing and future LNG customers. Further FEI appears to operate the tank for that purpose. As a result, the average storage volumes are about two thirds of the tank capacity. At any given time, however, there have been volumes ranging from 200 MMcf/day [sic – 200 MMcf or 0.2 Bcf] to 1,000 MMcf/day [sic – 1000 MMcf or 1 Bcf] that appear to be available for resiliency purposes.
>
> The evidence shows that FEI's existing liquification capacity would allow FEI to keep Tilbury Tank 1A more full than it currently chooses to do for operational reasons….

FEI remains of the view that resiliency planning should follow typical utility planning principles, and has thus assessed a variety of facility sizes with different allocations of the tank as between a "resiliency reserve" and gas supply functions. However, in response to the Adjournment Decision, FEI evaluated sensitivities for certain Supplemental Alternatives (referred to as "contingent" scenarios) to determine whether the availability of additional LNG volumes at Tilbury on the day of a no-flow event would materially mitigate customer outage risk.

FEI describes below why resiliency planning based on non-dependable LNG resources is risky, with reference to peaking gas supply utilization and forecasts for RS 46 LNG sales. In practice, it is a moot point when it comes to mitigating FEI's largest customer outage risk. Exponent's analysis confirms that none of the contingent scenarios would materially improve FEI's ability to withstand a winter T-South no-flow event even at average winter temperatures (refer to Section 2.5 of this Appendix). This would be true even under the assumption that the entirety of Tilbury 1A was present.

[18] Adjournment Decision, p. 29.

4.1 DESCRIPTION OF PLANNING AND CONTINGENT SCENARIOS

The planning and contingent scenarios in FEI's alternatives analysis are as follows:

- **Planning:** Supplemental Alternatives 1 to 9 have planning scenarios. The planning scenarios reflect any LNG volumes being allocated to resiliency, while any LNG volumes at Tilbury planned for RS 46 LNG sales and gas supply have no dependable value for resiliency. On a planning basis, it is not possible to treat a resource as being dependable for two different purposes.
- **Contingent:** Supplemental Alternatives 1, 2, 3, 4, and 4A, which are the alternatives that contemplate the existing Base Plant (a new 0.6 Bcf tank or a new 1 Bcf tank) also have contingent scenarios. These scenarios assume that some LNG is available from the existing Base Plant or a replacement facility on the day of a no-flow event and is used for resiliency instead of the intended purpose (i.e., gas supply). The amount of LNG assumed to be present is 0.35 Bcf for alternatives reliant on the existing derated Base Plant tank.[19] This volume could be attributable, for instance, to (a) partial consumption of the ACP gas supply allocation for peaking supply, or (b) Tilbury 1A volume not being available due to RS 46 sales, but the Base Plant tank being full to its reduced fill capacity of 0.35 Bcf. The amount of LNG assumed to be present is 0.6 Bcf for an alternative that assumes a like-for-like 0.6 Bcf tank intended to maintain existing gas supply functions,[20] and 1 Bcf for an alternative that contemplates a facility to optimize FEI's gas supply portfolio.[21]
- **Contingent with Tilbury 1A:** These sensitivities are the most optimistic. They assume that both of the following are available: (a) LNG volumes from the existing Tilbury Base Plant or a new facility as per the "contingent" scenarios; and (b) 0.4 Bcf from Tilbury 1A is present to further support resiliency, despite the intended purpose of RS 46 sales.[22]

4.2 CONTINGENT MODELLING SCENARIOS ARE NOT DEPENDABLE

Not having a dedicated resiliency reserve (as reflected in the contingent modelling scenarios) is a risky strategy, despite a modified approach to using liquefaction intended to maintain higher levels of LNG in the tanks. The three reasons for this are discussed in the following subsections.

4.2.1 FEI Peaking Gas Supply Requirements Exceed 0.6 Bcf in a Typical Winter

The first reason why the contingent scenarios are risky is that FEI's requirements for peaking gas supply exceed 0.6 Bcf in a typical winter. This would leave the available LNG on the day of a winter no-flow event below the amounts assumed in the contingent modelling scenarios.

[19] Supplemental Alternatives 1 (Contingent), 2 (Contingent), and 3 (Contingent).
[20] Supplemental Alternative 4 (Contingent).
[21] Supplemental Alternative 4A (Contingent).
[22] Supplemental Alternatives 1 (Contingent w/T1A), 2 (Contingent w/T1A), 3 (Contingent w/T1A), and 5 (Contingent w/T1A).

FEI's use of LNG for peaking supply depends on weather, and significant volumes are commonly used during the winter. For example, during winter 2022/23, the 0.6 Bcf allocation of Tilbury LNG for supply purposes was reduced to 0.17 Bcf by Christmas 2022 and was down to 0.07 Bcf by the beginning of March 2023 when FEI began filling the tank again. This was the product of high demand during cold weather periods in December and February, as well as operational reasons (e.g., compressor outages and tool runs).

Because FEI now operates the Base Plant at 0.35 Bcf for seismic reasons, and peak loads exceed the capabilities of the Tilbury Base Plant, FEI currently draws on LNG from Tilbury 1A to meet the incremental demand.

Moreover, if peaking supply is used for a resiliency event, it would leave FEI dependent on sourcing gas from the market to meet demand during typical cold weather events for the remainder of the winter. FEI discusses in Section 3.3.4.3 of the Supplemental Evidence how, under current market conditions, it would not be realistic to expect that FEI could replace the Tilbury peaking supply at the Sumas market. Significant curtailments of firm load in normal operations are a likely outcome.

4.2.2 Availability of Tilbury 1A Volumes on a Given Day Will Depend on Overall RS 46 Demand and Use Patterns During a Year

LNG levels in the Tilbury 1A tank are a function of both overall RS 46 demand and the patterns of sales over the course of a year. FEI discusses below how the past average storage levels and use patterns within the year are unlikely to be replicated in the future, as the market is growing and evolving. While RS 46 demand from Tilbury 1A has been impacted by the COVID-19 pandemic and delays in Tilbury Jetty approvals, RS 46 demand awaiting the jetty's completion exceeds the capacity of Tilbury 1A. While some of the LNG in the Tilbury 1A tank will potentially be available on a given day, realistically there are likely to be times at unpredictable intervals when the tank is very depleted. FEI's analysis suggests that its contingent scenario assumption of 0.4 Bcf being present at any one time should be considered an upper limit.

4.2.2.1 Future RS 46 Sales Growth and Evolving Use Patterns

As noted in the response to BCUC IR1 11.9.2 (Exhibit B-15), the tank volumes in Tilbury 1A over the past number of years have fluctuated depending on volume of sales and the need to refill the Base Plant tank (as the Base Plant tank is filled through an interconnecting line from the Tilbury 1A tank). The delay in utilizing more LNG production for LNG sales is linked to both the impacts to the supply chain from the COVID-19 pandemic, as well as the delays in regulatory approvals for the marine jetty planned adjacent to the Tilbury site (Tilbury Jetty). As discussed below, the overall annual sales under RS 46 are expected to increase significantly and, as such, the patterns of use will change as the market evolves. In particular, FEI expects the types of sales to change.

The types of sales impact the pattern of LNG use. LNG is currently sold in ISO containers or on road transport containers which are loaded through one of the two existing truck loading bays at the site. Once the Tilbury Jetty has been constructed, sales of LNG will likely shift from being loaded onto ISO containers towards being loaded onto ships for transport, most likely for use in displacing higher burning carbon fuels for ships in the Port of Vancouver. This shift in sales type is significant, as one ISO container is 40 m^3 (1,412ft^3) while an LNG bunker vessel (fuelling ship) can range from 3,000-18,000 m^3 (105,944 – 635,664 ft^3). When considering the graph of tank levels shown in the response to BCUC IR1 11.9.2 (reproduced below), the LNG was being sold through ISO or on-road transport containers – which is why the trends showed a period of filling and then a long slow drawdown of the tank as LNG was extracted to provide fuel for customers such as BC Ferries and Seaspan, as well as ISO customers.

With the construction of the Tilbury Jetty, larger vessels will be loading LNG, resulting in a much quicker drawdown. The purpose of the Tilbury 1A tank as it relates to LNG sales is to provide storage as a buffer for plant maintenance downtimes or for when sales temporarily exceed capacity. The Tilbury 1A tank holds 1 Bcf of LNG. The Tilbury 1A liquefaction plant produces approximately 33 MMcf/d with approximately 5 MMcf/d dedicated to utility use. As noted above, LNG bunker vessels can range in size; however, for illustrative purposes, FEI refers to a vessel recently announced by Seaspan which they plan to operate in the Port of Vancouver. This vessel is planned to be 0.163 Bcf in size. Considering this, the Tilbury 1A tank holds enough LNG to fill the Seaspan vessel just over 6 times (without refilling the tank).

Further, standard practice in the LNG industry is to develop annual delivery plans when considering LNG sales. These plans are built around customer delivery needs as well as to ensure the LNG facility can manage its maintenance activities. For Tilbury 1A, given FEI sells LNG both through its truck loading bays (current state) and intends to sell LNG through the Tilbury Jetty, the annual delivery plan would also assist with production planning to ensure FEI can meet all of its sales obligations. There is considerable uncertainty inherent in the development of yearly delivery plans as customer needs and requirements can change over time. A bunker vessel picking up fuel at Tilbury will be serving more than one end use customer and as a result, the delivery schedule for LNG will very likely be erratic during the year, although matched to the production capabilities of the facility.

The Tilbury 1A tank provides a mechanism to deal with the erratic nature of LNG scheduling. For example, as noted above, FEI could load six of the Seaspan bunker vessels (6 times 0.163 Bcf = 0.98 Bcf) if the plant was undergoing maintenance. If those ships were scheduled every third day, this would provide nearly 20 days of maintenance outage before the tank ran out of LNG. As another example, if the plant were running and considering the current liquefaction capacity of 0.25 MTPA, FEI could load one Seaspan vessel approximately every six days. In the first case, the tank level would be dropping with every load until it was empty. In the second case, the tank levels would remain relatively constant as delivery and production are matched. This could be considered an ideal situation.

The reality of LNG sales is that vessels are not loaded on a regular interval. More realistic is the requirement that loading is required every day for a period of time and then there is an interval of time where no loading occurs. In those cases, it is conceivable that the LNG level in the Tilbury 1A tank would drop with every ship loaded (as the capacity of the ship exceeds the production levels) until a time where no vessels can be loaded until inventory is replenished. The exact nature and times of year that this would occur cannot be known until the actual customers' requirements are known. However, the flexibility provided by the Tilbury 1A tank is very valuable to the LNG business as it enables FEI to accommodate (to a point) the timing of customers' loading requirements.

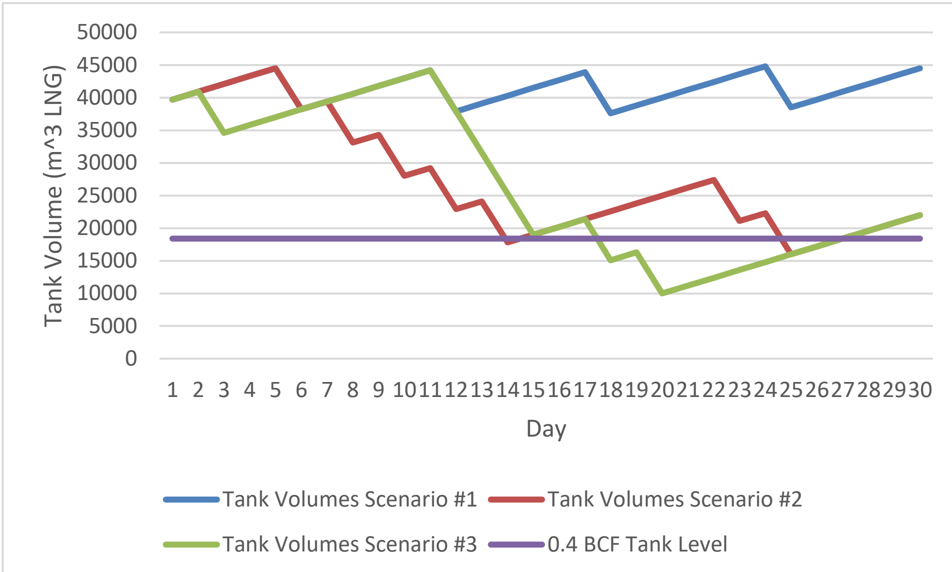
4.2.2.2 "Contingent w/T1A" Sensitivities Assumed 0.75 Bcf is Available (0.4 Bcf in Tilbury 1A Plus Full Base Plant)

Given expected future use of the Tilbury T1A tank and evolving use patterns discussed above, FEI undertook preliminary modelling of tank levels based on several scenarios (see Figure C-10 below) and determined that 0.4 Bcf would be the upper limit of what could or should be considered present in the Tilbury 1A tank at any one time. FEI's "Contingent w/T1A" sensitivities thus included 0.4 Bcf from Tilbury 1A, plus 0.35 Bcf in the Base Plant.

FEI's selection of 0.4 Bcf as an upper limit assumption for volume present in Tilbury 1A was based on an analysis of production and usage. Figure C-10 below shows different Tilbury 1A production and usage scenarios. FEI determined that 0.4 could be present in Tilbury 1A by considering likely loading scenarios based on FEI's current understanding of customer requirements:

- **Scenario #1** reflects an idealized balancing of loading with production (this example considers only Tilbury 1A production and reflects a vessel approximately every 6 days). This is an unrealistic scenario, since (as discussed above) the reality of LNG sales is that vessels are not loaded on a regular interval.
- **Scenarios #2 and #3** reflect situations where customer requirements result in periodic loading requirements throughout the month. Scenarios #2 and #3 are illustrative of potential sales patterns and were selected to show that any type of loading scenario that is not equally balanced throughout the year will result in fluctuating tank volumes. The actual loading scenarios will depend on the type of customers, their schedules and their fuelling requirements.

Figure C-10: T1A Tank Levels



Importantly, while FEI's analysis of certain contingent modelling scenarios has treated 0.4 Bcf as potentially available, in any given year the annual delivery plans developed for FEI LNG customers may require use of the LNG inventory below that level in order to meet sales commitments. As noted above, this means that unlike a resiliency reserve, these volumes are not dependable.

Moreover, as noted above and discussed in Section 3.3 of the Supplemental Evidence, FEI now operates the Base Plant tank at 0.35 Bcf and FEI's peaking gas requirements exceed that amount. FEI is temporarily relying on Tilbury 1A to maintain its Annual Contracting Plan requirements of 0.6 Bcf, pending the replacement of the Base Plant.

4.2.3 Changing How FEI Uses Liquefaction Would Not De-Risk Relying on Non-Dependable Volumes for Resiliency

Depending on the profile of the LNG sales, the LNG levels at Tilbury could remain depleted even with increased liquefaction.

Operationally, Tilbury works as follows:

- Tilbury 1A houses the only functioning liquefaction equipment. The Tilbury 1A tank can be refilled in approximately 30 days from empty. Operationally, FEI strives to maintain tank levels in Tilbury 1A at a minimum of 60 percent through the winter months to strike a balance between maintaining sufficient inventory versus frequent starting and stopping of the liquefaction equipment. The liquefaction equipment was designed to run continuously so frequent starting and stopping accelerates wear on equipment due to metal-on-metal wear in machinery, accelerated piping/vessel corrosion from thermal cycling, and accumulation of moisture in electrical equipment including motor windings and junction boxes, all of which are undesirable outcomes; and

- Since only the Base Plant has regasification equipment, and since the Base Plant no longer has functioning liquefaction equipment, the LNG in Tilbury 1A must be transferred to the Base Plant. The Base Plant tank is filled using Tilbury 1A production and the interconnecting line between the Tilbury 1A tank and the Base Plant tank. The maximum transfer/fill rate is approximately 5 MMcf/d. As such, it takes approximately 72 days to fill 0.35 Bcf of LNG into the Base Plant tank from empty, which means that refilling the Base Plant tank with additional LNG volumes from Tilbury 1A if the Base Plant is depleted for gas supply purposes would take the majority of the winter.

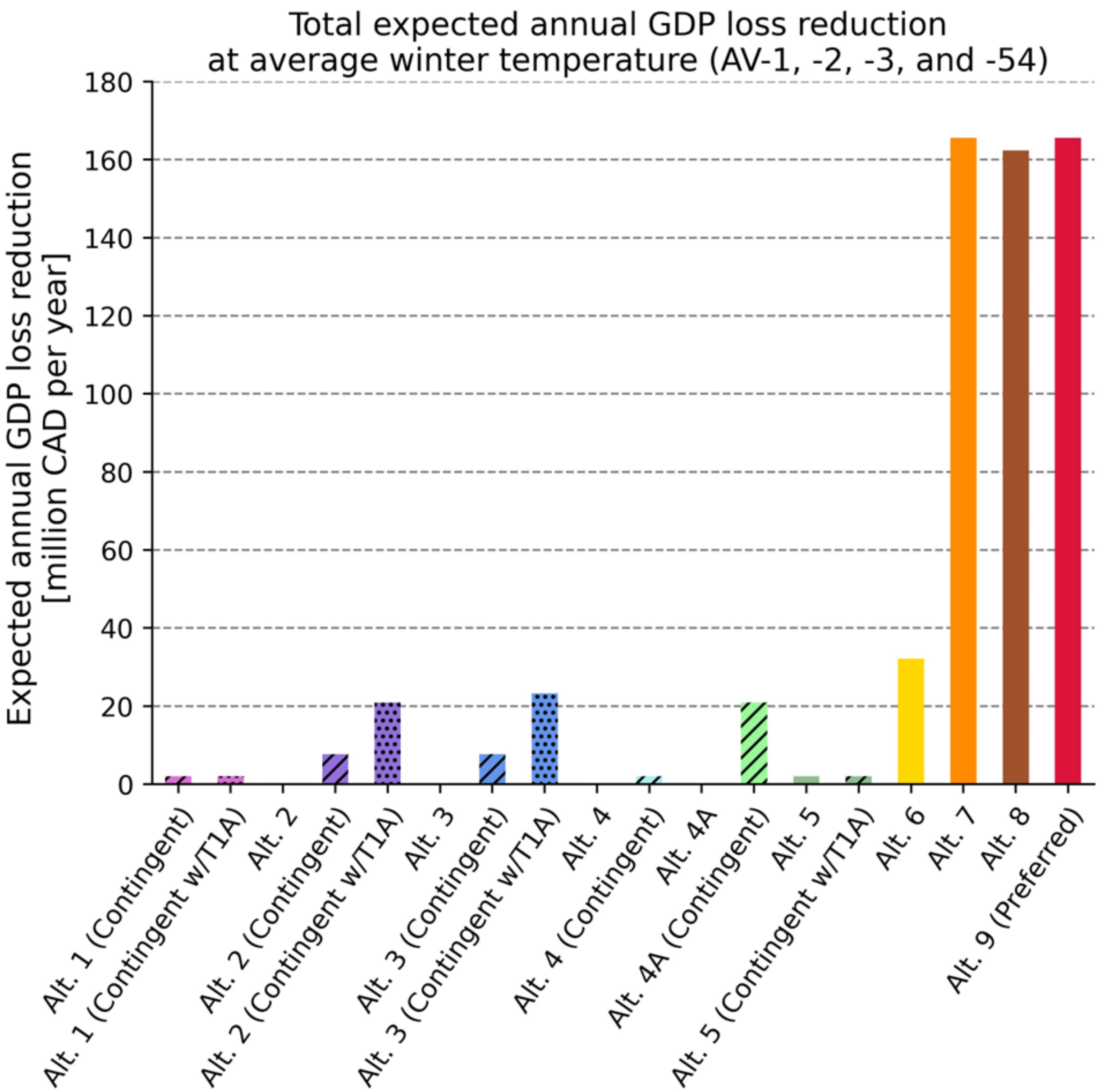
4.3 A FULL TILBURY 1A TANK WOULD NOT MATERIALLY REDUCE RISK EXPOSURE TO WINTER NO-FLOW EVENT

Exponent's results (see Figure C-11 below) confirm that none of the contingent scenarios would materially improve FEI's ability to withstand a winter T-South no-flow event even at average winter temperatures.

- In the case of the contingent scenarios for Supplemental Alternatives 1, 4, and 5, the 150 MMcf/d regasification capacity, which is insufficient to support system demand at average winter temperatures or colder, is not addressed and remains the primary constraint; and
- In the case of the contingent scenarios for Supplemental Alternative 2, the primary constraint is either insufficient regasification capacity (Supplemental Alternative 2 (Contingent w/ T1A)) or an insufficient available volume of LNG (Supplemental Alternative 2 (Contingent)). In the case of the contingent scenarios for Supplemental Alternative 3, there is an insufficient volume of LNG. In the case of Supplemental Alternative 4A, there is insufficient regasification capacity.

FEI did not specifically model a contingent sensitivity based on the assumption that the Tilbury 1A tank is completely full, given that this was considered to be highly unrealistic. However, Exponent's results in Figure C-11 for Supplemental Alternative 6 (1 Bcf and 800 MMcf/d) can be used as a proxy for the hypothetical scenario where the Tilbury 1A tank is full <u>and</u> the regasification constraint is removed. The level of risk mitigation provided by Supplemental Alternative 6 in Figure C-11 shows that a full Tilbury 1A tank would not materially reduce the risk associated with a winter T-South no-flow event, even if the existing limited regasification was replaced with new regasification equipment with over five times more regasification capacity.

Figure C-11: T-South at Avg. Winter – Expected Annual Loss Reduction



5. DETAILED INFORMATION SUPPORTING ASSESSMENT OF THE SUPPLEMENTAL ALTERNATIVES

This section provides the underlying information supporting FEI's assessment of each Supplemental Alternative, including those located at Tilbury, non-Tilbury alternatives raised by the BCUC in its Adjournment Decision, as well as a Southern Crossing Pipeline extension.

5.1 ALTERNATIVES RELYING ON EXISTING FACILITIES

In response to the Adjournment Decision, this section addresses three Supplemental Alternatives (1, 2, and 3) that contemplate continued reliance on the existing Tilbury Base Plant regasification and/or tank. These alternatives assume a "run until it is no longer usable" approach for some or all of the Base Plant assets.

For the reasons described below, this approach would be high-risk for customers in terms of:

- Exposure to widespread and prolonged customer outages following a no-flow event;
- Potential for an unplanned, multi-year loss of dependable peaking resources between the Base Plant's end-of-life and commissioning of a replacement facility; and
- A high likelihood of increasingly unreliable service in normal conditions.

FEI determined that Supplemental Alternative 1 is technically non-viable at Step 1 because the Tilbury Base Plant has reached end-of-life and can no longer reliably perform its intended function. Supplemental Alternatives 2 and 3 were found to be non-viable at Step 2 because they put FEI's ability to continue meeting peak load in normal conditions at risk.

5.1.1 Supplemental Alternative 1

Supplemental Alternative 1 includes the following:

- Continuing to rely on the existing regasification equipment (150 MMcf/d), which has reached end-of-life;
- Continuing to rely on a non-refurbished Base Plant tank, which has reached end-of-life and is operating at a lower maximum volume (0.35 Bcf), and leave unaddressed the seismic, environmental and flooding issues inherent in the original Base Plant design;
- Continuing to operate with no resiliency reserve; that is, from a planning perspective, all of the LNG at Tilbury would still be allocated to either gas supply or RS 46 LNG sales, such that those volumes may or may not be present upon a no-flow event;
- Changing how FEI operates the existing Tilbury 1A liquefaction to replenish consumed LNG faster, so as to increase the potential for LNG to be present on the day of a no-flow

event (i.e., 0.35 Bcf in the Base Plant tank and 0.4 Bcf in Tilbury 1A despite RS 46 LNG sales);[23]

- From the gas supply perspective, meet the peaking supply requirement of 1 Bcf and 200 MMcf/d by continuing to rely on the non-refurbished Base Plant until it is no longer usable, plus continuing to hold 50 MMcf/d of year-round pipeline capacity;
- When the existing Base Plant is no longer usable (assumed to be 2030 for the purpose of the financial analysis), FEI would be unable to replace the lost peaking capabilities of 150 MMcf/d and 0.6 Bcf storage with regional infrastructure since they are already fully contracted. As such, FEI would still hold the existing 50 MMcf/d of market pipeline capacity but would likely have to curtail firm loads in normal operations by up to 150 MMcf/d unless and until future regional infrastructure upgrades occur that could provide replacement peaking supply; and
- If and when regional infrastructure upgrades occur (assumed to be 2035 for the financial analysis), FEI could potentially end curtailments by holding gas supply contracts for 1.0 Bcf and 200 MMcf/d. FEI would pay a higher toll / charge that includes the costs of the upgrades.

5.1.1.1 Modelling Parameters

Table C-7 below sets out the resiliency and gas supply modelling parameters for the Supplemental Alternative 1 scenarios.

The planning scenario uses the maximum regasification (150 MMcf/d), paired with the volume of dependable LNG for resiliency (0 Bcf – no resiliency reserve) and, for gas supply, the amount included in the Annual Contracting Plan (0.6 Bcf).

FEI also modelled two contingent (i.e., non-dependable) scenarios based on more optimistic assumptions about how much LNG is present at Tilbury on the day of a no-flow event. While these additional scenarios address comments in the Adjournment Decision, as explained in Section 4.2 of this Appendix, FEI cannot rely on the LNG volumes assumed in the contingent scenarios being present on the day of a no-flow event.

[23] This assumption addresses the following BCUC commentary in the Adjournment Decision, p. 29: "With additional liquefaction the average storage volume could be increased thereby providing additional capacity available for resiliency purposes. While there is evidence that this would be more costly than the current operational strategy, the cost benefit analysis is incomplete. In order to fully evaluate a potential role of Tilbury Tank 1A in FEI's resiliency portfolio, a more fulsome analysis is required."

Table C-7: Supplemental Alternative 1 Planning and Contingent Modelling Scenarios

Supp. Alt. 1 Modelling Scenario	Description	Resiliency Modelling Parameters	Peaking Gas Supply Allocation (Normal Operations)[1]
Supplemental Alternative 1 (Planning)	No Resiliency Reserve[2]	0 Bcf at 150 MMcf/d	0.6 Bcf at 150 MMcf/d
Supplemental Alternative 1 (Contingent)	Assume Partial LNG Availability on Day of No-Flow[3]	0.35 Bcf at 150 MMcf/d	0.6 Bcf at 150 MMcf/d
Supplemental Alternative 1 (Contingent w/T1A)	Assume Base Plant Fully Available plus 0.4 Bcf in Tilbury 1A on Day of No-Flow	0.75 Bcf at 150 MMcf/d	0.6 Bcf at 150 MMcf/d

<u>Notes to Table:</u>

1 *Per the ACP, FEI allocates 0.6 Bcf from Tilbury for gas supply portfolio purposes, with a 0.25 Bcf portion temporarily obtained from Tilbury 1A. Actual volumes will decline with use for gas supply during winter, or if LNG volumes were used for resiliency.*

2 *When there is no resiliency reserve, on a planning basis there is no dependable LNG available on occurrence of no-flow event. Hence the resiliency modelling parameter is 0 Bcf.*

3 *Reduced volume available could be attributable to either: (a) Tilbury 1A volumes being unavailable due to RS 46 sales, leaving a maximum of 0.35 Bcf in the Base Plant tank at currently reduced fill levels; or (b) partial consumption for peaking gas supply of the 0.6 Bcf currently allocated to gas supply at Tilbury (which is currently comprised of 0.35 Bcf from the Base Plant plus 0.25 Bcf Tilbury 1A). The former is expected to occur in the future, and the latter is common over the course of a typical winter.*

5.1.1.2 Summary of Information and Analysis

Supplemental Alternative 1 did not pass the Step 1 viability screen because the Base Plant has reached end-of-life, such that continuing to rely on it without capital upgrades is not technically viable. However, for completeness, FEI assesses Supplemental Alternative 1 based on the five criteria utilized in Step 3 of the alternatives analysis. Further, as explained in Section 2.4 of this Appendix, FEI scored Alternatives 2 to 9 relative to Supplemental Alternative 1 based on the five criteria; thus, Supplemental Alternative 1 does not have an impact score for each criterion.

The following bullets provide a high-level description of how this alternative performs against the criteria, followed by sections providing additional details.

- **Resiliency:** Supplemental Alternative 1 would provide no additional risk mitigation against a winter T-South no-flow event. In particular, the limited regasification capacity at Tilbury of only 150 MMcf/d means Supplemental Alternative 1 (including the most optimistic contingent scenario) would not materially improve resiliency against FEI's largest customer outage risk. Even increased use of liquefaction does not change the consequence associated with a winter T-South no-flow event.

- **Gas Supply:** Supplemental Alternative 1 would retain FEI's existing on-system peaking capabilities for only as long as the Tilbury Base Plant remains functional and FEI is able to continue relying on LNG from Tilbury 1A to supplement the Base Plant's reduced capabilities. After that, there would likely be at least several years where there are significant curtailments in normal operations before FEI would be able to acquire enough replacement peaking supply on upgraded regional infrastructure.
- **Base Plant Challenges:** Supplemental Alternative 1 would not resolve the existing Base Plant's age-related challenges as it assumes no capital upgrades at Tilbury.
- **Levelized Total Rate Impact**: Supplemental Alternative 1 would have a levelized total rate impact of 1.8 percent over a 67-year analysis period. This is lower than Supplemental Alternative 9 because there are no capital costs pertaining to Supplemental Alternative 1, but it assumes FEI would be curtailing firm customers in normal operations for several years instead of incurring peaking gas costs.
- **Future Use:** FEI does not expect the Base Plant to still be in-service by 2050; therefore, FEI does not expect the facility to underutilized.

FEI discusses each of the five criteria in further detail below.

5.1.1.2.1 RESILIENCY

Supplemental Alternative 1 would provide no additional protection against a winter T-South no-flow event on T-South because it assumes no capital upgrades at Tilbury (i.e., maintains the status quo) and, therefore, does not address the regasification capacity constraint at Tilbury of only 150 MMcf/d for the contingent scenarios.

Regardless of how much liquefaction capacity, storage volume or inventory exists behind these regasification units, the most gas that FEI can access from Tilbury on any day is 150 MMcf. This is only a fraction of the daily load in the Lower Mainland on winter days. Even assuming an optimistic contingent scenario, the system would still fail on the day of a winter T-South no-flow event.

These results are confirmed in Exponent's figure (reproduced in Section 2.5.1 above) which summarizes the annual expected loss reduction associated with each Supplemental Alternative relative to the existing Base Plant with no capital upgrades (the Supplemental Alternative 1 (Planning) scenario).

The following table summarizes how long the existing Base Plant, in combination with FEI's other existing capabilities, will be able to sustain the Lower Mainland load following a winter no-flow event. FEI has consistently modelled three temperatures that are reflective of local conditions, since FEI's load increases as temperatures decrease.

Table C-8: Supplemental Alternative 1 Load Support Durations Under Different Winter Conditions

Supp. Alt. 1 Modelling Scenario	Approximate Time Until Customers in the Lower Mainland Begin Losing Service[24]		
	-10°C (very cold winter day)[25]	-1.4°C (warmest winter in 10 years, as defined in footnote)[26]	+4.0°C (average Lower Mainland winter)[27]
Planning (0 Bcf, 150 MMcf/d)	0 days and 0 hours	0 days and 0 hours	0 days and 0 hours
Contingent (0.35 Bcf, 150 MMcf/d)	0 days and 2 hours	0 days and 5 hours	0 days and 7 hours
Contingent w/T1A (0.75 Bcf, 150 MMcf/d)	0 days and 2 hours	0 days and 5 hours	0 days and 7 hours

Consistent with the framework established in Section 3.4.1.2.2 of FEI's 2024 Resiliency Plan, under average winter conditions, the support duration provided by Supplemental Alternative 1 (regardless of the scenario) would not be enough to execute a controlled shutdown. Therefore, a failure occurring on some parts of T-South could be expected to result in an uncontrolled shutdown in the Lower Mainland system, with attendant safety risks and service restoration challenges.

Figures C-12 to C-14 below show the transient modelling outputs used to determine the load support duration values in the table above. The figures show the results at various temperatures (+4°C, -1.4°C and -10°C) for the <u>most-optimistic</u> contingent scenario, which assumes both the Base Plant is full and 0.4 Bcf of LNG inventory is on hand in Tilbury 1A (totalling 0.75 of LNG at Tilbury on the day of a winter T-South no-flow event). FEI explains how to interpret these figures in Section 3.2.2.1.2 of the Supplemental Evidence.

[24] This represents the approximate duration of full firm load support for customers in the Lower Mainland. Except for the 0 Bcf case which does not account for linepack, the analysis considers support from on-system LNG and linepack from the CTS. Linepack was not considered in the 0 Bcf case such that an understanding of the absolute baseline risk could be had. The analysis also assumes that all interruptible customers are offline within 4 hours of the no-flow event, except for the -10°C analysis, wherein interruptible customers would already be offline due to the cold temperature condition.

[25] Due to the low probability of having multiple -10°C days in a row in the Lower Mainland, the -10°C temperature condition analysis assumes the following: the first day is -10°C, the second and third days are -7°C, the fourth day is -3°C, and all subsequent days are +4°C.

[26] The warmest winter in the last 10 years was found by determining the minimum daily average temperature for each year over a 10-year period from 2013-2022, then selecting the highest value. The analysis was based on data from the Vancouver International Airport (YVR).

[27] Defined as the average of the daily average temperatures for December, January, and February over a 10-year period from 2013-2022. The average winter day is based on data from YVR.

Figure C-12: Impact to Lower Mainland due to Loss of T-South Supply at +4°C with Supp. Alt. 1[28]

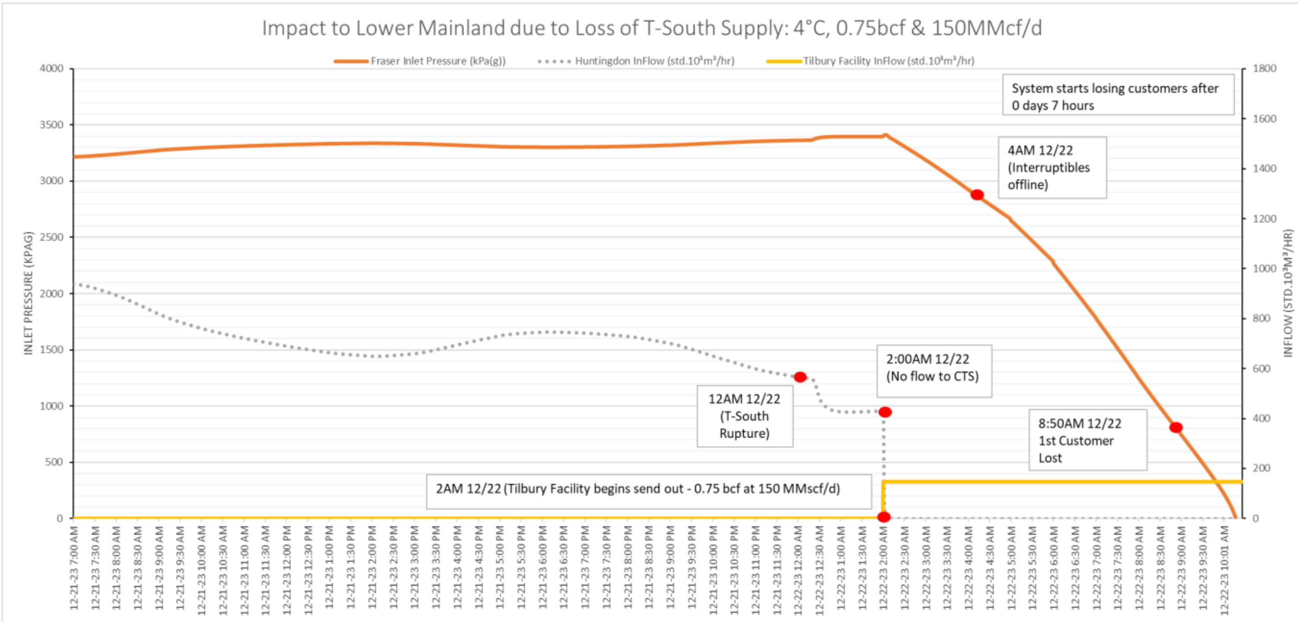
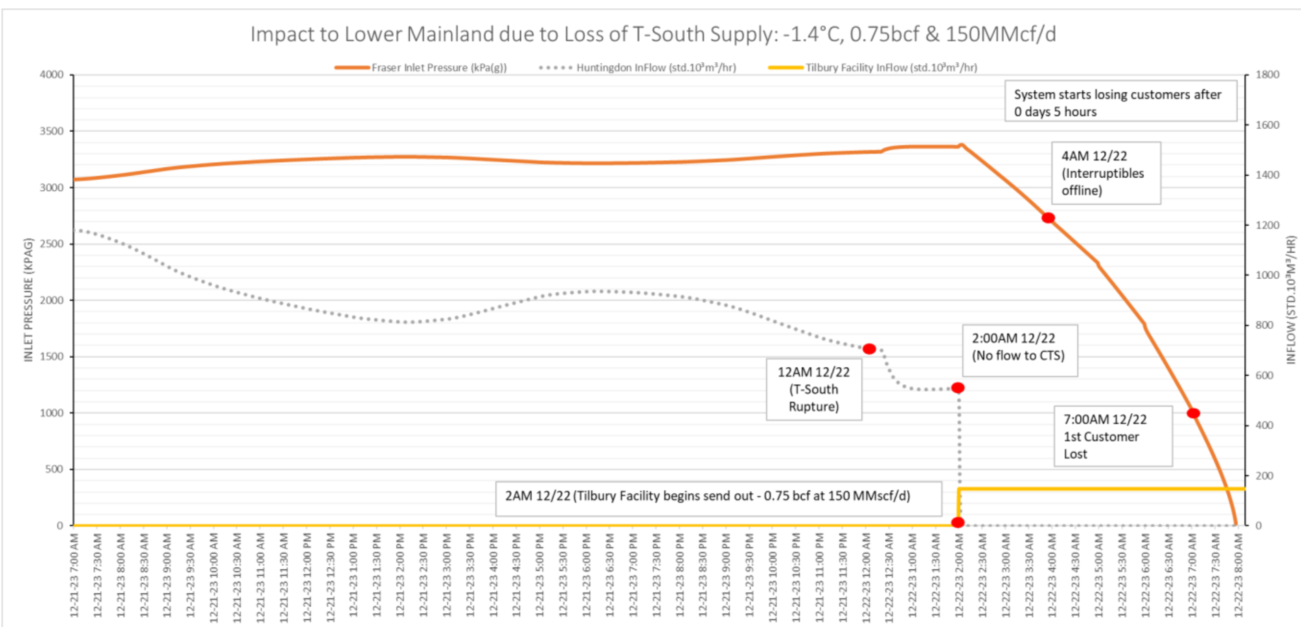
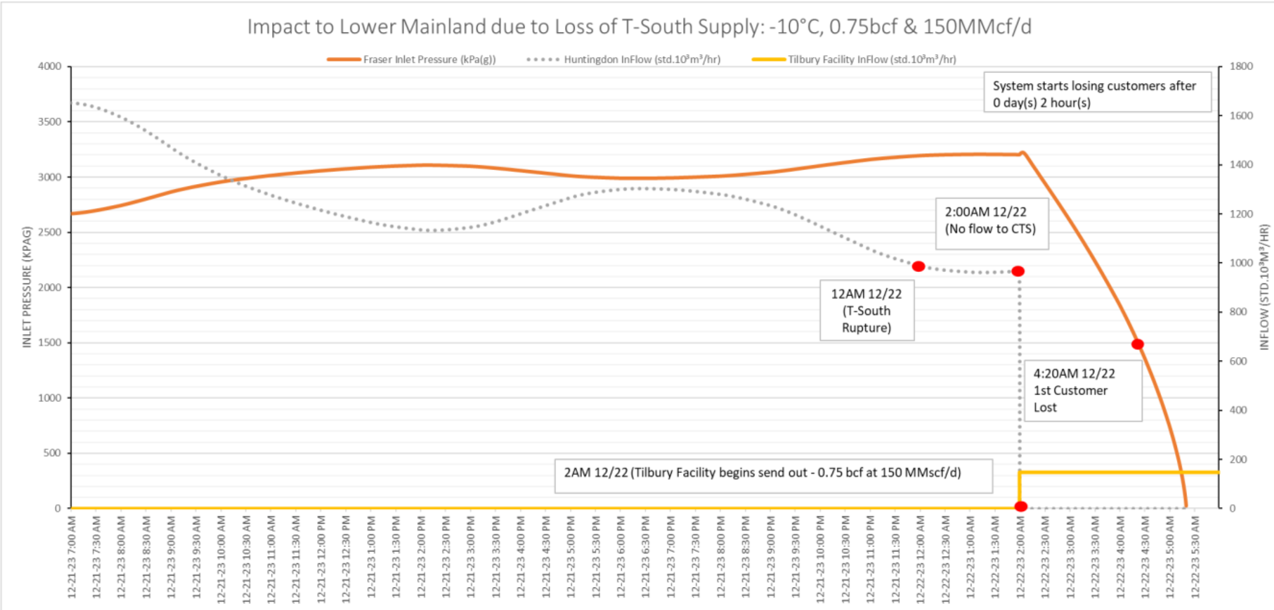


Figure C-13: Impact to Lower Mainland due to Loss of T-South Supply at -1.4°C with Supp. Alt. 1



[28] FEI's transient modelling for Supplemental Alternative 1 assumed not only that the full derated capacity of the Base Plant is present (0.35 Bcf), but also 0.4 Bcf in Tilbury 1A, for a total of 0.75 Bcf. There would be less LNG available if FEI had used any of this for peaking supply.

Figure C-14: Impact to Lower Mainland due to Loss of T-South Supply at -10°C with Supp. Alt. 1



5.1.1.2.2 GAS SUPPLY

Supplemental Alternative 1 would retain FEI's existing on-system peaking capabilities; however, as explained below, this is predicated on the continued availability of peaking capacity and energy at Tilbury when required, which is not technically viable.

The value of on-system LNG to a supply portfolio is the capacity it provides (i.e., the capability for rapid send-out when load spikes), backed by enough energy (LNG) to last the duration of the peak demand event. Peak loads already exceed Tilbury's capabilities. Further, FEI is entirely dependent on the existing Base Plant regasification equipment to access LNG for peaking capacity. As a result, Supplemental Alternative 1 only maintains the current peaking supply capabilities for so long as both: (1) the Base Plant remains operational; and (2) Tilbury 1A is not fully subscribed under RS 46, which would otherwise preclude FEI from continuing its existing temporary practice of using 0.25 Bcf from Tilbury 1A in the Annual Contracting Plan.

Further, as discussed in Section 3.3.4 of the Supplemental Evidence, FEI could not replace the Tilbury peaking supply resources currently included in the Annual Contracting Plan (150 MMcf/d and 0.6 Bcf) in the market and does not have control over regional infrastructure expansions that, if those expansions were to occur in the future, would entail significant annual gas supply costs for FEI customers. FEI's assessment, which is supported by the report of Mr. Raymond Mason, an expert in the regional gas supply market who FEI retained to opine on the role of on-system LNG storage in a supply portfolio, is that fully-contracted regional infrastructure would preclude replacing Tilbury's existing peaking capabilities with high-capacity long-term commercial contracts for peaking supply arrangements. In the absence of on-system LNG at Tilbury, the only way to secure dependable replacement peaking supply would be to participate in regional infrastructure upgrades.

5.1.1.2.3 BASE PLANT CHALLENGES

Supplemental Alternative 1 would not resolve the existing Base Plant's age-related challenges as it assumes no capital upgrades at Tilbury. For the reasons described in Sections 3.3 of the Supplemental Evidence, prolonging FEI's reliance on the end-of-life Base Plant would entail increasing risk that peaking capacity and energy will be unavailable when required in normal conditions:

5.1.1.2.1 LEVELIZED TOTAL RATE IMPACT

The levelized total rate impact for Supplemental Alternative 1 is estimated to be 1.8 percent over a 67-year analysis period. The levelized total rate impact is lower than Supplemental Alternative 9 because this alternative would involve no capital costs at Tilbury. However, once the 150 MMcf/d and 0.6 Bcf of on-system LNG is no longer available, FEI would be forced to curtail customers in normal operations which is reflected in the analysis as a gas supply savings.

There would still be rate impacts associated with maintaining the existing 50 MMcf/d of pipeline capacity that is currently used for peaking gas supply. If and when replacement peaking supply is available on regional infrastructure to replace the lost 150 MMcf/d and 0.6 Bcf (assumed to be 2035) FEI would pay higher tolls for its full holdings on expanded regional infrastructure. Please refer to Section 3.3 of this Appendix for discussion on the gas supply cost assumptions and the costs/savings used in the financial analysis for Supplemental Alternative 1.

5.1.1.2.2 FUTURE USE

FEI does not expect the Base Plant to still be in-service by 2050 as the facility would be 79 years old.

5.1.2 Supplemental Alternative 2

In the Adjournment Decision, the BCUC raised the potential of increasing the regasification capacity of the Base Plant while retaining the existing tank:[29]

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

[29] Adjournment Decision, p. 32.

> flow event that the existing infrastructure (Base Plant and Tilbury Tank 1A) with increased gasification could withstand.
>
> FEI also provides no information on whether, should the regassification capacity of the existing facility be increased, it would be compatible with a new tank, should one subsequently be approved and built.
>
> We recommend that FEI consider the potential costs and benefits associated with supplementing the existing storage assets at Tilbury with increased gasification. We note that such an alternative provides a potential bridging mechanism to enhance resiliency while allowing more time to understand the future of natural gas demand and supply in the LML.

FEI confirms that, leaving aside whether the Project objectives are met, it is technically feasible to construct additional regasification and connect it to the existing Tilbury 1A and Base Plant tank infrastructure. As discussed in the Application, FEI evaluated numerous regasification technologies and sizes and selected submerged combustion vessel technology at a unit size of 200 MMcf/d (which can be operated between 50 and 200 MMcf/d). Therefore, FEI could choose to install either one (200 MMcf/d), two (400 MMcf/d) or three (600 MMcf/d) units initially. A fourth unit, which would bring the total regasification capacity to 800 MMcf/d, would only be constructed at the same time as a new tank, as that level of regasification would very rapidly deplete the existing available tank volume, even assuming 0.4 Bcf of additional LNG supply from Tilbury 1A.

As explained in Section 4.4 of the Supplemental Evidence, FEI eliminated Supplemental Alternative 2 in Step 2 of the screening process. However, to be responsive to the BCUC's commentary in the Adjournment Decision, FEI has assessed this alternative against the five criteria utilized in Step 3 of the screening process as part of this Appendix.

Supplemental Alternative 2 includes the following:

- Replacing the existing Base Plant regasification units with 400 MMcf/d of regasification;
- Continuing to rely on a non-refurbished Base Plant tank that has reached end-of-life and is operating at a lower maximum capacity (0.35 Bcf), and leaving unaddressed the seismic, environmental and flooding issues inherent in the original Base Plant design;
- There continuing to be no resiliency reserve; that is, from a planning perspective, all of the LNG at Tilbury would still be allocated to either gas supply or RS 46 LNG sales, such that those volumes may or may not be present upon a no-flow event;
- Changing how FEI operates existing Tilbury 1A liquefaction to replenish consumed LNG faster, so as to increase the potential for LNG to be present on the day of a no-flow event (i.e., 0.35 Bcf in the Base Plant tank and 0.4 Bcf in Tilbury 1A despite RS 46 LNG sales).[30]

[30] This assumption addresses the following BCUC commentary in the Adjournment Decision, p. 29: "With additional liquefaction the average storage volume could be increased thereby providing additional capacity available for resiliency purposes. While there is evidence that this would be more costly than the current operational strategy, the

- From the gas supply perspective, continue meeting the peaking supply requirement of 1 Bcf and 200 MMcf/d by continuing to rely on the Base Plant, plus continuing to hold 50 MMcf/d of year-round pipeline capacity. The latter is still necessary despite the new regasification of 400 MMcf/d because the amount of LNG is a limitation;
- When the existing Base Plant tank must be operated at further reduced levels or is no longer usable, or Tilbury 1A LNG is unavailable (assumed to be 2030 for the purpose of the financial analysis), the new regasification will be of limited use. FEI would therefore lose the peaking capabilities of 0.6 Bcf and 400 MMcf/d from Tilbury and would be unable to replace it with capacity on regional infrastructure. As such, FEI would still hold the existing 50 MMcf/d of market pipeline capacity but would likely have to curtail firm loads in normal operations by up to 150 MMcf/d (the original regasification level currently included in the ACP) until future regional infrastructure upgrades occur; and
- If and when regional infrastructure upgrades occur (assumed to be 2035 for the financial analysis), it would offer the potential for FEI to end curtailments by holding gas supply contracts for 1.0 Bcf and 200 MMcf/d. FEI would pay a higher toll / charge that includes the costs of the upgrades.

5.1.2.1 Modelling Parameters

Table C-9 below sets out the resiliency and gas supply modelling parameters for the Supplemental Alternative 2 scenarios.

The planning scenario uses the maximum regasification (400 MMcf/d), paired with the volume of dependable LNG for resiliency (0 Bcf – no resiliency reserve) and, for peaking gas supply, the amount included in the Annual Contracting Plan (0.6 Bcf).

FEI also modelled two “contingent” (i.e., non-dependable) scenarios based on more optimistic assumptions about how much LNG is present at Tilbury on the day of a no-flow event. These scenarios are described in Section 4 of this Appendix.

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cost benefit analysis is incomplete. In order to fully evaluate a potential role of Tilbury Tank 1A in FEI’s resiliency portfolio, a more fulsome analysis is required.”

Table C-9: Supplemental Alternative 2 Planning and Contingent Modelling Scenarios

Supp. Alt. 2 Modelling Scenario	Description	Resiliency Modelling Parameters	Peaking Gas Supply Allocation (Normal Operations)[1]
Supplemental Alternative 2 (Planning)	New Regasification – 400 MMcf/d (No Resiliency Reserve)[2]	0 Bcf at 400 MMcf/d	0.6 Bcf at 400 MMcf/d
Supplemental Alternative 2 (Contingent)	Assume Partial LNG Availability on Day of No-Flow[3]	0.35 Bcf at 400 MMcf/d	0.6 Bcf at 400 MMcf/d
Supplemental Alternative 2 (Contingent w/T1A)	Assume Base Plant Fully Available plus 0.4 Bcf in Tilbury 1A on Day of No-Flow	0.75 Bcf at 400 MMCf/d	0.6 Bcf at 400 MMcf/d

Notes to Table:

1 Per the ACP, FEI allocates 0.6 Bcf from Tilbury for gas supply portfolio purposes, with a 0.25 Bcf portion temporarily obtained from Tilbury 1A. Actual volumes will decline with use during winter, including if LNG volumes were used for resiliency to respond to a no-flow event.

2 When there is no resiliency reserve, on a planning basis there is no dependable LNG available on occurrence of no-flow event. Hence the resiliency modelling parameter is 0 Bcf.

3 Reduced volume available could be attributable to either: (a) Tilbury 1A volumes being unavailable due to RS 46 sales, leaving a maximum of 0.35 Bcf in the Base Plant tank at currently reduced fill levels; or (b) partial consumption for peaking gas supply of the 0.6 Bcf currently allocated to gas supply at Tilbury (which is currently comprised of 0.35 Bcf from the Base Plant plus 0.25 Bcf Tilbury 1A). The former is expected to occur in the future, and the latter is common over the course of a typical winter.

5.1.2.2 Summary of Information and Analysis

FEI investigated Supplemental Alternative 2 with respect to the criteria discussed in Section 4.2.2.3 of the Supplemental Evidence. Supplemental Alternative 2 did not pass the Step 2 screen since it would not retain FEI's existing on-system peaking supply capabilities[31] due to the expected increase in RS 46 sales and the age-related seismic challenges associated with the Base Plant tank, which creates a risk that the operating level of the tank could be further reduced.[32] However, for completeness, FEI assesses Supplemental Alternative 2 based on the five criteria utilized in Step 3 of the alternatives analysis.

The following bullets provide a high-level description of how this alternative performs against the criteria, followed by sections providing additional details.

- **Resiliency (No Impact):** Supplemental Alternative 2 would not include a resiliency reserve and, even assuming some LNG inventory is present at Tilbury on the day of a no-flow event, would only provide very limited incremental mitigation against a winter T-South

[31] 0.6 Bcf and 150 MMcf/d of regasification capacity.
[32] See Section 4.4.1 of the Supplemental Evidence for further discussion regarding why Supplemental Alternative 2 did not pass the Step 2 screen.

no-flow event relative to the Supplemental Alternative 1 (Planning) scenario. A failure would result in similar consequences as the Supplemental Alternative 1 (Planning) scenario.

- **Gas Supply (No Impact):** Supplemental Alternative 2 would only maintain the current peaking supply capabilities for so long as: (a) Tilbury 1A is not fully subscribed under RS 46; and (b) the Base Plant tank can continue to operate at its current operating level without having to be further reduced. This is unlikely to occur beyond 2030. Thereafter, FEI would lose a significant portion of its dependable peaking resources unless and until a replacement LNG facility or costly regional infrastructure upgrades could be constructed.
- **Base Plant Challenges (Medium Positive Impact):** The replacement of the Base Plant's regasification equipment would address its reliability issues; however, the age-related challenges inherent in the Base Plant tank would remain unresolved.
- **Levelized Total Rate Impact (Low Negative Impact):** Supplemental Alternative 2 would have a levelized total rate impact of 3.3 percent over a 67-year analysis period. This is lower than Supplemental Alternative 9 since it only involves replacement of the regasification equipment, but it assumes FEI would be curtailing firm customers in normal operations for several years instead of incurring peaking gas costs.
- **Future Use (Medium Negative Impact):** FEI does not expect the Base Plant tank to still be in-service by 2050 as the facility would be 79 years old. Additionally, FEI expects Tilbury 1A to be sold out from RS 46 sales. This creates a stranded asset risk for the new regasification equipment, which would not be useful without the Base Plant tank or available LNG from Tilbury 1A.

FEI discusses the analysis for each of the five criteria in further detail below.

5.1.2.2.1 RESILIENCY (NO IMPACT)

Supplemental Alternative 2 would not include a resiliency reserve and, even assuming some LNG inventory is present at Tilbury on the day of a no-flow event, would only provide very limited incremental mitigation against a winter T-South no-flow event. FEI addresses the resiliency benefit of the Supplemental Alternative 2 scenarios below.

- Supplemental Alternative 2 (Planning) would improve the regasification capacity relative to the Supplemental Alternative 1, but would not fully address the existing regasification constraint at Tilbury. This is because, at average Lower Mainland winter temperature (+4°C), the send out capacity of 400 MMcf/d remains undersized for the system demand. Further, without a resiliency reserve, all LNG would continue to be allocated for planning purposes to either gas supply or RS 46 LNG sales, such that it may or may not be present on the day of a winter T-South no-flow event. Therefore, the system would still fail on the day of a winter T-South no-flow event, resulting in similar consequences as the Supplemental Alternative 1 (Planning) scenario.

- Supplemental Alternative 2 would also only provide limited incremental mitigation against a winter T-South no-flow event under either of the contingent scenarios, which both assume that some LNG inventory is present on the day of a winter T-South no-flow event. Based on Exponent's analysis, the customer outage risk would nonetheless remain significant under these optimistic contingent scenarios. In particular, the system would still fail on Day 1 (cold weather of -1.4°C) or Day 2 (at an average winter temperature of +4°C) of a winter no-flow event, resulting in similar consequences as the Supplemental Alternative 1 (Planning) scenario.

These results are confirmed in Exponent's figure (reproduced in Section 2.5.1 above) summarizing the annual expected loss reduction associated with each Supplemental Alternative relative to the Supplemental Alternative 1 (Planning) scenario.

The following table summarizes how long Supplemental Alternative 2, in combination with FEI's other existing capabilities, will be able to sustain the Lower Mainland load following a winter T-South no-flow event. FEI has consistently modelled three temperatures that are reflective of local conditions, since FEI's load increases as temperatures decrease.

Table C-10: Supplemental Alternative 2 Load Support Durations Under Different Winter Conditions

Supp. Alt. 2 Modelling Scenario	Approximate Time Until Customers in the Lower Mainland Begin Losing Service[33]		
	-10°C (very cold winter day)[34]	-1.4°C (warmest winter in 10 years, as defined in footnote)[35]	+4.0°C (average Lower Mainland winter)[36]
Planning (0 Bcf, 400 MMcf/d)	0 days and 0 hours	0 days and 0 hours	0 days and 0 hours
Contingent (0.35 Bcf, 400 MMcf/d)	0 days and 5 hours	0 days and 12 hours	1 day and 1 hour

[33] This represents the approximate duration of full firm load support for customers in the Lower Mainland. Except for the 0 Bcf case which does not account for linepack, the analysis considers support from on-system LNG and linepack from the CTS. Linepack was not considered in the 0 Bcf case such that an understanding of the absolute baseline risk could be had. The analysis also assumes that all interruptible customers are offline within 4 hours of the no-flow event, except for the -10°C analysis, wherein interruptible customers would already be offline due to the cold temperature condition.

[34] Due to the low probability of having multiple -10°C days in a row in the Lower Mainland, the -10°C temperature condition analysis assumes the following: the first day is -10°C, the second and third days are -7°C, the fourth day is -3°C, and all subsequent days are +4°C.

[35] The warmest winter in the last 10 years was found by determining the minimum daily average temperature for each year over a 10-year period from 2013-2022, then selecting the highest value. The analysis was based on data from YVR.

[36] Defined as the average of the daily average temperatures for December, January, and February over a 10-year period from 2013-2022. The average winter day is based on data from YVR.

Supp. Alt. 2 Modelling Scenario	Approximate Time Until Customers in the Lower Mainland Begin Losing Service[33]		
	-10°C (very cold winter day)[34]	-1.4°C (warmest winter in 10 years, as defined in footnote)[35]	+4.0°C (average Lower Mainland winter)[36]
Contingent w/T1A (0.75 Bcf, 400 MMcf/d)	0 days and 5 hours	0 days and 12 hours	1 day and 19 hours

Consistent with the framework established in Section 3.4.1.2.2 of FEI's 2024 Resiliency Plan, under average winter conditions, the support duration provided by the contingent scenarios for Supplemental Alternative 2 may or may not be enough to execute a controlled shutdown. Therefore, a failure occurring on some parts of T-South could result in a controlled or uncontrolled shutdown in the Lower Mainland system. The Supplemental Alternative 2 (Planning) scenario does not provide a support duration, and therefore, FEI expects a failure occurring on some parts of T-South would result in an uncontrolled shutdown.

The resiliency support provided by each Supplemental Alternative 2 scenario is discussed further below.

Supplemental Alternative 2 (Planning) – 0 Bcf, 400 MMcf/d

As shown in Table C-10 above, the Supplemental Alternative 2 (Planning) scenario assumes there is no LNG inventory present on the day of a winter T-South no-flow event, as there is no resiliency reserve. Therefore, this scenario would provide no resiliency support (i.e., the result is the same as the Supplemental Alternative 1 (Planning) scenario).

Supplemental Alternative 2 (Contingent) – 0.35 Bcf, 400 MMcf/d

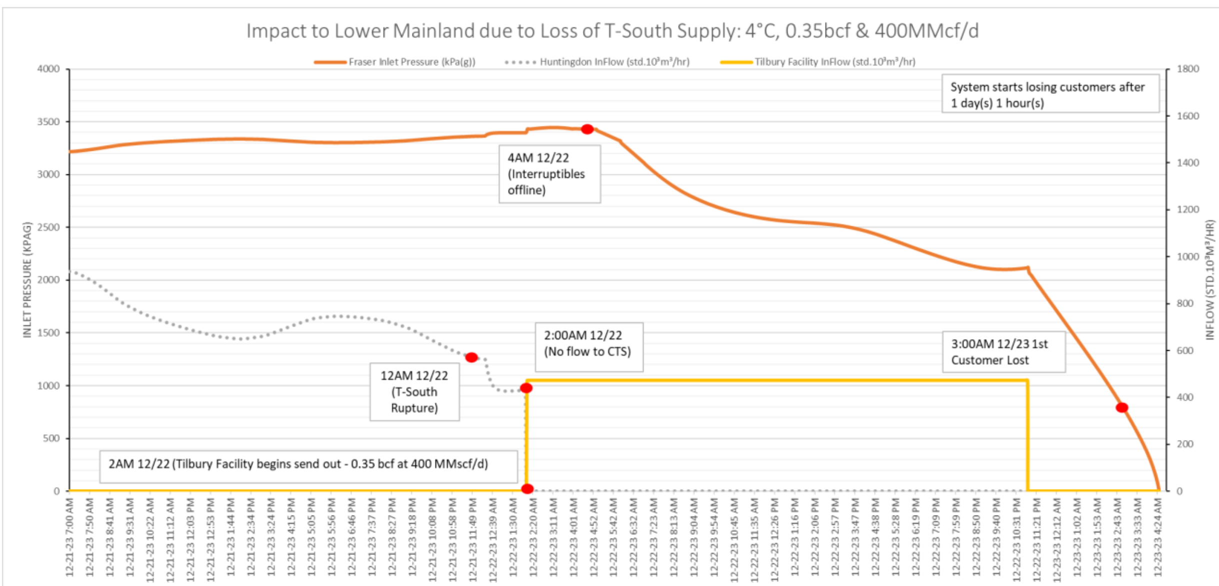
Supplemental Alternative 2 (Contingent) assumes 0.35 Bcf of LNG inventory is present on the day of a winter T-South no-flow event, which amounts to approximately 58 percent of the planning LNG inventory for gas supply purposes. The reduced LNG volume available could be attributable to either:

- Tilbury 1A volumes being unavailable due to RS 46 sales, leaving a maximum of 0.35 Bcf in the Base Plant tank at currently reduced fill levels; or
- Partial consumption for peaking gas supply of the 0.6 Bcf currently allocated to gas supply at Tilbury (which is currently comprised of 0.35 Bcf from the Base Plant plus 0.25 Bcf Tilbury 1A).

Because of the higher regasification capacity, this contingent scenario provides an increased resiliency benefit, in terms of duration of load support following a winter T-South no-flow event, across all temperature conditions considered relative to both the Supplemental Alternative 1 (Planning) and (Contingent) scenarios. However, the benefit is mainly observed under average winter conditions (+4°C) as, similar to Supplemental Alternative 1 (Contingent), under the colder temperature conditions of -10°C and -1.4°C, customer outages would still occur on the day of the no-flow event. This is due to the 400 MMcf/d regasification capacity being insufficient at the colder temperature conditions. Even at +4°C the 400 MMcf/d regasification capacity is insufficient for the entire Lower Mainland load. However, the capacity shortfall is smaller than in Supplemental Alternative 1 (Contingent) and thus Supplemental Alternative 2 (Contingent) shows more improvement at this temperature condition when compared to the colder temperature conditions of -10°C and -1.4°C.

Figures C-15 to C-17 below show the transient modelling outputs FEI used to determine the load support duration values for this scenario. As shown in Figure C-15, under average winter conditions (+4°C), the primary constraint is insufficient storage capacity.[37] However, as seen in Figures C-16 and C-17, the constraint switches back to being insufficient regasification under colder temperatures.[38]

Figure C-15: Impact to Lower Mainland due to Loss of T-South Supply at +4°C with Supp. Alt. 2 – 0.35bcf & 400MMcf/d



[37] The Tilbury facility sendout flow rate (yellow line) drops to zero before the first customer outage occurs.
[38] The Tilbury facility sendout flow rate (yellow line) remains above zero at the time of the first customer outage, indicating that there is still volume left in the tank when customer outages occur.

Figure C-16: Impact to Lower Mainland due to Loss of T-South Supply at -1.4°C with Supp. Alt. 2 – 0.35bcf & 400MMcf/d

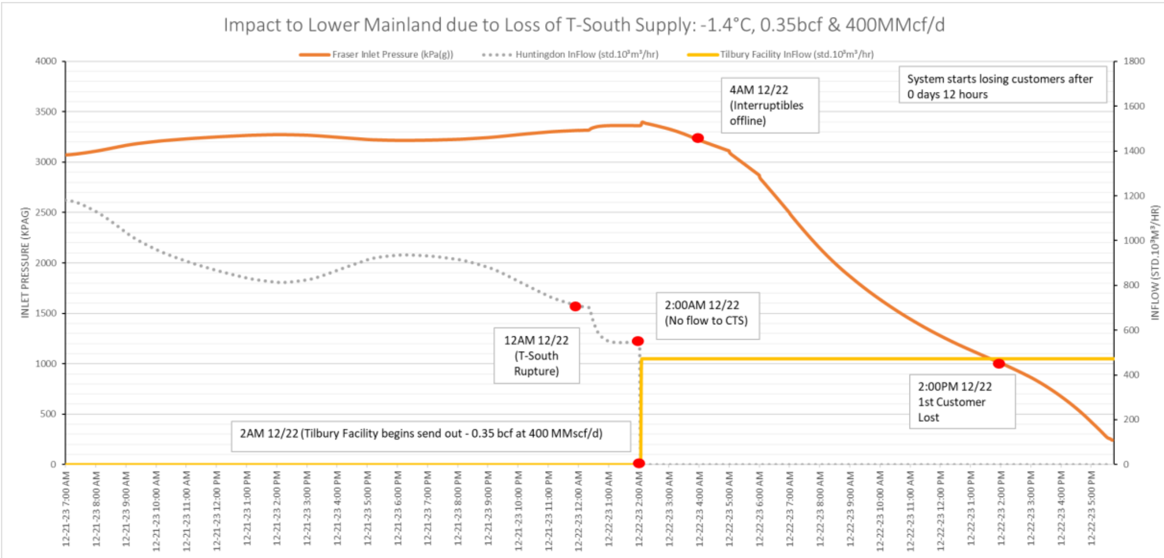
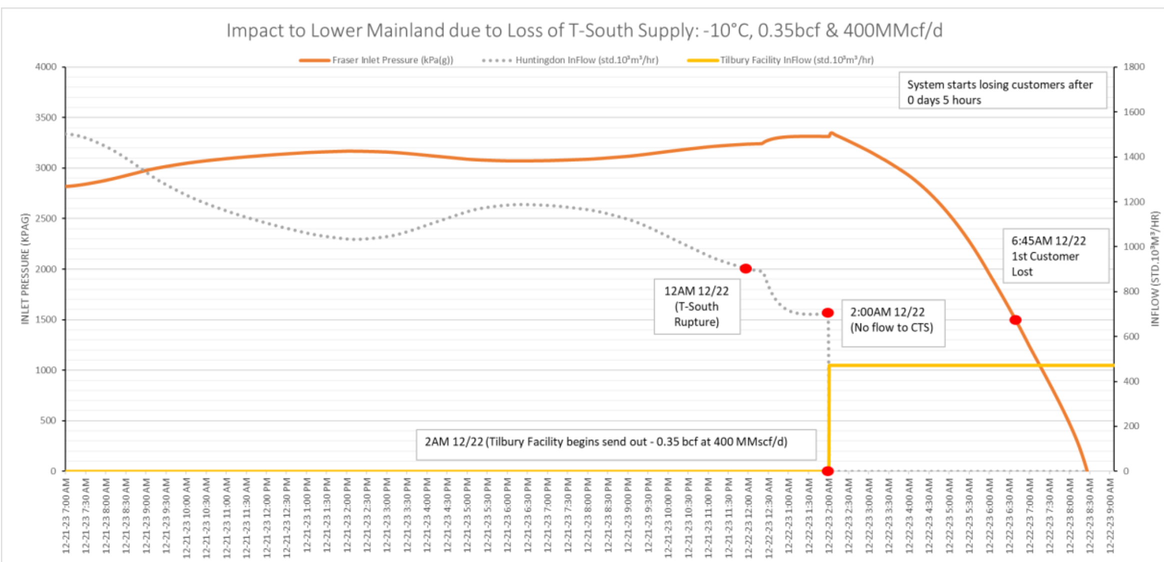


Figure C-17: Impact to Lower Mainland due to Loss of T-South Supply at -10°C with Supp. Alt. 2 – 0.35bcf & 400MMcf/d



Supplemental Alternative 2 (Contingent w/T1A) – 0.75 Bcf, 400 MMcf/d

Supplemental Alternative 2 (Contingent w/T1A) assumes 0.75 Bcf of LNG inventory is present on the day of a winter T-South no-flow event as follows:

- The Base Plant tank being full at its current reduced operating capacity (0.35 Bcf) and Tilbury 1A having 0.4 Bcf of LNG inventory on hand on the day of the winter T-South no-flow event.

Because of the higher regasification capacity, this contingent scenario would provide an increased resiliency benefit in terms of the duration of load support relative to Supplemental Alternative 1 (Contingent w/T1A).

Compared to Supplemental Alternative 2 (Contingent), under average winter conditions (+4°C), the additional available LNG volume would improve the load support duration to 1 day and 19 hours (an increase of 18 hours compared to Supplemental Alternative 2 (Contingent)). However, the support durations under the -1.4°C and -10°C temperature conditions are the same as for the Supplemental Alternative 2 (Contingent) scenario. This result reflects the constraining factor at these colder temperatures, insufficient regasification capacity, which is not remedied by increasing the available storage volume from 0.35 Bcf to 0.75 Bcf.

Figures C-18 to C-20 below show the transient modelling outputs FEI used to determine the load support duration values for this scenario.

Figure C-18: Impact to Lower Mainland due to Loss of T-South Supply at +4°C with Supp. Alt. 2 – 0.75bcf & 400MMcf/d

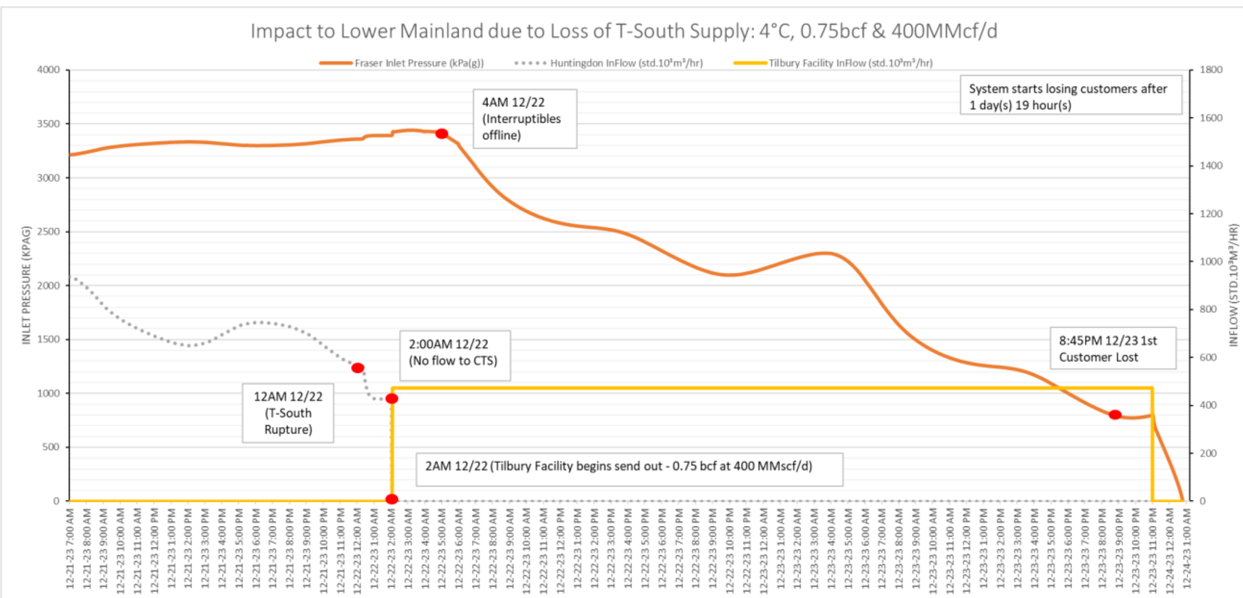


Figure C-19: Impact to Lower Mainland due to Loss of T-South Supply at -1.4°C with Supp. Alt. 2 – 0.75bcf & 400MMcf/d

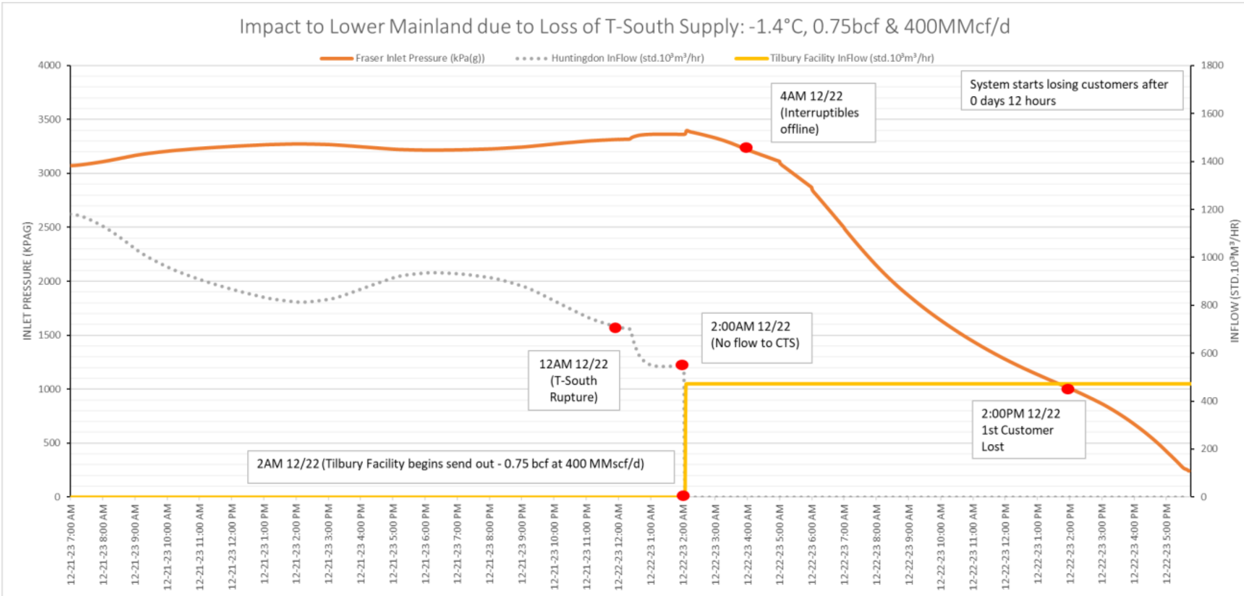
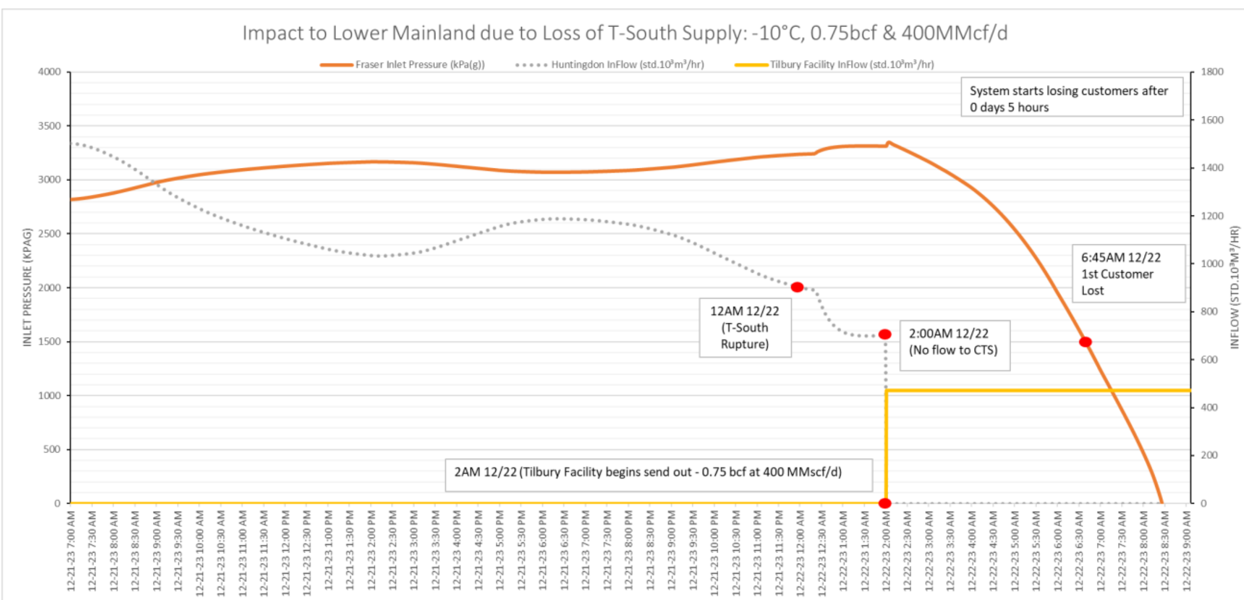


Figure C-20: Impact to Lower Mainland due to Loss of T-South Supply at -10°C with Supp. Alt. 2 – 0.75bcf & 400MMcf/d



5.1.2.2.2 GAS SUPPLY (NO IMPACT)

Supplemental Alternative 2 would not retain FEI's existing on-system peaking capabilities and, therefore, did not pass the Step 2 screen because of: (1) the expected increase in RS 46 sales which would prevent FEI from supplementing the operating volume of the Base Plant tank from Tilbury 1A; and (2) the increasing risk that even the reduced Base Plant tank volumes will be unavailable. FEI addresses each reason below.

First, Supplemental Alternative 2 would only maintain the current peaking supply capabilities for so long as Tilbury 1A is not fully subscribed under RS 46. Tilbury 1A currently supplements the current operating volume of the Base Plant tank (0.35 Bcf) with an additional 0.25 Bcf of LNG, such that the required LNG volume for peaking supply is available at Tilbury. Section 4.2.2.1 above discusses how FEI expects RS 46 demand to grow, particularly now that the Tilbury Jetty has received the necessary regulatory approvals to proceed. Once Tilbury 1A is fully subscribed, it would be difficult for FEI replace the lost gas supply support in the market as dependable peaking resources are not available in the market.

Second, Supplemental Alternative 2 would only maintain the current peaking supply capabilities if the Base Plant remains in operation at its current capacity. While the regasification challenges are resolved in Supplemental Alternative 2, the original 1971 Base Plant tank would still be relied on for gas supply. If the operating level of the tank were further reduced due to the seismic challenges that are inherent in the Base Plant design, FEI would again need to replace the lost supply by acquiring the equivalent resources on regional pipelines or storage.

As discussed in Section 3.3.4 of the Supplemental Evidence, FEI could not replace the Tilbury peaking supply resources currently included in the Annual Contracting Plan (150 MMcf/d and 0.6 Bcf) in the market and does not have control over regional infrastructure expansions that, if those expansions were to occur in the future, would entail very significant annual gas supply costs for FEI customers.

5.1.2.2.3 BASE PLANT CHALLENGES (MEDIUM POSITIVE IMPACT)

The replacement of the Base Plant's regasification equipment would address the reliability of the send-out equipment. However, this alternative would not address the Base Plant tank, which has reached end-of-life and, as such, the seismic, environmental and flooding issues inherent in the existing Base Plant tank design discussed in Section 3.3.2 of the Supplemental Evidence would remain unresolved.

5.1.2.2.1 LEVELIZED TOTAL RATE IMPACT (LOW NEGATIVE IMPACT)

The levelized total rate impact for Supplemental Alternative 2 is estimated to be 3.3 percent over a 67-year analysis period.

This reflects the estimated capital cost of $391.5 million to install the 400 MMcf/d of new regasification, operating costs over the expected life of the new assets, and the costs for gas supply from the regional market, if available, to meet FEI's full peaking gas requirement of 1.0 Bcf and 200 MMcf/d once there is no longer sufficient LNG available for peaking gas supply. For years when it is not possible to replace the peaking gas supply level currently provided by the Base Plant, FEI would have to curtail firm customers under normal operations. Please refer to Section 3.3 of this Appendix for details on the gas supply cost assumptions and the costs/savings used in the financial analysis for Supplemental Alternative 2.

5.1.2.2.2 FUTURE USE (MEDIUM NEGATIVE IMPACT)

Supplemental Alternative 2 creates a stranded asset risk for the new regasification equipment, which would not be useful without the Base Plant tank or available LNG from Tilbury 1A.

FEI does not expect the Base Plant tank to still be in-service by 2050 as the facility would be 79 years old and has reached end-of-life. Further, as Tilbury 1A will no longer be available due to an expected increase in RS 46 sales, unless a new tank is built, the regasification equipment would become a stranded asset.

The question of whether or not the facility contemplated under a Supplemental Alternative would be used and useful must be distinguished from whether or not it would deliver on the Project objectives. As discussed above, Supplemental Alternative 2 would not deliver improved resiliency against a winter T-South no-flow event, nor would it ensure that FEI is able to continue serving customers in normal operations (i.e., maintaining the critical gas supply function and other operational benefits provided by the Base Plant).

5.1.3 Supplemental Alternative 3

As explained in Section 4.4 of the Supplemental Evidence, FEI eliminated Supplemental Alternative 3 in Step 2 of the screening process. However, to be responsive to the BCUC's commentary in the Adjournment Decision, FEI has assessed this alternative against the five criteria utilized in Step 3 of the screening process as part of this Appendix.

Supplemental Alternative 3 includes the following:

- Replacing the existing Base Plant regasification units with 600 MMcf/d of regasification;
- Continuing to rely on a non-refurbished Base Plant tank that is operating at a lower maximum capacity (0.35 Bcf), and leaving unaddressed the seismic, environmental and flooding issues inherent in the original Base Plant design;
- There continuing to be no resiliency reserve; that is, from a planning perspective, all of the LNG at Tilbury would still be allocated to either gas supply or RS 46 LNG sales, such that those volumes may or may not be present upon a no-flow event;
- Changing how FEI operates existing Tilbury 1A liquefaction to replenish consumed LNG faster, so as to increase the potential for LNG to be present on the day of a no-flow event (i.e., 0.35 Bcf in the Base Plant tank and 0.4 Bcf in Tilbury 1A despite RS 46 LNG sales);[39]
- From the gas supply perspective, continue meeting the peaking supply requirement of 1 Bcf and 200 MMcf/d by continuing to rely on the Base Plant, plus continuing to hold 50

[39] This assumption addresses the following BCUC commentary in the Adjournment Decision, p. 29: "With additional liquefaction the average storage volume could be increased thereby providing additional capacity available for resiliency purposes. While there is evidence that this would be more costly than the current operational strategy, the cost benefit analysis is incomplete. In order to fully evaluate a potential role of Tilbury Tank 1A in FEI's resiliency portfolio, a more fulsome analysis is required."

MMcf/d of year-round pipeline capacity. The latter is still necessary despite the new regasification of 600 MMcf/d because the amount of LNG is a limitation;

- When the existing Base Plant tank must be operated at further reduced levels or is no longer usable, or Tilbury 1A LNG unavailable (assumed to be 2030 for the purpose of the financial analysis), the new regasification will be of limited use. FEI would therefore lose the peaking capabilities of 0.6 Bcf and 600 MMcf/d from Tilbury and would be unable to replace it with capacity on regional infrastructure. As such, FEI would still hold the existing 50 MMcf/d of market pipeline capacity but would likely have to curtail firm loads in normal operations by up to 150 MMcf/d (the original regasification level currently included in the ACP) until future regional infrastructure upgrades occur; and
- If and when regional infrastructure upgrades occur (assumed to be 2035 for the financial analysis), it would offer the potential for FEI to end curtailments by holding gas supply contracts for 1.0 Bcf and 200 MMcf/d. FEI would pay a higher toll / charge that includes the costs of the upgrades.

This alternative is the same as Supplemental Alternative 2, except the regasification capacity has been increased from 400 MMcf/d to 600 MMcf/d; therefore, many of the same considerations outlined in Supplemental Alternative 2 apply here as well.

5.1.3.1 Modelling Parameters

Table C-11 below sets out the resiliency and gas supply evaluation parameters for the Supplemental Alternative 3 scenarios.

The planning scenario uses the maximum regasification (600 MMcf/d), paired with the volume of dependable LNG for resiliency (0 Bcf – no resiliency reserve) and, for peaking gas supply, the amount included in the ACP (0.6 Bcf).

FEI also modelled two “contingent” (i.e., not dependable) resiliency scenarios based on more optimistic assumptions about how much LNG is present at Tilbury on the day of a no-flow event. These scenarios are described in Section 4 of this Appendix.

Table C-11: Supplemental Alternative 3 Planning and Contingent Modelling Scenarios

Supp. Alt. 3 Modelling Scenario	Description	Resiliency Modelling Parameters	Peaking Gas Supply Allocation (Normal Operations)[1]
Supplemental Alternative 3 (Planning)	New Regasification – 600 MMcf/d (No Resiliency Reserve)[2]	0 Bcf at 600 MMcf/d	0.6 Bcf at 600 MMcf/d
Supplemental Alternative 3 (Contingent)	Assume Partial LNG Availability on Day of No-Flow[3]	0.35 Bcf at 600 MMcf/d	0.6 Bcf at 600 MMcf/d
Supplemental Alternative 3 (Contingent w/T1A)	Assume Base Plant Fully Available plus 0.4 Bcf in Tilbury 1A on Day of No-Flow	0.75 Bcf at 600 MMcf/d	0.6 Bcf at 600 MMcf/d

<u>Notes to Table:</u>

[1] *Per the ACP, FEI allocates 0.6 Bcf from Tilbury for gas supply portfolio purposes, with a 0.25 Bcf portion temporarily obtained from Tilbury 1A. Actual volumes will decline with use during winter, including if LNG volumes were used for resiliency to respond to a no-flow event.*

[2] *When there is no resiliency reserve, on a planning basis there is no dependable LNG available on occurrence of no-flow event. Hence the resiliency modelling parameter is 0 Bcf.*

[3] *Reduced volume available could be attributable to either (a) Tilbury 1A volumes being unavailable due to RS 46 sales, leaving a maximum of 0.35 Bcf in the Base Plant tank at currently reduced fill levels; or (b) partial consumption for peaking gas supply of the 0.6 Bcf currently allocated to gas supply at Tilbury (which is currently comprised of 0.35 Bcf from the Base Plant plus 0.25 Bcf Tilbury 1A). The former is expected to occur in the future, and the latter is common over the course of a typical winter.*

5.1.3.2 Summary of Information and Analysis

FEI investigated Supplemental Alternative 3 with respect to the criterion discussed in Section 4.2 of the Supplemental Evidence. Supplemental Alternative 3 did not pass the Step 2 screen since it would not retain FEI's existing on-system peaking supply capabilities[40] due to the expected increase in RS 46 sales and the age-related seismic challenges associated with the Base Plant tank which create a risk that the operating level of the tank could be further reduced. However, for completeness, FEI assesses Supplemental Alternative 3 based on the five criteria utilized in Step 3 of the alternatives analysis.

The following bullets provide a high-level description of how this alternative performs against the criteria, followed by sections providing additional details.

- **Resiliency (No Impact):** Supplemental Alternative 3 would not include a resiliency reserve. Even assuming some LNG inventory is present at Tilbury on the day of a no-flow event, it would only provide very limited incremental mitigation against a winter T-South no-flow event relative to the Supplemental Alternative 1 (Planning) scenario. It would

[40] 0.6 Bcf and 150 MMcf/d of regasification capacity.

provide more mitigation than the Supplemental Alternative 2 scenarios at below-average winter temperatures. A failure would have similar consequences as the Supplemental Alternative 1 (Planning) scenario.

- **Gas Supply (No Impact):** Supplemental Alternative 3 would only maintain the current peaking supply capabilities for so long as: (a) Tilbury 1A is not fully subscribed under RS 46; and (b) the Base Plant tank does not require a further reduced fill elevation due to its seismic design challenges that are inherent in the Base Plant design. Thereafter, FEI would lose a significant portion of its dependable peaking resources unless and until a replacement LNG facility or costly regional infrastructure upgrades could be constructed.
- **Base Plant Challenges (Medium Positive Impact):** The replacement of the Base Plant regasification equipment would address its reliability issues; however, the age-related challenges inherent in the Base Plant tank would remain unresolved.
- **Levelized Total Rate Impact (Low Negative Impact):** Supplemental Alternative 3 would have a levelized total rate impact of 3.4 percent over a 67-year analysis period. This is lower than Supplemental Alternative 9 since it only involves replacement of the regasification equipment, but it assumes FEI would be curtailing firm customers in normal operations for several years instead of incurring peaking gas costs.
- **Future Use (Medium Negative Impact):** FEI does not expect the Base Plant tank to still be in-service by 2050 as the facility would be 79 years old. Additionally, FEI expects Tilbury 1A to be sold out from RS 46 sales. This creates a stranded asset risk for the new regasification equipment, which would not be useful without the Base Plant tank or available LNG from Tilbury 1A.

FEI discusses each of the five analysis criteria in further detail below.

5.1.3.2.1 RESILIENCY (NO IMPACT)

Supplemental Alternative 3 would not include a resiliency reserve and, even assuming some LNG inventory is present at Tilbury on the day of a no-flow event, would only provide very limited incremental mitigation against a winter T-South no-flow event, albeit more than the Supplemental Alternative 2 scenarios under below-average winter temperatures. FEI addresses the resiliency benefit of the Supplemental Alternative 3 scenarios below.

- The Supplemental Alternative 3 (Planning) scenario goes further than Supplemental Alternative 2 towards addressing the regasification constraint at Tilbury by increasing it to 600 MMcf/d. Further, without a resiliency reserve, all LNG would continue to be allocated for planning purposes to either gas supply or RS 46 LNG sales, such that it may or may not be present on the day of a winter T-South no-flow event. Therefore, from a planning perspective, the system would still fail on the day of a winter T-South no-flow event, resulting in the same consequences as the Supplemental Alternative 1 (Planning) scenario.
- Supplemental Alternative 3 would also only provide limited incremental mitigation against a winter T-South no-flow event under either of the contingent scenarios, which both

assume that some LNG inventory is present on the day of a winter T-South no-flow event. For example, while the most optimistic Supplemental Alternative 3 (Contingent w/T1A) scenario, which assumes that 0.75 Bcf of LNG inventory is present on the day of the no-flow event, would provide limited incremental mitigation against a winter T-South no-flow event relative to Supplemental Alternative 2 under average Lower Mainland winter temperatures (+4°C), the customer outage risk would nonetheless remain significant. In particular, the system would still fail on Day 1 (extreme cold weather of -10°C) or Day 2 (at -1.4°C and +4°C) of a winter no-flow event, resulting in similar consequences as the Supplemental Alternative 1 (Planning) scenario.

These results are confirmed in Exponent's figure (reproduced in Section 2.5.1 above) summarizing the annual expected loss reduction associated with each Supplemental Alternative relative to the Supplemental Alternative 1 (Planning) scenario.

The following table summarizes how long Supplemental Alternative 3, in combination with FEI's other existing capabilities, would be able to sustain the Lower Mainland load following a winter T-South no-flow event. FEI has consistently modelled three temperatures that are reflective of local conditions, since FEI's load increases as temperatures decrease.

Table C-12: Supplemental Alternative 3 Load Support Durations Under Different Winter Conditions

Supp. Alt. 3 Modelling Scenario	Approximate Time Until Customers in the Lower Mainland Begin Losing Service[41]		
	-10°C (very cold winter day)[42]	-1.4°C (warmest winter in 10 years, as defined in footnote)[43]	+4.0°C (average Lower Mainland winter)[44]
Planning (0 Bcf, 600 MMcf/d)	0 days and 0 hours	0 days and 0 hours	0 days and 0 hours
Contingent (0.35 Bcf, 600 MMcf/d)	0 days and 7 hours	0 days and 18 hours	1 day and 1 hour

[41] This represents the approximate duration of full firm load support for customers in the Lower Mainland. Except for the 0 Bcf case which does not account for linepack, the analysis considers support from on-system LNG and linepack from the CTS. Linepack was not considered in the 0 Bcf case such that an understanding of the absolute baseline risk could be had. The analysis also assumes that all interruptible customers are offline within 4 hours of the no-flow event, except for the -10°C analysis, wherein interruptible customers would already be offline due to the cold temperature condition.

[42] Due to the low probability of having multiple -10°C days in a row in the Lower Mainland, the -10°C temperature condition analysis assumes the following: the first day is -10°C, the second and third days are -7°C, the fourth day is -3°C, and all subsequent days are +4°C.

[43] The warmest winter in the last 10 years was found by determining the minimum daily average temperature for each year over a 10-year period from 2013-2022, then selecting the highest value. The analysis was based on data from YVR.

[44] Defined as the average of the daily average temperatures for December, January, and February over a 10-year period from 2013-2022. The average winter day is based on data from YVR.

Supp. Alt. 3 Modelling Scenario	Approximate Time Until Customers in the Lower Mainland Begin Losing Service[41]		
	-10°C (very cold winter day)[42]	-1.4°C (warmest winter in 10 years, as defined in footnote)[43]	+4.0°C (average Lower Mainland winter)[44]
Contingent w/T1A (0.75 Bcf, 600 MMcf/d)	0 days and 7 hours	1 day and 10 hours	1 day and 22 hours

Consistent with the framework established in Section 3.4.1.2.2 of FEI's 2024 Resiliency Plan, under average winter conditions, the support duration provided by the contingent scenarios for Supplemental Alternative 3 may or may not be enough to execute a controlled shutdown. Therefore, a failure occurring on some parts of T-South may result in a controlled or uncontrolled shutdown in the Lower Mainland system. The Supplemental Alternative 3 (Planning) scenario does not provide a support duration, and therefore, FEI expects a failure occurring on some parts of T-South would result in an uncontrolled shutdown.

The resiliency support provided by each Supplemental Alternative 3 scenario is discussed further below.

Supplemental Alternative 3 (Planning) - 0 Bcf, 600 MMcf/d

As shown in the table above, the Supplemental Alternative 3 (Planning) scenario assumes there is no LNG inventory present on the day of a winter T-South no-flow event, as there is no resiliency reserve. Therefore, this scenario would provide no more resiliency support than Supplementary Alternative 1 (Planning).

Supplemental Alternative 3 (Contingent) - 0.35 Bcf, 600 MMcf/d

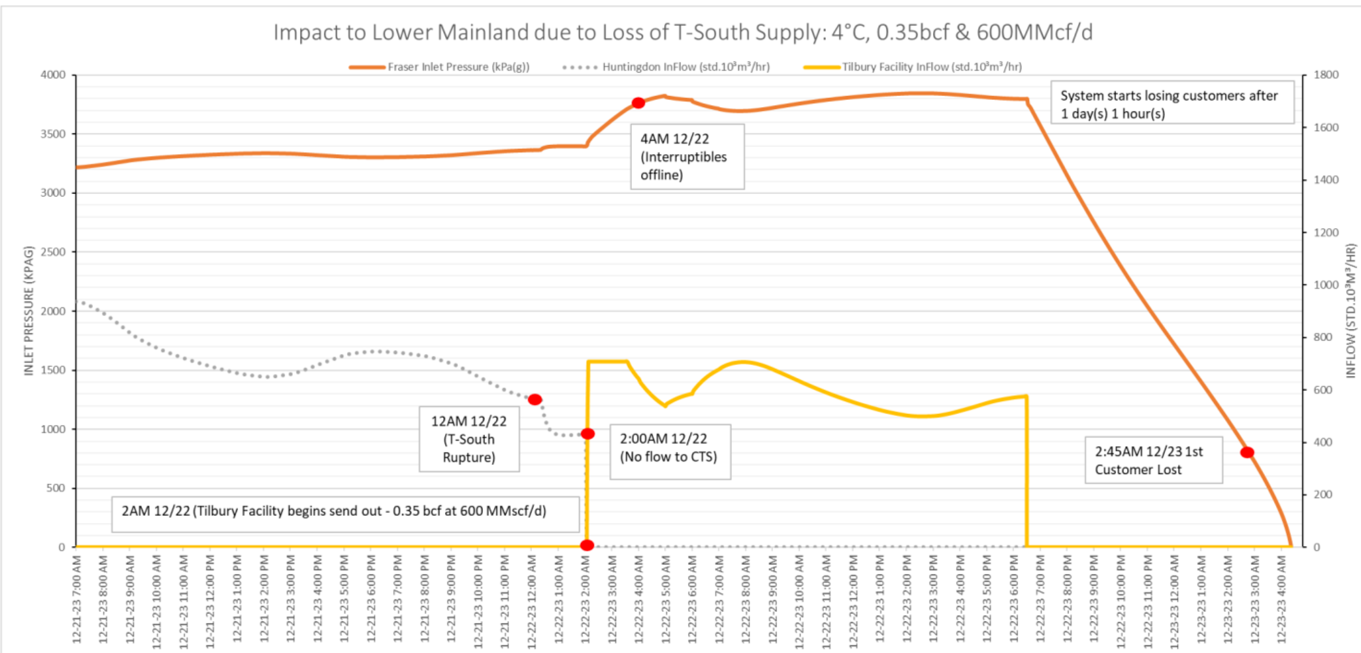
Supplemental Alternative 3 (Contingent) assumes 0.35 Bcf of LNG inventory is present on the day of a winter T-South no-flow event, which amounts to approximately 58 percent of the planning LNG inventory for gas supply purposes. The reduced LNG volume available could be attributable to either:

- Tilbury 1A volumes being unavailable due to RS 46 sales, leaving a maximum of 0.35 Bcf in the Base Plant tank at currently reduced fill levels; or
- Partial consumption for peaking gas supply of the 0.6 Bcf currently allocated to gas supply at Tilbury (which is currently comprised of 0.35 Bcf from the Base Plant plus 0.25 Bcf Tilbury 1A).

This contingent scenario would provide an increased resiliency benefit in terms of duration of load support relative to Supplemental Alternative 1 (Contingent). However, compared to Supplemental Alternative 2 (Contingent), Supplemental Alternative 3 (Contingent) would provide the same support duration under average winter conditions (+4°C), as both would be constrained by the available volume of LNG under this condition. Under the colder temperature conditions of -10°C and -1.4°C, Supplemental Alternative 3 (Contingent) would provide slightly longer support durations than Supplemental Alternative 2 (Contingent).

Figures C-21 to C-23 show the modelling outputs used to determine the load support duration values for this scenario. As shown in Figure C-21 and Figure C-22, at the +4°C and -1.4°C temperature conditions the primary constraint is insufficient storage capacity.[45] However, as seen in Figure C-23, the constraint switches back to being insufficient regasification under colder temperatures.

Figure C-21: Impact to Lower Mainland due to Loss of T-South Supply at +4°C with Supp. Alt. 3 – Contingent 0.35bcf & 600MMcf/d



45 The Tilbury facility send-out flow rate (yellow line) drops to zero before the first customer outage occurs.

Figure C-22: Impact to Lower Mainland due to Loss of T-South Supply at -1.4°C with Supp. Alt. 3 – Contingent 0.35bcf & 600MMcf/d

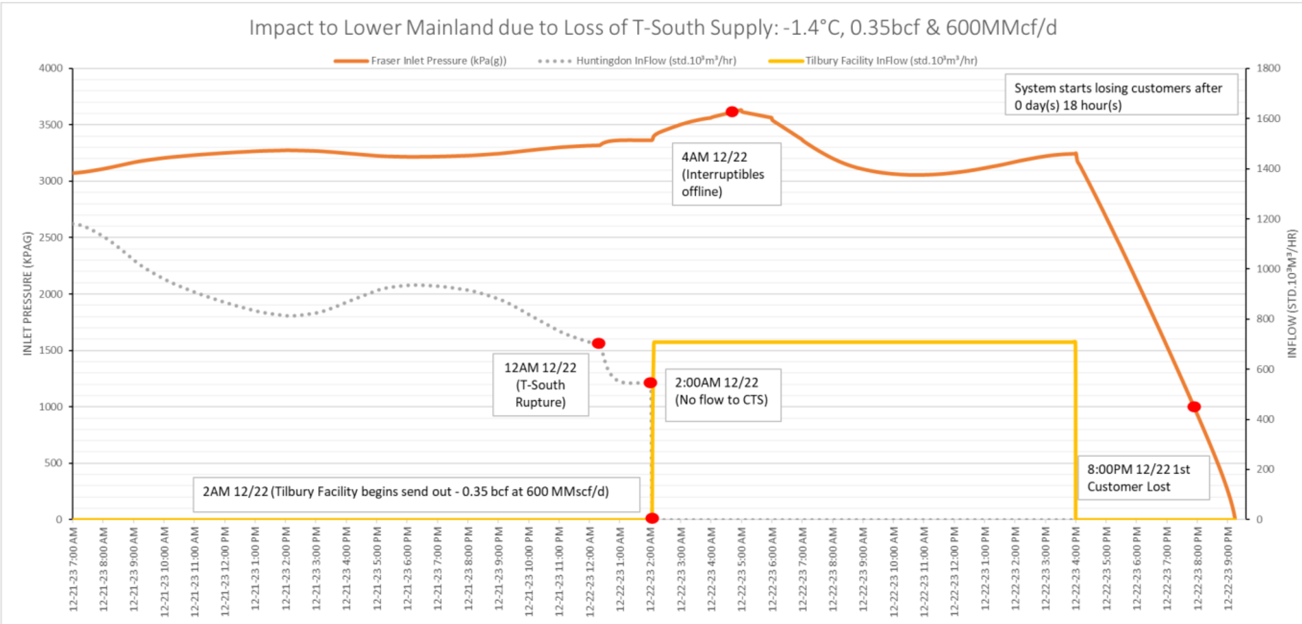
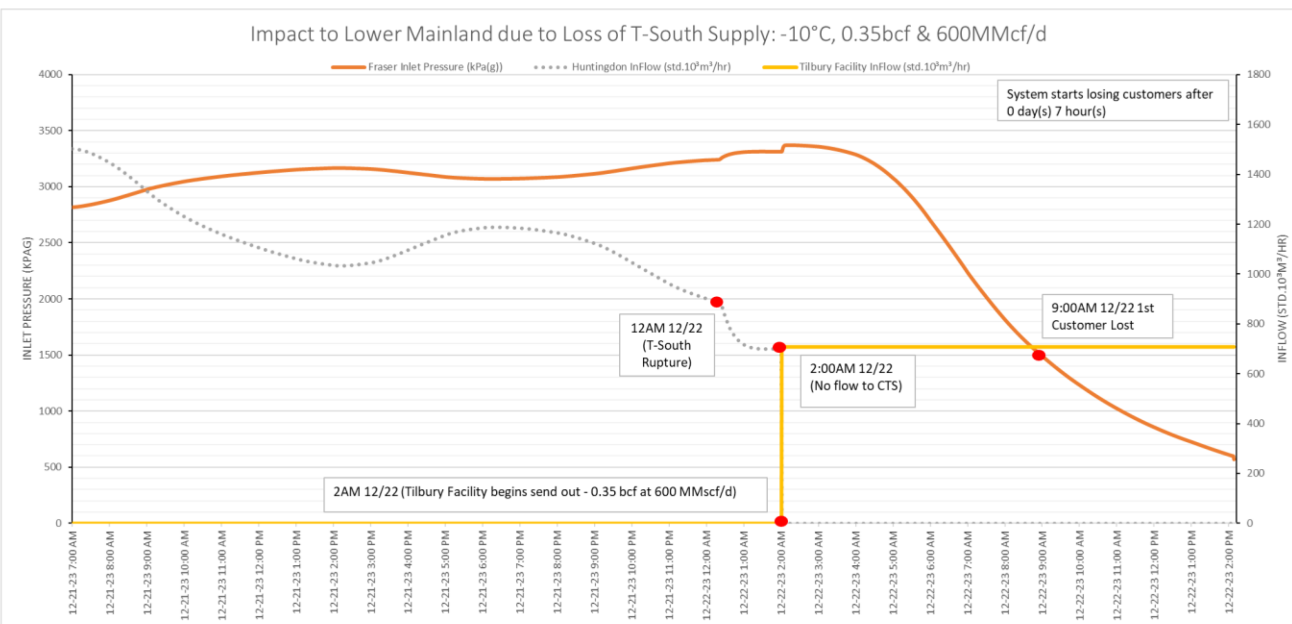


Figure C-23: Impact to Lower Mainland due to Loss of T-South Supply at -10°C with Supp. Alt. 3 – Contingent 0.35bcf & 600MMcf/d



Supplemental Alternative 3 (Contingent w/T1A) – 0.75 Bcf, 600 MMcf/d

Supplemental Alternative 3 (Contingent w/T1A) assumes 0.75 Bcf of LNG inventory is present on the day of a winter T-South no-flow event as follows:

- The Base Plant tank being full at its current operating capacity (0.35 Bcf) and Tilbury 1A having 0.4 Bcf of LNG inventory on hand on the day of the winter T-South no-flow event.

This contingent scenario would provide an increased resiliency benefit in terms of duration of load support relative to Supplemental Alternative 1 (Contingent w/T1A). Further, compared to Supplemental Alternative 2 (Contingent w/T1A) under average winter conditions (+4°C), the additional regasification capacity would improve the load support duration to 1 day and 22 hours (an increase of 3 hours compared to Supplemental Alternative 2 (Contingent w/T1A)). Increasing the regasification from 400 MMcf/d to 600 MMcf/d also improves the support duration under the -1.4°C temperature condition. At this temperature, Supplemental Alternative 3 (Contingent w/ T1A) provides a support duration that is 22 hours longer than Supplemental Alternative 2 (Contingent w/T1A). However, the support duration at the -10°C temperature condition is only 2 hours longer than that provided by Supplemental Alternative 2 (Contingent w/T1A).

When compared to Supplemental Alternative 3 (Contingent) at the +4°C and -1.4°C temperature conditions (i.e., the conditions where both modelling scenarios are constrained by the available volume of LNG), Supplemental Alternative 3 (Contingent w/ T1A) provides a longer load support duration because of the higher available LNG volumes. At the -10°C temperature condition the support durations between the two modelling scenarios are the same. This is because for both modelling scenarios the constraint at this temperature condition is due to the regasification capacity, which is not remedied by increasing the available LNG volume from 0.35 Bcf to 0.75 Bcf. This result reflects that the constraining factor at -10°C remains insufficient regasification capacity for Supplemental Alternative 3.

Figures C-24 to C-26 below show the modelling outputs used to determine the load support duration values in the table above for the second contingent scenario.

Figure C-24: Impact to Lower Mainland due to Loss of T-South Supply at +4°C with Supp. Alt. 3 – Contingent 0.75bcf & 600MMcf/d

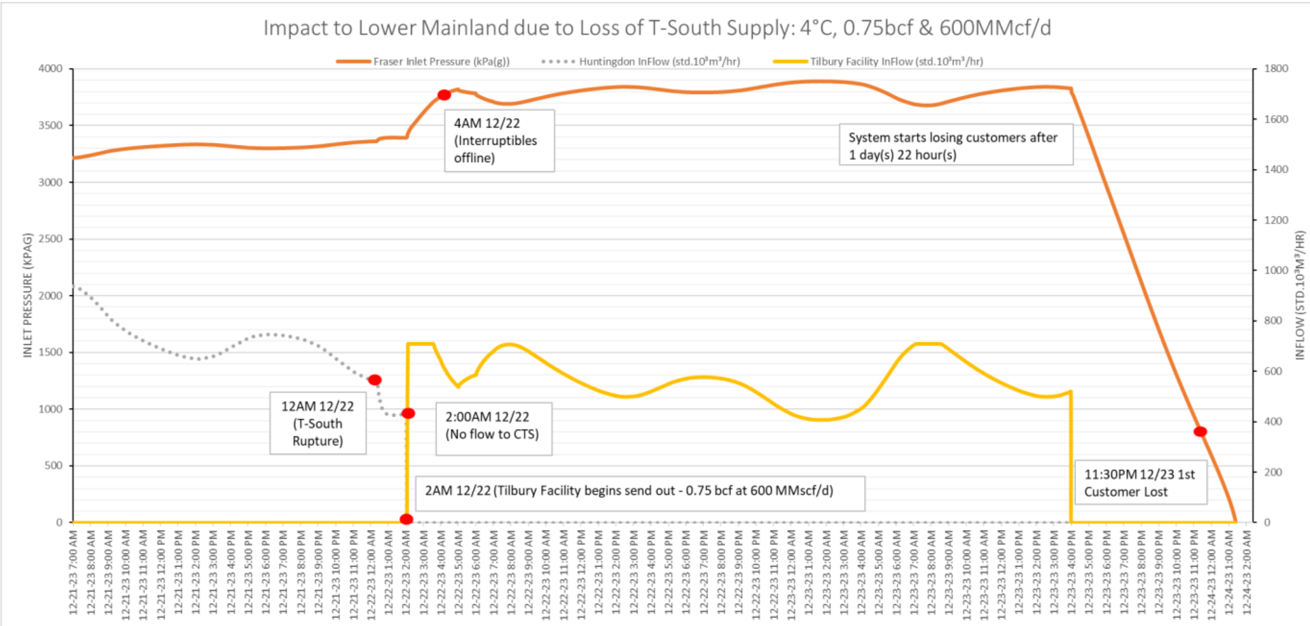


Figure C-25: Impact to Lower Mainland due to Loss of T-South Supply at -1.4°C with Supp. Alt. 3 – Contingent 0.75bcf & 600MMcf/d

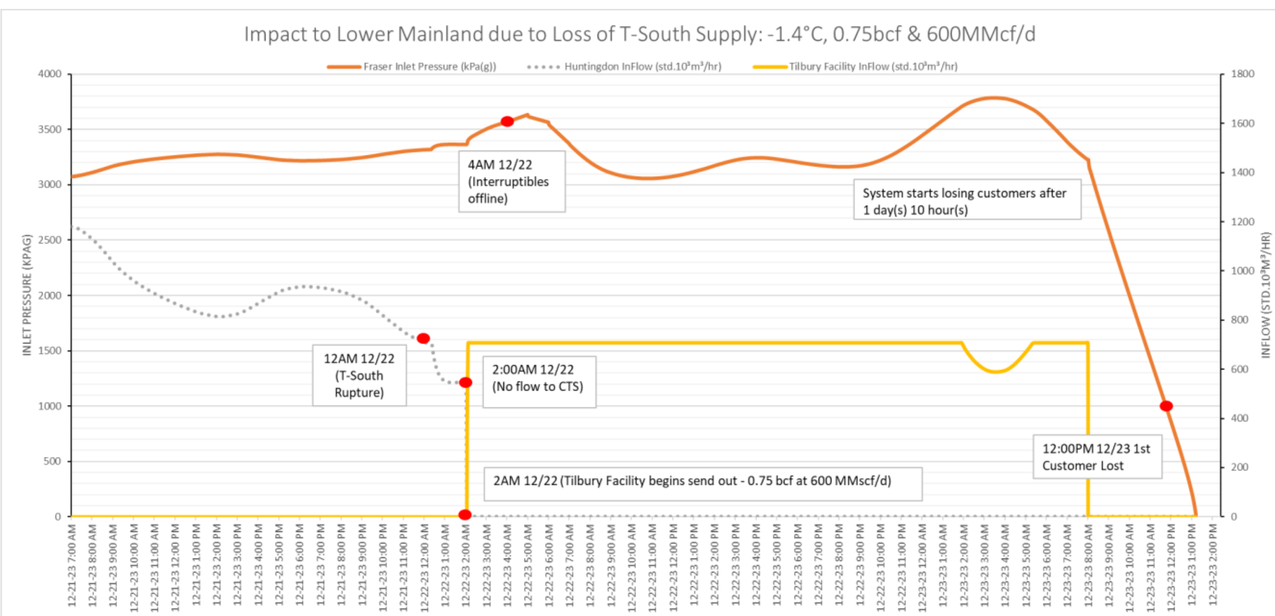
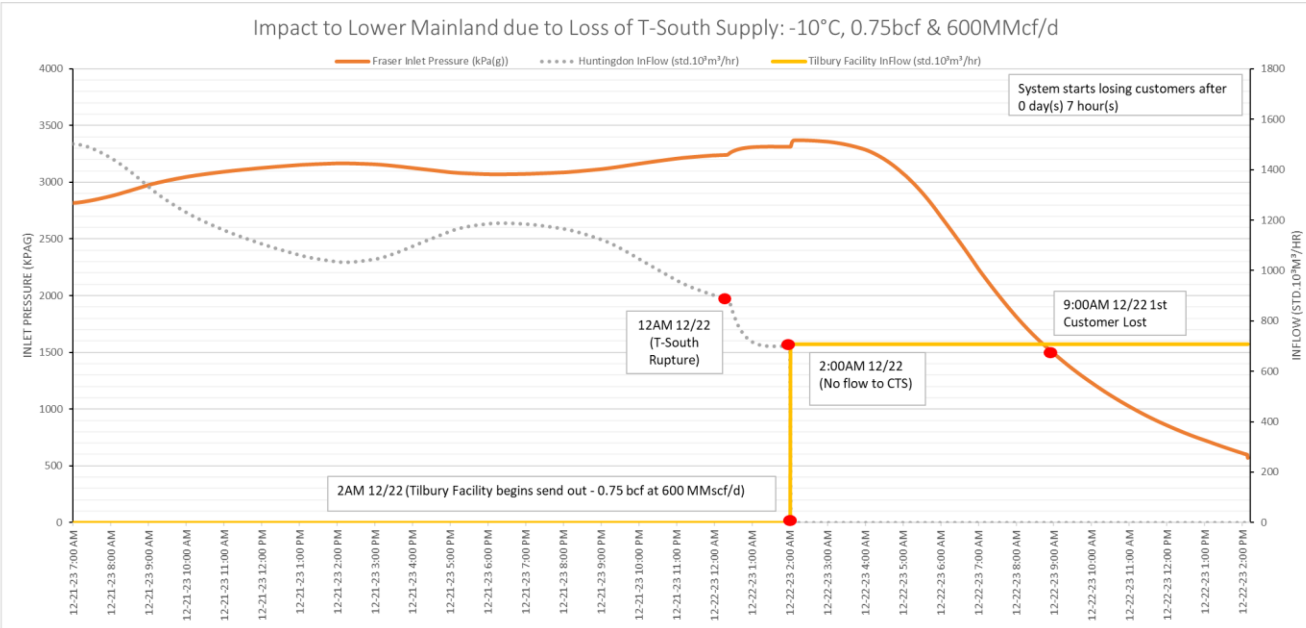


Figure C-26: Impact to Lower Mainland due to Loss of T-South Supply at -10°C with Supp. Alt. 3 – Contingent 0.75bcf & 600MMcf/d



5.1.3.2.2 GAS SUPPLY (NO IMPACT)

The same assessment from Supplemental Alternative 2 applies to Supplemental Alternative 3. Supplemental Alternative 3 would not retain FEI's existing on-system peaking capabilities and, therefore, did not pass the Step 2 screen.

5.1.3.2.3 BASE PLANT CHALLENGES (MEDIUM POSITIVE IMPACT)

The same assessment from Supplemental Alternative 2 applies to Supplemental Alternative 3.

5.1.3.2.1 LEVELIZED TOTAL RATE IMPACT (LOW NEGATIVE IMPACT)

The levelized total rate impact for Supplemental Alternative 3 is estimated to be 3.4 percent over a 67-year analysis period.

This reflects the estimated capital cost of $435.0 million to install the 600 MMcf/d of new regasification, the operating costs over the expected life of the new assets, and the costs for gas supply from regional market, if available, to meet FEI's full peaking gas requirement of 1.0 Bcf and 200 MMcf/d once there is no longer sufficient LNG available for peaking gas supply. For years when it is not possible to replace the peaking gas supply level currently provided by the Base Plant, FEI would have to curtail firm customers under normal operations. Please refer to Section 3.3 of this Appendix for details on the gas supply cost assumptions and the costs/savings used in the financial analysis for Supplemental Alternative 3.

5.1.3.2.2 FUTURE USE (MEDIUM NEGATIVE IMPACT)

The same assessment from Supplemental Alternative 2 applies to Supplemental Alternative 3. The new regasification equipment would have a stranded asset risk as it would not be useful without the Base Plant tank or available LNG from Tilbury 1A.

5.2 ALTERNATIVES WITH NEW FACILITY THAT MAINTAINS GAS SUPPLY BUT NO RESILIENCY RESERVE

This section discusses Supplemental Alternatives 4 and 4A, which would involve a replacement facility intended to mitigate the age-related challenges associated with the Base Plant and either avoid further deterioration of Tilbury's existing gas supply function (Supplemental Alternative 4) or optimize FEI's gas supply portfolio to provide sufficient peaking supply to meet FEI's entire requirements (Supplemental Alternative 4A). These Supplemental Alternatives would not add a resiliency reserve and, as such, customers would remain exposed to the current high risk of a widespread and prolonged outage in winter. Both Supplemental Alternatives 4 and 4A are viable alternatives, but would be inferior to Supplemental Alternative 9 from an overall customer value standpoint.

5.2.1 Supplemental Alternative 4

Supplemental Alternative 4 includes the following:

- Replacing the Base Plant with a new 0.6 Bcf tank and 150 MMcf/d of regasification capacity (the original 1971 design capacity of the Base Plant);
- There continuing to be no resiliency reserve; that is, from a planning perspective, all LNG in the new tank would be allocated to gas supply and all of Tilbury 1A would be allocated to RS 46 LNG sales, such that those volumes may or may not be present in a no-flow event;
- Using the new facility as a gas supply peaking resource, akin to how the Base Plant has always been used; and
- Continuing to rely on 50 MMcf/d of year-round pipeline capacity to achieve required peaking supply (1 Bcf and 200 MMcf/d).

5.2.1.1 Modelling Parameters

Table C-13 below sets out the resiliency and gas supply modelling parameters for the Supplemental Alternative 4 scenarios.

The planning scenario uses the maximum regasification (150 MMcf/d), paired with the volume of dependable LNG for resiliency (0 Bcf - no resiliency reserve) and, for peaking gas supply, the amount included in the Annual Contracting Plan (0.6 Bcf).

FEI also modelled a contingent (i.e., non-dependable) scenario based on optimistic assumptions about how much LNG is present at Tilbury on the day of a no-flow event. These scenarios are described in Section 4 of this Appendix.

Table C-13: Supplemental Alternative 4 Planning and Contingent Modelling Scenario

Supp. Alt. 4 Modelling Scenario	Description	Resiliency Modelling Parameters	Peaking Gas Supply Allocation (Normal Operations)[1]
Supplemental Alternative 4 (Planning)	Like-for-Like (No Resiliency Reserve)[2]	0 Bcf at 150 MMcf/d	0.6 Bcf at 150 MMcf/d
Supplemental Alternative 4 (Contingent)	Like-for-Like (Assume New Tank Full on Day of No-Flow)	0.6 Bcf at 150 MMcf/d	0.6 Bcf at 150 MMcf/d

<u>*Notes to Table:*</u>

[1] *FEI allocates 0.6 Bcf from Tilbury for gas supply portfolio purposes. Actual volumes will decline with use during winter, including if LNG volumes were used for resiliency to respond to a no-flow event.*

[2] *When there is no resiliency reserve, on a planning basis there is no dependable LNG available on occurrence of no-flow event. Hence the resiliency modelling parameter is 0 Bcf.*

5.2.1.2 Summary of Information and Analysis

FEI investigated Supplemental Alternative 4 with respect to the criteria discussed in Section 4.2 of the Supplemental Evidence. Supplemental Alternative 4 would be technically and commercially viable, while retaining FEI's existing on-system firm peaking supply; therefore, it was evaluated under Step 3 in the structured process to select a preferred alternative. Alternative 4 would be inferior to Supplemental Alternative 9 from an overall customer value standpoint.

The following bullets provide a high-level description of how this alternative performs against the criteria, followed by sections providing additional details.

- **Resiliency (No Impact):** Supplemental Alternative 4 would provide no additional risk mitigation against a winter T-South no-flow event relative to Supplemental Alternative 1. In particular, the limited regasification capacity of only 150 MMcf/d and the absence of a dedicated resiliency reserve mean that Supplemental Alternative 4 would provide the same inadequate level of resiliency as the existing Base Plant. A winter T-South no-flow event would have the same consequences as the Supplemental Alternative 1 (Planning) scenario.
- **Gas Supply (Medium Positive Impact):** As a new facility with a dedicated gas supply reserve of 0.6 Bcf, Supplemental Alternative 4 would improve the availability of dependable gas supply during peak demand when compared to Supplemental Alternative 1. However, FEI would need to continue acquiring an additional 50 MMcf/d and 0.4 Bcf of peaking resources from the market annually, which would be sub-optimal.
- **Base Plant Challenges (High Positive Impact):** The new facility would address the age-related issues with the existing Base Plant.
- **Levelized Total Rate Impact (Low Negative Impact):** Supplemental Alternative 4 would have a levelized total rate impact of 3.2 percent over a 67-year analysis period.

- **Future Use (No Impact):** Supplemental Alternative 4 would remain useful and not underutilized for the period between the in-service date and 2050.

FEI discusses each of the five analysis criteria in further detail below.

5.2.1.2.1 RESILIENCY (NO IMPACT)

Supplemental Alternative 4 would not include a resiliency reserve and, even assuming some LNG inventory is present at Tilbury on the day of a no-flow event, would provide no additional risk mitigation against a winter T-South no-flow event relative to Supplemental Alternative 1. FEI addresses the resiliency benefit of the Supplemental Alternative 4 scenarios below.

- Like Supplemental Alternative 1, the Supplemental Alternative 4 (Planning) scenario would not address the regasification constraint of only 150 MMcf/d at Tilbury. This is only a fraction of the daily load in the Lower Mainland on winter days. Further, without a resiliency reserve, all LNG would continue to be allocated for planning purposes to either gas supply or RS 46 LNG sales, such that it may or may not be present on the day of a winter T-South no-flow event.
- The Supplemental Alternative 4 (Contingent) scenario, which assumes that 0.6 Bcf of LNG is available on the day of a no-flow event, would similarly be unable to mitigate additional risk because, like the planning scenario, the like-for-like replacement of the existing Base Plant would not address the regasification constraint of only 150 MMcf/d.

Under both the planning and contingent scenarios, the system would still fail on the day of a winter T-South no-flow event, resulting in similar consequences as the Supplemental Alternative 1 (Planning) scenario. These results are confirmed in Exponent’s figure (reproduced in the Section 2.5.1 above) summarizing the annual expected loss reduction associated with each Supplemental Alternative relative to the Supplemental Alternative 1 (Planning) scenario.

The following table summarizes how long the Supplemental Alternative 4 scenarios would be able to support the Lower Mainland load following a winter T-South no-flow event. FEI has consistently modelled three temperatures that are reflective of local conditions, since FEI’s load increases as temperatures decrease.

Table C-14: Supplemental Alternative 4 Load Support Durations Under Different Winter Conditions

Supp. Alt. 4 Modelling Scenario	Approximate Time Until Customers in the Lower Mainland Begin Losing Service[46]		
	-10°C (very cold winter day)[47]	-1.4°C (warmest winter in 10 years, as defined in footnote)[48]	+4.0°C (average Lower Mainland winter)[49]
Planning (0 Bcf, 150 MMcf/d)	0 days and 0 hours	0 days and 0 hours	0 days and 0 hours
Contingent (0.6 Bcf, 150 MMcf/d)	0 days and 2 hours	0 days and 5 hours	0 days and 7 hours

Consistent with the framework established in Section 3.4.1.2.2 of FEI's 2024 Resiliency Plan, under average winter conditions, the support duration provided by the Supplemental Alternative 4 scenarios would not be enough to execute a controlled shutdown. Therefore, FEI expects that a failure occurring on some parts of T-South would result in an uncontrolled shutdown in the Lower Mainland system, with attendant safety risks and service restoration challenges.

The transient modelling outputs for the Supplemental Alternative 4 (Contingent) scenario are identical to those of the Supplemental Alternative 1 (Contingent w/T1A) scenario, as provided in Section 2.5 above. This is due to Supplemental Alternative 4 having the same regasification capacity as Supplemental Alternative 1, as well as the regasification constraint not being fully addressed by either Supplemental Alternative.

5.2.1.2.2 GAS SUPPLY (MEDIUM POSITIVE IMPACT)

Supplemental Alternative 4 would improve the availability of dependable gas supply during peak demand relative to Supplemental Alternative 1 and, therefore, passed the Step 2 screen.

Supplemental Alternative 4 would involve constructing a new LNG storage tank and regasification that is dedicated to gas supply, thus retaining FEI's existing firm peaking gas supply capabilities

[46] This represents the approximate duration of full firm load support for customers in the Lower Mainland. Except for the 0 Bcf case which does not account for linepack, the analysis considers support from on-system LNG and linepack from the CTS. Linepack was not considered in the 0 Bcf case such that an understanding of the absolute baseline risk could be had. The analysis also assumes that all interruptible customers are offline within 4 hours of the no-flow event, except for the -10°C analysis, wherein interruptible customers would already be offline due to the cold temperature condition.

[47] Due to the low probability of having multiple -10°C days in a row in the Lower Mainland, the -10°C temperature condition analysis assumes the following: the first day is -10°C, the second and third days are -7°C, the fourth day is -3°C, and all subsequent days are +4°C.

[48] The warmest winter in the last 10 years was found by determining the minimum daily average temperature for each year over a 10-year period from 2013-2022, then selecting the highest value. The analysis was based on data from YVR.

[49] Defined as the average of the daily average temperatures for December, January, and February over a 10-year period from 2013-2022. The average winter day is based on data from YVR.

that have long been included in the Annual Contracting Plan (0.6 Bcf gas supply reserve and 150 MMcf/d of send-out) while also resolving the gas supply concerns associated with the existing Base Plant, which are driven by the age-related dependability challenges discussed in Section 3.3 of the Supplemental Evidence. This alternative would also address the challenges associated with the stop-gap measure of relying on 0.25 Bcf from Tilbury 1A (i.e., LNG that is intended for RS 46 sales) to compensate for the Base Plant tank being operated at 0.35 Bcf for seismic reasons. This represents an improvement from Supplemental Alternative 1.

However, while Supplemental Alternative 4 would avoid the need to replace the existing on-system peaking gas supply provided by Tilbury with capacity on regional infrastructure at considerable cost, it would not provide FEI's full peaking supply requirements (200 MMcf/d and 1 Bcf). As such, FEI would need to continue acquiring an additional 50 MMcf/d and 0.4 Bcf of peaking resources from the market annually – which would be sub-optimal and increase FEI's gas supply costs.

Further, if the Supplemental Alternative 4 (Contingent) scenario were to be realized (i.e., a failure event occurred, and FEI utilized the hypothetically available LNG volume from the new tank for resiliency), FEI would be forced to try to make up the lost peaking gas supply from the market for the remainder of the winter. To the extent that this was possible, it would increase FEI's gas supply costs for the remainder of the year.

5.2.1.2.3 BASE PLANT CHALLENGES (HIGH POSITIVE IMPACT)

Like other alternatives that would involve a new tank and regasification, Supplemental Alternative 4 would address the age-related challenges associated with continuing to rely on the Base Plant and, in particular, would restore the reliability of Tilbury's critical gas supply function.

5.2.1.2.4 LEVELIZED TOTAL RATE IMPACT (LOW NEGATIVE IMPACT)

The levelized total rate impact for Supplemental Alternative 4 is estimated to be 3.2 percent over a 67-year analysis period.

This reflects the estimated capital cost of $826.9 million to install a new 0.6 Bcf tank and 150 MMcf/d of new regasification as well as the operating costs over the expected life of the new assets. Supplemental Alternative 4 will avoid the costs of securing 0.6 Bcf and 150 MMcf/d for peaking gas supply from the regional market, resulting in estimated savings of $46 million starting in 2035, but FEI would continue to incur gas supply costs for the year-round 50 MMcf/d to make up FEI's full peaking gas requirement of 1.0 Bcf and 200 MMcf/d. Please refer to Section 3.3 of this Appendix for discussion on the gas supply cost assumptions and the costs/savings used in the financial analysis for Supplemental Alternative 4.

FEI notes the following regarding the results of the financial analysis:

- Supplemental Alternative 4 would have a lower levelized total rate impact than Supplemental Alternative 9, but would provide no additional protection against a winter T-South no-flow event relative to Supplemental Alternative 1; and

- There are significant economies of scale with LNG facility construction, as Supplemental Alternative 9 (which is five times larger) costs only 28 percent more than Supplemental Alternative 4.

5.2.1.2.5 FUTURE USE (NO IMPACT)

Supplemental Alternative 4 would be useful and not underutilized between the in-service date and 2050.

In Section 4.5.5 of the Supplemental Evidence, FEI describes how an on-system LNG facility is a unique asset when it comes to the flexibility afforded in response to changing load. Supplemental Alternative 4, as an LNG facility, would remain used and useful between the in-service date and 2050. Even under the mDEP (2% and 5%) hypothetical adverse load sensitivities, the 2050 load would still be too large for the facility to be underutilized for peaking gas supply.

The question of whether or not the facility contemplated under a Supplemental Alternative would be used and useful must be distinguished from whether or not it would deliver on the Project objectives. Supplemental Alternative 4 will never be able to avoid the consequences of a winter T-South no-flow event at any time between the in-service date and 2050. The current daily load vastly exceeds the regasification capacity of Supplemental Alternative 4, as do the 2050 mDEP (2% and 5%) daily loads. For example, under the most pessimistic future load sensitivity considered by FEI (mDEP (5%)), in 2050 the Lower Mainland load at +4°C is estimated to be approximately 321 MMcf/d, which is more than double the Supplemental Alternative 4 send-out capacity of 150 MMcf/d.

Similarly, FEI's peaking supply requirements currently exceed what Supplemental Alternative 4 could provide, such that FEI is already augmenting its supply with year-round pipeline capacity. This would remain the case for some time under the mDEP (2% and 5%) hypothetical adverse load loss sensitivities discussed in Section 4.5.5 of the Supplemental Evidence.

5.2.2 Supplemental Alternative 4A

Supplemental Alternative 4A would involve replacing the existing Tilbury Base Plant with a new facility for gas supply. The sizing of the new facility reflects the smallest possible facility that would meet FEI's peaking supply requirements and thus optimize FEI's gas supply portfolio. Due to significant increases in load, FEI's on-system peak gas supply needs have increased since the construction of the Base Plant in 1971. As a result, a facility that is larger than the Base Plant is necessary to meet those peaking supply requirements and optimize FEI's gas supply portfolio.

Supplementary Alternative 4A includes the following:

- Replacing the Base Plant with a new 1 Bcf tank and 400 MMcf/d (2 x 200 MMcf/d vapourizers) of regasification capacity;
- There continuing to be no resiliency reserve; that is, from a planning perspective, all LNG in the new tank would be allocated to gas supply and all of Tilbury 1A would be allocated

to RS 46 LNG sales, such that those volumes may or may not be present upon a no-flow event; and

- Allocating all of the 1 Bcf tank volume to gas supply, therefore providing sufficient peaking supply to meet FEI's full requirements of 1.0 Bcf and 200 MMcf/d and avoiding the need to continue augmenting the peaking supply with regional market resources.

5.2.2.1 Modelling Parameters

Table C-15 below sets out the resiliency and gas supply modelling parameters for the Supplemental Alternative 4A scenarios.

The planning scenario uses the maximum regasification (400 MMcf/d), paired with the volume of dependable LNG for resiliency (0 Bcf - no resiliency reserve) and 1 Bcf of peaking gas supply.

FEI also modelled a contingent (i.e., non-dependable) scenario based on optimistic assumptions about how much LNG is present at Tilbury on the day of a no-flow event. These scenarios are described in Section 4 of this Appendix.

Table C-15: Supplemental Alternative 4A Planning and Contingent Modelling Scenario

Supp. Alt. 4A Modelling Scenario	Description	Resiliency Modelling Parameters	Peaking Gas Supply Allocation (Normal Operations)[1]
Supplemental Alternative 4A (Planning)	New 1 Bcf Tank and 400 MMcf/d Regasification[2]	0 Bcf at 400 MMcf/d	1 Bcf at 400 MMcf/d
Supplemental Alternative 4A (Contingent)	New 1 Bcf Tank and 400 MMcf/d Regasification (Assume New Tank Full on Day of No-Flow)	1 Bcf at 400 MMcf/d	1 Bcf at 400 MMcf/d

<u>*Notes to Table:*</u>

[1] *In Supplemental Alternative 4A FEI allocates 1 Bcf from Tilbury for gas supply portfolio purposes. Actual volumes will decline with use during winter, including if LNG volumes were used for resiliency to respond to a no-flow event.*

[2] *When there is no resiliency reserve, on a planning basis there is no dependable LNG available on occurrence of no-flow event. Hence the resiliency modelling parameter is 0 Bcf.*

5.2.2.2 Summary of Information and Analysis

FEI investigated Supplemental Alternative 4A with respect to the criteria discussed in Section 4.2 of the Supplemental Evidence. Supplemental Alternative 4A would be technically and commercially viable, while retaining FEI's existing on-system firm peaking supply and, therefore, was evaluated under Step 3 in the structured process to select a preferred alternative. Supplemental Alternative 4A would be superior to some options but inferior to Supplemental Alternative 9 from an overall customer value standpoint.

The following bullets provide a high-level description of how this alternative performs against the criteria, followed by sections providing additional details.

- **Resiliency (No Impact):** Supplemental Alternative 4A would not include a resiliency reserve and, even assuming some LNG inventory is present at Tilbury on the day of a no-flow event, would provide no material incremental risk mitigation against a winter T-South no-flow event relative to Supplemental Alternative 1 because the send-out capacity of 400 MMcf/d remains undersized for the system demand.
- **Gas Supply (High Positive Impact):** As a new facility with a dedicated gas supply reserve of 1 Bcf, Supplemental Alternative 4A would improve the availability of dependable gas supply during peak demand when compared to Supplemental Alternative 1. It would also provide the same gas supply benefits as Supplemental Alternative 9 by virtue of meeting FEI's entire peaking supply requirements. This would provide considerable flexibility for gas supply planning and winter operation, and potentially would allow FEI to displace other sub-optimal gas portfolio assets.
- **Base Plant Challenges (High Positive Impact):** The new facility would address the age-related issues with the existing Base Plant.
- **Levelized Total Rate Impact (Low Negative Impact):** Supplemental Alternative 4A would have a levelized total rate impact of 3.0 percent over a 67-year analysis period, which is lower than Supplemental Alternative 4 due to the additional gas supply benefits.
- **Future Use (No Impact):** Supplemental Alternative 4A would remain useful and not underutilized for the period between the in-service date and 2050.

FEI discusses each of the five analysis criteria in further detail below.

5.2.2.2.1 RESILIENCY (NO IMPACT)

Supplemental Alternative 4A would not include a resiliency reserve and, even assuming some LNG inventory is present at Tilbury on the day of a no-flow event, would provide no material incremental risk mitigation against a winter T-South no-flow event relative to Supplemental Alternative 1. FEI addresses the resiliency benefit of the Supplemental Alternative 4A scenarios below.

- The Supplemental Alternative 4A (Planning) scenario would provide no additional protection against a winter T-South no-flow event relative to the Supplemental Alternative 1 (Planning) scenario. This is because Supplemental Alternative 4A (Planning) would not have a dedicated resiliency reserve, and therefore, could not support the entire Lower Mainland for any duration on the day of a winter T-South no-flow event, resulting in the same consequences as the Supplemental Alternative 1 (Planning) scenario.
- The Supplemental Alternative 4A (Contingent) scenario, which assumes that 1 Bcf of LNG is available on the day of a winter T-South no-flow event, would provide improved risk mitigation relative to both the Supplemental Alternative 1 (Contingent) and Supplemental Alternative 1 (Contingent w/ T1A) scenarios; however, the improvement would not be

material. This is because, like Supplemental Alternative 2, Supplemental Alternative 4A would improve the regasification capacity relative to the capacity of the existing Base Plant (150 MMcf/d), but would not fully address the existing regasification constraint at Tilbury.

- At average Lower Mainland winter conditions (+4°C), the send-out capacity of 400 MMcf/d would remain undersized for the system demand. As a result, the Supplemental Alternative 4A (Contingent) scenario would provide the same level of risk mitigation as the Supplemental Alternative 2 (Contingent w/T1A) scenario. Although the Supplemental Alternative 4A (Contingent) scenario assumes more LNG would be available than the Supplemental Alternative 2 (Contingent w/ T1A) scenario (1.0 vs. 0.75 Bcf), the support duration and risk mitigation results are identical since the constraining factor, regasification capacity, remains unresolved for both Supplemental Alternatives. As such, the system would still fail on Day 1 (cold weather of -1.4°C) or Day 2 (at an average winter temperature of +4°C) of a winter no-flow event, resulting in similar consequences as the Supplemental Alternative 1 (Planning) scenario.

These results are confirmed in Exponent's figure (reproduced in the Section 2.5.1 above) summarizing the annual expected loss reduction associated with each Supplemental Alternative relative to the existing Base Plant with no capital upgrades (the Supplemental Alternative 1 (Planning) scenario).

The following table summarizes how long the Supplemental Alternative 4A scenarios would be able to support the Lower Mainland load following a winter T-South no-flow event. FEI has consistently modelled three temperatures that are reflective of local conditions, since FEI's load increases as temperatures decrease.

Table C-16: Supplemental Alternative 4A Load Support Durations Under Different Winter Conditions

Supp. Alt. 4A Modelling Scenario	Approximate Time Until Customers in the Lower Mainland Begin Losing Service[50]		
	-10°C (very cold winter day)[51]	-1.4°C (warmest winter in 10 years, as defined in footnote)[52]	+4.0°C (average Lower Mainland winter)[53]
Planning (0 Bcf, 400 MMcf/d)	0 days and 0 hours	0 days and 0 hours	0 days and 0 hours
Contingent (1 Bcf, 400 MMcf/d)	0 days and 5 hours	0 days and 12 hours	1 day and 19 hours

Consistent with the framework established in Section 3.4.1.2.2 of FEI's 2024 Resiliency Plan, under average winter conditions, the support duration provided by the Supplemental Alternative 4A (Planning) scenario would not be enough to execute a controlled shutdown. Therefore, a failure occurring on some parts of T-South could be expected to result in an uncontrolled shutdown in the Lower Mainland system, with attendant safety risks and service restoration challenges. Under average winter conditions, the support duration provided by the Supplemental Alternative 4A (Contingent) scenario may or may not be enough to execute a controlled shutdown. Therefore, a T-South failure in some segments could result in a controlled or uncontrolled shutdown in the Lower Mainland system.

The transient modelling outputs for Supplemental Alternative 4A (Contingent) are identical to those of Supplemental Alternative 2 (Contingent w/T1A). This is due to Supplemental Alternative 4A having the same regasification capacity as Supplemental Alternative 2 (Contingent w/ T1A), as well as the regasification constraint not being fully addressed by either Supplemental Alternative. As a result, while the Supplemental Alternative 4A (Contingent) scenario assumes a greater volume of LNG being available than the Supplemental Alternative 2 (Contingent w/ T1A) scenario, it does not result in a longer support duration or additional risk mitigation.

[50] This represents the approximate duration of full firm load support for customers in the Lower Mainland. Except for the 0 Bcf case which does not account for linepack, the analysis considers support from on-system LNG and linepack from the CTS. Linepack was not considered in the 0 Bcf case such that an understanding of the absolute baseline risk could be had. The analysis also assumes that all interruptible customers are offline within 4 hours of the no-flow event, except for the -10°C analysis, wherein interruptible customers would already be offline due to the cold temperature condition.

[51] Due to the low probability of having multiple -10°C days in a row in the Lower Mainland, the -10°C temperature condition analysis assumes the following: the first day is -10°C, the second and third days are -7°C, the fourth day is -3°C, and all subsequent days are +4°C.

[52] The warmest winter in the last 10 years was found by determining the minimum daily average temperature for each year over a 10-year period from 2013-2022, then selecting the highest value. The analysis was based on data from YVR.

[53] Defined as the average of the daily average temperatures for December, January, and February over a 10-year period from 2013-2022. The average winter day is based on data from YVR.

5.2.2.2.2 GAS SUPPLY (HIGH POSITIVE IMPACT)

Supplemental Alternative 4A would improve the availability of dependable gas supply during peak demand relative to Supplemental Alternative 1 and, therefore, passed the Step 2 screen.

Supplemental Alternative 4A would involve constructing a new LNG storage tank and regasification that is dedicated to gas supply (1 Bcf paired with 200 MMcf/d[54] of send out), thus optimizing FEI's gas supply function while resolving the gas supply concerns associated with the existing Base Plant, which are driven by the age-related dependability challenges discussed in Section 3.3 of the Supplemental Evidence. The additional 0.4 Bcf that is dedicated to gas supply, paired with the additional 50 MMcf/d of send-out, would provide FEI considerable flexibility for gas supply planning and winter operation, and potentially displace other higher cost gas portfolio assets. Similar to Supplemental Alternative 4, this alternative would also address the challenges associated with the stop-gap measure of relying on 0.25 Bcf from Tilbury 1A (i.e., LNG that is intended for RS 46 sales) to compensate for the Base Plant tank being operated at 0.35 Bcf for seismic reasons.

Further, by expanding both the available volume of LNG for gas supply and the regasification capacity beyond what FEI currently relies on for on-system peaking supply in the Annual Contracting Plan (i.e., 0.6 Bcf and 150 MMcf/d), Supplemental Alternative 4A would also provide incremental gas supply benefits, including allowing FEI to optimize its ACP by potentially displacing other gas portfolio assets.

FEI notes that if the Supplemental Alternative 4A (Contingent) scenario were to be realized (i.e., a failure event occurred and FEI utilized the hypothetically available LNG volume from the new tank for resiliency), FEI would be forced to try to make up the lost peaking gas supply from the market for the remainder of the winter. To the extent that this was possible, it would increase FEI's gas supply costs for the remainder of the year.

5.2.2.2.3 BASE PLANT CHALLENGES (HIGH POSITIVE IMPACT)

Like other alternatives that involve a new tank and regasification, Supplemental Alternative 4A would address the age-related challenges associated with continuing to rely on the Base Plant and, in particular, would restore the reliability of Tilbury's critical gas supply function.

5.2.2.2.4 LEVELIZED TOTAL RATE IMPACT (LOW NEGATIVE IMPACT)

The levelized total rate impact for Supplemental Alternative 4A is estimated to be 3.0 percent over a 67-year analysis period.

This reflects the estimated capital cost of $893.2 million to install a new 1.0 Bcf tank and 400 MMcf/d of new regasification as well as the operating costs over the expected life of the new assets. Given Supplemental Alternative 4A would be able to meet FEI's full peaking gas requirement of 1.0 Bcf and 200 MMcf/d under the optimized portfolio, it would avoid the costs of securing the same amount of peaking gas from the regional market. The benefits begin

[54] Supplemental Alternative 4A includes 400 MMcf/d of send out capacity, however for gas supply planning purposes only 200 MMcf/d is required.

immediately following the in-service date, as FEI would initially avoid the need to continue holding 50 MMcf/d of year-round pipeline capacity. The estimated avoided costs reach $63 million starting in 2035. Please refer to Section 3.3 of this Appendix for discussion on the gas supply cost assumptions and the costs/savings used in the financial analysis for Supplemental Alternative 4A.

FEI notes the following regarding the financial analysis:

- Supplemental Alternative 4A would have a lower levelized total rate impact than the smaller like-for-like facility (Supplemental Alternative 4) by virtue of the economies of scale in LNG facility construction and the additional gas supply benefits;
- Supplemental Alternative 4A would have a lower capital cost and levelized total rate impact than Supplemental Alternative 9 but would provide no additional protection against a winter T-South no-flow event relative to Supplemental Alternative 1; and
- There are significant economies of scale with LNG facility construction, as Supplemental Alternative 9 (which is three times larger) will cost only 22 percent more than Supplemental Alternative 4.

5.2.2.2.5 FUTURE USE (NO IMPACT)

Supplemental Alternative 4A would be useful and not underutilized between the in-service date and 2050.

In Section 4.5.5 of the Supplemental Evidence, FEI describes how an on-system LNG facility is a unique asset when it comes to the flexibility afforded in response to changing load. Supplemental Alternative 4A, as an LNG facility, would remain used and useful between the in-service date and 2050. Even under the mDEP (2% and 5%) hypothetical adverse load sensitivities, the 2050 load would still be too large for the facility to be underutilized for peaking gas supply.

The question of whether or not the facility contemplated under a Supplemental Alternative would be used and useful must be distinguished from whether or not it would deliver on the Project objectives. Without a dedicated resiliency reserve, Supplemental Alternative 4A would not be able to avoid the consequences of a winter T-South no-flow event at any time between the in-service date and 2050.

5.3 ALTERNATIVES WITH NEW FACILITY THAT PROVIDES RESILIENCY RESERVE BUT NO GAS SUPPLY

Supplementary Alternatives 5, 6 and 7 would involve replacing the Base Plant with new 0.6, 1.0 or 2 Bcf facilities, where the entire volume would be set aside as a dependable resiliency reserve – necessitating that FEI try to secure replacement gas supply in the market. FEI's ability to withstand a winter T-South no-flow event would increase as the regasification capacity and resiliency reserve increase in tandem, and a 2 Bcf resiliency reserve would provide appropriate risk reduction. However, as set out in Table C-5 above, the capital cost of building a smaller facility approaches the cost of Supplemental Alternative 9 due to significant economies of scale in tank construction. For example, a 1 Bcf facility with 800 MMcf/d regasification would only cost 18 percent less to construct than a 3 Bcf facility with the equivalent regasification. FEI customers would also be subject to curtailments in normal operations and significant annual gas costs to meet FEI's peaking supply requirements with capacity on regional infrastructure. As a result, these options would have lower overall customer value relative to Supplemental Alternative 9.

5.3.1 Supplemental Alternative 5

Supplemental Alternative 5 is the same as Supplemental Alternative 4 in terms of the physical facilities constructed, but would differ in terms of how the capabilities are allocated for planning purposes.

Supplemental Alternative 5 would involve:

- Replacing the Base Plant with a new 0.6 Bcf tank and 150 MMcf/d of regasification capacity (the original 1971 design capacity of the Base Plant);
- Allocating all of the 0.6 Bcf tank volume to a resiliency reserve and no allocation for peaking gas supply;
- FEI would, therefore, have to rely entirely on the regional market to meet its full peaking gas supply requirements. However, given that regional infrastructure is already fully contracted, FEI would be unable to replace the entire peaking gas supply requirement immediately. As such, FEI would still hold the existing 50 MMcf/d of market pipeline capacity but would likely have to curtail firm loads in normal operations by up to 150 MMcf/d until future regional infrastructure upgrades occurred; and
- If and when regional infrastructure upgrades occur (consistently assumed to be 2035 for the financial analysis), it would offer the potential for FEI to end curtailments by holding gas supply contracts for 1.0 Bcf and 200 MMcf/d. FEI would pay a higher toll / charge that includes the costs of the upgrades.

5.3.1.1 Modelling Parameters

Table C-17 sets out the resiliency and gas supply modelling parameters for the Supplemental Alternative 5 scenarios.

The planning scenario uses the maximum regasification (150 MMcf/d), paired with 0.6 Bcf of dependable LNG for resiliency (a full resiliency reserve) and 0 Bcf of peaking gas supply – meaning FEI would need to attempt to replace lost peaking gas supply with capacity on regional pipeline or storage infrastructure at additional cost.

FEI also modelled a contingent (i.e., non-dependable) scenario based on optimistic assumptions about how much LNG is present at Tilbury on the day of a no-flow event. These scenarios are described in Section 4 of this Appendix.

Table C-17: Supplemental Alternative 5 Planning and Contingent Modelling Scenarios

Supp. Alt. 5 Modelling Scenario	Description	Resiliency Modelling Parameters	Peaking Gas Supply Allocation (Normal Operations)[1]
Supplemental Alternative 5 (Planning)	Like-for-Like (Full Resiliency Reserve)[2]	0.6 Bcf at 150 MMcf/d	0 Bcf at 150 MMcf/d
Supplemental Alternative 5 (Contingent w/ T1A)	Like-for-Like (Full Resiliency Reserve and T1A Available on Day of No-Flow)	1 Bcf at 150 MMcf/d	0 Bcf at 150 MMcf/d

Notes to Table:

[1] *On a planning basis, since the tank is fully allocated to a resiliency reserve, FEI would not be able to meet the requirements of the ACP. In order to have dependable peaking supply, FEI would have to obtain those resources in the form of pipeline capacity or regional storage capacity.*

[2] *When there is a resiliency reserve, on a planning basis there is dependable LNG available on occurrence of no-flow event. Hence the resiliency modelling parameter is 0.6 Bcf.*

5.3.1.2 Summary of Information and Analysis

FEI investigated Supplemental Alternative 5 with respect to the criteria discussed in Section 4.2 of the Supplemental Evidence. Supplemental Alternative 5 did not pass the Step 2 screen because, without a dedicated gas supply reserve, it would fail to retain FEI's existing on-system peaking gas supply capabilities.[55]

The following bullets provide a high-level description of how this alternative performs against the criteria, followed by sections providing additional details.

- **Resiliency (No Impact):** Although Supplemental Alternative 5 would allocate all of the 0.6 Bcf tank to a resiliency reserve, it would still not provide material risk mitigation against a winter T-South no-flow event because it would not address the regasification constraint at Tilbury.
- **Gas Supply (No Impact):** Since Supplemental Alternative 5 would allocate the entire 0.6 Bcf tank to a resiliency reserve, FEI would have to attempt to replace FEI's existing peaking gas supply from Tilbury in the market. Similar to Supplemental Alternative 1, there would likely be at least several years where there are significant curtailments in normal operations before FEI would be able to acquire enough replacement peaking supply on upgraded regional infrastructure.
- **Base Plant Challenges (High Positive Impact):** The new facility would address the age-related challenges associated with the existing Base Plant.

[55] 0.6 Bcf and 150 MMcf/d of regasification capacity.

- **Levelized Total Rate Impact (Medium Negative Impact):** Supplemental Alternative 5 would have a levelized total rate impact of 4.4 percent over a 67-year analysis period.
- **Future Use (No Impact):** Supplemental Alternative 5 would remain useful and not underutilized for the period between the in-service date and 2050.

FEI discusses each of the five analysis criteria in further detail below.

5.3.1.2.1 RESILIENCY (NO IMPACT)

While Supplemental Alternative 5 would add a resiliency reserve, it would still not provide material risk mitigation against a winter T-South no-flow event relative to Supplemental Alternative 1 because it would not address the regasification constraint at Tilbury. FEI addresses the resiliency benefit of the Supplemental Alternative 5 scenarios below.

- The Supplemental Alternative 5 (Planning) scenario would provide additional risk mitigation against a winter T-South no-flow event on T-South when compared to the Supplemental Alternative 1 (Planning) scenario. This is due to Supplemental Alternative 5 having a dedicated resiliency reserve whereas Supplemental Alternative 1 does not. However, the amount of additional mitigation is not material and could not support the entire Lower Mainland for any material duration. Supplemental Alternative 5 (Planning) scenario is equivalent to the Supplemental Alternative 1 (Contingent) and Supplemental Alternative 1 (Contingent w/T1A) scenarios. This is because the alternative would not address the regasification constraint at Tilbury (150 MMcf/d), which would not be sufficient to meet the Lower Mainland daily demand in winter.
- The Supplemental Alternative 5 (Contingent w/T1A) scenario, which assumes that an additional 0.4 Bcf from Tilbury 1A is available to use for resiliency, would also not resolve the regasification constraint and, therefore, would provide the same amount of outage risk mitigation as Supplemental Alternative 5 (Planning).

Under both planning and contingent scenarios, the system would still fail on the day of a winter T-South no-flow event, resulting in similar consequences as the Supplemental Alternative 1 (Planning) scenario. These results are confirmed in Exponent's figure (reproduced in the Section 2.5.1 above) summarizing the annual expected loss reduction associated with each Supplemental Alternative relative to the Supplemental Alternative 1 (Planning) scenario.

The following table summarizes how long Supplemental Alternative 5 would be able to support the Lower Mainland load following a winter T-South no-flow event. FEI has consistently modelled three temperatures that are reflective of local conditions, since FEI's load increases as temperatures decrease.

Table C-18: Supplemental Alternative 5 Load Support Durations Under Different Winter Conditions

Supp. Alt. 5 Modelling Scenario	Approximate Time Until Customers in the Lower Mainland Begin Losing Service[56]		
	-10°C (very cold winter day)[57]	-1.4°C (warmest winter in 10 years, as defined in footnote)[58]	+4.0°C (average Lower Mainland winter)[59]
Planning (0.6 Bcf, 150 MMcf/d)	0 days and 2 hours	0 days and 5 hours	0 days and 7 hours
Contingent (1 Bcf, 150 MMcf/d)	0 days and 2 hours	0 days and 5 hours	0 days and 7 hours

Consistent with the framework established in Section 3.4.1.2.2 of FEI's 2024 Resiliency Plan, under average winter conditions, the support duration provided by Supplemental Alternative 5 would not be enough to execute a controlled shutdown. Therefore, a failure occurring on some portions of T-South could be expected to result in an uncontrolled shutdown in the Lower Mainland system, with attendant safety risks and service restoration challenges.

The transient modelling outputs for Supplemental Alternative 5 are identical to those of the Supplemental Alternative 1 (Contingent w/T1A) scenario, as provided in Section 5.1.1 above.

5.3.1.2.2 GAS SUPPLY (NO IMPACT)

Supplemental Alternative 5 would not retain FEI's existing on-system peaking capabilities and, therefore, did not pass the Step 2 screen.

Supplemental Alternative 5 allocates the entire tank to a resiliency reserve (like Supplemental Alternatives 6 and 7) and, as a result, FEI would have to attempt to replace the existing peaking gas supply at considerable cost by acquiring the equivalent resources on regional pipelines or storage. However, as discussed in Section 3.3.4 of the Supplemental Evidence, FEI could not replace the Tilbury peaking supply resources currently included in the Annual Contracting Plan (150 MMcf/d and 0.6 Bcf) in the market.

56 This represents the approximate duration of full firm load support for customers in the Lower Mainland. The analysis considers support from on-system LNG and linepack from the CTS. The analysis also assumes that all interruptible customers are offline within 4 hours of the no-flow event, except for the -10°C analysis, wherein interruptible customers would already be offline due to the cold temperature condition.

57 Due to the low probability of having multiple -10°C days in a row in the Lower Mainland, the -10°C temperature condition analysis assumes the following: the first day is -10°C, the second and third days are -7°C, the fourth day is -3°C, and all subsequent days are +4°C.

58 The warmest winter in the last 10 years was found by determining the minimum daily average temperature for each year over a 10-year period from 2013-2022, then selecting the highest value. The analysis was based on data from YVR.

59 Defined as the average of the daily average temperatures for December, January, and February over a 10-year period from 2013-2022. The average winter day is based on data from YVR.

5.3.1.2.3 BASE PLANT CHALLENGES (HIGH POSITIVE IMPACT)

Like other alternatives that involve a new tank and regasification, Supplemental Alternative 5 would address the age-related challenges associated with continuing to rely on the aging Base Plant.

5.3.1.2.1 LEVELIZED TOTAL RATE IMPACT (MEDIUM NEGATIVE IMPACT)

The levelized total rate impact for Supplemental Alternative 5 is estimated to be 4.4 percent over a 67-year analysis period.

This reflects the estimated capital cost of $826.9 million to install a new 0.6 Bcf tank and 150 MMcf/d of new regasification as well as the operating costs over the expected life of the new assets. However, since this alternative would leave no allocation of the on-system LNG for peaking gas supply, FEI would have to secure its entire peaking gas requirement of 1.0 Bcf and 200 MMcf/d from the regional market. The annual peaking supply costs would initially consist of the cost of continuing to hold the 50 MMcf/d of year-round pipeline capacity, with significant curtailments in normal operations. The annual gas supply costs would reach an estimated $63 million starting in 2035 when regional infrastructure upgrades are assumed to be possible. Please refer to Section 3.3 of this Appendix for discussion on the gas supply cost assumptions and the costs/savings used in the financial analysis for Supplemental Alternative 5.

FEI notes the following regarding the financial analysis:

- Supplemental Alternative 5 has the same capital cost as Supplemental Alternative 4 ($826.9 million), as both of these alternatives would involve using the same asset (a new 0.6 Bcf tank and 150 MMcf/d of regasification). The only difference is in the way the facility is allocated for planning purposes (i.e., this alternative dedicates the entire volume to a resiliency reserve, while Supplemental Alternative 4 allocates the entire volume to gas supply); and
- Supplemental Alternative 5 is inferior to Supplemental Alternative 9 with a higher levelized total rate impact due to the increase in gas supply costs, which fully offset the lower capital cost for the smaller facility (given the significant economies of scale with LNG facility construction).

5.3.1.2.2 FUTURE USE (NO IMPACT)

Supplemental Alternative 5 would be useful and not underutilized between the in-service date and 2050.

In Section 4.5.5 of the Supplemental Evidence, FEI describes how an on-system LNG facility is a unique asset when it comes to the flexibility afforded in response to changing load. Supplemental Alternative 5, as an LNG facility, would remain used and useful between the in-service date and 2050. Even under the mDEP (2% and 5%) hypothetical adverse load sensitivities, the 2050 load would still be too large for the facility to be underutilized for peaking gas supply.

The question of whether or not the facility contemplated under a Supplemental Alternative would be used and useful must be distinguished from whether or not it would deliver on the Project objectives. Supplemental Alternative 5 would never be able to avoid the consequences of a winter T-South no-flow event at any time between the in-service date and 2050. The current daily load vastly exceeds the regasification capacity, as do the 2050 mDEP (2% and 5%) daily loads. For example, under the most pessimistic future load sensitivity considered by FEI (mDEP (5%)), in 2050 the Lower Mainland load at +4°C is estimated to be approximately 321 MMcf/d, which is more than double the Supplemental Alternative 5 sendout capacity of 150 MMcf/d.

5.3.2 Supplemental Alternative 6

Supplemental Alternative 6 includes the following:

- Replacing the Base Plant with a new 1 Bcf tank and 800 MMcf/d (4 x 200 MMcf/d vapourizers) of regasification capacity;
- Allocating all of the 1 Bcf tank volume to a resiliency reserve and no allocation for peaking gas supply;
- FEI would, therefore, have to rely entirely on the regional market to meet its full peaking gas supply requirements. However, given that regional infrastructure is already fully contracted, FEI would be unable to replace the entire peaking gas supply requirement immediately. As such, FEI would still hold the existing 50 MMcf/d of market pipeline capacity but would likely have to curtail firm loads in normal operations by up to 150 MMcf/d until future regional infrastructure upgrades to occur; and
- If and when regional infrastructure upgrades occur (consistently assumed to be 2035 for the financial analysis), it would offer the potential for FEI to end curtailments by holding gas supply contracts for 1.0 Bcf and 200 MMcf/d. FEI would pay a higher toll / charge that includes the costs of the upgrades.

5.3.2.1 Modelling Parameters

Table C-19 sets out the resiliency and gas supply modelling parameters for Supplemental Alternative 6.

The only modelling scenario is a planning scenario, focused on dependable resources. The scenario treats the entire tank (1 Bcf) as a resiliency reserve that would be available on the day of a no-flow event. As such, FEI would need to replace lost peaking gas supply at additional cost with capacity on regional pipeline or storage infrastructure.

Table C-19: Supplemental Alternative 6 Planning Modelling Scenarios

Supp. Alt. 6 Modelling Scenario	Description	Resiliency Modelling Parameters	Peaking Gas Supply Allocation (Normal Operations)[1]
Supplemental Alternative 6 (Planning)	New 1 Bcf Tank (Full Resiliency Reserve) and 800 MMcf/d Regasification[2]	1 Bcf at 800 MMcf/d	0 Bcf at 800 MMcf/d

Notes to Table:

[1] *On a planning basis, since the tank is fully allocated to a resiliency reserve, FEI would not be able to meet the requirements of the ACP. In order to have dependable peaking supply, FEI would have to obtain those resources in the market in the form of pipeline capacity or regional storage capacity.*

[2] *When there is a resiliency reserve, on a planning basis there is dependable LNG available on occurrence of no-flow event. Hence the resiliency modelling parameter is 1 Bcf.*

5.3.2.2 Summary of Information and Analysis

FEI investigated Supplemental Alternative 6 with respect to the criteria discussed in Section 4.2 of the Supplemental Evidence. Supplemental Alternative 6 did not pass the Step 2 screen because, without a dedicated gas supply reserve, Supplemental Alternative 6 would fail to retain FEI's existing on-system peaking gas supply capabilities.[60]

The following bullets provide a high-level description of how this alternative performs against the criteria, followed by sections providing additional details.

- **Resiliency (No Impact):** Although Supplemental Alternative 6 would allocate all of the 1 Bcf tank volume to a resiliency reserve and significantly increase the regasification capacity, it would provide little additional protection against a winter T-South no-flow event because the tank volume is insufficient to bridge a regulatory shutdown of at least 3 days.
- **Gas Supply (No Impact):** Since Supplemental Alternative 6 would allocate the entire 1 Bcf tank to a resiliency reserve, FEI would have to attempt to replace the existing peaking gas supply from Tilbury in the market. Similar to Supplemental Alternative 1, there would likely be at least several years where there are significant curtailments in normal operations before FEI would be able to acquire enough replacement peaking supply on upgraded regional infrastructure.
- **Base Plant Challenges (High Positive Impact):** The new facility would address the age-related challenges associated with the existing Base Plant.
- **Levelized Total Rate Impact (High Negative Impact):** Supplemental Alternative 6 would have a levelized total rate impact of 4.9 percent over a 67-year analysis period.

[60] 0.6 Bcf and 150 MMcf/d of regasification capacity.

- **Future Use (No Impact):** Supplemental Alternative 6 would remain useful and not underutilized for the period between the in-service date and 2050.

FEI discusses each of the five analysis criteria in further detail below.

5.3.2.2.1 RESILIENCY (NO IMPACT)

Supplemental Alternative 6 would improve resiliency relative to Supplemental Alternative 1 by increasing regasification capacity at Tilbury to 800 MMcf/d (addressing the existing regasification constraint at Tilbury) and including a 1 Bcf resiliency reserve, which would ensure LNG volumes are available to support the system on the day of a winter T-South no-flow event. However, Exponent's analysis confirms that 1 Bcf does not materially improve FEI's ability to withstand a winter T-South no-flow event relative to the existing capabilities of the Tilbury Base Plant. This result is confirmed in Exponent's figure (reproduced in Section 2.5.1 above) summarizing the annual expected loss reduction associated with each Supplemental Alternative relative to the Supplemental Alternative 1 (Planning) scenario.

The following table summarizes the load support duration modelling results at various temperatures.

Table C-20: Supplemental Alternative 6 Load Support Durations Under Different Winter Conditions

Supp. Alt. 6 Modelling Scenario	Approximate Time Until Customers in the Lower Mainland Begin Losing Service[61]		
	-10°C (very cold winter day)[62]	-1.4°C (warmest winter in 10 years, as defined in footnote)[63]	+4.0°C (average Lower Mainland winter)[64]
Planning (1 Bcf, 800 MMcf/d)	1 day and 9 hours	1 day and 21 hours	2 days and 10 hours

Consistent with the framework established in Section 3.4.1.2.2 of FEI's 2024 Resiliency Plan, under average winter conditions, the support duration provided by the Supplemental Alternative 6 may or may not be enough to execute a controlled shutdown. Therefore, a T-South failure in

[61] This represents the approximate duration of full firm load support for customers in the Lower Mainland. The analysis considers support from on-system LNG and linepack from the CTS. The analysis also assumes that all interruptible customers are offline within 4 hours of the no-flow event, except for the -10°C analysis, wherein interruptible customers would already be offline due to the cold temperature condition.

[62] Due to the low probability of having multiple -10°C days in a row in the Lower Mainland, the -10°C temperature condition analysis assumes the following: the first day is -10°C, the second and third days are -7°C, the fourth day is -3°C, and all subsequent days are +4°C.

[63] The warmest winter in the last 10 years was found by determining the minimum daily average temperature for each year over a 10-year period from 2013-2022, then selecting the highest value. The analysis was based on data from YVR.

[64] Defined as the average of the daily average temperatures for December, January, and February over a 10-year period from 2013-2022. The average winter day is based on data from YVR.

some segments could result in a controlled or uncontrolled shutdown in the Lower Mainland system.

Figures C-27 to C-29 below show the modelling outputs used to determine the load support duration values at various temperatures (+4°C, -1.4°C and -10.0°C) in the table above. As noted above, Supplemental Alternative 6 assumes there is 1 Bcf of LNG inventory present on the day of a winter T-South no-flow event, as there would be a resiliency reserve.

Figure C-27: Impact to Lower Mainland due to Loss of T-South Supply at +4°C with Supp. Alt. 6 – 1bcf & 800MMcf/d

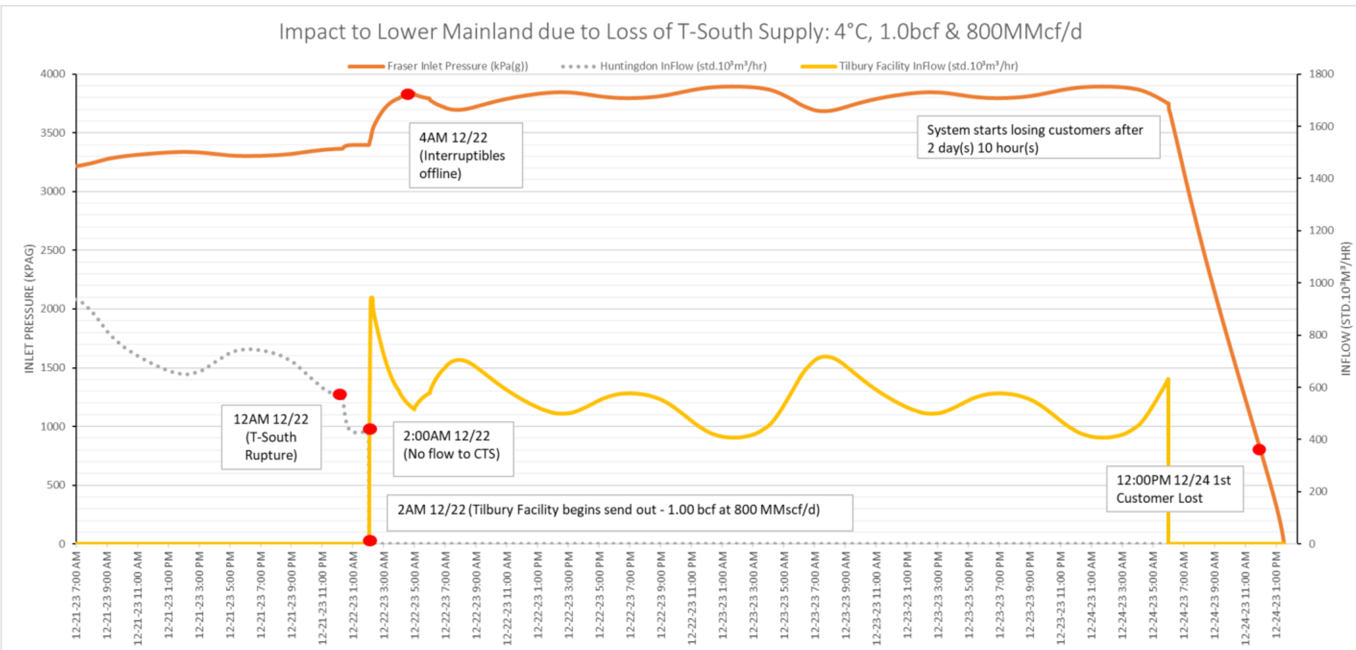


Figure C-28: Impact to Lower Mainland due to Loss of T-South Supply at -1.4°C with Supp. Alt. 6 – 1bcf & 800MMcf/d

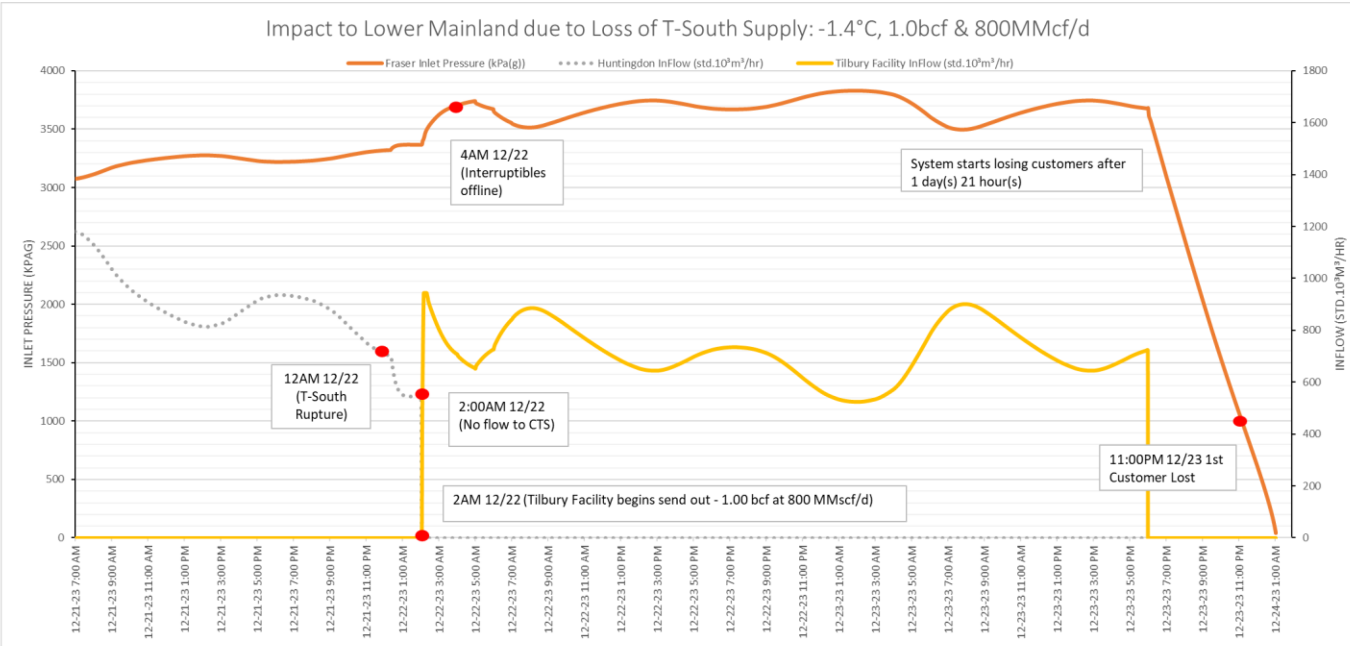
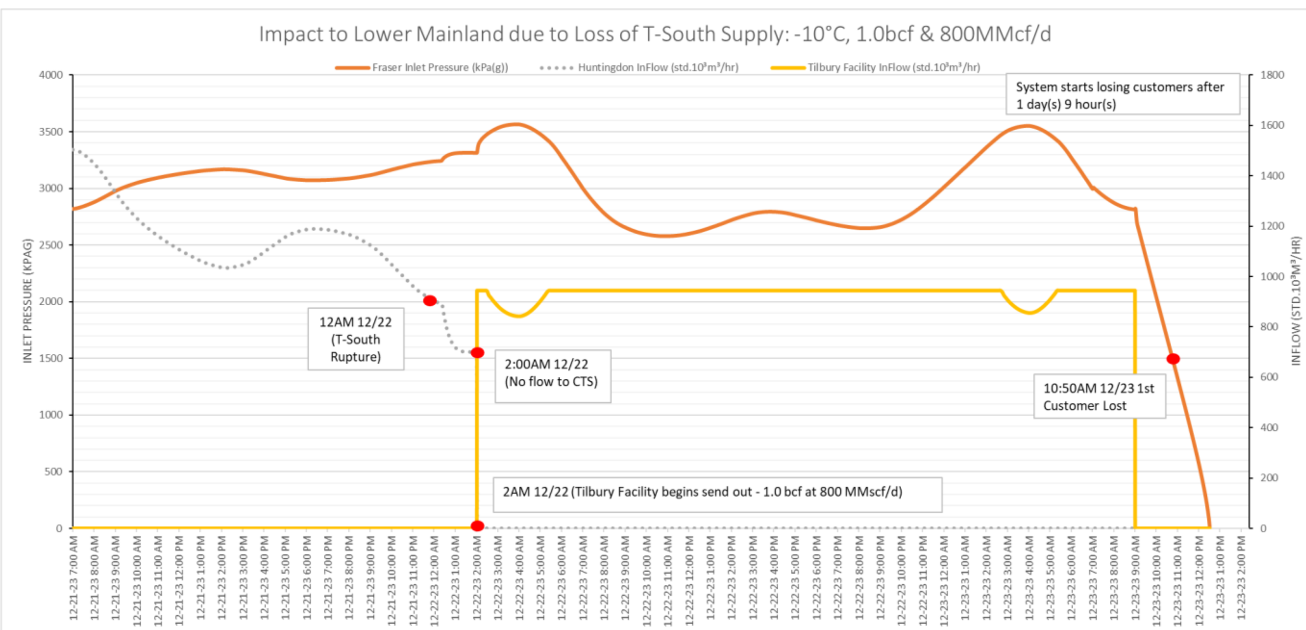


Figure C-29: Impact to Lower Mainland due to Loss of T-South Supply at -10°C with Supp. Alt. 6 – 1bcf & 800MMcf/d



5.3.2.2.2 GAS SUPPLY (NO IMPACT)

Supplemental Alternative 6 would not retain FEI's existing on-system peaking capabilities and, therefore, did not pass the Step 2 screen.

Supplemental Alternative 6 would be identical to Supplemental Alternatives 5 and 7 from a gas supply perspective insofar as the entire tank would be allocated to a resiliency reserve. As a result, FEI would need to attempt to replace the existing peaking gas supply in the market, which would not be possible given that regional infrastructure is fully contracted.

5.3.2.2.3 BASE PLANT CHALLENGES (HIGH POSITIVE IMPACT)

Like other alternatives that would involve a new tank and regasification, Supplemental Alternative 6 would address the age-related challenges associated with continuing to rely on the Base Plant.

5.3.2.2.1 LEVELIZED TOTAL RATE IMPACT (HIGH NEGATIVE IMPACT)

The levelized total rate impact for Supplemental Alternative 6 is estimated to be 4.9 percent over a 67-year analysis period.

This reflects the estimated capital cost of $933.5 million to install a new 1.0 Bcf tank and 800 MMcf/d of new regasification as well as the operating costs over the expected life of the new assets. However, since this alternative would leave no allocation of the on-system LNG for peaking gas supply, FEI would have to secure its entire peaking gas requirement of 1.0 Bcf and 200 MMcf/d from the regional market. The annual peaking supply costs would initially consist of the cost of continuing to hold the 50 MMcf/d of year-round pipeline capacity, with significant curtailments in normal operations. The annual gas supply costs would reach an estimated $63 million starting in 2035 when regional infrastructure upgrades are assumed to be possible. Please refer to Section 3.3 of this Appendix for discussion on the gas supply cost assumptions and the costs/savings used in the financial analysis for Supplemental Alternative 6.

Based on the results of the levelized total rate impact, Supplemental Alternative 6 is inferior to Supplemental Alternative 9 with a higher levelized total rate impact due to the increase in gas supply costs outweighing the reduction in capital costs for a smaller facility (given the significant economies of scale with LNG facility construction). Supplemental Alternative 9 would provide both resiliency and availability of dependable gas supply during peak demand.

5.3.2.2.2 FUTURE USE (NO IMPACT)

Supplemental Alternative 6 would be useful and not underutilized between the in-service date and 2050.

In Section 4.5.5 of the Supplemental Evidence, FEI describes how an on-system LNG facility is a unique asset when it comes to the flexibility afforded in response to changing load. Supplemental Alternative 6, as an LNG facility, would remain used and useful between the in-service date and 2050. Even under the mDEP (2% and 5%) hypothetical adverse load sensitivities, the 2050 load would still be too large for the facility to be underutilized for peaking gas supply.

5.3.3 Supplemental Alternative 7

Supplemental Alternative 7 includes the following:

- Replacing the Base Plant tank with a new 2 Bcf tank;

- Replacing the existing Base Plant regasification capacity with 800 MMcf/d (4 x 200 MMcf/d vapourizers);
- Allocating all of the 2 Bcf tank volume to a resiliency reserve and no allocation for peaking gas supply;
- FEI would, therefore, have to rely entirely on the regional market to meet its full peaking gas supply requirements. However, given that regional infrastructure is already fully contracted, FEI would be unable to replace the entire peaking gas supply requirement immediately. As such, FEI would still hold the existing 50 MMcf/d of market pipeline capacity but would likely have to curtail firm loads in normal operations by up to 150 MMcf/d until future regional infrastructure upgrades to occur; and
- If and when regional infrastructure upgrades occur (consistently assumed to be 2035 for the financial analysis), it would offer the potential for FEI to end curtailments by holding gas supply contracts for 1.0 Bcf and 200 MMcf/d. FEI would pay a higher toll / charge that includes the costs of the upgrades.

Supplemental Alternatives 7 and 8 are similar in terms of the physical asset being constructed but contemplate different uses for the tank for planning purposes. Whereas Supplemental Alternative 8 contemplates splitting the tank between gas supply and resiliency, this alternative dedicates the entire tank to resiliency.

5.3.3.1 Modelling Parameters

Table C-21 sets out the resiliency and gas supply modelling parameters for Supplemental Alternative 7.

The modelling scenario is a planning scenario, focused on dependable resources. The scenario treats the entire tank (2 Bcf) as a dependable resiliency reserve that would be available on the day of a no-flow event. As such, FEI would need to replace lost peaking gas supply at additional cost with capacity on regional pipeline or storage infrastructure.

Table C-21: Supplemental Alternative 7 Planning Modelling Scenarios

Supp. Alt. 7 Modelling Scenario	Description	Resiliency Modelling Parameters	Peaking Gas Supply Allocation (Normal Operations)[1]
Supplemental Alternative 7 (Planning)	New 2 Bcf Tank (Full Resiliency Reserve) and 800 MMcf/d Regasification[2]	2 Bcf at 800 MMcf/d	0 Bcf at 800 MMcf/d

Notes to Table:

[1] *On a planning basis, since the tank is fully allocated to resiliency reserve, FEI would not be able to meet the requirements of the ACP. In order to have dependable peaking supply, FEI would have to obtain those resources in the market in the form of pipeline capacity or regional storage capacity.*

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

5.3.3.2 Summary of Information and Analysis

FEI investigated Supplemental Alternative 7 with respect to the criteria discussed in Section 4.2 of the Supplemental Evidence. Supplemental Alternative 7 did not pass the Step 2 screen because, without a dedicated gas supply reserve, Supplemental Alternative 7 would fail to retain FEI's existing on-system peaking gas supply capabilities.[65]

The following bullets provide a high-level description of how this alternative performs against the criteria, followed by sections providing additional details.

- **Resiliency (High Positive Impact):** At both average winter and colder temperatures, Supplemental Alternative 7 would provide superior risk mitigation against a winter T-South no-flow event relative to all other alternatives apart from Supplemental Alternative 9 which has the same 2 Bcf resiliency reserve.[66]
- **Gas Supply (No Impact):** Since Supplemental Alternative 7 would allocate the entire 2 Bcf tank to a resiliency reserve, FEI would have to attempt to replace FEI's existing peaking gas supply from Tilbury in the market. As with a no capital upgrades option, there would likely be at least several years where there are significant curtailments in normal operations before FEI would be able to acquire enough replacement peaking supply on upgraded regional infrastructure.
- **Base Plant Challenges (High Positive Impact):** The new facility would address the age-related challenges associated with the existing Base Plant.
- **Levelized Total Rate Impact (High Negative Impact):** Supplemental Alternative 7 would have a levelized total rate impact of 5.6 percent over a 67-year analysis period.
- **Future Use (No Impact):** Supplemental Alternative 7 would remain useful and not underutilized for the period between the in-service date and 2050.

FEI discusses each of the five analysis criteria in further detail below.

5.3.3.2.1 RESILIENCY (HIGH POSITIVE IMPACT)

Supplemental Alternative 7 would significantly improve resiliency relative to Supplemental Alternative 1 by: (1) increasing regasification capacity at Tilbury to 800 MMcf/d; and (2) creating a 2 Bcf resiliency reserve, which would ensure LNG volumes are available to support the system on the day of a winter T-South no-flow event.

While Supplemental Alternatives 7, 8 and the 9 would provide similar risk mitigation under average winter temperatures of +4°C (as shown in Section 2.5.1 above), a 2 Bcf resiliency reserve

[65] 0.6 Bcf and 150 MMcf/d of regasification capacity.
[66] As explained further in Section 2.5.1 of this Appendix, Supplemental Alternatives 7, 8 and 9 provide similar risk mitigation at average winter temperatures.

would provide superior risk mitigation at colder temperatures (a temperature range of approximately +1.7°C to -6.8°C). This is because, within this temperature range, a 2 Bcf resiliency reserve can bridge a 3-day regulatory shutdown while smaller reserves cannot (e.g., the 1.4 Bcf resiliency reserve of Supplemental Alternative 8 cannot). Exponent describes the performance of a 2 Bcf resiliency reserve with 800 MMcf/d of regasification as a "substantial benefit" over other alternatives.[67]

The following table summarizes the load support duration modelling results at various temperatures.

Table C-22: Supplemental Alternative 7 Load Support Durations Under Different Winter Conditions

Supp. Alt. 7 Scenario	Approximate Time Until Customers in the Lower Mainland Begin Losing Service[68]		
	-10°C (very cold winter day)[69]	-1.4°C (warmest winter in 10 years, as defined in footnote)[70]	+4.0°C (average Lower Mainland winter)[71]
Planning (2 Bcf, 800 MMcf/d)	2 days and 17 hours	3 days and 12 hours	4 days and 13 hours

Consistent with the framework established in Section 3.4.1.2.2 of FEI's 2024 Resiliency Plan, under the +4°C and -1.4°C temperature conditions, the support duration provided by Supplemental Alternative 7 is long enough to execute a controlled shutdown. Therefore, at these temperature conditions, FEI expects that an outage caused by a T-South failure (i.e., a T-South failure where the no-flow duration exceeds the support duration and thus an outage occurs) would result in a controlled shutdown in the Lower Mainland system. Under the -10°C temperature condition (i.e., a support duration just under 3 days) a controlled shutdown may or may not be possible, and therefore, the shutdown may be controlled or uncontrolled. However, given that the support duration is almost 3-days, it is more likely that the shutdown would be controlled than uncontrolled.[72]

67 Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, p. 150.
68 This represents the approximate duration of full firm load support for customers in the Lower Mainland. The analysis considers support from on-system LNG and linepack from the CTS. The analysis also assumes that all interruptible customers are offline within 4 hours of the no-flow event, except for the -10°C analysis, wherein interruptible customers would already be offline due to the cold temperature condition.
69 Due to the low probability of having multiple -10°C days in a row in the Lower Mainland, the -10°C temperature condition analysis assumes the following: the first day is -10°C, the second and third days are -7°C, the fourth day is -3°C, and all subsequent days are +4°C.
70 The warmest winter in the last 10 years was found by determining the minimum daily average temperature for each year over a 10-year period from 2013-2022, then selecting the highest value. The analysis was based on data from YVR.
71 Defined as the average of the daily average temperatures for December, January, and February over a 10-year period from 2013-2022. The average winter day is based on data from YVR.
72 Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, Report Appendix U, Figure U.2.

Figures C-30 to C-32 below show the modelling outputs used to determine the load support duration values at various temperatures (+4°C, -1.4°C and -10.0°C) in the table above. As noted above, Supplemental Alternative 7 assumes there is 2 Bcf of LNG inventory present on the day of a winter T-South no-flow event, as there is a resiliency reserve. FEI has provided an explanation of how to interpret these figures in Section 3.2.2.1.2 of the Supplemental Evidence.

Figure C-30: Impact to Lower Mainland due to Loss of T-South Supply at +4°C with Supp. Alt. 7 – 2 Bcf & 800MMcf/d

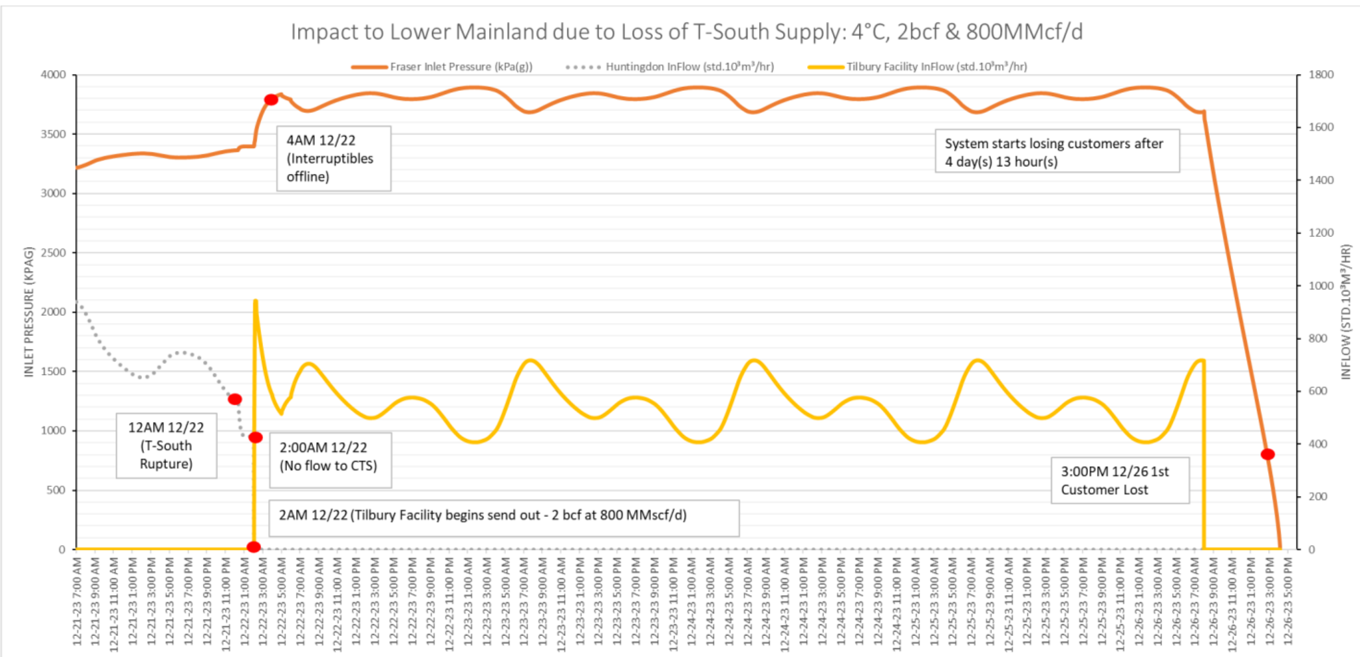


Figure C-31: Impact to Lower Mainland due to Loss of T-South Supply at -1.4°C with Supp. Alt. 7 – 2 Bcf & 800MMcf/d

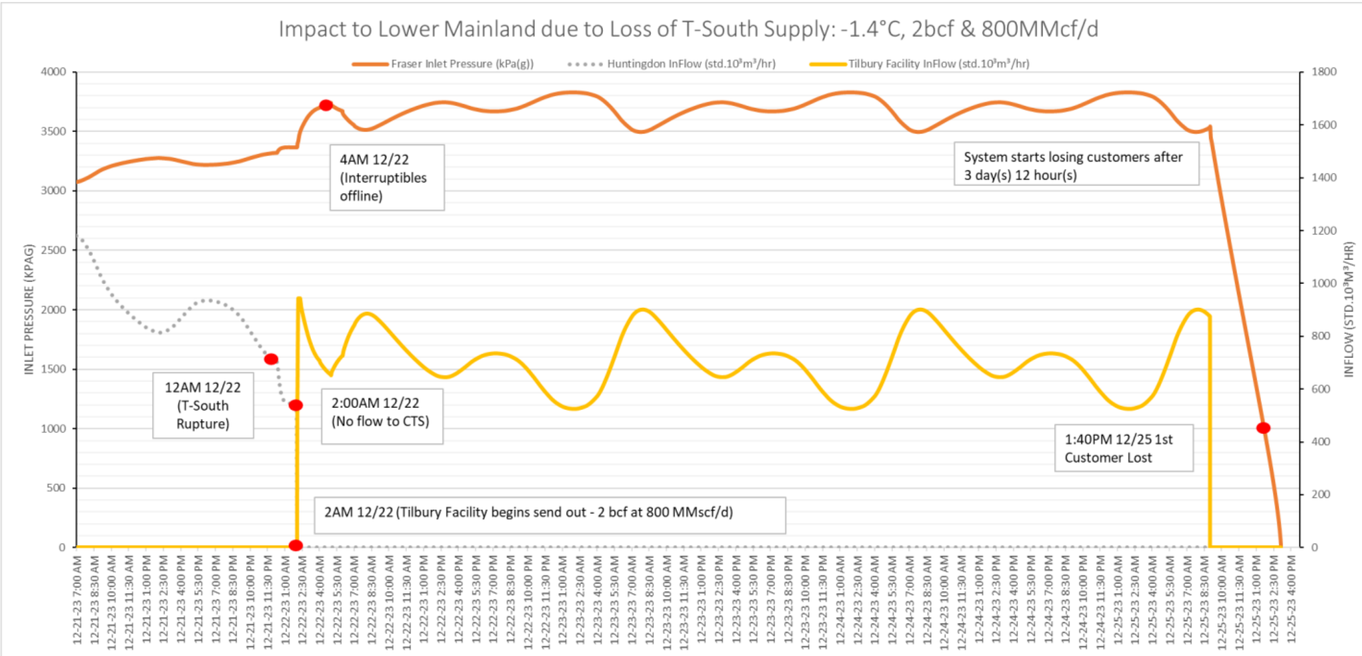
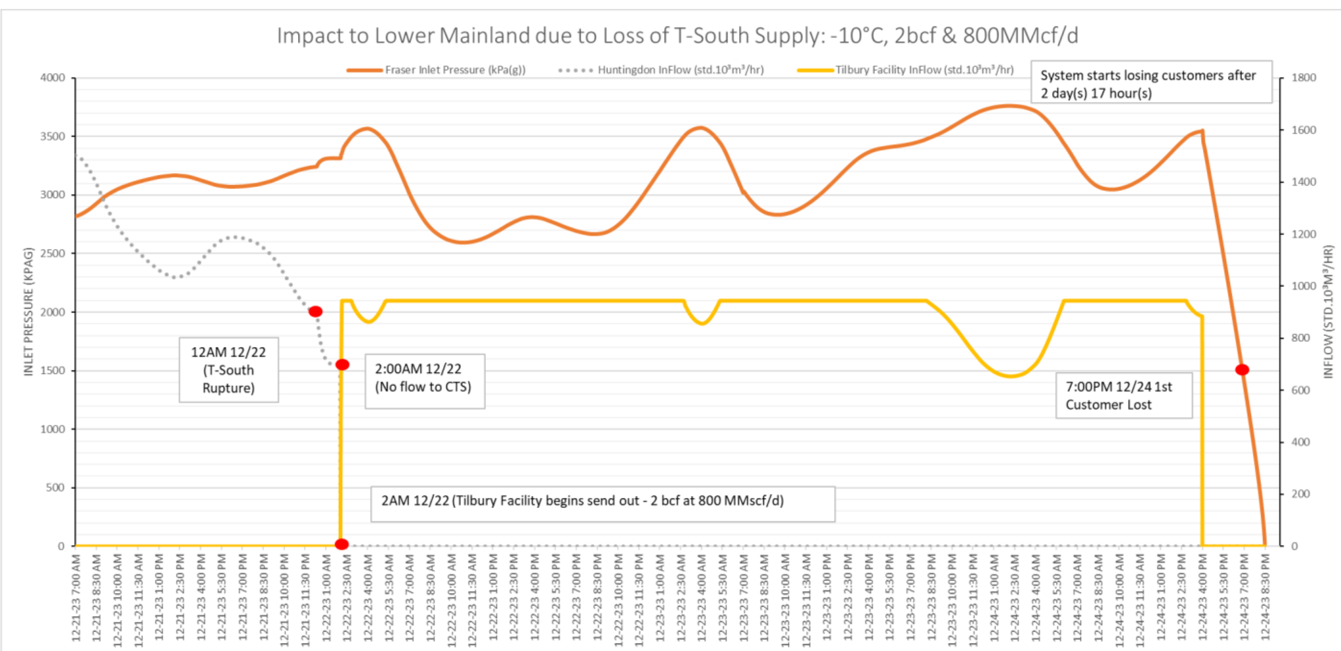


Figure C-32: Impact to Lower Mainland due to Loss of T-South Supply at -10°C with Supp. Alt. 7 – 2 Bcf & 800MMcf/d



5.3.3.2.1 GAS SUPPLY (NO IMPACT)

Supplemental Alternative 7 would not retain FEI's existing on-system peaking capabilities and, therefore, did not pass the Step 2 screen.

Supplemental Alternative 7 is identical to Supplemental Alternatives 5 and 6 from a gas supply perspective insofar as the entire tank would be allocated to a resiliency reserve. As a result, FEI would need to attempt to replace the existing peaking gas supply in the market, which would not be possible given that regional infrastructure is fully contracted.

5.3.3.2.2 BASE PLANT CHALLENGES (HIGH POSITIVE IMPACT)

Like other alternatives that would involve a new tank and regasification, Supplemental Alternative 7 would address the age-related challenges associated with continuing to rely on the Base Plant.

5.3.3.2.3 LEVELIZED TOTAL RATE IMPACT (HIGH NEGATIVE IMPACT)

The levelized total rate impact for Supplemental Alternative 7 is estimated to be 5.6 percent over a 67-year analysis period.

This reflects the estimated capital cost of $1,030.3 million to install a new 2.0 Bcf tank and 800 MMcf/d of new regasification as well as the operating costs over the expected life of the new assets. However, since this alternative would leave no allocation of the on-system LNG for peaking gas supply, FEI would have to secure its entire peaking gas requirement of 1.0 Bcf and 200 MMcf/d from the regional market. The annual peaking supply costs would initially consist of the cost of continuing to hold the 50 MMcf/d of year-round pipeline capacity, with significant curtailments in normal operations. The annual gas supply costs would reach an estimated $63 million starting in 2035 when regional infrastructure upgrades are assumed to be possible. Please refer to Section 3.3 of this Appendix for discussion on the gas supply cost assumptions and the costs/savings used in the financial analysis for Supplemental Alternative 7.

Based on the results of the levelized total rate impact, Supplemental Alternative 7 is inferior to Supplemental Alternative 9 with a higher levelized total rate impact due to the increase in gas supply costs which outweigh the reduction in capital costs for a smaller facility.

5.3.3.2.4 FUTURE USE (NO IMPACT)

Supplemental Alternative 7 would remain useful and not underutilized for the period between the in-service date and 2050.

In Section 4.5.5 of the Supplemental Evidence, FEI describes how an on-system LNG facility is a unique asset when it comes to the flexibility afforded in response to changing load. Supplemental Alternative 7, as an LNG facility, would remain used and useful between the in-service date and 2050. Even under the mDEP (2% and 5%) hypothetical adverse load sensitivities, the 2050 load would still be too large for the facility to be underutilized for peaking gas supply.

5.4 ALTERNATIVES WITH NEW FACILITY THAT PROVIDES BOTH RESILIENCY RESERVE AND GAS SUPPLY

Supplemental Alternatives 8 and 9 involve replacing the existing Base Plant with new 2 and 3 Bcf facilities, respectively. In both cases a portion of the tank volume would be set aside as a dependable resiliency reserve and the remainder of the tank volume would be used for peaking gas supply. While Supplemental Alternatives 8 and 9 provide similar risk mitigation under average winter temperatures (refer to Section 2.5.1 above), the larger resiliency reserve provided by Supplemental Alternative 9 will make it superior at colder temperatures. As a result, and along with the superior gas supply benefit, FEI determined that Supplemental Alternative 9 is the preferred alternative.

5.4.1 Supplemental Alternative 8

Supplemental Alternative 8 includes the following:

- Replacing the Base Plant tank with a new 2 Bcf tank;
- Replacing the existing Base Plant regasification capacity with 800 MMcf/d (4 x 200 MMcf/d vapourizers);
- Allocating 1.4 Bcf of the tank volume to a resiliency reserve;
- Allocating 0.6 Bcf of the tank volume to gas supply to maintain existing peaking gas supply at Tilbury; and
- Continuing to hold the existing 50 MMcf/d of year-round pipeline capacity to meet FEI's full peaking supply requirements of 200 MMcf/d and 1.0 Bcf.

Supplemental Alternatives 7 and 8 are the same in terms of the physical asset being constructed but contemplate different uses for the tank for planning purposes. Whereas Supplemental Alternative 7 dedicates the entire tank to resiliency, this alternative contemplates splitting the tank between gas supply and resiliency.

5.4.1.1 Modelling Parameters

Table C-23 sets out the resiliency and gas supply modelling parameters for Supplemental Alternative 8.

The only modelling scenario is a planning scenario, focused on dependable resources. The maximum regasification capacity is 800 MMcf/d with the 2 Bcf tank divided between a dependable 1.4 Bcf resiliency reserve and 0.6 Bcf of dependable gas supply.

Table C-23: Alternative 8 Planning Modelling Scenarios

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

Notes to Table:

[1] On a planning basis, since the tank is only partially allocated to 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 Supplementary 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.

5.4.1.2 Summary of Information and Analysis

FEI investigated Supplemental Alternative 8 with respect to the criteria discussed in Section 4.2 of the Supplemental Evidence. Supplemental Alternative 8 would be inferior to Supplemental Alternative 9 from an overall customer value standpoint.

The following bullets provide a high-level description of how this alternative performs against the criteria, followed by sections providing additional details.

- **Resiliency (Medium Positive Impact):** Supplemental Alternative 8 would provide significantly improved risk mitigation compared to the Supplemental Alternative 1 scenarios. Compared to Supplemental Alternatives 7 and 9, which contemplate resiliency reserves of 2 Bcf, Supplemental Alternative 8 would provide similar risk mitigation at average Lower Mainland winter temperatures (i.e., +4°C). However, at colder temperatures that occur in typical winters (i.e., between -6.8°C to +1.7°C), the risk mitigation provided by Supplemental Alternative 8 would be significantly less than Supplemental Alternatives 7 and 9. As a result, its resiliency benefit would be inferior to Alternatives 7 and 9.
- **Gas Supply (Medium Positive Impact):** As a new facility with a dedicated gas supply reserve of 0.6 Bcf, Supplemental Alternative 8 would improve the availability of dependable gas supply during peak demand when compared to the Supplemental Alternative 1 scenarios. However, FEI would need to continue holding its additional 50 MMcf/d of year-round pipeline capacity to meet FEI's 1.0 Bcf peaking supply requirement, which would be sub-optimal from a portfolio design perspective and increase FEI's gas supply costs.
- **Base Plant Challenges (High Positive Impact):** The new facility would address the age-related challenges associated with the existing Base Plant.
- **Levelized Total Rate Impact (Medium Negative Impact):** Supplemental Alternative 8 would have a levelized total rate impact of 4.4 percent over a 67-year analysis period. Although this alternative involves constructing a smaller facility than Supplemental Alternative 9 (i.e., 2 Bcf vs. 3 Bcf storage tank), the levelized total rate impact is higher than Supplemental Alternative 9. The annual costs of supplementing FEI's peaking supply with an additional 0.4 Bcf from the regional market to make up FEI's full peaking gas requirement of 1.0 Bcf would outweigh the benefit of lower capital costs for the smaller facility.

- **Future Use (No Impact):** Supplemental Alternative 8 would remain useful and not underutilized for the period between the in-service date and 2050.

FEI discusses each of the five analysis criteria in further detail below.

5.4.1.2.1 RESILIENCY (MEDIUM POSITIVE IMPACT)

Supplemental Alternative 8 would improve resiliency relative to Supplemental Alternative 1 by: (1) increasing Tilbury regasification capacity to 800 MMcf/d; and (2) creating a 1.4 Bcf resiliency reserve, which ensures LNG volumes would be available to support the system on the day of a winter T-South no-flow event.

The load support durations provided by a 1.4 Bcf resiliency reserve are materially shorter than the durations provided by a 2 Bcf reserve. A 1.4 Bcf resiliency reserve would provide similar risk mitigation under average winter temperatures of +4°C as a 2 Bcf resiliency reserve (as shown in Section 2.5.1 above). However, a 1.4 Bcf resiliency reserve could not bridge a 3-day regulatory shutdown period at temperatures colder than +1.7°C, and therefore, would lack the significant resiliency benefit provided by Alternatives 7 and 9.[73] Please refer to Section 4.5.1 of the Supplemental Evidence which provides a detailed comparison of the risk mitigation provided by Supplemental Alternatives 8 and 9 in colder conditions that are present for periods of the winter.

The following table summarizes the load support duration modelling results at various temperatures.

Table C-24: Supplemental Alternative 8 Load Support Durations Under Different Winter Conditions

Supp. Alt. 8 Modelling Scenario	Approximate Time Until Customers in the Lower Mainland Begin Losing Service[74]		
	-10°C (very cold winter day)[75]	-1.4°C (warmest winter in 10 years, as defined in footnote)[76]	+4.0C (average Lower Mainland winter)[77]
Planning (1.4 Bcf, 800 MMcf/d)	1 day and 22 hours	2 days and 13 hours	3 days and 8 hours

[73] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, Section 9.
[74] This represents the approximate duration of full firm load support for customers in the Lower Mainland. The analysis considers support from on-system LNG and linepack from the CTS. The analysis also assumes that all interruptible customers are offline within 4 hours of the no-flow event, except for the -10°C analysis, wherein interruptible customers would already be offline due to the cold temperature condition.
[75] Due to the low probability of having multiple -10°C days in a row in the Lower Mainland, the -10°C temperature condition analysis assumes the following: the first day is -10°C, the second and third days are -7°C, the fourth day is -3°C, and all subsequent days are +4°C.
[76] The warmest winter in the last 10 years was found by determining the minimum daily average temperature for each year over a 10-year period from 2013-2022, then selecting the highest value. The analysis was based on data from YVR.
[77] Defined as the average of the daily average temperatures for December, January, and February over a 10-year period from 2013-2022. The average winter day is based on data from YVR.

Consistent with the framework established in Section 3.4.1.2.2 of FEI's 2024 Resiliency Plan, under the +4°C temperature condition, the support duration provided by the supplemental alternative would be long enough to execute a controlled shutdown. Therefore, at this temperature condition, FEI expects that an outage caused by a T-South failure (i.e., a T-South failure where the no-flow duration exceeds the support duration and thus an outage occurs) would result in a controlled shutdown in the Lower Mainland system. The support duration at the -1.4°C and -10°C temperature conditions creates uncertainty as to whether a controlled shutdown would be possible, and therefore, the shutdown may be controlled or uncontrolled.

Figures C-33 to C-35 below show the modelling outputs used to determine the load support duration values at various temperatures (+4°C, -1.4°C and -10.0°C) in the table above. As noted above, Supplemental Alternative 8 assumes there is 1.4 Bcf of LNG inventory present on the day of a winter T-South no-flow event, as there is a resiliency reserve.

Figure C-33: Impact to Lower Mainland due to Loss of T-South Supply at +4°C with Supp. Alt. 8 – 1.4 Bcf & 800MMcf/d

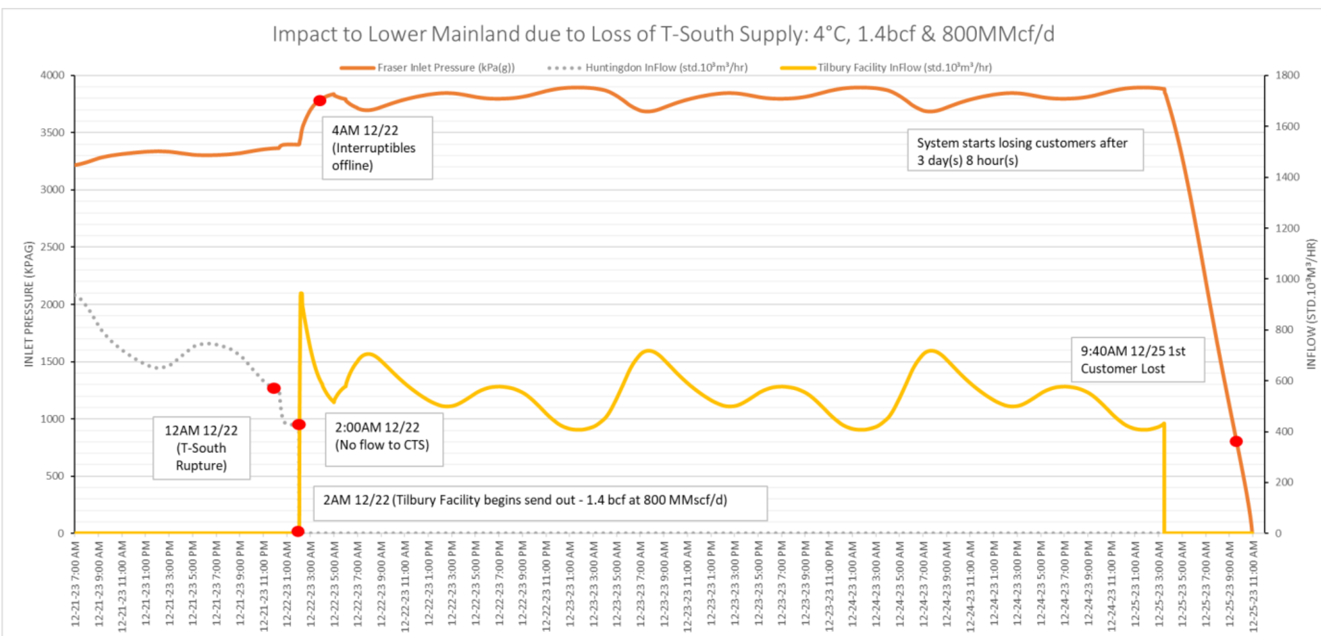


Figure C-34: Impact to Lower Mainland due to Loss of T-South Supply at -1.4°C with Supp. Alt. 8 – 1.4 Bcf & 800MMcf/d

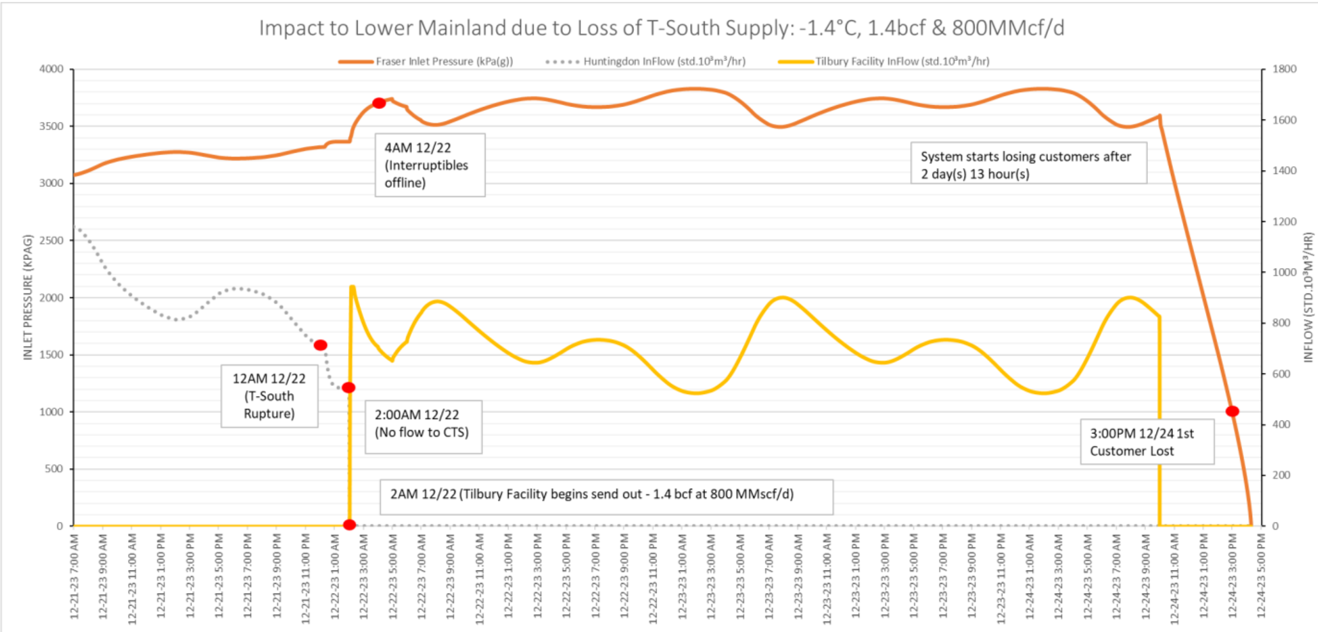
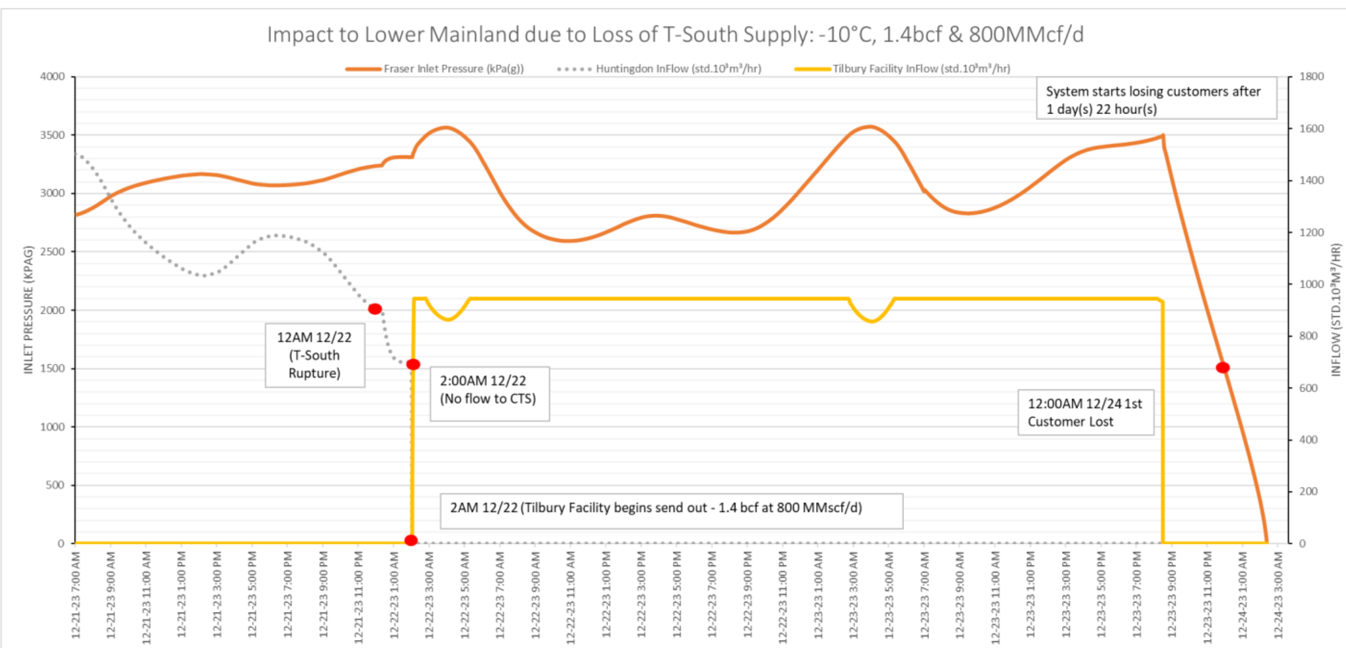


Figure C-35: Impact to Lower Mainland due to Loss of T-South Supply at -10°C with Supp. Alt. 8 – 1.4 Bcf & 800MMcf/d



5.4.1.2.2 GAS SUPPLY (MEDIUM POSITIVE IMPACT)

Supplemental Alternative 8 would improve the availability of dependable gas supply during peak demand relative to Supplemental Alternative 1 and, therefore, passed the Step 2 screen.

Supplemental Alternative 8 would involve constructing a new LNG storage tank and regasification that is partially dedicated to gas supply, thus retaining FEI's existing firm peaking gas supply capabilities that have long been included in the Annual Contracting Plan (0.6 Bcf gas supply reserve and 150 MMcf/d of send-out) while also resolving the gas supply concerns associated with the existing Base Plant, which are driven by the age-related dependability challenges discussed in Section 3.3 of the Supplemental Evidence. This alternative would also address the challenges associated with the stop-gap measure of relying on 0.25 Bcf from Tilbury 1A (i.e., LNG that is intended for RS 46 sales) to compensate for the Base Plant tank being operated at 0.35 Bcf for seismic reasons. This represents an improvement from Supplemental Alternative 1.

However, while Supplemental Alternative 8 would avoid the need to replace the existing on-system peaking gas supply provided by Tilbury with capacity on regional infrastructure at considerable cost, it would not provide the full 200 MMcf/d and 1 Bcf of peaking supply that FEI requires. Having the ability to meet FEI's entire peaking supply requirements with LNG would: (1) provide FEI considerable flexibility for gas supply planning and winter operation; and (2) potentially displace other higher cost gas portfolio assets. While the additional regasification associated with Supplemental Alternative 8 would provide some additional operational flexibility, the extent of the benefit would be constrained due to the limited gas supply reserve of only 0.6 Bcf. As such, FEI would need to continue to hold an additional 50 MMcf/d year-round pipeline capacity to deliver the remaining 0.4 Bcf of peaking resources – which would be sub-optimal from a portfolio design perspective and increase FEI's gas supply costs.

5.4.1.2.3 BASE PLANT CHALLENGES (HIGH POSITIVE IMPACT)

Like other alternatives that would involve a new tank and regasification, Supplemental Alternative 8 would address the age-related challenges associated with continuing to rely on the aging Base Plant and, in particular, would restore the reliability of Tilbury's critical gas supply function.

5.4.1.2.4 LEVELIZED TOTAL RATE IMPACT (MEDIUM NEGATIVE IMPACT)

The levelized total rate impact for Supplemental Alternative 8 is estimated to be 4.4 percent over a 67-year analysis period.

This reflects the estimated capital cost of $1,030.3 million to install a new 2.0 Bcf tank and 800 MMcf/d of new regasification as well as the operating costs over the expected life of the new assets. Supplemental Alternative 8 will avoid the costs of securing 0.6 Bcf and 150 MMcf/d for peaking gas supply from the regional market, estimated as savings of $46 million starting in 2035, but FEI would continue to incur gas supply costs for the year-round 50 MMcf/d to make up the full peaking gas requirement of 1.0 Bcf and 200 MMcf/d. Please refer to Section 3.3 of this Appendix for discussion on the gas supply cost assumptions and the costs/savings used in the financial analysis for Supplemental Alternative 8.

FEI notes the following regarding the financial analysis:

- Supplemental Alternative 8 has the same capital cost as Supplemental Alternative 7 ($1,030.3 million), as both of these alternatives would involve using the same asset (a new 2.0 Bcf tank and 800 MMcf/d of regasification). The only difference is in the way the facility is allocated for planning purposes (i.e., this alternative allocates 1.4 Bcf for resiliency and the remaining 0.6 Bcf for gas supply purposes while Supplemental Alternative 7 allocates the entire volume to resiliency). The value of the avoided gas supply costs pertaining to the 0.6 Bcf allocated to gas supply result in the levelized total rate impact for Supplemental Alternative 8 being less than Supplemental Alternative 7 (which has no allocation for gas supply purposes); and
- Although Supplemental Alternatives 8 and 9 both provide resiliency and availability of dependable gas supply during peak demand, Supplemental Alternative 8 is inferior to Supplemental Alternative 9 with a slightly higher levelized total rate impact. The higher gas supply costs associated with Supplemental Alternative 8 outweigh the benefit of lower capital costs for a smaller facility.

5.4.1.2.5 FUTURE USE (NO IMPACT)

Supplemental Alternative 8 would remain useful and not underutilized for the period between the in-service date and 2050.

Supplemental Alternative 8 would involve building the same physical facility as Supplemental Alternative 7 (i.e., the two supplemental alternatives only differ in how the tank volume is allocated) and, as such, the Future Use analysis for both Supplemental Alternatives is the same.

5.4.2 Supplemental Alternative 9 (Preferred Alternative)

Supplemental Alternative 9 is the Preferred Alternative and includes the following:

- Replacing the Base Plant tank with a new 3 Bcf tank;
- Replacing the existing Base Plant regasification with 800 MMcf/d regasification capacity (4 x 200 MMcf/d vapourizers);
- Allocating 2 Bcf of tank volume to a resiliency reserve; and
- Allocating 1 Bcf of tank volume to gas supply; therefore, FEI is not required to augment the peaking supply with regional market resources.

Please refer to Section 5 of the Supplemental Evidence which provides an updated Project Description.

5.4.2.1 Modelling Parameters

Table C-25 sets out the resiliency and gas supply modelling parameters for Supplemental Alternative 9.

The modelling scenario is a planning scenario, focused on dependable resources. The maximum regasification capacity is 800 MMcf/d with the 3 Bcf tank divided between a dependable 2 Bcf resiliency reserve and 1 Bcf of dependable gas supply.

Table C-25: Supplemental Alternative 9 Planning Modelling Scenarios

Supp. Alt. 9 Modelling Scenario	Description	Resiliency Modelling Parameters	Peaking Gas Supply Allocation (Normal Operations)[1]
Supplemental Alternative 9 (Preferred)	New 3 Bcf Tank (2 Bcf Resiliency Reserve) and 800 MMcf/d Regasification[2]	2 Bcf at 800 MMcf/d	1 Bcf at 800 MMcf/d

<u>*Notes to Table:*</u>

[1] *On a planning basis, since the tank is only partially allocated to a resiliency reserve, FEI would be able to meet the requirements of the ACP and would be able to achieve incremental supply benefits relative to Supplementary Alternative 1 (Planning).*

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

5.4.2.2 Summary of Information and Analysis

Supplemental Alternative 9 will provide superior overall customer value, having regard to risk mitigation, restored peaking gas supply, resolving the age-related challenges associated with the Base Plant, the levelized total rate impact, as well as utilization and usefulness in the future. Supplemental Alternative 9 scored the highest in Step 3 of the alternative selection process, and is therefore the Preferred Alternative. The following bullets provide a high-level description of how this alternative performs against the criteria. Section 4 of the Supplemental Evidence addresses each of the five alternatives analysis criterion in detail.

- **Resiliency (High Positive Impact):** At both average winter and colder temperatures, Supplemental Alternative 9 will provide superior risk mitigation against a winter T-South no-flow event relative to all other alternatives apart from Supplemental Alternative 7, which has the same 2 Bcf resiliency reserve. Please refer to Section 5.3.3.2.1 above regarding Supplemental Alternative 7 and Sections 4.5 and 4.7 of the Supplemental Evidence for an in-depth discussion of the resiliency performance of Supplemental Alterative 9.
- **Gas Supply (High Positive Impact):** As a new facility with a dedicated gas supply reserve of 1 Bcf and an increased send-out capacity of 800 MMcf/d, Supplemental Alternative 9 will improve the availability of dependable gas supply during peak demand when compared to the Supplemental Alternative 1 scenarios. Supplemental Alternative 9 will also provide FEI with considerable flexibility for gas supply planning and winter operation, and potentially displace other higher cost gas portfolio assets. Please refer to Section 5.2.2.2.2 above regarding Supplemental Alternative 4A and Section 4 of the Supplemental Evidence for further discussion of the gas supply criterion.

- **Base Plant Challenges (High Positive Impact):** The new facility addresses the age-related issues with the existing Base Plant.
- **Levelized Total Rate Impact (Medium Negative Impact):** Supplemental Alternative 9 has a levelized total rate impact of 4.2 percent over a 67-year analysis period. Although the LNG facility under this alternative would be the largest with the highest capital cost, it has the lowest levelized total rate impact amongst the Supplemental Alternatives that include a new LNG storage tank with allocation reserved for resiliency. This is primarily due to the significant economies of scale associated with LNG facility construction, combined with the benefits of avoided gas supply costs that are achieved due to the 1.0 Bcf gas supply reserve which meets the full peaking gas supply requirement. These benefits outweigh the increase in capital cost. Please refer to Section 3.3 of this Appendix for discussion on the gas supply cost assumptions and the costs/savings used in the financial analysis for Supplemental Alternative 9.
- **Future Use (No Impact):** Supplemental Alternative 9 will remain useful and not underutilized for the period between the in-service date and 2050. Please refer to Section 4.5.5 of the Supplemental Evidence where FEI provides a detailed analysis of how Supplemental Alternative 9 performs against the Future Use criterion.

5.5 OTHER NON-TILBURY ALTERNATIVES IDENTIFIED BY THE BCUC

The BCUC indicated in the Adjournment Decision that it required further information about other non-Tilbury alternatives. FEI has considered those alternatives as Supplemental Alternatives 10, 11, and 12. After further review, FEI determined that constructing facilities to permit reverse-flow on the VITS (Supplemental Alternative 10), LNG from Woodfibre LNG (Supplemental Alternative 11), and floating storage (Supplemental Alternative 12) would not be viable for a variety of reasons. FEI addresses each non-viable alternative below.

5.5.1 Supplemental Alternative 10

FEI explained in its prior evidence that, during winter, the VITS system hydraulics are such that FEI cannot rely on Mt. Hayes LNG to serve the Lower Mainland following a T-South winter no-flow event. Gas typically flows westward on the VITS (i.e., from Coquitlam to Vancouver Island). In normal operating conditions, FEI can serve the Lower Mainland from Mt. Hayes notionally, by displacement (i.e., FEI uses Mt. Hayes LNG to serve more load on Vancouver Island, thereby permitting FEI to use gas in the Lower Mainland that was otherwise going to Vancouver Island). In the summer, it is hydraulically possible for small amounts of gas to physically flow eastwards through the VITS into the Lower Mainland. However, that is not possible in winter.[78]

In this section, FEI considers a potential alternative of constructing the necessary facilities to allow FEI to reverse the flow on VITS in winter to flow sufficient gas towards the Lower Mainland to provide a material resiliency improvement. FEI's analysis concluded that Supplemental

[78] Exhibit B-15, BCUC IR1 11.7.

Alternative 10 is not viable; therefore, it was not considered beyond Step 1 of the alternatives analysis.

Supplemental Alternative 10 would involve:

- Using the existing Tilbury facilities with no capital upgrades (i.e., Supplemental Alternative 1), with the primary constraint remaining that regasification capacity at Tilbury would be insufficient to prevent a widespread customer outage within hours; and
- Constructing the necessary facilities to reverse flow 400 MMcf/d on the VITS, which is the upper bound of what could be reverse-flowed on the VITS (as described below).

5.5.1.1 VITS Reverse Flow is Limited to Approximately 400 MMcf/d Due to the Coquitlam Watershed

FEI's VITS includes an approximately 28 km segment of NPS 12 pipeline that passes through the Coquitlam Watershed. Due to environmental and permitting challenges, constructing additional pipeline infrastructure in the Coquitlam Watershed would be insurmountable in a reasonable amount of time.[79] As a result, the capacity of the VITS through the watershed is limited to the existing capabilities of the NPS 12 pipeline. FEI conducted a hydraulic analysis and found that, based on the length, diameter, and maximum operating pressure, the flow rate through the watershed is limited to approximately 400 MMcf/d.

The constraint through the watershed creates a bottleneck for the entire VITS. While it may be possible to upgrade other segments of the VITS to flow more than 400 MMcf/d, the overall VITS reverse flow capability would still be limited by the watershed segment. As such, approximately 400 MMcf/d is the upper bound for what the VITS could potentially reverse flow.

5.5.1.2 Substantial Upgrades are Required to Reverse Flow 400 MMcf/d on the VITS

While the VITS could potentially reverse flow up to 400 MMcf/d, FEI would need to complete significant infrastructure upgrades. FEI undertook a hydraulic analysis to identify the necessary upgrades:[80]

- Looping the VITS with approximately 273 km of new NPS 20 pipeline;[81]
- Substantially upgrading FEI's existing V3 and V4 compressor stations (e.g., HP expansion and re-configuration to allow for bi-directional flow);
- Re-configuring FEI's future V2 compressor station to allow for bi-directional flow; and

[79] When FEI constructed the VITS in the early 1990s, construction through the watershed included stringent conditions. This included that the pipeline be overbuilt such that FEI would not have to disturb the watershed in the future for capacity upgrade projects.
[80] The listed upgrades are high-level and are not exhaustive.
[81] The analysis assumes that FEI's future Eagle Mountain Pipeline 610 is in place. Without this pipeline, additional looping would be required.

- More than tripling the regasification capacity of FEI's Mt. Hayes LNG Facility.

The required upgrades represent a significant and complex scope of work. While FEI has not developed any of the potential upgrades, it expects that a project of this scale would have considerable challenges associated with permitting, environment, land / Statutory Right of Way (SRW) acquisition, and consultation. Table C-26 below compares the existing parameters of the VITS to the parameters required to reverse flow 400 MMcf/d.

Table C-26: Comparison of Existing VITS to Upgraded VITS

Parameter	Existing VITS	Upgraded VITS
Vancouver Mainland 273/323 Flow Rate[82]	155 MMcf/d[83]	400 MMcf/d
VITS Pipeline Length	624 km[84]	Existing + 273 km of NPS 20
V3 Cmp Power	7,300 HP	11,000 HP
V4 Cmp Power	7,300 HP	16,000 HP
Mt. Hayes LNG Regasification	150 MMcf/d	550 MMcf/d

5.5.1.3 Reversing Flow to the Lower Mainland Would Degrade Resiliency in the VITS

FEI used its transient hydraulic system modelling to determine the support duration Supplemental Alternative 10 would provide to the Lower Mainland under average winter conditions (+4°C). FEI assumed that the Lower Mainland would be supported by the Tilbury Base Plant with additional LNG volumes from Tilbury 1A (totalling 0.75 Bcf and 150 MMcf/d), and by reverse flow from Mt. Hayes (1 Bcf and 400 MMcf/d). For the purposes of modelling, it was assumed that 1 Bcf from Mt. Hayes would be available for reverse flow, while the remaining 0.5 Bcf would be used to support customers within the VITS.

Based on the modelling results, Supplemental Alternative 10 would provide 3 days and 16 hours of support duration to the Lower Mainland; however, by drawing from the Mt. Hayes storage tank to supply the Lower Mainland, this alternative would degrade the resiliency of the VITS. At present, assuming the VITS has access to the full Mt. Hayes storage volume, under average winter conditions, FEI estimates a VITS support duration of approximately 13 days. By reversing flow to the Lower Mainland, where the VITS is limited to 0.5 Bcf from Mt. Hayes, the support duration would be reduced to approximately 4 days and 10 hours. Therefore, the VITS would experience an outage if a no-flow duration exceeded 4 days and 10 hours (compared to 13 days under existing conditions).

[82] The Vancouver Mainland 273 and Vancouver Mainland 323 pipelines are the pipelines within the VITS that bring gas from the Lower Mainland to Vancouver Island.
[83] Based on the current model year VITS Design Degree Day load.
[84] Approximate sum of the length of all pipelines that make up the VITS.

5.5.1.4 Supplemental Alternative 10 is Inferior to the Equivalent Tilbury Facility Alternative

As noted above, the support duration provided by Supplemental Alternative 10 is approximately 3 days and 16 hours. Based on FEI's hydraulic system modelling, Supplemental Alternative 8 (new 2 Bcf tank, 1.4 Bcf resiliency reserve and 800 MMcf/d regasification) would provide a duration of 3 days and 8 hours at average winter temperatures (+4°C) without the following challenges associated with Supplemental Alternative 10:

- A larger and more complex scope of work;
- Greater challenges associated with permitting, environment, land/SRW acquisition, and consultation;
- Degradation of the existing VITS resiliency; and
- The expected project costs per kilometre of the Eagle Mountain Pipeline of approximately $30 million per kilometre, multiplied by 273 km, suggests that Supplemental Alternative 10 could cost as much as $8 billion to implement.

Therefore, FEI concluded that Supplemental Alternative 10 is not viable, and it was not considered beyond Step 1 of the alternatives analysis.

5.5.2 Supplemental Alternative 11

In the Adjournment Decision, the BCUC stated:[85]

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

The Application did not address this option because it was never regarded as plausible. In order to address the BCUC's commentary, FEI elaborates on why Supplemental Alternative 11 is not viable. FEI did not consider Supplemental Alternative 11 beyond Step 1 of the alternatives analysis.

[85] Adjournment Decision, p. 29.

Supplemental Alternative 11 would involve:

- Using the existing Tilbury facilities with no capital upgrades (Supplemental Alternative 1), with the primary constraint being that the regasification capacity is insufficient to prevent a widespread customer outage within hours;
- FEI entering into a contract with Woodfibre LNG for a long-term firm supply of LNG; and
- FEI either:
  - Custom building a vessel for transporting LNG up the Fraser River to the Tilbury facility, constructing a facility at Tilbury for offloading the LNG from the vessel, and adding more regasification capacity at Tilbury to address the existing regasification constraint; or
  - Acquiring property rights from Woodfibre LNG on which FEI constructs a regasification facility at Woodfibre, while also constructing facilities to permit reversing the flow of VITS and using VITS linepack.

5.5.2.1 Supplying Tilbury Would Be Inconsistent with Woodfibre LNG's Business Model and LNG Markets

The realities of Woodfibre LNG's business and LNG markets rule out this alternative as discussed in further detail below.

First, Woodfibre LNG has publicly announced that it has entered into firm contracts for 1.95 MTPA – meaning that over 90 percent of their planned plant capacity (2.1 MTPA) is allocated to customers. As such, there is not sufficient uncontracted capacity available from that facility to support FEI resiliency. Further, given the nature of their business, any LNG storage they have on the site is being inventoried to ensure the next customer vessel can be filled on schedule. If that vessel has just been loaded and left the LNG facility, it is very likely there would be no LNG storage available to support FEI needs.

Second, even if sufficient contracted capacity were available for FEI to have access to LNG stored at Woodfibre in the event of an emergency, Woodfibre LNG would have to negotiate contracts with customers that would allow for the interruption of supply to their firm customers. This would be a very non-standard commercial arrangement in the LNG bulk export market and would make Woodfibre's offering less competitive than their competitors internationally. In particular, the nature of the bulk export LNG business is that the LNG liquefaction plant and loading terminal are just one part of a global supply chain which includes the upstream gas production, transportation to the LNG facility, liquefying the natural gas, loading it onto ocean going vessels, transporting it to customers and typically to a regasification terminal where the LNG vessel is received and offloaded. This supply chain is tightly controlled to ensure that production at each stage (production of the natural gas, production of the LNG, shipping, receiving) is optimized to ensure minimal, if any, interruptions. For example, if production of LNG is interrupted for any reason, it would cause ripple effects and would affect both upstream production, activities at the receiving terminal and delays and additional costs to the shipping companies. In the event the LNG production facility cannot provide the contracted volumes of LNG, that facility is then responsible to provide what are commonly referred to as “make-up quantities” and may also pay a penalty for not being available for service.

Ultimately, FEI does not believe that there is any commercial arrangement that FEI could make with Woodfibre LNG that would not be extremely disadvantageous to FEI’s customers, as Woodfibre would be injecting significant uncertainty into their business model.

5.5.2.2 Required Infrastructure to Rely on Woodfibre LNG Supply Would be Impractical

Even assuming FEI were able to contract for LNG supply from Woodfibre, FEI would then need new infrastructure to make use of the LNG:

- **Option #1:** Custom building a vessel for transporting LNG up the Fraser River to the Tilbury facility, constructing a facility at Tilbury for offloading the LNG from the vessel, and adding more regasification capacity at Tilbury to address the existing regasification constraint; or
- **Option #2:** Acquiring property rights from Woodfibre LNG on which FEI constructs a regasification facility at Woodfibre, while also constructing facilities to permit reversing the flow of VITS and using VITS linepack.

FEI discusses each option below.

5.5.2.2.1 CUSTOM BUILD VESSEL, NEW OFFLOADING FACILITY, NEW REGASIFICATION CAPACITY

Option #1 would involve FEI: (1) custom building a vessel for transporting LNG up the Fraser River to Tilbury; (2) constructing a facility for offloading the LNG from the vessel; and (3) adding more regasification capacity to address the existing regasification constraint at Tilbury. This option is not viable for the reasons below.

First, since there are restrictions on the sizes of vessels that can travel up the Fraser River, FEI would need to either lease or rent a vessel that could meet these size restrictions or custom build an LNG vessel to navigate the Fraser River to the Tilbury facility. The size of vessel that can transit up the Fraser is not a standard size in the LNG business, so it is highly unlikely that this could be found and, even if a vessel could be found, it is even less likely that it would be available at the time it would be required. This means that in order to ensure that the vessel is available when needed it would need to be custom built.

Second, even if FEI were able to either lease an LNG carrier on short notice or construct a custom vessel and get it to the Woodfibre LNG facility to be loaded, FEI would still need to build an LNG receiving terminal and pipeline infrastructure to connect to FEI’s CTS, thereby enabling FEI to deliver the LNG to the Lower Mainland.

Third, the Environmental Assessment Certificate (EAC) granted to Woodfibre LNG for the shipping of LNG in and out of the Woodfibre facility did not consider alternative vessel routing or the possibility of utilizing Woodfibre LNG to backstop FEI's emergency system needs. Therefore, Woodfibre would require an amendment to their EAC to consider potential impacts from any alternative routing required to support FEI's needs.

5.5.2.2.2 ACQUIRE LAND FROM WOODFIBRE LNG, CONSTRUCT NEW REGASIFICATION AND REVERSE-FLOW CAPABILITIES ON VITS

Option #2 would involve FEI: (1) acquiring property rights from Woodfibre LNG on which FEI constructs a regasification facility at Woodfibre; and (2) constructing facilities to permit reversing the flow of VITS and using VITS linepack. This option is not viable for the reasons below.

In Section 5.5.1 to this Appendix, FEI explained why reverse flow on the VITS with FEI's Mt. Hayes LNG Facility as the source of supply is not viable. As the Woodfibre LNG facility is located much closer to the CTS than the Mt. Hayes LNG facility, the pipeline looping required in Supplemental Alternative 10 would be avoided. Further, the successful implementation of this option would not diminish the resiliency on the VITS provided by FEI's Mt. Hayes LNG facility. However, the constraint through the Coquitlam watershed would still apply, which creates a bottleneck for the entire VITS that limits the flow rate to approximately 400 MMcf/d.

FEI reached out to Woodfibre LNG regarding adding additional infrastructure at their site. Woodfibre LNG responded that their existing facility configuration was subject to an extensive Nation-led environmental assessment resulting in the Squamish Nation Environmental Assessment Agreement. Any changes to the infrastructure on the site would require lengthy consultation with, and approval from, the Squamish Nation – potentially involving an amendment to the Agreement which also could require a member referendum.

5.5.2.3 In Winter the Lower Mainland Cannot Access EGP Linepack

The BCUC noted the potential for linepack to be available to support the Lower Mainland. As such, FEI evaluated the potential for linepack in the new Eagle Mountain pipeline (EGP) to provide resiliency to the Lower Mainland. FEI found that:

- EGP linepack cannot reverse flow to the Lower Mainland in winter, and thus can only be used to support the VITS; and
- The support provided by the EGP linepack to the VITS cannot replace the support provided by on-system LNG.

In its prior evidence, FEI discussed how, in winter, reverse flow from the VITS to the Lower Mainland is not possible.[86] The hydraulic constraints which prevent FEI from reverse flowing from the VITS to the CTS in winter are not resolved by the EGP. Therefore, in winter, FEI does not expect to be able to access the EGP linepack to support the Lower Mainland. However, the linepack from the EGP could be used to support the VITS.

[86] Exhibit B-17, BCUC IR1 11.7.

At average winter conditions (+4°C), and assuming the EGP were in place, FEI estimates the support duration provided by the VITS linepack (i.e., from the existing VITS transmission pipelines and the new EGP) would be approximately 13.4 hours. Without the EGP, the support duration provided by the VITS linepack would be approximately 7 hours (i.e., the EGP increases the linepack support duration by 6.4 hours at average winter conditions). While the additional support provided by the EGP linepack would be valuable, as it would provide time for FEI to implement other resiliency capabilities (e.g., begin sending out from Mt. Hayes), it would not be a substitute for the support provided by on-system LNG.

The above analysis assumes that Woodfibre LNG is immediately curtailed following the assumed no-flow event. Any consumption of the VITS linepack by Woodfibre LNG would reduce the estimated support duration.

5.5.3 Supplemental Alternative 12

FEI initially considered, but rejected, the potential to use floating LNG storage as an alternative to the TLSE Project. The BCUC commented in the Adjournment Decision:[87]

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

In response to the BCUC's commentary, FEI considered Supplemental Alternative 12. FEI provides additional discussion regarding floating LNG storage below.

FEI's additional analysis has not changed its initial determination. In particular, Supplemental Alternative 12 is so complex as to likely be infeasible. Even if it were feasible, it would be very costly – without providing commensurately greater resiliency benefits. Therefore, FEI concluded that Supplemental Alternative 11 is not viable, and it was not considered beyond Step 1 of the alternatives analysis.

[87] Adjournment Decision, p. 30.

5.5.3.1 Requirements for Using Floating LNG Storage

Supplemental Alternative 12 would involve:

- Purchasing a vessel to provide floating LNG storage to increase the available energy (LNG) in the event of a supply emergency affecting the Lower Mainland;
- Acquiring a water lot that would allow for permanent mooring;
- Adding sufficient new regasification capacity, either as an integrated component of the LNG storage vessel or on the adjacent shoreline, to address the existing regasification constraint at Tilbury that will currently result in a widespread customer outage within hours of a winter T-South no-flow event; and
- Other onshore facilities, including a jetty and pipes to interconnect with the CTS; and
- New environmental assessment approvals.

An example of a floating storage and regasification unit[88] (263,000m3) is depicted below.

To assess this alternative, FEI engaged an independent consultant (Ogee Development Inc.) to assess the viability of a floating storage unit (FSU) at a number of locations with access to the CTS. The consultant's analysis indicated that the availability of a suitably sized floating storage vessel could be a challenge:[89]

[88] https://www.world-energy.org/article/33637.html.
[89] Appendix C-1, p. 13.

Most of the new build FSU's in the current market are approximately 170,000 m3 in capacity. The older previous generation FSU's were in the size range of 130,000-140,000 m3 capacity. This presents the challenge of using an older existing FSU by way of lease/time charter or purchase. This option of an older FSU would require extensive inspections/verifications and possible modifications, repair, or re-certifications to satisfy todays codes and industry standards.

In the sections below, FEI describes why this Supplemental Alternative is not viable.

5.5.3.2 There Are No Appropriate Sites

The 2024 Resiliency Plan confirmed that the greatest customer outage risk facing FEI is associated with a winter T-South no-flow event. In order to mitigate the risk associated with a winter no-flow event, floating LNG storage would need to be sited close to FEI's largest load in the Lower Mainland to facilitate access to gas within hours of the no-flow event. FEI identified a number of on-water sites (i.e., offshore) with nearby access to the CTS and sought expert analysis to assess the feasibility of tying into each. The most feasible of these options was then compared against the option of onshore storage and regasification at Tilbury.

Of the sites identified, all of the offshore sites had issues with technical feasibility either due to the tie-in point pressure rating, pipeline capacity or execution difficulties caused by the location of the tie-in point in the Fraser River. The matrix below shows the viability of the identified offshore storage options.

Table C-27: Offshore LNG Storage Viability Matrix

	Base Case TLSE	Location 1 Tilbury Site	Location 2 Fraser River Crossing	Location 3 Burrard Inlet	Location 4 Squamish
Technical					
Economic					
Environmental					
Commercial					
Organizational					
Political					

Not viable (i.e. "fatal flaw")

Viable but multiple challenges

Viable

The most practical of the offshore options is the location at Tilbury due to the proximity to the CTS main artery and existing infrastructure. This option was analysed in further detail against onshore

LNG storage at Tilbury; however, as described below, even this offshore option was deemed not viable.

5.5.3.3 On-system Storage and Regasification on an Existing Site Is Preferable

Offshore LNG storage at Tilbury presents many issues in terms of practicality, including:

- The water depth of the Fraser River, which would likely require ongoing dredging around the floating storage vessel;
- The cost of additional marine infrastructure such as required mooring and jetty systems; and
- Concerns from other river users or stakeholders regarding restrictions around an LNG storage vessel that would require exclusion zones to operate safely.

Further, based on its prior experience, FEI's independent consultant concluded that offshore storage alone would likely cost 20-35 percent more than the onshore equivalent. This does not include the additional costs associated with marine infrastructure or mooring requirements.

Following the analysis of the possible sites that could provide access to the CTS, FEI's consultant concluded that "[f]loating LNG Storage options are considered 'not viable' due to one or more fatal flaws at each of the four potential offshore locations identified" and recommended "that the onshore TLSE Base Case option be considered as the viable option for this project."[90]

5.6 SOUTHERN CROSSING PIPELINE EXTENSION / RGSD PROJECT

The Application included discussion of pipeline alternatives, including two configurations extending the South Crossing Pipeline that FEI was exploring, which is referred to as the Regional Gas Supply Diversity (RGSD) Project. One potential configuration of the RGSD Project (Oliver to Huntingdon) would bypass T-South and avoid single-point-of-failure risk, whereas the other route would reduce the length of T-South where single-point-of-failure risk exists.[91] FEI concluded that, regardless of the configuration, the RGSD pipeline capacity is best viewed as complementary to the TLSE Project, rather than a substitute for the resiliency on-system LNG provides. In this regard, the BCUC stated in the Adjournment Decision:[92]

> The RGSD project is currently being planned by FEI. RCIA has identified a difference in the intended capacity of that project. Given this uncertainty we are unable to make any finding regarding how the RGSD project may or may not impact the need for the TLSE Project. This further supports the need for a more

[90] Appendix C-1, p. 17.
[91] Exhibit B-1-4, Application, p. 87.
[92] Adjournment Decision, p. 48.

> holistic resiliency plan to better understand the interaction of different projects that FEI may be contemplating in order to achieve greater resiliency."[93]
>
> ….
>
> The resiliency plan states that the RGSD project "would allow FEI to split the optimal amount of pipeline capacity between T-South and RGSD, thereby reducing FEI's current heavy dependence on the T-South system." However, IR responses filed in both proceedings suggest that reduced dependence on the T-South System has little to no impact on the TLSE Project. In any event, due to uncertainties in the scope of the RGSD project, we noted in Section 4.1 of our Decision that we are unable to make any finding regarding how the RGSD project may or may not impact the need for the TLSE Project."

FEI has recently determined not to pursue RGSD on its own, although FEI has not foreclosed participating with others in a similar pipeline project. Regardless, in this section, FEI provides additional explanation for why a Southern Crossing Pipeline extension would fill a different role than new on-system LNG from the perspective of resiliency and within FEI's gas supply portfolio. Regardless of size or end-point, an extension to the Southern Crossing Pipeline could not prevent a Day 1 depressurization of the Lower Mainland system following a T-South no-flow event.

5.6.1 The Lower Mainland Would Lose Service Before FEI Could Get Gas from a Southern Crossing Pipeline Extension

Following a winter T-South no-flow event, the Lower Mainland system will depressurize before FEI could access sufficient gas from a Southern Crossing Pipeline extension to restore pressure.

It would take approximately two days for FEI to be able to deliver supply through a Southern Crossing Pipeline extension to the Lower Mainland. Pipeline operators plan daily operations and shippers mitigate unutilized capacity in the open markets by scheduling pipeline supply the day before current day delivery. At 5:30AM each morning, FEI's gas traders make gas delivery arrangements based on the demand forecast for the next day. If there was excess capacity, traders mitigate the capacity through buy and sell gas at different gas markets. The revenue from daily trading activities reduces the fixed pipeline costs paid by FEI's customers. FEI cannot rely on the new pipeline within the first two days of a T-South failure because commercial deals have been transacted and parties are bound by their contracts.

As such, send out from the TLSE Project would be the only dependable supply to make up for the loss of T-South supply on the first two days of a no-flow event on T-South – a period in which FEI would need to make commercial arrangements in the market to bring additional gas from the new pipeline. The amount of additional supply FEI could secure on the Southern Crossing Pipeline extension would depend on the market conditions when an incident occurs. FEI plans its

[93] Adjournment Decision, p. 25.

required supply months before gas year starts; therefore, it would likely be challenging to secure a significant amount of supply from the markets within a short period of time.

FEI has characterized RGSD as complementary to the TLSE Project from a resiliency standpoint because, once sufficient on-system LNG is in place to bridge the initial period before piped gas can arrive, a new pipeline could add significant resiliency. In particular, it would provide an alternative source of supply that will reduce the risk posed by long-term capacity shortfalls or duration issues (such as those experienced during Phases 2 and 3 of the 2018 T-South Incident).

5.6.2 Tilbury LNG Provides Peak Capacity, Whereas Pipeline Provides Year-Round Energy

From a gas portfolio standpoint, on-system LNG is providing critical capacity to serve daily load in peak periods. By contrast, a Southern Crossing Pipeline extension would provide year-round energy that would be a like-for-like substitute for FEI's existing long-duration pipeline capacity on T-South.

In order to replicate the capacity function that Tilbury provides today, FEI would have to hold 150 MMcf/d of pipeline capacity year-round over and above what it required for year-round base load. As discussed in Section 3.3.4.5 of the Supplemental Evidence, the 150 MMcf/d of peaking capacity would be underutilized for all but a handful of days in winter. This is not economic in comparison to on-system LNG storage and exposes FEI customers to significant risk that the unused capacity could not be resold to mitigate the cost. In any event, there is not enough supply available in the market to replace 150 MMcf/d and 0.6 Bcf at Tilbury.

5.6.3 FEI Is No Longer Pursuing RGSD on its Own

In its sixth quarterly progress report filed on April 30, 2024, FEI summarized the conclusions of its screening analysis, including how FEI evaluated three RGSD Project delivery options, discussed the material market developments that have an impact on FEI and the Pacific Northwest operating marketplace and discussed how FEI concluded that the analysis supports options for a regional infrastructure solution with other market participants.

FEI's evaluation of potential alternative pipeline routes as part of its development work on the RGSD Project found that collaborating with other regional market participants on an integrated solution could be beneficial for the region and FEI's customers. This strategy would enhance the use of existing regional infrastructure, potentially lower costs, and balance risks for FEI and its customers. Therefore, FEI considers the current phase of the RGSD Project to have concluded and intends to explore commercial discussions with other market participants to continue to advance an optimal integrated solution for the region.

Appendix C-1

FLOATING LNG STORAGE CONCEPT ANALYSIS

Project:	TLSE - Floating LNG Storage Concept Analysis	**Job No.:**	FEI24-04493
Location:	Tilbury, BC	**SMCI Doc. No.:**	04493-31-3700-REP-0001
		FEI Doc. No.:	

Rev	**Date** (dd-mmm-yyyy)	Status	Prepared by	Checked by	Approved by
0	20-Mar-2024	Issued for Use	BGO	TIP/DKH	NRM

FORTISBC ENERGY INC.

PROJECT DEVELOPMENT

FLOATING LNG STORAGE CONCEPT ANALYSIS

Prepared by:

Ogee Development Inc.

Project:	TLSE - Floating LNG Storage Concept Analysis	**Job No.:**	FEI24-04493
Location:	Tilbury, BC	**SMCI Doc. No.:**	04493-31-3700-REP-0001
		FEI Doc. No.:	

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Project:	TLSE - Floating LNG Storage Concept Analysis	**Job No.:**	FEI24-04493
Location:	Tilbury, BC	**SMCI Doc. No.:**	04493-31-3700-REP-0001
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REVISION HISTORY

DATE	PAGE / SECTION	DESCRIPTION

Project:	TLSE - Floating LNG Storage Concept Analysis	**Job No.:**	FEI24-04493
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Executive Summary

OgeeDev's recommendation to use proven onshore LNG storage rather than floating LNG storage is based on numerous considerations, including technical, environmental, economic, commercial, organizational, and political (see section 2.3). It is true that LNG liquefaction with associated storage is often the best choice for remote stranded offshore gas reserves, where installing a long and potentially difficult pipeline to bring the gas onshore would otherwise make the development uneconomic. In addition to avoiding a costly subsea pipeline, the floating solution allows the project developers to relocate the facilities, allowing for smaller reserves to be produced. The floating solution will likely be faster and cheaper when faced with those challenges.

However, in most cases where suitable onshore land is available, the cost of a subsea pipeline is not a consideration, and there are no other requirements to install additional infrastructure to support marine facilities and their operations, such as the export or import of LNG by sea, the best and preferred solution is to install onshore facilities. This is because the floating solution often requires higher upfront costs and complexity than the onshore solution.

The exception to this rule was when the development of the onshore facility was in a remote location without significant infrastructure, limited or no labor availability, environmental sensitivity, or use restrictions. The other factors that have resulted in the use of floating LNG import, or FSRU facilities were the availability of low cost vessels that could be converted quickly and cheaply and third parties were willing to provide the capital investment to build and own the facility and provide the facilities on a leased basis where the project developer could avoid the higher upfront capital expense by agreeing to pay an ongoing operational expense.

This alternative commercial arrangement was particularly attractive for developers who could not obtain the capital to build the more conventional facility. At the time when this option was popular, both used and newly built vessels could be acquired quickly and, in some cases, cheaper than the onshore infrastructure and facilities could be developed. However, the current high demand for LNG ships and the limited shipyards capable of building specialty cryogenic vessels have increased both, the cost and schedule to obtain these vessels.

In this specific case, the added complexity of adopting a floating storage solution with the high cost and long procurement times for the floating vessels, designing and implementing the associated marine infrastructure, and resolving competing river access and usage issues is expected to result in the onshore storage option to remain the low cost and shorter schedule project with less uncertainty and risk.

1.0 GENERAL INFORMATION

1.1 Background

Fortis Energy Inc. (FEI) has been requested by the BC Utilities Commission (BCUC) to provide a supplemental submission for its Tilbury LNG Storage Expansion (TLSE) project application. As part of the submission, FEI has been asked to address additional alternatives.

One of the alternatives FEI is to address is floating LNG storage, based on the following BCUC comments in their Adjournment Decision:

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

1.2 Purpose

To perform a high-level qualitative screening assessment of the viability of conventional onshore LNG storage vs. floating LNG storage options for meeting the resiliency needs of the FEI system in the Lower Mainland area of British Columbia.

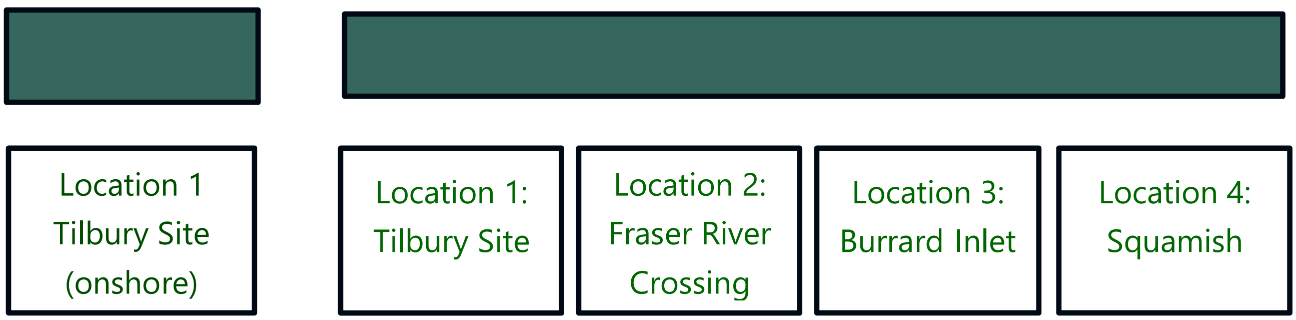
1.3 Scope of Services

OgeeDev has conducted a high-level concept / screening assessment on the viability of utilizing a Floating Storage Unit (FSU) or Floating Storage and Regasification Unit (FSRU) to support the resiliency needs of the FEI system.

This analysis has been presented in this technical memo.

1.4 Terms of Reference

Following cases have been evaluated in this document:



1. Base Case – TLSE comprising of LNG Storage (onshore) and Regasification unit (onshore) installed at the existing FEI Tilbury LNG facility.
2. Floating LNG Storage (FSU or FSRU), installed at any one the following potential locations:

   2.1 Tilbury Island

   2.2 Fraser River Crossing near the Port Mann Bridge

   2.3 Burrard Inlet

   2.4 Squamish, at a location near the Woodfibre LNG plant

1.5 Approach and Methodology

The following approach and methodology have been used in this analysis:

1. The OgeeDev project team, in association with FEI's project team, identified potential locations for the installation of Floating LNG Storage (FSU or FSRU) and characterized potential key features of each location to determine the best solution for site selection.
2. The key factors for the identification / shortlisting of potential locations for the Floating LNG Storage were:

   (i) Close to the FortisBC's Coastal Transmission System (CTS) that distributes gas to the lower mainland and Vancouver Island,

   (ii) Large enough pipeline diameter to handle the required flowrates of the CTS to minimize hydraulic losses,

   (iii) Similar coverage of customer density.

(iv) Proximity to a suitable water lot, ability to obtain a water lot, create adequate physical access to the water lot, interactions with the shipping and ports.

3. Next, the OgeeDev project team conducted a high-level comparison of a TLSE (onshore) design versus an FSU/FSRU (offshore) design at Tilbury Island. The team examined the benefits and challenges of onshore versus offshore floating LNG storage.
4. To develop list of challenges and risks associated with the floating storage, the TEECOP framework was utilized whereby Technical, Economic, Environmental, Commercial, Organizational, Political (TEECOP) issues and concerns were screened and identified. TEECOP is a risk analysis framework used to help identify and identify assess risks in projects. The primary domain categories represent the major domains that a project must mature as the project moves through the project development cycle.
5. The analysis of the options above helped to prepare a summary recommendations table (go / no-go screening type) for the study.

1.6 Basis

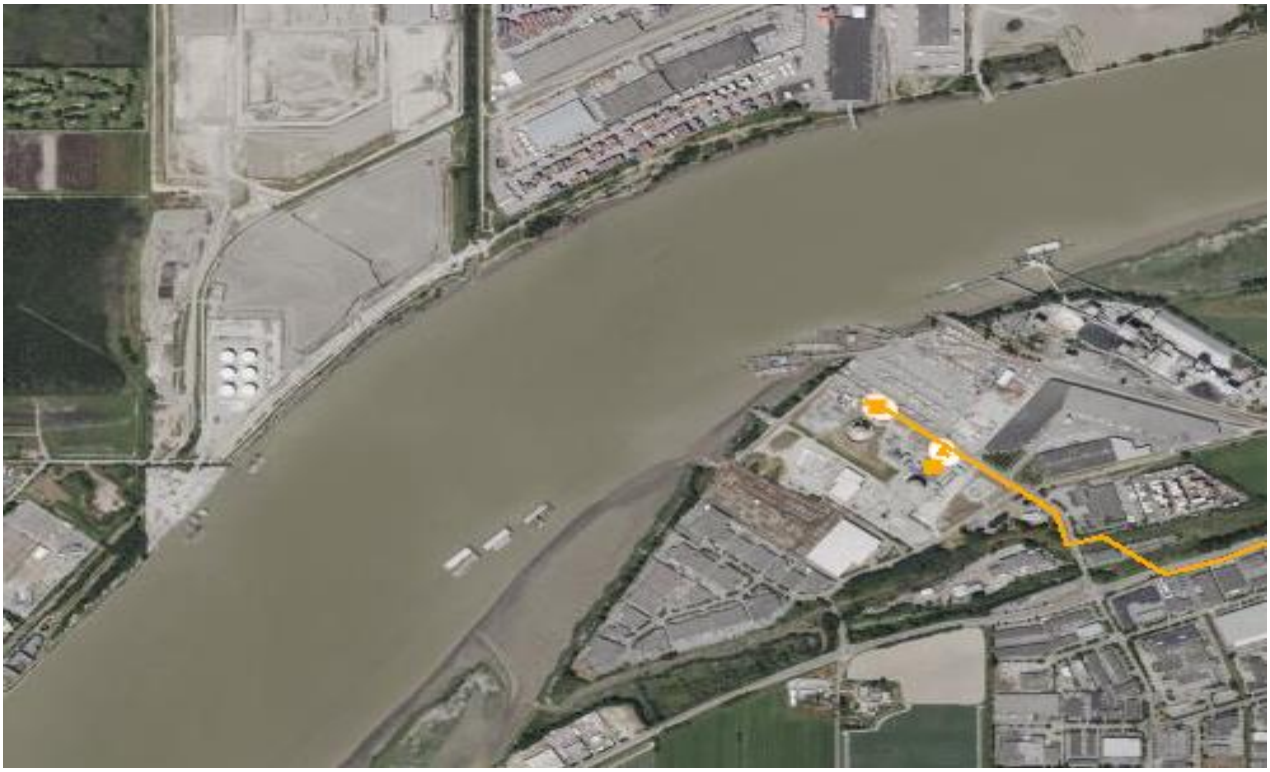
The following data was used in the as the basis for the resiliency study:

LNG Storage Capacity considered: 28,500 – 142,400 m^3

2.0 HIGH-LEVEL EVALUATION

2.1 Floating LNG Storage – Potential Locations

2.1.1 Tilbury Island



Note: Yellow line is existing FEI pipeline routing

Key features:

1. Connects to the main arteries of the CTS and thereby serving the entirety of the Coastal Transmission System.
2. Close to existing Tilbury Island LNG Facility, comprising of the Base Plant and T1A LNG Plants. Has existing liquefaction and LNG Storage facilities. Has been operating as a peak shaving facility and LNG production facility for over 50 years.
3. Potential to use the existing LNG liquefaction plant to fill the FSU with LNG
4. Close to water lot on the Fraser River.

2.1.2 Fraser River Crossing near the Port Mann Bridge

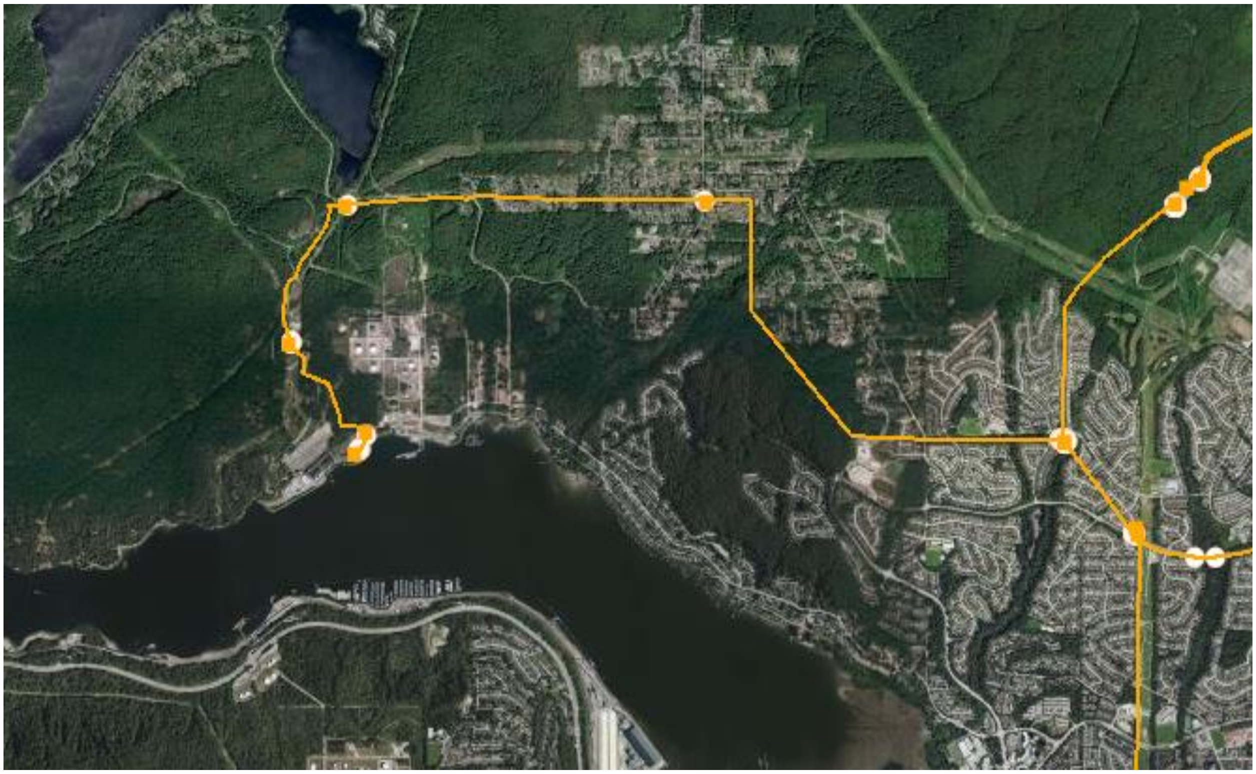
Note: Yellow line is existing FEI pipeline routing

Key Features:

1. Connects to the main arteries of the CTS and thereby serving the entirety of the Coastal Transmission System.
2. The location is close to a water lot on the Fraser River. However, this section of the Fraser River is one of the narrowest portions of the river and could lead to potential ship traffic issues in the busy Fraser River should the FSU have loss of control or any other mechanical / operational issues.
3. The CTS pipeline is buried deep in this location due to the HDD river crossing. Substantial jetty work and tie-in infrastructure is required to connect the FSRU to the pipeline at this location. These issues make it difficult and expensive to work at this location.

   The BC Hydro 500 kV transmission grid overhead powerlines are just downstream of this location and the busy Port Mann Bridge is just upstream. The existing infrastructure can cause further limitation to the ease of any work in this area.

2.1.3 Burrard Inlet



Note: Yellow line is existing FEI pipeline routing

Key Features:

1. Indirect connection to the main artery of the CTS; it is connected through a 20" line that is planned to be derated in 2024 due to the decommissioning of the Burrard Thermal Generating Station and integrity management requirements through the BCUC approved CTS TIMC project. Injection at this location would require reinstatement to a higher pressure, which would require pipeline integrity validation and an Engineering Assessment.
2. Close to water lot on the Burrard Bay.

2.1.4 Squamish, at a location near the Woodfibre LNG plant

Note: Yellow line is existing FEI pipeline routing

Key Features:

1. Indirect connection to the main artery of the CTS; the existing and planned pipeline network between this location and the CTS is unable to transport sufficient gas to support the CTS during cold weather conditions.
2. Pipeline access rights from the water.
3. Proximity to northwestern shoreline of upper Howe Sound, Squamish.

Based on the analysis above for the four potential site locations to install an FSU, the Tilbury Island location is most suited but still has several challenges which are discussed in the sections below.

2.2 Base Case TLSE

Key Features:

Existing infrastructure at Tilbury Island may be utilized to support the new facilities of TLSE (LNG Tank and Regasification facilities), such as:

1. Existing LNG liquefaction plant, T1A can be used to fill the new TLSE LNG Tank, if no additional liquefaction is installed.
2. Space for a new LNG storage tank and additional liquefaction currently available.
3. Space for a new regasification unit currently available.
4. Existing Control room may be shared with the TLSE facility.
5. Operations and Maintenance staff and associated costs may be shared.
6. Short run for connectivity to the existing CTS pipeline.
7. No new marine or jetty interface is required.
8. No major challenges have been identified with this TLSE option.

2.3 Floating LNG Storage – Tilbury Island

Based on the analysis of potential locations analyzed in section 2.1 above, the Tilbury Island location will be evaluated in this section to identify the challenges associated with the offshore storage option.

For simplicity of the analysis, the FSU and FSRU will both be considered the same in this section, and whichever is easier to procure can be considered for the installation, subject to the review of the challenges for this option. The generic term FSU will be used in this evaluation.

2.3.1 Technical Challenges:

1. Availability
   - (i) Most of the new build FSU's in the current market are approximately 170,000 m^3 in capacity. The older previous generation FSU's were in the size range of 130,000-140,000 m^3 capacity. This presents the challenge of using an older existing FSU by way of lease/time charter or purchase. This option of an older FSU would require extensive inspections/verifications and possible modifications, repair, or re-certifications to satisfy todays codes and industry standards.
   - (ii) Alternately, a new custom build FSU with capacity 140,000 m3 may have to be procured which would be relatively much more expensive.

Both options above require extensive market analysis, compatibility studies, appointment of brokerage, warranty surveyors etc. These skill sets are typically available with shipping operators and not with natural gas operator companies such as FEI.

2. Mooring of the FSU at Tilbury Island

    (i) Water depth in the Fraser River will need to be further studied to handle LNG filled vessel draft. Dredging requirements may have to be established for the entire operating life of the FSU.

    (ii) Assessment of the Massey Tunnel access with respect to water depth required for the FSU.

    (iii) New marine infrastructure will be required at Tilbury including a new jetty, mooring systems etc.

    (iv) New ship to shore interfaces such as a send-out gas pipeline, communication systems, utilities, power, controls and shutdown systems, and safety system etc. would be required.

    (v) Availability of LNG for filling the FSU from Tilbury or relying on external sources of LNG.

    (vi) Potential impact to the existing BOG system used for filling (from existing liquefaction train at Tilbury). The existing BOG compressor may require upgrade / modifications to handle the additional BOG generated during the FSU filling operation or may have to be managed by some limitations on existing operations during the filling cycle.

    (vii) Fraser river ship traffic impact study due to FSU moored at Tilbury. Exclusion zones, safety system, logs etc. May cause restrictions to other users on the Fraser River.

    (viii) Limits use of Tilbury jetty for future developments. For example, potential export projects. Space constraints between the jetty and new LNG Carriers coming in. Associated risk assessments need to be carried out.

All the above issues require further detailed specialist studies, resources, and time.

2.3.2 Economic Challenges

(i) CAPEX and OPEX of an existing FSU charter / purchase or a new custom-built FSU may be higher than a full containment onshore LNG storage tank depending on the global LNG ship market conditions. The current shipping market is very tight, as the fabrication yards are facing a severe capacity crunch due to an increased amount of global ship orders.

(ii) Comparing between the new build options, a new conventional onshore TLSE tank versus a new FSU, the latter is materially more expensive. Based on experience, this can be 20-35% higher in the order of magnitude.

(iii) CAPEX for new marine infrastructure including a dedicated jetty at Tilbury is required.

(iv) CAPEX for the onshore-offshore interfaces including an LNG loading system and send out system is required.

(v) The cost of a new pipeline to connect the FSU to the gas transmission pipeline across the jetty and/or a longer run of LNG offloading line to the onshore regasification unit is required.

(vi) Long term CAPEX/OPEX costs for the FSU moored in the Fraser River. These costs would include items such as frequent dredging, debris clearance, mooring system, vessel dry docking for hull and topsides, potential tugboats operation, new operations and maintenance staff and shipping skillsets needed, etc. Ship marine classification requirements may be impacted.

All the above issues require further detailed specialist studies, resources, and time.

2.3.3 Environmental, permits, regulatory approval challenges.

(i) New Environmental Assessment (EA) or change to existing EA application will be required. Impact to fisheries and other marine life will need to be further studied for all operating and construction scenarios. Could be significant impact to project schedule.
(ii) Permits for pipeline, jetty, marine infrastructure/mooring system.
(iii) Pipeline ROW permit.
(iv) Construction permits for offshore and onshore work.
(v) Assessment and handling of the emissions, effluent discharge, noise from the FSU.
(vi) Risk assessments (i.e. Quantitative Risk Analyses).

All the above issues require further detailed specialist studies, resources, and time.

2.3.4 Commercial challenges

Contracts – multiple international and local contracts would be required.

(i) The FSU option would involve multiple international contracts and associated challenges for design, procurement, installation, and operation, depending on the origin and condition of the vessel. Also, permits, regulatory approvals etc.
(ii) If an existing older FSU or a new build is purchased as the option going forward, it will be an asset outside of FEI's core business. Associated liabilities, labor issues, management and operational contracts and commercial impacts.
(iii) Contractor for pipeline, jetty, marine infrastructure.
(iv) Contract for FSU charter, purchase, or new build.
(v) LNG supply/fill contracts, if required.

(vi) Contracts for local surveys - water ways, mooring system, river traffic impact assessment etc.

All the above issues require further detailed specialist studies, specialist contracts and legal resources and time.

2.3.5 Organizational

(i) New operators or training current operations staff for the FSU and jetty operations.
(ii) Marine crew for the FSU.
(iii) Interface between operators of FSU control and safety shutdown system and the onshore facilities.
(iv) Development of offshore, onshore and interface operating protocols.
(v) Re-classification of the FSU for permanent moored operation, as applicable.
(vi) Development of FSU emergency safety interface with the shore facilities.
(vii) Training of local support services for the FSU such as firefighting, bunker, river traffic management, municipal-provincial-federal interfaces etc.
(viii) FSU Operation/maintenance/management is not core to FEI's business and would be a new area of business, the organization would have to be expanded to include this in the portfolio, along-with the associated risks which would need to be analyzed.

All the above issues require detailed specialist studies, specialist operator training, manuals, and time.

2.3.6 Political

(i) First Nations engagements and approvals.
(ii) Public social and political impact due to permanently moored FSU in the Fraser River.
(iii) Impact to surrounding facilities. Municipal issues. Provincial and Federal issues.

All the above issues require detailed engagement with stake holders and impact assessment.

Project:	TLSE - Floating LNG Storage Concept Analysis	**Job No.:**	FEI24-04493
Location:	Tilbury, BC	**SMCI Doc. No.:**	04493-31-3700-REP-0001
		FEI Doc. No.:	

3.0 RECOMMENDATIONS

The Onshore TLSE and Offshore Floating LNG Storage options have been analyzed. The Floating LNG Storage options are considered "not viable" due to one or more fatal flaws at each of the four potential offshore locations identified.

It is recommended that the onshore TLSE Base Case option be considered as the viable option for this project.

	Base Case TLSE	Location 1 Tilbury Site	Location 2 Fraser River Crossing	Location 3 Burrard Inlet	Location 4 Squamish
Technical					
Economic					
Environmental					
Commercial					
Organizational					
Political					

Not viable **(i.e. "fatal flaw")**	**Viable but multiple challenges**	**Viable**

Appendix D

CB&I REPORT

FILED CONFIDENTIALLY

Appendix E

WSP REPORT

FILED CONFIDENTIALLY

Appendix F

RAYMOND MASON REPORT

Dated: July 2, 2024

FortisBC Energy Inc. Tilbury Liquefied Natural Gas Expansion Project: Gas Supply Considerations

Provided to:

Fasken

Fasken, Martineau DuMoulin LLP
550 Burrard Street, Suite 2900
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Prepared by:

Raymond Mason
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Victoria, British Columbia

TABLE OF CONTENTS

INTRODUCTION AND SUMMARY OF CONCLUSIONS

My consulting services have been engaged by Fasken Martineau DuMoulin LLP ("Fasken") as it relates to FortisBC Energy Inc. (FEI)'s Certificate of Public Convenience and Necessity for the Tilbury Liquefied Natural Gas Storage Expansion ("TLSE") Project (the "Regulatory Proceeding"). My industry knowledge and experience (provided in Appendix B) was considered valuable for the purposes of providing an independent expert assessment of questions set out in the Letter of Instruction dated April 18, 2024 and attached to my report as Appendix A. I am aware that I have a duty to assist the regulator and not to be an advocate for any party ("Duty of Independence"). I prepared this report in accordance with the Duty of Independence, and if called upon to give oral or written testimony, I will give testimony in conformity with this duty.

At a high level, I was asked to consider what commercial attributes of the proposed TLSE Project may carry throughout its operational lifetime. Set out below is a summary of my answers to the specific questions put to me in the Letter of Instruction with supplementary information included in the body of my report.

1. What are the elements of an optimal resource portfolio for FEI and its customers?

The development of an efficient natural gas supply portfolio for a utility is predicated on the resource options that are accessible in the area it operates. Though natural gas is a homogeneous form of energy, how the molecules move from the supply to demand region(s) is unique. The characteristics of supply and demand are also not static and will continue to shift to achieve economic balance. In particular, a natural gas portfolio that has been optimized by the utility will respond to shifts in supply and demand to maintain security of supply, while balancing the economic benefits to customers. The elements of an optimal resource portfolio for FEI are therefore multi-faceted, leveraging transportation, storage, peak shaving facilities, and third-party arrangements to meet the demands of its customers throughout the year.

2. **FEI has, since 1971, included on-system liquified natural gas ("LNG") at the Tilbury facility in its supply portfolio as a peaking capacity resource (i.e., rapid send-out capability, backed by sufficient LNG to meet short-duration peak load). FEI's current Annual Contracting Plan includes 150 MMcf/d of regasification and 0.6 Bcf of LNG from the Tilbury facility. We seek your opinion on the peaking capacity alternatives available to FEI in the event that FEI was no longer able to include some or all of these peaking resources in its supply portfolio. In particular:**
   A. **Based on your assessment of the natural gas markets accessible to FEI, would FEI be able to contract for peaking resources (capacity/energy supply) as a potential alternative to on-system LNG in its gas supply portfolio, and if so on what terms?**
   B. **If appropriate peaking resources (capacity/energy supply) are unavailable to FEI in the market, what other potential investments could FEI explore as a potential alternative to on-system LNG as peaking resources (capacity/energy supply) in its gas supply portfolio? For clarity, in this regard we are requesting that you identify potential peaking supply (capacity/energy supply) alternatives based on your understanding of the regional system, as opposed to undertaking a financial analysis of those options.**

In my opinion, FEI would not be able to contract for peaking capacity resources that I would consider dependable, beyond those that are currently committed, as an alternative to on-system LNG storage. The deployment duration and dispatch capability of a resource remain the main criteria for security of supply from a peaking capacity resource. Due to the nature of the regional demands of FEI's customers, third-party off-system storage and companies offering peaking gas supply arrangements, are constrained by the ability to transport the underlying supply of natural gas, as well as the potential for unplanned outages. Furthermore, based on the results of my market research evaluating third-party arrangements, the costs for peaking resources are extremely expensive, do not support a consistent long term supply resource, and would require a portfolio of participants to be able to meet FEI winter demand. To put this in perspective, FEI would be competing/accessing the Huntingdon/Sumas gas supply market, on the coldest days of the winter, for significant volumes historically destined to the PNW (rapidly escalating pricing throughout daily trading hours). These factors, when taken together, are not conducive to contract for dependable peaking supply resources.

In the absence of readily available dependable peaking resources (including sufficient existing on-system storage), FEI would need to make significant investments (including capital investments and/or contractual capacity commitments) to meet its peaking capacity needs. The types of investments could include expanding mainline transportation, and the associated interconnected off-system storage facilities, and/or developing on-system peak shaving LNG. Building these types of resources takes time, especially capital projects that require consultation with multiple parties throughout the planning and construction phases. For example, increasing WEI mainline capacity and associated interconnected off-system storage facility (i.e., Aitken Creek) would likely require longer development periods than increasing off-system storage displacement in the Pacific Northwest and/or increasing on-system peak shaving LNG.

In my opinion, the development of a proprietary on-system asset, such as the proposed TLSE Project, has advantages over the alternative infrastructure investments when it comes to designing a gas supply portfolio. Constructing a mainline transportation resource, for the purposes of meeting winter demand, would also result in inefficient utilization due to underutilized capacity in non-winter months. Any investments considered by FEI should consider the assets' long-term utilization parameters and the timing in which the resource could be deployed.

The TLSE Project would provide FEI with operational backup for disruption: (a) to existing off-system storage and/or mainline transmission; and (b) that may not necessarily affect FEI customers, but those of peer utilities, that source gas supply from Huntingdon/Sumas. The proposed TLSE Project's proximity to a larger US export market could also be a benefit to FEI's customers. In particular, peer utilities in the US, servicing a growing gas-powered electricity and industrial demand are, and will be for the foreseeable future, evaluating the cost/benefit of limiting pricing exposure to Huntingdon/Sumas, in response to growing peaking demand, by either: (a) sourcing peaking services like what the proposed TLSE Project could provide; or (b) committing to long-term mainline transportation.

Furthermore, while meeting the needs of FEI's customers for safe and reliable service, a proprietary LNG peaking facility will continue to carry long-term value for the utility and its customers. If the demand profiles of FEI's customers were to shift over time (i.e., lowering annual demand while maintaining the need for winter supply), the ease of de-contracting mainland transportation is more appropriate than shedding reliable on-system capacity as on-system storage is designed to be deployed only when it is required.

3. **Assuming a hypothetical scenario where the TLSE Project is constructed with 3 Bcf of storage volume and at 800 MMcf/d of regasification capacity, and FEI no longer requires the full storage and regasification capacity to meet its own gas supply and resiliency requirements, do you expect that FEI would be able to monetize the surplus by selling peaking resources in the gas markets? If so, how much daily send-out capacity would the market reasonably absorb.**

Assuming that the TLSE Project is constructed, and FEI were to have spare capacity that is not required to meet customer demand or resiliency, FEI would be able to generate revenues to offset the cost of service of the facility by selling its excess supply into the market. Based on my assessment of the available supply and demand in the Huntingdon/Sumas natural gas market and assuming current market conditions persist, I expect the daily market can reasonably absorb 300-400 MMcf/d of natural gas across multiple days (e.g., 10 days) during winter without influencing daily prices in a manner that could limit monetization values (i.e., materially decreasing the revenues generated through mitigation into the market).

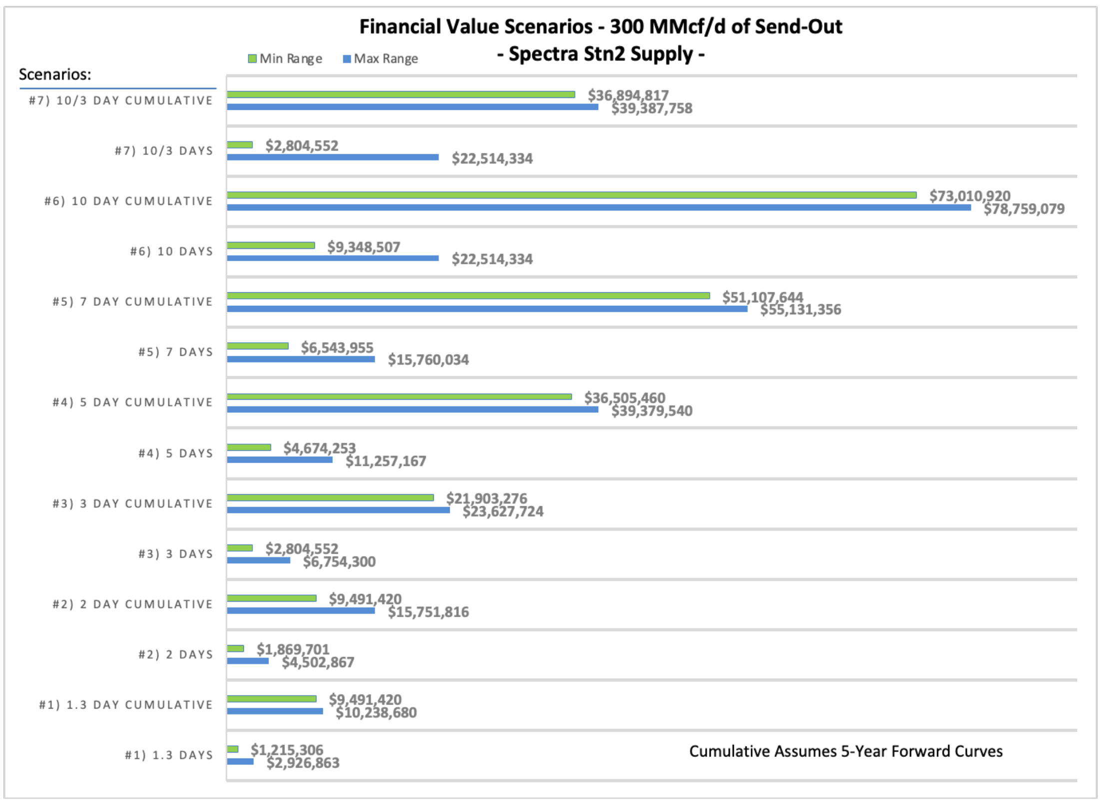
4. **Assuming FEI is able to monetize its hypothetical surplus from the TLSE Project as contemplated in the Question 3 scenario, what annual financial value could FEI recover for its customers in the following scenarios where, in one year, FEI can deliver and the market can absorb a maximum of**

   Scenario #1: 300 MMcf/d of send-out sold over 1.3 peak days (300 MMcf/d x 1.3 = 0.4 Bcf of LNG);
   Scenario #2: 300 MMcf/d of send-out sold over 2 peak days (300 MMcf/d x 2 = 0.6 Bcf of LNG);
   Scenario #3: 300 MMcf/d of send-out sold over 3 peak days (300 MMcf/d x 3 = 0.9 Bcf of LNG);
   Scenario #4: 300 MMcf/d of send-out sold over 5 peak days (300 MMcf/d x 5 = 1.5 Bcf of LNG);
   Scenario #5: 300 MMcf/d of send-out sold over 7 peak days (300 MMcf/d x 7 = 2.1 Bcf of LNG); and
   Scenario #6: 300 MMcf/d of send-out sold over 10 peak days (300 MMcf/d x 10 = 3.0 Bcf of LNG).

   For each scenario, please calculate the financial value FEI could recover over a 5-year period, taking into account FEI's estimated variable operating costs for the Tilbury facility, which has been provided to you, and assuming FEI's commodity cost to produce LNG reflects gas prices in the summer when FEI typically fills its LNG tank. Please also add another five-year scenario:

   Scenario #7: in year 1, 300 MMcf/d sold over 10 peak days (300 MMcf/d x 10 = 3.0 Bcf of LNG), and in each of years 2-5, 300 MMcf/d is sold over 3 peak days (300 MMcf/d x 3 = 0.9 Bcf of LNG);

The results of my financial analysis are presented in the figure below. The figure identifies the range of financial values (i.e., Min to Max) for Scenarios #1 through #7, and the respective 5-year cumulative values assuming 300 MMcf/d of send-out capacity from the TLSE Project, before including any value that FEI would receive for a standing demand charge. The results of my analysis show that, over a 5-year period, FEI could recover between $73.0 MM CDN to $78.8 MM CDN of financial value for its customers over 10 peak days in the winter. Assuming Scenario #7, a combination of 10 peak days of send-out capacity in year one and 3 peak days of send-out capacity in years 2 through 5, FEI could recover between $36.9 MM CDN to $39.4 MM CDN of financial value for its customers. [1]



The financial results presented in figure above do not include additional incremental value that FEI could capture by implementing a standing demand charge. Please refer to Appendix C for a detailed analysis of this calculation. I estimate that FEI could generate the following range of additional incremental value through an annual standing demand charge:

- *$5.2 MM CDN - $7.0 MM CDN for every 50 MMcf/d*

[1] Based on forward markets dated February 29, 2024

Assuming Scenario #6 (i.e., 10 days of send-out, cumulative over 5-years) and Scenario #7 (i.e., 10 days of send-out year 1 and 3 days of send-out over years 2-5) and that FEI's gas supply department is successful in contracting a standing demand charge with a third-party for 50 MMcf/d of send-out capacity from the TLSE Project, FEI could increase the average cumulative financial value as follows:

Scenario #6: From $75.9 MM CDN to $106.4 MM CDN; and
Scenario #7: From $38.2 MM CDN to $68.7 MM CDN

SUPPORTING REVIEW AND EVALUATION

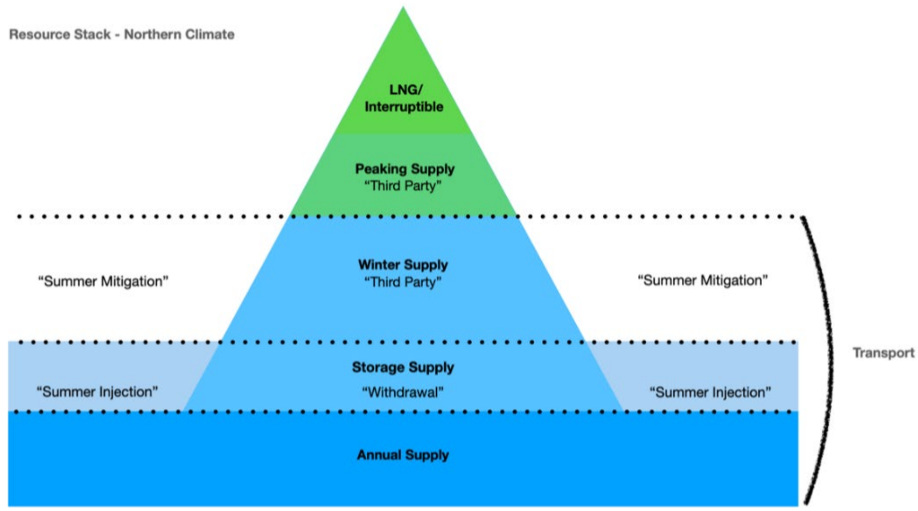
Response to Question #1

What are the elements of an optimal resource portfolio for FortisBC Energy Inc. ("FEI") and its customers?

The development of an efficient natural gas supply portfolio for a utility is predicated on the resource options that are accessible in the area it operates. Though natural gas is a homogeneous form of energy, how the molecules move from the supply to demand region is unique. The characteristics of supply and demand are also not static and will continue to shift to achieve economic balance. In particular, a natural gas portfolio that has been optimized by the utility will respond to shifts in supply and demand to maintain security of supply, while balancing the economic benefits to customers. The elements of an optimal resource portfolio for FEI are therefore multi-faceted, leveraging transportation, storage, peak shaving facilities, and third-party arrangements to meet the demands of its customers throughout the year.

Figure 1 below shows a general stack of resources a utility might utilize for its natural gas portfolio. Assuming a 365-day distribution, the foundation of the stack represents the necessary transportation delivery to facilitate 100% load factor demand and the deliverability of off-system storage injection and withdrawal seasons. While the stacking of resources will evolve over time as demand profiles shift and marketed products and services are introduced (e.g., storage, transportation, industrial customers, etc.), the contractual commitments of certain resources can extend over long timeframes due to their underlying capital investment structure. As a result, acquiring and eliminating a resource can take a long time, as well as creating overlaps in a portfolio as one resource is implemented and another is retired.

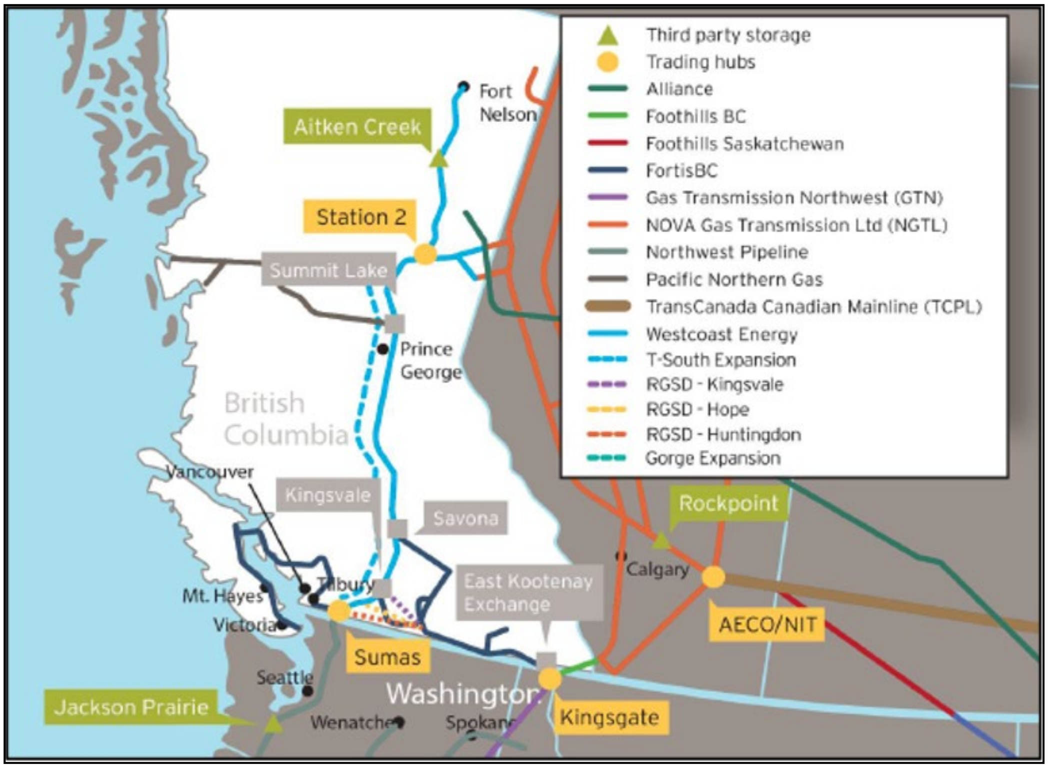
Figure 1



In addition to being in a state of constant change over time, the region FEI operates faces unique challenges among utilities in North America when sourcing its gas supply portfolio. First, the consumer demand is located a significant distance from its source of natural gas. As a result, market participants must undertake additional measures to secure pipeline transportation to move supply to the consumer. Second, because of the characteristics of the supply region and FEI's customer use profiles (i.e., coincidental peaking for power and natural gas), FEI is required to invest in and/or contract for additional resources including: alternative pipeline transportation, off-system storage, on-system peaking alternatives (e.g., interruptible tariffs and Liquified Natural Gas ("LNG"), and contractual gas supply peaking arrangements. As no one resource will provide security of supply, FEI must combine resources and evaluate their dispatch abilities. By understanding a given resource's economic viability, market availability, and associated contractual commitment necessary to secure it, FEI is able to shape the resource development of its broader gas supply portfolio.

In the sections below, I discuss the types of resources that are available in the region, each resource's dependency on another for deployment and how these resources can be combined to create an economic portfolio for FEI's customers. Figure 2 below shows the resources currently available to FEI, as well as potential resources that could be developed in the future (in one form or another).

Figure 2



I. Transportation (Pipeline Capacity) Resources

Transportation resource diversification helps shape an efficient gas supply portfolio. The contract parameters and operation criteria of transportation resources require continuous evaluation to ensure they remain economical and continues to benefit FEI's customers. As part of this evaluation, a utility such as FEI will consider tenure commitments, renewal rights, mitigation capabilities (i.e., during periods of time when transportation is not required), upstream and downstream interconnection reliability, and corresponding capacity availability.

The regions served by FEI are supplied by two upstream transportation pipelines, the Westcoast Energy Inc. ("WEI") T-South pipeline and FEI's Southern Crossing Natural Gas Pipeline ("SCP"). While WEI is interconnected with SCP and the Williams Northwest Pipeline ("NWP"), the SCP is interconnected with the Foothills System ("Foothills"), which connects to the NOVA Gas Transmission System in Alberta.

WEI operates segments of transport in British Columbia that FEI has contracted, Transportation North ("T-North") and Transportation South ("T-South"). The T-North section of pipeline provides access to the Aitken Creek North Gas Storage Facility ("Aitken Creek") and is the critical linkage for many processing plants that bring natural gas production onto the WEI system. T-South is the mainline transportation pipeline from Northern BC (T-North interconnect) to the United States border at Huntingdon/Sumas. WEI's T-South pipeline transverses over some of the most difficult geological terrain in North America and was put into service in 1956.

SCP consists of a 24-inch pipe extending 300 kilometers from Yahk, BC to Oliver, BC in the Okanagan Valley. The SCP interconnects, in the East, to the Foothills pipeline that delivers supply from Alberta to the United States while in the West, SCP connects to the WEI's T-South pipeline. SCP was put into service in the early 2000's.

Foothills is 1,237-kilometer network of pipelines that sources Alberta natural gas and transports through the southern portion of British Columbia from Sparwood (BC/Alberta border) to Kingsgate (US border of Idaho). The original pipeline commenced service in 1981. This pipeline interconnects with Gas Transmission Northwest ("GTN") that continues through to Washington, Oregon, Nevada, and the California border.

The NWP system interconnects with WEI T-South at the Canadian/US border and GTN at Stanfield, Oregon. The NWP begins at Sumas, Washington and extends southeast through Oregon, Idaho, northern Utah, Wyoming, and southward into the San Juan Basin in southern Colorado. NWP typically flows north to south and, therefore, is heavily dependent on WEI's deliverability on a daily basis. There are also two storage facilities interconnected to NWP, Mist Underground Natural Gas Storage Facility ("Mist") located near the community of Mist in Columbia County, Oregon, and the Jackson Prairie Underground Natural Gas Storage Facility ("JPS") located in Southwest Washington.

The foundation of FEI's supply portfolio is mainline transportation that can service customers throughout the year. As such, diversifying access to alternate supply regions would strengthen FEI's supply portfolio and, if an opportunity of this kind arose, should be carefully considered (i.e., assuming the costs are reasonable for the consumers).

Producers consider the advantages and disadvantages of carrying the fixed costs of transporting natural gas, as these costs are generally significant. For example, a producer may need to balance accessing a premium priced market to offset the fixed costs of transportation and what shareholders and/or equity markets felt was necessary to diversify the producer's operating costs. Utilities consider the advantages and disadvantages of carrying the fixed costs of transporting natural gas when sourcing gas from suppliers, as these costs will be passed onto customers. Utilities will generally seek to balance security of supply with the economic benefits of sourcing gas supplies, while avoiding higher priced markets.

FEI has continued to maintain a strategic transportation resource portfolio. Responding to customer demand by contracting for incremental capacity and constructing new capacity when economically viable. The foundation of firm transportation, operating 365 days a year, has afforded consumers significant cost of gas savings and diversification of supply (i.e., Spectra Stn2 and/or AECO AB-NIT[2]). These cost savings will persist for those gas supplies that are currently serviced by the existing portfolio. However, given current market conditions, any incremental demand from consumers within FEI's and its peers' regions will require the construction of incremental transportation capacity to meet the markets call for supply – which will come with an associated cost.

II. Off-System Storage Resources

Off-system storage resource options exist upstream and downstream of FEI's core customer demand regions. Upstream, Aitken Creek is located northeast of Fort St. John, British Columbia. Downstream, the Mist storage facility is in Columbia County, Oregon and the JPS facility is located in Southwest Washington. A storage resource, and connectivity to mainline transportation, is critical to its usefulness. Upstream storage and its associated supply characteristic differ from those downstream of FEI's core customer demand regions. As such, I evaluated each resource in turn below.

i. Upstream Off-system Storage

Upstream, the gas supply regions of Northern British Columbia and Alberta differ to others in North America. Extreme low winters temperatures can create gas well performance issues, and

[2] ICE NGX - https://www.ice.com/products/69723159/AB-NIT-Fixed-Price-Future

from season to season, access to some remote locations can hamper the continuous supply of natural gas from producers. This is commonly known, to industry players, as winter freeze-off and spring break up. Natural gas production can be at risk following a gas well freeze-off as many operators must inspect pipe, valves, compressors, reservoir integrity, etc. prior to restarting production. Further, spring break up delays will affect those wells that have been drilled but not yet completed (i.e., uncompleted natural gas wells that have been drilled but not yet undergone well completion activities to start the production of gas). Northern upstream storage therefore minimizes market production variability while the supply region is continuously adjusting to meet its own economic balance and fulfill commitments to the market.

Aitken Creek, for example, has a working capacity of 77 billion cubic feet. This resource, combined with other supply commitments, can provide 168,000 GJs/day (approx. 12%) of the supply portfolio for FEI downstream customers during the winter (November - March). Supply sourcing in the region also typically carries a lower price in the summer months, resulting in a cost of gas benefit for customers during the winter withdrawal season. Beyond the significant savings to FEI’s customers from avoiding the Huntingdon/Sumas market, Aitken Creek capacity provides supplemental gas pricing benefits even when incorporating the incremental costs of transporting this supply source to FEI customers. Finally, the facility offers operational flexibility for supply disruptions during busy maintenance periods for the entire energy industry.

ii. Downstream Off-system Storage

FEI and peer utilities located in Washington and Oregon share similar customer load profiles. In particular, seasonal demand is higher in the winter months and lower in the summer months. These peer utilities also rely on T-South transportation to ship gas supplies from northern British Columbia to the US border. Approximately 70%[3] of the gas supply transported through T-South is exported to the US. Southern storage injects gas supply during the summer, commingled and accumulated, for future winter withdraw. The north to south hydraulic nature of T-South mainline transportation means FEI’s contracted downstream storage is utilized by displacement (i.e., gas supplies destined to travel south of British Columbia, during the storage withdraw period, will be diverted to the Lower Mainland and the associated diverted gas supply will be replenished by

[3] Canadian Energy Regulator, https://www.cer-rec.gc.ca/en/data-analysis/facilities-we-regulate/pipeline-profiles/index.html

storage capacity at Mist and/or JPS). This leaves the southern US market whole while the utilization of mainline transportation remains high.

Southern off-system storage facilities in the United States do not rely solely on the T-South system to utilize natural gas capacity. These facilities are interconnected to the NWP network, which gains access to alternative gas supply regions in Alberta (i.e., through interconnection with GTN), Wyoming, and Utah. FEI is sourcing 100,000 GJs/day and 110,000 GJs/day respectively from JPS and Mist storage facilities (i.e., 15% of FEI's peak day requirements), which demonstrates the importance of these off-system resources as part of FEI's gas supply portfolio. The NWP interconnecting pipeline network is fully contracted, limiting all incremental deliverability, from the JPS and/or Mist storage facilities. Any expansions in these regions will come at a cost and its recovery will be reflected in the contracting of service(s). The market is responding to demand in the region with the proposed Northwest Pipelines Gorge and GTN's XPress expansions. If these expansions proceed, incremental deliverability from interconnected storage facilities could be explored. For FEI, its ability to make use of any incremental resources secured in this region will be subject to displacement availability on the T-South transmission system.

As demonstrated above, off-system storage remains a necessary tool within FEI's resource portfolio. The resource helps meet median customer demand profiles during winter seasons (151 days from November through to March), deployable on a monitored basis as winter weather volatility persists. The deliverability of off-system storage relies on the pipeline infrastructure that it is interconnected with, which must be considered when developing a gas supply portfolio. Further, as it stands, all interconnecting services are fully utilized and the only way to increase capacity is through infrastructure expansion(s). As a potentially interested counterparty that manages an evolving resource portfolio, researching the cost/benefit of supporting (i.e., through contractual arrangements) such expansion(s) is important. In addition, determining the timing of any expansion is important as these types of projects can take considerable time to complete.

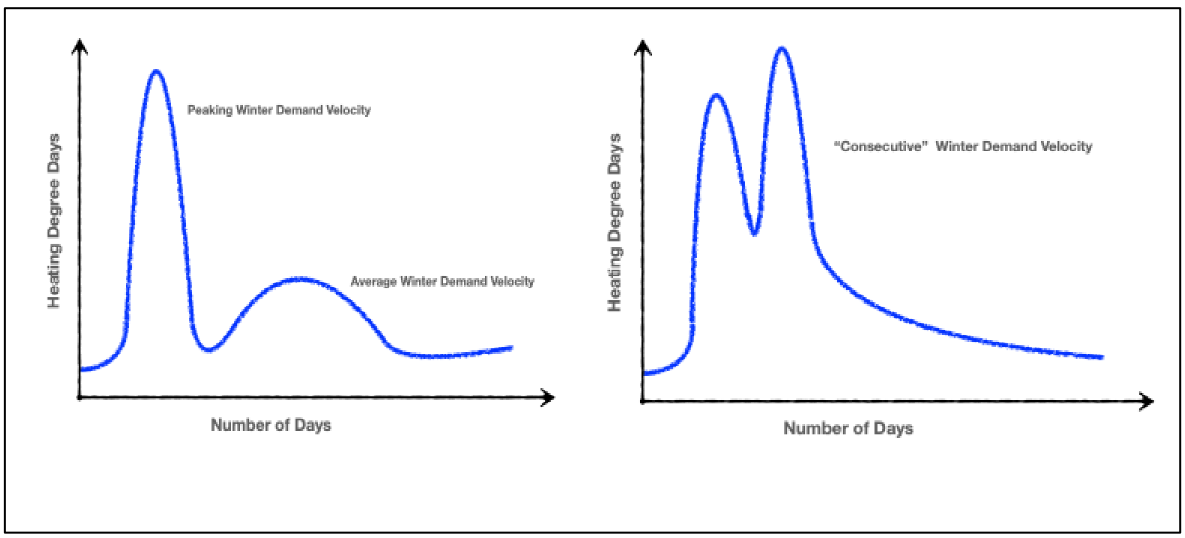
Given the heavy use of off-system storage, storage customers (including FEI) must remain diligent in monitoring the reservoirs deliverability (i.e., during maintenance and high demand periods).

III. Peaking Resources

Peaking resources are those resources that are deployed during a "super peak" when customer demand reaches its peak. This typically coincides with colder-than-normal temperatures and the visual response, by consumers, to winter conditions (e.g., snowfall).[4]

Ideally, peaking resources would be accessible by consumers within a 24-hour period and deployable for multiple days. Sizing the resource, from an energy supply perspective, will also depend on the velocity of incremental demand during regional weather changes. As depicted in Figure 3 below, the onset of colder than normal weather can create exponential increases in customer demand. The charts in Figure 3 show multiple winter weather scenarios. The left chart shows a colder-than-normal winter weather event followed by an average winter weather event and the right chart shows two consecutive colder-than-normal winter weather events (i.e., as heating degree days rise (temperature declines), customer demand increases). Utilities must model and forecast for such scenarios and, as discussed below, develop a portfolio of peak resources to manage these potential weather events.

Figure 3



The reliance on consistent weather forecasts is also critical to the operation of the distribution system that is highly sensitive to consumer demand. Velocity will also change even within a smaller geographical service area. Examples include the variability of consumer demand from coastal communities such as the City of Victoria versus the Lower Mainland. Though

[4] Assuming temperatures are the same with and without snow, a customer will react differently to the sight of snow.

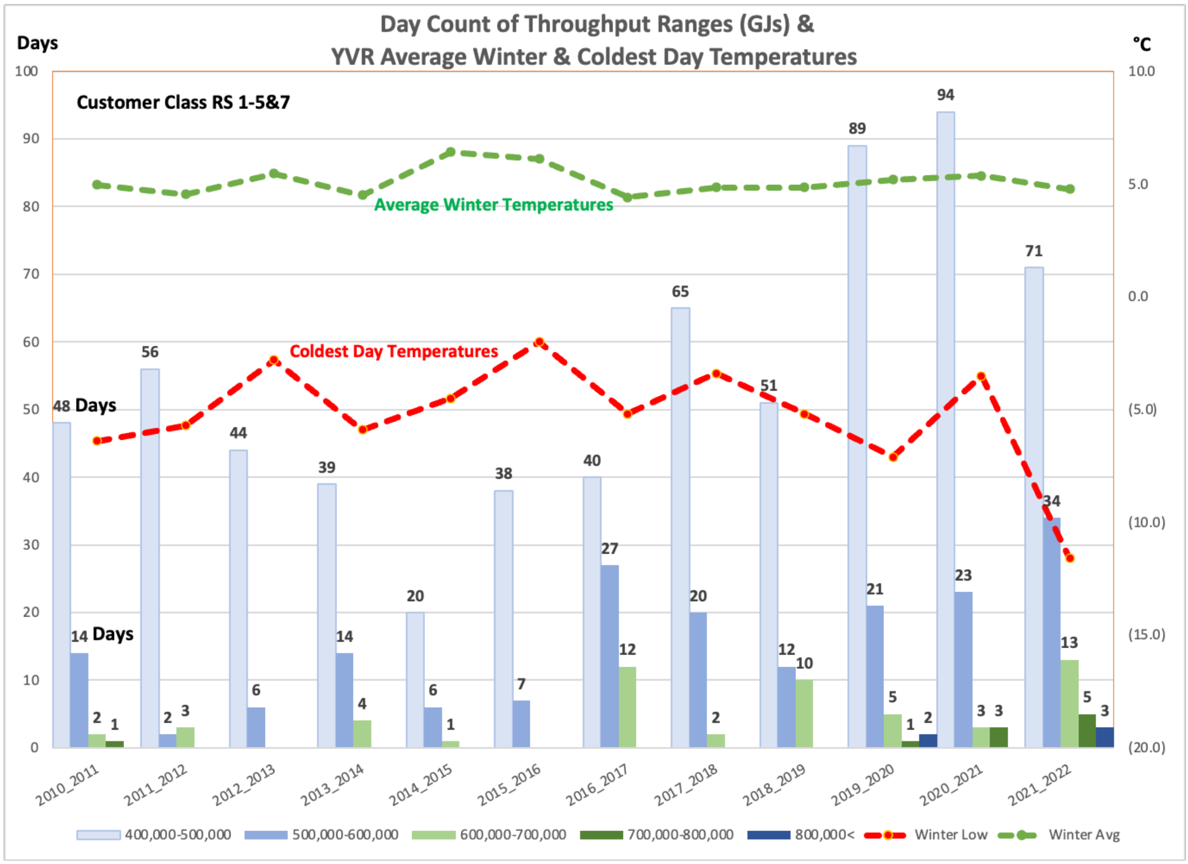
geographically close in proximity, their coastal weather differences can drive unique demand responses. While weather forecasting technology continues to improve, radical changes and its severity cannot always be predicted.

On-system peaking resource(s) must be able to provide (at a minimum) continuous availability to bridge any gaps in winter weather events. As such, in anticipation of a forecasted weather event, a peaking resource can remain idle (i.e., operational ready to deploy gas supply) while actual weather unfolds and can typically be ramped up within hours. This operational flexibility enhances the assets value compared to an alternate resource that requires 24-hours notice to be deployed (e.g., off-system storage and mainline transportation) or if there is an unplanned operational mainline transportation disruption. For example, when a utility elects to nominate an off-system resource and the weather forecast doesn't materialize as expected, it will be left with excess gas that will require mitigation. After mitigation, the off-system resource will be depleted should future weather events or unplanned outages occur. This contrasts with an on-system peaking resource which can be deployed when access to gas supplies from mainline transportation or off-system storage faces an unplanned outage.

Figure 4 below provides additional context regarding the velocity of load (i.e., peaking volume throughput) based on the demand of FEI's RS 1, 2, 3, 4, 5 and 7 customers. The dashed lines show YVR weather[5] (°C) consecutive winter terms (November to March) from 2010 to 2022. The green line shows average winter temperatures during this term, while the red line shows the winter low temperature as recorded in a given month during the same period.

[5] https://climate.weather.gc.ca/climate_data/daily_data_e.html?StationID=51442

Figure 4



I identified three results in my review of the data provided by FEI regarding RS 1, 2, 3, 4, 5 and 7 customers. First, in each year reviewed there are considerably more days within the throughput range of 400,000-500,000 GJs, when compared to the other higher throughput ranges. Second, FEI experiences a significant increase in system throughput when temperatures drop below historical lows. Third, there has been an underlying shift in customer demand since 2019. In particular, from 2010-2019, system throughput remained between 400,000 and 500,000 GJs during average gas winter temperatures for an average of 60 days, while between 2019-2022, this average increased to 85 days (i.e., 15 additional days of higher than historical average system throughput). Further, the 2019-2022 period also saw a significant increase in throughput when temperatures dropped below -5°C, reaching the 600,000-700,000 GJs and 800,000+ GJs ranges.

In conclusion, higher-than-historical-average system throughput during average winter temperatures, an increase in the number of days average winter demand persists, and the increase in peak day demand, operationally managing winter weather anomalies becomes increasingly more difficult. As such, on-system peaking resources are, and will likely continue to be, an important part of FEI's resource portfolio.

In the sections below, I provide a detailed review of the peaking resources accessible to FEI.

i. Interruptible Customer Peaking Resource

Access to "on-system" natural gas supplies, through the displacement of one customer (i.e., interruptible) for the benefit of others (i.e., core customers), is a method of managing capacity which should be maximized wherever possible.[6] Utilities and pipelines offer interruptible tariffs with the understanding that the customer can be interrupted and receive compensation for their displacement. Typically, these customers have an ability to fuel switch, leaving their supply and capacity available for other customers. The compensation provided to these customers could be a lower tariff, or compensation mechanism(s) to cover the underlying fuel cost and any operational disruption nuance(s) (i.e., increase labor expenses). Regardless, the customer acknowledges that their service can be interrupted.

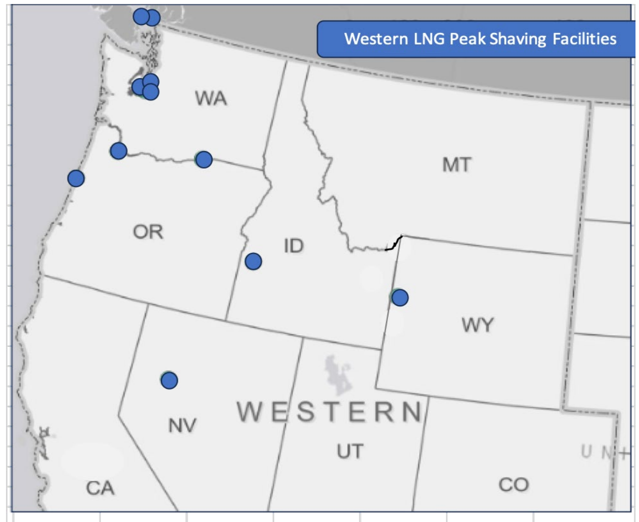
Based on information provided by FEI, its Lower Mainland region has seen a 10% decline in the number of interruptible customers between 2018 and 2023. As such, there is less of this contractual peaking resource available to FEI.

ii. LNG Resource (On-system storage)

LNG peak-shaving plants ensure that adequate supplies of natural gas are readily available when demand is at its peak. Throughout North America, natural gas transmission pipeline operators and/or utilities, use these facilities to liquefy natural gas for storage. When demand is lower (i.e., typically in the summer), the operator can liquefy natural gas for above ground storage and then regasify the LNG when demand is high.[7]

[6] For the purposes of my analysis, I assume interruptible customer peaking resources may include capacity displacement and/or sequestering delivered natural gas supply for FEI's own use.
[7] https://www.phmsa.dot.gov/pipeline/liquified-natural-gas/lng-facility-siting

These facilities typically provide reliable supply in areas where pipeline/distribution capacity limitations and/or weather conditions tend to cause supply and demand discrepancies. The development of LNG-peak shaving resources is generally strategic. In particular, utilities will undertake a deployment analysis to determine the cost/benefit of a given facility when compared to alternate resources such as compression addition(s) and infrastructure looping. Underlying gas supply cost avoidance is another benefit that utilities can gain as part of this evaluation process.



FEI's Mt. Hayes LNG facility continues to provide capacity, commercial peaking resource, and system operational benefits to customers on Vancouver Island and beyond. For example, the facility allows FEI to manage operational and balancing parameters where distribution assets interconnect with mainline transmission systems. This is especially important during periods of peak winter demand (i.e., 6 am and 6 pm as consumers go about their daily routines). While there are typically flow parameters in place to ensure system off-takes do not adversely affect mainline transmission operations during high draws from distribution assets, deploying a peak shaving facility during bursts of demand can alleviate some of the peak draws on mainline transportation interconnections. Within the regions FEI serves, assets for peak shaving can offset alternative options such as securing long-term third-party transportation and off-system storage, as well as avoiding one of the most volatile pricing indexes (i.e., constrained supply region with high demand) in North America, Huntingdon/Sumas.

iii. Peaking Supply Resource (Seasonal Supply)

Peaking supply resources, governed by contractual agreements from third parties, could be a viable resource. This service requires an evaluation of the third-party credit worthiness, their proprietary physical assets to meet the contractual commitments offered under an agreement, and historical operating experience in the regions FEI operates. The third-parties offering this service would need to maintain firm service transportation, storage capacity, and/or their own proprietary interruptible customer base to emulate FEI's current displacement capabilities. I review third-party peaking resources, and their deliverables, further in my response to Question 2 below.

IV. Conclusions to Question #1

The physical location of FEI's core customer demand is in a region that is challenging to provide safe and reliable service at a reasonable price. As discussed above, a gas supply portfolio has to be constructed from the resources that are available in the market, while also considering the resources contractual commitments including, tenure, carry costs, and any ongoing benefits when secured.

FEI relies on third-party resources to service 100% of its consumer portfolio (i.e., to fulfill core customer demand from FEI's proprietary distribution, transportation, and/or on-system peaking assets, FEI requires interconnections with third-party upstream and downstream off-system storage, third-party mainline transportation, and third-party gas supplies to gain access to markets). Although FEI can leverage existing supplemental resources such as on-system LNG and interruptible arrangements, these resources must be supplied with gas from third-parties. Any interruption to these resources hampers the deliverability of supply and ongoing consumer satisfaction. With that said, price volatility follows an inconsistency in market dynamics driven by weather and infrastructure constraints servicing this demand. An ability to insulate oneself from price volatility generally correlates to the increased reliability of a resource. Alternatively, having a resource that can be deployed during price volatility brings immense commercial/financial value, as well as increased flexibility.

It is important to note, resource portfolio development continues to be a challenging task especially when resource availability becomes finite and peer regions are vying for similar assets to meet their needs. Regardless, an inflection point will transpire when the need for incremental infrastructure will be necessary to meet the current trajectory of consumer demand for energy. The necessary lead time for major projects is critical, and from what I have observed, FEI has continued to recommend key elements of an optimal resource portfolio to service its customers.

Response to Question #2

FEI has, since 1971, included on-system LNG in its supply portfolio as a peaking capacity resource (i.e., rapid send-out capability, backed by sufficient LNG to meet short-duration peak load). We seek your opinion on the peaking capacity alternatives available to FEI so as to inform our understanding of the financial value of on-system LNG from a gas supply portfolio perspective by reference to avoided supply portfolio costs. In particular:

A. Based on your assessment of the natural gas markets accessible to FEI, would FEI be able to contract for peaking resources (capacity/energy supply) as a potential alternative to on-system LNG in its gas supply portfolio, and if so on what terms?

B. If appropriate peaking resources (capacity/energy supply) are unavailable to FEI in the market, what other potential investments could FEI explore as a potential alternative to on-system LNG as peaking resources (capacity/energy supply) in its gas supply portfolio? For clarity, in this regard we are requesting that you identify potential peaking supply (capacity/energy supply) alternatives based on your understanding of the regional system, as opposed to an undertaking a financial analysis of those options.

In my opinion, FEI would not be able to contract for peaking capacity resources that I would consider dependable, beyond those that are currently committed, as an alternative to on-system LNG storage. The deployment duration and dispatch capability remain the main criteria for security of supply from a peaking capacity resource. Due to the nature of the regional demands, third-party off-system storage and companies offering peaking gas supply arrangements, are constrained by the ability to transport the underlying supply of natural gas as well as the potential for unplanned outages. Furthermore, based on the results of my market research evaluating third-party arrangements, the costs for peaking resources are extremely expensive, do not support a consistent long term supply resource, and would require a portfolio of participants to be able to meet FEI winter demand. To put this in perspective, FEI would be competing/accessing the Huntingdon/Sumas gas supply market, on the coldest days of the winter, for significant volumes historically destined to the PNW (rapidly escalating pricing throughout daily trading hours). These factors, when taken together, are not conducive to contract for dependable peaking supply resources.

In the absence of readily available dependable peaking resources (including sufficient on-system storage), FEI would need to make significant investments (including capital investments and/or contractual capacity commitments) to meet its peaking capacity needs. The types of investments could include expanding mainline transportation, and the associated interconnected storage facilities, and/or developing on-system peak shaving LNG. Building these types of resources takes time, especially capital projects that require consultation with multiple parties throughout the planning and construction phases. Constructing a mainline transportation resource, for the purposes of meeting winter demand, would also result in inefficient utilization because it would remain underutilized in the non-winter months. Any investments considered by FEI should consider the assets long-term utilization parameters and the timing in which the resource could be deployed.

In the sections below, I first consider what alternative resources are operable in the region, determine if these alternatives are constrained, and discuss whether any of these investments could be an alternative to FEI's proposed on-system LNG project at its existing Tilbury facility. I begin by discussing on-system storage, before addressing off-system storage, and contractual third-party peaking gas supply.

I. "On-System" Gas Supply

On-system resources, are located where customer demand exists, and are the most dependable resources when compared to off-system storage and contractual third-party peaking supply agreements. As previously discussed, interruptible customers and LNG peak shaving gas supply can be deployed more quickly than other resources (i.e., in advance of a 24-hour notice period) and instantaneously support capacity.[8] This assumes FEI has: (1) sequestered Interior gas supply that has already been moved through the T-South pipeline; and/or (2) initiated capacity displacement from interruptible customers in the Lower Mainland.

While displacement from interruptible customers is contractual and predicated on the customer reducing or ceasing their use of natural gas, this type of resource is more deployable than third-party contractual agreements for peaking capacity. This is because an interrupted customer has already moved gas supplies onto the FEI system, while a third-party must rely on transportation and/or storage resources to fulfil their commitments.

FEI's Mt. Hayes LNG and Tilbury LNG facilities continue to provide operational and commercial value for FEI customers. From an operational standpoint, the integration of these facilities provides sound flexibility to meet significant velocity swings in consumer demand. Furthermore, from an avoided cost perspective, with high demand correlating to higher energy prices, the

[8] Here support capacity refers to gas supplies that have already been moved into the utilities distribution or pipelines mainline network and does not require additional compression to move gas supplies to a desired location.

facilities are serving their design purpose while minimizing price exposures to Huntingdon/Sumas. In particular, the Mt. Hayes LNG facility continues to meet core demand "pull" from consumers throughout the Sunshine Coast and Vancouver Island. The combination of compression, and the strategic location of Mt. Hayes on-system gas supply, ensures reliability for Vancouver Island customers. A resource in this location also helps minimize the need to move incremental gas supplies through the Lower Mainland system that could be experiencing coincidental demand constraints.

In conclusion, FEI's existing on-system storage resources are utilized to their designed capabilities. Persistent weather variability, coupled with high velocity demand from consumers requires FEI to continue to rely on on-system resources. Furthermore, interruptible customers remain a key element to peak day management, despite their declining numbers. These assets continue to be strategic to FEI in meeting on-system capacity constraints during peak demand and insulate consumers from the financial exposures in spot prices at Huntingdon/Sumas.

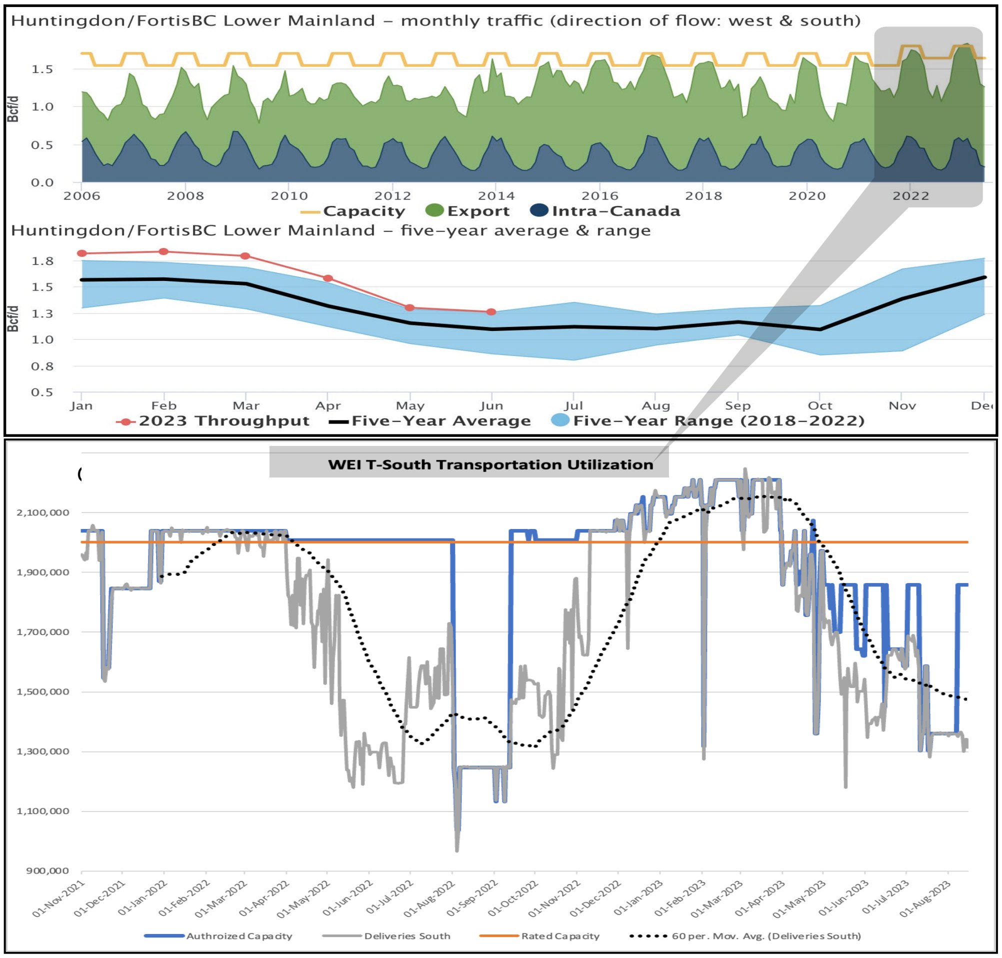
II. Off-system Storage

While, increasing existing upstream (i.e., Aitken Creek) and/or downstream (i.e., Mist and JPS) off-system storage is theoretically an alternative capacity resource, in practice, these facilities are currently fully contracted and will require expansions to meet any incremental capacity requests from FEI. In addition, increases to off-system storage resources will remain contingent on the deliverability of interconnected mainline pipeline networks (i.e., which are already facing capacity constraints).

For Aitken Creek, the interconnected deliverability of the T-South system is limited, as shown in Figure 5 below.[9] [10] The upper chart provides T-South rated capacity (gold line) and actual system throughput (export in green and intra-Canada in blue) for the terms from 2006-2023. The lower chart shows the daily characteristics of T-South system from 2021-2023, which includes rated capacity (red line), actual throughput (grey line), and authorized capacity (blue line).

[9] https://www.cer-rec.gc.ca/en/data-analysis/facilities-we-regulate/pipeline-profiles/natural-gas/pipeline-profiles-westcoast-bc-pipeline.html
[10] https://noms.wei-pipeline.com/customer-activities/pipeline.php

Figure 5



The data shows winter throughput on the T-South system has surpassed rated pipeline capacity while summer throughput-to-rated-capacity utilization has averaged as high as 80%. Also, please note the authorized capacity adjustments during summer periods while the pipeline conducts maintenance (i.e., blue line limits grey line). Depending on the type of maintenance, capacity can be limited, impeding shippers' deliveries. The high summer demand identified in the lower chart corresponds to the higher summer export utilization, as identified in the shaded area of the upper chart.[11]

[11] Higher summer utilization is an important observation during this analysis. All pipelines, storage facilities, and large industrial operations (i.e., Commercial LNG, Refining, etc.) require ongoing maintenance, a period that will affect the operations of resources in the region. A facility that can offer an alternative supply resource during these disruptions carries commercial/financial value (i.e., peak shaving LNG, southern off-system storage displacement, and/or line pack utilization). For example, commercial LNG economics are driven by world prices, and refining facilities are influenced by the liquids market they serve. An asset that can backstop natural gas supply, while mainline transportation maintenance is conducted, minimizes disruptions to an industry's feedstocks and revenue streams.

Considering the current contracted capacity of off-system storage and the associated winter utilization of T-South, incremental storage from Aitken Creek is therefore not a viable resource option without significant investments in mainline transmission and the storage reservoir. Furthermore, southern off-system storage facilities (i.e., Mist and JPS) remain fully contracted, eliminating an opportunity of securing incremental capacity without triggering an expansion. While a financial commitment for incremental southern off-system storage is likely to be less than committing to incremental WEI transportation and Aitken Creek storage,[12] the deliverability issues discussed above remain.

III. Third-party Peaking Gas Supply Contracts

Third-party peaking gas supply contracts are governed by agreements that provide firm service gas supplies delivered at a pre-determined delivery point. The contract to deliver, when called upon, is only as good as the delivery options the third-party utilizes. The entities offering this service should possess transportation, storage and/or their own portfolio of interruptible customers to physically backstop the contractual commitments for peaking gas supply.

These commercial arrangements typically maintain 24-hour notice periods prior to the deployment of the resource. A third-party offering this service will want to recover the underlying costs of maintaining their asset portfolio while earning a fair return for its use during the period it is contracted. In particular, a third-party's fee would consider the "stand by" nature of the arrangement (i.e., the resources remain at the ready to deploy whether it is utilized or not). The arrangement typically carries a contract fee that includes a demand charge (i.e., monthly fee over the tenure of the agreement), and a commodity charge (i.e., a price charged on the day any volumes are used).

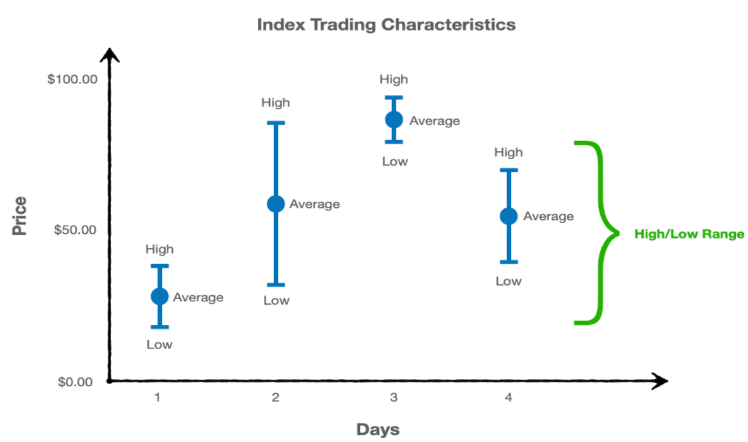
The demand charge would incorporate underlying carry costs associated with pipeline(s) tolls, storage tariff(s), and any other proprietary services that are required to support a peaking supply arrangement. Though a peaking supply arrangement may lay dormant during summer months (April-October), its underlying costs do not. Cost recovery of un-utilized assets will be incorporated into winter periods when the arrangement is active (November-March). The dormant period costs will be market driven, meaning they will fluctuate in price, driven by the success of

[12] The contractual tenure commitments, to drive investments, is likely lower, and this resource alternative does not incur summer capacity mitigation exposure a pipeline alternative does.

cost mitigation attempts during the summer. Higher success of mitigating costs during the summer may translate to lower demand charges for winter peaking arrangements.

A third-party gas supply peaking arrangement also includes a commodity charge portion, which I discuss in further detail below. Since these agreements are required for daily deployment, their underling commodity charge(s) are based on daily spot pricing. Daily spot prices trade in a range throughout a trading day, and in some instances, can trade at a significantly wide range (as depicted in Figure 6 below). The figure shows a sample **range** of price, from the highest to the lowest, on any given day prior to the day's settled price.

Figure 6



For the purpose of selling peaking gas services, the third-party will want to ensure daily volatility is minimized by constructing a contract that explicitly details that the buyer of the resource is paying the higher range of prices on any given day. The higher price range ensures that the third-party selling the resource, is not economically disadvantaged by offering the service at average prices.

Figure 7 below shows the range of price fluctuation on a given day. The daily transaction data, as recorded by Platts from 2016-2022, captures all trades consummated (i.e., when a buyer and seller trade) throughout the day prior to the end-of-day settlement. During the winter (i.e., November-March) prices ranged from $0.8689/GJ to $47.30/GJ, while in the summer (i.e., April-October), prices ranged from $0.1261/GJ to $4.23/GJ. The values presented in the chart are derived by subtracting the high price from the lower price.

Figure 7

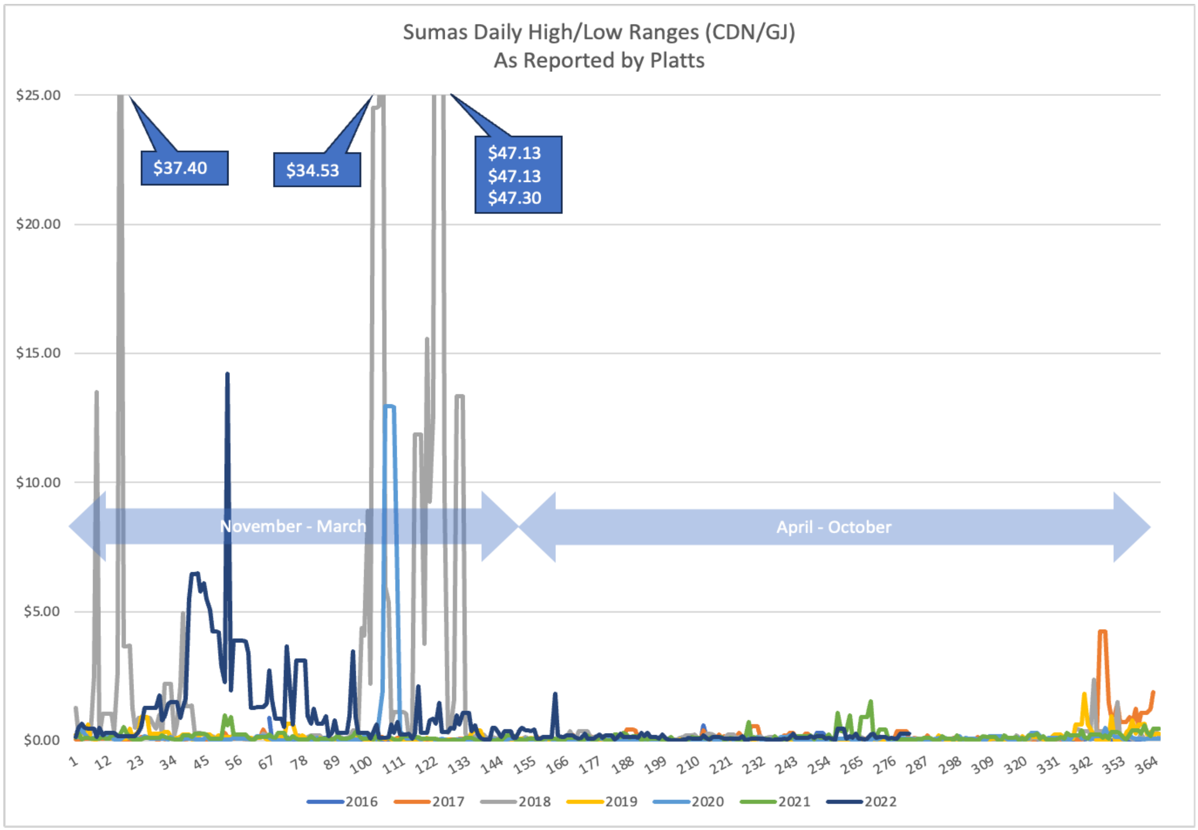
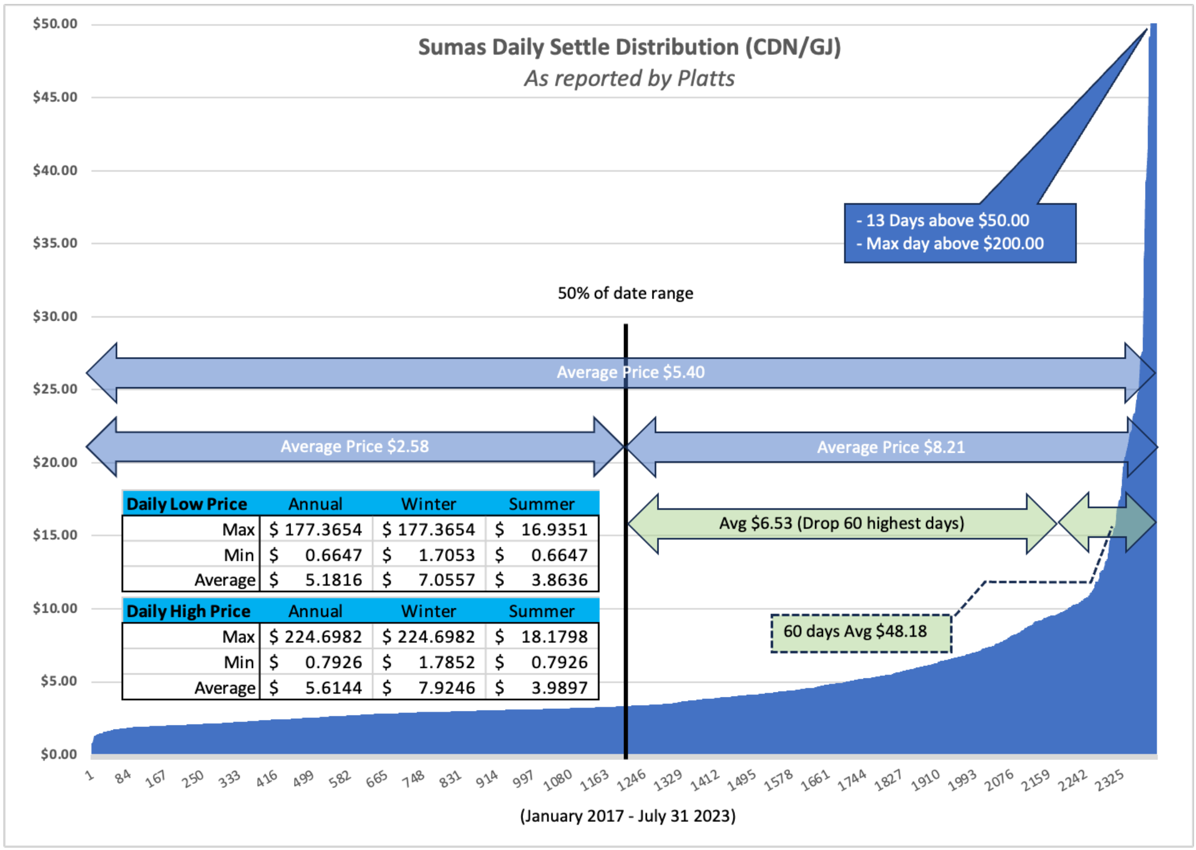


Figure 8 below shows actual price settles (i.e., not the range) for the term January 2017 to July 2023.[13] The daily prices (blue filled line) have been stacked from the lowest price of $0.73 CDN/GJ to the highest price at $201.03 CDN/GJ. The average daily settled price over the entire term was $5.40 CDN/GJ. 50% of the higher data range averaged $8.21 CDN/GJ while the lower averaged $2.58 CDN/GJ. The table embedded within the figure shows the daily high/low price ranges (i.e., not price settlement). For example, the actual settled price of $201.03 had a Daily High Price "Max" of $224.70 CDN/GJ, or $23.67 CDN/GJ higher than the actual end-of-day price. The table embedded in the figure also shows the volatility in pricing within a given trading day.

[13] The data represented has not been manipulated by removing time segments that could include price influences from mainline pipeline maintenance and/or outage as these events will likely occur in some form or another in the future. Further, the time period selected for this analysis was not selected because it included a pipeline outage, but rather, because it is included within the period of time analyzed.

Figure 8



Daily Low Price	Annual	Winter	Summer
Max	$ 177.3654	$ 177.3654	$ 16.9351
Min	$ 0.6647	$ 1.7053	$ 0.6647
Average	$ 5.1816	$ 7.0557	$ 3.8636

Daily High Price	Annual	Winter	Summer
Max	$ 224.6982	$ 224.6982	$ 18.1798
Min	$ 0.7926	$ 1.7852	$ 0.7926
Average	$ 5.6144	$ 7.9246	$ 3.9897

The data shown in Figure 8 demonstrates the financial value potential a peaking resource can have operating in the Huntingdon/Sumas index region. For example, avoiding or participating in trading activities during the highest 60 days of pricing (which averaged $48.18 CDN/GJ) would have a significant impact on a utility's rates.

In the sections below, I provide my conclusions in response to the specific sub-questions to Question 2.

Response to Question #2A

A. Based on your assessment of the natural gas markets accessible to FEI, would FEI be able to contract for peaking resources (capacity/energy supply) as a potential alternative to on-system LNG in its gas supply portfolio, and if so on what terms?

My assessment of the natural gas market has determined that FEI would not be able to contract for peaking capacity resources as a potential alternative to on-system LNG. First, off-system storage alternatives remain constrained. In particular, as discussed above, the Aitken Creek storage option would require incremental WEI transportation capacity, and the Mist and/or JPS storage facilities remain fully contracted and would require their own expansions to meet any FEI incremental calls for capacity. Second, third-party peaking gas supply contracts are not a dependable resource and also remain cost prohibitive. To confirm my analysis of third-party peaking supply, I provide the following market research assessment which confirms my conclusion that FEI would not be able to contract for peaking resources (i.e., capacity/energy supply) as a potential alternative to on-system LNG in its gas supply portfolio.

FEI would require a portfolio of third-party peaking contracts to meet the needs of its gas supply portfolio as no one counterparty can provide sufficient supply. The pool of available counterparties is also limited and there is considerable turnover in participants in the marketplace. In particular, I only identified 9 entities that maintain T-South capacity with sufficient proprietary supply to be considered as a portfolio participant for FEI. Furthermore, due to the nature of the arrangement(s), these third-parties would face similar mainline transportation disruptions that FEI does. In an attempt to alleviate this risk, FEI would need to contract "more than face value" supply arrangements to offset the potential of being cut during a mainline disruption.

The availability of these resources will also remain market-based, potentially resulting in even higher premiums than previously witnessed. Furthermore, marketing companies tend to keep their proprietary trading assets free of any contractual commitments to extract maximum value from the market. With winter demand high, and an increasing summer demand persisting in the Pacific Northwest, these companies will be less interested in committing resources that could inhibit profits. All of these factors ultimately limit FEI's ability to contract peaking resources.

Response to Question #2B

B. If appropriate peaking resources (capacity/energy supply) are unavailable to FEI in the market, what other potential investments could FEI explore as a potential alternative to on-system LNG as peaking resources (capacity/energy supply) in its gas supply portfolio? For clarity, in this regard we are requesting that you identify potential peaking supply (capacity/energy supply) alternatives based on your understanding of the regional system, as opposed to an undertaking a financial analysis of those options.

With no capacity resource alternatives to on-system LNG currently available, the other alternatives contemplated would require significant financial investment(s) (whether contractual or otherwise) to support expansions to mainline transportation and/or off-system storage. Keep in mind, expansion projects of this nature require the necessary time to implement, create asset utilization variability, and should include an analysis of incremental long-term benefits for the call on expanded capacity. Investments in alternative resources are also costly and shift market characteristics for long periods of time. In the sections below, I provide an overview of peaking supply resource alternatives based on my understanding of the regional system FEI operates within. My analysis does not suggest or contemplate estimates to the capital costs for these resource alternatives. FEI would need to consider the timing necessary to deploy each alternative, including engaging with interested parties, organizing investment capital (if necessary), gaining regulatory approval, and final construction deployment. All of these steps generally take considerable time to complete. During this process, FEI would have to manage customer expectations for secure, reliable, and cost-effective resources.

The following peaking supply resource alternative analysis is based on what resources could be implemented with the understanding that capital investments would be required to increase the call on capacity. I have broken my analysis into two parts. First, I review mainline transportation capacity increases through T-South and/or SCP, and any interconnected off-system storage. Second, I review southern alternatives such as increasing southern off-system storage displacement and/or increasing on-system LNG peak shaving.

I. Analysis of Mainline Transportation

In the sections below I assess the following two mainline transportation solutions: (i) increasing capacity on the T-South system; and/or (ii) increasing capacity on the SCP. There is an asset utilization consideration with pipelines expansions for peaking supply, which is avoided with storage. In particular sizing an expansion to provide winter peaking capacity for FEI leaves significant underutilization in the other times of the year that require mitigation efforts to offset those costs.

i. Increasing T-South Capacity

In the absence of peaking resources, FEI could consider sourcing additional T-South firm service from WEI. As discussed below, WEI has responded to market demand in the past by offering an open season for market interest in expanding T-South capacity.

First, in the Spring of 2017, WEI was successful in securing firm interest to expand T-South. This open season saw significant market interest for a T-South expansion. In particular, WEI received a competitive response with participants bidding contractual firm service tenures out as far as long as 60 years, which is the longest that I am aware of in my 30-year career. In addition, the demand for incremental capacity surpassed the 190 MMcf/d offered by WEI in its open season. This was the highest amount of incremental capacity it could develop without significant increases to existing tolls. Beyond this level, the incremental gains in capacity, versus the capital deployed, would not be as efficient.

Second, in November 2022, WEI announced another open season to gauge shipper interest in a further annual capacity increase for T-South of 300 MMcf/d (i.e., The Sunrise Expansion Program).[14] Following a successful open season, that resulted in requests for additional transportation capacity, WEI is proposing this expansion to have an in-service date by late 2028.

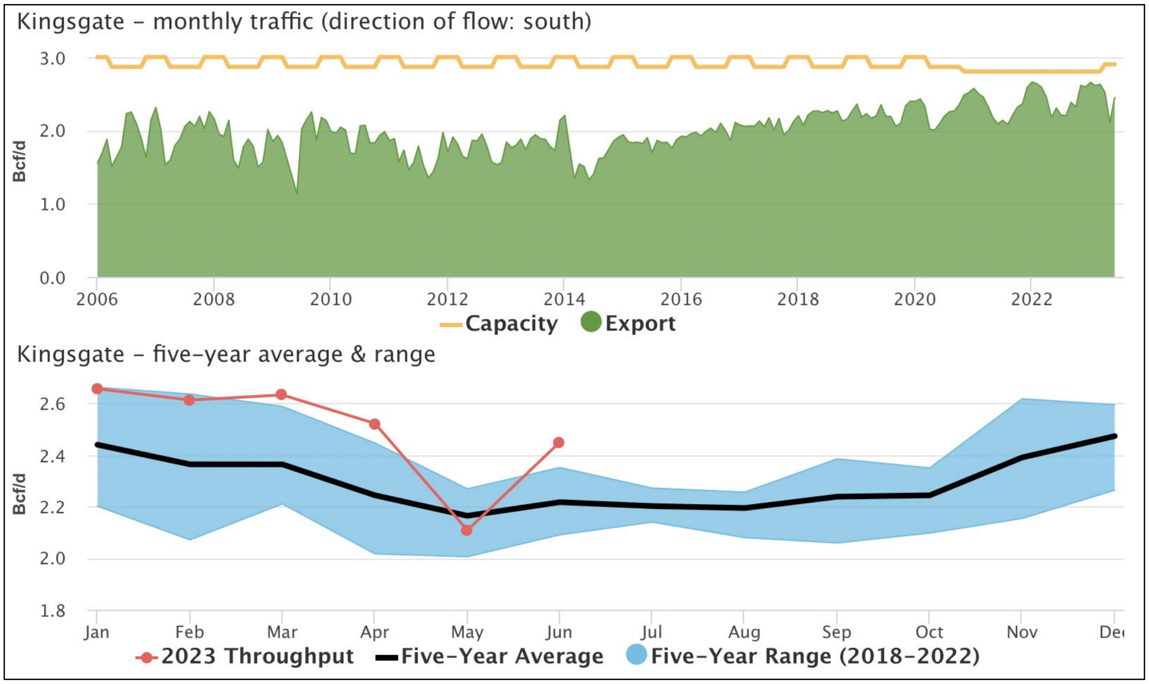
Assuming WEI responded to FEI's call for incremental capacity above what had already been committed, FEI would need to evaluate the cost of this capacity and the duration of the associated commitment. In particular, while this type of annual commitment would meet FEI's winter demand requirement, it would also require FEI to mitigate capacity into the market during summer when demand is lower. Furthermore, mainline transportation expansion would trigger additional capital investment for any associated off-system Aitken Creek storage. This assumes a one for one matching of transportation capacity to meet send out capabilities for storage.

ii. SCP Expansion

As previously discussed, in the East, the SCP interconnects to the Foothills pipeline that delivers supply from Alberta to the United States while, in the west, SCP connects to the T-South mainline 240 km north of Vancouver at Kingsvale. Figure 9 below provides the historical southern throughput on the Foothills pipeline where SCP interconnects.[15]

[14] https://www.enbridge.com/projects-and-infrastructure/projects/sunrise-expansion-program
[15] http://www.cer-rec.gc.ca/en/data-analysis/facilities-we-regulate/pipeline-profiles/natural-gas/pipeline-profiles-foothills.html

Figure 9



Although the most recent data shows monthly throughput reaching 90-95% utilization, the NGTL West Path pipeline expansion ("NGTL Expansion") has been approved, underpinned by 250 MMcf/d of firm service contracts. The NGTL Expansion will increase North to South flows from Canada to the US and confirms that the Southern US demand continues to seek Alberta sourced supply. This expansion could represent incremental SCP take away capacity if the SCP were to expand through compression/looping. Increasing SCP throughput would have to include a parallel expansion on T-South from Kingsvale to Huntingdon/Sumas, or an extension of SCP from Oliver to Huntingdon/Sumas. 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.

As part of my review of an SCP expansion I identified a number of supplemental benefits that should be considered when reviewing the embedded costs of the mainline transportation alternatives. First, the interconnectivity of SCP to a larger supply basin provides the financial and physical price risk management tools to insulate FEI customers from price volatility. Such insulation is more difficult to achieve at Spectra-Stn2. In particular, the Alberta supply basin increases the number of credit worthy counterparties FEI could engage, increasing the diversity of its supply portfolio including RNG. Second, although FEI would have the option to access more off-system storage, unlike a T-South expansion, this would not necessarily be required as the physical liquidity is robust enough to meet FEI needs on any given day. Third, an SCP expansion would enable FEI to have greater access to a market that is aggressively, with the support of Federal and Provincial funding, exploring Carbon Capture Utilization and Storage ("CCUS"). This could represent environmental benefits for FEI customers and peer utilities throughout the Pacific Northwest; assuming that a SCP expansion was supported by other shippers during an open season process.

II. Analysis of Southern Resource Alternatives

In the sections below I assess increasing off-system storage in the US. Prior to delving into this alternative, I note the following.

First, as with the option of committing to more long-term mainline transportation, the intended use of the southern resource alternatives may shift as FEI's resource stack evolves over time. Even so, these resources will generally maintain underlying commercial deployment value over their useful life. For example, annual demand shifts do not represent a one for one change to peak demand. Annual demand could decline while peak demand escalates, requiring a different stack of resources to manage a shift in consumer demand. Both of these resource alternatives are intended to be deployed during the winter, thereby avoiding the summer mitigation costs associated with a mainline transportation alternative.

Second, the regional market has become accustomed to accessing the capacity on T-South that is contracted for the Woodfibre LNG facility but being released into the market until the facility enters service. Both the summer and winter periods will be shorter in supply (i.e., estimated at 300 MMcf/day) when the Woodfibre LNG facility becomes operational. In particular, while T-South will remain fully utilized, markets south of Huntingdon/Sumas will not be able to access this supply all year once the Woodfibre capacity is no longer available in the market in 2027. This shift will create a tighter price environment for buyers. The Sunrise Expansion Program will only offset the lost Woodfibre capacity, returning the market to its current constrained state.

A southern off-system storage resource from Mist and/or JPS is contractual in nature and has a number of benefits. It does not carry investment capital risk for FEI and its contract commitment would cease if FEI determined the resource was no longer required (i.e., it is believed the tenure of the contract commitment would be less than a T-South alternative). Furthermore, since this is a storage option, its utilization would be seasonally dependent and not carry summer mitigation costs that a mainline transportation option requires.

There are nonetheless a couple of drawbacks to consider with a southern off-system storage option. First, there is a likelihood of a call back provision(s) from the counterparty offering the service. For example, FEI does not currently hold renewal rights for capacity with the Mist storage facility. This option provides an opportunity, by the peer utility, to terminate arrangement(s), sequestering the capacity to meet their own peak customer demand. Second, the southern off-system storage option lacks the resiliency value that would be provided from an on-system LNG peak shaving facility.

Conclusions to Question #2

In my opinion, the development of a proprietary on-system asset, such as the proposed TLSE Project, has advantages over other types of infrastructure investments from a gas supply perspective. The TLSE Project would provide FEI with operational backup for disruption: (a) to existing off-system storage and/or mainline transmission; and (b) that may not necessarily affect FEI customers, but those of peer utilities, that source gas supply from Huntingdon/Sumas. The proposed TLSE Project's proximity to a larger US export market could also be a benefit to FEI's customers. In particular, peer utilities in the US, servicing a growing gas-powered electricity and industrial demand are, and will be for the foreseeable future, evaluating the cost/benefit of limiting pricing exposure to Huntingdon/Sumas, in response to growing peaking demand, by either: (a) sourcing peaking services like what could be provided by the proposed TLSE Project; or (b) committing to long-term mainline transportation. Furthermore, while meeting the needs of FEI's customers for safe and reliable service, a proprietary LNG peaking facility will continue to carry long-term value for the utility and its customers. If the demand profiles of FEI's customers were to shift over time (i.e., lowering annual demand while maintaining the need for winter supply), the ease of de-contracting mainland transportation is more appropriate than shedding reliable on-system capacity as on-system storage is designed to be deployed only when it is required.

Response to Question #3

Assuming a hypothetical scenario where the TLSE Project is constructed at 800 MMcf/d and 3.0 Bcf and FEI does not require the full regasification capacity and stored LNG for its own resiliency and gas supply requirements, do you expect that FEI would be able to monetize its uncommitted peaking capacity by selling it in the gas markets? If so, how much daily send-out capacity could the market reasonably absorb.

Assuming that the TLSE Project is constructed, and FEI were to have spare capacity that is not required to meet customer demand or resiliency, FEI would be able to generate revenues to offset the cost of service of the facility by selling its excess supply into the market. Based on my assessment of the available supply and demand in the Huntingdon/Sumas natural gas market, and assuming current market conditions persist, I expect the daily market can reasonably absorb 300-400 MMcf/d of natural gas across multiple days (e.g., 10 days) during winter without influencing daily prices in a manner that could limit monetization values (i.e., materially decreasing the revenues generated through mitigation into the market). In the sections below, I discuss the drivers of increased natural gas demand and provide a detailed discussion of my market absorption analysis.

I. Demand for Natural Gas is Expected to Continue to Increase Due to Several Drivers

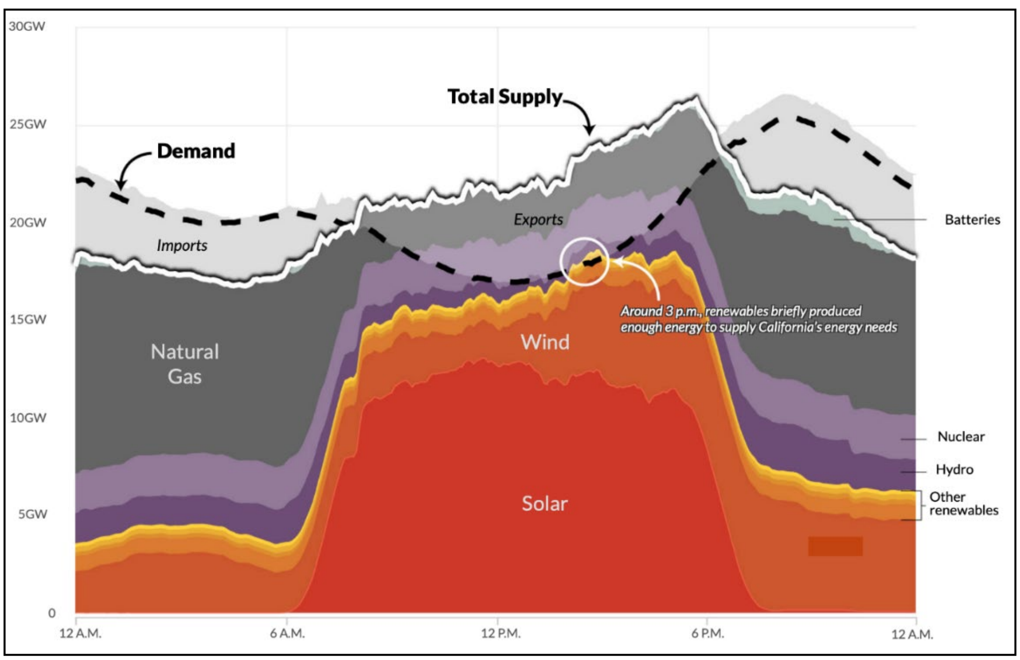
Managing the financial value and any associated benefits of an asset cannot be reviewed in isolation. By virtue of their infrastructure connectivity, British Columbia, Alberta, the States of Washington, Oregon, Idaho, Utah, and California share similar energy challenges. In the discussion below, I summarize the drivers of market demand, such as: (i) seasonal weather; (ii) social and economic pressures to reduce GHG emissions; (iii) advancement of new technologies; and (iv) large industrial development, which inform my assessment of the future demand (post-2027) for natural gas resources in the Huntingdon/Sumas region.

i. The Impact of Seasonal Weather on Demand

Weather from Northern British Columbia to the Southern State of California varies from season to season due to its topography and geographical location. Typically, the integration of a region's electric and natural gas systems will operate harmoniously, moving resources from one region to another through a multitude of pipelines and transmission lines. However, during winter weather conditions, one region's system will draw on another to fulfil its customer demands. This may include a scenario where warmer than normal temperatures, in Oregon and California, create significant electrical demand for air-conditioning that is serviced by an assortment of hydro, wind, solar and natural gas generation throughout their own region but also those regions they are interconnected with. Alternatively, colder than normal temperatures, in that same region, will draw on the same resources but the energy mix deployed will be different. Weather remains unpredictable, and there is the likelihood that regions will experience coincidental peak demand pressure from consumers regardless of their region. Taxing infrastructure to its limits should ensure that each region has a diversified portfolio of resources and, in particular, resources that provide security of supply, while remaining economical to the consumers they serve.

An example of natural gas usage in a region that has extensive renewable resources is California. Understanding that California is a significant distance from British Columbia, the State's energy landscape has evolved over a long period of time with a significant emphasis on the integration of gas and power systems and the advancement of wind, solar and battery storage technologies. Though tremendous progress has been made to reduce the use of fossil fuels in California (i.e., as illustrated in Figure 10 below which shows the time required for new energy technologies to be into integrated into the California market), the State's dependency on natural gas remains because it is a reliable, economical, and dispatchable resource when compared to the current state of renewable resources.

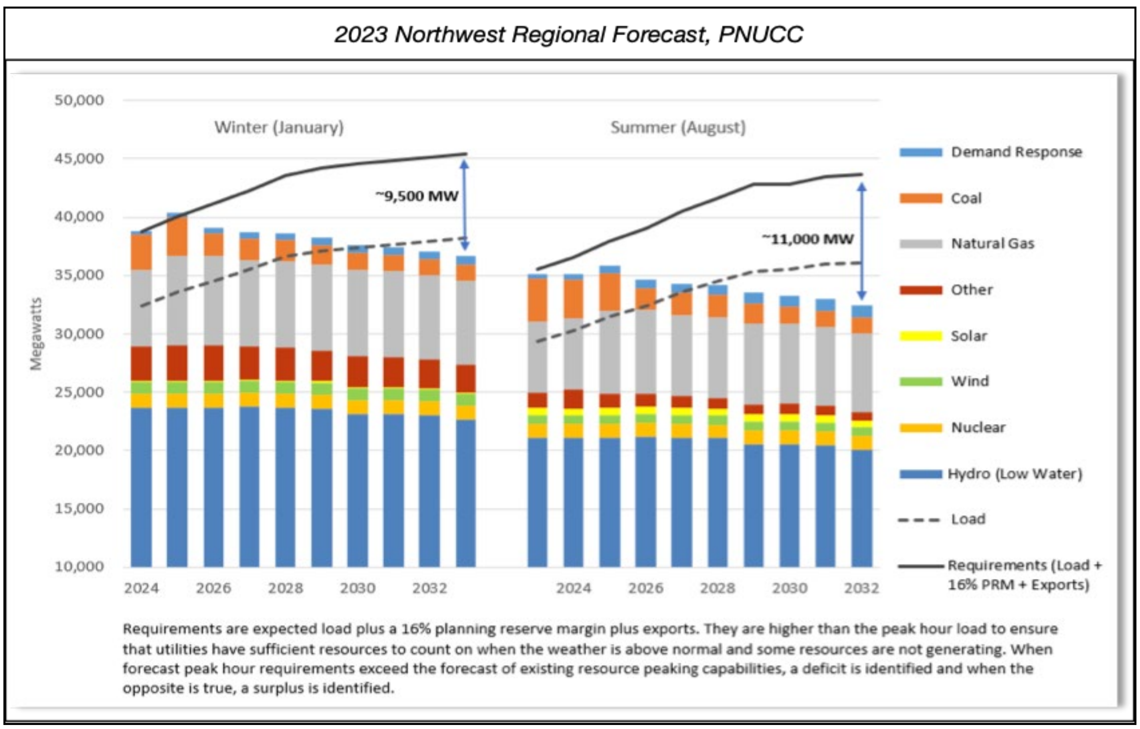
Figure 10



Despite the continued importance of natural gas in the California energy market, the share of renewable energy in the California market is gradually increasing. For example, on April 30, 2022, the California Independent System Operator ("CISO") set a record of using 100% renewable energy for approximately 1 hour. However, CISO continues to forecast that natural gas will remain in the mix of assets well-beyond 2045. Again, the cost of transiting the resources in an energy market is expensive and can only progress at a pace in which the consumer can absorb.

Another region forecast to go through significant resource growth challenges is the Pacific Northwest. Within a period of 24 to 48 months, electricity in the region is forecasted to meet capacity for winter and summer weather peaks. In addition, there remains a tremendous effort to minimize existing coal fired generation. Though retirements had been scheduled, they have been postponed while utilities re-evaluate resource portfolios. As shown in Figure 11 below, the energy market in the Pacific Northwest is constrained in both the summer and winter periods.[16]

Figure 11



Therefore, while no one resource can be deployed to meet growing demand driven by seasonal weather, the expansiveness of interconnecting regions in the United States will help support the continued need for peaking resources (such as FEI's proposed TLSE Project) well into the future.

[16] The figure also shows the region's move away from coal and expectation that natural gas resources play a steady role in servicing peak in the region.
https://www.pnucc.org/wp-content/uploads/2023-PNUCC-Northwest-Regional-Forecast-final.pdf

This need is especially acute during extreme weather conditions present in the Pacific Northwest. As a result, I expect the need for additional natural gas power generation will be required to serve seasonal demand.

ii. Social & Economic Pressures to Reduce GHG Emissions

Beyond the seasonal weather conditions discussed above, all regions (including the Pacific Northwest) are moving towards minimizing GHG emissions. The speed of implementation from region-to-region will vary based on political will, a consumer's mindset, and the economics in which the market participants can bear. Governments can and will provide incentives to create change while social desire/pressure will influence a consumer's behavior. Moving electrification in any one direction too quickly will create challenges, especially when it is imposed on a market that must absorb the costs in a prudent manner. In addition, the influence of one region on another must be monitored. For example, all levels of government (i.e., Federal, Provincial/State, City, and Municipal) could impose their own transitional processes to meet a specific agenda. The path may include tax options (i.e., incentive rebates, financial penalties, etc.), new market implementations (i.e., carbon trading), or parameters for corporate reporting (i.e., Environmental, Social, and Corporate Governance ("ESG") reporting). These initiatives, depending on how they are deployed and digested by the market, will influence consumer and industry energy consumption.

As shown by the examples below, consumer and industry hunger for energy has already created pressures on existing infrastructure, with many regions witnessing record demand.

Northwest Pipeline (May 2022):[17]

> Northwest Pipeline finished 2021 with the highest annual throughput in the pipeline's history, reaching over 869 billion cubic feet, and is already setting records in 2022. "It was the highest peak electric generation demand year in the history of Northwest Pipeline," said Gary Venz, director of commercial services "The Pacific Northwest is relying on Northwest Pipeline more than ever as coal-fired plants continue to be retired."

Northwest Regional Forecast of Power Loads and Resources (May 2023):[18]

> Several utilities are steadily phasing out coal-fired generation. By 2026, these utilities will have reduced their reliance on coal by over 4,800 megawatts since 2019. As utilities keep some

[17] https://www.williams.com/2022/05/27/northwest-pipeline-at-peak-performance-to-meet-natural-gas-demand/#:~:text=Northwest%20Pipeline%27s%20bi%2Ddirectional%20design,already%20setting%20records%20in%202022.
[18] https://www.pnucc.org/wp-content/uploads/2023-PNUCC-Northwest-Regional-Forecast-final.pdf

> options on the table to meet near-term increases in demand during a period with high resource development risk, plans are shifting. Compared to last year's Forecast, 222 megawatts of planned coal exits were pushed back from no later than the end of 2025 to be no later than the end of 2029. Also, natural gas resources are forecast to have an increased role for reliability until energy storage and other emerging technologies are proven. Plans are progressing to convert Jim Bridger coal units 1 and 2 to natural gas in 2024. These resources provide a bridge to meet peak demand and fill in during potential low water years until sufficient new capacity resource technologies and transmission can be added.

Western Assessment of Resource Adequacy (November 2023):[19]

> "Based on balancing authorities 'current resource plans, the West is not prepared to meet future demand over the next 10 years. An increasingly variable resource stack and uncertain demand growth make it harder for the region to close the gap, according to the Western Electricity Coordinating Council's 2023 resource-adequacy assesment…".

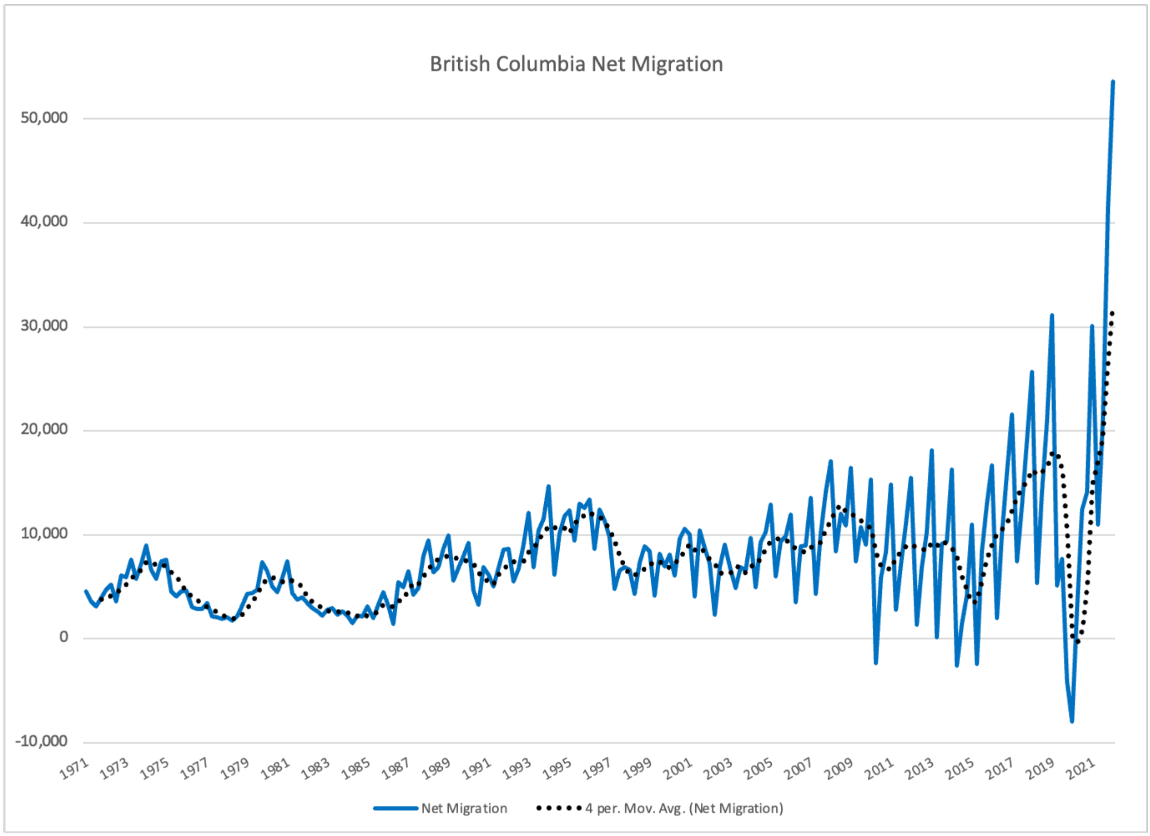
While demand for energy continues to escalate with population growth, and society's desire to experience new products and services (i.e., electric vehicles, personal devices and their reliance on server storage, smart homes, etc.), increasingly frequent warmer than normal temperatures have prompted change within the cooling industry to ensure access to air-conditioning. Further, although many consumers are attempting to lower their GHG emissions, the speed in which they can bear the associated costs will differ and are also driven, at least in part, by wider governmental policies such as changes to building codes and Demand Side Management ("DSM") initiatives.

According to Statistics Canada, and as shown in Figure 12 below, FEI's interconnecting regions are experiencing significant population growth similar to British Columbia. Assuming population in these regions grows as trending shows,[20] a peak shaving LNG facility, that can be deployed during higher velocity demand, will maintain significant commercial value. Higher peak demand, during the winter or summer, coincides with higher daily prices which provides commercial/financial asset value.

[19] Read the full paper at the following link:
https://www.wecc.org/Administrative/2023%20Western%20Assessment%20of%20Resource%20Adequacy.pdf

[20] Statistics Canada,
https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1710000901&cubeTimeFrame.startMonth=01&cubeTimeFrame.startYear=2016&cubeTimeFrame.endMonth=10&cubeTimeFrame.endYear=2023&referencePeriods=20160101%2C20231001.

Figure 12



iii. Introduction of New Technologies

The energy industry is on the cusp of advancing significantly into new technologies that are intended to assist in mitigating GHG emissions growth. The advancement of these mitigation efforts through already significant investment in new technologies will, in turn, ensure that natural gas remains a valuable component of the energy market. In particular, commercializing the measurement and quantification of GHG emissions has gained momentum since 2018 with an increase of participants from investors, bankers, and financial intermediaries. Measurement and quantification of emissions is a necessary precursor to: (a) enabling broader cap and trade activities worldwide; (b) the large-scale commercial deployment of CCUS; and (c) continuing investments in Low Carbon Fuels. I address each in turn below.

a) **Cap and Trade Activities:** Carbon trading provides the platform to quantify and value GHG emissions. Underpinning the financing for a resource's expansion will be easier if the market can quantify the displacement of these emissions. Broader cap and trade activities worldwide, that allow more countries to participate in the carbon market, will ensure natural gas continues to be a foundational peaking resource in the energy market as governmental GHG reduction policies mature.

b) **Carbon Capture Utilization and Storage:** Investments in CCUS technology has the potential to align "large scale carbon capture with large scale power generation" in order to mitigate GHG emissions from conventional natural gas as a fuel source for electrical generation. For example, in Alberta, 25 CCUS projects have been selected for further evaluation.[21] Of these, seven new projects, with known capacity and commissioning dates plus expansions of already existing projects, have the potential to increase the provincial CCUS capacity to about 56 million tonnes of (carbon dioxide) CO2 per year by 2030. This is equivalent to 22% of the 256.5 million tonnes of CO2 emissions in Alberta in 2020. The remaining 18 projects would further increase future provincial carbon capture capacity if completed. CCUS projects, if commercialized, could support incremental pipeline expansions and their access to regions that have carbon capture technology.

c) **Low Carbon Fuels:** The blending of low carbon fuels, such as Renewable Natural Gas ("RNG")[22] and hydrogen into the existing natural gas system continues to be an effective and efficient means of mitigating GHG emissions by increasing the amount of low carbon energies in the market. As reported by the Canadian Energy Regulator,[23] the number of RNG projects operating in Canada are expected to more than double between 2021 and 2025, increasing capacity from 7.2 petajoules (PJ) in 2021 to 17.1 PJ in 2025. Further, the 2019 British Columbia Hydrogen Study[24] demonstrated that concentrations of hydrogen between 5 and 15 percent by volume, blended into the existing natural gas system, could be a viable opportunity of delivering renewable energy to markets without significantly increasing risks/cost to the energy value chain (i.e., production, midstream, transportation, distribution, and consumption). Aligning a peak shaving (on-system) resource, with the potential of

[21] Canadian Energy Regulator, https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/2022/market-snapshot-new-projects-alberta-could-add-significant-carbon-storage-capacity-2030.html.

[22] RNG to include but not limited to landfill waste, water treatment waste, and livestock digester gas

[23] Canadian Energy Regulator, https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/2023/market-snapshot-two-decades-growth-renewable-natural-gas-canada.html

[24] BC Hydrogen Study, https://www2.gov.bc.ca/assets/gov/government/ministries-organizations/zen-bcbn-hydrogen-study-final-v6.pdf.

increased renewable benefits, will continue to bring social and commercial market value.

iv. Large Industrial Development

Unlike population growth demand, which typically grows progressively, large industrial demand grows in large increments, taxing infrastructure that was designed to assume a moderating growth pattern. Large industrial infrastructure, such as LNG turbine compression and power; fuel refining;[25] and data centres,[26] are increasingly being developed in the Pacific Northwest region, driving increased demand for energy and, as a result, demand for infrastructure investments to address the already constrained energy market. For example, the viability of the Woodfibre LNG project was driven by the proponent's ability to secure long-term transportation capacity on the T-South system to source natural gas in northern British Columbia. When the Woodfibre LNG facility becomes operable, the resulting increase in demand will further tax the infrastructure in the region which, in turn, could lead to higher prices. As such, in my opinion, peak shaving (on-system) resources will play an increasingly important role to support balancing energy peaks in the Pacific Northwest region and beyond.

II. Market Absorption Analysis of the Huntingdon/Sumas Region

As discussed above, there are several drivers of market demand which inform my assessment of the future demand (post-2027) for natural gas resources in the Huntingdon/Sumas region. While the Huntingdon/Sumas market is made up of annual, monthly, and daily trading activities,[27] for the purposes of this analysis, I use daily market data to review the pricing characteristics of the Huntingdon/Sumas region as it relates to the monetization of uncommitted peaking capacity sold by FEI into the gas market. This review was conducted to determine the level of send-out capacity that the market could reasonably absorb.

Before addressing the Huntingdon/Sumas market specifically, I note that my initial analysis relies on Electronic Exchange Trading ("EET") data, which is a public form of transaction data between buyers and sellers for physical natural gas. Unlike transactions which are undertaken directly

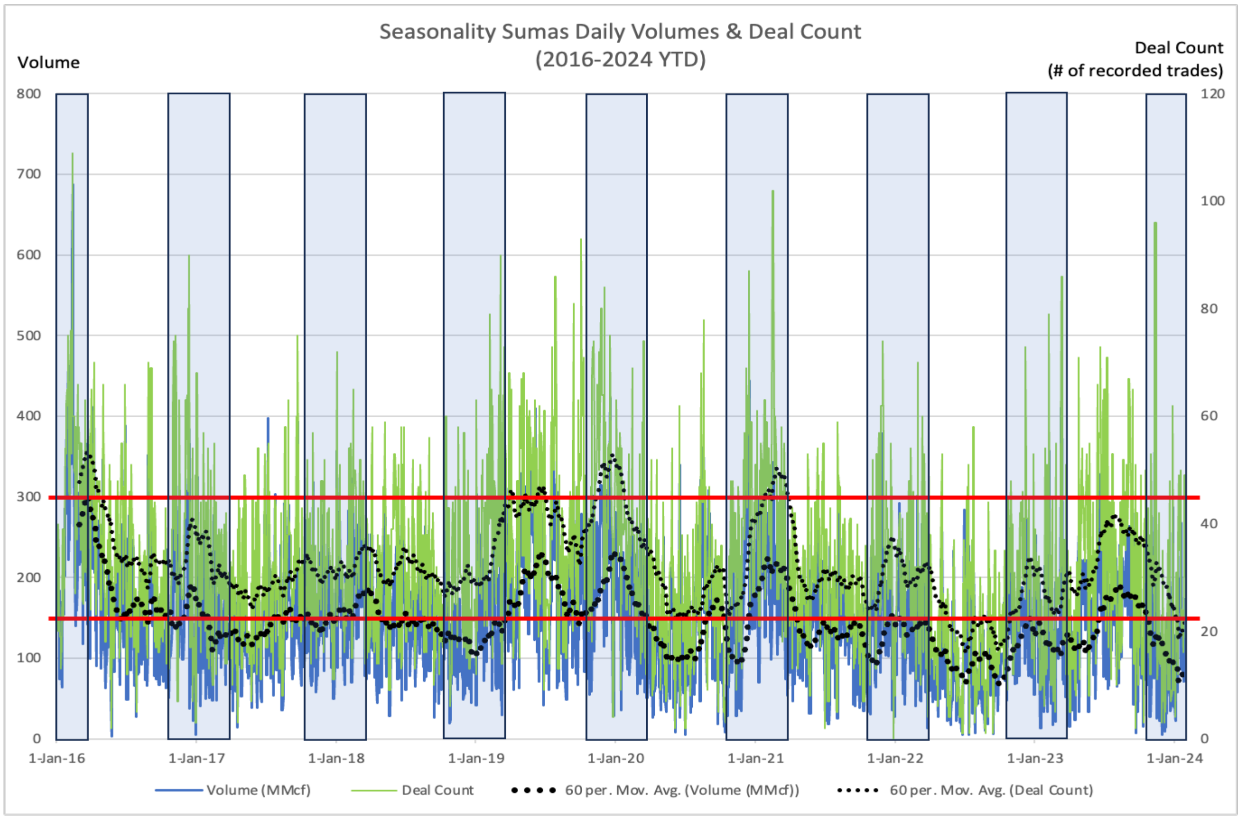
[25] Refining Crude Oil, https://www.eia.gov/energyexplained/oil-and-petroleum-products/refining-crude-oil-the-refining-process.php
[26] Energy, https://www.iea.org/energy-system/buildings/data-centres-and-data-transmission-networks.
[27] Daily pricing variability represents real time scenarios the FortisBC gas supply department would experience during peak day demand.

between counterparties (i.e., bilateral transactions), EET data is executed through the use of an electronic exchange - meaning data (i.e., such as the number of trades, volume, and pricing) is recorded and accessible by the market. While records of bilateral transactions are not publicly available, they typically use information that the electronic exchange is producing (i.e., EET data) during trading hours to help bilateral counterparties generate their own trade parameters (i.e., price and associated volume). In my professional experience, and as confirmed by the experience of FEI's gas supply department, the ratio between EET and bilateral trading is approximately 50/50. As such, my analysis of EET data represents approximately 50 percent of possible market absorption. I address the incorporation of the bilateral market into my analysis after first summarizing the findings from EET dataset.

i. EET Dataset Demonstrate Ample Market Absorption

As discussed below, the EET market is able to easily absorb 150 MMcf/d across the time period surveyed, including during winter, before prices tend to moderate when volumes surpass 200 MMcf/d. In Figure 13 below, I have compiled daily EET data from 2016 to January 2024 to visualize the seasonality characteristics of the market.

Figure 13

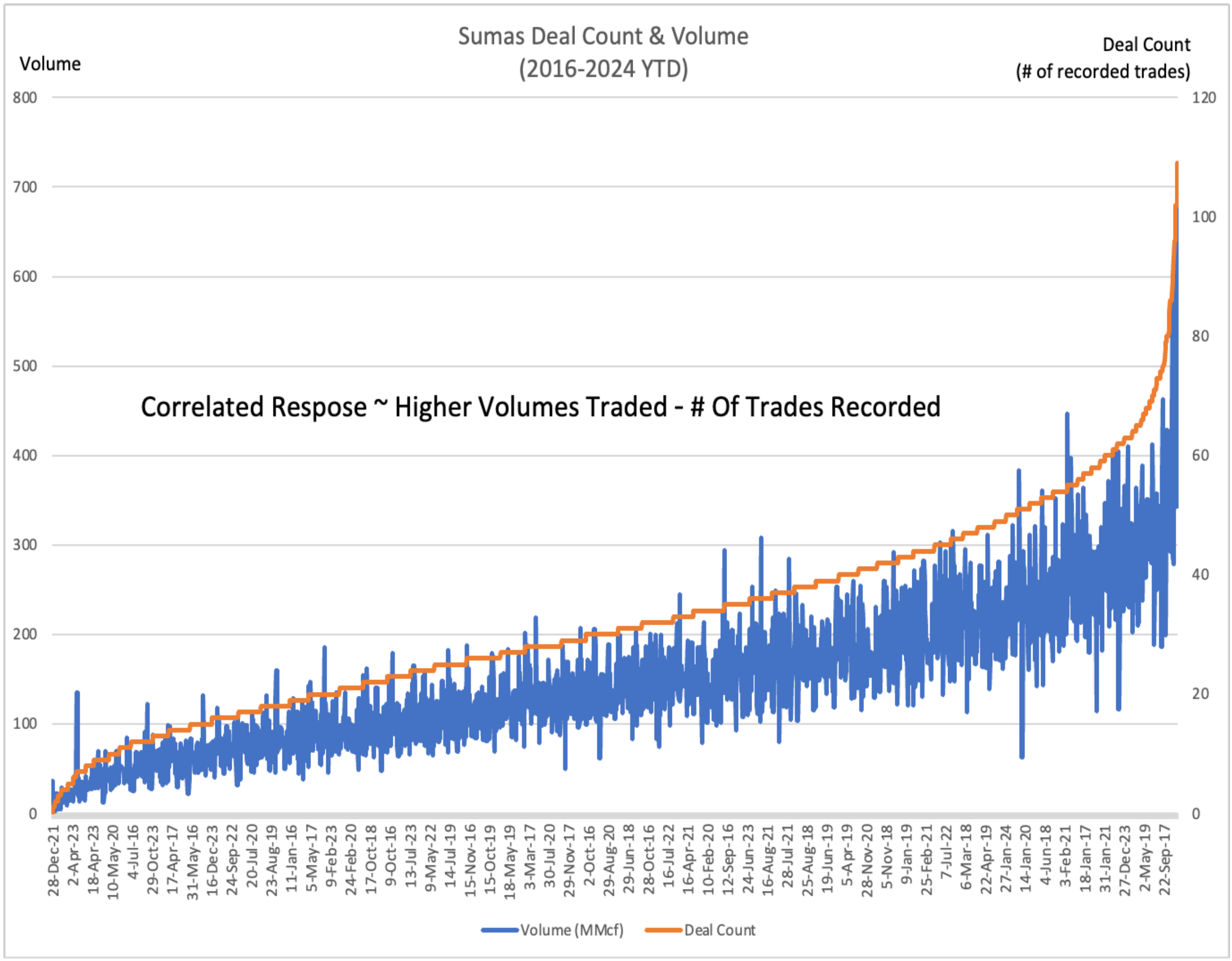


The green data (right Y axis), represents the number of trades on a given day (Deal Count), the blue data (left Y axis) represents the total volumes (MMcf) traded on the day, the black dotted lines represent the 60-day rolling average across the time period visualized, and the transparent blue boxes identify the winter season (November-March) for each year presented. The **red** lines across the chart correlate the volume to the number of trades and show that:

1. an average of 25 trades were required to sell 150 MMcf/d in the EET market;
2. an average of 45 trades were required to sell 300 MMcf/d in the EET market;
3. the EET market could generally absorb 150 MMcf/d year-round; and
4. during the winter periods shown, the EET market could easily absorb 300 MMcf/d.

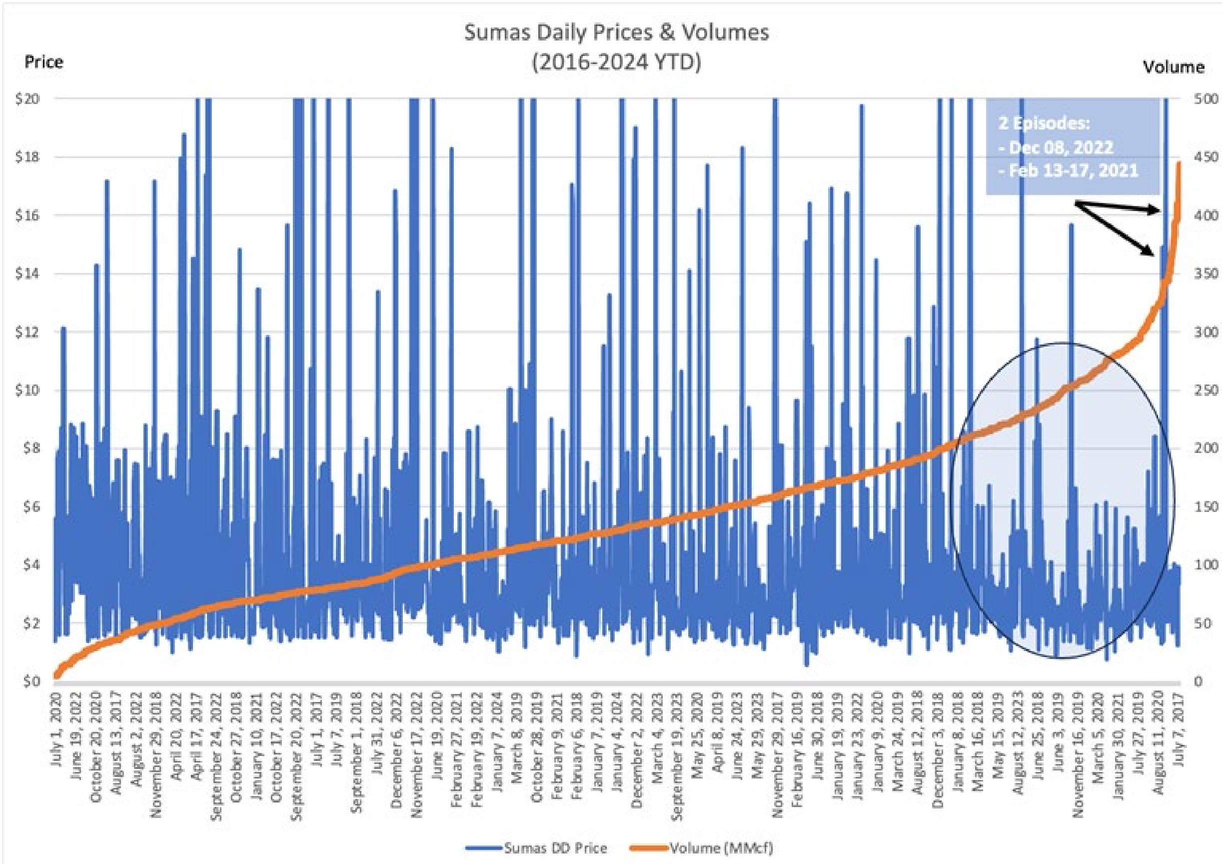
Figure 14 below uses the same EET dataset, but re-arranges the number of trades from lowest to highest. This chart confirms that an increase in the number of trades corresponds to an increase in volumes sold into the market on a given day.

Figure 14



Finally, Figure 15 below shows the daily pricing over the same period. The red line (right Y axis) shows the volume data arranged from lowest to highest, with the day's corresponding daily (settled) price at Huntingdon/Sumas represented by the blue data (left Y axis).

Figure 15



The figures above show that the EET market can easily absorb volumes up to 150 MMcf/d, however, prices for natural gas at Huntingdon/Sumas tend to moderate when volumes surpass the 200 MMcf/d threshold (blue transparent circle). Even so, there are examples in the dataset where unforeseen events (e.g., weather and/or supply constraints) create market conditions that require volumes above 200 MMcf/d and prices do not moderate. These events are identified in the blue transparent box and the associated blue bars within Figure 15, and are described below:

1. *As reported by the U.S. Energy Information Administration (EIA) on December 21, 2022,*[28] *daily natural gas spot prices at three major trading hubs in the western United States (Pacific Gas & Electric [PG&E] Citygate, Northwest Sumas on the Canada-Washington border, and Malin, Oregon) were higher than $50.00 per million British thermal units (MMBtu). These hub prices were higher than in any other market and averaged $48.12/MMBtu above the Henry Hub benchmark, which was $6.14/MMBtu on December 21. PG&E Citygate in Northern California and Malin, Oregon, the northern delivery point into the PG&E service territory, reported the highest natural gas spot prices since*

[28] EIA, https://www.eia.gov/todayinenergy/detail.php?id=55279#:~:text=On%20December%2021%2C%202022%2C%20daily,British%20thermal%20units%20(MMBtu).

December 2000—in both real and nominal terms—according to pricing data from Natural Gas Intelligence. The price at Southern California (SoCal) Citygate was highest on December 13 at $49.67/MMBtu.

Several events occurring simultaneously in the West contributed to prices rising to these levels:

1. *Widespread, below-normal temperatures*
2. *High natural gas consumption*
3. *Lower natural gas imports from Canada*
4. *Pipeline constraints, including maintenance in West Texas*
5. *Low natural gas storage levels in the Pacific region*

Please note the price occurrence above started its advancement on December 8, 2021.

2. *As reported by the EIA on January 6, 2022,*[29] *In mid-February, an intense winter storm in the central United States both increased energy consumption and disrupted energy supply. Daily dry natural gas production in Texas fell by almost half on Wednesday, February 17, according to estimates from IHS Markit, mostly because of well freeze-offs, which occur when water in the raw natural gas stream freezes. The Henry Hub spot price of natural gas increased to nearly $24/MMBtu on February 17, the highest daily price (in real, inflation-adjusted terms) since February 2003. According to Natural Gas Intelligence data, many natural gas pricing hubs throughout the country also saw record-high prices around that time [including Sumas].*

ii. Incorporation of Bilateral Trades Doubles Market Absorption

As noted above, the EET market represents approximately 50 percent of the volume traded at the Huntingdon/Sumas market and, therefore, only half of what the volumes the market was able to absorb. In order to account for the remaining 50 percent of the market (i.e., the bilateral), I have assumed a 100 percent escalation of the EET volume data. This approach ensures that the natural gas volumes traded through the bilateral market data are represented in my analysis, reflecting that the characteristics of bilateral trades tend to mirror EET trades (i.e., volume, price, and number of trades). While volumes traded in the bilateral market are not represented in the three previous figures, based on the results of my analysis, the price point at which natural gas prices at Huntingdon/Sumas moderated would be similar to the EET market at 150-200 MMcf/d. Therefore, 200 MMcf/d could be traded <u>in their respective portion of the Huntingdon/Sumas market</u> (i.e., 200 MMcf/d EET + 200 MMcf/d bilateral = 400 MMcf/d total) before prices tend to moderate. As noted above, such moderation generally does not occur where unforeseen events: (1) drive an increase in demand; or (2) cause a supply constraint in the market.

[29] EIA, https://www.eia.gov/todayinenergy/detail.php?id=50778.

III. Conclusions to Question #3: Analysis Results Confirm Market Absorption Will Likely Increase in the Future as the Market Becomes Further Constrained

When both the Huntingdon/Sumas EET and bilateral markets are considered, I expect the daily market could absorb 300-400 MMcf/d across multiple days (e.g., 10 days) during the winter without influencing daily prices in a manner that could limit monetization values. Assuming no other resources are implemented, the minimum amount the Huntingdon/Sumas market can absorb will likely increase as the market becomes further constrained – thereby increasing the volume threshold at which prices tend to moderate under normal market conditions.

For example, as previously discussed in Question 2B, the future operations of the Woodfibre LNG facility, which is currently scheduled to enter service in 2027, will have a significant impact on the available supplies currently being consumed by the Huntingdon/Sumas market. In particular, as noted above, the 300 MMcf/d currently contracted for the Woodfibre LNG facility no longer being sold into the market when the facility enters service will result in a corresponding decrease in available supply at Huntingdon/Sumas. This large decrease in available supply, coupled with a continued increase in demand for natural gas resources in the Pacific Northwest due to, for example, increasing electrification across the region, would only increase what the market can reasonably absorb on a given day. Therefore, even assuming the proposed WEI Sunrise Expansion Program is successfully implemented and constructed, this project would only *replace* Woodfibre LNG supplies, leaving the conditions at the Huntingdon/Sumas market in a similar supply/demand and pricing position as today (i.e., 300-400 MMcf/d of market absorption potential). This continues to present a significant market opportunity for increased calls on daily natural gas peaking resource(s) such as the proposed TLSE Project.

Ultimately, without new resources being added, such as the proposed TLSE Project, the Huntingdon/Sumas market will remain constrained after 2027 (when the Sunshine Expansion Program is expected to enter service) and, therefore, will continue to be able to absorb 300-400 MMcf/d across multiple days (e.g., 10 days) during the winter without influencing daily prices in a manner that could limit monetization values.

Response to Question #4

Assuming FEI is able to monetize its hypothetical surplus from the TLSE Project as contemplated in the Question 3 scenario, what annual financial value could FEI recover for its customers in the following scenarios where, in one year, FEI can deliver and the market can absorb a maximum of

Scenario #1: 300 MMcf/d of send-out sold over 1.3 peak days (300 MMcf/d x 1.3 = 0.4 Bcf of LNG);
Scenario #2: 300 MMcf/d of send-out sold over 2 peak days (300 MMcf/d x 2 = 0.6 Bcf of LNG);
Scenario #3: 300 MMcf/d of send-out sold over 3 peak days (300 MMcf/d x 3 = 0.9 Bcf of LNG);
Scenario #4: 300 MMcf/d of send-out sold over 5 peak days (300 MMcf/d x 5 = 1.5 Bcf of LNG);
Scenario #5: 300 MMcf/d of send-out sold over 7 peak days (300 MMcf/d x 7 = 2.1 Bcf of LNG); and
Scenario #6: 300 MMcf/d of send-out sold over 10 peak days (300 MMcf/d x 10 = 3.0 Bcf of LNG).

For each scenario, please calculate the financial value FEI could recover over a 5-year period, taking into account FEI's estimated variable operating costs for the Tilbury facility, which has been provided to you, and assuming FEI's commodity cost to produce LNG reflects gas prices in the summer when FEI typically fills its LNG tank. Please also add another five-year scenario:

Scenario #7: in year 1, 300 MMcf/d sold over 10 peak days (300 MMcf/d x 10 = 3.0 Bcf of LNG), and in each of years 2-5, 300 MMcf/d is sold over 3 peak days (300 MMcf/d x 3 = 0.9 Bcf of LNG);

Please note that the financial variables used to generate the financial value results below are based on the 5-year forward market prices (2024-2029)[30] at Huntingdon/Sumas and Spectra-Stn2. As previously discussed in Question 3, the ongoing supply/demand imbalance (lack of energy infrastructure to meet existing and growing customer demand), is likely to persists throughout the proposed TLSE Project's projected term of operations. While I realize that the proposed TLSE Project is not yet in service, in my opinion, using current forward market prices is appropriate for the purposes of the requested analysis given volatility in the market is expected to increase, or at minimum persist, beyond a 5-year time horizon.

To replicate the filling of the TLSE Project tank during the summer (April-October), my analysis uses summer forward prices for Spectra-Stn2, which I have adjusted to reflect their respective tolls/motor fuel for delivery to Huntingdon/Sumas. To replicate regasification during the winter

[30] Based on forward markets dated February 29, 2024.

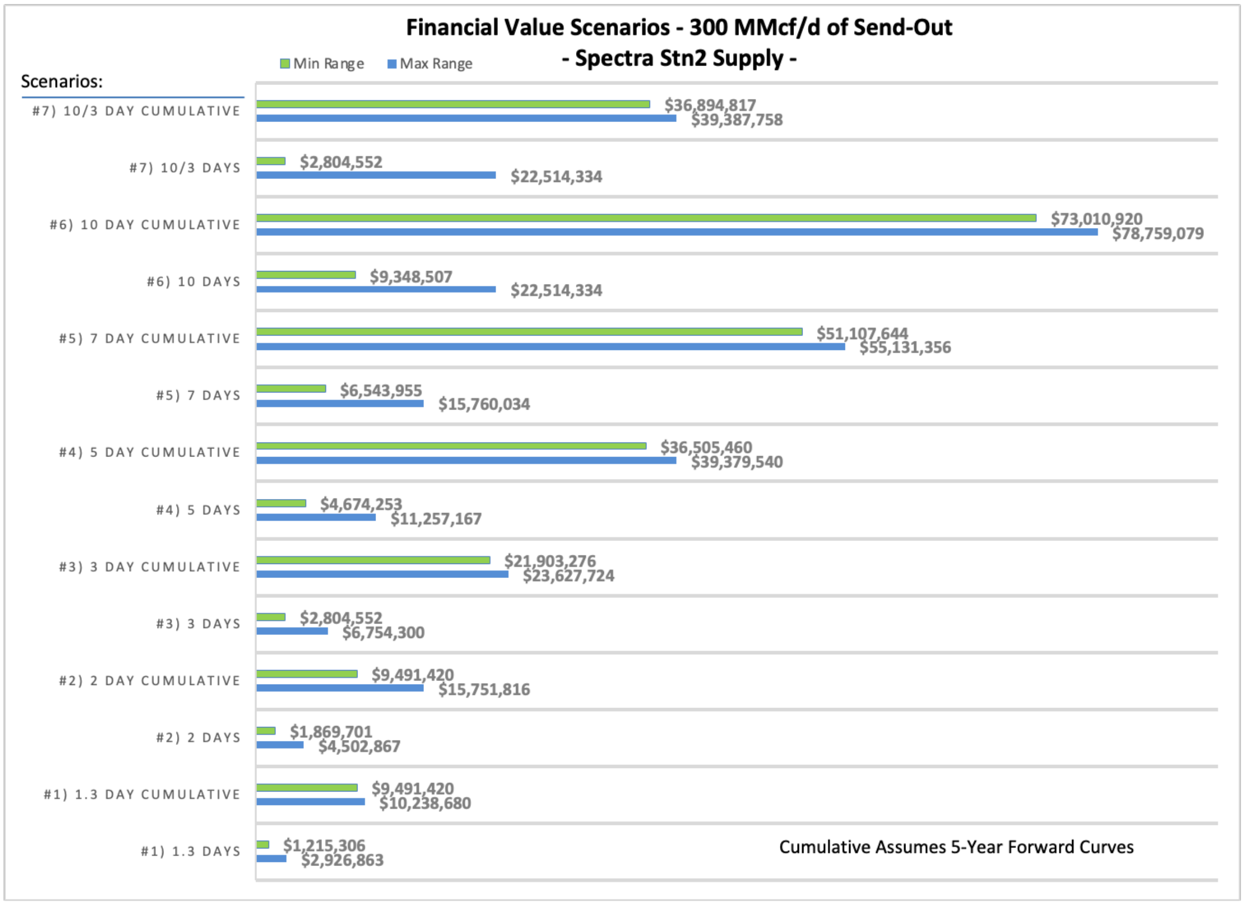
(December-February), my analysis uses winter forward prices at Huntingdon/Sumas to which I then applied a “daily escalator” to replicate future daily volatility that would be experienced by FEI’s gas supply department. Finally, I have generated scenarios for a standing demand charge, monetary value incremental to market price spreads (i.e., Spectra-Stn2 to Huntingdon/Sumas prices), that could be accessed by FEI’s gas supply department. For clarity, a standing demand charge is a fee, collected by FEI from a third-party, who, in these scenarios, has contractually committed to LNG capacity from the TLSE Project. Please refer to Appendix C, Supplemental Energy Market Information, for a detailed breakdown of the calculations underpinning the financial value results for each scenario.

While the results of my analysis demonstrate that volatility in the Huntingdon/Sumas market can generate significant monetary value, accessing this value is predicated on access to a dependable peaking resource, which currently does not exist in the market. Put simply, if the TLSE Project were not constructed, FEI cannot currently rely on purchasing similar volumes from the market.

The results of my financial analysis are presented in Figure 16 below. The figure identifies a Spectra-Stn2 delivery point,[31] the range of financial values (i.e., Min to Max) for Scenarios #1 through #7, and the respective 5-year cumulative values assuming 300 MMcf/d of send-out capacity. The results of my analysis show that, over a 5-year period, FEI could recover between $73.0 MM CDN to $78.8 MM CDN of financial value for its customers over 10 peak days in the winter. Furthermore, assuming Scenario #7, a combination of 10-days of send-out capacity in year one and 3 peak days of send-out capacity in years two through five, FEI could recover between $36.9 MM CDN to $39.4 MM CDN of financial value for its customers. I provide a summary of the 5-year cumulative results for Scenarios 1# through #7 in Figure 16 below.

[31] ICE NGX - https://www.ice.com/products/73447570/ICE-NGX-Spectra-Station-2-Fixed-Price-Daily.

Figure 16



The financial results presented in Figure 16 above do not include additional incremental value that FEI could capture by implementing a standing demand charge. Please refer to Appendix C, Generating A Standing Demand Charge, for a detailed analysis of its structure. I estimate that FEI could generate the following range of additional incremental value through an annual standing demand charge:

- *$5.2 MM CDN - $7.0 MM CDN for every 50 MMcf/d*

Assuming Scenario #6 (i.e., 10 days of send-out, cumulative over 5-years) and Scenario #7 (i.e., 10 days of send-out year 1 and 3 days of send-out over years 2-5) and that FEI's gas supply department is successful in contracting a standing demand charge with a third-party for 50 MMcf/d of send-out capacity from the TLSE Project,[32] FEI could increase the average cumulative financial value as follows:

Scenario #6: From $75.9 MM CDN[33] to $106.4 MM CDN;[34] and
Scenario #7: From $38.2 MM CDN[35] to $68.7 MM CDN[36]

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[32] Calculation of average standing demand charge over five years: (($5.2 MM + $7.0 MM)/2) x 5 years = $30.5 MM
[33] Calculation of 10-day cumulative average financial value for Scenario #6: ($73.0 MM + $78.8 MM)/2 = $75.9 MM
[34] Calculation of average standing demand charge over five years and 10-day cumulative average financial value for Scenario #6: $30.5 MM + $75.9 MM = $106.4 MM
[35] Calculation of 10-day year 1 and 3-day years 2-5 financial value for Scenario #7: ($36.9 MM + $39.4 MM)/2 = $38.2 MM
[36] Calculation of average standing demand charge over 5 years and 10-day year 1 and 3-day years2-5 financial value for Scenario #7: $30.5 MM + $38.2 MM = $68.7 MM

APPENDIX A

Letter of Instruction

FASKEN

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April 15, 2024
File No.: 240148.00966

Via Email
Privileged and Confidential

1459488 B.C. Ltd
1201 Fort Street, Suite 506
Victoria, British Columbia
V8V 0G1

Attention: Raymond Mason

Dear Sirs/Mesdames

Re: FortisBC Energy Inc. ("FEI") – Tilbury Liquefied Natural Gas Storage Expansion ("TLSE") Project CPCN Application (the "Regulatory Proceeding")

We, as counsel for FEI in the above referenced Regulatory Proceeding, request that you prepare an independent expert report to be introduced into evidence in that Regulatory Proceeding. This letter outlines the matters to be addressed and provides some general guidance as to the format of your report.

Apart from our instructions below as to the matters to be addressed and the format of your report, the contents of your report are entirely for you in the exercise of your independent professional judgment. You have been retained to provide independent expert evidence for the above referenced Regulatory Proceeding, not as an advocate for our client. The integrity of your conclusions is dependent upon your objectivity.

Matters on Which Your Opinion is Requested

We request that your report set out your independent objective opinion with respect to the following:

1. What are the elements of an optimal resource portfolio for FEI and its customers?

2. FEI has, since 1971, included on-system liquified natural gas ("LNG") at the Tilbury facility in its supply portfolio as a peaking capacity resource (i.e., rapid send-out capability, backed by sufficient LNG to meet short-duration peak load). FEI's current Annual Contracting Plan includes 150 MMcf/d of regasification and 0.6 Bcf of LNG from the

Tilbury facility. We seek your opinion on the peaking capacity alternatives available to FEI in the event that FEI was no longer able to include some or all of these peaking resources in its supply portfolio. In particular:

- Based on your assessment of the natural gas markets accessible to FEI, would FEI be able to contract for peaking resources (capacity/energy supply) as a potential alternative to on-system LNG in its gas supply portfolio, and if so on what terms?

- If appropriate peaking resources (capacity/energy supply) are unavailable to FEI in the market, what other potential investments could FEI explore as a potential alternative to on-system LNG as peaking resources (capacity/energy supply) in its gas supply portfolio? For clarity, in this regard we are requesting that you identify potential peaking supply (capacity/energy supply) alternatives based on your understanding of the regional system, as opposed to a undertaking a financial analysis of those options.

3. Assuming a hypothetical scenario where the TLSE Project is constructed with 3 Bcf of storage volume and 800 MMcf/d of regasification capacity, and FEI no longer requires the full storage and regasification capacity to meet its own gas supply and resiliency requirements, do you expect that FEI would be able to monetize the surplus by selling peaking resources in the gas market? If so, how much daily send-out capacity would the market reasonably absorb?

4. Assuming FEI is able to monetize its hypothetical surplus from the TLSE Project as contemplated in the Question 3 scenario, what annual financial value could FEI recover for its customers in the following scenarios where, in one year, FEI can deliver and the market can absorb a maximum of

- Scenario #1: 300 MMcf/d of send-out sold over 1.3 peak days (300 MMcf/d x 1.3 = 0.4 Bcf of LNG);

- Scenario #2: 300 MMcf/d of send-out sold over 2 peak days (300 MMcf/d x 2 = 0.6 Bcf of LNG);

- Scenario #3: 300 MMcf/d of send-out sold over 3 peak days (300 MMcf/d x 3 = 0.9 Bcf of LNG);

- Scenario #4: 300 MMcf/d of send-out sold over 5 peak days (300 MMcf/d x 5 = 1.5 Bcf of LNG);

- Scenario #5: 300 MMcf/d of send-out sold over 7 peak days (300 MMcf/d x 7 = 2.1 Bcf of LNG); and

- Scenario #6: 300 MMcf/d of send-out sold over 10 peak days (300 MMcf/d x 10 = 3.0 Bcf of LNG).

For each scenario, please calculate the financial value FEI could recover over a 5-year period, taking into account FEI's estimated variable operating costs for the Tilbury facility, which has been provided to you, and assuming FEI's commodity cost to produce LNG reflects gas prices in the summer when FEI typically fills its LNG tank. Please also add another five-year scenario:

- Scenario #7: in year 1, 300 MMcf/d sold over 10 peak days (300 MMcf/d x 10 = 3.0 Bcf of LNG), and in each of years 2-5, 300 MMcf/d is sold over 3 peak days (300 MMcf/d x 3 = 0.9 Bcf of LNG);

In order to facilitate your analysis and the preparation of your report, FEI will make available information that your request. You can assume, for the purposes of your analysis, that any information provided by FEI is accurate.

Overview of the Structure of Your Report

We request that your independent expert report be set out generally consistent with the following structure.

A. Introduction and Summary of Opinion

Your introduction should

- reference the nature of your engagement as an independent expert as per this letter,
- identify the questions posed to you, and
- set forth, in a summary fashion, your independent objective opinions on each matter upon which your opinion is requested, as set out above in this letter.

Please state, in a summary fashion, the professional qualifications, technical education, training and experience of those individuals who are responsible for the content. Explain how the authors' expertise relates to the subject matter of your opinions. Detailed *curricula vitae* should be attached as an appendix.

We confirm that you have a duty to assist the regulator and are not to be an advocate for any party ("Duty of Independence"). In this section of your report, please certify the following:

- You are aware of your Duty of Independence,
- You have prepared your report in accordance with the Duty of Independence, and
- If called to give oral or written testimony, you will give that testimony in conformity with the Duty of Independence.

B. Supporting Review and Evaluation

Under this heading, you should set out in full your independent objective opinions on each of the matters in the same order that the matters are presented above. You should provide the reasons for your opinions including reference to pertinent facts or assumptions and any research you conducted that led you to form the opinion.

C. Conclusion

You may provide a conclusion if you wish.

Appendices

Please include this letter, and your *curricula vitae* as appendices to your report. If additional instructions are required, then supplementary letters of instruction from us should also be attached to your report. You may attach other documents or schedules that elaborate on, or are integral to your analysis.

In conclusion, if you have any questions with respect to the nature and scope of your engagement, please contact the writer at your soonest convenience.

Yours truly,

FASKEN MARTINEAU DuMOULIN LLP

Matthew T. Ghikas
Personal Law Corporation

MTG/NR

cc Sarah Walsh
Director, Regulatory Affairs
FortisBC Energy Inc.

APPENDIX B
Work Experience

Raymond Mason
M4 - Energy & Capital Markets Consulting

Victoria, British Columbia

Professional Summary:

I am a commodity & derivatives professional with over 28 years of experience focusing primarily on natural resources and capital markets. I have provided market risk, sales & origination knowledge to the entire value chain within the Oil & Gas, Renewable Natural Gas, Electricity, Agriculture, and Metals industries. Expertise with price risk management portfolios, underwriting derivative structures, commodity linked financing, regulatory oversight, and business development. My career has engaged with Bay Street and Wall Street capital markets, the Federal Energy Regulatory Commission, US Securities Exchange Commission, Municipal Bond markets, Western Canadian Utilities Commissions, and the BC Vegetable Marketing Commission.

I have maintained leadership, guidance, and sensibility roles in the ever-changing derivatives and commodities landscape. This has continued to demonstrate an ability to advise and partner with a wide range of clients (C-suite public and private) across global businesses while ensuring risk weighted profits are maintained. My experience provides key strategic understanding of the development of commodity franchises in new and evolving market dynamics. This is instrumental in assisting internal partners with market risk, regulatory, tax, legal, and front and back-office functions for franchise trading activities.

Skills / Experience:

- Business Development
- Sales & Marketing
- Derivatives, Asset Backed Securities, and Commodity linked financing
- Financial and Physical Commodity Price Risk Management
- Operations and Maintenance of Pipelines, Distribution, Storage, and Industrial
- Trucking, Vessel, and Rail Logistics & Scheduling
- Market Risk Evaluation & Monitoring
- Font/Back Office Functions & Reporting (Billing, Accounting, Balance sheet analysis)
- Capital Cost Analyses and Implementation

Professional Background:

Financial Institution – Capital Markets & Commodity Trading

For the past 16 years, I have been active with the implementation, development, and success of building an energy trading franchise for The Toronto Dominion Bank ("TD"). Was active under the TD franchises: TD Securities, TD Securities USA LLC., and TD Energy Trading Inc. These franchises encompassed my activities in the financial and physical commodities business, capital markets, municipal bonds, interest rates and currency exchange platforms.

The initial launch of TD's physical energy franchise in 2003, I was responsible for establishing client relations and successfully negotiating ISDA / GasEDI / NAESB / Energy Management Service contracts to service financial and physical derivative risk management and operations solutions for new clients. The initiative was a collaborative effort with industry, and peers within the Firm, to align the "go to market" products while ensuring a proper business foundation was being built. Throughout the early years of the franchise development, it was critical to ensure business operations were sound with the appropriate risk controls, deal entry, operations, and accounting functions. Industry communications via conferences and speaking engagements helped me articulate how TD was building its business within a capital intense industry. TD Energy soon became the leading marketing and trading franchise in Canada and the Western United States.

I continued to develop new initiatives within the Firm that consisted of balance sheet reconciliation, capital risk modelling, underwriting derivative portfolios, commodity-based financing, and the US expansion of physical trading.

To increase franchise efficiencies and profitability, I performed internal business balance sheet audits. This ensured new regulations were being properly measured and implemented. In addition, the audits helped the development of a new directional risk counter-party exposure model to lower Basel III CVA capital which improved business profitability.

I managed the derivative portfolios of the Firm's US private equity energy producer franchise. The franchise initiatives included the underwriting of derivative portfolios which required knowledge of capital exposures and price risks. This process was undertaken while coordinating with Investment

Banking initiatives during client mergers and acquisitions efforts and peer banks during underwriting processes.

Commodity-based financing, also known as Municipal Pre-Pays, was a newly formed US franchise that provided a new source of funding for TD. I managed all energy related aspects of the franchise which included 30 year financial and physical commodity transactions. Deal size funding typically ranged from $750 MM to $1,000 MM per transaction. Collaborated with investment banking, municipal bonds, asset back securities, corporate lending, and equities teams to create a detailed business plan and policy parameters while tracking performance on a regular basis. The creation of the franchise required significant educational process for internal partners in risk, legal, regulatory compliance, finance, and trading. This franchise furthered TD's clients reach into the entire energy value chain which included producers, municipal power & gas utilities, refineries, petrol-chemical, pulp & paper, transportation/aviation, auto manufacturing, peer financial institutions, and energy marketing companies.

Developed the initial business plan for an expanded physical natural gas franchise into the US; while providing guidance to outside legal and tax council for the regulatory opinions regarding the Firm's operations under Canadian and US Bank regulatory frameworks. This continued to the coordination with internal partners for the approval of risk, compliance, legal, Federal and State tax, and staffing policies for the new initiative. Supervised and maintained business development liaison with internal partners for the ongoing implementation of the Firm's United States physical natural gas initiative.

Physical Commodities – Distribution, Midstream, Transmission and Trading

Throughout the early part of the 1990's, I was active in developing and maintaining financial regulatory modelling for Westcoast Energy's natural gas assets on Vancouver Island, Sunshine Coast, and Whistler. The assets included the high-pressure natural gas transmission line, utility distribution assets, and piped propane networks in Whistler and Port Alice. Provided support for applications to the British Columbia Utilities Commission that included Integrated Resource Plans, Certificate of Public Convenience and Necessity, and Cost of Gas Passthrough applications.

The latter part of 1990's, I assumed the responsibilities of gas operations for Centra Gas Inc. As Gas Operations Coordinator, I was responsible for the movement of natural gas throughout the British Columbia resource portfolio (storage and midstream) and the interconnections with FEI and

Northwest Pipeline. The role required an understanding of natural gas pricing, supply and demand fundamentals, core customer demand needs, hydraulic compression & meter station measurement operations (Scada monitoring), line pack utilization, and any operation & maintenance with peer pipelines, power generation, and large industrial industries. The propane systems required knowledge of liquids pricing, and rail scheduling/pricing. In addition, I provided negotiation support for gas supply portfolio resources for Centra Gas's core customers. This included long and short-term transportation, peaking gas supply, storage, and seasonal supply contracts.

In early 2000, I expanded my experience to include physical commodities trading in electricity. This new role included managing a small regional trading franchise in Vancouver, British Columbia. The regional coverage of clients included British Columbia, Washington, Oregon, Idaho, and California, with the client portfolio consisting of pipelines, midstream, storage, utilities, power generation, and industrials.

Agriculture – Deregulation, Franchise Development & Commodity Trading

As head of sales & logistics, I ran the day-to-day operations of a continental greenhouse sales and logistics business, as well as the regional management of Canada. The launch of this franchise was made possible with the deregulation of the hothouse industry in British Columbia. Introduced marketing contracts that included take or pay arrangements, peak supply off-take, and backstopped production arrangements not typically seen in the produce industry.

The new franchise responsibilities included the implementation of deal entry, risk management systems and employee oversight. Operations included the sale of proprietary and third-party marketed produce and the logistics of trucking/rail throughout Canada, United States, and Mexico. Established new relations with wholesale, brokerage houses and retailers for the off take of produce, as well as corporate sales initiatives with associated marketing entities such as Dole Food Group, Safeway, Costco, Kroger, Winn Dixie, etc.

APPENDIX C
Supplemental Energy Market Information

I have reviewed the following supplemental energy market information to determine market fundamentals derived by historical and futures pricing trends. I have then used the fundamental trends to generate the financial variables necessary to calculate financial values requested in Question 4.

Historical Pricing Analysis

In the discussion below, I provide a pricing analysis to support the estimation of financial value(s) for the TLSE Project. Similar to the high/low range analysis from Question 2, III “Third-party Peaking Gas Supply”, I want to investigate the value opportunities of sourcing gas supply from Northern British Columbia (Spectra-Stn2), delivering it to Huntingdon/Sumas, and then selling it into the Sumas market. This process will replicate the financial value that could have been hypothetically generated by the TLSE Project had it been in service as early as 2020 (i.e., cost of gas supply and transportation prior to liquefaction and regasification). The analysis shows there would have been opportunities to generate significant financial benefit from selling gas supplies, from the TLSE facility, into the market.

Figure 1 below identifies the incremental transportation and fuel gas costs to source gas supplies from Northern British Columbia. Spectra-Stn2 pricing incurs the T-South toll and associated fuel gas (i.e., average of $0.64 CDN/GJ). Adding the toll and fuel costs to the Spectra-Stn2 prices generates the total embedded costs to deliver gas supply to the Huntingdon/Sumas region prior to its resale.

Figure 1

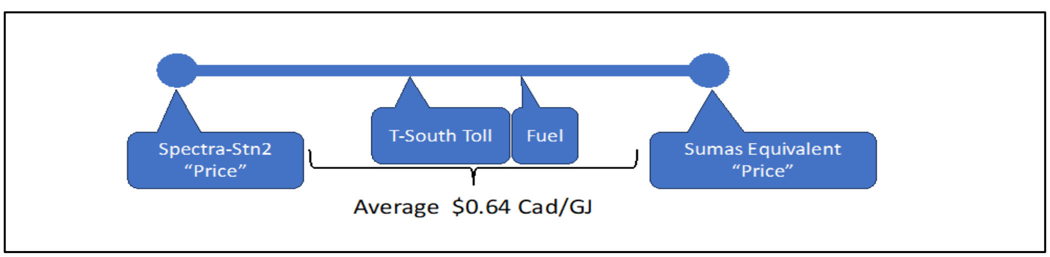
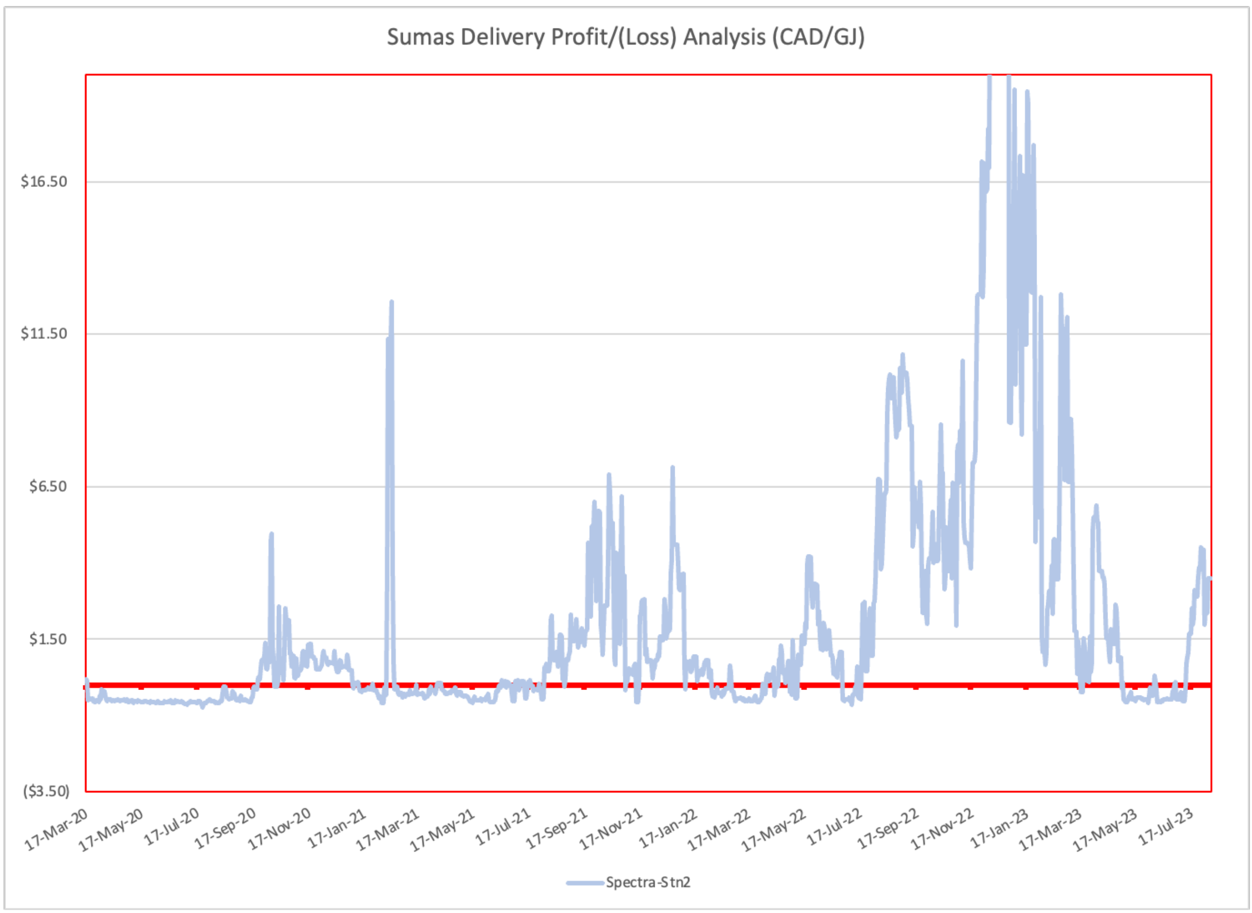


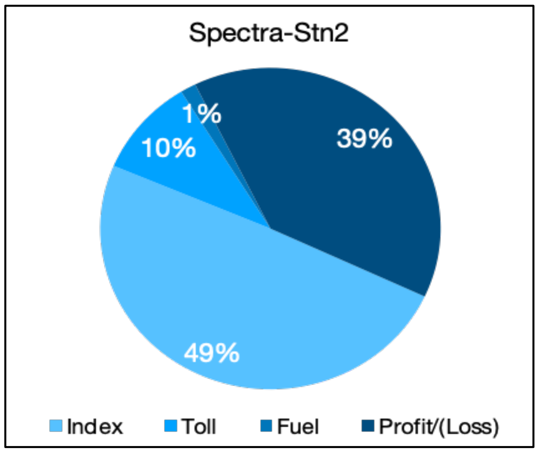
Figure 2 below, uses the above methodology, as well as, incorporating daily Sumas prices (i.e., March 2020 to August 2023). The Sumas daily index is used to replicate a price that would have been captured when selling the previously delivered gas supply from Northern British Columbia. For example, the Sumas daily prices were subtracted from the embedded delivered Spectra-Stn2 (light blue line) daily prices (i.e., which includes respective toll and fuel costs). The red line assumes the "break-even" of the pricing location in relation to the Sumas daily index. Any data point **below** the red line, indicates that Spectra-Stn2 pricing is <u>more expensive</u> than buying the Sumas index. Any data points **above** the red line indicates that pricing from Spectra-Stn2 is a <u>less expensive</u> delivered priced supply than buying the Sumas index. The chart indicates there are significant periods of time that sourcing gas supply from Northern British Columbia, delivering it to the Huntingdon/Sumas region, and selling into the Sumas market, generates financial value.

Figure 2



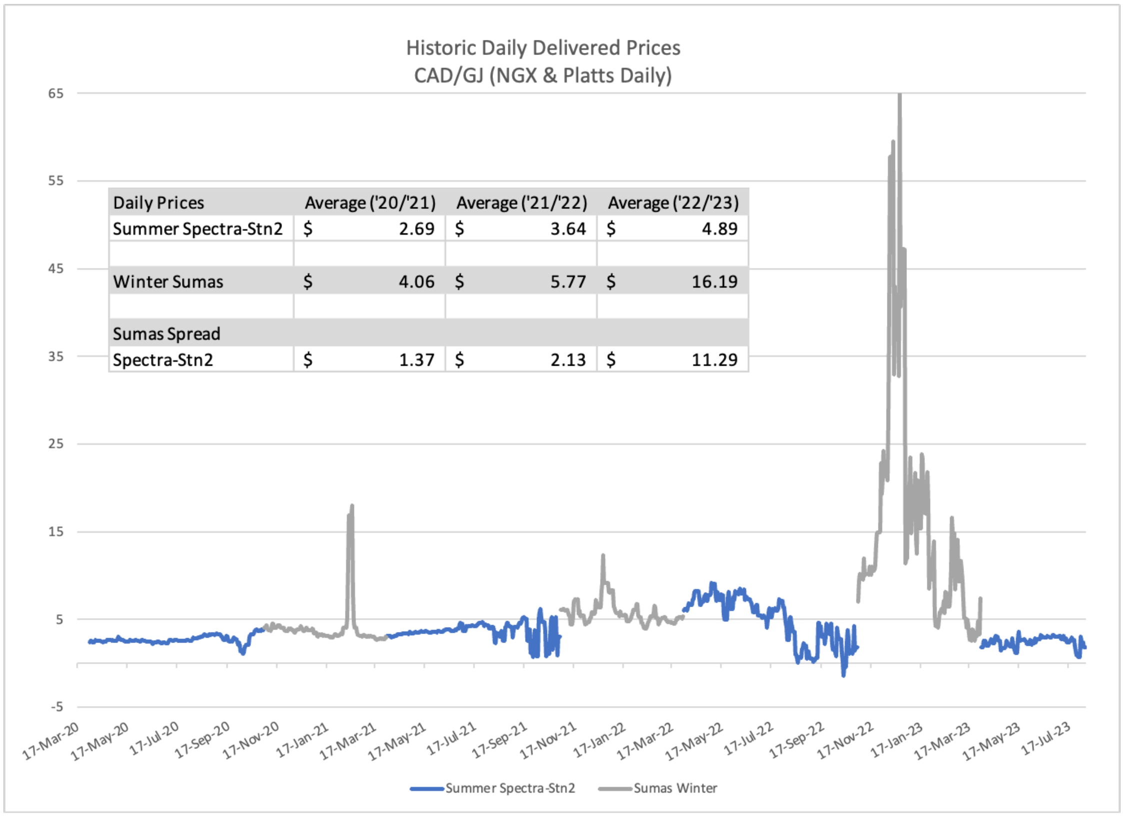
Using the same historical pricing data as above (March 2020 to August 2023), the following pie chart (Figure 3) was created to show the percentage break down of the delivered costs for Spectra-Stn2, and resulting profits that could have been generated by selling gas supplies at Sumas (e.g., Sumas price minus Spectra-Stn2 price plus T-South toll and fuel). The pie chart data supports the pricing advantages of sourcing gas supply from either Spectra-Stn2 and delivering it to Huntingdon/Sumas (Toll and Fuel) for resale (Profit/(Loss)). For example, the Spectra-Stn2 pie chart represents a percentage breakdown of costs as it relates to gross financial value generate when selling gas supply at Sumas. Therefore, assuming 100% of the gross value of a Sumas sale, roughly 60% of the value is offset by Spectra-Stn2 commodity cost, transportation toll, and fuel gas.

Figure 3



To further refine my financial value analysis of sourcing gas supply from Northern British Columbia, I reviewed the seasonal benefits of sourcing gas supplies in the summer, storing it, and then selling it in the winter. For example, Figure 4 below "Historic Daily Delivered Prices" shows summer (April-October) Spectra-Stn2 (blue line) prices and subsequent winter (November-March) Sumas prices (grey line). As in previous figures, Spectra-Stn2 daily prices have been adjusted to reflect their respective transportation toll and fuel gas costs (Index price + toll + fuel gas).

Figure 4



Daily Prices	Average ('20/'21)	Average ('21/'22)	Average ('22/'23)
Summer Spectra-Stn2	$ 2.69	$ 3.64	$ 4.89
Winter Sumas	$ 4.06	$ 5.77	$ 16.19
Sumas Spread			
Spectra-Stn2	$ 1.37	$ 2.13	$ 11.29

The result of this financial analysis is located in the embedded table in Figure 4 above. Summer Spectra-Stn2 numbers represent the average daily prices over the months of April to October for their respective terms (e.g., summer Spectra-Stn2, April 2020 to October 2020 = $2.69 CDN/GJ). The Winter Sumas numbers represent the average daily prices over the months of November to March for their respective terms (e.g., winter Sumas, November 2020 to March 2021 = $4.06 CDN/GJ). Finally, the resulting Sumas Spread for Spectra-Stn2 is generated by subtracting the summer average prices from the winter Sumas prices to generate the Sumas Spread (e.g., winter Sumas minus summer Spectra-Stn2 = Sumas Spread ~ $4.06 - $2.69 = $1.37 CDN/GJ). Therefore, Sumas Spread prices have been seasonally adjusted to generate "profit" from sourcing Spectra-Stn2 summer gas, transporting it to Huntingdon/Sumas, and then selling it in the winter market at Sumas prices (i.e., cost of gas supply and transportation prior to liquefaction and regasification costs).

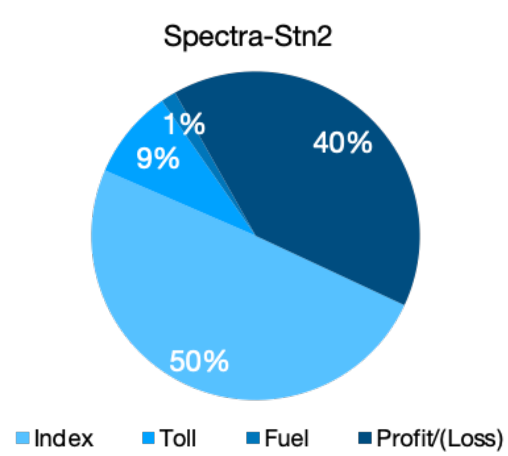
Please note that this exercise is only identifying the pricing differentials between the points discussed and not representative of what someone, or an entity, could extract from the market in its entirety. That would assume a person had executed every trade in the exact right moment, an action that is not plausible. Therefore, one must assume future financial values would be a subset of the spreads if FEI, as the owner of the TLSE facility, was acting commercially.

Futures Pricing Analysis

The following futures pricing analysis is similar to the above analysis, however, I have used the 5-year futures market monthly index prices (March 2024 to February 2029) for Spectra-Stn2 and Sumas. In addition, any associated tolls and fuel gas costs, to replicate delivery cost to move supply from Northern British Columbia, were based on historical averages. This analysis shows there are opportunities to generate significant financial benefit selling gas supplies, from the TLSE facility, into the market.

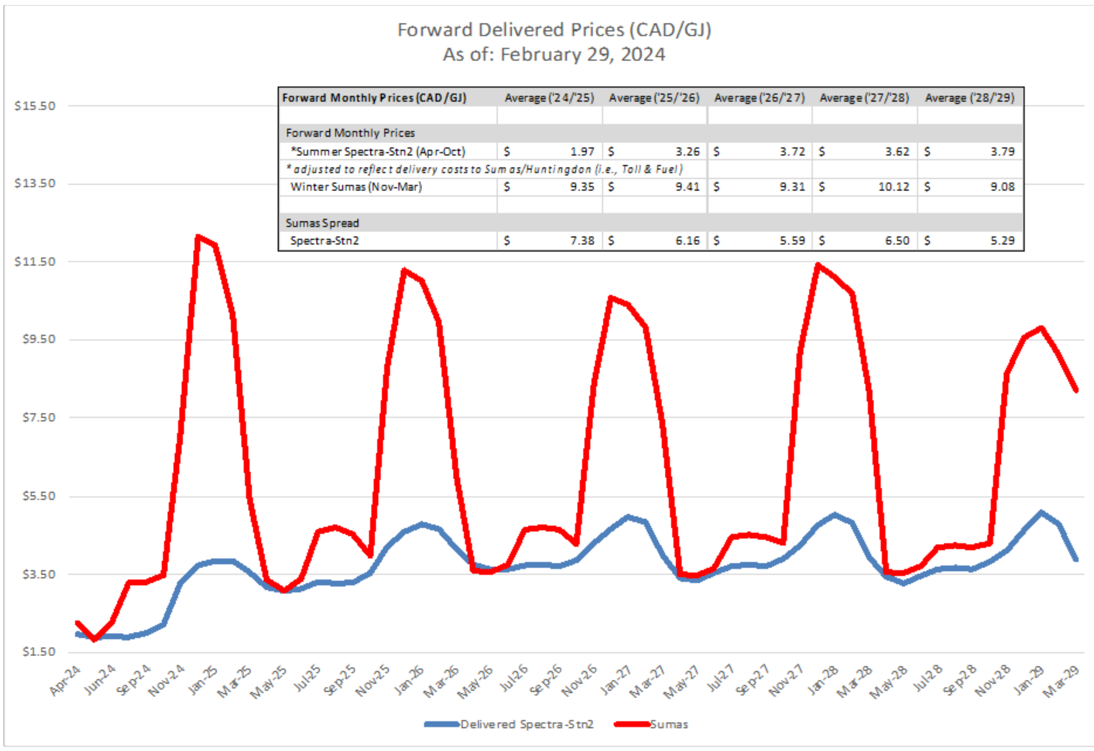
Using the futures pricing data, while applying the same methodology as before, the following pie chart was created to show the percentage break down of the delivered costs for Spectra-Stn2, and resulting profits that could be generated by selling gas supplies at Sumas. The futures market data continues to support pricing advantages of sourcing gas supply from Spectra-Stn2 and delivering it to Huntingdon/Sumas (Toll and Fuel) for resale (Profit/(Loss)). For example, the Spectra-Stn2 pie chart (Figure 5) below represents a percentage breakdown of costs as it relates to gross financial value generate when selling gas supply at Sumas. Therefore, assuming 100% of the gross value of a future Sumas sale, roughly 60% of the value is offset by Spectra-Stn2 commodity cost, transportation toll, and fuel gas.

Figure 5



Using the same futures data as above (March 2024 – February 2029) and adjusting Spectra-Stn2 to reflect the respective delivery cost to Huntingdon/Sumas, the following Figure 6 was developed. As identified in the chart, Sumas prices (red line) rise significantly higher than Spectra-Stn2 (light blue line) prices in the winter. The financial values presented in the embedded table, continues to show that over the next five-years, Sumas Spreads remain profitable. For example, the Sumas spread for Spectra-Stn2, ranges from $7.38 CDN/GJ to $5.29 CDN/GJ.

Figure 6



The above data analysis confirms that the Huntingdon/Sumas region is predicting that resource will remain constrained over the next 5-years and beyond.

Financial Variables Analysis

Using the data results from the historical and futures pricing analysis above, I generated the financial *variables* that would be used to forecast the financial *values*, in the hypothetical scenario where the TLSE Project is constructed and where FEI no longer requires the full regasification capacity and stored LNG for its own resiliency. As part of this stage of my analysis, I apply the financial variables to the futures market data in order to align the hypothetical daily operations of the TLSE facility.

My analysis of the financial variables is broken into three parts:

I. Refining the forward monthly prices;
II. Developing a daily price escalator to replicate daily trading activities; and
III. Generating a standing demand charge.

Note: though historical natural gas pricing data has daily and monthly settles, the forward/futures pricing market only generates monthly prices. Therefore, I developed a methodology to replicate future daily prices (as discussed further below).

I. Refining Forward Monthly Prices

The natural gas industry breaks the calendar year into winter and summer time periods. The summer consists of the months of April to October and the winter November to March (i.e., carries over two calendar years; for example, November 2023 to March 2024). In the Huntingdon/Sumas pricing region there can be significant monthly variations in customer demand throughout the winter period. Specifically, the months of December, January, and February are typically the months that experience higher demand influenced by weather and/or unforeseen infrastructure outages. I have shortened the winter Sumas sales period to only include forward prices for the months December, January, and February, assuming that regasification from the TLSE Project would take place during periods of peak demand at Huntingdon/Sumas. I believe this is appropriate because it closely aligns peak demand with when gas supplies have historically been sold into the market.

II. Daily Price Escalator Development

Based on my experience in the Huntingdon/Sumas market, FEI's gas supply department would be active in the daily market when mitigating excess gas supply. As previously discussed in Question 2, III Third-party Peaking Gas Supply, there is an incremental daily range value that could be accessed by FEI during LNG peaking operations (i.e., Daily Escalator). Therefore, by utilizing the monthly forward prices, for December to February, and incorporating a daily range estimate, I was able to formalize the financial estimates requested in Question 4.

The development of the daily price escalator was based on historical Huntingdon/Sumas daily price ranges from 2017 to 2023. This data is presented in the chart (Sumas Daily High/Low

Ranges) on page 28-29 of the report. In addition to the historical Sumas daily price range data, I have incorporated peaking supply pricing mechanisms that I became familiar with as part of my role as gas supply marketer. I have created the following Daily Escalator Scenarios based the analysis of this historical data and the application of pricing mechanisms used in the market.

Daily Escalator Scenario A

Daily Escalator Scenario A was derived from historically recorded "high trades" [1] at Huntingdon/Sumas for the months December to February over the periods of 2017-2023. These high trades were subtracted from their respective daily settled price to generate the range value. These range values were then averaged generating the mean variable of $0.47 CDN/GJ.

For example: Assuming the monthly forward index for the Month of December was $7.00 CDN/GJ (i.e., $7.00 x 31 days), the Daily Escalator Scenario A of $0.47 CDN /GJ would be added to the $7.00 (i.e., $7.00 + $0.47 = $7.47) which represents the incremental daily variable estimate that FEI gas supply department could extract in the future daily market. For the purpose of applying this daily escalator, I assumed that FEI's gas supply department had constructed a peaking gas arrangement with a third-party who has agreed to pay the Huntingdon/Sumas high price, as recorded by the market, on the day gas supply was required. Therefore, in this scenario, the Daily Escalator Scenario A would be applied to the forward monthly prices for the winter terms of December, January, and February.

Daily Escalator Scenario B

For the Daily Escalator Scenario B, I conducted a descriptive statistics analysis[2] using the same term (2017-2023), Huntingdon/Sumas daily recorded high price, and the respective Sumas daily settled price as Daily Escalator Scenario A above. The descriptive statistics analysis of the historic data generates a lower range (mean – confidence level) and a

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[1] "High trades" refers to those recorded by the EET market that set the highest point in the range on any given day prior to end-of-day settlement.

[2] Descriptive Statistics as described by Microsoft Excel Analysis Tools. The Descriptive Statistics analysis tool generates a report of univariate statistics for data in the input range, providing information about the central tendency and variability of the data.

higher range (mean + confidence level) of prices. The resulting high prices are subtracted from the settled prices to generate the Daily Escalator Scenario B.

For example: In the following Figure 7, the high recorded prices in column 1 and the settles prices in column 2, represent the average (mean), lower, and high ranges generated by the descriptive statistics analysis. The Daily Escalator Scenario B (i) and B (ii) (i.e., Escalator Column 1-2) provides the lower ($0.3778 CND/GJ) and higher ($0.5697 CND/GJ) range for this scenario.

Figure 7

Escalator A & B Sumas (Cad/GJ)	**High Recorded Prices (Column 1)**	**Settled Prices (Column 2)**	**Escalator (Column 1-2)**	
Mean	$8.5941	$8.1203	**A**	**$0.4738**
Confidence Level @ 95.0%	0.972856166	0.87689191		
Lower (Mean - CL)	$7.6212	$7.2434	**B (i)**	**$0.3778**
Higher (Mean + CL)	$9.5670	$8.9972	**B (ii)**	**$0.5697**

Please note that the mean for the Daily Escalator Scenario A remains the same in this analysis.

Daily Escalator Scenario C

The Daily Escalator Scenario C was generated multiplying the forward winter (December, January, and February) Huntingdon/Sumas monthly price by 102% and deducting forward summer (April to October) monthly prices for Spectra-Stn2 (i.e., adjusted to reflect their respective toll and fuel costs). This scenario assumes that the buyer has agreed to pay 102% of the Huntingdon/Sumas daily settled price, prior to the settlement actually transpiring. This arrangement is similar to products that I have structured during my tenure as an energy marketer. The % charged by the seller fluctuates based on what the market will bear. For the purposes of this analysis, I have assumed that the FEI gas supply department had replicated this structure and has used 102%.

Resulting Financial Variables Analysis

Considering FEI's estimate of the TLSE LNG Variable Operating Costs (i.e., as referenced in the table below, Financial Variables), which have been provided to me, and assuming FEI's commodity cost to produce LNG reflects gas prices in the summer when FEI typically fills its LNG tank, the following Financial Variables table (Figure 8) has been generated. Furthermore, the creation of the daily escalators is an attempt to replicate actual daily trading activities FEI's gas supply department could execute, assuming similar arrangements were constructed in agreements, for marketed peaking gas supply that would be sold into the market. These variables have been used while estimating the financial value scenarios requested in Question 4.

Figure 8

Financial Variables	Average ('24/'25)	Average ('25/'26)	Average ('26/'27)	Average ('27/'28)	Average ('28/'29)
Cad/GJ					
Forward Monthly Prices					
*Summer Spectra-Stn2 (Apr-Oct)	$ 1.97	$ 3.26	$ 3.72	$ 3.62	$ 3.79
Winter Sumas (Dec-Jan-Feb)	$ 11.41	$ 10.75	$ 10.27	$ 11.08	$ 9.51
** adjusted to reflect delivery costs to Sumas/Huntingdon (i.e., Toll & Fuel)*					
TLSE LNG Variable Operating Cost	$ (3.00)	$ (3.00)	$ (3.00)	$ (3.00)	$ (3.00)
Daily Escalator A	$ 0.47	$ 0.47	$ 0.47	$ 0.47	$ 0.47
Daily Escalator B (i)	$ 0.38	$ 0.38	$ 0.38	$ 0.38	$ 0.38
(ii)	$ 0.57	$ 0.57	$ 0.57	$ 0.57	$ 0.57
Daily Escalator C	102%	102%	102%	102%	102%

Example: assuming the forward average prices for the term 2023/2024, Winter Sumas plus Daily Escalator A, less the Summer Spectra-Stn2, less TLSE LNG Variable Cost, multiplied by send-out volume and # of days, the financial value generated would be ((($11.41 + $0.47 - $1.97 - $3.00) x 321,238 GJs*) x 2 Days) =* ***$4.44 MM CDN****.* *{*300 MMcf/d = 321,238 GJs}*

III. Generating a Standing Demand Charge

As previously discussed in Question 2 III above, I have assumed FEI's gas supply department would replicate peaking gas supply arrangements offered by companies in the market at Huntingdon/Sumas. Therefore, the service offered by FEI should attempt to recover the underlying costs of maintaining their asset portfolio while earning a fair return for its use during the period it is contracted. FEI's gas supply department could charge a "stand-by" fee (i.e., a monthly demand charge) if the capacity at the proposed TLSE facility is reserved by a third-party for a pre-determined period.

The demand charge could incorporate underlying carry costs associated with pipeline(s) tolls, storage tariff(s), and any other proprietary services that are required to support a peaking supply arrangement. Although a peaking supply arrangement may not be used (i.e., contracted) during summer months (April-October), there is still an underlying cost to the utility associated with having the asset year-round. As such, cost recovery from the period where an asset is underutilized during the summer could be incorporated into winter periods when an arrangement with a customer for peaking gas supply is active (November-March). The underutilized period costs will be market-driven, meaning they will fluctuate in price, driven by the success of cost mitigation attempts during the summer. Higher success of mitigating costs during the summer may result in lower demand charges for winter peaking arrangements.

For the purposes of generating a standing demand charge, I have assumed the fee charged would recovery T-South tolls and associated fuel. Therefore, for estimating purposes, I used $0.64 CDN/GJ (i.e., WEI T-South historical average).

Annual Standing Demand Charge Scenarios

Scenario #I: Recouping T-South tolls and fuel for 100% of the winter period (i.e., ($0.64 CDN/GJ x contracted daily volume x 151 days [November – March])); and

Scenario #II: Recouping T-South tolls and fuel for 100% of the winter period and 25% for the summer period (i.e., ($0.64 CDN/GJ x contracted daily volume x 151 days) + ($0.64 CDN/GJ x contracted daily volume x 214 days [April - October]) x 25%)).

The results of the above scenarios generate incremental annual financial value to the commodity pricing spreads derived by FEI's gas supply department, buying summer gas from Spectra-Stn2 and selling winter gas at Huntingdon/Sumas. FEI's gas supply department could charge a "stand-by" fee (i.e., a monthly demand charge), assuming the capacity, at the proposed TLSE facility, is reserved by a third-party for a pre-determined period. For example, a third-party might contract winter (i.e., November-March) peaking capacity, with the right to call up to 10 days of 50 MMcf/d capacity over the term. Therefore, the third-party pays FEI the standing demand charge fee and the associated Huntingdon/Sumas day price (i.e., FEI crystalizing a price spread from buying summer gas and selling winter gas). The results of the scenarios for an annual standing demand charge are as follows:

Results of Annual Demand Charge Scenarios

Scenario #I: $5.2 MM CDN annually for every 50 MMcf/d. (50 MMcf/d = 53,540 GJs/d)

Scenario #II: $7.0 MM CDN annually for every 50 MMcf/d (50 MMcf/d = 53,540 GJs/d)

Detailed Financial Values Tables

The results of my financial values analysis are presented in the following table. These results are derived using the above financial variables and futures prices for Spectra-Stn2 and Huntingdon/Sumas as of February 29, 2024. These variables were used when calculating Question 4 scenarios #1 through #7 (i.e., variables added to market prices and then multiplied by their respective scenario volumes and days). Furthermore, these financial values do not incorporate value from an Annual Demand Charge.

Spectra-Stn2	Average ('24/'25)	Average ('25/'26)	Average ('26/'27)	Average ('27/'28)	Average ('28/'29)
Cad Dollars					
Scenario #1 (a) Annual (300 MMcf/d x 1.3 Days)					
Daily Escalator A	$ 2,885,102	$ 2,075,025	$ 1,680,236	$ 2,057,370	$ 1,332,143
Daily Escalator B (i)	$ 2,847,518	$ 2,037,440	$ 1,642,652	$ 2,019,785	$ 1,294,558
(ii)	$ 2,926,863	$ 2,116,786	$ 1,721,997	$ 2,099,131	$ 1,373,903
Daily Escalator C	$ 2,784,143	$ 1,968,571	$ 1,569,769	$ 1,953,630	$ 1,215,306
Scenario #1 (b) 5-Year Cumulative (300 MMcf/d x 1.3 Days)					
Daily Escalator A	$ 2,885,102	$ 4,960,127	$ 6,640,363	$ 8,697,733	$ 10,029,876
Daily Escalator B (i)	$ 2,847,518	$ 4,884,957	$ 6,527,609	$ 8,547,394	$ 9,841,951
(ii)	$ 2,926,863	$ 5,043,649	$ 6,765,646	$ 8,864,777	$ 10,238,680
Daily Escalator C	$ 2,784,143	$ 4,752,714	$ 6,322,484	$ 8,276,114	$ 9,491,420
Scenario #2 (a) Annual (300 MMcf/d x 2 Days)					
Daily Escalator A	$ 4,438,619	$ 3,192,346	$ 2,584,979	$ 3,165,184	$ 2,049,450
Daily Escalator B (i)	$ 4,380,796	$ 3,134,523	$ 2,527,156	$ 3,107,361	$ 1,991,627
(ii)	$ 4,502,867	$ 3,256,593	$ 2,649,227	$ 3,229,432	$ 2,113,698
Daily Escalator C	$ 4,283,297	$ 3,028,571	$ 2,415,030	$ 3,005,585	$ 1,869,701
Scenario #2 (b) 5-Year Cumulative (300 MMcf/d x 2 Days)					
Daily Escalator A	$ 4,438,619	$ 7,630,965	$ 10,215,944	$ 13,381,128	$ 15,430,578
Daily Escalator B (i)	$ 4,380,796	$ 7,515,319	$ 10,042,475	$ 13,149,836	$ 15,141,464
(ii)	$ 4,502,867	$ 7,759,460	$ 10,408,687	$ 13,638,118	$ 15,751,816
Daily Escalator C	$ 4,283,297	$ 7,311,868	$ 9,726,898	$ 12,732,483	$ 14,602,184
Scenario #3 (a) Annual (300 MMcf/d x 3 Days)					
Daily Escalator A	$ 6,657,929	$ 4,788,518	$ 3,877,469	$ 4,747,776	$ 3,074,175
Daily Escalator B (i)	$ 6,571,194	$ 4,701,784	$ 3,790,734	$ 4,661,042	$ 2,987,441
(ii)	$ 6,754,300	$ 4,884,890	$ 3,973,840	$ 4,844,148	$ 3,170,546
Daily Escalator C	$ 6,424,946	$ 4,542,856	$ 3,622,545	$ 4,508,377	$ 2,804,552
Scenario #3 (b) 5-Year Cumulative (300 MMcf/d x 3 Days)					
Daily Escalator A	$ 6,657,929	$ 11,446,447	$ 15,323,916	$ 20,071,692	$ 23,145,867
Daily Escalator B (i)	$ 6,571,194	$ 11,272,979	$ 15,063,713	$ 19,724,755	$ 22,712,196
(ii)	$ 6,754,300	$ 11,639,190	$ 15,613,030	$ 20,457,177	$ 23,627,724
Daily Escalator C	$ 6,424,946	$ 10,967,802	$ 14,590,347	$ 19,098,724	$ 21,903,276
Scenario #4 (a) Annual (300 MMcf/d x 5 Days)					
Daily Escalator A	$ 11,096,548	$ 7,980,864	$ 6,462,448	$ 7,912,960	$ 5,123,625
Daily Escalator B (i)	$ 10,951,991	$ 7,836,307	$ 6,317,891	$ 7,768,403	$ 4,979,068
(ii)	$ 11,257,167	$ 8,141,483	$ 6,623,067	$ 8,073,579	$ 5,284,244
Daily Escalator C	$ 10,708,244	$ 7,571,427	$ 6,037,575	$ 7,513,962	$ 4,674,253
Scenario #4 (b) 5-Year Cumulative (300 MMcf/d x 5 Days)					
Daily Escalator A	$ 11,096,548	$ 19,077,412	$ 25,539,859	$ 33,452,820	$ 38,576,445
Daily Escalator B (i)	$ 10,951,991	$ 18,788,298	$ 25,106,188	$ 32,874,591	$ 37,853,659
(ii)	$ 11,257,167	$ 19,398,650	$ 26,021,716	$ 34,095,296	$ 39,379,540
Daily Escalator C	$ 10,708,244	$ 18,279,670	$ 24,317,245	$ 31,831,207	$ 36,505,460
Scenario #5 (a) Annual (300 MMcf/d x 7 Days)					
Daily Escalator A	$ 15,535,167	$ 11,173,209	$ 9,047,427	$ 11,078,144	$ 7,173,075
Daily Escalator B (i)	$ 15,332,787	$ 10,970,829	$ 8,845,047	$ 10,875,764	$ 6,970,695
(ii)	$ 15,760,034	$ 11,398,076	$ 9,272,293	$ 11,303,011	$ 7,397,942
Daily Escalator C	$ 14,991,541	$ 10,599,997	$ 8,452,605	$ 10,519,546	$ 6,543,955
Scenario #5 (b) 5-Year Cumulative (300 MMcf/d x 7 Days)					
Daily Escalator A	$ 15,535,167	$ 26,708,376	$ 35,755,803	$ 46,833,947	$ 54,007,023
Daily Escalator B (i)	$ 15,332,787	$ 26,303,617	$ 35,148,663	$ 46,024,428	$ 52,995,123
(ii)	$ 15,760,034	$ 27,158,110	$ 36,430,403	$ 47,733,414	$ 55,131,356
Daily Escalator C	$ 14,991,541	$ 25,591,538	$ 34,044,143	$ 44,563,689	$ 51,107,644
Scenario #6 (a) Annual (300 MMcf/d x 10 Days)					
Daily Escalator A	$ 22,193,096	$ 15,961,728	$ 12,924,895	$ 15,825,920	$ 10,247,250
Daily Escalator B (i)	$ 21,903,982	$ 15,672,613	$ 12,635,781	$ 15,536,806	$ 9,958,136
(ii)	$ 22,514,334	$ 16,282,966	$ 13,246,133	$ 16,147,158	$ 10,568,488
Daily Escalator C	$ 21,416,487	$ 15,142,853	$ 12,075,150	$ 15,027,923	$ 9,348,507
Scenario #6 (b) 5-Year Cumulative (300 MMcf/d x 10 Days)					
Daily Escalator A	$ 22,193,096	$ 38,154,824	$ 51,079,719	$ 66,905,639	$ 77,152,889
Daily Escalator B (i)	$ 21,903,982	$ 37,576,595	$ 50,212,376	$ 65,749,182	$ 75,707,318
(ii)	$ 22,514,334	$ 38,797,300	$ 52,043,433	$ 68,190,591	$ 78,759,079
Daily Escalator C	$ 21,416,487	$ 36,559,341	$ 48,634,490	$ 63,662,413	$ 73,010,920
Scenario #7 (a) Annual (300 MMcf/d x 10 Days Year 1 & 3 Days Years 2-5)					
Daily Escalator A	$ 22,193,096	$ 4,788,518	$ 3,877,469	$ 4,747,776	$ 3,074,175
Daily Escalator B (i)	$ 21,903,982	$ 4,701,784	$ 3,790,734	$ 4,661,042	$ 2,987,441
(ii)	$ 22,514,334	$ 4,884,890	$ 3,973,840	$ 4,844,148	$ 3,170,546
Daily Escalator C	$ 21,416,487	$ 4,542,856	$ 3,622,545	$ 4,508,377	$ 2,804,552
Scenario #7 (b) 5-Year Cumulative (300 MMcf/d x 10 Days Year 1 & 3 Days Years 2-5)					
Daily Escalator A	$ 22,193,096	$ 26,981,614	$ 30,859,083	$ 35,606,859	$ 38,681,034
Daily Escalator B (i)	$ 21,903,982	$ 26,605,766	$ 30,396,500	$ 35,057,542	$ 38,044,983
(ii)	$ 22,514,334	$ 27,399,224	$ 31,373,064	$ 36,217,211	$ 39,387,758
Daily Escalator C	$ 21,416,487	$ 25,959,343	$ 29,581,888	$ 34,090,265	$ 36,894,817

<u>Formulas:</u>
Daily Escalator A ((Sumas Winter + Daily Escalator A) - Summer Spectra-Stn2) x 321,238 Gjs
Daily Escalator B ((Sumas Winter + Daily Escalator B) - Summer Spectra-Stn2) x 321,238 Gjs
Daily Escalator C ((Sumas Winter x Daily Escalator C) - Summer Spectra-Stn2) x 321,238 Gjs

Appendix G

TLSE DETAILED COST ESTIMATE SUMMARY 3 BCF

FILED CONFIDENTIALLY

Appendix H

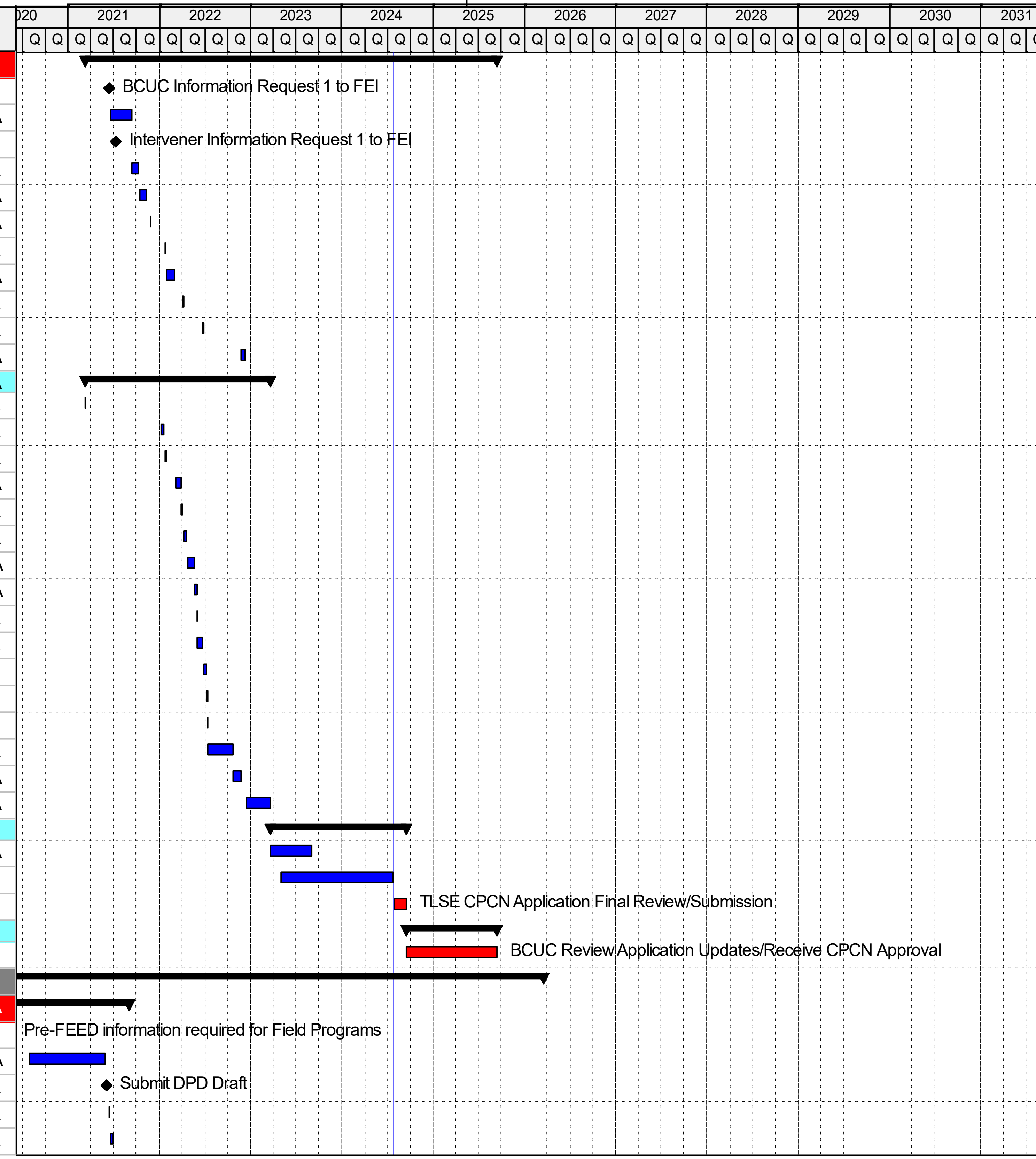
DETAILED PROJECT SCHEDULE

Activity ID	Activity Name	Rem. Duration	Start	Finish
Tilbury Island LNG Facility Expansion (3 BCF)		1570d	03-Jun-19 A	16-Dec-30
Tilbury LNG Storage Expansion (TLSE)		1570d	03-Jun-19 A	16-Dec-30
Milestones		1537d	03-Jun-19 A	16-Dec-30
Tilbury LNG Storage Expansion (TLSE) Project Milestones		1537d	06-Jul-20 A	16-Dec-30
MST102	Regas. Package Risk Evaluation	0d		06-Jul-20 A
MST104	Regas. Package Basic Engineering Completion	0d		21-Jul-20 A
MST106	LNG Storage Tank/Auxiliary System FEED Completion	0d		31-Jul-20 A
MST110	Submit CPCN Application	0d		29-Dec-20 A
MST182	Re-Submit CPCN Application	0d		13-Sep-24
MST192	Submit Phase 2 Draft EA Application to EAO	0d		13-Sep-24
MST202	BC EAO Provides Feedback on Draft Application	0d		09-May-25
MST122	Submit Phase 2 EA Application	0d		06-Jun-25
MST120	Receive CPCN Approval	0d		12-Sep-25
MST121	Phase Gate Health Check (TBC)	0d		29-Jan-26
MST134	Phase 2 EA Certificate (Provincial/Federal)	0d		16-Mar-26
MST114	TLSE EPC Contract/SO Award	0d		29-Jun-26
MST128	Auxiliary System EPC Kick-Off Meeting	0d		30-Jun-26
MST131	Early Ground Work Mobilization/Construction Start - Regas Area	0d		02-Nov-26
MST130	Base Plant Demolition Kick-Off Meeting	0d		17-Feb-27
MST132	Early Ground Work Completion - Regas Area (TBC)	0d		23-Mar-27
MST138	LNG Storage Tank Detailed Design Completion	0d		23-Jul-27
MST142	Regas. Packages Auxiliary System Construction Completion	0d		07-Dec-27
MST140	Regas. Packages/Auxiliary Systems Ph1 Commissioning	0d		22-Aug-28
MST144	Base Plant Demolition Completion	0d		23-May-29
MST148	Regas. Packages/Auxiliary Systems Ph2 Commissioning	0d		21-Jun-29
MST150	LNG Tank Auxiliary System Completion	0d		18-Oct-30
MST152	LNG Storage Tank Expansion Completion and Commissioning	0d		18-Oct-30
MST162	TLSE Project In Service	0d		18-Oct-30
MST172	TLSE Project Technical/Commercial Close-out	0d		16-Dec-30
Tilbury LNG Storage Expansion (TLSE) Assurance Milestones		866d	24-Apr-20 A	18-Oct-30
Tilbury LNG Storage Expansion (TLSE) Executive Level Milestones		1296d	03-Jun-19 A	16-Dec-30
Execution		1530d	15-May-20 A	18-Oct-30
CPCN Application Review & Approval Process		274d	16-May-20 A	12-Sep-25
Tank and Re-gasification Equipment Inputs		0d	18-May-20 A	10-Jun-20 A
CPT020102.1	Feasible Alternative Class 4 Estimate	0d	18-May-20 A	10-Jun-20 A
Draft CPCN Application		0d	16-May-20 A	28-Oct-20 A
CPT020202.1	Draft CPCN Application (All Sections)	0d	16-May-20 A	28-Oct-20 A
CPCN Application Reviews/Submission		0d	18-May-20 A	29-Dec-20 A
CPT020302	Revie, Finalize and Submit Application	0d	18-May-20 A	29-Dec-20 A
CPT020304	Submit CPCN Application	0d		29-Dec-20 A

Remaining Level of Effort — Actual Work — Critical Remaining Work
Actual Level of Effort — Remaining Work — Critical Secondary

Date	Revision	Checked	Approved
19-Aug-24	IFI		

Activity ID	Activity Name	Rem. Duration	Start	Finish
CPCN BCUC Review/Approval		**274d**	**11-Mar-21 A**	**12-Sep-25**
CPT020412.01	BCUC Information Request 1 to FEI	0d	17-Jun-21 A	
CPT020412.03	FEI Response to BCUC and Intervener Information Request 1	0d	22-Jun-21 A	13-Sep-21 A
CPT020412.02	Intervener Information Request 1 to FEI	0d	09-Jul-21 A	
CPT020412.04	BCUC and Intervener IR2 to FEI	0d	14-Sep-21 A	12-Oct-21 A
CPT020412.05	FEI Responses to BCUC and Intervener IR2	0d	13-Oct-21 A	10-Nov-21 A
CPT020412.06	Procedural Conference *Time & Format TBD by BCUC*	0d	29-Nov-21 A	29-Nov-21 A
CPT020412.12	Panel Information Request (IR) No. 1 to FEI	0d	24-Jan-22 A	25-Jan-22 A
CPT020412.14	FEI Response to Panel IR No. 1 & and Confidential Panel IR No. 1	0d	31-Jan-22 A	04-Mar-22 A
CPT020412.16	TWN Oral Intervener Evidence	0d	05-Apr-22 A	06-Apr-22 A
CPT020412.21	FEI Responses to IRs on Rebuttal Evidence/Reply Submission on Further Proces	0d	24-Jun-22 A	28-Jun-22 A
CPT020412.23	FEI Written Reply Argument	0d	24-Nov-22 A	12-Dec-22 A
BCUC Preliminary Review		**0d**	**11-Mar-21 A**	**23-Mar-23 A**
CPT020412	CPCN Workshop	0d	11-Mar-21 A	11-Mar-21 A
CPT020412.11	FEI & Intervener Submissions on TWN Request to Exclude Interveners from Heari	0d	10-Jan-22 A	21-Jan-22 A
CPT020412.13	TWN Reply to Submissions on TWN Request to Exclude Interveners from Hearing	0d	26-Jan-22 A	28-Jan-22 A
CPT020412.15	Intervener Written Evidence (except TWN)	0d	07-Mar-22 A	28-Mar-22 A
CPT020412.15.1	TWN Written Evidence	0d	29-Mar-22 A	04-Apr-22 A
CPT020412.17	BCUC, FEI and Intervener IRs on Intervener Written Evidence (except TWN Writte	0d	07-Apr-22 A	22-Apr-22 A
CPT020412.17.1	BCUC, FEI and Intervener IRS on TWN Written and Oral Evidence	0d	25-Apr-22 A	20-May-22 A
CPT020412.18	Responses to IRs on Intervener Written Evidence and TWN Oral Evidence	0d	23-May-22 A	30-May-22 A
CPT020412.19	Rebuttal Evidence (if required)	0d	31-May-22 A	02-Jun-22 A
CPT020412.20	IRs on Rebuttal Evidence	0d	03-Jun-22 A	23-Jun-22 A
CPT020412.21.1	Intervener Submissions on Further Process	0d	29-Jun-22 A	06-Jul-22 A
CPT020412.21.2	FEI responses to IRs on Rebuttal Evidence	0d	07-Jul-22 A	14-Jul-22 A
CPT020412.21.3	FEI Reply submission on further process	0d	14-Jul-22 A	14-Jul-22 A
CPT020412.21.4	FEI Written Final Argument	0d	15-Jul-22 A	24-Oct-22 A
CPT020412.22	Intervener Written Final Arguments	0d	25-Oct-22 A	23-Nov-22 A
CPT020412.24	Received BCUC Questions	0d	13-Dec-22 A	23-Mar-23 A
CPCN Application Update (Reboot)		**33d**	**24-Mar-23 A**	**13-Sep-24**
CPT020412.25	Review Questions by Management Team	0d	24-Mar-23 A	31-Aug-23 A
CPT020412.26	Prepare Answers/TLSE Estimate Update & Resiliency	0d	02-May-23 A	26-Jul-24 A
CPT020412.27	TLSE CPCN Application Final Review/Submission	33d	29-Jul-24	13-Sep-24
BCUC Final Review & Approval		**241d**	**16-Sep-24**	**12-Sep-25**
CPT020404	BCUC Review Application Updates/Receive CPCN Approval	241d	16-Sep-24	12-Sep-25
Environmental Assessment - Phase 2 (Execution Phase)		**392d**	**15-May-20 A**	**16-Mar-26**
Detailed Project Description Development		**0d**	**15-May-20 A**	**03-Sep-21 A**
EAT020313	Pre-FEED information required for Field Programs	0d	15-May-20 A	
EAT020314	Develop DPD and AIR + FEI Reviews	0d	27-Jul-20 A	31-May-21 A
EAT020315	Submit DPD Draft	0d		01-Jun-21 A
EAT020315.1	DPD Part 2 Workshop	0d	16-Jun-21 A	16-Jun-21 A
EAT020315.2	DPD Technical Advisor Review	0d	17-Jun-21 A	30-Jun-21 A



Remaining Level of Effort | Actual Work | Critical Remaining Work
Actual Level of Effort | Remaining Work | Critical Secondary

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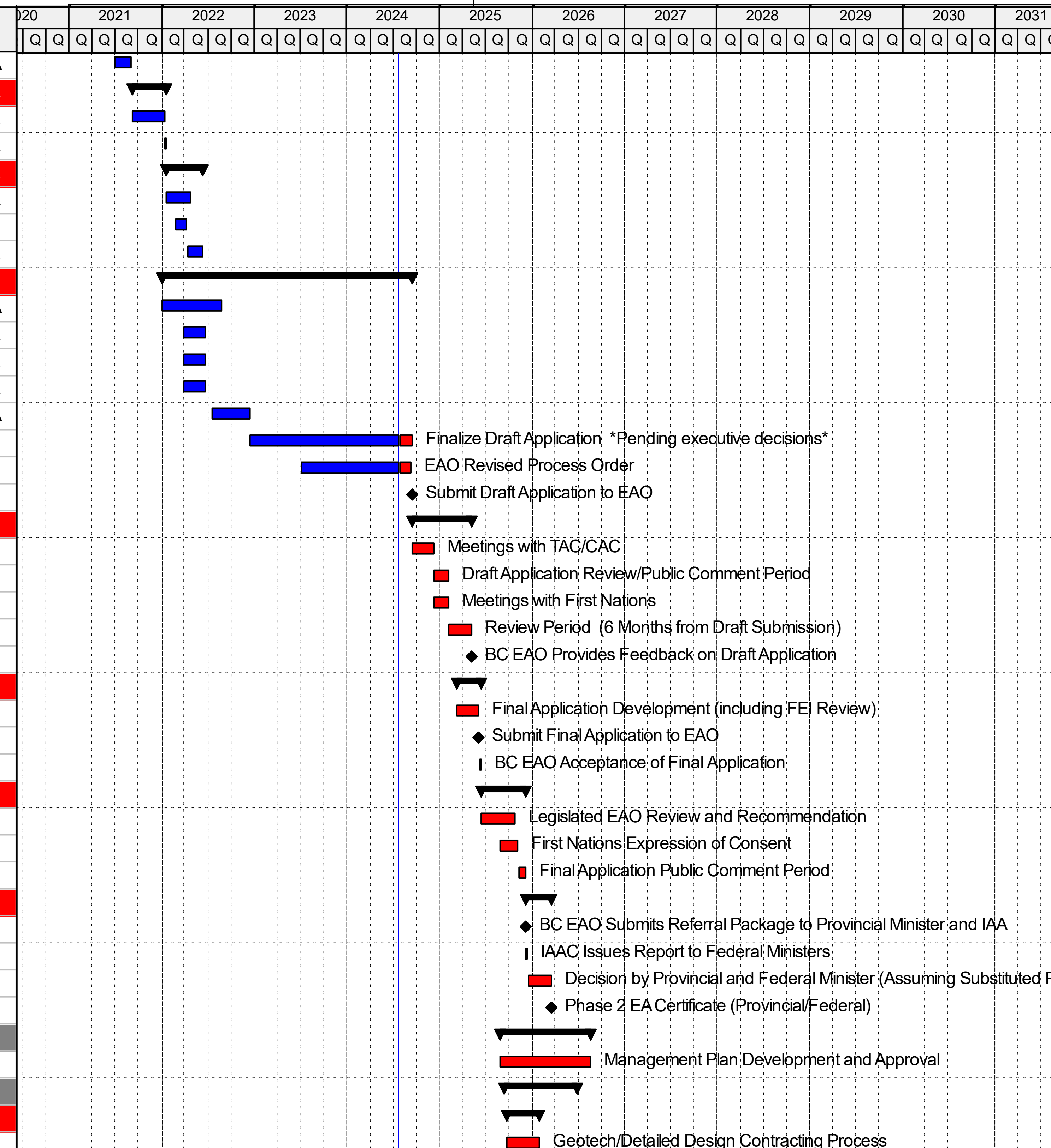
FORTIS BC™

Tilbury Island LNG Facility Expansion (3 BCF)
TLSE Sub-Projects Integrated Schedule-Detailed

SOLARIS MANAGEMENT CONSULTANTS INC.

Activity ID	Activity Name	Rem. Duration	Start	Finish
EAT20845	Submit DPD Final	0d	02-Jul-21 A	03-Sep-21 A
Readiness Decision (Detailed Project Description Review)		0d	09-Sep-21 A	20-Jan-22 A
EAT020417	BC EAO Readiness Decision and Seeking Consensus	0d	09-Sep-21 A	12-Jan-22 A
EAT020529	IAAC IA Determination and Substitution Decision	0d	13-Jan-22 A	20-Jan-22 A
BC EAO Process Planning		0d	21-Jan-22 A	13-Jun-22 A
EAT020519	Meetings with TAC/CAC, Finalize AIR, and Develop Permit Plan	0d	21-Jan-22 A	22-Apr-22 A
EAT020520	Public Comment Period on Draft Process Order	0d	24-Feb-22 A	11-Apr-22 A
EAT020521	Issue BC EAO Process Order	0d	12-Apr-22 A	13-Jun-22 A
Draft Application Development		33d	04-Jan-22 A	13-Sep-24
EAT020627	Draft Application Development + FEI Review	0d	04-Jan-22 A	26-Aug-22 A
EAT020624	Field work planning	0d	31-Mar-22 A	23-Jun-22 A
EAT020625	Biophysical Baseline Data Collection and Analysis	0d	31-Mar-22 A	23-Jun-22 A
EAT020626	TEK/ TUS Studies	0d	31-Mar-22 A	23-Jun-22 A
EAT020628	Stakeholder Draft Application Review	0d	18-Jul-22 A	15-Dec-22 A
EAT020629	Finalize Draft Application *Pending executive decisions*	33d	16-Dec-22 A	13-Sep-24
EAT020629.1	EAO Revised Process Order	29d	04-Jul-23 A	09-Sep-24
EAT020630	Submit Draft Application to EAO	0d		13-Sep-24
BC EAO Draft Application Review		155d	16-Sep-24	09-May-25
EAT020732	Meetings with TAC/CAC	60d	16-Sep-24	11-Dec-24
EAT020733	Draft Application Review/Public Comment Period	30d	12-Dec-24	05-Feb-25
EAT020734	Meetings with First Nations	30d	12-Dec-24	05-Feb-25
EAT020734.1	Review Period (6 Months from Draft Submission)	65d	06-Feb-25	09-May-25
EAT020735	BC EAO Provides Feedback on Draft Application	0d		09-May-25
Final Application Development		65d	13-Mar-25	13-Jun-25
EAT020737	Final Application Development (including FEI Review)	60d	13-Mar-25	06-Jun-25
EAT020738	Submit Final Application to EAO	0d		06-Jun-25
EAT020739	BC EAO Acceptance of Final Application	5d	09-Jun-25	13-Jun-25
BC EAO Effects Assessment and Recommendation		120d	16-Jun-25	08-Dec-25
EAT020841	Legislated EAO Review and Recommendation	90d	16-Jun-25	24-Oct-25
EAT020843	First Nations Expression of Consent	50d	27-Aug-25	07-Nov-25
EAT020842	Final Application Public Comment Period	20d	10-Nov-25	08-Dec-25
Application Submission and Approval Period		60d	08-Dec-25	16-Mar-26
EAT020844	BC EAO Submits Referral Package to Provincial Minister and IAA	0d		08-Dec-25
EAT020844.1	IAAC Issues Report to Federal Ministers	5d	09-Dec-25	15-Dec-25
EAT020845	Decision by Provincial and Federal Minister (Assuming Substituted Process)	55d	16-Dec-25	16-Mar-26
MST134.1	Phase 2 EA Certificate (Provincial/Federal)	0d		16-Mar-26
Management Plan for Ph2 EAC		240d	27-Aug-25	21-Aug-26
GIT500010	Management Plan Development and Approval	240d	27-Aug-25	21-Aug-26
TLSE Contracting		191d	15-Sep-25	29-Jun-26
Geotech/Ground Improvement		80d	24-Sep-25	29-Jan-26
GR0.0	Geotech/Detailed Design Contracting Process	80d	24-Sep-25	29-Jan-26



Remaining Level of Effort | Actual Work | Critical Remaining Work
Actual Level of Effort | Remaining Work | Critical Secondary

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Activity ID	Activity Name	Rem. Duration	Start	Finish
EPC		191d	15-Sep-25	29-Jun-26
TRP296202	Prepare Bidding Documents	40d	15-Sep-25	12-Nov-25
TRP600201	Cash Flow Planned Start Date - Regas. Packages (See Act. Note)	0d	15-Sep-25	
TAX296100	Cash Flow Planned Start Date - Auxiliary (See Act. Note)	0d	15-Sep-25	
TBP296102	Cash Flow Planned Start Date - Base Plant Demo (See Act. Note)	0d	15-Sep-25	
TTK296102	Cash Flow Planned Start Date - LNG Tank (See Act. Note)	0d	15-Sep-25	
TRP296204	Contract Request Form/Email	5d	07-Nov-25	14-Nov-25
TRP296206	Review/Draft Requirements and Discussion with Stakeholders	10d	17-Nov-25	28-Nov-25
TRP296208	Review Competetive Bid Documents	10d	24-Nov-25	05-Dec-25
TRP296210	Circulate RFQ Internally for Review, Comments and Amendments	10d	01-Dec-25	12-Dec-25
TRP296212	Legal Review	10d	08-Dec-25	19-Dec-25
TRP296214	Finalize RFQ	10d	12-Dec-25	07-Jan-26
TRP296216	Issue TLSE EPC RFQ	0d		07-Jan-26
TRP296218	Receive Vendor/Contractors Proposals & Clarification	60d	08-Jan-26	02-Apr-26
TRP296220	Finalize SOW/Update Cost Estimate/Bid Evaluation//Negotiation/PR Creation and /	60d	03-Apr-26	29-Jun-26
TRP296222	Award EPC Contract (Excluding LNG Tank Proc./Const.)	0d		29-Jun-26
Phase Gate Health Check (Required Deliverables/Documents and Review)		87d	15-Sep-25	29-Jan-26
Phase Gate Health Check Required Deliverables/Documents		60d	15-Sep-25	10-Dec-25
TLT240200	Phase Gate Health Check Scope/Deliverables (TBD)	60d	15-Sep-25	10-Dec-25
Gate (Health Check) Review		27d	10-Dec-25	29-Jan-26
TLT240302	Issue Documents to Peer Review Team	0d		10-Dec-25
TLT240304	Peer Review	5d	11-Dec-25	17-Dec-25
TLT240306	Incorporate Comments and Provide Feedback to Peer Review Team	10d	18-Dec-25	13-Jan-26
TLT240308	Generate Recommendation Completion	0d		15-Jan-26
TLT240310	Phase Gate Health Check Review Period	10d	16-Jan-26	29-Jan-26
Mid Phase 4 Review - Required Deliverables/Documents and Review		55d	30-Mar-27	16-Jun-27
Mid Phase 4 Review - Required Deliverables/Documents		35d	30-Mar-27	18-May-27
Lessons Learned - Phase 3		35d	30-Mar-27	18-May-27
A9992	Prepare and Issue Previous Phase Lesson Learned - IFIR	20d	30-Mar-27	28-Apr-27
A9993	Internal/Peer Review - Previous Phase Lesson Learned	5d	28-Apr-27	04-May-27
A9994	Incorporate Comments and Issue Previous Phase Lesson Learned - IFGR	10d	05-May-27	18-May-27
PEP (Project Execution Plan) Final		35d	30-Mar-27	18-May-27
A9986	Prepare and Issue PEP - IFIR	20d	30-Mar-27	28-Apr-27
A9987	Internal/Peer Review - PEP	5d	28-Apr-27	04-May-27
A9988	Incorporate Comments and Issue PEP - IFGR	10d	05-May-27	18-May-27
Project Organization Plan: Final		35d	30-Mar-27	18-May-27
A10004	Prepare and Issue Project Organization Plan - IFIR	20d	30-Mar-27	28-Apr-27
A10005	Internal/Peer Review - Project Organization Plan	5d	28-Apr-27	04-May-27
A10006	Incorporate Comments and Issue Project Organization Plan - IFGR	10d	05-May-27	18-May-27
Cost Estimate: AACE Class 2		35d	30-Mar-27	18-May-27
A10007	Prepare and Issue Class 2 Cost Estimate - IFIR	20d	30-Mar-27	28-Apr-27
A10008	Internal/Peer Review - Class 2 Cost Estimate	5d	28-Apr-27	04-May-27

Remaining Level of Effort — Actual Work — Critical Remaining Work
Actual Level of Effort — Remaining Work — Critical Secondary

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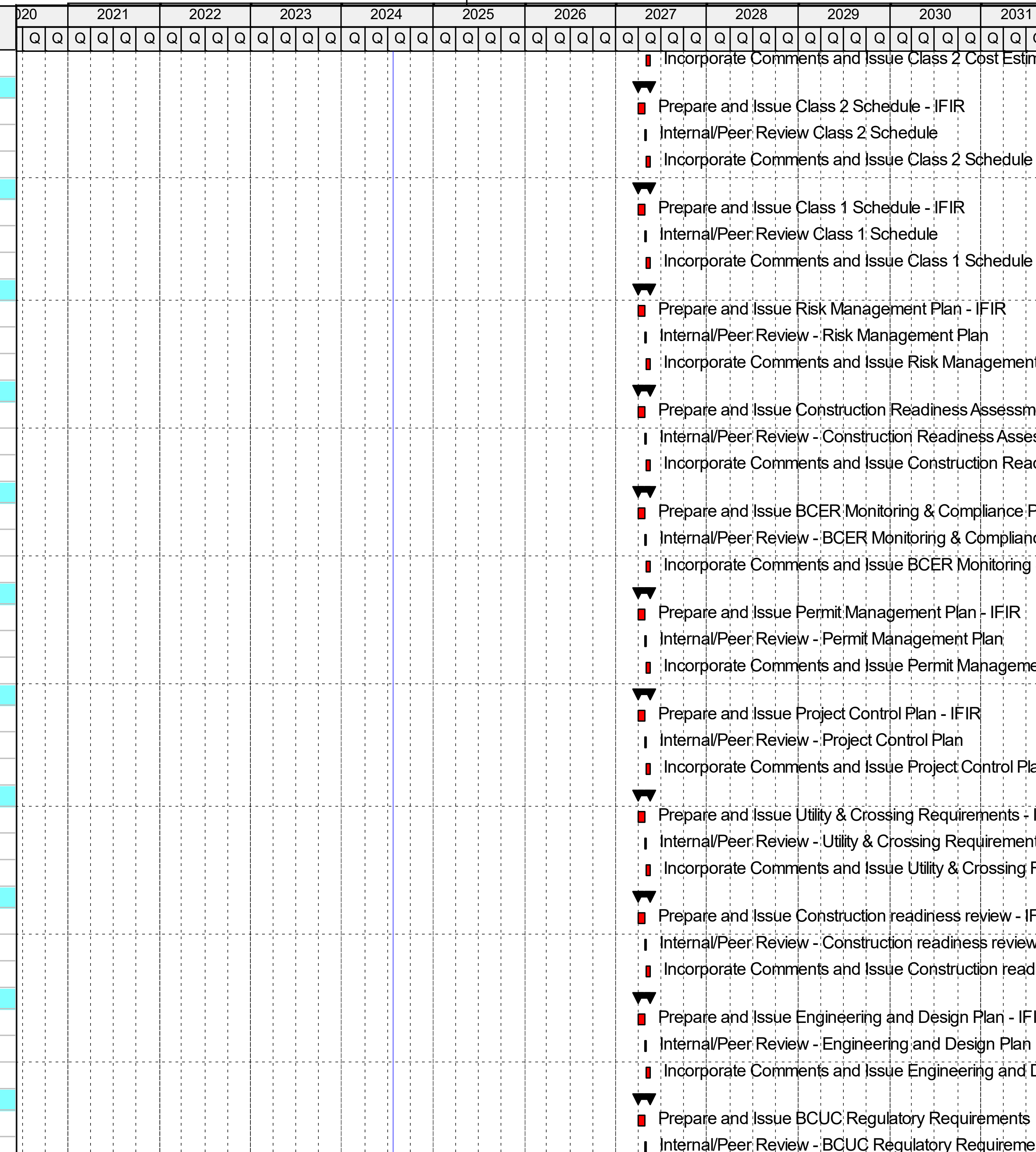
Activity ID	Activity Name	Rem. Duration	Start	Finish
A10009	Incorporate Comments and Issue Class 2 Cost Estimate - IFGR	10d	05-May-27	18-May-27
Master Schedule: AACE Class 2		35d	30-Mar-27	18-May-27
A10010	Prepare and Issue Class 2 Schedule - IFIR	20d	30-Mar-27	28-Apr-27
A10011	Internal/Peer Review Class 2 Schedule	5d	28-Apr-27	04-May-27
A10012	Incorporate Comments and Issue Class 2 Schedule - IFGR	10d	05-May-27	18-May-27
Schedule: AACE Class 1 (as required)		35d	30-Mar-27	18-May-27
A12000	Prepare and Issue Class 1 Schedule - IFIR	20d	30-Mar-27	28-Apr-27
A12010	Internal/Peer Review Class 1 Schedule	5d	28-Apr-27	04-May-27
A12020	Incorporate Comments and Issue Class 1 Schedule - IFGR	10d	05-May-27	18-May-27
Risk Management Plan: Audit		35d	30-Mar-27	18-May-27
A10013	Prepare and Issue Risk Management Plan - IFIR	20d	30-Mar-27	28-Apr-27
A10014	Internal/Peer Review - Risk Management Plan	5d	28-Apr-27	04-May-27
A10015	Incorporate Comments and Issue Risk Management Plan - IFGR	10d	05-May-27	18-May-27
Construction Readiness Assessment		35d	30-Mar-27	18-May-27
A9989	Prepare and Issue Construction Readiness Assessment - IFIR	20d	30-Mar-27	28-Apr-27
A9990	Internal/Peer Review - Construction Readiness Assessment	5d	28-Apr-27	04-May-27
A9991	Incorporate Comments and Issue Construction Readiness Assessment - IFGR	10d	05-May-27	18-May-27
BCER Monitoring & Compliance Plan: Final		35d	30-Mar-27	18-May-27
A9995	Prepare and Issue BCER Monitoring & Compliance Plan - IFIR	20d	30-Mar-27	28-Apr-27
A9996	Internal/Peer Review - BCER Monitoring & Compliance Plan	5d	28-Apr-27	04-May-27
A9997	Incorporate Comments and Issue BCER Monitoring & Compliance Plan - IFGR	10d	05-May-27	18-May-27
Permit Monitoring & Compliance Plan: Final		35d	30-Mar-27	18-May-27
A10034	Prepare and Issue Permit Management Plan - IFIR	20d	30-Mar-27	28-Apr-27
A10035	Internal/Peer Review - Permit Management Plan	5d	28-Apr-27	04-May-27
A10036	Incorporate Comments and Issue Permit Management Plan - IFGR	10d	05-May-27	18-May-27
Project Controls Plan: Final Project Performance Baselines		35d	30-Mar-27	18-May-27
A10001	Prepare and Issue Project Control Plan - IFIR	20d	30-Mar-27	28-Apr-27
A10002	Internal/Peer Review - Project Control Plan	5d	28-Apr-27	04-May-27
A10003	Incorporate Comments and Issue Project Control Plan - IFGR	10d	05-May-27	18-May-27
Utility & Crossing Requirements		35d	30-Mar-27	18-May-27
A9998	Prepare and Issue Utility & Crossing Requirements - IFIR	20d	30-Mar-27	28-Apr-27
A9999	Internal/Peer Review - Utility & Crossing Requirements	5d	28-Apr-27	04-May-27
A10000	Incorporate Comments and Issue Utility & Crossing Requirements - IFGR	10d	05-May-27	18-May-27
Construction readiness review		35d	30-Mar-27	18-May-27
A10022	Prepare and Issue Construction readiness review - IFIR	20d	30-Mar-27	28-Apr-27
A10023	Internal/Peer Review - Construction readiness review	5d	28-Apr-27	04-May-27
A10024	Incorporate Comments and Issue Construction readiness review - IFGR	10d	05-May-27	18-May-27
Engineering and Design Plan		35d	30-Mar-27	18-May-27
A10016	Prepare and Issue Engineering and Design Plan - IFIR	20d	30-Mar-27	28-Apr-27
A10017	Internal/Peer Review - Engineering and Design Plan	5d	28-Apr-27	04-May-27
A10018	Incorporate Comments and Issue Engineering and Design Plan - IFGR	10d	05-May-27	18-May-27
BCUC Regulatory Requirements		35d	30-Mar-27	18-May-27
A10019	Prepare and Issue BCUC Regulatory Requirements - IFIR	20d	30-Mar-27	28-Apr-27
A10020	Internal/Peer Review - BCUC Regulatory Requirements	5d	28-Apr-27	04-May-27



Remaining Level of Effort | Actual Work | Critical Remaining Work
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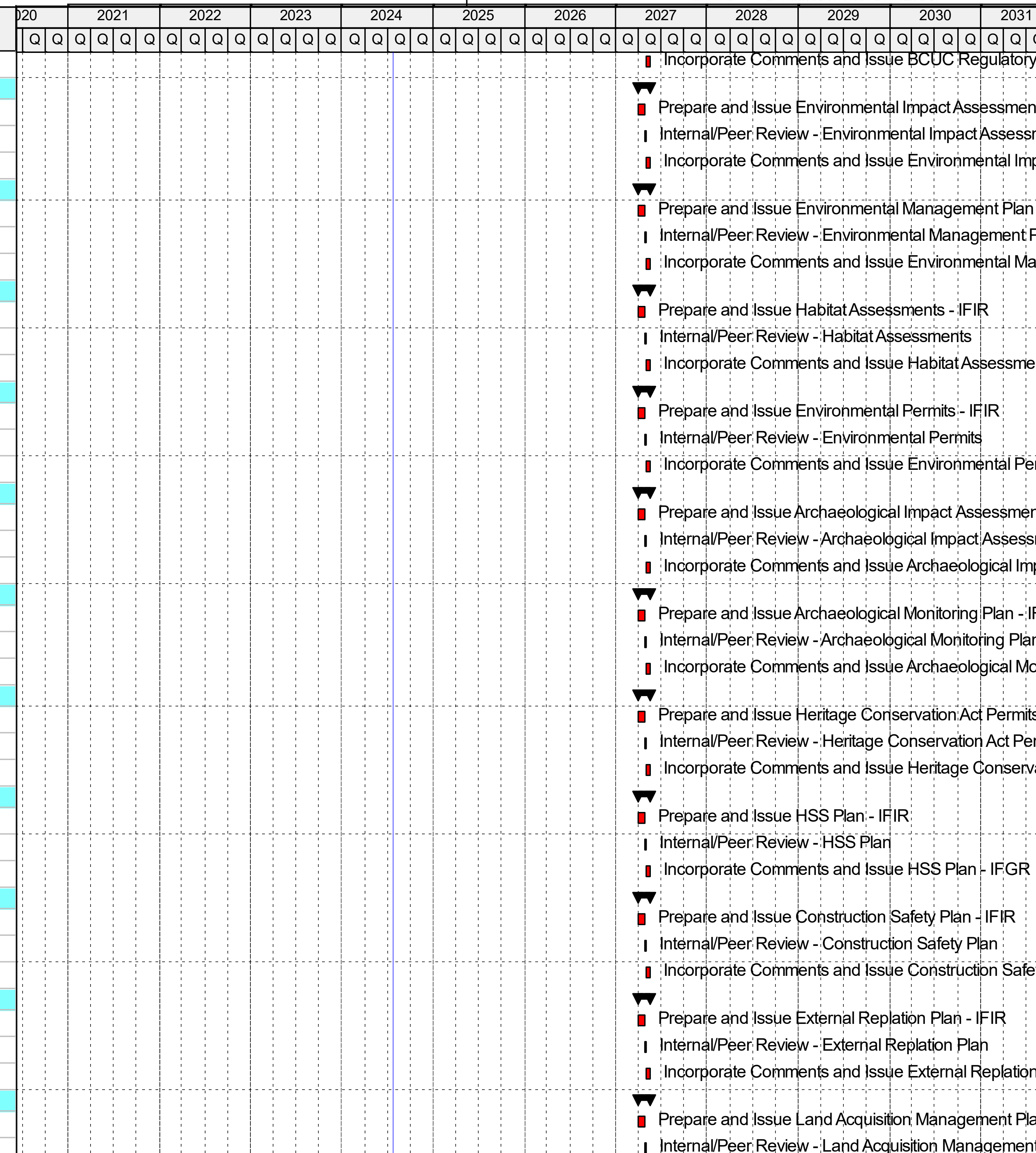
Activity ID	Activity Name	Rem. Duration	Start	Finish
A10021	Incorporate Comments and Issue BCUC Regulatory Requirements - IFGR	10d	05-May-27	18-May-27
Environmental Impact Assessment and Pre-Construction Surveys (field work)		35d	30-Mar-27	18-May-27
A10037	Prepare and Issue Environmental Impact Assessment and Pre-Construction Surve	20d	30-Mar-27	28-Apr-27
A10038	Internal/Peer Review - Environmental Impact Assessment and Pre-Construction Su	5d	28-Apr-27	04-May-27
A10039	Incorporate Comments and Issue Environmental Impact Assessment and Pre-Cor	10d	05-May-27	18-May-27
Environmental Management Plan (includes archaeology)		35d	30-Mar-27	18-May-27
A12030	Prepare and Issue Environmental Management Plan - IFIR	20d	30-Mar-27	28-Apr-27
A12040	Internal/Peer Review - Environmental Management Plan	5d	28-Apr-27	04-May-27
A12050	Incorporate Comments and Issue Environmental Management Plan - IFGR	10d	05-May-27	18-May-27
Habitat Assessments - based on project sensitivities		35d	30-Mar-27	18-May-27
A10025	Prepare and Issue Habitat Assessments - IFIR	20d	30-Mar-27	28-Apr-27
A10026	Internal/Peer Review - Habitat Assessments	5d	28-Apr-27	04-May-27
A10027	Incorporate Comments and Issue Habitat Assessments - IFGR	10d	05-May-27	18-May-27
Environmental Permits		35d	30-Mar-27	18-May-27
A12060	Prepare and Issue Environmental Permits - IFIR	20d	30-Mar-27	28-Apr-27
A12070	Internal/Peer Review - Environmental Permits	5d	28-Apr-27	04-May-27
A12080	Incorporate Comments and Issue Environmental Permits - IFGR	10d	05-May-27	18-May-27
Archaeological Impact Assessment - Final		35d	30-Mar-27	18-May-27
A10040	Prepare and Issue Archaeological Impact Assessment - IFIR	20d	30-Mar-27	28-Apr-27
A10041	Internal/Peer Review - Archaeological Impact Assessment	5d	28-Apr-27	04-May-27
A10042	Incorporate Comments and Issue Archaeological Impact Assessment - IFGR	10d	05-May-27	18-May-27
Archaeological Monitoring Plan & implementation during construction		35d	30-Mar-27	18-May-27
A12090	Prepare and Issue Archaeological Monitoring Plan - IFIR	20d	30-Mar-27	28-Apr-27
A12100	Internal/Peer Review - Archaeological Monitoring Plan	5d	28-Apr-27	04-May-27
A12110	Incorporate Comments and Issue Archaeological Monitoring Plan - IFGR	10d	05-May-27	18-May-27
Heritage Conservation Act Permits		35d	30-Mar-27	18-May-27
A10031	Prepare and Issue Heritage Conservation Act Permits - IFIR	20d	30-Mar-27	28-Apr-27
A10032	Internal/Peer Review - Heritage Conservation Act Permits	5d	28-Apr-27	04-May-27
A10033	Incorporate Comments and Issue Heritage Conservation Act Permits - IFGR	10d	05-May-27	18-May-27
HSS Compliance Monitoring: Audit		35d	30-Mar-27	18-May-27
A10043	Prepare and Issue HSS Plan - IFIR	20d	30-Mar-27	28-Apr-27
A10044	Internal/Peer Review - HSS Plan	5d	28-Apr-27	04-May-27
A10045	Incorporate Comments and Issue HSS Plan - IFGR	10d	05-May-27	18-May-27
Construction Safety Plan		35d	30-Mar-27	18-May-27
A12120	Prepare and Issue Construction Safety Plan - IFIR	20d	30-Mar-27	28-Apr-27
A12130	Internal/Peer Review - Construction Safety Plan	5d	28-Apr-27	04-May-27
A12140	Incorporate Comments and Issue Construction Safety Plan - IFGR	10d	05-May-27	18-May-27
External Relations Plan - Update: Final		35d	30-Mar-27	18-May-27
A10046	Prepare and Issue External Replation Plan - IFIR	20d	30-Mar-27	28-Apr-27
A10047	Internal/Peer Review - External Replation Plan	5d	28-Apr-27	04-May-27
A10048	Incorporate Comments and Issue External Replation Plan - IFGR	10d	05-May-27	18-May-27
Land Acquisition Management Plan: Final		35d	30-Mar-27	18-May-27
A10049	Prepare and Issue Land Acquisition Management Plan - IFIR	20d	30-Mar-27	28-Apr-27
A10050	Internal/Peer Review - Land Acquisition Management Plan	5d	28-Apr-27	04-May-27



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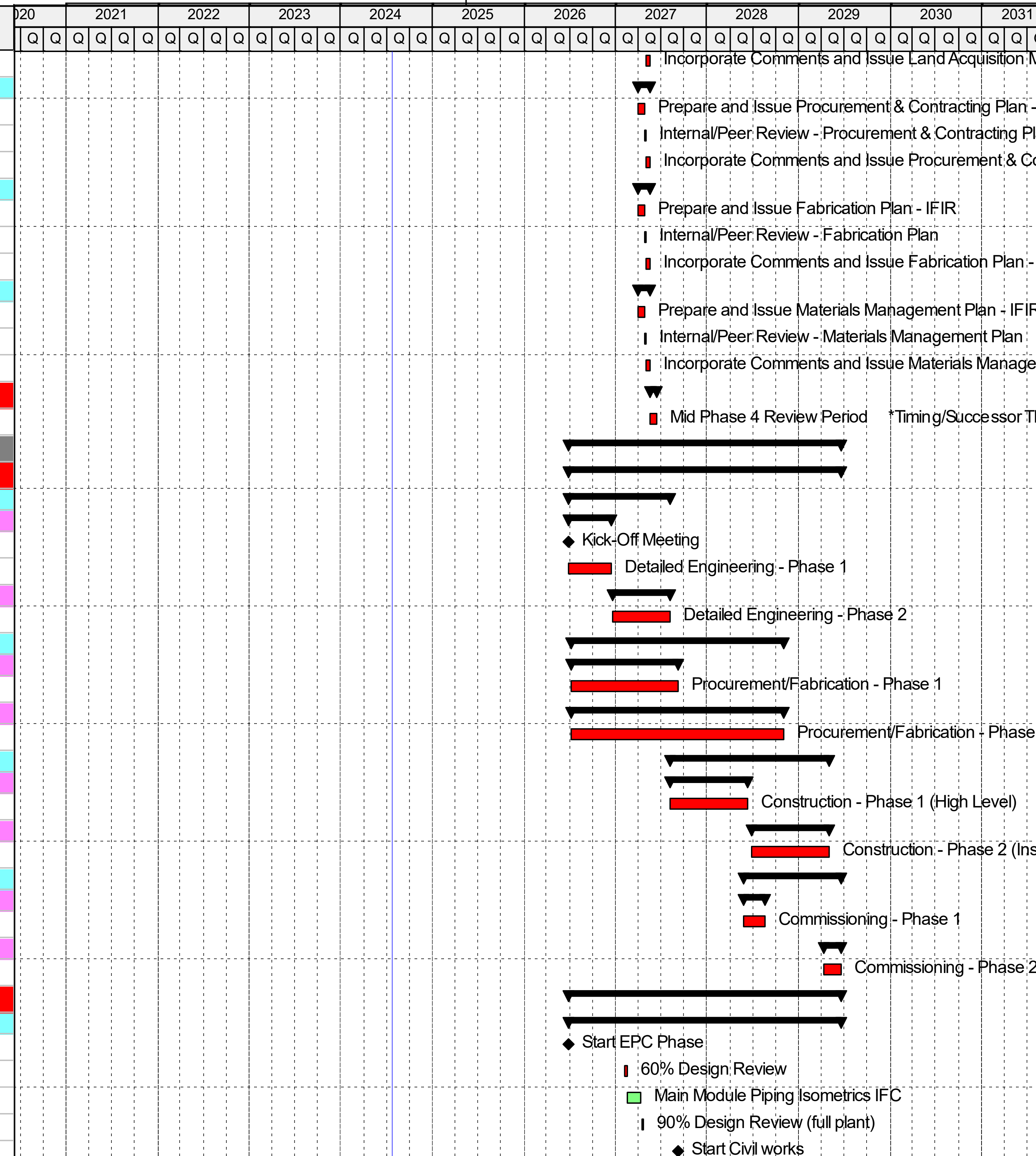
Activity ID	Activity Name	Rem. Duration	Start	Finish
A10051	Incorporate Comments and Issue Land Acquisition Management Plan - IFGR	10d	05-May-27	18-May-27
Procurement & Contracting Plan: Final		35d	30-Mar-27	18-May-27
A12150	Prepare and Issue Procurement & Contracting Plan - IFIR	20d	30-Mar-27	28-Apr-27
A12160	Internal/Peer Review - Procurement & Contracting Plan	5d	28-Apr-27	04-May-27
A12170	Incorporate Comments and Issue Procurement & Contracting Plan - IFGR	10d	05-May-27	18-May-27
Fabrication Plan: Final		35d	30-Mar-27	18-May-27
A12180	Prepare and Issue Fabrication Plan - IFIR	20d	30-Mar-27	28-Apr-27
A12190	Internal/Peer Review - Fabrication Plan	5d	28-Apr-27	04-May-27
A12200	Incorporate Comments and Issue Fabrication Plan - IFGR	10d	05-May-27	18-May-27
Materials Management Plan: Final		35d	30-Mar-27	18-May-27
A12210	Prepare and Issue Materials Management Plan - IFIR	20d	30-Mar-27	28-Apr-27
A12220	Internal/Peer Review - Materials Management Plan	5d	28-Apr-27	04-May-27
A12230	Incorporate Comments and Issue Materials Management Plan - IFGR	10d	05-May-27	18-May-27
Mid Phase 4 Review		20d	19-May-27	16-Jun-27
A10070	Mid Phase 4 Review Period *Timing/Successor TBD*	20d	19-May-27	16-Jun-27
Regasification Packages		737d	30-Jun-26	21-Jun-29
EPC (High Level)		737d	30-Jun-26	21-Jun-29
Detailed Engineering		274d	30-Jun-26	09-Aug-27
Phase 1		117d	30-Jun-26	16-Dec-26
TRP300010	Kick-Off Meeting	0d	30-Jun-26	
TRP300100	Detailed Engineering - Phase 1	116d	30-Jun-26	16-Dec-26
Phase 2		153d	22-Dec-26	09-Aug-27
TRP300200	Detailed Engineering - Phase 2	153d	22-Dec-26	09-Aug-27
Procurement / Fabrication		577d	07-Jul-26	02-Nov-28
Phase 1		290d	07-Jul-26	08-Sep-27
TRP400100	Procurement/Fabrication - Phase 1	290d	07-Jul-26	08-Sep-27
Phase 2		577d	07-Jul-26	02-Nov-28
TRP400200	Procurement/Fabrication - Phase 2	577d	07-Jul-26	02-Nov-28
Construction		428d	09-Aug-27	02-May-29
Phase 1		210d	09-Aug-27	14-Jun-28
TRP500100	Construction - Phase 1 (High Level)	210d	09-Aug-27	14-Jun-28
Phase 2		210d	26-Jun-28	02-May-29
TRP500200	Construction - Phase 2 (Install Remaining Vaporizers-High Level)	210d	26-Jun-28	02-May-29
Commissioning		265d	29-May-28	21-Jun-29
Phase 1		60d	29-May-28	22-Aug-28
TRP600100	Commissioning - Phase 1	60d	29-May-28	22-Aug-28
Phase 2		50d	11-Apr-29	21-Jun-29
TRP600200	Commissioning - Phase 2	50d	11-Apr-29	21-Jun-29
EPC (Detailed - Contractor)		737d	30-Jun-26	21-Jun-29
Milestones		737d	30-Jun-26	21-Jun-29
PM1050	Start EPC Phase	0d	30-Jun-26	
A1A01070	60% Design Review	5d	09-Feb-27	16-Feb-27
EN1100	Main Module Piping Isometrics IFC	40d	17-Feb-27	14-Apr-27
A1A01080	90% Design Review (full plant)	5d	15-Apr-27	21-Apr-27
A1A01090	Start Civil works	0d	07-Sep-27	



Remaining Level of Effort | Actual Work | Critical Remaining Work
Actual Level of Effort | Remaining Work | Critical Secondary

Data Date:26-Jul-24

Date	Revision	Checked	Approved
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Activity ID	Activity Name	Rem. Duration	Start	Finish
A1A01140	Module Set 3 at site	0d		06-Jul-28
A1A01150	Module Set 2 at site	0d		08-Sep-28
A1A01130	Module Set 1 at site	0d		30-Oct-28
A1A01110	MC - Mechanical Completion	0d		22-Mar-29
A1A01120	Performance Test Run Completed	0d		15-Jun-29
PM1070	Plant in Operation	0d		21-Jun-29
Engineering		271d	30-Jun-26	04-Aug-27
Systems Engineering		184d	30-Jun-26	30-Mar-27
A1A01010	Engineering Kick Off Meeting	1d	30-Jun-26	30-Jun-26
A1EF1100	MSB Analyser, L, T, P	15d	07-Jul-26	27-Jul-26
A1EF1070	MSB other Inline Instruments	20d	07-Jul-26	04-Aug-26
A1EF1120	P&ID Issue G	80d	07-Jul-26	29-Oct-26
A1EF1130	P&ID Issue H	60d	30-Oct-26	01-Feb-27
A1EF1170	Operating Manual and Training, Comm. Planning	80d	30-Nov-26	30-Mar-27
Equipment Engineering		150d	21-Jul-26	02-Mar-27
A1070	Equipment Engineering	150d	21-Jul-26	02-Mar-27
Civil & Steel Structure Engineering		225d	16-Jul-26	14-Jun-27
A1EN1020	Steel Structures detail eng. for Modules (IFC)	130d	16-Jul-26	27-Jan-27
A1EN1030	Steel Structures detail eng. Field (IFC)	120d	19-Aug-26	16-Feb-27
A1EC1010	Civil detail engineering foundations (IFC)	90d	04-Feb-27	14-Jun-27
Piping Design		193d	14-Aug-26	27-May-27
A1EL1100	Detailed Piping Design	160d	14-Aug-26	09-Apr-27
A1EC1040	Equipment & Structural Foundation Loads	45d	16-Dec-26	25-Feb-27
A1EL1030	Final Dimensions of Control Valves	10d	21-Dec-26	11-Jan-27
A1EL1070	Design Review 60%	5d	09-Feb-27	16-Feb-27
A1EL1080	On Modules isometrics	40d	17-Feb-27	14-Apr-27
A1EL1090	Design Review 90%	5d	15-Apr-27	21-Apr-27
A1EL1110	Off Modules isometrics	20d	29-Apr-27	27-May-27
Piping Material		163d	13-Oct-26	10-Jun-27
A1ER1000	Piping Material 1st MTO for Inquiry	10d	13-Oct-26	26-Oct-26
A1ER1010	Piping Material 2nd MTO	5d	09-Dec-26	15-Dec-26
A1ER1020	Piping Material 3rd MTO	5d	24-Mar-27	30-Mar-27
A1ER1030	Piping Material 4th MTO	5d	20-May-27	27-May-27
A1ER1040	Piping Material Last MTO	5d	04-Jun-27	10-Jun-27
Electrical & Instrumentation Engineering		138d	14-Sep-26	07-Apr-27
A1EE1100	Electrical Detail Engineering	125d	14-Sep-26	18-Mar-27
A1EE1010	Inquiry Specification MV Motor	30d	14-Sep-26	26-Oct-26
A1EJ1030	Inquiry Specification DCS & PESS	35d	14-Sep-26	02-Nov-26
A1EJ1100	Instrumentation Detail Engineering	125d	01-Oct-26	07-Apr-27
A1EJ1020	Data sheets Critical CV's & Inline devices	20d	01-Oct-26	29-Oct-26
A1EE1020	Inquiry Specification MV Switchgear	20d	27-Oct-26	24-Nov-26
A1EJ1050	Data sheets other Inline Instruments	20d	30-Oct-26	27-Nov-26
Construction Engineering		240d	14-Aug-26	04-Aug-27

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Activity ID	Activity Name	Rem. Duration	Start	Finish
A1EX1100	Construction Engineering TBC	240d	14-Aug-26	04-Aug-27
Procurement / Fabrication		578d	02-Jul-26	30-Oct-28
Stationary Equipment		438d	02-Jul-26	11-Apr-28
Inquiry & Order		138d	02-Jul-26	25-Jan-27
A1PB1010	Order Vessels	25d	02-Jul-26	06-Aug-26
A1PB1020	Order Heat Exchangers	25d	02-Jul-26	06-Aug-26
A1PB1000	Order Air Cooler	25d	02-Jul-26	06-Aug-26
A1PB1030	Order LL Columns	25d	02-Jul-26	06-Aug-26
A1PB1050	Order Package Units	25d	02-Jul-26	06-Aug-26
A1PB1100	Order ColdBox (internal)	3d	09-Jul-26	13-Jul-26
A1PB1110	Inquiry & Order Columns	58d	17-Sep-26	09-Dec-26
A1PB1040	Inquiry & Order other Equipment	70d	08-Oct-26	25-Jan-27
Fabrication & Delivery		400d	14-Jul-26	28-Feb-28
PC1040	Fabr. & Del. Cold Box	400d	14-Jul-26	28-Feb-28
A1FB1020	Fabr. & Del. Vessels	185d	23-Jul-26	23-Apr-27
PC1060	Fabr. & Del. of LL Columns	305d	07-Aug-26	29-Oct-27
A1FB1000	Fabr. & Del. Air Coolers	308d	07-Aug-26	03-Nov-27
A1FB1030	Fabr. & Del. Heat Exchangers	180d	07-Aug-26	30-Apr-27
A1FB1050	Fabr. & Del. Package Units	285d	07-Aug-26	30-Sep-27
A1FB1010	Fabr. & Del. Columns	190d	10-Dec-26	17-Sep-27
A1FB1040	Fabr. & Del. other Equipment	200d	21-Dec-26	13-Oct-27
Transport		238d	26-Apr-27	11-Apr-28
A1120	Transport Vessels to Yard	30d	26-Apr-27	07-Jun-27
A1130	Transport Heat Exchangers to Yard	30d	03-May-27	14-Jun-27
A1110	Transport Columns to Yard	30d	20-Sep-27	01-Nov-27
A1200	Transport Package Units to site	30d	01-Oct-27	15-Nov-27
A1140	Transport other Equipment to Yard	30d	14-Oct-27	25-Nov-27
A1100	Transport LL Columns to site	30d	01-Nov-27	13-Dec-27
A1090	Transport Air Coolers to Yard	30d	04-Nov-27	16-Dec-27
A1080	Transport ColdBox to Site	30d	29-Feb-28	11-Apr-28
Rotating Equipment		372d	02-Jul-26	06-Jan-28
Inquiry & Order		15d	02-Jul-26	22-Jul-26
A1PM1000	Order Compressors	15d	02-Jul-26	22-Jul-26
A1PM1030	Order Pumps	15d	02-Jul-26	22-Jul-26
Fabrication & Delivery		327d	23-Jul-26	17-Nov-27
PC1050	Fabr. & Del. Feed Gas Compressor	327d	23-Jul-26	17-Nov-27
A1FM1000	Fabr. & Del. Tank Return Gas Compressor	327d	23-Jul-26	17-Nov-27
A1FM1010	Fabr. & Del. Pumps	305d	23-Jul-26	15-Oct-27
PC1070	Fabr. & Del. Regeneration Gas Compressor	262d	23-Jul-26	13-Aug-27
PC1080	Fabr. & Del. Cycle Compressor	262d	23-Jul-26	13-Aug-27
Transport		95d	16-Aug-27	06-Jan-28
A1180	Transport Cycle Compressor to site	30d	16-Aug-27	27-Sep-27
A1190	Transport Regeneration Gas Compressor to yard	20d	16-Aug-27	13-Sep-27

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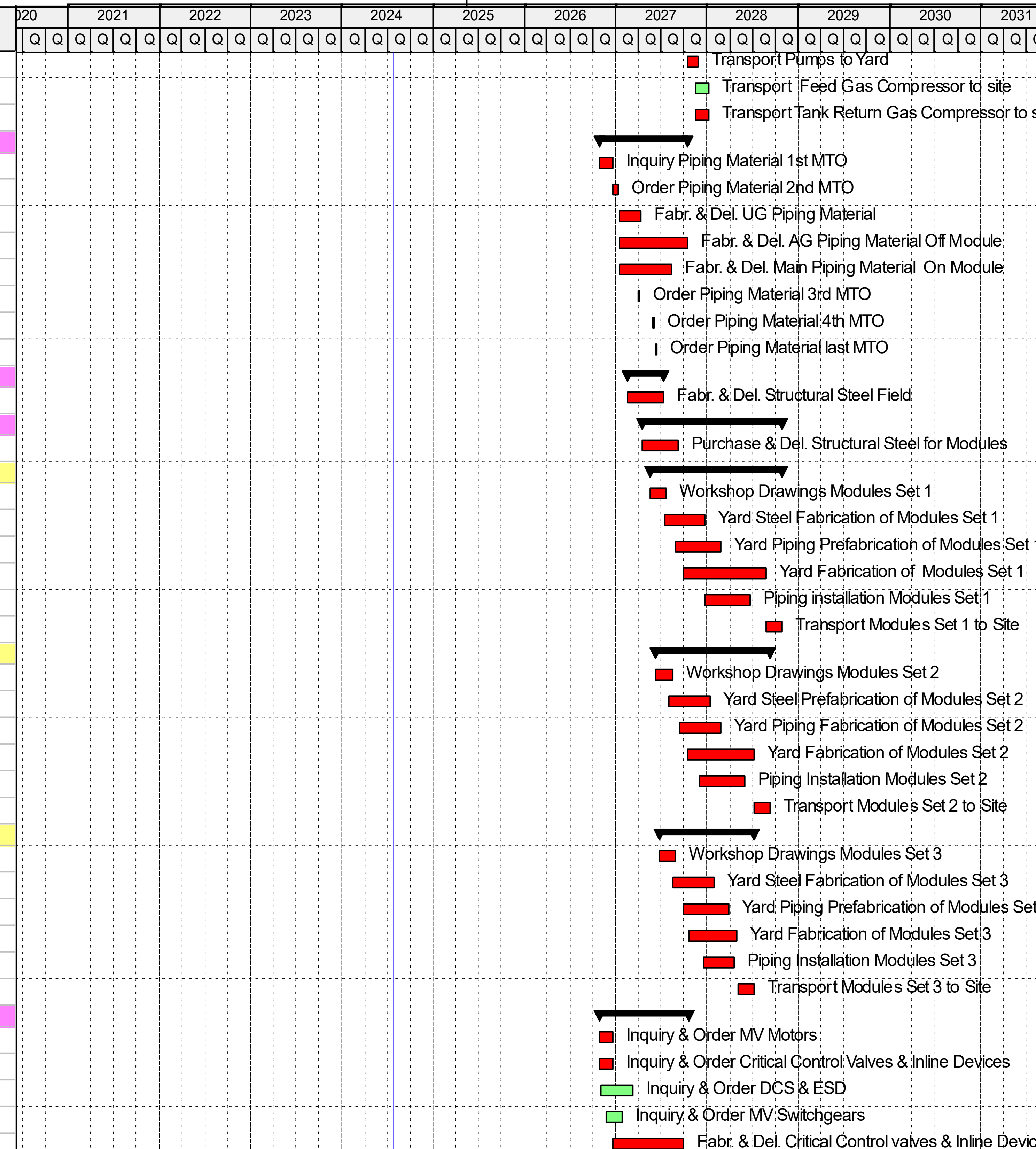
Tilbury Island LNG Facility Expansion (3 BCF)

TLSE Sub-Projects Integrated Schedule-Detailed

FORTIS BC™

SOLARIS MANAGEMENT CONSULTANTS INC.

Activity ID	Activity Name	Rem. Duration	Start	Finish
A1170	Transport Pumps to Yard	30d	18-Oct-27	29-Nov-27
A1150	Transport Feed Gas Compressor to site	30d	18-Nov-27	06-Jan-28
A1160	Transport Tank Return Gas Compressor to site	30d	18-Nov-27	06-Jan-28
Piping Material		240d	27-Oct-26	15-Oct-27
A1PR1000	Inquiry Piping Material 1st MTO	40d	27-Oct-26	22-Dec-26
A1PR1010	Order Piping Material 2nd MTO	10d	23-Dec-26	13-Jan-27
A1FR1010	Fabr. & Del. UG Piping Material	60d	14-Jan-27	09-Apr-27
A1FR1020	Fabr. & Del. AG Piping Material Off Module	190d	14-Jan-27	15-Oct-27
A1FR1000	Fabr. & Del. Main Piping Material On Module	145d	14-Jan-27	11-Aug-27
A1PR1020	Order Piping Material 3rd MTO	5d	31-Mar-27	07-Apr-27
A1PR1030	Order Piping Material 4th MTO	5d	28-May-27	03-Jun-27
A1PR1040	Order Piping Material last MTO	5d	11-Jun-27	17-Jun-27
Structural Steel		100d	17-Feb-27	09-Jul-27
A1FN1010	Fabr. & Del. Structural Steel Field	100d	17-Feb-27	09-Jul-27
Modules / Skids		385d	15-Apr-27	30-Oct-28
A1FN1000	Purchase & Del. Structural Steel for Modules	100d	15-Apr-27	07-Sep-27
Module Set 1		360d	20-May-27	30-Oct-28
A1FY1150	Workshop Drawings Modules Set 1	45d	20-May-27	23-Jul-27
A1FY1000	Yard Steel Fabrication of Modules Set 1	110d	19-Jul-27	23-Dec-27
A1FY1120	Yard Piping Prefabrication of Modules Set 1	120d	31-Aug-27	28-Feb-28
A1FY1020	Yard Fabrication of Modules Set 1	225d	29-Sep-27	24-Aug-28
A1FY1060	Piping installation Modules Set 1	120d	24-Dec-27	21-Jun-28
A1FY1040	Transport Modules Set 1 to Site	45d	25-Aug-28	30-Oct-28
Module Set 2 - medium complexity		310d	11-Jun-27	08-Sep-28
A1FY1180	Workshop Drawings Modules Set 2	45d	11-Jun-27	16-Aug-27
A1FY1010	Yard Steel Prefabrication of Modules Set 2	110d	03-Aug-27	14-Jan-28
A1FY1140	Yard Piping Fabrication of Modules Set 2	110d	15-Sep-27	28-Feb-28
A1FY1030	Yard Fabrication of Modules Set 2	180d	14-Oct-27	06-Jul-28
A1FY1070	Piping Installation Modules Set 2	120d	03-Dec-27	31-May-28
A1FY1050	Transport Modules Set 2 to Site	45d	07-Jul-28	08-Sep-28
Module Set 3 - Pipe Racks		255d	25-Jun-27	06-Jul-28
A1FY1160	Workshop Drawings Modules Set 3	45d	25-Jun-27	30-Aug-27
A1FY1080	Yard Steel Fabrication of Modules Set 3	110d	17-Aug-27	28-Jan-28
A1FY1130	Yard Piping Prefabrication of Modules Set 3	121d	29-Sep-27	28-Mar-28
A1FY1100	Yard Fabrication of Modules Set 3	130d	21-Oct-27	02-May-28
A1FY1170	Piping Installation Modules Set 3	80d	17-Dec-27	18-Apr-28
A1FY1110	Transport Modules Set 3 to Site	45d	03-May-28	06-Jul-28
Electrical & Instrumentation		245d	27-Oct-26	22-Oct-27
A1PE1000	Inquiry & Order MV Motors	40d	27-Oct-26	22-Dec-26
A1PJ1000	Inquiry & Order Critical Control Valves & Inline Devices	35d	30-Oct-26	18-Dec-26
A1PJ1010	Inquiry & Order DCS & ESD	85d	03-Nov-26	11-Mar-27
A1PE1010	Inquiry & Order MV Switchgears	40d	25-Nov-26	27-Jan-27
A1FJ1000	Fabr. & Del. Critical Control valves & Inline Devices	190d	21-Dec-26	28-Sep-27



Remaining Level of Effort — Actual Work — Critical Remaining Work

Actual Level of Effort — Remaining Work — Critical Secondary

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Activity ID	Activity Name	Rem. Duration	Start	Finish
A1FE1000	Fabr. & Del.MV Motors	190d	23-Dec-26	30-Sep-27
A1FE1010	Fabr. & Del. MV/LV Switchgear Container Bldgs.	150d	28-Jan-27	01-Sep-27
A1FJ1010	Fabr. & Del. DCS & PESS FER Container Bldg.	155d	12-Mar-27	22-Oct-27
Construction Subcontracts		63d	28-Sep-26	04-Jan-27
A1PX1000	Inquiry & Order Civil Construction Contractor	50d	28-Sep-26	08-Dec-26
A1PX1020	Inquiry & Order General Site construction Contractor	50d	28-Sep-26	08-Dec-26
A1PX1010	Inquiry & Order Yard fabrication Contractor	50d	28-Sep-26	08-Dec-26
A1PN1000	Inquiry & Order Structural Steel (Site)	50d	16-Oct-26	04-Jan-27
Regulatory Permits (Contractor Scope)		228d	23-Nov-26	25-Oct-27
City Of Delta MD		160d	23-Nov-26	16-Jul-27
Building Permit - Delta Building/Plumbing Bylaw (No. 6060)		30d	08-Apr-27	19-May-27
RGT106382	Prepare Building Permit Application	10d	08-Apr-27	21-Apr-27
RGT106384	Submit Application	3d	19-Apr-27	21-Apr-27
RGT106386	Review Period	20d	22-Apr-27	19-May-27
RGT106388	Receive Approval/Permit - Delta City Building	0d		19-May-27
Temporary Buildings Permit - Delta Building/Plumbing Bylaw (No. 6060)		30d	08-Apr-27	19-May-27
RGT616759	Prepare Building Permit Application	10d	08-Apr-27	21-Apr-27
RGT616762	Submit Application	3d	19-Apr-27	21-Apr-27
RGT616760	Review Period	20d	22-Apr-27	19-May-27
RGT616761	Receive Approval/Permit - Delta City Building	0d		19-May-27
Plumbing Permit - Delta Building/Plumbing Bylaw (No. 6060)		40d	20-May-27	16-Jul-27
RGT616747	Prepare Plumbing Permit Application	20d	20-May-27	17-Jun-27
RGT616748	Submit Application	3d	15-Jun-27	17-Jun-27
RGT616749	Review Period	20d	18-Jun-27	16-Jul-27
RGT616750	Receive Approval/Permit - Plumbing	0d		16-Jul-27
Sprinkler Permit - Delta Building/Sprinkler Bylaw (No. 6060)		40d	20-May-27	16-Jul-27
RGT616751	Prepare Sprinkler Permit Application	20d	20-May-27	17-Jun-27
RGT616752	Submit Application	3d	15-Jun-27	17-Jun-27
RGT616753	Review Period	20d	18-Jun-27	16-Jul-27
RGT616754	Receive Approval/Permit - Sprinkler Permit	0d		16-Jul-27
Occupancy Permit - Delta Building/Occupancy Bylaw (No. 6060)		40d	20-May-27	16-Jul-27
RGT616755	Prepare Occupancy Permit Application	20d	20-May-27	17-Jun-27
RGT616756	Submit Application	3d	15-Jun-27	17-Jun-27
RGT616757	Review Period	20d	18-Jun-27	16-Jul-27
RGT616758	Receive Approval/Permit - Occupancy Permit	0d		16-Jul-27
Highway Use Permit - Delta Bylaw No. 6922		90d	09-Feb-27	17-Jun-27
Necessary Deliverables		10d	09-Feb-27	23-Feb-27
RGT106112	Deliverable(s)	10d	09-Feb-27	23-Feb-27
Application		90d	09-Feb-27	17-Jun-27
RGT106182	Prepare Highway Use and Inspection Permits Application	10d	09-Feb-27	23-Feb-27
RGT106184	Submit Application	3d	19-Feb-27	23-Feb-27
RGT106186	Review Period	80d	24-Feb-27	17-Jun-27
RGT106188	Receive Approval/Permit - Delta City Highway Use	0d		17-Jun-27
Development Permit (Commercial/Industrial) - Delta Official Community Plan Bylaws		140d	23-Nov-26	17-Jun-27

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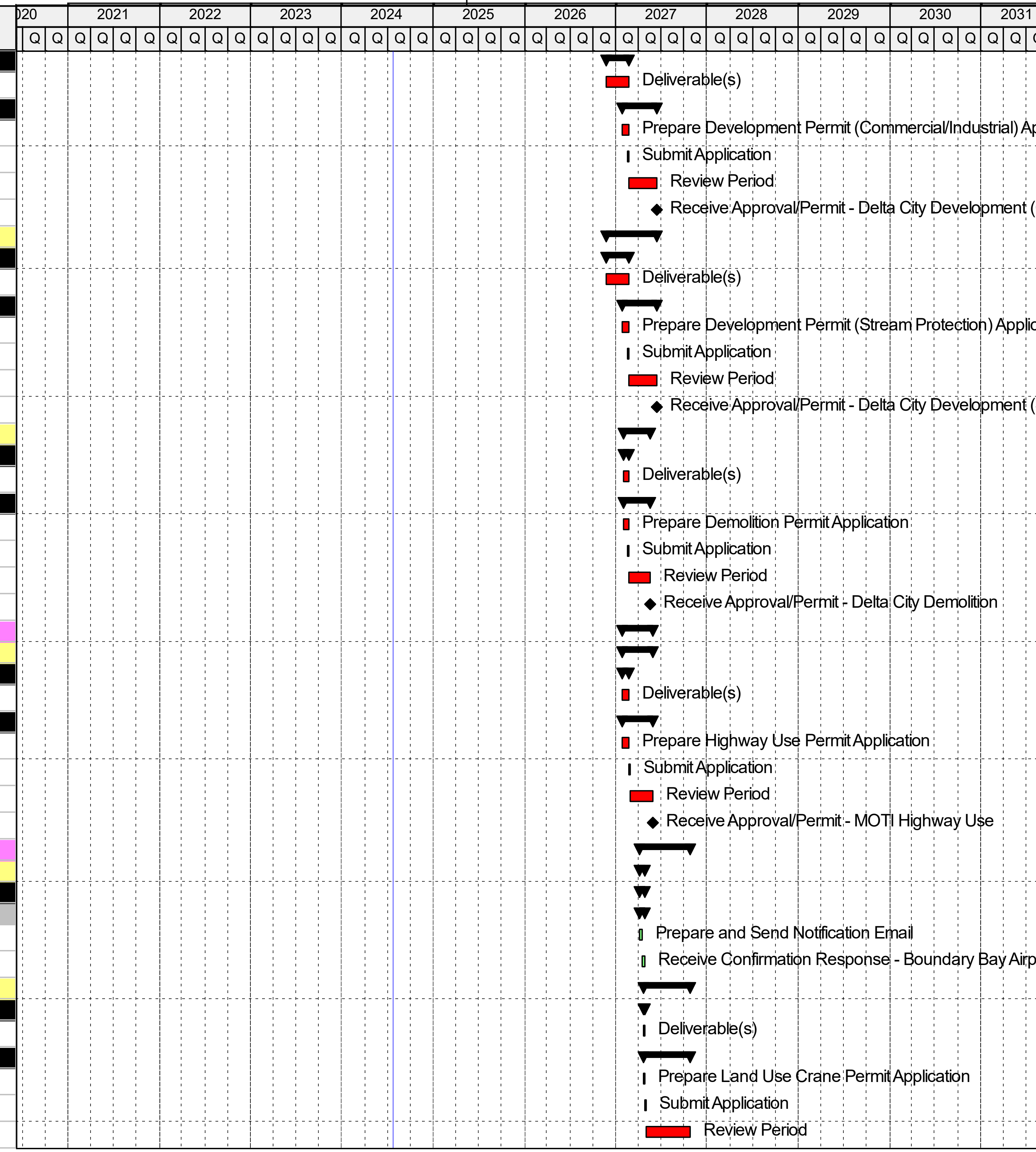
Necessary Deliverables		60d	23-Nov-26	23-Feb-27
RGT106412	Deliverable(s)	60d	23-Nov-26	23-Feb-27
Application		100d	26-Jan-27	17-Jun-27
RGT106482	Prepare Development Permit (Commercial/Industrial) Application	20d	26-Jan-27	23-Feb-27
RGT106484	Submit Application	3d	19-Feb-27	23-Feb-27
RGT106486	Review Period	80d	24-Feb-27	17-Jun-27
RGT106488	Receive Approval/Permit - Delta City Development (Commercial/Industrial)	0d		17-Jun-27
Development Permit (Streamside Protection & Enhancement) - Bylaw No. 6349		140d	23-Nov-26	17-Jun-27
Necessary Deliverables		60d	23-Nov-26	23-Feb-27
RGT106512	Deliverable(s)	60d	23-Nov-26	23-Feb-27
Application		100d	26-Jan-27	17-Jun-27
RGT106582	Prepare Development Permit (Stream Protection) Application	20d	26-Jan-27	23-Feb-27
RGT106584	Submit Application	3d	19-Feb-27	23-Feb-27
RGT106586	Review Period	80d	24-Feb-27	17-Jun-27
RGT106588	Receive Approval/Permit - Delta City Development (Stream Protection)	0d		17-Jun-27
Demolition Permit - Delta Official Community Plan Bylaws *BasePlant*		75d	02-Feb-27	19-May-27
Necessary Deliverables		15d	02-Feb-27	23-Feb-27
RGT106612	Deliverable(s)	15d	02-Feb-27	23-Feb-27
Application		75d	02-Feb-27	19-May-27
RGT106682	Prepare Demolition Permit Application	15d	02-Feb-27	23-Feb-27
RGT106684	Submit Application	3d	19-Feb-27	23-Feb-27
RGT106686	Review Period	60d	24-Feb-27	19-May-27
RGT106688	Receive Approval/Permit - Delta City Demolition	0d		19-May-27
MOTI		85d	26-Jan-27	27-May-27
Highway Use Permit - Transportation Act		85d	26-Jan-27	27-May-27
Necessary Deliverables		20d	26-Jan-27	23-Feb-27
RGT110112	Deliverable(s)	20d	26-Jan-27	23-Feb-27
Application		85d	26-Jan-27	27-May-27
RGT110182	Prepare Highway Use Permit Application	20d	26-Jan-27	23-Feb-27
RGT110184	Submit Application	3d	24-Feb-27	26-Feb-27
RGT110186	Review Period	62d	01-Mar-27	27-May-27
RGT110188	Receive Approval/Permit - MOTI Highway Use	0d		27-May-27
Nav Canada		138d	08-Apr-27	25-Oct-27
Boundary Bay Airport Email Notification		15d	08-Apr-27	28-Apr-27
Email Notification		15d	08-Apr-27	28-Apr-27
Application		15d	08-Apr-27	28-Apr-27
RGT104184	Prepare and Send Notification Email	5d	08-Apr-27	15-Apr-27
RGT104188	Receive Confirmation Response - Boundary Bay Airport	10d	15-Apr-27	28-Apr-27
Land Use Program - Crane		128d	22-Apr-27	25-Oct-27
Necessary Deliverables		5d	22-Apr-27	28-Apr-27
RGT111112	Deliverable(s)	5d	22-Apr-27	28-Apr-27
Application		128d	22-Apr-27	25-Oct-27
RGT111182	Prepare Land Use Crane Permit Application	5d	22-Apr-27	28-Apr-27
RGT111184	Submit Application	3d	29-Apr-27	03-May-27
RGT111186	Review Period	120d	04-May-27	25-Oct-27



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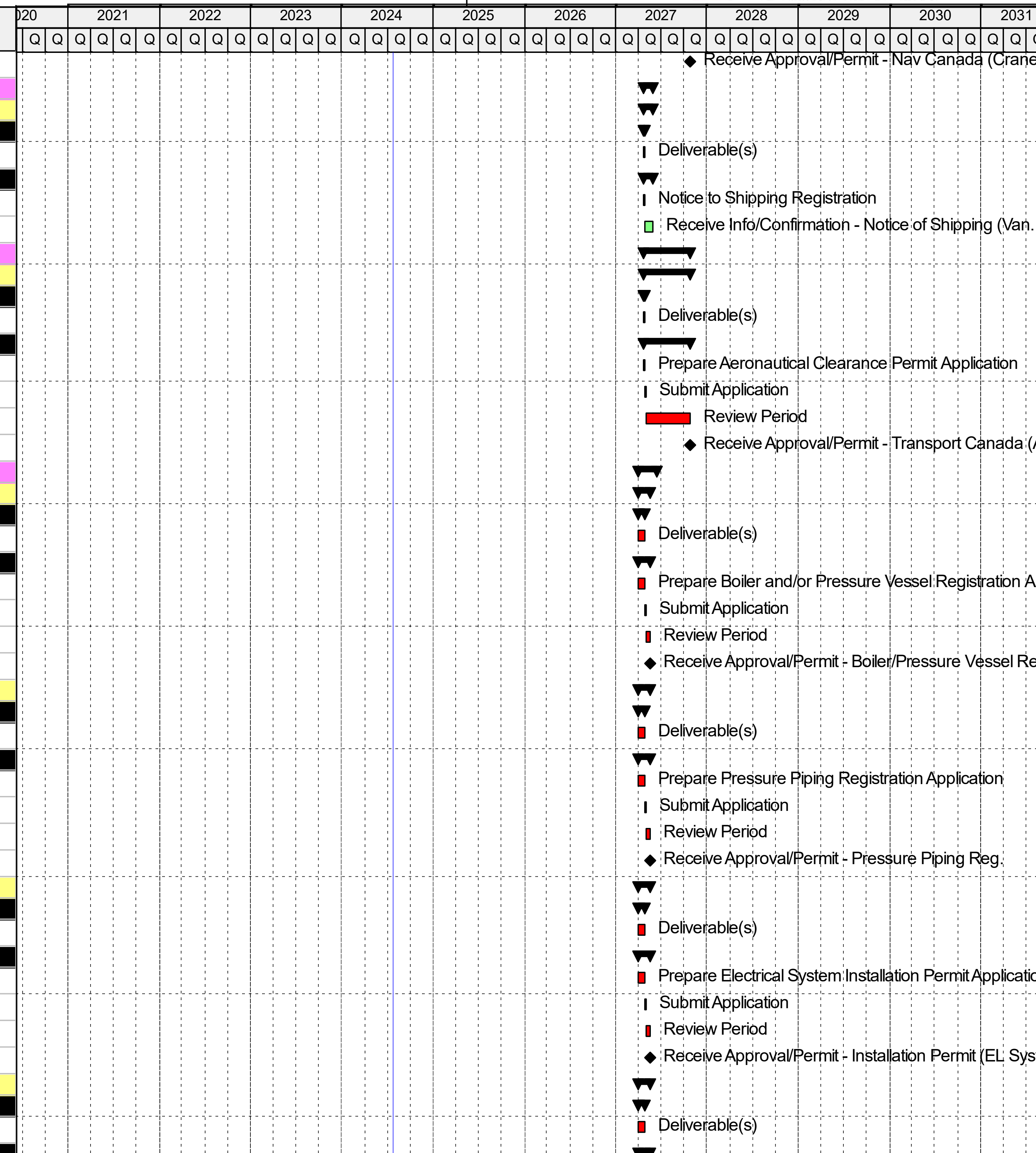
FORTIS BC

Tilbury Island LNG Facility Expansion (3 BCF)
TLSE Sub-Projects Integrated Schedule-Detailed

SOLARIS MANAGEMENT CONSULTANTS INC.

Activity ID	Activity Name	Rem. Duration	Start	Finish
RGT111188	Receive Approval/Permit - Nav Canada (Crane)	0d		25-Oct-27
Port of Vancouver		25d	22-Apr-27	27-May-27
Notice to Shipping - Canada Marine Act		25d	22-Apr-27	27-May-27
Necessary Deliverables		5d	22-Apr-27	28-Apr-27
RGT113112	Deliverable(s)	5d	22-Apr-27	28-Apr-27
Application		25d	22-Apr-27	27-May-27
RGT113184	Notice to Shipping Registration	5d	22-Apr-27	28-Apr-27
RGT113188	Receive Info/Confirmation - Notice of Shipping (Van. Port)	20d	29-Apr-27	27-May-27
Transport Canada		128d	22-Apr-27	25-Oct-27
Aeronautical Clearance - Canadian Aviation Regulations (CARs)		128d	22-Apr-27	25-Oct-27
Necessary Deliverables		5d	22-Apr-27	28-Apr-27
RGT114112	Deliverable(s)	5d	22-Apr-27	28-Apr-27
Application		128d	22-Apr-27	25-Oct-27
RGT114182	Prepare Aeronautical Clearance Permit Application	5d	22-Apr-27	28-Apr-27
RGT114184	Submit Application	3d	29-Apr-27	03-May-27
RGT114186	Review Period	120d	04-May-27	25-Oct-27
RGT114188	Receive Approval/Permit - Transport Canada (Aeronautical)	0d		25-Oct-27
TSBC - Safety Standards Act		53d	31-Mar-27	15-Jun-27
Boiler and/or Pressure Vessel Registration / Approval		33d	31-Mar-27	17-May-27
Necessary Deliverables		20d	31-Mar-27	28-Apr-27
RGT115112	Deliverable(s)	20d	31-Mar-27	28-Apr-27
Application		33d	31-Mar-27	17-May-27
RGT115182	Prepare Boiler and/or Pressure Vessel Registration Application	20d	31-Mar-27	28-Apr-27
RGT115184	Submit Application	3d	29-Apr-27	03-May-27
RGT115186	Review Period	10d	04-May-27	17-May-27
RGT115188	Receive Approval/Permit - Boiler/Pressure Vessel Reg.	0d		17-May-27
Pressure Piping Registration / Approval		33d	31-Mar-27	17-May-27
Necessary Deliverables		20d	31-Mar-27	28-Apr-27
RGT115212	Deliverable(s)	20d	31-Mar-27	28-Apr-27
Application		33d	31-Mar-27	17-May-27
RGT115282	Prepare Pressure Piping Registration Application	20d	31-Mar-27	28-Apr-27
RGT115284	Submit Application	3d	29-Apr-27	03-May-27
RGT115286	Review Period	10d	04-May-27	17-May-27
RGT115288	Receive Approval/Permit - Pressure Piping Reg.	0d		17-May-27
Installation permits - Electrical System		33d	31-Mar-27	17-May-27
Necessary Deliverables		20d	31-Mar-27	28-Apr-27
RGT115312	Deliverable(s)	20d	31-Mar-27	28-Apr-27
Application		33d	31-Mar-27	17-May-27
RGT115382	Prepare Electrical System Installation Permit Application	20d	31-Mar-27	28-Apr-27
RGT115384	Submit Application	3d	29-Apr-27	03-May-27
RGT115386	Review Period	10d	04-May-27	17-May-27
RGT115388	Receive Approval/Permit - Installation Permit (EL System)	0d		17-May-27
Installation permits - Refrigeration System		33d	31-Mar-27	17-May-27
Necessary Deliverables		20d	31-Mar-27	28-Apr-27
RGT115412	Deliverable(s)	20d	31-Mar-27	28-Apr-27
Application		33d	31-Mar-27	17-May-27



Remaining Level of Effort | Actual Work | Critical Remaining Work
Actual Level of Effort | Remaining Work | Critical Secondary

Data Date: 26-Jul-24

Date	Revision	Checked	Approved
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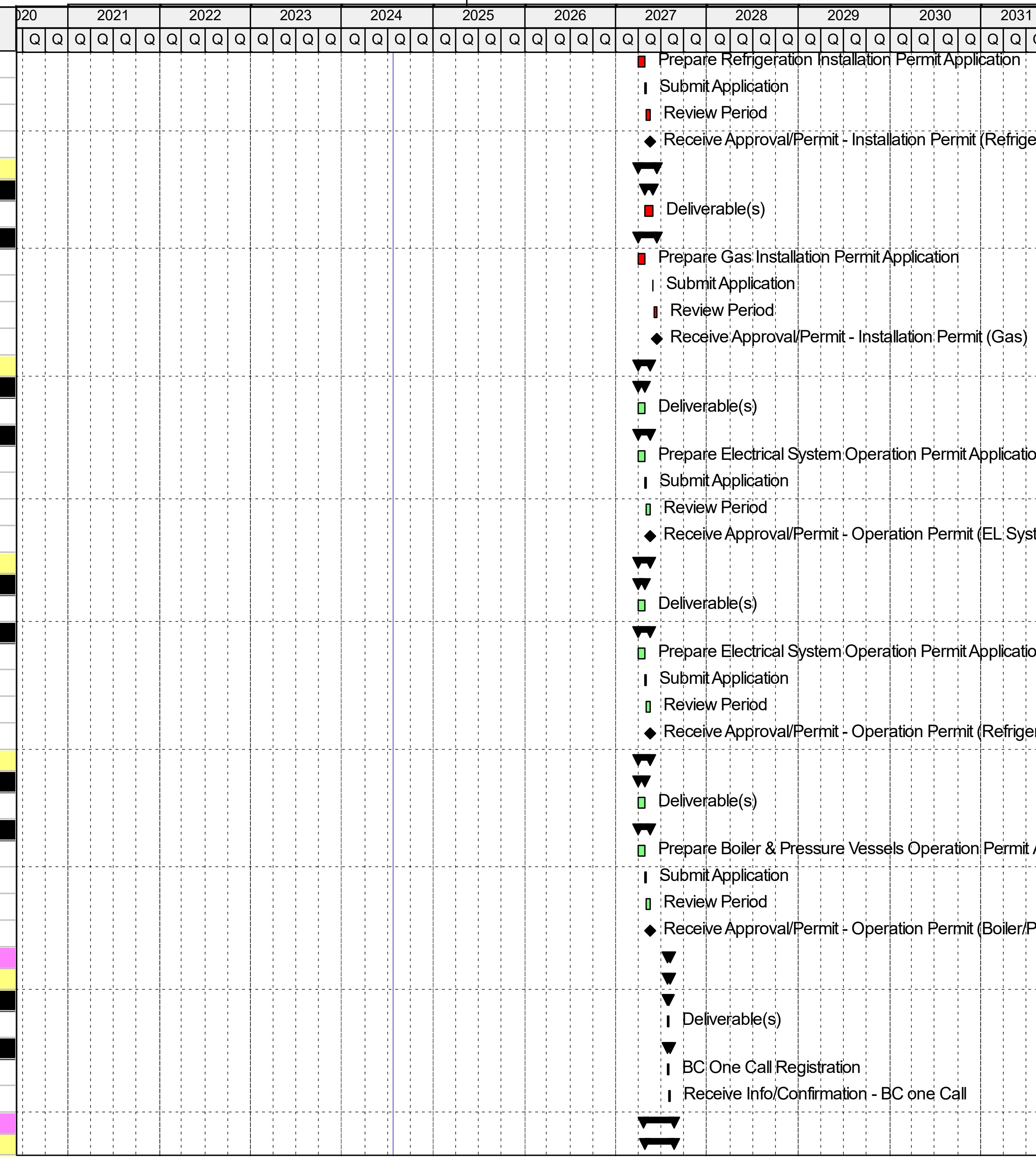
Activity ID	Activity Name	Rem. Duration	Start	Finish
RGT115482	Prepare Refrigeration Installation Permit Application	20d	31-Mar-27	28-Apr-27
RGT115484	Submit Application	3d	29-Apr-27	03-May-27
RGT115486	Review Period	10d	04-May-27	17-May-27
RGT115488	Receive Approval/Permit - Installation Permit (Refrigeration System)	0d		17-May-27
Installation permits - Gas		53d	31-Mar-27	15-Jun-27
Necessary Deliverables		20d	29-Apr-27	27-May-27
RGT115512	Deliverable(s)	20d	29-Apr-27	27-May-27
Application		53d	31-Mar-27	15-Jun-27
RGT115582	Prepare Gas Installation Permit Application	20d	31-Mar-27	28-Apr-27
RGT115584	Submit Application	3d	28-May-27	01-Jun-27
RGT115586	Review Period	10d	02-Jun-27	15-Jun-27
RGT115588	Receive Approval/Permit - Installation Permit (Gas)	0d		15-Jun-27
Operation permits - Electrical System		33d	31-Mar-27	17-May-27
Necessary Deliverables		20d	31-Mar-27	28-Apr-27
RGT115612	Deliverable(s)	20d	31-Mar-27	28-Apr-27
Application		33d	31-Mar-27	17-May-27
RGT115682	Prepare Electrical System Operation Permit Application	20d	31-Mar-27	28-Apr-27
RGT115684	Submit Application	3d	29-Apr-27	03-May-27
RGT115686	Review Period	10d	04-May-27	17-May-27
RGT115688	Receive Approval/Permit - Operation Permit (EL System)	0d		17-May-27
Operation permits - Refrigeration System		33d	31-Mar-27	17-May-27
Necessary Deliverables		20d	31-Mar-27	28-Apr-27
RGT115712	Deliverable(s)	20d	31-Mar-27	28-Apr-27
Application		33d	31-Mar-27	17-May-27
RGT115782	Prepare Electrical System Operation Permit Application	20d	31-Mar-27	28-Apr-27
RGT115784	Submit Application	3d	29-Apr-27	03-May-27
RGT115786	Review Period	10d	04-May-27	17-May-27
RGT115788	Receive Approval/Permit - Operation Permit (Refrigeratioin System)	0d		17-May-27
Operation permits (Boiler, Pressure Vessels)		33d	31-Mar-27	17-May-27
Necessary Deliverables		20d	31-Mar-27	28-Apr-27
RGT115812	Deliverable(s)	20d	31-Mar-27	28-Apr-27
Application		33d	31-Mar-27	17-May-27
RGT115882	Prepare Boiler & Pressure Vessels Operation Permit Application	20d	31-Mar-27	28-Apr-27
RGT115884	Submit Application	3d	29-Apr-27	03-May-27
RGT115886	Review Period	10d	04-May-27	17-May-27
RGT115888	Receive Approval/Permit - Operation Permit (Boiler/Pressure Vessel)	0d		17-May-27
BC One Call		8d	26-Jul-27	06-Aug-27
BC One Call Registration		8d	26-Jul-27	06-Aug-27
Necessary Deliverables		5d	26-Jul-27	03-Aug-27
RGT101112	Deliverable(s)	5d	26-Jul-27	03-Aug-27
Application		4d	30-Jul-27	06-Aug-27
RGT101184	BC One Call Registration	1d	30-Jul-27	03-Aug-27
RGT101188	Receive Info/Confirmation - BC one Call	3d	03-Aug-27	06-Aug-27
Work Safe BC * TBC Might Be Part of Construction Contractor Scope:*		85d	22-Apr-27	23-Aug-27
Guidelines 20.3-2 Qualified coordinators		81d	28-Apr-27	23-Aug-27



Remaining Level of Effort | Actual Work | Critical Remaining Work
Actual Level of Effort | Remaining Work | Critical Secondary

Date	Revision	Checked	Approved
19-Aug-24	IFI		

Activity ID	Activity Name	Rem. Duration	Start	Finish
Necessary Deliverables		5d	09-Aug-27	16-Aug-27
RGT116112	Deliverable(s)	5d	09-Aug-27	16-Aug-27
Application		81d	28-Apr-27	23-Aug-27
RGT116182	Prepare Application of Guidelines 20.3-2 Qualified coordinators	1d	28-Apr-27	28-Apr-27
RGT116184	Submit Application	3d	16-Aug-27	19-Aug-27
RGT116186	Review Period	2d	19-Aug-27	23-Aug-27
RGT116188	Receive Approval/Permit - WSBC Qualified coordinators	0d		23-Aug-27
G20.2(1)/20.2.1(1) Notice of Project, Section 20.2(1) of the OHS Regulation		10d	22-Apr-27	05-May-27
Necessary Deliverables		5d	22-Apr-27	28-Apr-27
RGT116212	Deliverable(s)	5d	22-Apr-27	28-Apr-27
Application		6d	28-Apr-27	05-May-27
RGT116282	Prepare Work Safe BC Application - Notice of Project	1d	28-Apr-27	28-Apr-27
RGT116284	Submit Application	3d	29-Apr-27	03-May-27
RGT116286	Review Period	2d	04-May-27	05-May-27
RGT116288	Receive Approval/Permit - WSBC Notic of Project	0d		05-May-27
30M33 Permit - OHS Regulation Sections 19		10d	22-Apr-27	05-May-27
Necessary Deliverables		5d	22-Apr-27	28-Apr-27
RGT116312	Deliverable(s)	5d	22-Apr-27	28-Apr-27
Application		6d	28-Apr-27	05-May-27
RGT116382	Prepare Work Safe BC Application - 30M33 Permit	1d	28-Apr-27	28-Apr-27
RGT116384	Submit Application	3d	29-Apr-27	03-May-27
RGT116386	Review Period	2d	04-May-27	05-May-27
RGT116388	Receive Approval/Permit - WSBC 30M33	0d		05-May-27
Construction		400d	09-Aug-27	22-Mar-29
Civil Works		212d	09-Aug-27	16-Jun-28
A1XC2000	Site Mobilisation (Regas. Linde Detailed)	20d	09-Aug-27	07-Sep-27
A1XC2020	General Foundation Works, Trenches & Roads	192d	07-Sep-27	16-Jun-28
A1XY1080	Foundations Set 3	130d	03-Dec-27	15-Jun-28
A1XY1060	Foundations Set 1	65d	09-Dec-27	20-Mar-28
A1XY1070	Foundations Set 2	65d	28-Jan-28	02-May-28
Equipment		168d	16-Nov-27	20-Jul-28
A1XM1060	Erection Package Units	40d	16-Nov-27	18-Jan-28
A1XM1040	Erection of LL Columns	60d	14-Dec-27	15-Mar-28
A1XB1000	Installation Field Equipment	130d	14-Jan-28	20-Jul-28
A1XM1020	Erection Tank Return Gas Compressor	65d	04-Feb-28	09-May-28
A1XM1030	Erection Feed Gas Compressor	40d	04-Feb-28	04-Apr-28
A1XM1050	Erection Compressors	100d	04-Feb-28	28-Jun-28
Structural Steel		200d	20-Mar-28	10-Jan-29
A1XN1000	Installation Steel Structures Field	200d	20-Mar-28	10-Jan-29
Modules / Skids		120d	07-Jul-28	03-Jan-29
A1XY1040	Installation Modules Set 3	10d	07-Jul-28	20-Jul-28
A1XY1100	Modules Set 3 hook-up	30d	21-Jul-28	31-Aug-28
A1XY1010	Installation Modules Set 2	10d	11-Sep-28	22-Sep-28
A1XY1110	Modules Set 2 hook-up	30d	25-Sep-28	06-Nov-28

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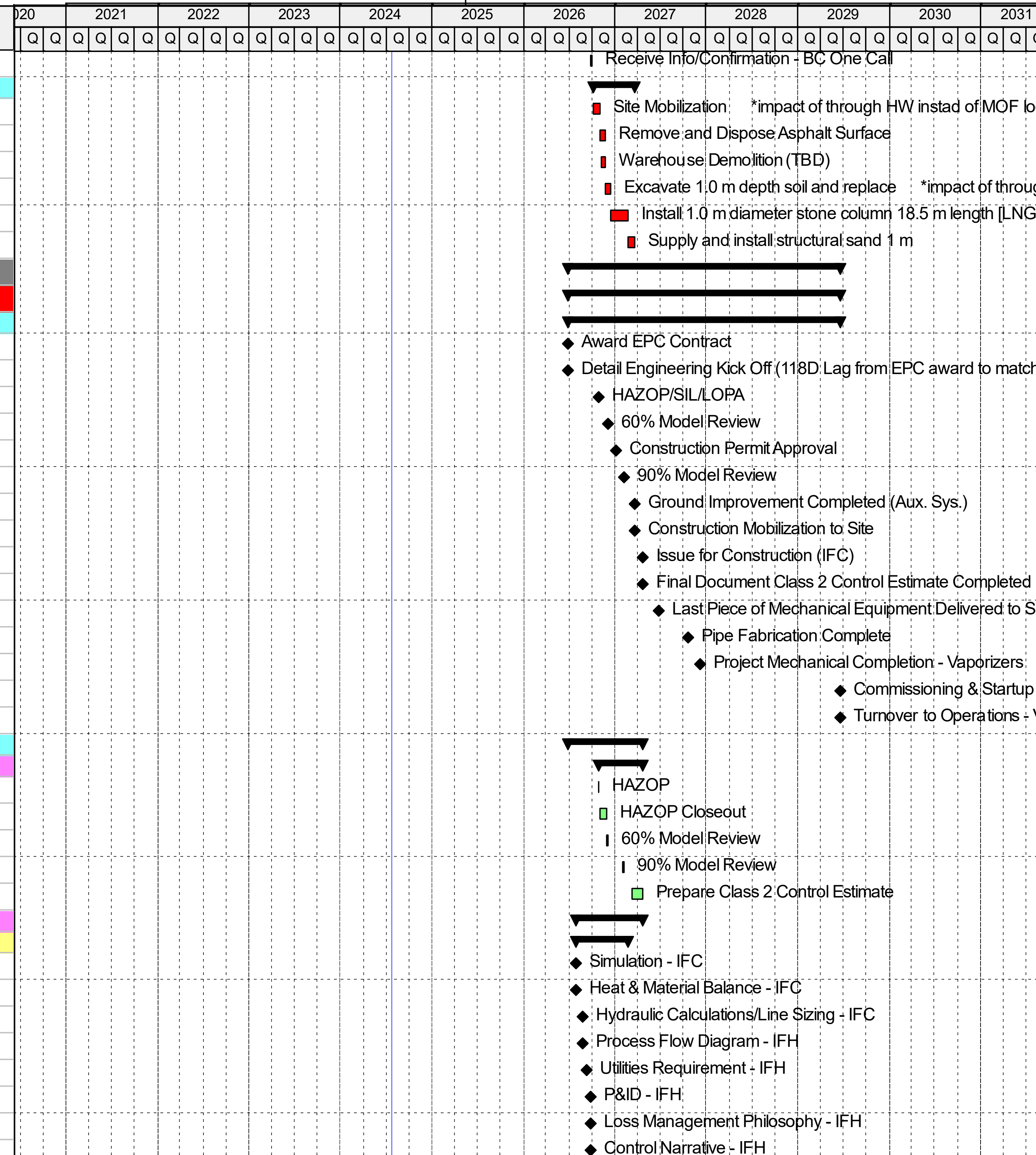
Activity ID	Activity Name	Rem. Duration	Start	Finish
A1XY1000	Installation Modules Set 1	10d	31-Oct-28	14-Nov-28
A1XY1090	Modules Set 1 hook-up	30d	15-Nov-28	03-Jan-29
Piping		160d	08-Jun-28	01-Feb-29
A1XR1010	Piping Field Installation & Testing	160d	08-Jun-28	01-Feb-29
Electrical & Instrumentation		180d	16-Jun-28	12-Mar-29
A1XE1010	Installation MV / LV Switchgear (Prefab Distr. Center)	20d	16-Jun-28	17-Jul-28
A1XJ1010	Installation DCS & ESD (Prefab Distr. Center)	20d	16-Jun-28	17-Jul-28
A1XE1000	Electrical Field Installation incl. Testing	160d	22-Jun-28	15-Feb-29
A1XJ1000	Instrumentation Field Installation incl. Testing	130d	14-Aug-28	26-Feb-29
A1XE1020	Electr. Substation energized	0d	30-Oct-28	
A1XJ1020	Loop Testing	70d	23-Nov-28	12-Mar-29
Painting & Insulation		136d	25-Aug-28	19-Mar-29
A1XW1000	Surface Protection Field	130d	25-Aug-28	09-Mar-29
A1XV1000	Insulation Field	130d	05-Sep-28	19-Mar-29
Precommissioning		100d	23-Oct-28	22-Mar-29
A1YF1000	Precommissioning	100d	23-Oct-28	22-Mar-29
Commissioning & Start Up		100d	29-Jan-29	21-Jun-29
A1YF1010	Commissioning & Start Up	100d	29-Jan-29	21-Jun-29
A1YF1030	Test Run	2d	13-Jun-29	15-Jun-29
Ground Improvement & Early Works - Regasification Area		283d	30-Jan-26	23-Mar-27
Geotechnical Investigation		110d	30-Jan-26	08-Jul-26
GR1.1	Geotechical Field Investigation Including Coordination	60d	30-Jan-26	27-Apr-26
GR1.2	Geotechical Analyses and Reporting Including Laboratory Testing	80d	16-Mar-26	08-Jul-26
Detailed Engineering		80d	28-Apr-26	20-Aug-26
GIT500020	Outside Tank Area Area Ground Improvement Detailed Engineering	80d	28-Apr-26	20-Aug-26
Ground Improv. Construction Contract (Concrete Fnd. Excluded)		137d	16-Mar-26	29-Sep-26
GR01	Prepare Bidding Documents	20d	16-Mar-26	13-Apr-26
GR02	Contract Request Form/Email	1d	14-Apr-26	14-Apr-26
GR03	Review/Draft Requirements and Discussion with Stakeholders	10d	15-Apr-26	28-Apr-26
GR04	Review Competetive Bid Documents	10d	29-Apr-26	12-May-26
GR05	Circulate RFQ Internally for Review, Comments and Amendments	10d	13-May-26	27-May-26
GR06	Legal Review	10d	28-May-26	10-Jun-26
GR07	Finalize RFQ	10d	11-Jun-26	24-Jun-26
GR08	Receive Vendor/Contractors Proposals/Clarification	40d	25-Jun-26	21-Aug-26
GR09	Finalize SOW/Update Cost Estimate/Bid Evaluation//Negotiation/PR Creation and /	20d	24-Aug-26	21-Sep-26
GR12	Prepare and Award Contract - Only Construction	10d	16-Sep-26	29-Sep-26
Construction Work		123d	21-Sep-26	23-Mar-27
Regulatory Permits		9d	21-Sep-26	01-Oct-26
BC One Call		9d	21-Sep-26	01-Oct-26
Necessary Deliverables		5d	21-Sep-26	28-Sep-26
RGT301112	Prepare Ticket	5d	21-Sep-26	28-Sep-26
Application		4d	28-Sep-26	01-Oct-26
RGT301184	BC One Call Registration	1d	28-Sep-26	28-Sep-26

Activity ID	Activity Name	Rem. Duration	Start	Finish
RGT301188	Receive Info/Confirmation - BC One Call	3d	29-Sep-26	01-Oct-26
Regasification Area Civil Work		113d	05-Oct-26	23-Mar-27
GR2.0	Site Mobilization *impact of through HW instad of MOF logistic ?*	20d	05-Oct-26	02-Nov-26
GR2.1	Remove and Dispose Asphalt Surface	15d	03-Nov-26	24-Nov-26
GR2.1.1	Warehouse Demolition (TBD)	12d	06-Nov-26	24-Nov-26
GR2.2	Excavate 1.0 m depth soil and replace *impact of through HW instad of MOF lo(	15d	25-Nov-26	15-Dec-26
GR3.1	Install 1.0 m diameter stone column 18.5 m length [LNG Expansion Area Outside tl	45d	14-Dec-26	23-Feb-27
GR2.3	Supply and install structural sand 1 m	20d	24-Feb-27	23-Mar-27
Auxiliary Systems (Utility Rack & Equipment) Tie-in to Vaporizer Package		737d	29-Jun-26	21-Jun-29
EPC (Detailed - Contractor)		737d	29-Jun-26	21-Jun-29
General		737d	29-Jun-26	21-Jun-29
TAX296120	Award EPC Contract	0d		29-Jun-26
G0000002	Detail Engineering Kick Off (118D Lag from EPC award to match CPCN App Sch.)	0d	30-Jun-26	
G0000005	HAZOP/SIL/LOPA	0d		30-Oct-26
G0000007	60% Model Review	0d		07-Dec-26
E0001801	Construction Permit Approval	0d	06-Jan-27	
G0000006	90% Model Review	0d		09-Feb-27
E0001811	Ground Improvement Completed (Aux. Sys.)	0d		23-Mar-27
G0000076	Construction Mobilization to Site	0d	24-Mar-27	
G0000016	Issue for Construction (IFC)	0d		22-Apr-27
G0000046	Final Document Class 2 Control Estimate Completed	0d		22-Apr-27
G0000086	Last Piece of Mechanical Equipment Delivered to Site	0d		25-Jun-27
E0005891	Pipe Fabrication Complete	0d		21-Oct-27
G0000066	Project Mechanical Completion - Vaporizers	0d		07-Dec-27
G0000096	Commissioning & Startup Completed - Vaporizers	0d		21-Jun-29
G0000126	Turnover to Operations - Vaporizers	0d		21-Jun-29
Engineering & Design		200d	30-Jun-26	22-Apr-27
General		120d	26-Oct-26	22-Apr-27
E0000071	HAZOP	5d	26-Oct-26	30-Oct-26
E0000081	HAZOP Closeout	20d	02-Nov-26	30-Nov-26
G0000091	60% Model Review	5d	01-Dec-26	07-Dec-26
G0000101	90% Model Review	5d	03-Feb-27	09-Feb-27
E0000121	Prepare Class 2 Control Estimate	30d	11-Mar-27	22-Apr-27
Milestones		180d	28-Jul-26	22-Apr-27
Process		140d	28-Jul-26	24-Feb-27
E0003871	Simulation - IFC	0d		28-Jul-26
E0003921	Heat & Material Balance - IFC	0d		28-Jul-26
E0004201	Hydraulic Calculations/Line Sizing - IFC	0d		26-Aug-26
E0004251	Process Flow Diagram - IFH	0d		26-Aug-26
E0004091	Utilities Requirement - IFH	0d		10-Sep-26
E0000031	P&ID - IFH	0d		24-Sep-26
E0004611	Loss Management Philosophy - IFH	0d		24-Sep-26
E0004781	Control Narrative - IFH	0d		24-Sep-26



Activity ID	Activity Name	Rem. Duration	Start	Finish
E0006451	Vendor P&ID - IFH	0d		24-Sep-26
E0003981	Material Selection Diagram - IFH	0d		08-Oct-26
E0004361	Utility Flow Diagram - IFH	0d		08-Oct-26
E0004681	Operating Philosophy - IFH	0d		23-Oct-26
E0004741	Pressure Relief Summary - IFH	0d		23-Oct-26
E0004311	Process Flow Diagram - IFC	0d		14-Dec-26
E0000061	P&ID - IFC	0d		12-Jan-27
E0004701	Loss Management Philosophy - IFC	0d		12-Jan-27
E0006481	Control Narrative - IFC	0d		12-Jan-27
E0001831	C&SU Procedure - IFC	0d		19-Jan-27
E0004141	Utilities Requirement - IFC	0d		19-Jan-27
E0004031	Material Selection Diagram - IFC	0d		02-Feb-27
E0004601	Utility Flow Diagram - IFC	0d		02-Feb-27
E0006471	Vendor P&ID - IFC	0d		02-Feb-27
E0004721	Operating Philosophy - IFC	0d		24-Feb-27
E0004761	Pressure Relief Summary - IFC	0d		24-Feb-27
Civiil/Structural/Architectural		**150d**	**12-Aug-26**	**24-Mar-27**
E0000341	Civil Engineering Design Criteria - IFC	0d		12-Aug-26
E0000611	Structural Engineering Design Criteria - IFC	0d		12-Aug-26
E0000781	Piperack Structural Capacity Report - IFC	0d		12-Aug-26
E0000821	C/S/A Standard Drawings & Details - IFC	0d		12-Aug-26
E0001131	C/S/A Specifications - IFC	0d		12-Aug-26
E0000201	Structural Steel Location Plans - IFC	0d		10-Mar-27
E0000231	Building Drawings - IFC	0d		24-Mar-27
E0000261	Foundation Details & Drawings - IFC	0d		24-Mar-27
E0000291	Earthworks/Civil Drawings - IFC	0d		24-Mar-27
E0000791	MIscellaneous Steel - Support Details - IFC	0d		24-Mar-27
E0000801	Structural Steel MTO for Estimating	0d		24-Mar-27
Mechanical		**100d**	**12-Aug-26**	**12-Jan-27**
E0006491	Equipment Specifications - IFC	0d		12-Aug-26
E0001221	Spare Parts Listing	0d		02-Sep-26
E0000311	Equipment List - IFH	0d		24-Sep-26
E0001141	Fire Fighting Equipment List - IFH	0d		24-Sep-26
E0000331	Equipment List - IFC	0d		12-Jan-27
E0001171	Fire Fighting Equipment List - IFC	0d		12-Jan-27
Piping Engineering		**130d**	**12-Aug-26**	**24-Feb-27**
E0004851	Piping Specifications - IFC	0d		12-Aug-26
E0000741	LDT - IFH	0d		24-Sep-26
E0001851	LDT - IFC	0d		12-Jan-27
E0000871	Stress Analysis Reports - IFC	0d		24-Feb-27
E0004791	SP Item List - IFC	0d		24-Feb-27
Piping Design		**155d**	**12-Aug-26**	**31-Mar-27**

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E0005021	Pipe Support Details - IFC	0d		12-Aug-26
E0005041	Piping Standard Drawings & Details - IFC	0d		12-Aug-26
E0006461	Plot Plan - IFH	0d		24-Sep-26
E0001231	Tie-in List - IFH	0d		23-Oct-26
E0005071	Fire Protection & Safety Equipment Layout - IFH	0d		23-Oct-26
E0005141	Plot Plan - IFC	0d		12-Jan-27
E0000901	Equipment Location Plan - IFC	0d		02-Feb-27
E0004971	Utility Location Plan - IFC	0d		02-Feb-27
E0001661	Piping Tie-in List - IFC	0d		24-Feb-27
E0004961	Equipment General Arrangement Drawings - IFC	0d		24-Feb-27
E0000851	Piping (PVF, Insulation Piping SP Items) MTO for Estimating	0d		24-Mar-27
E0001711	General Arrangement Key Plan - IFC	0d		24-Mar-27
E0004881	Model Key Plan - IFC	0d		24-Mar-27
E0004901	Construction Isos - IFC	0d		24-Mar-27
E0005101	Fire Protection & Safety Equipment Layout - IFC	0d		24-Mar-27
E0004921	Piping General Arrangement Drawings - IFC	0d		31-Mar-27
Electrical		170d	12-Aug-26	22-Apr-27
E0005341	Electrical Standard Drawings & Details - IFC	0d		12-Aug-26
E0005361	Electrical Specifications - IFC	0d		12-Aug-26
E0005521	Grounding/Cathodic Protection Details - IFC	0d		12-Aug-26
E0005221	Area Classification Diagram - IFH	0d		23-Oct-26
E0005181	Single Line Diagram - IFC	0d		09-Feb-27
E0005201	Cable Schedule - IFC	0d		09-Feb-27
E0005161	Electrical Load List - IFC	0d		24-Feb-27
E0005241	Area Classification Diagram - IFC	0d		24-Feb-27
E0005481	Tie-In List - IFC	0d		24-Feb-27
E0005961	ETAP/Arc Flash - IFC	0d		24-Feb-27
E0005261	24V Distribution Wiring Schematics - IFC	0d		10-Mar-27
E0005281	120V Schematics - IFC	0d		10-Mar-27
E0005301	600V/480V Schematics - IFC	0d		10-Mar-27
E0005321	4160V Schematics - IFC	0d		10-Mar-27
E0001211	Issue Electrical (Cable/Tray/Conduit/Junction Box) MTO for Estimating	0d		24-Mar-27
E0005401	Junction Box Layout - IFC	0d		24-Mar-27
E0005421	Contactor Panel Layout - IFC	0d		24-Mar-27
E0005461	Control Panel Layout - IFC	0d		24-Mar-27
E0005471	Distribution Panel Drawings - IFC	0d		24-Mar-27
E0005571	Electrical Equipment Layout - IFC	0d		24-Mar-27
E0005611	New Substation Layout - IFC	0d		24-Mar-27
E0005381	Input/Output Drawings - IFC	0d		22-Apr-27
E0005551	Cable, Raceway, Lighting & Grounding Layout - IFC	0d		22-Apr-27
E0005631	Cable Tray Layout - IFC	0d		22-Apr-27
E0006511	Heat Tracing Layout - IFC	0d		22-Apr-27

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Activity ID	Activity Name	Rem. Duration	Start	Finish
Instrumentation		170d	12-Aug-26	22-Apr-27
E0005931	Standard Drawings & Details - IFC	0d		12-Aug-26
E0005941	I&C Specifications - IFC	0d		12-Aug-26
E0001541	Shut Down Key - IFH	0d		24-Sep-26
E0001561	Instrument Index - IFH	0d		23-Oct-26
E0001581	Alarm Set Point Table - IFH	0d		23-Oct-26
E0005701	Metering Schematics - IFH	0d		23-Oct-26
E0005771	Fire & Gas Detection Drawings - IFH	0d		23-Oct-26
E0005911	PCS/PLC/SIS/SCADA Architecture Diagram - IFH	0d		23-Oct-26
E0001891	Shut Down Key - IFC	0d		12-Jan-27
E0001911	Alarm Set Point Table - IFC	0d		24-Feb-27
E0004551	Instrument Index - IFC	0d		24-Feb-27
E0005641	System Block Diagram - IFC	0d		24-Feb-27
E0005681	I&C Tie-In Drawing - IFC	0d		24-Feb-27
E0005731	Metering Schematics - IFC	0d		24-Feb-27
E0005781	Fire & Gas Detection Drawings - IFC	0d		24-Feb-27
E0005921	PCS/PLC/SIS/SCADA Architecture Diagram - IFC	0d		24-Feb-27
E0001611	Instrumentation & Controls MTO	0d		24-Mar-27
E0005661	Instrument Layout - IFC	0d		22-Apr-27
Process		160d	30-Jun-26	24-Feb-27
Simulation		20d	30-Jun-26	28-Jul-26
E0000281	Simulation - IFC	20d	30-Jun-26	28-Jul-26
Heat & Material Balance		20d	30-Jun-26	28-Jul-26
E0000761	Heat & Material Balance - IFC	20d	30-Jun-26	28-Jul-26
Material Selection Diagram		105d	27-Aug-26	02-Feb-27
E0000751	Material Selection Diagram - IFH	30d	27-Aug-26	08-Oct-26
E0000771	Material Selection Diagram - IFC	30d	15-Dec-26	02-Feb-27
Utilities		115d	29-Jul-26	19-Jan-27
E0000111	Utilities Requirement - IFH	30d	29-Jul-26	10-Sep-26
E0000221	Utilities Requirement - IFC	30d	01-Dec-26	19-Jan-27
Hydraulic Calculations		20d	29-Jul-26	26-Aug-26
E0004771	Hydraulic Calculations/Line Sizing - IFC	20d	29-Jul-26	26-Aug-26
Flow Diagram		125d	29-Jul-26	02-Feb-27
E0000091	Process Flow Diagram Development - IFH	20d	29-Jul-26	26-Aug-26
E0004641	Utility Flow Diagram Development - IFH	30d	27-Aug-26	08-Oct-26
E0000101	Process Flow Diagram Development - IFC	10d	01-Dec-26	14-Dec-26
E0004651	Utility Flow Diagram Development - IFC	30d	15-Dec-26	02-Feb-27
Piping & Instrument Diagram (P&ID)		105d	27-Aug-26	02-Feb-27
E0000021	P&ID Development IFH	20d	27-Aug-26	24-Sep-26
E0004661	Vendor P&ID - IFH	20d	27-Aug-26	24-Sep-26
E0000041	P&ID Development IFC	15d	15-Dec-26	12-Jan-27
E0004671	Vendor P&ID - IFC	30d	15-Dec-26	02-Feb-27
Instrument Data Sheet		10d	29-Jul-26	12-Aug-26

Remaining Level of Effort · Actual Work · Critical Remaining Work · Actual Level of Effort · Remaining Work · Critical Secondary

Date	Revision	Checked	Approved
19-Aug-24	IFI		

FORTIS BC™

Tilbury Island LNG Facility Expansion (3 BCF)

TLSE Sub-Projects Integrated Schedule-Detailed

SOLARIS MANAGEMENT CONSULTANTS INC.

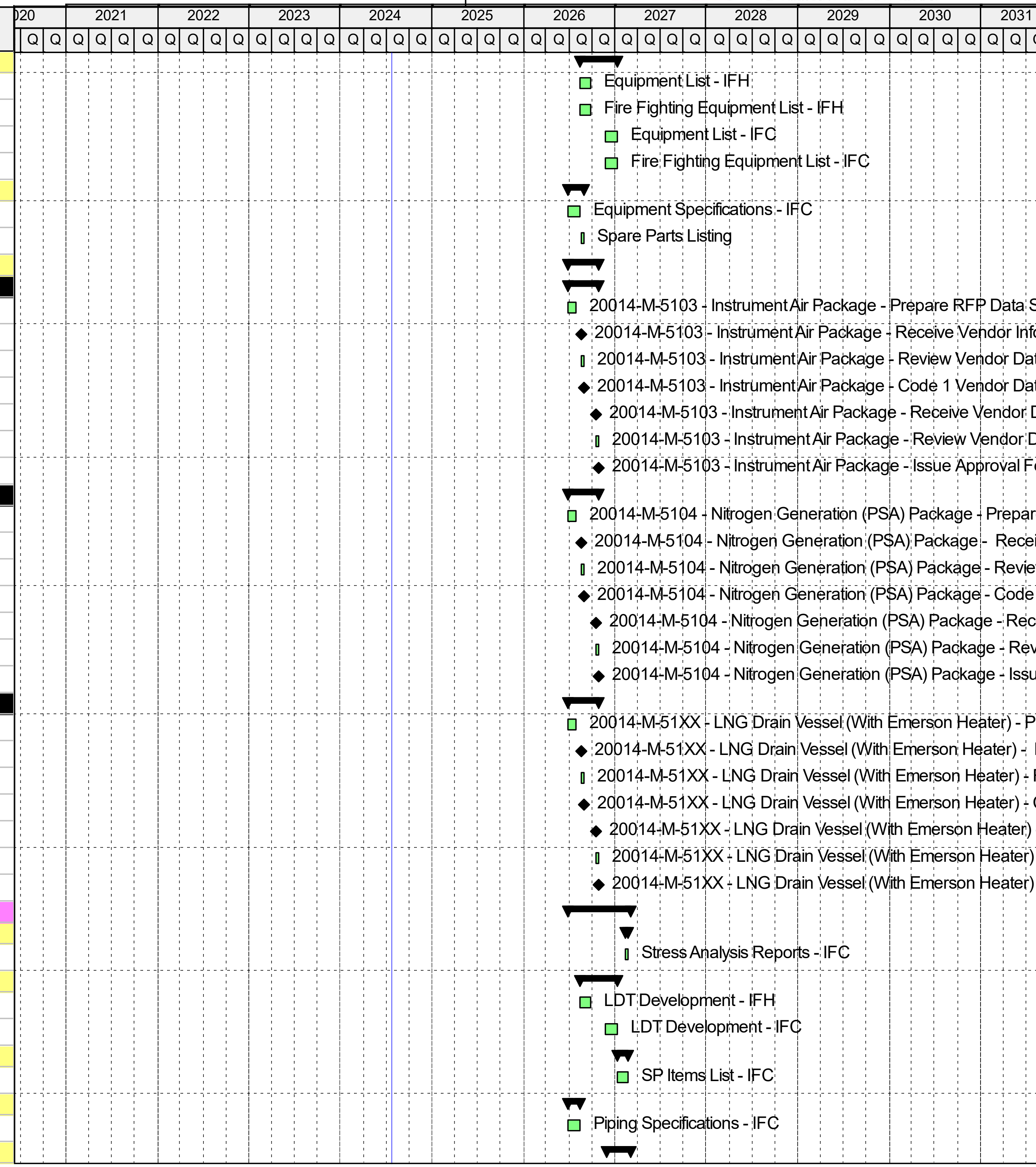
Activity ID	Activity Name	Rem. Duration	Start	Finish
E0004691	Instruments Sizing Calculations - IFP	10d	29-Jul-26	12-Aug-26
Loss Management Philosophy		100d	13-Aug-26	12-Jan-27
E0004561	Loss Management Philosophy - IFH	30d	13-Aug-26	24-Sep-26
E0004571	Loss Management Philosophy - IFC	30d	24-Nov-26	12-Jan-27
Operating Philosophy		100d	25-Sep-26	24-Feb-27
E0004581	Operating Philosophy - IFH	20d	25-Sep-26	23-Oct-26
E0004591	Operating Philosophy - IFC	30d	13-Jan-27	24-Feb-27
Pressure Relief Summary		100d	25-Sep-26	24-Feb-27
E0004621	Pressure Relief Summary - IFH	20d	25-Sep-26	23-Oct-26
E0004631	Pressure Relief Summary - IFC	30d	13-Jan-27	24-Feb-27
Control Narrative		95d	27-Aug-26	19-Jan-27
E0000251	Prepare Control Narrative - IFH	20d	27-Aug-26	24-Sep-26
E0001621	Prepare Control Narrative - IFC	30d	24-Nov-26	12-Jan-27
E0000141	Prepare C&SU Procedure - IFC	30d	01-Dec-26	19-Jan-27
Civil/Structural/Architectural		180d	30-Jun-26	24-Mar-27
Design Criteria		30d	30-Jun-26	12-Aug-26
E0004801	Civil Engineering Design Criteria - IFC	30d	30-Jun-26	12-Aug-26
E0004811	Structural Engineering Design Criteria - IFC	30d	30-Jun-26	12-Aug-26
Modeling		145d	30-Jun-26	02-Feb-27
G0000001	C/S/A Modeling to 60%	104d	30-Jun-26	27-Nov-26
E0000171	C/S/A Modeling to 90%	35d	08-Dec-26	02-Feb-27
Sitework		30d	10-Feb-27	24-Mar-27
E0000271	Earthworks/Civil Drawings - IFC	30d	10-Feb-27	24-Mar-27
Foundation		30d	10-Feb-27	24-Mar-27
E0000241	Foundation Details & Drawings - IFC	30d	10-Feb-27	24-Mar-27
Structural Steel		180d	30-Jun-26	24-Mar-27
E0004861	Piperack Structural Capacity Report - IFC	30d	30-Jun-26	12-Aug-26
E0005881	Miscellaneous Steel - Support Details - IFC	30d	10-Feb-27	24-Mar-27
E0000181	Structural Steel Drawings - IFC	10d	25-Feb-27	10-Mar-27
Buildings		30d	10-Feb-27	24-Mar-27
E0004831	Building Drawings - IFC	30d	10-Feb-27	24-Mar-27
Material Take Off		30d	10-Feb-27	24-Mar-27
E0004871	Structural Steel MTO for Estimating	30d	10-Feb-27	24-Mar-27
Standard Drawings & Details		30d	30-Jun-26	12-Aug-26
E0004821	C/S/A Standard Drawings & Details - IFC	30d	30-Jun-26	12-Aug-26
Specification		30d	30-Jun-26	12-Aug-26
E0004841	C/S/A Specifications - IFC	30d	30-Jun-26	12-Aug-26
Requisition		20d	30-Jun-26	28-Jul-26
20014-C-5302: Galvanized Steel		20d	30-Jun-26	28-Jul-26
E0002901	20014-C-5302: Galvanized Steel - Prepare IFP Data Sheets & Specifications	20d	30-Jun-26	28-Jul-26
20014-C-5303: Concrete		20d	30-Jun-26	28-Jul-26
E0002961	20014-C-5303 - Concrete - Prepare IFP Data Sheets & Specifications	20d	30-Jun-26	28-Jul-26
20014-C-53XX: Fill Materials		20d	30-Jun-26	28-Jul-26
E0003021	20014-C-53XX - Fill Materials - Prepare IFP Data Sheets & Specifications	20d	30-Jun-26	28-Jul-26
Mechanical		130d	30-Jun-26	12-Jan-27

Remaining Level of Effort
Actual Level of Effort
Actual Work
Remaining Work
Critical Remaining Work
Critical Secondary

Data Date:26-Jul-24

Date	Revision	Checked	Approved
19-Aug-24	IFI		

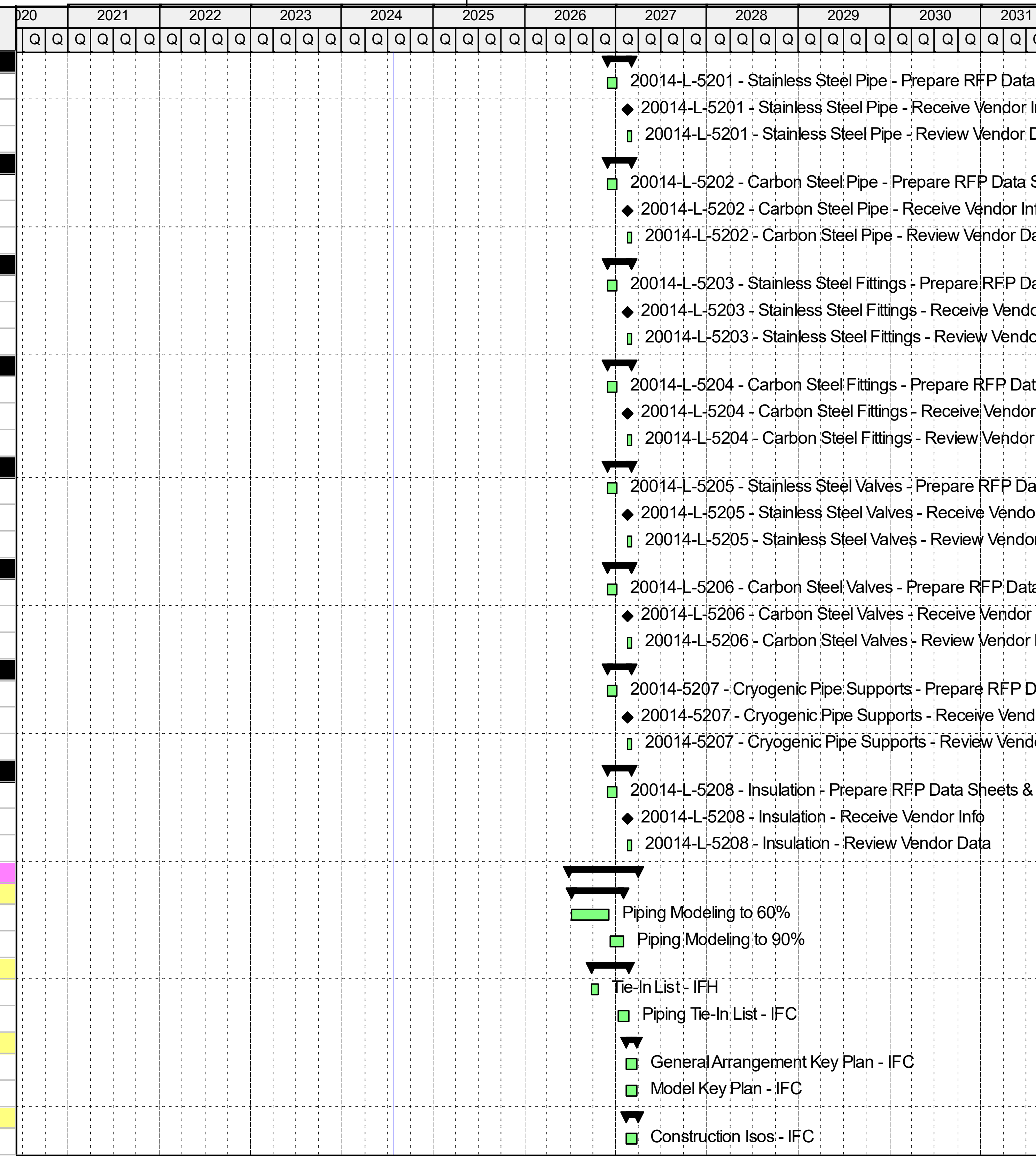
Activity ID	Activity Name	Rem. Duration	Start	Finish
Equipment List		100d	13-Aug-26	12-Jan-27
E0000301	Equipment List - IFH	30d	13-Aug-26	24-Sep-26
E0005501	Fire Fighting Equipment List - IFH	30d	13-Aug-26	24-Sep-26
E0000321	Equipment List - IFC	30d	24-Nov-26	12-Jan-27
E0005511	Fire Fighting Equipment List - IFC	30d	24-Nov-26	12-Jan-27
Spare Parts		45d	30-Jun-26	02-Sep-26
E0006321	Equipment Specifications - IFC	30d	30-Jun-26	12-Aug-26
E0005531	Spare Parts Listing	10d	20-Aug-26	02-Sep-26
Requisition		85d	30-Jun-26	30-Oct-26
20014-M-5103: Instrument Air Package		85d	30-Jun-26	30-Oct-26
E0000381	20014-M-5103 - Instrument Air Package - Prepare RFP Data Sheets & Specificatic	20d	30-Jun-26	28-Jul-26
E0000391	20014-M-5103 - Instrument Air Package - Receive Vendor Info	0d	20-Aug-26	
E0000401	20014-M-5103 - Instrument Air Package - Review Vendor Data	10d	20-Aug-26	02-Sep-26
E0000461	20014-M-5103 - Instrument Air Package - Code 1 Vendor Data	0d		02-Sep-26
E0000471	20014-M-5103 - Instrument Air Package - Receive Vendor Data Books	0d	19-Oct-26	
E0000481	20014-M-5103 - Instrument Air Package - Review Vendor Data Books	10d	19-Oct-26	30-Oct-26
E0000491	20014-M-5103 - Instrument Air Package - Issue Approval For Payment	0d		30-Oct-26
20014-M-5104: Nitrogen Generation (PSA) Package		85d	30-Jun-26	30-Oct-26
E0000641	20014-M-5104 - Nitrogen Generation (PSA) Package - Prepare RFP Data Sheets	20d	30-Jun-26	28-Jul-26
E0000651	20014-M-5104 - Nitrogen Generation (PSA) Package - Receive Vendor Info	0d	20-Aug-26	
E0000661	20014-M-5104 - Nitrogen Generation (PSA) Package - Review Vendor Data	10d	20-Aug-26	02-Sep-26
E0000671	20014-M-5104 - Nitrogen Generation (PSA) Package - Code 1 Vendor Data	0d		02-Sep-26
E0000911	20014-M-5104 - Nitrogen Generation (PSA) Package - Receive Vendor Data Bool	0d	19-Oct-26	
E0000921	20014-M-5104 - Nitrogen Generation (PSA) Package - Review Vendor Data Book	10d	19-Oct-26	30-Oct-26
E0000961	20014-M-5104 - Nitrogen Generation (PSA) Package - Issue Approval For Payme	0d		30-Oct-26
20014-M-51XX: LNG Drain Vessel (With Emerson Heater)		85d	30-Jun-26	30-Oct-26
E14801	20014-M-51XX - LNG Drain Vessel (With Emerson Heater) - Prepare RFP Data S	20d	30-Jun-26	28-Jul-26
E14811	20014-M-51XX - LNG Drain Vessel (With Emerson Heater) - Receive Vendor Info	0d	20-Aug-26	
E14821	20014-M-51XX - LNG Drain Vessel (With Emerson Heater) - Review Vendor Data	10d	20-Aug-26	02-Sep-26
E14831	20014-M-51XX - LNG Drain Vessel (With Emerson Heater) - Code 1 Vendor Data	0d		02-Sep-26
E14841	20014-M-51XX - LNG Drain Vessel (With Emerson Heater) - Receive Vendor Dat	0d	19-Oct-26	
E14851	20014-M-51XX - LNG Drain Vessel (With Emerson Heater) - Review Vendor Data	10d	19-Oct-26	30-Oct-26
E14861	20014-M-51XX - LNG Drain Vessel (With Emerson Heater) - Issue Approval For P	0d		30-Oct-26
Piping Engineering		165d	30-Jun-26	03-Mar-27
Stress		10d	10-Feb-27	24-Feb-27
E0005541	Stress Analysis Reports - IFC	10d	10-Feb-27	24-Feb-27
Line Designation Table (LDT)		100d	13-Aug-26	12-Jan-27
E0000731	LDT Development - IFH	30d	13-Aug-26	24-Sep-26
E0001841	LDT Development - IFC	30d	24-Nov-26	12-Jan-27
Specialty Items		30d	13-Jan-27	24-Feb-27
E0005561	SP Items List - IFC	30d	13-Jan-27	24-Feb-27
Specifications		30d	30-Jun-26	12-Aug-26
E0006501	Piping Specifications - IFC	30d	30-Jun-26	12-Aug-26
Requisition		60d	01-Dec-26	03-Mar-27



Remaining Level of Effort | Actual Work | Critical Remaining Work
Actual Level of Effort | Remaining Work | Critical Secondary

Date	Revision	Checked	Approved
19-Aug-24	IFI		

Activity ID	Activity Name	Rem. Duration	Start	Finish
20014-L-5201 - Stainless Steel Pipe		**60d**	**01-Dec-26**	**03-Mar-27**
E0002441	20014-L-5201 - Stainless Steel Pipe - Prepare RFP Data Sheets & Specifications	20d	01-Dec-26	05-Jan-27
E0002451	20014-L-5201 - Stainless Steel Pipe - Receive Vendor Info	0d	18-Feb-27	
E0002461	20014-L-5201 - Stainless Steel Pipe - Review Vendor Data	10d	18-Feb-27	03-Mar-27
20014-L-5202 - Carbon Steel Pipe		**60d**	**01-Dec-26**	**03-Mar-27**
E0002361	20014-L-5202 - Carbon Steel Pipe - Prepare RFP Data Sheets & Specifications	20d	01-Dec-26	05-Jan-27
E0002371	20014-L-5202 - Carbon Steel Pipe - Receive Vendor Info	0d	18-Feb-27	
E0002381	20014-L-5202 - Carbon Steel Pipe - Review Vendor Data	10d	18-Feb-27	03-Mar-27
20014-L-5203 - Stainless Steel Fittings		**60d**	**01-Dec-26**	**03-Mar-27**
E0002681	20014-L-5203 - Stainless Steel Fittings - Prepare RFP Data Sheets & Specificatior	20d	01-Dec-26	05-Jan-27
E0002691	20014-L-5203 - Stainless Steel Fittings - Receive Vendor Info	0d	18-Feb-27	
E0002701	20014-L-5203 - Stainless Steel Fittings - Review Vendor Data	10d	18-Feb-27	03-Mar-27
20014-L-5204 - Carbon Steel Fittings		**60d**	**01-Dec-26**	**03-Mar-27**
E14481	20014-L-5204 - Carbon Steel Fittings - Prepare RFP Data Sheets & Specifications	20d	01-Dec-26	05-Jan-27
E14491	20014-L-5204 - Carbon Steel Fittings - Receive Vendor Info	0d	18-Feb-27	
E14501	20014-L-5204 - Carbon Steel Fittings - Review Vendor Data	10d	18-Feb-27	03-Mar-27
20014-L-5205 - Stainless Steel Valves		**60d**	**01-Dec-26**	**03-Mar-27**
E0000581	20014-L-5205 - Stainless Steel Valves - Prepare RFP Data Sheets & Specification:	20d	01-Dec-26	05-Jan-27
E0000591	20014-L-5205 - Stainless Steel Valves - Receive Vendor Info	0d	18-Feb-27	
E0000601	20014-L-5205 - Stainless Steel Valves - Review Vendor Data	10d	18-Feb-27	03-Mar-27
20014-L-5206 - Carbon Steel Valves		**60d**	**01-Dec-26**	**03-Mar-27**
E14631	20014-L-5206 - Carbon Steel Valves - Prepare RFP Data Sheets & Specifications	20d	01-Dec-26	05-Jan-27
E14641	20014-L-5206 - Carbon Steel Valves - Receive Vendor Info	0d	18-Feb-27	
E14651	20014-L-5206 - Carbon Steel Valves - Review Vendor Data	10d	18-Feb-27	03-Mar-27
20014-5207 - Cryogenic Pipe Supports		**60d**	**01-Dec-26**	**03-Mar-27**
E0002601	20014-5207 - Cryogenic Pipe Supports - Prepare RFP Data Sheets & Specificatio	20d	01-Dec-26	05-Jan-27
E0002611	20014-5207 - Cryogenic Pipe Supports - Receive Vendor Info	0d	18-Feb-27	
E0002621	20014-5207 - Cryogenic Pipe Supports - Review Vendor Data	10d	18-Feb-27	03-Mar-27
20014-L-5208 - Insulation		**60d**	**01-Dec-26**	**03-Mar-27**
E0002761	20014-L-5208 - Insulation - Prepare RFP Data Sheets & Specifications	20d	01-Dec-26	05-Jan-27
E0002771	20014-L-5208 - Insulation - Receive Vendor Info	0d	18-Feb-27	
E0002781	20014-L-5208 - Insulation - Review Vendor Data	10d	18-Feb-27	03-Mar-27
Piping Design		**185d**	**30-Jun-26**	**31-Mar-27**
Modeling		**139d**	**09-Jul-26**	**02-Feb-27**
G0000003	Piping Modeling to 60%	104d	09-Jul-26	07-Dec-26
E0000831	Piping Modeling to 90%	35d	08-Dec-26	02-Feb-27
Tie-In		**100d**	**25-Sep-26**	**24-Feb-27**
E0005591	Tie-In List - IFH	20d	25-Sep-26	23-Oct-26
E0005601	Piping Tie-In List - IFC	30d	13-Jan-27	24-Feb-27
Key Plan		**30d**	**10-Feb-27**	**24-Mar-27**
E0005651	General Arrangement Key Plan - IFC	30d	10-Feb-27	24-Mar-27
E0005691	Model Key Plan - IFC	30d	10-Feb-27	24-Mar-27
Piping General Arrangements/Isos		**35d**	**10-Feb-27**	**31-Mar-27**
E0000891	Construction Isos - IFC	30d	10-Feb-27	24-Mar-27

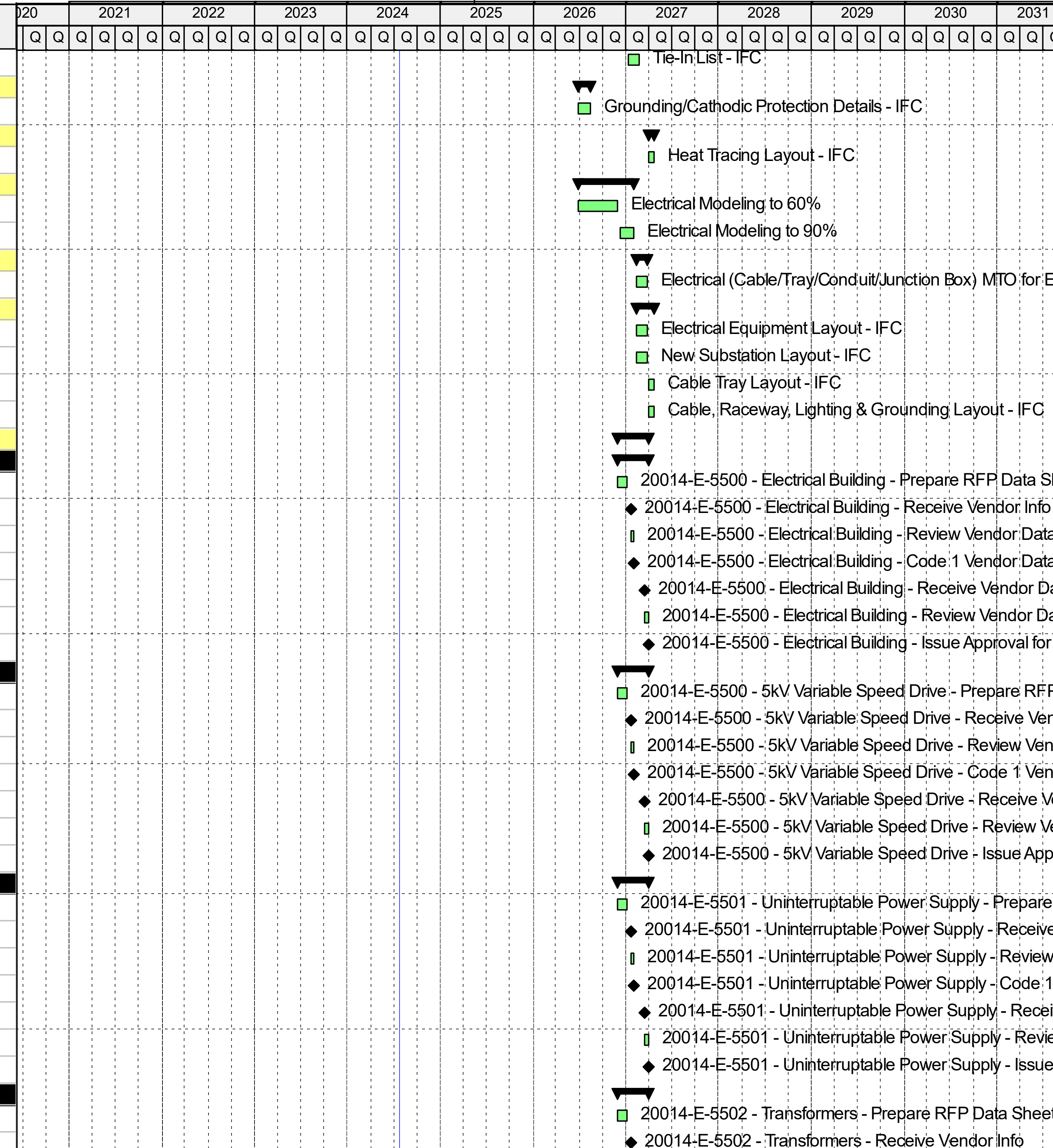


Activity ID	Activity Name	Rem. Duration	Start	Finish
E0005671	Equipment General Arrangement Drawings - IFC	10d	10-Feb-27	24-Feb-27
E0000881	Piping General Arrangement Drawings - IFC	15d	11-Mar-27	31-Mar-27
Location Plan		105d	27-Aug-26	02-Feb-27
E0005491	Plot Plan - IFH	20d	27-Aug-26	24-Sep-26
E0005121	Plot Plan - IFC	15d	15-Dec-26	12-Jan-27
E0001871	Equipment Location Plan - IFC	15d	13-Jan-27	02-Feb-27
E0005621	Utility Station Location Plan - IFC	15d	13-Jan-27	02-Feb-27
Pipe Support		30d	30-Jun-26	12-Aug-26
E0005721	Pipe Support Details - IFC	30d	30-Jun-26	12-Aug-26
Standard Drawings & Details		30d	30-Jun-26	12-Aug-26
E0005741	Piping Standard Drawings & Details - IFC	30d	30-Jun-26	12-Aug-26
Material Take Off		30d	10-Feb-27	24-Mar-27
E0000841	Piping (PVF, Insulation Piping SP Items) MTO for Estimating	30d	10-Feb-27	24-Mar-27
Fire Protection		120d	25-Sep-26	24-Mar-27
E0005751	Fire Protection & Safety Equipment Layout - IFH	20d	25-Sep-26	23-Oct-26
E0005761	Fire Protection & Safety Equipment Layout - IFC	30d	10-Feb-27	24-Mar-27
Electrical Engineering & Design		200d	30-Jun-26	22-Apr-27
Load List		30d	13-Jan-27	24-Feb-27
E0005061	Electrical Load List - IFC	30d	13-Jan-27	24-Feb-27
Single Line Diagram		20d	13-Jan-27	09-Feb-27
E0005451	Single Line Diagram - IFC	20d	13-Jan-27	09-Feb-27
ETAP/Arc Flash		30d	13-Jan-27	24-Feb-27
E0005951	ETAP/Arc Flash - IFC	30d	13-Jan-27	24-Feb-27
Cable		20d	13-Jan-27	09-Feb-27
E0005091	Cable Schedule - IFC	20d	13-Jan-27	09-Feb-27
Area Classification		100d	25-Sep-26	24-Feb-27
E0001181	Area Classification Diagram - IFH	20d	25-Sep-26	23-Oct-26
E0005441	Area Classification Diagram - IFC	30d	13-Jan-27	24-Feb-27
Schematics		20d	10-Feb-27	10-Mar-27
E0005291	24V DIstribution Wiring Schematics - IFC	20d	10-Feb-27	10-Mar-27
E0005311	120V Schematics - IFC	20d	10-Feb-27	10-Mar-27
E0005331	600V/480V Schematics - IFC	20d	10-Feb-27	10-Mar-27
E0005351	4160V Schematics - IFC	20d	10-Feb-27	10-Mar-27
Standard Drawings & Details		30d	30-Jun-26	12-Aug-26
E0005411	Electrical Standard Drawings & Details - IFC	30d	30-Jun-26	12-Aug-26
Specifications		30d	30-Jun-26	12-Aug-26
E0005431	Electrical Specifications - IFC	30d	30-Jun-26	12-Aug-26
Input/Output Drawings		30d	11-Mar-27	22-Apr-27
E0005391	Input/Output Drawings - IFC	30d	11-Mar-27	22-Apr-27
Junction Box & Panel Drawings/Layout		30d	10-Feb-27	24-Mar-27
E0005231	Junction Box Layout - IFC	30d	10-Feb-27	24-Mar-27
E0005251	Contactor Panel Layout - IFC	30d	10-Feb-27	24-Mar-27
E0005271	Control Panel Layout - IFC	30d	10-Feb-27	24-Mar-27
E0005371	Distribution Panel Drawings - IFC	30d	10-Feb-27	24-Mar-27
Tie-In		30d	13-Jan-27	24-Feb-27

Tilbury Island LNG Facility Expansion (3 BCF)
TLSE Sub-Projects Integrated Schedule-Detailed

FORTIS BC — SOLARIS MANAGEMENT CONSULTANTS INC.

Activity ID	Activity Name	Rem. Duration	Start	Finish
E0005191	Tie-In List - IFC	30d	13-Jan-27	24-Feb-27
Grounding/Cathodic Protection		30d	30-Jun-26	12-Aug-26
E0005111	Grounding/Cathodic Protection Details - IFC	30d	30-Jun-26	12-Aug-26
Heat Trace		15d	01-Apr-27	22-Apr-27
E0005211	Heat Tracing Layout - IFC	15d	01-Apr-27	22-Apr-27
Modeling		145d	30-Jun-26	02-Feb-27
E0001192	Electrical Modeling to 60%	104d	30-Jun-26	27-Nov-26
E0001191	Electrical Modeling to 90%	35d	08-Dec-26	02-Feb-27
Material Take Off		30d	10-Feb-27	24-Mar-27
E0001201	Electrical (Cable/Tray/Conduit/Junction Box) MTO for Estimating	30d	10-Feb-27	24-Mar-27
Electrical Layouts/Isos		50d	10-Feb-27	22-Apr-27
E0005151	Electrical Equipment Layout - IFC	30d	10-Feb-27	24-Mar-27
E0005171	New Substation Layout - IFC	30d	10-Feb-27	24-Mar-27
E0005081	Cable Tray Layout - IFC	15d	01-Apr-27	22-Apr-27
E0005131	Cable, Raceway, Lighting & Grounding Layout - IFC	15d	01-Apr-27	22-Apr-27
Requisition		80d	01-Dec-26	31-Mar-27
20014-E-5500: Electrical Building		80d	01-Dec-26	31-Mar-27
E14731	20014-E-5500 - Electrical Building - Prepare RFP Data Sheets & Specifications	20d	01-Dec-26	05-Jan-27
E14741	20014-E-5500 - Electrical Building - Receive Vendor Info	0d	20-Jan-27	
E14751	20014-E-5500 - Electrical Building - Review Vendor Data	10d	20-Jan-27	02-Feb-27
E14761	20014-E-5500 - Electrical Building - Code 1 Vendor Data	0d		02-Feb-27
E14771	20014-E-5500 - Electrical Building - Receive Vendor Data Books	0d	18-Mar-27	
E14781	20014-E-5500 - Electrical Building - Review Vendor Data Books	10d	18-Mar-27	31-Mar-27
E14791	20014-E-5500 - Electrical Building - Issue Approval for Payment	0d		31-Mar-27
20014-E-5500: 5kV Variable Speed Drive		80d	01-Dec-26	31-Mar-27
E0001421	20014-E-5500 - 5kV Variable Speed Drive - Prepare RFP Data Sheets & Specifica	20d	01-Dec-26	05-Jan-27
E0001431	20014-E-5500 - 5kV Variable Speed Drive - Receive Vendor Info	0d	20-Jan-27	
E0001441	20014-E-5500 - 5kV Variable Speed Drive - Review Vendor Data	10d	20-Jan-27	02-Feb-27
E0001451	20014-E-5500 - 5kV Variable Speed Drive - Code 1 Vendor Data	0d		02-Feb-27
E0001461	20014-E-5500 - 5kV Variable Speed Drive - Receive Vendor Data Books	0d	18-Mar-27	
E0001931	20014-E-5500 - 5kV Variable Speed Drive - Review Vendor Data Books	10d	18-Mar-27	31-Mar-27
E0001941	20014-E-5500 - 5kV Variable Speed Drive - Issue Approval for Payment	0d		31-Mar-27
20014-E-5501: Uninterruptable Power Supply (UPS)		80d	01-Dec-26	31-Mar-27
E0002121	20014-E-5501 - Uninterruptable Power Supply - Prepare RFP Data Sheets & Spe	20d	01-Dec-26	05-Jan-27
E0002131	20014-E-5501 - Uninterruptable Power Supply - Receive Vendor Info	0d	20-Jan-27	
E0002141	20014-E-5501 - Uninterruptable Power Supply - Review Vendor Data	10d	20-Jan-27	02-Feb-27
E0002151	20014-E-5501 - Uninterruptable Power Supply - Code 1 Vendor Data	0d		02-Feb-27
E0002161	20014-E-5501 - Uninterruptable Power Supply - Receive Vendor Data Books	0d	18-Mar-27	
E0002171	20014-E-5501 - Uninterruptable Power Supply - Review Vendor Data Books	10d	18-Mar-27	31-Mar-27
E0002181	20014-E-5501 - Uninterruptable Power Supply - Issue Approval for Payment	0d		31-Mar-27
20014-E-5502: Transformers		80d	01-Dec-26	31-Mar-27
E0002241	20014-E-5502 - Transformers - Prepare RFP Data Sheets & Specifications	20d	01-Dec-26	05-Jan-27
E0002251	20014-E-5502 - Transformers - Receive Vendor Info	0d	20-Jan-27	

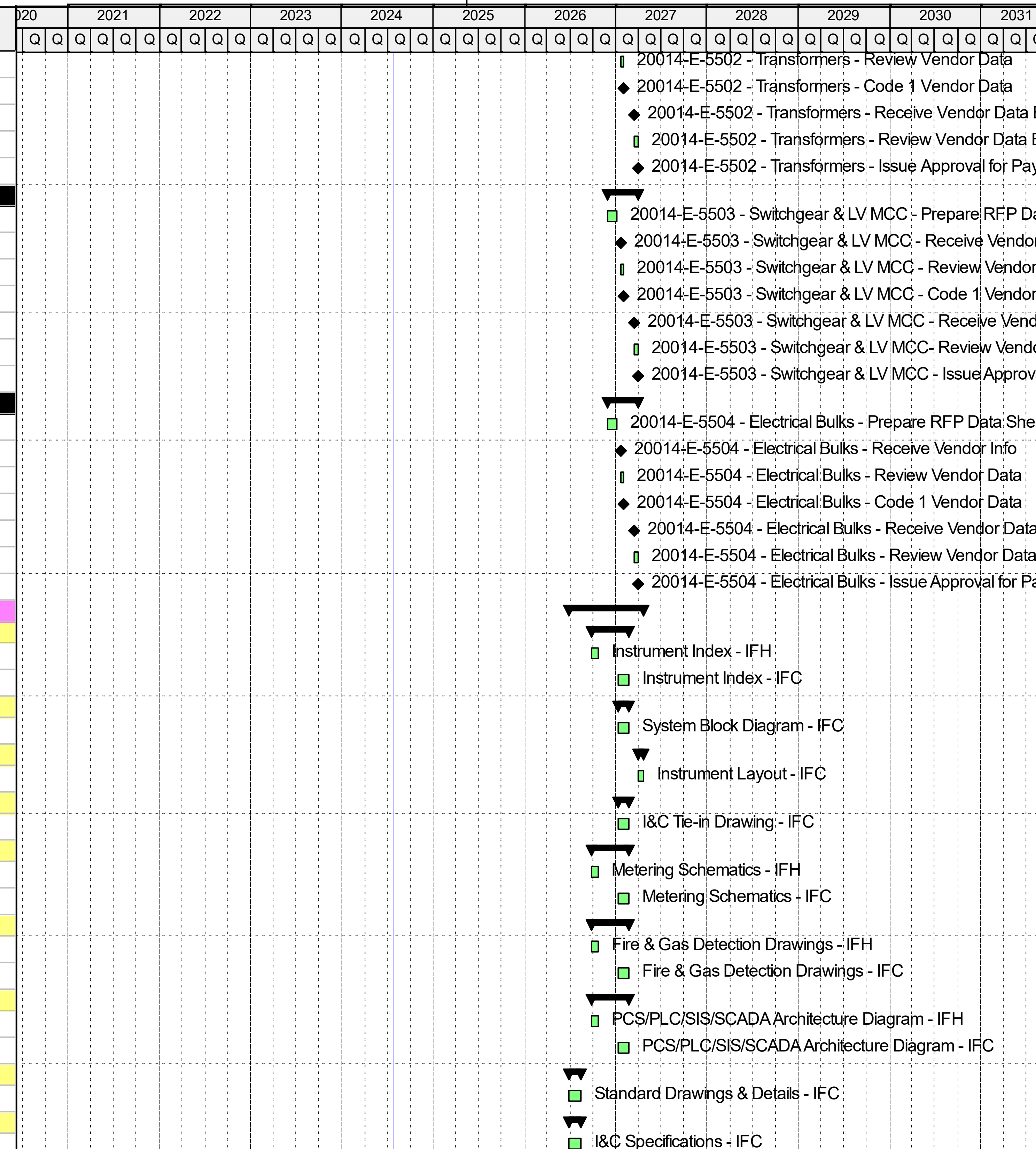


Remaining Level of Effort — Actual Work — Critical Remaining Work
Actual Level of Effort — Remaining Work — Critical Secondary

Data Date:26-Jul-24

Date	Revision	Checked	Approved
19-Aug-24	IFI		

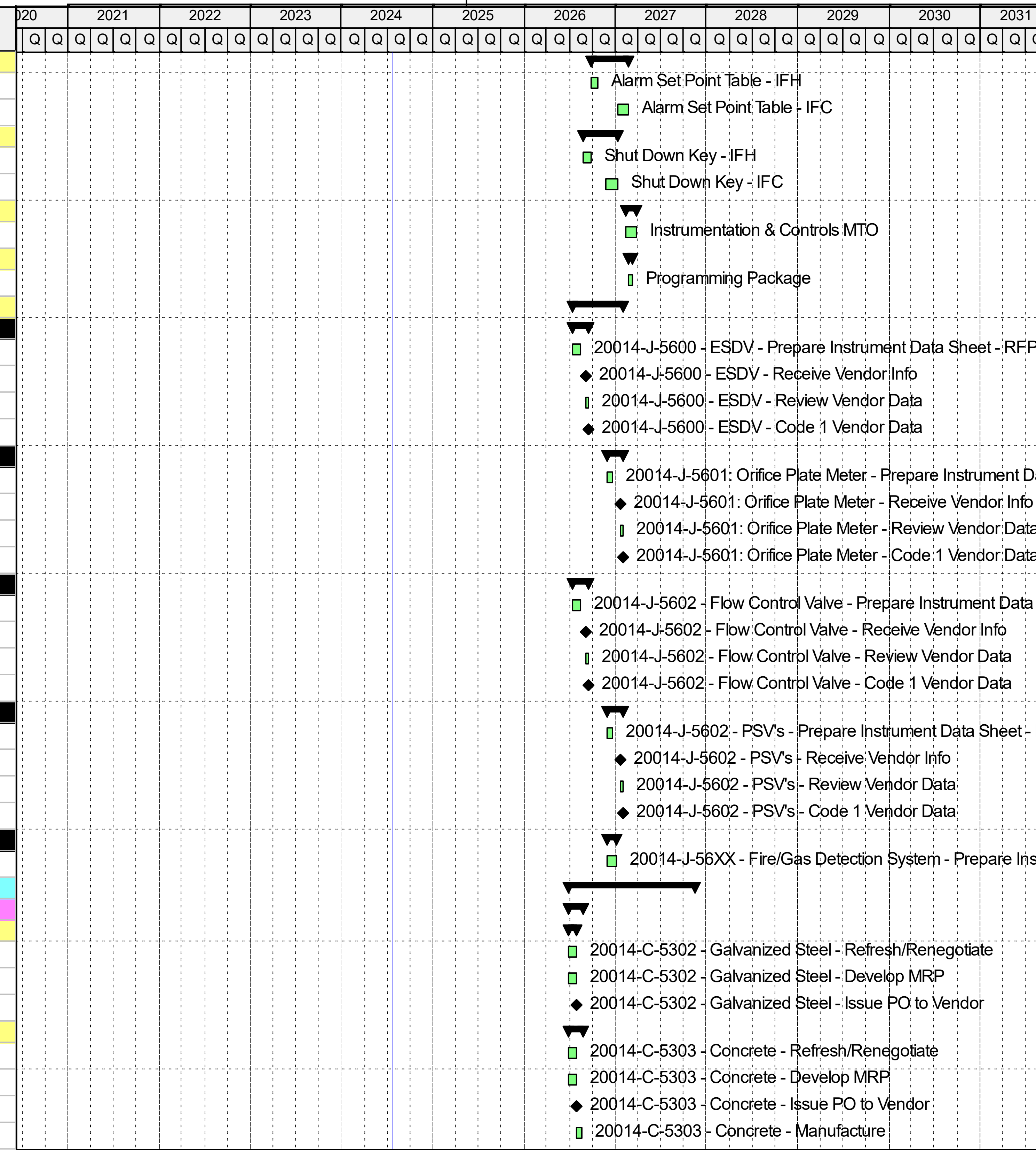
Activity ID	Activity Name	Rem. Duration	Start	Finish
E0002261	20014-E-5502 - Transformers - Review Vendor Data	10d	20-Jan-27	02-Feb-27
E0002271	20014-E-5502 - Transformers - Code 1 Vendor Data	0d		02-Feb-27
E0002281	20014-E-5502 - Transformers - Receive Vendor Data Books	0d	18-Mar-27	
E0002291	20014-E-5502 - Transformers - Review Vendor Data Books	10d	18-Mar-27	31-Mar-27
E0002301	20014-E-5502 - Transformers - Issue Approval for Payment	0d		31-Mar-27
20014-E-5503: Switchgear & LV MCC		**80d**	**01-Dec-26**	**31-Mar-27**
E0002001	20014-E-5503 - Switchgear & LV MCC - Prepare RFP Data Sheets & Specificatior	20d	01-Dec-26	05-Jan-27
E0002011	20014-E-5503 - Switchgear & LV MCC - Receive Vendor Info	0d	20-Jan-27	
E0002021	20014-E-5503 - Switchgear & LV MCC - Review Vendor Data	10d	20-Jan-27	02-Feb-27
E0002031	20014-E-5503 - Switchgear & LV MCC - Code 1 Vendor Data	0d		02-Feb-27
E0002041	20014-E-5503 - Switchgear & LV MCC - Receive Vendor Data Books	0d	18-Mar-27	
E0002051	20014-E-5503 - Switchgear & LV MCC- Review Vendor Data Books	10d	18-Mar-27	31-Mar-27
E0002061	20014-E-5503 - Switchgear & LV MCC - Issue Approval for Payment	0d		31-Mar-27
20014-E-5504: Electrical Bulks		**80d**	**01-Dec-26**	**31-Mar-27**
E0000931	20014-E-5504 - Electrical Bulks - Prepare RFP Data Sheets & Specifications	20d	01-Dec-26	05-Jan-27
E0000941	20014-E-5504 - Electrical Bulks - Receive Vendor Info	0d	20-Jan-27	
E0000951	20014-E-5504 - Electrical Bulks - Review Vendor Data	10d	20-Jan-27	02-Feb-27
E0000991	20014-E-5504 - Electrical Bulks - Code 1 Vendor Data	0d		02-Feb-27
E0001001	20014-E-5504 - Electrical Bulks - Receive Vendor Data Books	0d	18-Mar-27	
E0001011	20014-E-5504 - Electrical Bulks - Review Vendor Data Books	10d	18-Mar-27	31-Mar-27
E0001021	20014-E-5504 - Electrical Bulks - Issue Approval for Payment	0d		31-Mar-27
Instrumentation Engineering & Design		**200d**	**30-Jun-26**	**22-Apr-27**
Instrument Index		**100d**	**25-Sep-26**	**24-Feb-27**
E0001551	Instrument Index - IFH	20d	25-Sep-26	23-Oct-26
E0004541	Instrument Index - IFC	30d	13-Jan-27	24-Feb-27
System Block Diagram		**30d**	**13-Jan-27**	**24-Feb-27**
E0004891	System Block Diagram - IFC	30d	13-Jan-27	24-Feb-27
Instrument Layout		**15d**	**01-Apr-27**	**22-Apr-27**
E0004911	Instrument Layout - IFC	15d	01-Apr-27	22-Apr-27
Tie-in		**30d**	**13-Jan-27**	**24-Feb-27**
E0004931	I&C Tie-in Drawing - IFC	30d	13-Jan-27	24-Feb-27
Metering Schematics		**100d**	**25-Sep-26**	**24-Feb-27**
E0004941	Metering Schematics - IFH	20d	25-Sep-26	23-Oct-26
E0004951	Metering Schematics - IFC	30d	13-Jan-27	24-Feb-27
Fire & Gas Detection Drawings		**100d**	**25-Sep-26**	**24-Feb-27**
E0004981	Fire & Gas Detection Drawings - IFH	20d	25-Sep-26	23-Oct-26
E0004991	Fire & Gas Detection Drawings - IFC	30d	13-Jan-27	24-Feb-27
Architectural Diagram		**100d**	**25-Sep-26**	**24-Feb-27**
E0005001	PCS/PLC/SIS/SCADA Architecture Diagram - IFH	20d	25-Sep-26	23-Oct-26
E0005011	PCS/PLC/SIS/SCADA Architecture Diagram - IFC	30d	13-Jan-27	24-Feb-27
Standard Drawings & Details		**30d**	**30-Jun-26**	**12-Aug-26**
E0005031	Standard Drawings & Details - IFC	30d	30-Jun-26	12-Aug-26
Specifications		**30d**	**30-Jun-26**	**12-Aug-26**
E0005051	I&C Specifications - IFC	30d	30-Jun-26	12-Aug-26



Remaining Level of Effort — Actual Work — Critical Remaining Work
Actual Level of Effort — Remaining Work — Critical Secondary

Date	Revision	Checked	Approved
19-Aug-24	IFI		

Activity ID	Activity Name	Rem. Duration	Start	Finish
Alarm/Set Point Table		**100d**	**25-Sep-26**	**24-Feb-27**
E0001571	Alarm Set Point Table - IFH	20d	25-Sep-26	23-Oct-26
E0001901	Alarm Set Point Table - IFC	30d	13-Jan-27	24-Feb-27
Shutdown Key		**90d**	**27-Aug-26**	**12-Jan-27**
E0001531	Shut Down Key - IFH	20d	27-Aug-26	24-Sep-26
E0001881	Shut Down Key - IFC	30d	24-Nov-26	12-Jan-27
Material Take Off		**30d**	**10-Feb-27**	**24-Mar-27**
E0001601	Instrumentation & Controls MTO	30d	10-Feb-27	24-Mar-27
Programming		**10d**	**25-Feb-27**	**10-Mar-27**
E0001521	Programming Package	10d	25-Feb-27	10-Mar-27
Requisition		**135d**	**15-Jul-26**	**02-Feb-27**
20014-J-5600 - ESDV		**45d**	**15-Jul-26**	**17-Sep-26**
E0001271	20014-J-5600 - ESDV - Prepare Instrument Data Sheet - RFP	20d	15-Jul-26	12-Aug-26
E0004341	20014-J-5600 - ESDV - Receive Vendor Info	0d	03-Sep-26	
E0004531	20014-J-5600 - ESDV - Review Vendor Data	10d	03-Sep-26	17-Sep-26
E0004711	20014-J-5600 - ESDV - Code 1 Vendor Data	0d		17-Sep-26
20014-J-5601: Orifice Plate Meter		**40d**	**01-Dec-26**	**02-Feb-27**
E0003381	20014-J-5601: Orifice Plate Meter - Prepare Instrument Data Sheet - RFP	15d	01-Dec-26	21-Dec-26
E0004131	20014-J-5601: Orifice Plate Meter - Receive Vendor Info	0d	20-Jan-27	
E0006391	20014-J-5601: Orifice Plate Meter - Review Vendor Data	10d	20-Jan-27	02-Feb-27
E0006401	20014-J-5601: Orifice Plate Meter - Code 1 Vendor Data	0d		02-Feb-27
20014-J-5602 - Flow Control Valve		**45d**	**15-Jul-26**	**17-Sep-26**
E0003201	20014-J-5602 - Flow Control Valve - Prepare Instrument Data Sheet - RFP	20d	15-Jul-26	12-Aug-26
E0003911	20014-J-5602 - Flow Control Valve - Receive Vendor Info	0d	03-Sep-26	
E0005581	20014-J-5602 - Flow Control Valve - Review Vendor Data	10d	03-Sep-26	17-Sep-26
E0005711	20014-J-5602 - Flow Control Valve - Code 1 Vendor Data	0d		17-Sep-26
20014-J-5602 - PSV's		**40d**	**01-Dec-26**	**02-Feb-27**
E0003261	20014-J-5602 - PSV's - Prepare Instrument Data Sheet - RFP	15d	01-Dec-26	21-Dec-26
E0004241	20014-J-5602 - PSV's - Receive Vendor Info	0d	20-Jan-27	
E0006331	20014-J-5602 - PSV's - Review Vendor Data	10d	20-Jan-27	02-Feb-27
E0006341	20014-J-5602 - PSV's - Code 1 Vendor Data	0d		02-Feb-27
20014-J-56XX: Fire/Gas Detedtion System		**20d**	**01-Dec-26**	**05-Jan-27**
E0003501	20014-J-56XX - Fire/Gas Detection System - Prepare Instrument Data Sheet - RF	20d	01-Dec-26	05-Jan-27
Procurement		**340d**	**30-Jun-26**	**15-Nov-27**
Civil/Structural/Architectural		**40d**	**30-Jun-26**	**27-Aug-26**
20014-C-5302: Galvanized Steel		**20d**	**30-Jun-26**	**28-Jul-26**
E0002911	20014-C-5302 - Galvanized Steel - Refresh/Renegotiate	20d	30-Jun-26	28-Jul-26
E0002921	20014-C-5302 - Galvanized Steel - Develop MRP	20d	30-Jun-26	28-Jul-26
E0002931	20014-C-5302 - Galvanized Steel - Issue PO to Vendor	0d		28-Jul-26
20014-C-5303: Concrete		**40d**	**30-Jun-26**	**27-Aug-26**
E0002971	20014-C-5303 - Concrete - Refresh/Renegotiate	20d	30-Jun-26	28-Jul-26
E0002981	20014-C-5303 - Concrete - Develop MRP	20d	30-Jun-26	28-Jul-26
E0002991	20014-C-5303 - Concrete - Issue PO to Vendor	0d		28-Jul-26
E0006301	20014-C-5303 - Concrete - Manufacture	15d	29-Jul-26	19-Aug-26



Remaining Level of Effort | Actual Work | Critical Remaining Work
Actual Level of Effort | Remaining Work | Critical Secondary

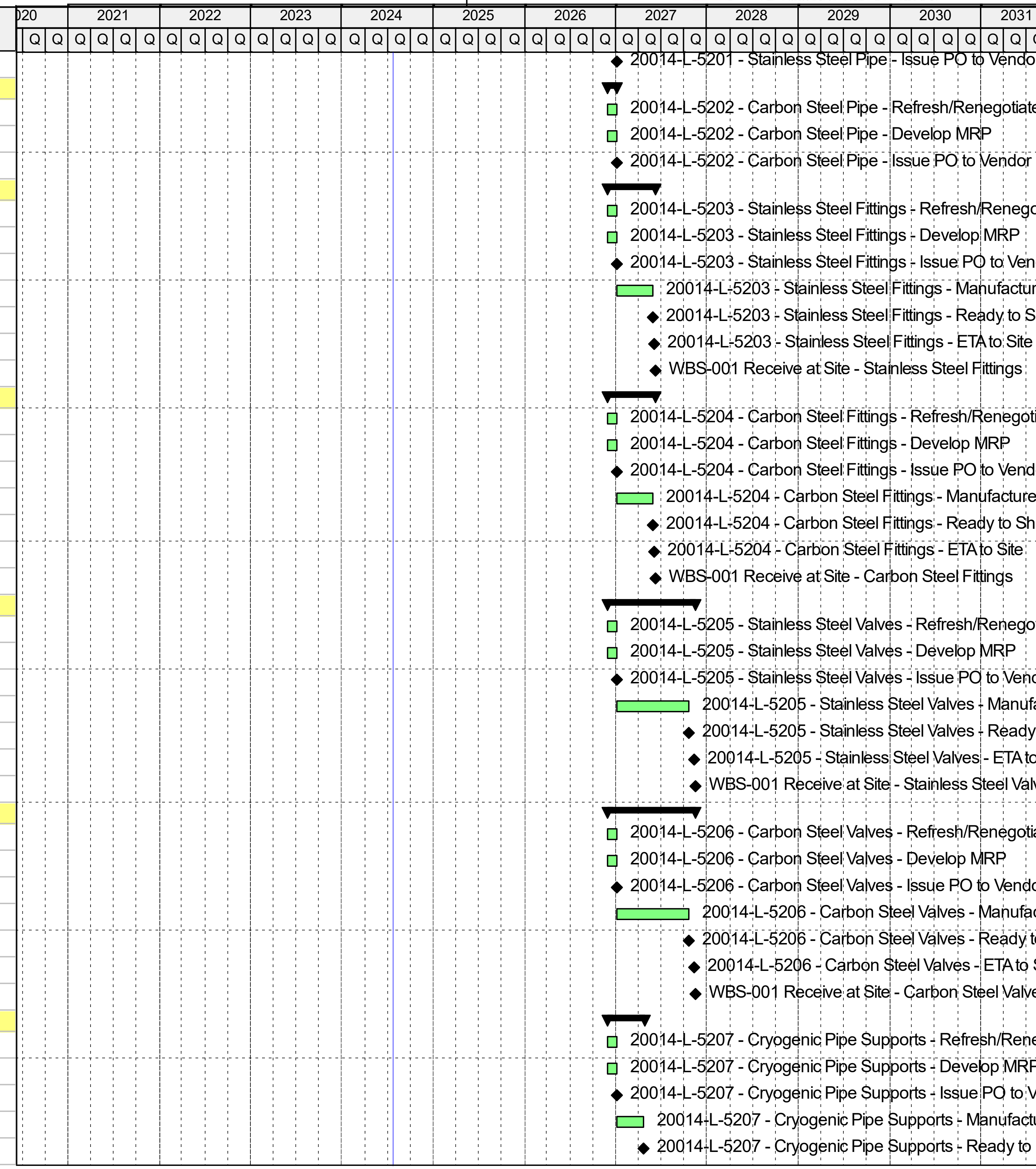
Date	Revision	Checked	Approved
19-Aug-24	IFI		

Activity ID	Activity Name	Rem. Duration	Start	Finish
E0003001	20014-C-5303 - Concrete - Ready to Ship	0d		19-Aug-26
E0003011	20014-C-5303 - Concrete - ETA to Site	0d		26-Aug-26
E0008991	WBS-001 Receive at Site Concrete & Foundation Materials	0d	27-Aug-26	
20014-C-53XX: Fill Materials		40d	30-Jun-26	27-Aug-26
E0003031	20014-C-53XX - Fill Materials - Refresh/Renegotiate	20d	30-Jun-26	28-Jul-26
E0003041	20014-C-53XX - Fill Materials - Develop MRP	20d	30-Jun-26	28-Jul-26
E0003051	20014-C-53XX - Fill Materials - Issue PO to Vendor	0d		28-Jul-26
E0006311	20014-C-53XX - Fill Materials - Manufacture	15d	29-Jul-26	19-Aug-26
E0003061	20014-C-53XX - Fill Materials - Ready to Ship	0d		19-Aug-26
E0003071	20014-C-53XX - Fill Materials - ETA to Site	0d		26-Aug-26
E0008981	WBS-001 Receive at Site Fill Materials	0d	27-Aug-26	
Mechanical		245d	30-Jun-26	28-Jun-27
20014-M-5103: Instrument Air Package		235d	30-Jun-26	14-Jun-27
E0000501	20014-M-5103 - Instrument Air Package - Refresh/Renegotiation	20d	30-Jun-26	28-Jul-26
E0000551	20014-M-5103 - Instrument Air Package - Develop MRP	20d	30-Jun-26	28-Jul-26
E0000561	20014-M-5103 - Instrument Air Package - Issue PO to Vendor	0d		28-Jul-26
E0006041	20014-M-5103 - Instrument Air Package - Manufacture	200d	29-Jul-26	20-May-27
E0005821	20014-M-5103 - Instrument Air Package - Testing & Inspection	2d	21-May-27	25-May-27
E0000571	20014-M-5103 - Instrument Air Package - Ready to Ship	0d		28-May-27
E0000631	20014-M-5103 - Instrument Air Package - ETA to Site	0d		11-Jun-27
E15091	WBS-001 Receive at Site - Instrument Air Package	0d	14-Jun-27	
20014-M-5104: Nitrogen Generation (PSA) Package		245d	30-Jun-26	28-Jun-27
E0000971	20014-M-5104 - Nitrogen Generation (PSA) Package - Refresh/Renegotiation	20d	30-Jun-26	28-Jul-26
E0000981	20014-M-5104 - Nitrogen Generation (PSA) Package - Develop MRP	20d	30-Jun-26	28-Jul-26
E0001041	20014-M-5104 - Nitrogen Generation (PSA) Package - Issue PO to Vendor	0d		28-Jul-26
E0006051	20014-M-5104 - Nitrogen Generation (PSA) Package - Manufacture	200d	29-Jul-26	20-May-27
E0005831	20014-M-5104 - Nitrogen Generation (PSA) Package - Testing & Inspection	2d	21-May-27	25-May-27
E0001051	20014-M-5104 - Nitrogen Generation (PSA) Package - Ready to Ship	0d		28-May-27
E0001061	20014-M-5104 - Nitrogen Generation (PSA) Package - ETA to Site	0d		25-Jun-27
E15071	WBS-001 Receive at Site - Nitrogen Generation (PSA) Package	0d	28-Jun-27	
20014-M-51XX: LNG Drain Vessel (With Emerson Heater)		245d	30-Jun-26	28-Jun-27
E14871	20014-M-51XX - LNG Drain Vessel (With Emerson Heater) - Refresh/Renegotiatic	20d	30-Jun-26	28-Jul-26
E14881	20014-M-51XX - LNG Drain Vessel (With Emerson Heater) - Develop MRP	20d	30-Jun-26	28-Jul-26
E14891	20014-M-51XX - LNG Drain Vessel (With Emerson Heater) - Issue PO to Vendor	0d		28-Jul-26
E14931	20014-M-51XX - LNG Drain Vessel (With Emerson Heater) - Manufacture	200d	29-Jul-26	20-May-27
E14921	20014-M-51XX - LNG Drain Vessel (With Emerson Heater) - Testing & Inspection	2d	21-May-27	25-May-27
E14901	20014-M-51XX - LNG Drain Vessel (With Emerson Heater) - Ready to Ship	0d		28-May-27
E14911	20014-M-51XX - LNG Drain Vessel (With Emerson Heater) - ETA to Site	0d		25-Jun-27
E15121	WBS-001 Receive at Site - LNG Drain Vessel (With Emerson Heater)	0d	28-Jun-27	
Piping		235d	01-Dec-26	15-Nov-27
20014-L-5201: Stainless Steel Pipe		20d	01-Dec-26	05-Jan-27
E0002471	20014-L-5201 - Stainless Steel Pipe - Refresh/Renegotiate	20d	01-Dec-26	05-Jan-27
E0002481	20014-L-5201 - Stainless Steel Pipe - Develop MRP	20d	01-Dec-26	05-Jan-27

Remaining Level of Effort | Actual Work | Critical Remaining Work
Actual Level of Effort | Remaining Work | Critical Secondary

Date	Revision	Checked	Approved
19-Aug-24	IFI		

Activity ID	Activity Name	Rem. Duration	Start	Finish
E0002491	20014-L-5201 - Stainless Steel Pipe - Issue PO to Vendor	0d		05-Jan-27
20014-L-5202: Carbon Steel Pipe		**20d**	**01-Dec-26**	**05-Jan-27**
E0002391	20014-L-5202 - Carbon Steel Pipe - Refresh/Renegotiate	20d	01-Dec-26	05-Jan-27
E0002401	20014-L-5202 - Carbon Steel Pipe - Develop MRP	20d	01-Dec-26	05-Jan-27
E0002411	20014-L-5202 - Carbon Steel Pipe - Issue PO to Vendor	0d		05-Jan-27
20014-L-5203: Stainless Steel Fittings		**125d**	**01-Dec-26**	**07-Jun-27**
E0002711	20014-L-5203 - Stainless Steel Fittings - Refresh/Renegotiate	20d	01-Dec-26	05-Jan-27
E0002721	20014-L-5203 - Stainless Steel Fittings - Develop MRP	20d	01-Dec-26	05-Jan-27
E0002731	20014-L-5203 - Stainless Steel Fittings - Issue PO to Vendor	0d		05-Jan-27
E0006111	20014-L-5203 - Stainless Steel Fittings - Manufacture	100d	06-Jan-27	28-May-27
E0002741	20014-L-5203 - Stainless Steel Fittings - Ready to Ship	0d		28-May-27
E0002751	20014-L-5203 - Stainless Steel Fittings - ETA to Site	0d		04-Jun-27
E14951	WBS-001 Receive at Site - Stainless Steel Fittings	0d	07-Jun-27	
20014-L-5204: Carbon Steel Fittings		**125d**	**01-Dec-26**	**07-Jun-27**
E14511	20014-L-5204 - Carbon Steel Fittings - Refresh/Renegotiate	20d	01-Dec-26	05-Jan-27
E14521	20014-L-5204 - Carbon Steel Fittings - Develop MRP	20d	01-Dec-26	05-Jan-27
E14531	20014-L-5204 - Carbon Steel Fittings - Issue PO to Vendor	0d		05-Jan-27
E14561	20014-L-5204 - Carbon Steel Fittings - Manufacture	100d	06-Jan-27	28-May-27
E14541	20014-L-5204 - Carbon Steel Fittings - Ready to Ship	0d		28-May-27
E14551	20014-L-5204 - Carbon Steel Fittings - ETA to Site	0d		04-Jun-27
E14961	WBS-001 Receive at Site - Carbon Steel Fittings	0d	07-Jun-27	
20014-L-5205: Stainless Steel Valves		**235d**	**01-Dec-26**	**15-Nov-27**
E0000621	20014-L-5205 - Stainless Steel Valves - Refresh/Renegotiate	20d	01-Dec-26	05-Jan-27
E0000681	20014-L-5205 - Stainless Steel Valves - Develop MRP	20d	01-Dec-26	05-Jan-27
E0000691	20014-L-5205 - Stainless Steel Valves - Issue PO to Vendor	0d		05-Jan-27
E0006091	20014-L-5205 - Stainless Steel Valves - Manufacture	200d	06-Jan-27	21-Oct-27
E0000701	20014-L-5205 - Stainless Steel Valves - Ready to Ship	0d		21-Oct-27
E0000711	20014-L-5205 - Stainless Steel Valves - ETA to Site	0d		12-Nov-27
E0009021	WBS-001 Receive at Site - Stainless Steel Valves	0d	15-Nov-27	
20014-L-5206: Carbon Steel Valves		**235d**	**01-Dec-26**	**15-Nov-27**
E14571	20014-L-5206 - Carbon Steel Valves - Refresh/Renegotiate	20d	01-Dec-26	05-Jan-27
E14581	20014-L-5206 - Carbon Steel Valves - Develop MRP	20d	01-Dec-26	05-Jan-27
E14591	20014-L-5206 - Carbon Steel Valves - Issue PO to Vendor	0d		05-Jan-27
E14621	20014-L-5206 - Carbon Steel Valves - Manufacture	200d	06-Jan-27	21-Oct-27
E14601	20014-L-5206 - Carbon Steel Valves - Ready to Ship	0d		21-Oct-27
E14611	20014-L-5206 - Carbon Steel Valves - ETA to Site	0d		12-Nov-27
E14971	WBS-001 Receive at Site - Carbon Steel Valves	0d	15-Nov-27	
20014-L-5207: Cryogenic Pipe Supports		**100d**	**01-Dec-26**	**30-Apr-27**
E0002631	20014-L-5207 - Cryogenic Pipe Supports - Refresh/Renegotiate	20d	01-Dec-26	05-Jan-27
E0002641	20014-L-5207 - Cryogenic Pipe Supports - Develop MRP	20d	01-Dec-26	05-Jan-27
E0002651	20014-L-5207 - Cryogenic Pipe Supports - Issue PO to Vendor	0d		05-Jan-27
E0006101	20014-L-5207 - Cryogenic Pipe Supports - Manufacture	75d	06-Jan-27	22-Apr-27
E0002661	20014-L-5207 - Cryogenic Pipe Supports - Ready to Ship	0d		22-Apr-27



Remaining Level of Effort — Actual Work — Critical Remaining Work
Actual Level of Effort — Remaining Work — Critical Secondary

Date	Revision	Checked	Approved
19-Aug-24	IFI		

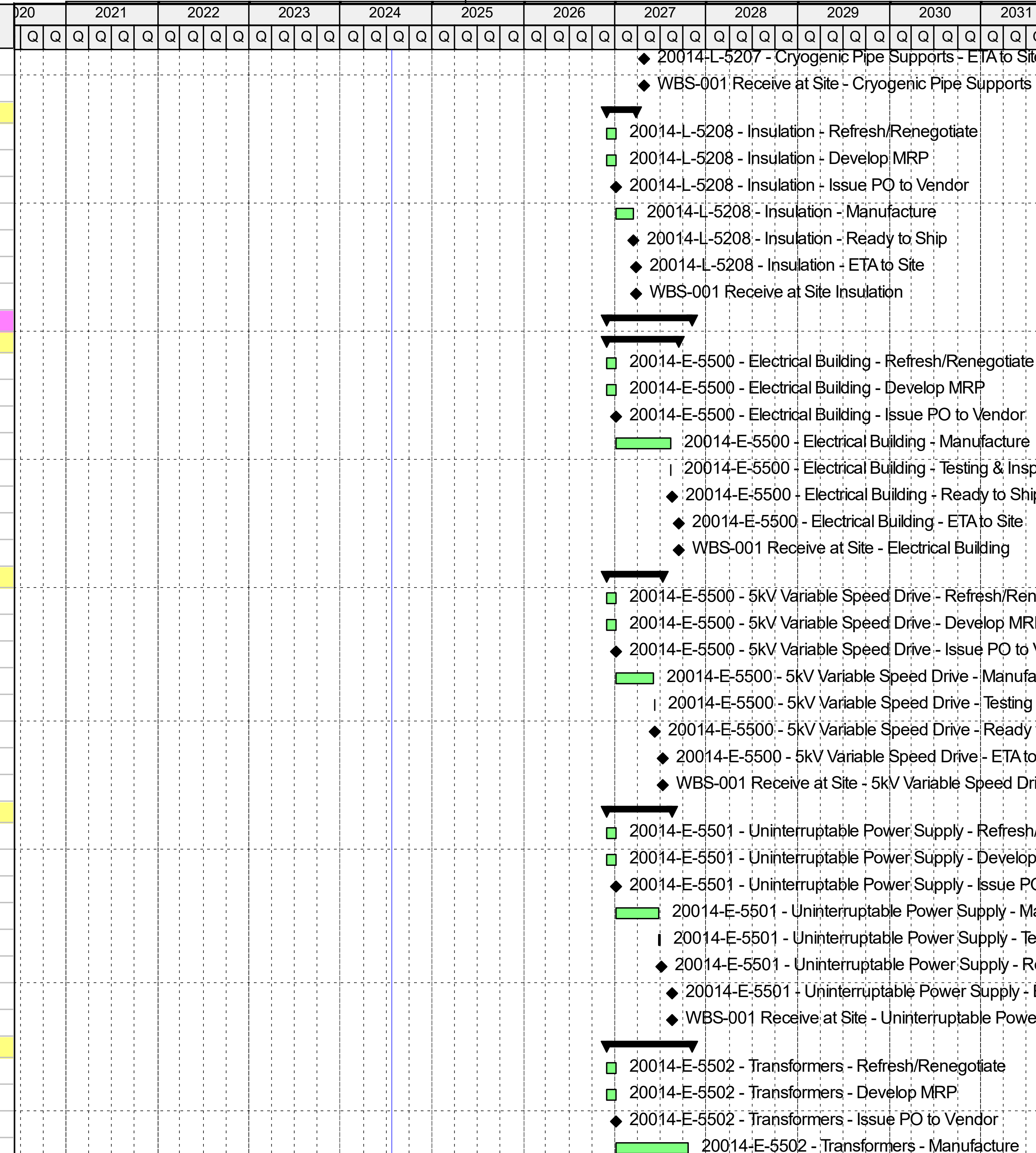
Tilbury Island LNG Facility Expansion (3 BCF)

TLSE Sub-Projects Integrated Schedule-Detailed

FORTIS BC

SOLARIS MANAGEMENT CONSULTANTS INC.

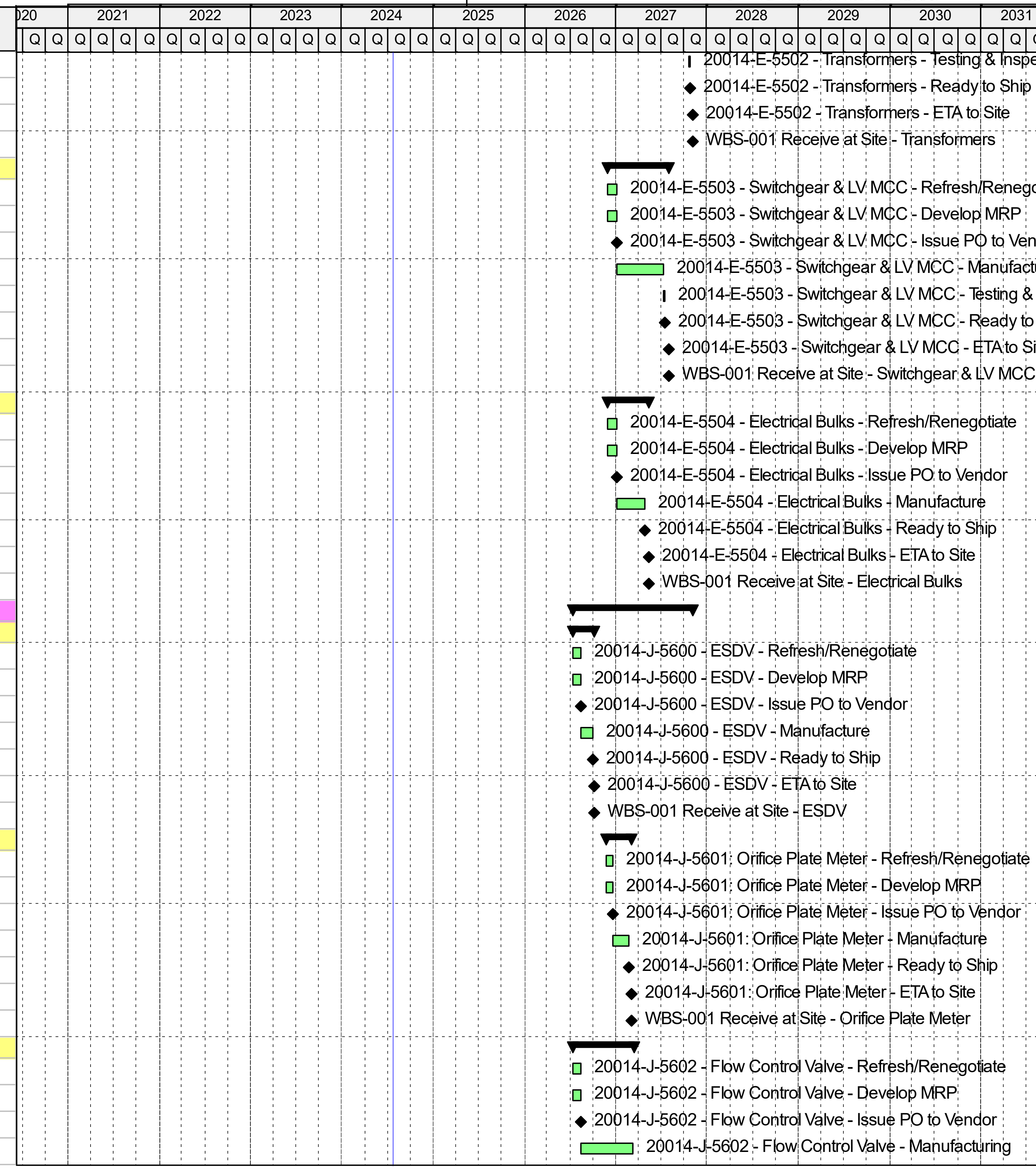
Activity ID	Activity Name	Rem. Duration	Start	Finish
E0002671	20014-L-5207 - Cryogenic Pipe Supports - ETA to Site	0d		29-Apr-27
E14941	WBS-001 Receive at Site - Cryogenic Pipe Supports	0d	30-Apr-27	
20014-L-5208: Insulation		**75d**	**01-Dec-26**	**25-Mar-27**
E0002791	20014-L-5208 - Insulation - Refresh/Renegotiate	20d	01-Dec-26	05-Jan-27
E0002801	20014-L-5208 - Insulation - Develop MRP	20d	01-Dec-26	05-Jan-27
E0002811	20014-L-5208 - Insulation - Issue PO to Vendor	0d		05-Jan-27
E0006121	20014-L-5208 - Insulation - Manufacture	50d	06-Jan-27	17-Mar-27
E0002821	20014-L-5208 - Insulation - Ready to Ship	0d		17-Mar-27
E0002831	20014-L-5208 - Insulation - ETA to Site	0d		24-Mar-27
E0009361	WBS-001 Receive at Site Insulation	0d	25-Mar-27	
Electrical		**230d**	**01-Dec-26**	**05-Nov-27**
20014-E-5500 - Electrical Building		**195d**	**01-Dec-26**	**16-Sep-27**
E14661	20014-E-5500 - Electrical Building - Refresh/Renegotiate	20d	01-Dec-26	05-Jan-27
E14671	20014-E-5500 - Electrical Building - Develop MRP	20d	01-Dec-26	05-Jan-27
E14681	20014-E-5500 - Electrical Building - Issue PO to Vendor	0d		05-Jan-27
E14721	20014-E-5500 - Electrical Building - Manufacture	150d	06-Jan-27	10-Aug-27
E14711	20014-E-5500 - Electrical Building - Testing & Inspection	2d	11-Aug-27	12-Aug-27
E14691	20014-E-5500 - Electrical Building - Ready to Ship	0d		17-Aug-27
E14701	20014-E-5500 - Electrical Building - ETA to Site	0d		15-Sep-27
E15021	WBS-001 Receive at Site - Electrical Building	0d	16-Sep-27	
20014-E-5500 - 5kV Variable Speed Drive		**150d**	**01-Dec-26**	**13-Jul-27**
E0001951	20014-E-5500 - 5kV Variable Speed Drive - Refresh/Renegotiate	20d	01-Dec-26	05-Jan-27
E0001961	20014-E-5500 - 5kV Variable Speed Drive - Develop MRP	20d	01-Dec-26	05-Jan-27
E0001971	20014-E-5500 - 5kV Variable Speed Drive - Issue PO to Vendor	0d		05-Jan-27
E0006131	20014-E-5500 - 5kV Variable Speed Drive - Manufacture	105d	06-Jan-27	04-Jun-27
E0005841	20014-E-5500 - 5kV Variable Speed Drive - Testing & Inspection	2d	07-Jun-27	08-Jun-27
E0001981	20014-E-5500 - 5kV Variable Speed Drive - Ready to Ship	0d		11-Jun-27
E0001991	20014-E-5500 - 5kV Variable Speed Drive - ETA to Site	0d		12-Jul-27
E14981	WBS-001 Receive at Site - 5kV Variable Speed Drive	0d	13-Jul-27	
20014-E-5501 - Uninterruptable Power Supply		**175d**	**01-Dec-26**	**18-Aug-27**
E0002191	20014-E-5501 - Uninterruptable Power Supply - Refresh/Renegotiate	20d	01-Dec-26	05-Jan-27
E0002201	20014-E-5501 - Uninterruptable Power Supply - Develop MRP	20d	01-Dec-26	05-Jan-27
E0002211	20014-E-5501 - Uninterruptable Power Supply - Issue PO to Vendor	0d		05-Jan-27
E0006141	20014-E-5501 - Uninterruptable Power Supply - Manufacture	120d	06-Jan-27	25-Jun-27
E0005851	20014-E-5501 - Uninterruptable Power Supply - Testing & Inspection	2d	28-Jun-27	29-Jun-27
E0002221	20014-E-5501 - Uninterruptable Power Supply - Ready to Ship	0d		05-Jul-27
E0002231	20014-E-5501 - Uninterruptable Power Supply - ETA to Site	0d		17-Aug-27
E15001	WBS-001 Receive at Site - Uninterruptable Power Supply	0d	18-Aug-27	
20014-E-5502 - Transformers		**230d**	**01-Dec-26**	**05-Nov-27**
E0002311	20014-E-5502 - Transformers - Refresh/Renegotiate	20d	01-Dec-26	05-Jan-27
E0002321	20014-E-5502 - Transformers - Develop MRP	20d	01-Dec-26	05-Jan-27
E0002331	20014-E-5502 - Transformers - Issue PO to Vendor	0d		05-Jan-27
E0006151	20014-E-5502 - Transformers - Manufacture	200d	06-Jan-27	21-Oct-27



Remaining Level of Effort | Actual Work | Critical Remaining Work
Actual Level of Effort | Remaining Work | Critical Secondary

Date	Revision	Checked	Approved
19-Aug-24	IFI		

Activity ID	Activity Name	Rem. Duration	Start	Finish
E0005861	20014-E-5502 - Transformers - Testing & Inspection	2d	22-Oct-27	25-Oct-27
E0002341	20014-E-5502 - Transformers - Ready to Ship	0d		28-Oct-27
E0002351	20014-E-5502 - Transformers - ETA to Site	0d		04-Nov-27
E15011	WBS-001 Receive at Site - Transformers	0d	05-Nov-27	
20014-E-5503 - Switchgear & LV MCC		**165d**	**01-Dec-26**	**04-Aug-27**
E0002071	20014-E-5503 - Switchgear & LV MCC - Refresh/Renegotiate	20d	01-Dec-26	05-Jan-27
E0002081	20014-E-5503 - Switchgear & LV MCC - Develop MRP	20d	01-Dec-26	05-Jan-27
E0002091	20014-E-5503 - Switchgear & LV MCC - Issue PO to Vendor	0d		05-Jan-27
E0006161	20014-E-5503 - Switchgear & LV MCC - Manufacture	130d	06-Jan-27	12-Jul-27
E0005871	20014-E-5503 - Switchgear & LV MCC - Testing & Inspection	2d	13-Jul-27	14-Jul-27
E0002101	20014-E-5503 - Switchgear & LV MCC - Ready to Ship	0d		19-Jul-27
E0002111	20014-E-5503 - Switchgear & LV MCC - ETA to Site	0d		03-Aug-27
E14991	WBS-001 Receive at Site - Switchgear & LV MCC	0d	04-Aug-27	
20014-E-5504 - Electrical Bulks		**110d**	**01-Dec-26**	**14-May-27**
E0001031	20014-E-5504 - Electrical Bulks - Refresh/Renegotiate	20d	01-Dec-26	05-Jan-27
E0001091	20014-E-5504 - Electrical Bulks - Develop MRP	20d	01-Dec-26	05-Jan-27
E0001101	20014-E-5504 - Electrical Bulks - Issue PO to Vendor	0d		05-Jan-27
E0006171	20014-E-5504 - Electrical Bulks - Manufacture	80d	06-Jan-27	29-Apr-27
E0001111	20014-E-5504 - Electrical Bulks - Ready to Ship	0d		29-Apr-27
E0001121	20014-E-5504 - Electrical Bulks - ETA to Site	0d		13-May-27
E0009751	WBS-001 Receive at Site - Electrical Bulks	0d	14-May-27	
Instrumentation		**325d**	**15-Jul-26**	**05-Nov-27**
20014-J-5600: ESDV		**60d**	**15-Jul-26**	**09-Oct-26**
E0001281	20014-J-5600 - ESDV - Refresh/Renegotiate	20d	15-Jul-26	12-Aug-26
E0001341	20014-J-5600 - ESDV - Develop MRP	20d	15-Jul-26	12-Aug-26
E0001351	20014-J-5600 - ESDV - Issue PO to Vendor	0d		12-Aug-26
E0006191	20014-J-5600 - ESDV - Manufacture	35d	13-Aug-26	01-Oct-26
E0001361	20014-J-5600 - ESDV - Ready to Ship	0d		01-Oct-26
E0001371	20014-J-5600 - ESDV - ETA to Site	0d		08-Oct-26
E0009321	WBS-001 Receive at Site - ESDV	0d	09-Oct-26	
20014-J-5601 Orifice Plate Meter		**65d**	**24-Nov-26**	**04-Mar-27**
E0003391	20014-J-5601: Orifice Plate Meter - Refresh/Renegotiate	20d	24-Nov-26	21-Dec-26
E0003401	20014-J-5601: Orifice Plate Meter - Develop MRP	20d	24-Nov-26	21-Dec-26
E0003411	20014-J-5601: Orifice Plate Meter - Issue PO to Vendor	0d		21-Dec-26
E0006241	20014-J-5601: Orifice Plate Meter - Manufacture	40d	22-Dec-26	24-Feb-27
E0003421	20014-J-5601: Orifice Plate Meter - Ready to Ship	0d		24-Feb-27
E0003431	20014-J-5601: Orifice Plate Meter - ETA to Site	0d		03-Mar-27
E15051	WBS-001 Receive at Site - Orifice Plate Meter	0d	04-Mar-27	
20014-J-5602: Flow Control Valve		**165d**	**15-Jul-26**	**18-Mar-27**
E0003211	20014-J-5602 - Flow Control Valve - Refresh/Renegotiate	20d	15-Jul-26	12-Aug-26
E0003221	20014-J-5602 - Flow Control Valve - Develop MRP	20d	15-Jul-26	12-Aug-26
E0003231	20014-J-5602 - Flow Control Valve - Issue PO to Vendor	0d		12-Aug-26
E0006201	20014-J-5602 - Flow Control Valve - Manufacturing	140d	13-Aug-26	10-Mar-27

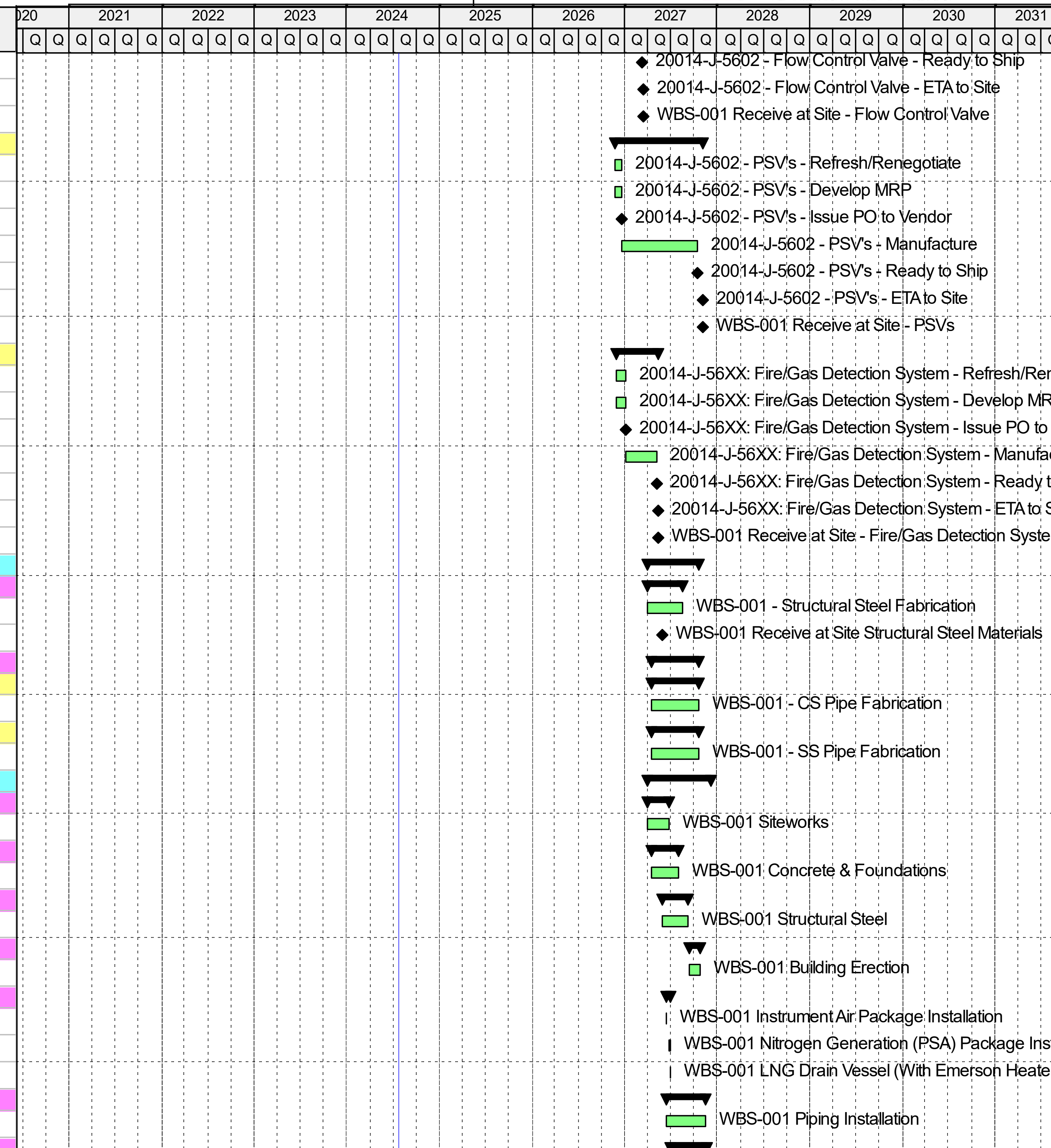


Remaining Level of Effort — Actual Work — Critical Remaining Work
Actual Level of Effort — Remaining Work — Critical Secondary

Date	Revision	Checked	Approved
19-Aug-24	IFI		

Tilbury Island LNG Facility Expansion (3 BCF)
TLSE Sub-Projects Integrated Schedule-Detailed

Activity ID	Activity Name	Rem. Duration	Start	Finish
E0003241	20014-J-5602 - Flow Control Valve - Ready to Ship	0d		10-Mar-27
E0003251	20014-J-5602 - Flow Control Valve - ETA to Site	0d		17-Mar-27
E15031	WBS-001 Receive at Site - Flow Control Valve	0d	18-Mar-27	
20014-J-5602: PSV's		235d	24-Nov-26	05-Nov-27
E0003271	20014-J-5602 - PSV's - Refresh/Renegotiate	20d	24-Nov-26	21-Dec-26
E0003281	20014-J-5602 - PSV's - Develop MRP	20d	24-Nov-26	21-Dec-26
E0003291	20014-J-5602 - PSV's - Issue PO to Vendor	0d		21-Dec-26
E0006211	20014-J-5602 - PSV's - Manufacture	200d	22-Dec-26	14-Oct-27
E0003301	20014-J-5602 - PSV's - Ready to Ship	0d		14-Oct-27
E0003311	20014-J-5602 - PSV's - ETA to Site	0d		04-Nov-27
E15041	WBS-001 Receive at Site - PSVs	0d	05-Nov-27	
20014-J-56XX: Fire/Gas Detection System		110d	01-Dec-26	14-May-27
E0003511	20014-J-56XX: Fire/Gas Detection System - Refresh/Renegotiate	20d	01-Dec-26	05-Jan-27
E0003521	20014-J-56XX: Fire/Gas Detection System - Develop MRP	20d	01-Dec-26	05-Jan-27
E0003531	20014-J-56XX: Fire/Gas Detection System - Issue PO to Vendor	0d		05-Jan-27
E0006181	20014-J-56XX: Fire/Gas Detection System - Manufacture	85d	06-Jan-27	06-May-27
E0003541	20014-J-56XX: Fire/Gas Detection System - Ready to Ship	0d		06-May-27
E0003551	20014-J-56XX: Fire/Gas Detection System - ETA to Site	0d		13-May-27
E15061	WBS-001 Receive at Site - Fire/Gas Detection System	0d	14-May-27	
Fabrication		140d	01-Apr-27	21-Oct-27
Structural Steel		95d	01-Apr-27	17-Aug-27
E0008211	WBS-001 - Structural Steel Fabrication	95d	01-Apr-27	17-Aug-27
E0009001	WBS-001 Receive at Site Structural Steel Materials	0d	31-May-27	
Piping		130d	16-Apr-27	21-Oct-27
Carbon Steel		130d	16-Apr-27	21-Oct-27
E0006801	WBS-001 - CS Pipe Fabrication	130d	16-Apr-27	21-Oct-27
Stainless Steel		130d	16-Apr-27	21-Oct-27
E0006891	WBS-001 - SS Pipe Fabrication	130d	16-Apr-27	21-Oct-27
Construction		172d	01-Apr-27	07-Dec-27
Civil		60d	01-Apr-27	25-Jun-27
E0008871	WBS-001 Siteworks	60d	01-Apr-27	25-Jun-27
Concrete & Foundations		75d	16-Apr-27	03-Aug-27
E0008901	WBS-001 Concrete & Foundations	75d	16-Apr-27	03-Aug-27
Structural Steel		70d	31-May-27	08-Sep-27
E0009031	WBS-001 Structural Steel	70d	31-May-27	08-Sep-27
Buildings		30d	16-Sep-27	28-Oct-27
E0010471	WBS-001 Building Erection	30d	16-Sep-27	28-Oct-27
Equipment		14d	14-Jun-27	02-Jul-27
E15151	WBS-001 Instrument Air Package Installation	2d	14-Jun-27	15-Jun-27
E15161	WBS-001 Nitrogen Generation (PSA) Package Installation	2d	28-Jun-27	29-Jun-27
E15171	WBS-001 LNG Drain Vessel (With Emerson Heater) Installation	2d	30-Jun-27	02-Jul-27
Piping		105d	16-Jun-27	16-Nov-27
E0009081	WBS-001 Piping Installation	105d	16-Jun-27	16-Nov-27
Electrical		100d	30-Jun-27	23-Nov-27



Remaining Level of Effort | Actual Work | Critical Remaining Work
Actual Level of Effort | Remaining Work | Critical Secondary

Data Date:26-Jul-24

Date	Revision	Checked	Approved
19-Aug-24	IFI		

Activity ID	Activity Name	Rem. Duration	Start	Finish
E0009181	WBS-001 Electrical Installation	100d	30-Jun-27	23-Nov-27
Instrumentatiion & Controls		95d	15-Jul-27	30-Nov-27
E0009391	WBS-001 Install Instrumentation	95d	15-Jul-27	30-Nov-27
Insulation		90d	29-Jul-27	07-Dec-27
E0009401	WBS-001 Install Insulation	90d	29-Jul-27	07-Dec-27
Phase 1 Commissioning & Start up		50d	12-Jun-28	22-Aug-28
E0001761.1	WBS-001 Pre-Commissioning	45d	12-Jun-28	15-Aug-28
E0006521.1	WBS-001 Commissioning	45d	19-Jun-28	22-Aug-28
E0001771.1	WBS-001 Start Up	0d		22-Aug-28
Phase 2 Commissioning & Start up		50d	11-Apr-29	21-Jun-29
E0001761.2	WBS-001 Pre-Commissioning (Phase 2)	45d	11-Apr-29	14-Jun-29
E0006521.2	WBS-001 Commissioning (Pahse 2)	45d	18-Apr-29	21-Jun-29
E0001771.2	WBS-001 Start Up (Phase 2)	0d		21-Jun-29
Base Plant Demolition		562d	17-Feb-27	23-May-29
EPC (Detailed - SMCI)		562d	17-Feb-27	23-May-29
Engineering		90d	17-Feb-27	25-Jun-27
TBP296122	Kick off Meeting	0d	17-Feb-27	
TBP300000	Detailed Design	90d	17-Feb-27	25-Jun-27
Regulatory Permits (Contractor Scope)		148d	08-Mar-28	06-Oct-28
City Of Delta MD		147d	08-Mar-28	05-Oct-28
Highway Use Permit - Delta Bylaw No. 6922		93d	25-May-28	05-Oct-28
RGT606182	Prepare Highway Use and Inspection Permits Application	10d	25-May-28	08-Jun-28
RGT606184	Submit Application	3d	08-Jun-28	13-Jun-28
RGT606186	Review Period	80d	13-Jun-28	05-Oct-28
RGT606188	Receive Approval/Permit	0d		05-Oct-28
Complex Building Permit - Delta Building/Plumbing Bylaw (No. 6060)		30d	08-Jun-28	21-Jul-28
RGT606382	Prepare Complex Building Permit Application	10d	08-Jun-28	22-Jun-28
RGT606384	Submit Application	3d	19-Jun-28	22-Jun-28
RGT606386	Review Period	20d	22-Jun-28	21-Jul-28
RGT606388	Receive Approval/Permit - Complex Building Permit	0d		21-Jul-28
Temporary Buildings Permit - Delta Building/Plumbing Bylaw (No. 6060)		30d	30-May-28	12-Jul-28
RGT616763	Prepare Complex Building Permit Application	10d	30-May-28	13-Jun-28
RGT616766	Submit Application	3d	08-Jun-28	13-Jun-28
RGT616764	Review Period	20d	13-Jun-28	12-Jul-28
RGT616765	Receive Approval/Permit - Complex Building Permit	0d		12-Jul-28
Development Permit (Commercial/Industrial) - Delta Official Community Plan Bylaws		143d	08-Mar-28	29-Sep-28
RGT606482	Prepare Development Permit (Commercial/Industrial) Application	60d	08-Mar-28	02-Jun-28
RGT606484	Submit Application	3d	02-Jun-28	07-Jun-28
RGT606486	Review Period	80d	07-Jun-28	29-Sep-28
RGT606488	Receive Approval/Permit	0d		29-Sep-28
Development Permit (Streamside Protection & Enhancement) - Bylaw No. 6349		143d	08-Mar-28	29-Sep-28
RGT606582	Prepare Development Permit (Commercial/Industrial) Application	60d	08-Mar-28	02-Jun-28
RGT606584	Submit Application	3d	02-Jun-28	07-Jun-28
RGT606586	Review Period	80d	07-Jun-28	29-Sep-28

Remaining Level of Effort
Actual Level of Effort
Actual Work
Remaining Work
Critical Remaining Work
Critical Secondary

Date	Revision	Checked	Approved
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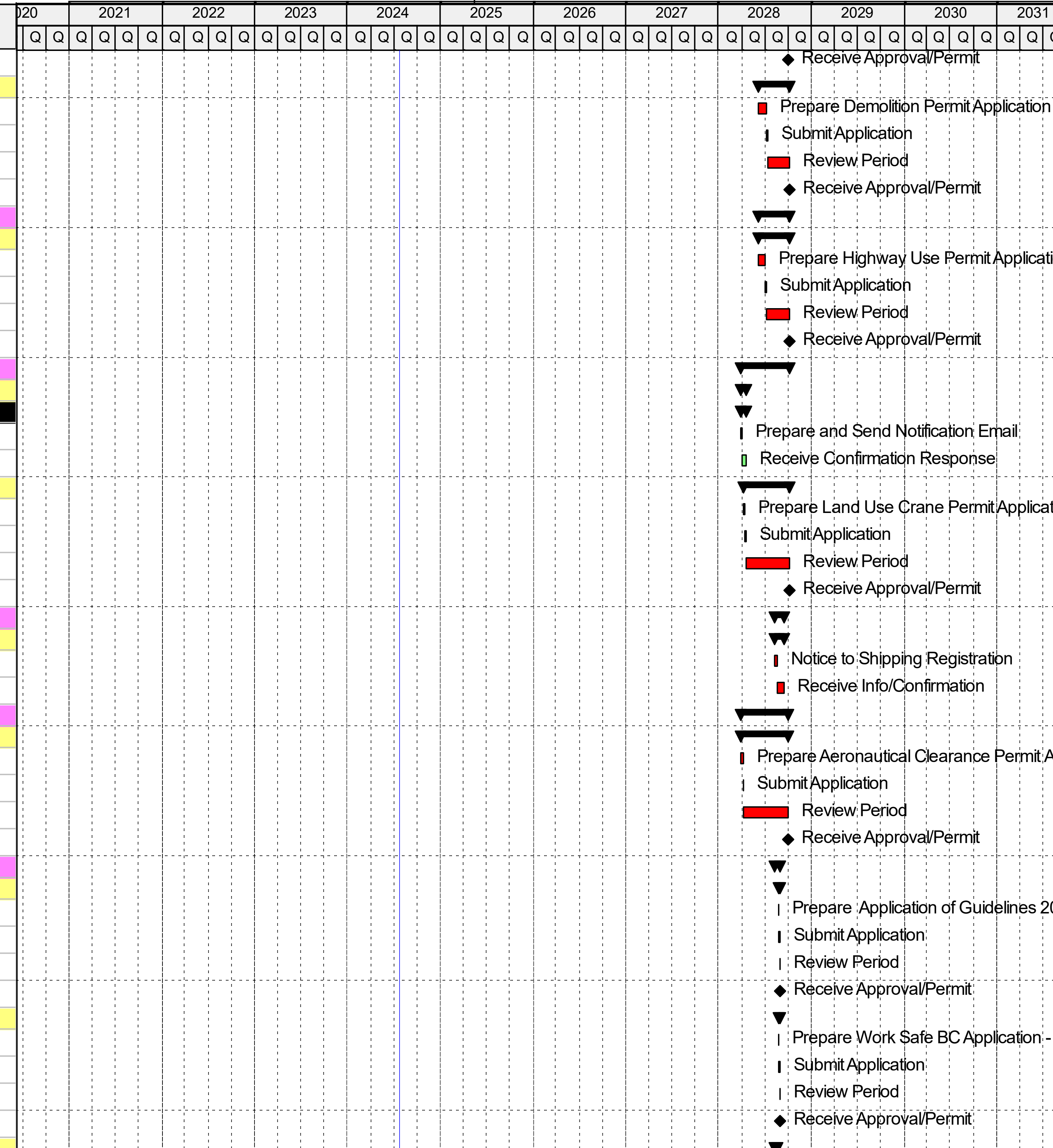
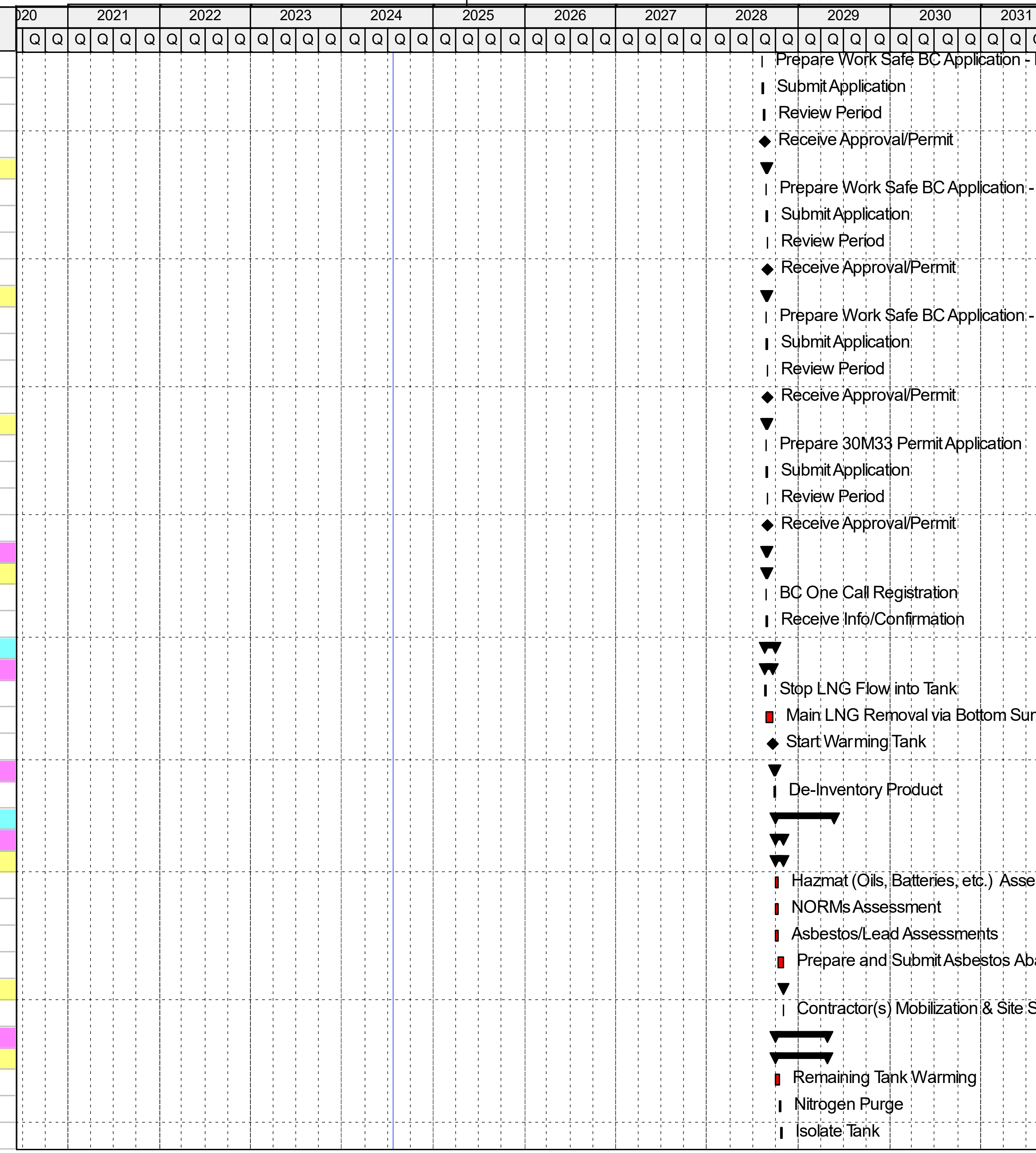
Activity ID	Activity Name	Rem. Duration	Start	Finish
RGT606588	Receive Approval/Permit	0d		29-Sep-28
Demolition Permit - Delta Official Community Plan Bylaws		83d	08-Jun-28	05-Oct-28
RGT606682	Prepare Demolition Permit Application	20d	08-Jun-28	07-Jul-28
RGT606684	Submit Application	3d	07-Jul-28	12-Jul-28
RGT606686	Review Period	60d	12-Jul-28	05-Oct-28
RGT606688	Receive Approval/Permit	0d		05-Oct-28
MOTI		85d	06-Jun-28	05-Oct-28
Highway Use Permit - Transportation Act		85d	06-Jun-28	05-Oct-28
RGT610182	Prepare Highway Use Permit Application	20d	06-Jun-28	05-Jul-28
RGT610184	Submit Application	3d	05-Jul-28	10-Jul-28
RGT610186	Review Period	62d	10-Jul-28	05-Oct-28
RGT610188	Receive Approval/Permit	0d		05-Oct-28
Nav Canada		135d	27-Mar-28	06-Oct-28
Boundary Bay Airport Email Notification		15d	27-Mar-28	18-Apr-28
Email Notification		15d	27-Mar-28	18-Apr-28
RGT604184	Prepare and Send Notification Email	5d	27-Mar-28	04-Apr-28
RGT604188	Receive Confirmation Response	10d	04-Apr-28	18-Apr-28
Land Use Program - Crane		128d	06-Apr-28	06-Oct-28
RGT611182	Prepare Land Use Crane Permit Application	5d	06-Apr-28	13-Apr-28
RGT611184	Submit Application	3d	13-Apr-28	18-Apr-28
RGT611186	Review Period	120d	18-Apr-28	06-Oct-28
RGT611188	Receive Approval/Permit	0d		06-Oct-28
Port of Vancouver		25d	11-Aug-28	18-Sep-28
Notice to Shipping - Canada Marine Act		25d	11-Aug-28	18-Sep-28
RGT613184	Notice to Shipping Registration	5d	11-Aug-28	18-Aug-28
RGT613188	Receive Info/Confirmation	20d	18-Aug-28	18-Sep-28
Transport Canada		128d	29-Mar-28	29-Sep-28
Aeronautical Clearance - Canadian Aviation Regulations (CARs)		128d	29-Mar-28	29-Sep-28
RGT614182	Prepare Aeronautical Clearance Permit Application	5d	29-Mar-28	06-Apr-28
RGT614184	Submit Application	3d	06-Apr-28	11-Apr-28
RGT614186	Review Period	120d	11-Apr-28	29-Sep-28
RGT614188	Receive Approval/Permit	0d		29-Sep-28
Work Safe BC - Worker Compenstion Act/OHS Regulation		15d	10-Aug-28	31-Aug-28
Guidelines 20.3-2 Qualified coordinators		6d	23-Aug-28	31-Aug-28
RGT616182	Prepare Application of Guidelines 20.3-2 Qualified coordinators	1d	23-Aug-28	24-Aug-28
RGT616184	Submit Application	3d	24-Aug-28	29-Aug-28
RGT616186	Review Period	2d	29-Aug-28	31-Aug-28
RGT616188	Receive Approval/Permit	0d		31-Aug-28
G20.2(1)/20.2.1(1) Notice of Project, Section 20.2(1) of the OHS Regulation		6d	23-Aug-28	31-Aug-28
RGT616282	Prepare Work Safe BC Application - Notice of Project	1d	23-Aug-28	24-Aug-28
RGT616284	Submit Application	3d	24-Aug-28	29-Aug-28
RGT616286	Review Period	2d	29-Aug-28	31-Aug-28
RGT616288	Receive Approval/Permit	0d		31-Aug-28
G20.2.1(1) and (2) Notice of project for asbestos - Ongoing work, OH&S 20.112		6d	10-Aug-28	18-Aug-28



Remaining Level of Effort | Actual Work | Critical Remaining Work
Actual Level of Effort | Remaining Work | Critical Secondary

Date	Revision	Checked	Approved
19-Aug-24	IFI		

Activity ID	Activity Name	Rem. Duration	Start	Finish
RGT616382	Prepare Work Safe BC Application - Notice of Project for asbestos	1d	10-Aug-28	11-Aug-28
RGT616384	Submit Application	3d	11-Aug-28	16-Aug-28
RGT616386	Review Period	2d	16-Aug-28	18-Aug-28
RGT616388	Receive Approval/Permit	0d		18-Aug-28
G20.2.1(2) (c) Notice of project -Significant distrubance of lead-containing material-OH&S 20.112		6d	23-Aug-28	31-Aug-28
RGT616482	Prepare Work Safe BC Application - Notice of Project (Significant distrubance of lea	1d	23-Aug-28	24-Aug-28
RGT616484	Submit Application	3d	24-Aug-28	29-Aug-28
RGT616486	Review Period	2d	29-Aug-28	31-Aug-28
RGT616488	Receive Approval/Permit	0d		31-Aug-28
G220.2.1(2) (d) Notice of project - Other similar exposure work activities-OH&S 20.113		6d	23-Aug-28	31-Aug-28
RGT616582	Prepare Work Safe BC Application - Notice of Project (Other similar exposure work	1d	23-Aug-28	24-Aug-28
RGT616584	Submit Application	3d	24-Aug-28	29-Aug-28
RGT616586	Review Period	2d	29-Aug-28	31-Aug-28
RGT616588	Receive Approval/Permit	0d		31-Aug-28
30M33 Permit - OHS Regulation Sections 19		6d	23-Aug-28	31-Aug-28
RGT616682	Prepare 30M33 Permit Application	1d	23-Aug-28	24-Aug-28
RGT616684	Submit Application	3d	24-Aug-28	29-Aug-28
RGT616686	Review Period	2d	29-Aug-28	31-Aug-28
RGT616688	Receive Approval/Permit	0d		31-Aug-28
BC One Call		4d	23-Aug-28	29-Aug-28
BC One Call Registration		4d	23-Aug-28	29-Aug-28
RGT601184	BC One Call Registration	1d	23-Aug-28	24-Aug-28
RGT601188	Receive Info/Confirmation	3d	24-Aug-28	29-Aug-28
LNG Product Removal and Tank De-Inventory		31d	22-Aug-28	04-Oct-28
Preparation		21d	22-Aug-28	20-Sep-28
C0102	Stop LNG Flow into Tank	1d	22-Aug-28	23-Aug-28
C0104	Main LNG Removal via Bottom Sump	20d	23-Aug-28	20-Sep-28
C0106	Start Warming Tank	0d	20-Sep-28	
De-Inventory		5d	27-Sep-28	04-Oct-28
A0108	De-Inventory Product	5d	27-Sep-28	04-Oct-28
Demolition		165d	04-Oct-28	23-May-29
Base Plant Mobilization		22d	04-Oct-28	02-Nov-28
Premobilization Assessments		20d	04-Oct-28	01-Nov-28
D0202	Hazmat (Oils, Batteries, etc.) Assessment	5d	04-Oct-28	11-Oct-28
D0204	NORMs Assessment	5d	04-Oct-28	11-Oct-28
D0206	Asbestos/Lead Assessments	5d	04-Oct-28	11-Oct-28
D0208	Prepare and Submit Asbestos Abatement Documentation	15d	11-Oct-28	01-Nov-28
Mobilization		2d	01-Nov-28	02-Nov-28
D0210	Contractor(s) Mobilization & Site Setup	2d	01-Nov-28	02-Nov-28
LNG Tank Demolition Work		145d	04-Oct-28	25-Apr-29
Tank (Tag 200)		145d	04-Oct-28	25-Apr-29
D0302	Remaining Tank Warming	10d	04-Oct-28	18-Oct-28
D0304	Nitrogen Purge	5d	18-Oct-28	25-Oct-28
D0306	Isolate Tank	2d	25-Oct-28	26-Oct-28



Tilbury Island LNG Facility Expansion (3 BCF)

TLSE Sub-Projects Integrated Schedule-Detailed

FORTIS BC

SOLARIS MANAGEMENT CONSULTANTS INC.

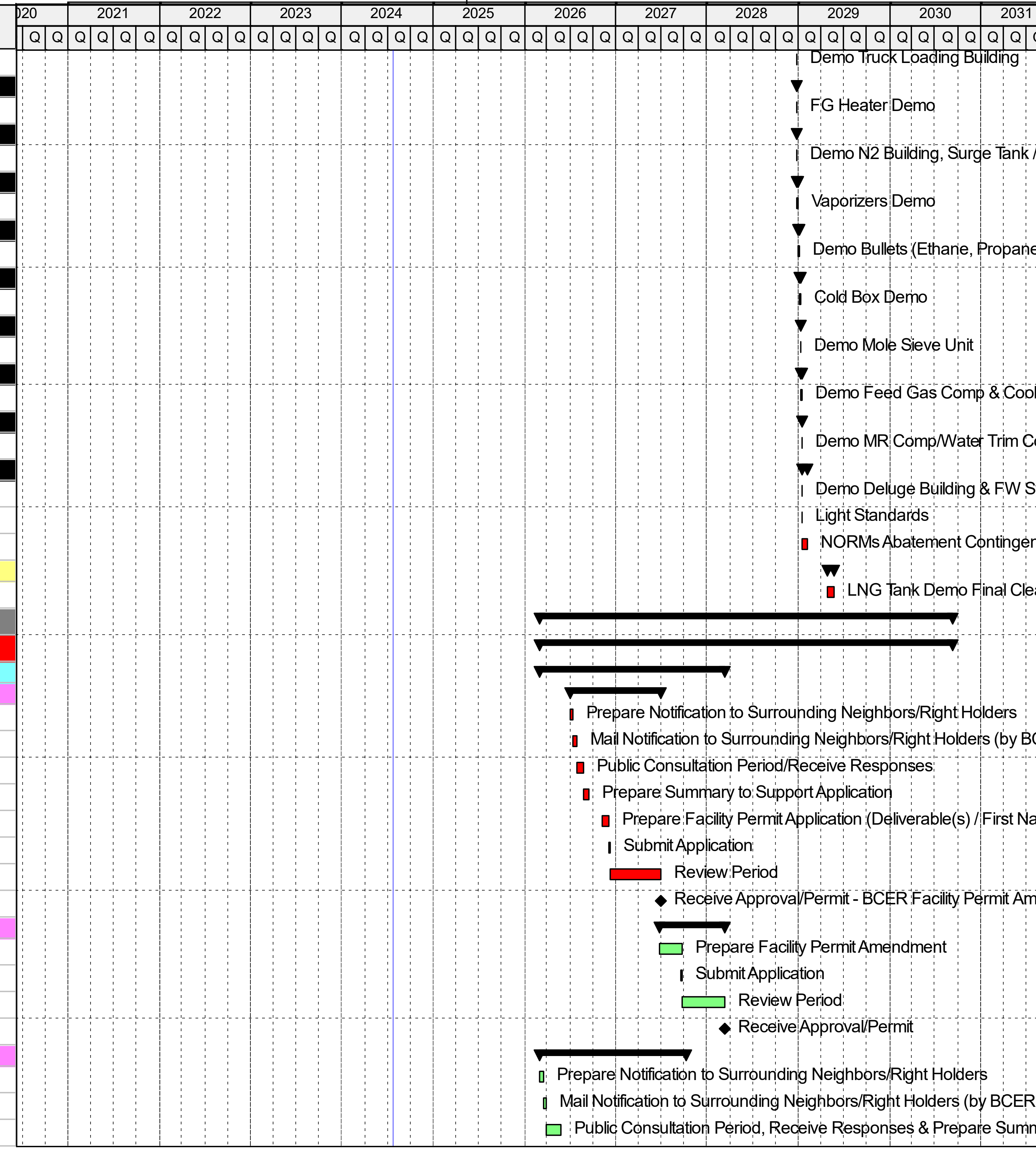
Activity ID	Activity Name	Rem. Duration	Start	Finish
D0308	Air Purge	7d	26-Oct-28	06-Nov-28
D0310	LNG Tank Demo (containment excluded)	100d	06-Dec-28	25-Apr-29
Demo Other Items (Tags 202, 202A, 202B)		35d	04-Oct-28	22-Nov-28
D0322	Nitrogen Purge	10d	04-Oct-28	18-Oct-28
D0324	Flush & Clean	10d	18-Oct-28	01-Nov-28
D0326	Demo 202, 202A/B	15d	01-Nov-28	22-Nov-28
Base Plant Demolition Work		144d	02-Nov-28	23-May-29
Hazardous Material Abatement		33d	02-Nov-28	19-Dec-28
D0402	N2 Purge Base Plant Piping & Equipment Interconnect at T1A	3d	02-Nov-28	07-Nov-28
D0404	Asbestos Abatement (Allowance)	25d	07-Nov-28	12-Dec-28
D0406	Hazmat Abatement	30d	07-Nov-28	19-Dec-28
D0408	NORM Abatement (Allowance)	15d	07-Nov-28	28-Nov-28
Demo Crew A		54d	13-Nov-28	29-Jan-29
Foam System Building/Water Tank		1d	13-Nov-28	14-Nov-28
D0410	Demo Foam System-Building, Water Tanks	1d	13-Nov-28	14-Nov-28
LNG Tank Bund Wall		7d	14-Nov-28	23-Nov-28
D0420	LNG Tank Containment Wall Demo	7d	14-Nov-28	23-Nov-28
LNG Access Site		14d	23-Nov-28	13-Dec-28
D0432	Demo LNG Access Stile	1d	23-Nov-28	24-Nov-28
D0434	Prepare for Tank Demo Crew Access	5d	23-Nov-28	30-Nov-28
D0436	Interconnect Piping Demo	5d	06-Dec-28	13-Dec-28
Foam Generating Building		2d	19-Dec-28	22-Dec-28
D0442	Inlet Area Piping Demo	2d	19-Dec-28	21-Dec-28
D0444	Demo Foam Generation Building	1d	21-Dec-28	22-Dec-28
Maintenance Building		2d	22-Dec-28	26-Dec-28
D0450	Demo Maintenance Building	2d	22-Dec-28	26-Dec-28
Office/Control Room & MCC		7d	26-Dec-28	04-Jan-29
D0460	Demo Office/Control Room/MCC	7d	26-Dec-28	04-Jan-29
BOG & Cycle Comp Building		7d	04-Jan-29	15-Jan-29
D0470	Demo BOG & Cycle Comp Building	7d	04-Jan-29	15-Jan-29
Station & Transformer		1d	15-Jan-29	16-Jan-29
D0480	Demo Station & Transformer	1d	15-Jan-29	16-Jan-29
Emergency Generator Building		1d	16-Jan-29	17-Jan-29
D0490	Demo Emergency Generator Building	1d	16-Jan-29	17-Jan-29
Diesel Storage Tank		1d	17-Jan-29	18-Jan-29
D0510	Demo Diesel Storage Tank	1d	17-Jan-29	18-Jan-29
Utility Building		1d	18-Jan-29	19-Jan-29
A0520	Demo Utility Building	1d	18-Jan-29	19-Jan-29
Storage Shed Building		6d	19-Jan-29	29-Jan-29
D0532	Demo Storage Shed Building	1d	19-Jan-29	22-Jan-29
D0534	NORMs Abatement Contingency	5d	22-Jan-29	29-Jan-29
Demo Crew B		36d	19-Dec-28	07-Feb-29
Piperacks		5d	19-Dec-28	26-Dec-28
D0610	Piperacks Demo	5d	19-Dec-28	26-Dec-28
Truck Loading Building		1d	26-Dec-28	27-Dec-28

Remaining Level of Effort | Actual Work | Critical Remaining Work

Actual Level of Effort | Remaining Work | Critical Secondary

Date	Revision	Checked	Approved
19-Aug-24	IFI		

Activity ID	Activity Name	Rem. Duration	Start	Finish
D0620	Demo Truck Loading Building	1d	26-Dec-28	27-Dec-28
FG Heater		1d	26-Dec-28	27-Dec-28
D0630	FG Heater Demo	1d	26-Dec-28	27-Dec-28
N2 Building, Surge Tank/Sea Can		1d	26-Dec-28	27-Dec-28
D0640	Demo N2 Building, Surge Tank / Sea Can	1d	26-Dec-28	27-Dec-28
Vaporizers		2d	27-Dec-28	29-Dec-28
D0660	Vaporizers Demo	2d	27-Dec-28	29-Dec-28
Bullets (Ethane. Propane, Butane)		4d	29-Dec-28	04-Jan-29
D0670	Demo Bullets (Ethane, Propane, Butane)	4d	29-Dec-28	04-Jan-29
Cold Box		5d	04-Jan-29	11-Jan-29
D0680	Cold Box Demo	5d	04-Jan-29	11-Jan-29
Mole Sieve Unit		1d	11-Jan-29	12-Jan-29
D0690	Demo Mole Sieve Unit	1d	11-Jan-29	12-Jan-29
Feed Gas Comp & Coolers		1d	12-Jan-29	15-Jan-29
D0710	Demo Feed Gas Comp & Coolers	1d	12-Jan-29	15-Jan-29
MR Comp/Water Trim Coolers		1d	15-Jan-29	15-Jan-29
D0720	Demo MR Comp/Water Trim Coolers	1d	15-Jan-29	15-Jan-29
Deluge Building & FW System		17d	15-Jan-29	07-Feb-29
D0732	Demo Deluge Building & FW System	1d	15-Jan-29	16-Jan-29
D0734	Light Standards	1d	16-Jan-29	17-Jan-29
D0736	NORMs Abatement Contingency	15d	17-Jan-29	07-Feb-29
Base Plant - inc LNG Tank Disposal - Demobilization Work & Final Cleanup		20d	25-Apr-29	23-May-29
D0800	LNG Tank Demo Final Cleanup/Demob	20d	25-Apr-29	23-May-29
Regulatory Permits (FEI Scope)		1121d	03-Mar-26	11-Sep-30
BCER		1121d	03-Mar-26	11-Sep-30
Facility Permit Amendment- Oil and Gas Activities Act		503d	03-Mar-26	15-Mar-28
Regasification		246d	02-Jul-26	29-Jun-27
RGT112180.1	Prepare Notification to Surrounding Neighbors/Right Holders	10d	02-Jul-26	16-Jul-26
RGT112180.2	Mail Notification to Surrounding Neighbors/Right Holders (by BCER)	10d	16-Jul-26	30-Jul-26
RGT112180.3	Public Consultation Period/Receive Responses	20d	30-Jul-26	28-Aug-26
RGT112180.4	Prepare Summary to Support Application	10d	28-Aug-26	14-Sep-26
RGT112182	Prepare Facility Permit Application (Deliverable(s) / First Nation Consultation)	20d	06-Nov-26	04-Dec-26
RGT112184	Submit Application	3d	07-Dec-26	09-Dec-26
RGT112186	Review Period	135d	10-Dec-26	29-Jun-27
RGT112188	Receive Approval/Permit - BCER Facility Permit Amendment	0d		29-Jun-27
Base Plant & Tank Demolition		176d	25-Jun-27	15-Mar-28
RGT612182	Prepare Facility Permit Amendment	60d	25-Jun-27	22-Sep-27
RGT612184	Submit Application	3d	17-Sep-27	22-Sep-27
RGT612186	Review Period	116d	22-Sep-27	15-Mar-28
RGT612188	Receive Approval/Permit	0d		15-Mar-28
LNG Tank Expansion		401d	03-Mar-26	12-Oct-27
RGT412182.1	Prepare Notification to Surrounding Neighbors/Right Holders	10d	03-Mar-26	16-Mar-26
RGT412182.2	Mail Notification to Surrounding Neighbors/Right Holders (by BCER)	10d	17-Mar-26	30-Mar-26
RGT412182.3	Public Consultation Period, Receive Responses & Prepare Summary to Support A	40d	31-Mar-26	27-May-26



Remaining Level of Effort | Actual Work | Critical Remaining Work
Actual Level of Effort | Remaining Work | Critical Secondary

Data Date:26-Jul-24

Date	Revision	Checked	Approved
19-Aug-24	IFI		

Activity ID	Activity Name	Rem. Duration	Start	Finish
RGT412182	Prepare Facility Permit Amendment Application	62d	18-Jan-27	15-Apr-27
RGT412184	Submit Application	3d	16-Apr-27	20-Apr-27
RGT412186	Review Period	120d	21-Apr-27	12-Oct-27
RGT412188	Receive Approval/Permit	0d		12-Oct-27
Waste Discharge Authorization - EM Act; Oil & Gas Waste Regulation		291d	16-Dec-26	25-Feb-28
Regasification		195d	16-Dec-26	01-Oct-27
RGT616723	Prepare Waste Discharge Authorization Application	40d	16-Dec-26	19-Feb-27
RGT616724	Submit Application	3d	16-Feb-27	19-Feb-27
RGT616725	Review Period	155d	19-Feb-27	01-Oct-27
RGT616726	Receive Approval/Permit - Waste Discharge Authorization	0d		01-Oct-27
Base Plant & Tank Demolition *TB Deleted*		203d	29-Apr-27	25-Feb-28
RGT616727	Prepare Waste Discharge Authorization Application TBC	40d	29-Apr-27	25-Jun-27
RGT616728	Submit Application	3d	25-Jun-27	30-Jun-27
RGT616729	Review Period	160d	30-Jun-27	25-Feb-28
RGT616730	Receive Approval/Permit - Waste Discharge Authorization	0d		25-Feb-28
LNG Tank Expansion		203d	28-Apr-27	23-Feb-28
RGT412282	Prepare Waste Discharge Authorization Application *Dur. TBC*	40d	28-Apr-27	23-Jun-27
RGT412284	Submit Application	3d	24-Jun-27	28-Jun-27
RGT412286	Review Period	160d	29-Jun-27	23-Feb-28
RGT412288	Receive Approval/Permit - Waste Discharge Authorization	0d		23-Feb-28
Facility NOI - Oil and Gas Activities Act		21d	09-Jul-27	09-Aug-27
Regasification		20d	09-Jul-27	09-Aug-27
RGA16290	Relevant IFC Drawings; P&IDs, Schematic	5d	09-Jul-27	16-Jul-27
RGA16291	Plot Plan	5d	09-Jul-27	16-Jul-27
RGA16292	Project Description	5d	09-Jul-27	16-Jul-27
RGA16293	Stamped Record Drawings (Post-NOI submission)	5d	09-Jul-27	16-Jul-27
RGA16294	Email notification 2 weeks prior to construction start	5d	09-Jul-27	16-Jul-27
RGA16288	Prepare Notice of Intent Document	5d	16-Jul-27	23-Jul-27
RGA16289	Review/Approval Period - BCER NOI	10d	23-Jul-27	09-Aug-27
LNG Tank Expansion		20d	12-Jul-27	09-Aug-27
RGA16297	Relevant IFC Drawings; P&IDs, Schematic	5d	12-Jul-27	19-Jul-27
RGA16298	Plot Plan	5d	12-Jul-27	19-Jul-27
RGA16299	Project Description	5d	12-Jul-27	19-Jul-27
RGA16300	Stamped Record Drawings (Post-NOI submission)	5d	12-Jul-27	19-Jul-27
RGA16301	Email notification 2 weeks prior to construction start	5d	12-Jul-27	19-Jul-27
RGA16295	Prepare Notice of Intent Document	5d	19-Jul-27	23-Jul-27
RGA16296	Review/Approval Period - BCER NOI	10d	26-Jul-27	09-Aug-27
LNGFR - Leave to Construct		203d	02-Jun-27	29-Mar-28
Regasification		30d	02-Jun-27	14-Jul-27
A10854	Deliverable(s) as per PCTT (See Activity Notebook)	20d	02-Jun-27	29-Jun-27
RGB816390	Prepare and Send Leave to Construct Notification	5d	23-Jun-27	29-Jun-27
RGB816391	Review Period - LtC	10d	30-Jun-27	14-Jul-27
Base Plant & Tank Demolition		30d	15-Feb-28	29-Mar-28

Remaining Level of Effort | Actual Work | Critical Remaining Work
Actual Level of Effort | Remaining Work | Critical Secondary

Date	Revision	Checked	Approved
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Activity ID	Activity Name	Rem. Duration	Start	Finish
A10856	Deliverable(s) as per PCTT (See Activity Notebook)	20d	15-Feb-28	15-Mar-28
RGB816393	Prepare and Send Leave to Construct Notification	5d	08-Mar-28	15-Mar-28
RGB816394	Review Period	10d	15-Mar-28	29-Mar-28
LNG Tank Expansion		30d	14-Sep-27	26-Oct-27
A10857	Deliverable(s) as per PCTT (See Activity Notebook)	20d	14-Sep-27	12-Oct-27
RGB816395	Prepare and Send Leave to Construct Notification	5d	05-Oct-27	12-Oct-27
RGB816396	Review Period	10d	13-Oct-27	26-Oct-27
LNGFR - Leave to Operate		942d	18-Nov-26	11-Sep-30
Regasification		30d	18-Nov-26	07-Jan-27
A10855	Deliverable(s) as per PCTT (See Activity Notebook)	20d	18-Nov-26	16-Dec-26
RGB816389	Prepare and Send Leave to Operate Notification	5d	09-Dec-26	16-Dec-26
RGB816392	Review Period	10d	16-Dec-26	07-Jan-27
LNG Tank Expansion		30d	29-Jul-30	11-Sep-30
A10859	Deliverable(s) as per PCTT (See Activity Notebook)	20d	29-Jul-30	27-Aug-30
RGB816399	Prepare and Send Leave to Operate Notification	5d	20-Aug-30	27-Aug-30
RGB816400	Review Period	10d	27-Aug-30	11-Sep-30
Metro Vancouver		445d	02-Dec-26	19-Sep-28
Waste Discharge - Metro Vancouver Bylaw 1082		435d	16-Dec-26	19-Sep-28
Regasification		268d	16-Dec-26	24-Jan-28
RGT108182	Prepare Waste Permit Application	20d	16-Dec-26	21-Jan-27
RGT108184	Submit Application	3d	21-Jan-27	26-Jan-27
RGT108186	Review Period	245d	26-Jan-27	24-Jan-28
RGT108188	Receive Approval/Permit - Waste Discharge	0d		24-Jan-28
Base Plant & Tank Demolition		328d	12-May-27	05-Sep-28
RGT608182	Prepare Waste Permit Application TBC	80d	12-May-27	03-Sep-27
RGT608184	Submit Application	3d	07-Sep-27	09-Sep-27
RGT608186	Review Period	245d	10-Sep-27	05-Sep-28
RGT608188	Receive Approval/Permit - Waste Discharge TBC	0d		05-Sep-28
LNG Tank Expansion		328d	27-May-27	19-Sep-28
RGT408182	Prepare Waste Permit Application	80d	27-May-27	20-Sep-27
RGT408184	Submit Application	3d	21-Sep-27	23-Sep-27
RGT408186	Review Period	245d	24-Sep-27	19-Sep-28
RGT408188	Receive Approval/Permit - Waste Discharge	0d		19-Sep-28
Waste Discharge Permit (Air Emission) - AQM Bylaw No. 1082, 2008		445d	02-Dec-26	19-Sep-28
Regasification		268d	02-Dec-26	10-Jan-28
RGT108282	Prepare Waste Dsicharge Permit Application	20d	02-Dec-26	07-Jan-27
RGT108284	Submit Application	3d	07-Jan-27	12-Jan-27
RGT108286	Review Period	245d	12-Jan-27	10-Jan-28
RGT108288	Receive Approval/Permit - MV Waste Dsicharge Permit (AIR)	0d		10-Jan-28
Base Plan & Tank Demolition		328d	12-May-27	05-Sep-28
RGT408252	Prepare Waste Dsicharge Permit Application	80d	12-May-27	03-Sep-27
RGT408254	Submit Application	3d	07-Sep-27	09-Sep-27
RGT408255	Review Period	245d	10-Sep-27	05-Sep-28
RGT408256	Receive Approval/Permit - MV Waste Discharge Permit (AIR)	0d		05-Sep-28

Remaining Level of Effort — Actual Work — Critical Remaining Work
Actual Level of Effort — Remaining Work — Critical Secondary

Date	Revision	Checked	Approved
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Tilbury Island LNG Facility Expansion (3 BCF)
TLSE Sub-Projects Integrated Schedule-Detailed

SOLARIS MANAGEMENT CONSULTANTS INC.

Activity ID	Activity Name	Rem. Duration	Start	Finish
LNG Tank Expansion *To be deleted if not needed*		328d	27-May-27	19-Sep-28
RGT408282	Prepare Waste Discharge Permit Application	80d	27-May-27	20-Sep-27
RGT408284	Submit Application	3d	21-Sep-27	23-Sep-27
RGT408286	Review Period	245d	24-Sep-27	19-Sep-28
RGT408288	Receive Approval/Permit - MV Waste Discharge Permit (AIR)	0d		19-Sep-28
City of Delta		364d	07-May-26	26-Oct-27
Soil Deposit and Removal Permit - Bylaw No. 7221, 2016		364d	07-May-26	26-Oct-27
Ground Improvement		103d	07-May-26	02-Oct-26
RGT306282	Prepare Soil Deposit and Removal Permit Application (See Act. Notebook)	20d	07-May-26	04-Jun-26
RGT306284	Submit Application	3d	05-Jun-26	09-Jun-26
RGT306286	Review Period	80d	10-Jun-26	02-Oct-26
RGT306288	Receive Approval/Permit - Soil Deposit	0d		02-Oct-26
Regasification		100d	26-Jan-27	17-Jun-27
RGT106782	Prepare Soil Deposit and Removal Permit Application	20d	26-Jan-27	23-Feb-27
RGT106784	Submit Application	3d	19-Feb-27	23-Feb-27
RGT106786	Review Period	80d	24-Feb-27	17-Jun-27
RGT106788	Receive Approval/Permit - Delta City Soil Deposit/Removal	0d		17-Jun-27
Base Plant & Tank Demolition *TB Deleted*		103d	28-May-27	26-Oct-27
RGT606782	Prepare Soil Deposit and Removal Permit Application	20d	28-May-27	25-Jun-27
RGT606784	Submit Application	3d	25-Jun-27	30-Jun-27
RGT606786	Review Period	80d	30-Jun-27	26-Oct-27
RGT606788	Receive Approval/Permit	0d		26-Oct-27
LNG Tank Expansion		103d	01-Feb-27	28-Jun-27
RGT406782	Prepare Soil Deposit and Removal Permit Application	20d	01-Feb-27	01-Mar-27
RGT406784	Submit Application	3d	02-Mar-27	04-Mar-27
RGT406786	Review Period	80d	05-Mar-27	28-Jun-27
RGT406788	Receive Approval/Permit	0d		28-Jun-27
Transport Canada		279d	05-Nov-26	22-Dec-27
Aeronautical Clearance - Canadian Aviation Regulations (CARs)		194d	18-Jan-27	25-Oct-27
Regasification		128d	22-Apr-27	25-Oct-27
RGT616706	Prepare Aeronautical Clearance Permit Application	5d	22-Apr-27	28-Apr-27
RGT616707	Submit Application	3d	29-Apr-27	03-May-27
RGT616708	Review Period	120d	04-May-27	25-Oct-27
RGT616709	Receive Approval/Permit - Transport Canada (Aeronautical)	0d		25-Oct-27
LNG Tank Expansion		128d	18-Jan-27	20-Jul-27
RGT616711	Prepare Aeronautical Clearance Permit Application	5d	18-Jan-27	22-Jan-27
RGT616712	Submit Application	3d	25-Jan-27	27-Jan-27
RGT616713	Review Period	120d	28-Jan-27	20-Jul-27
RGT616714	Receive Approval/Permit	0d		20-Jul-27
Navigable Waters Act Approval - Canadian Navigable Waters Act		279d	05-Nov-26	22-Dec-27
Base Plant		183d	31-Mar-27	22-Dec-27
RGT614282	Prepare Navigable Water Permit Application	60d	31-Mar-27	25-Jun-27
RGT614284	Submit Application	3d	25-Jun-27	30-Jun-27
RGT614286	Review Period	120d	30-Jun-27	22-Dec-27

Remaining Level of Effort | Actual Work | Critical Remaining Work
Actual Level of Effort | Remaining Work | Critical Secondary

Date	Revision	Checked	Approved
19-Aug-24	IFI		

FORTIS BC

Tilbury Island LNG Facility Expansion (3 BCF)

TLSE Sub-Projects Integrated Schedule-Detailed

SOLARIS MANAGEMENT CONSULTANTS INC.

Activity ID	Activity Name	Rem. Duration	Start	Finish
RGT614288	Receive Approval/Permit	0d		22-Dec-27
LNG Tank		183d	05-Nov-26	04-Aug-27
RGT616719	Prepare Navigable Water Permit Application	60d	05-Nov-26	05-Feb-27
RGT616720	Submit Application	3d	08-Feb-27	10-Feb-27
RGT616721	Review Period	120d	11-Feb-27	04-Aug-27
RGT616722	Receive Approval/Permit	0d		04-Aug-27
Ministry of Environment		103d	07-May-26	02-Oct-26
Site Profile Submission (TBD) - EM Act; Contaminated Sites Regulation		103d	07-May-26	02-Oct-26
Ground Improvement		103d	07-May-26	02-Oct-26
RGT309182	Prepare EM Permit Application (Forms/Fees,Attached Deliverables)	20d	07-May-26	04-Jun-26
RGT309184	Submit Application	3d	05-Jun-26	09-Jun-26
RGT309186	Review Period	80d	10-Jun-26	02-Oct-26
RGT309188	Receive Approval/Permit - Environment Management	0d		02-Oct-26
Auxiliary Systems (Utility Rack & Equipment) Tie-in to T3 Tank		932d	18-Jan-27	18-Oct-30
EPC (Detailed - Contractor)		932d	18-Jan-27	18-Oct-30
General		932d	18-Jan-27	18-Oct-30
G136	Detail Engineering Kick Off	0d	18-Jan-27	
G166	HAZOP/SIL/LOPA	0d		26-May-27
G266	60% Model Review	0d		30-Jun-27
E15991	Construction Permit Approval	0d	16-Jul-27	
G176	90% Model Review	0d		27-Aug-27
E16001	Ground Improvement Completed	0d		30-Sep-27
G226	Construction Mobilization to Site	0d	05-Oct-27	
G196	Final Document Class 2 Control Estimate Completed	0d		09-Nov-27
G186	Issue for Construction (IFC)	0d		24-Nov-27
E18631	Pipe Fabrication Complete	0d		29-May-28
G236	Last Piece of Mechanical Equipment Delivered to Site	0d		06-Jun-28
G216	Project Mechanical Completion	0d		20-Aug-30
G246	Commissioning & Startup Completed	0d		18-Oct-30
G256	Turnover to Operations - LNG Tank	0d		18-Oct-30
Engineering & Design		215d	18-Jan-27	24-Nov-27
General		120d	19-May-27	09-Nov-27
E16111	HAZOP	5d	19-May-27	26-May-27
E16121	HAZOP Closeout	20d	27-May-27	23-Jun-27
G126	60% Model Review	5d	24-Jun-27	30-Jun-27
G206	90% Model Review	5d	23-Aug-27	27-Aug-27
E19901	Prepare Class 2 Control Estimate	30d	28-Sep-27	09-Nov-27
Milestones		195d	12-Feb-27	24-Nov-27
Process		145d	12-Feb-27	13-Sep-27
E18651	Simulation - IFC	0d		12-Feb-27
E18661	Heat & Material Balance - IFC	0d		12-Feb-27
E18711	Hydraulic Calculations/Line Sizing - IFC	0d		15-Mar-27
E18721	Process Flow Diagram - IFH	0d		15-Mar-27

Remaining Level of Effort
Actual Level of Effort
Actual Work
Remaining Work
Critical Remaining Work
Critical Secondary

Date	Revision	Checked	Approved
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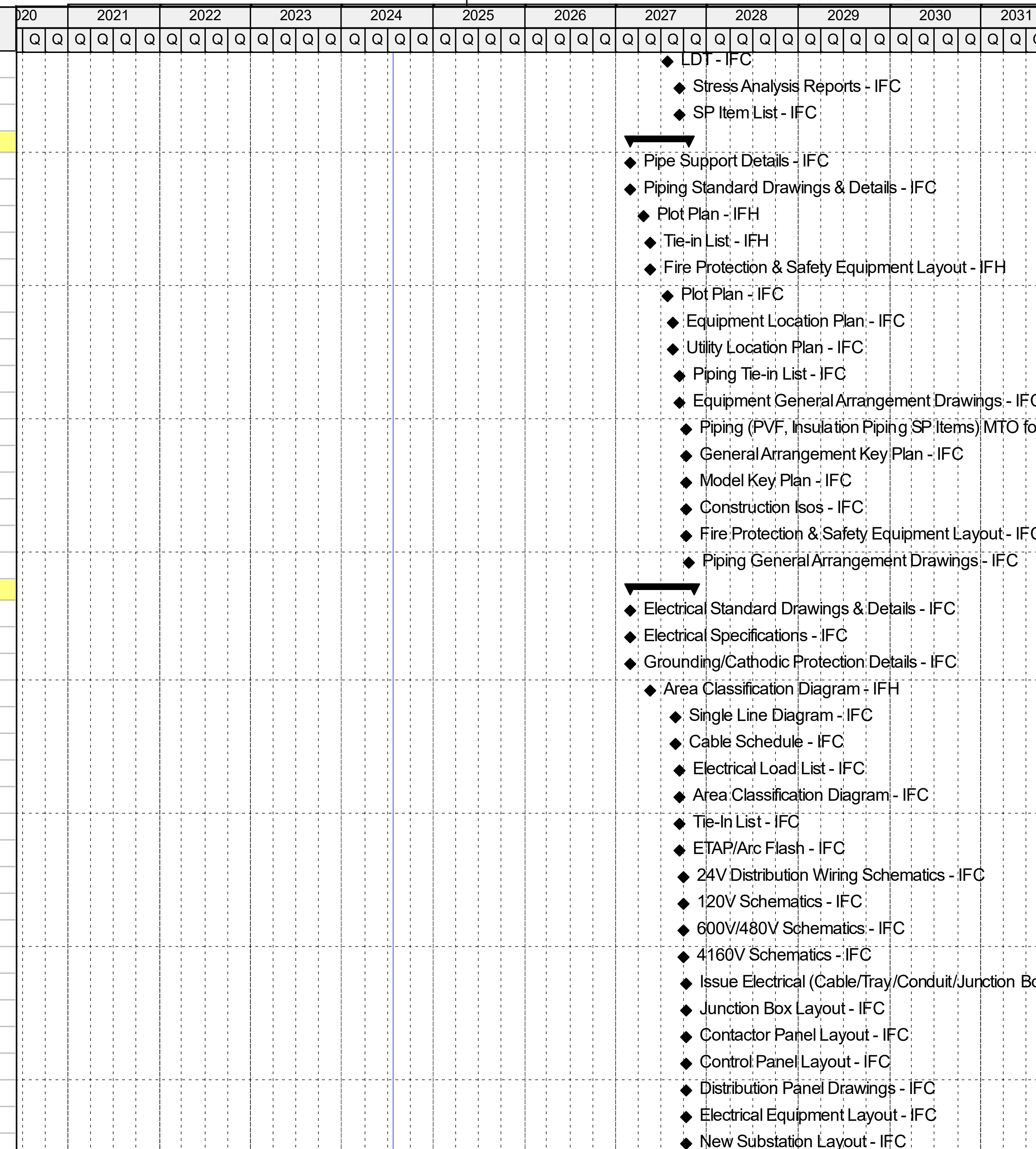
Activity ID	Activity Name	Rem. Duration	Start	Finish
E18691	Utilities Requirement - IFH	0d		29-Mar-27
E15191	P&ID - IFH	0d		21-Apr-27
E18761	Loss Management Philosophy - IFH	0d		21-Apr-27
E18821	Control Narrative - IFH	0d		21-Apr-27
E18671	Material Selection Diagram - IFH	0d		27-Apr-27
E18741	Utility Flow Diagram - IFH	0d		27-Apr-27
E18771	Operating Philosophy - IFH	0d		18-May-27
E18801	Pressure Relief Summary - IFH	0d		18-May-27
E19831	Vendor P&ID - IFH	0d		18-May-27
E18731	Process Flow Diagram - IFC	0d		08-Jul-27
E16021	P&ID - IFC	0d		29-Jul-27
E18781	Loss Management Philosophy - IFC	0d		29-Jul-27
E19861	Control Narrative - IFC	0d		29-Jul-27
E16031	C&SU Procedure - IFC	0d		06-Aug-27
E18701	Utilities Requirement - IFC	0d		06-Aug-27
E18681	Material Selection Diagram - IFC	0d		20-Aug-27
E18751	Utility Flow Diagram - IFC	0d		20-Aug-27
E19851	Vendor P&ID - IFC	0d		20-Aug-27
E18791	Operating Philosophy - IFC	0d		13-Sep-27
E18811	Pressure Relief Summary - IFC	0d		13-Sep-27
Civiil/Structural/Architectural		**185d**	**01-Mar-27**	**24-Nov-27**
E18831	Civil Engineering Design Criteria - IFC	0d		01-Mar-27
E18841	Structural Engineering Design Criteria - IFC	0d		01-Mar-27
E18851	Piperack Structural Capacity Report - IFC	0d		01-Mar-27
E18881	C/S/A Standard Drawings & Details - IFC	0d		01-Mar-27
E18891	C/S/A Specifications - IFC	0d		01-Mar-27
E15231	Structural Steel Location Plans - IFC	0d		27-Sep-27
E15241	Building Drawings - IFC	0d		12-Oct-27
E15261	Foundation Details & Drawings - IFC	0d		12-Oct-27
E15281	Earthworks/Civil Drawings - IFC	0d		12-Oct-27
E18871	Structural Steel MTO for Estimating	0d		12-Oct-27
E18861	MIscellaneous Steel - Support Details - IFC	0d		24-Nov-27
Mechanical		**105d**	**01-Mar-27**	**29-Jul-27**
E19871	Equipment Specifications - IFC	0d		01-Mar-27
E15301	Equipment List - IFH	0d		21-Apr-27
E18901	Fire Fighting Equipment List - IFH	0d		21-Apr-27
E18921	Spare Parts Listing	0d		04-May-27
E17741	Equipment List - IFC	0d		29-Jul-27
E18911	Fire Fighting Equipment List - IFC	0d		29-Jul-27
Piping Engineering		**135d**	**01-Mar-27**	**13-Sep-27**
E18941	Piping Specifications - IFC	0d		01-Mar-27
E15521	LDT - IFH	0d		21-Apr-27

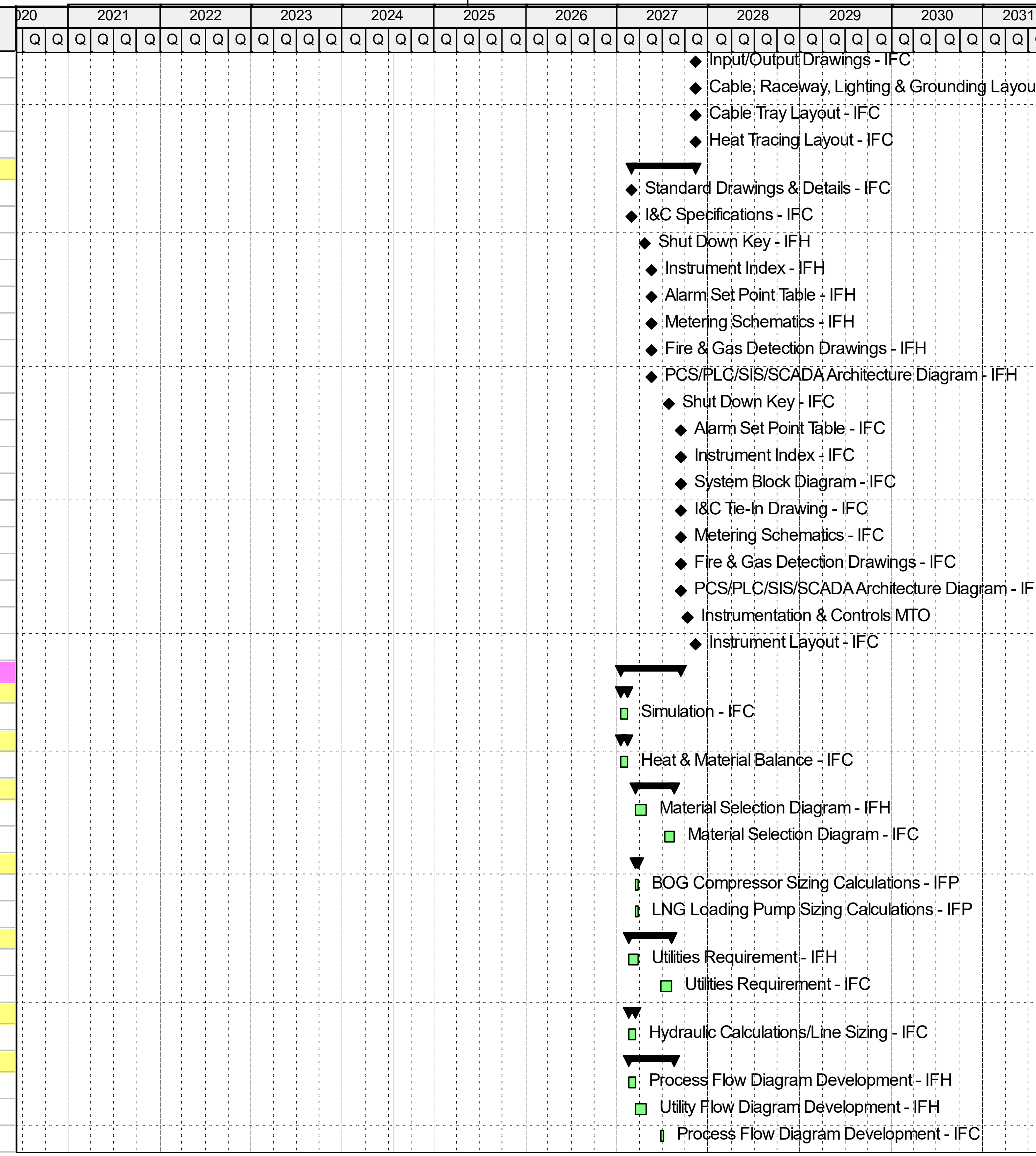
Activity ID	Activity Name	Rem. Duration	Start	Finish
E16051	LDT - IFC	0d		29-Jul-27
E15561	Stress Analysis Reports - IFC	0d		13-Sep-27
E18931	SP Item List - IFC	0d		13-Sep-27
Piping Design		160d	01-Mar-27	19-Oct-27
E19031	Pipe Support Details - IFC	0d		01-Mar-27
E19041	Piping Standard Drawings & Details - IFC	0d		01-Mar-27
E19841	Plot Plan - IFH	0d		21-Apr-27
E18951	Tie-in List - IFH	0d		18-May-27
E19051	Fire Protection & Safety Equipment Layout - IFH	0d		18-May-27
E19081	Plot Plan - IFC	0d		29-Jul-27
E15591	Equipment Location Plan - IFC	0d		20-Aug-27
E19021	Utility Location Plan - IFC	0d		20-Aug-27
E18961	Piping Tie-in List - IFC	0d		13-Sep-27
E19011	Equipment General Arrangement Drawings - IFC	0d		13-Sep-27
E15551	Piping (PVF, Insulation Piping SP Items) MTO for Estimating	0d		12-Oct-27
E18971	General Arrangement Key Plan - IFC	0d		12-Oct-27
E18981	Model Key Plan - IFC	0d		12-Oct-27
E18991	Construction Isos - IFC	0d		12-Oct-27
E19061	Fire Protection & Safety Equipment Layout - IFC	0d		12-Oct-27
E19001	Piping General Arrangement Drawings - IFC	0d		19-Oct-27
Electrical		175d	01-Mar-27	09-Nov-27
E19181	Electrical Standard Drawings & Details - IFC	0d		01-Mar-27
E19191	Electrical Specifications - IFC	0d		01-Mar-27
E19261	Grounding/Cathodic Protection Details - IFC	0d		01-Mar-27
E19121	Area Classification Diagram - IFH	0d		18-May-27
E19101	Single Line Diagram - IFC	0d		27-Aug-27
E19111	Cable Schedule - IFC	0d		27-Aug-27
E19091	Electrical Load List - IFC	0d		13-Sep-27
E19131	Area Classification Diagram - IFC	0d		13-Sep-27
E19251	Tie-In List - IFC	0d		13-Sep-27
E19431	ETAP/Arc Flash - IFC	0d		13-Sep-27
E19141	24V Distribution Wiring Schematics - IFC	0d		27-Sep-27
E19151	120V Schematics - IFC	0d		27-Sep-27
E19161	600V/480V Schematics - IFC	0d		27-Sep-27
E19171	4160V Schematics - IFC	0d		27-Sep-27
E15751	Issue Electrical (Cable/Tray/Conduit/Junction Box) MTO for Estimating	0d		12-Oct-27
E19211	Junction Box Layout - IFC	0d		12-Oct-27
E19221	Contactor Panel Layout - IFC	0d		12-Oct-27
E19231	Control Panel Layout - IFC	0d		12-Oct-27
E19241	Distribution Panel Drawings - IFC	0d		12-Oct-27
E19281	Electrical Equipment Layout - IFC	0d		12-Oct-27
E19291	New Substation Layout - IFC	0d		12-Oct-27



Remaining Level of Effort | Actual Work | Critical Remaining Work
Actual Level of Effort | Remaining Work | Critical Secondary

Date	Revision	Checked	Approved
19-Aug-24	IFI		

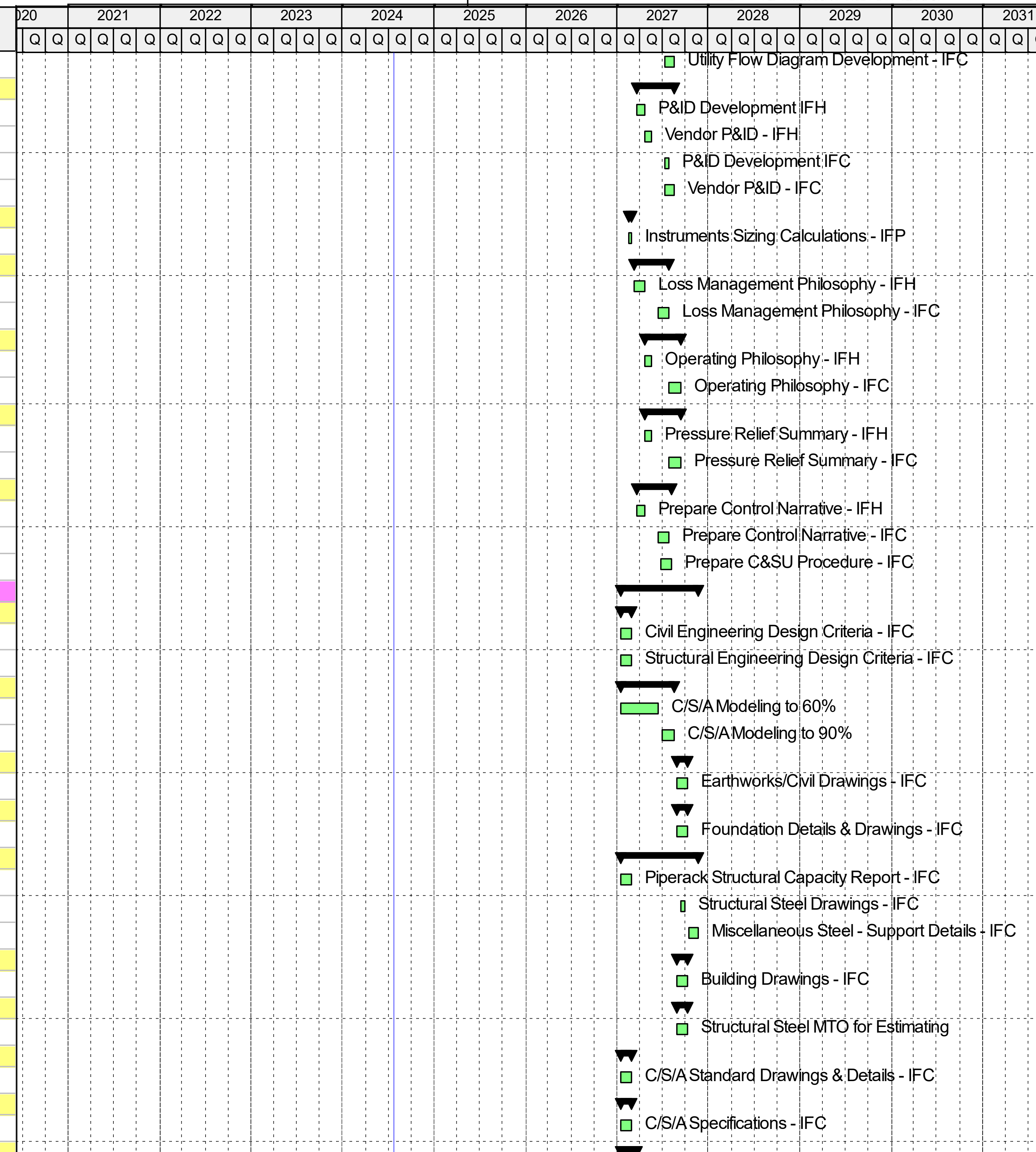
Activity ID	Activity Name	Rem. Duration	Start	Finish
E19201	Input/Output Drawings - IFC	0d		09-Nov-27
E19271	Cable, Raceway, Lighting & Grounding Layout - IFC	0d		09-Nov-27
E19301	Cable Tray Layout - IFC	0d		09-Nov-27
E19891	Heat Tracing Layout - IFC	0d		09-Nov-27
Instrumentation		175d	01-Mar-27	09-Nov-27
E19401	Standard Drawings & Details - IFC	0d		01-Mar-27
E19411	I&C Specifications - IFC	0d		01-Mar-27
E15901	Shut Down Key - IFH	0d		21-Apr-27
E15921	Instrument Index - IFH	0d		18-May-27
E15941	Alarm Set Point Table - IFH	0d		18-May-27
E19341	Metering Schematics - IFH	0d		18-May-27
E19361	Fire & Gas Detection Drawings - IFH	0d		18-May-27
E19381	PCS/PLC/SIS/SCADA Architecture Diagram - IFH	0d		18-May-27
E16081	Shut Down Key - IFC	0d		29-Jul-27
E16101	Alarm Set Point Table - IFC	0d		13-Sep-27
E17761	Instrument Index - IFC	0d		13-Sep-27
E19311	System Block Diagram - IFC	0d		13-Sep-27
E19331	I&C Tie-In Drawing - IFC	0d		13-Sep-27
E19351	Metering Schematics - IFC	0d		13-Sep-27
E19371	Fire & Gas Detection Drawings - IFC	0d		13-Sep-27
E19391	PCS/PLC/SIS/SCADA Architecture Diagram - IFC	0d		13-Sep-27
E15961	Instrumentation & Controls MTO	0d		12-Oct-27
E19321	Instrument Layout - IFC	0d		09-Nov-27
Process		165d	18-Jan-27	13-Sep-27
Simulation		20d	18-Jan-27	12-Feb-27
E17811	Simulation - IFC	20d	18-Jan-27	12-Feb-27
Heat & Material Balance		20d	18-Jan-27	12-Feb-27
E17821	Heat & Material Balance - IFC	20d	18-Jan-27	12-Feb-27
Material Selection Diagram		110d	16-Mar-27	20-Aug-27
E17831	Material Selection Diagram - IFH	30d	16-Mar-27	27-Apr-27
E17841	Material Selection Diagram - IFC	30d	09-Jul-27	20-Aug-27
Equipment Data Sheet		10d	16-Mar-27	29-Mar-27
E17961	BOG Compressor Sizing Calculations - IFP	10d	16-Mar-27	29-Mar-27
E17971	LNG Loading Pump Sizing Calculations - IFP	10d	16-Mar-27	29-Mar-27
Utilities		120d	16-Feb-27	06-Aug-27
E17791	Utilities Requirement - IFH	30d	16-Feb-27	29-Mar-27
E17801	Utilities Requirement - IFC	30d	24-Jun-27	06-Aug-27
Hydraulic Calculations		20d	16-Feb-27	15-Mar-27
E17981	Hydraulic Calculations/Line Sizing - IFC	20d	16-Feb-27	15-Mar-27
Flow Diagram		130d	16-Feb-27	20-Aug-27
E17771	Process Flow Diagram Development - IFH	20d	16-Feb-27	15-Mar-27
E17911	Utility Flow Diagram Development - IFH	30d	16-Mar-27	27-Apr-27
E17781	Process Flow Diagram Development - IFC	10d	24-Jun-27	08-Jul-27



Remaining Level of Effort | Actual Work | Critical Remaining Work
Actual Level of Effort | Remaining Work | Critical Secondary

Date	Revision	Checked	Approved
19-Aug-24	IFI		

Activity ID	Activity Name	Rem. Duration	Start	Finish
E17921	Utility Flow Diagram Development - IFC	30d	09-Jul-27	20-Aug-27
Piping & Instrument Diagram (P&ID)		105d	23-Mar-27	20-Aug-27
E15181	P&ID Development IFH	20d	23-Mar-27	21-Apr-27
E17931	Vendor P&ID - IFH	20d	21-Apr-27	18-May-27
E16011	P&ID Development IFC	15d	09-Jul-27	29-Jul-27
E17941	Vendor P&ID - IFC	30d	09-Jul-27	20-Aug-27
Instrument Data Sheet		10d	16-Feb-27	01-Mar-27
E17951	Instruments Sizing Calculations - IFP	10d	16-Feb-27	01-Mar-27
Loss Management Philosophy		100d	09-Mar-27	29-Jul-27
E17851	Loss Management Philosophy - IFH	30d	09-Mar-27	21-Apr-27
E17861	Loss Management Philosophy - IFC	30d	17-Jun-27	29-Jul-27
Operating Philosophy		100d	21-Apr-27	13-Sep-27
E17871	Operating Philosophy - IFH	20d	21-Apr-27	18-May-27
E17881	Operating Philosophy - IFC	30d	30-Jul-27	13-Sep-27
Pressure Relief Summary		100d	21-Apr-27	13-Sep-27
E17891	Pressure Relief Summary - IFH	20d	21-Apr-27	18-May-27
E17901	Pressure Relief Summary - IFC	30d	30-Jul-27	13-Sep-27
Control Narrative		95d	23-Mar-27	06-Aug-27
E18641	Prepare Control Narrative - IFH	20d	23-Mar-27	21-Apr-27
E19691	Prepare Control Narrative - IFC	30d	17-Jun-27	29-Jul-27
E15201	Prepare C&SU Procedure - IFC	30d	24-Jun-27	06-Aug-27
Civil/Structural/Architectural		215d	18-Jan-27	24-Nov-27
Design Criteria		30d	18-Jan-27	01-Mar-27
E17991	Civil Engineering Design Criteria - IFC	30d	18-Jan-27	01-Mar-27
E18001	Structural Engineering Design Criteria - IFC	30d	18-Jan-27	01-Mar-27
Modeling		150d	18-Jan-27	20-Aug-27
G156	C/S/A Modeling to 60%	104d	18-Jan-27	15-Jun-27
E15211	C/S/A Modeling to 90%	35d	02-Jul-27	20-Aug-27
Sitework		30d	30-Aug-27	12-Oct-27
E15271	Earthworks/Civil Drawings - IFC	30d	30-Aug-27	12-Oct-27
Foundation		30d	30-Aug-27	12-Oct-27
E15251	Foundation Details & Drawings - IFC	30d	30-Aug-27	12-Oct-27
Structural Steel		215d	18-Jan-27	24-Nov-27
E18041	Piperack Structural Capacity Report - IFC	30d	18-Jan-27	01-Mar-27
E15221	Structural Steel Drawings - IFC	10d	14-Sep-27	27-Sep-27
E18621	Miscellaneous Steel - Support Details - IFC	30d	13-Oct-27	24-Nov-27
Buildings		30d	30-Aug-27	12-Oct-27
E18021	Building Drawings - IFC	30d	30-Aug-27	12-Oct-27
Material Take Off		30d	30-Aug-27	12-Oct-27
E18051	Structural Steel MTO for Estimating	30d	30-Aug-27	12-Oct-27
Standard Drawings & Details		30d	18-Jan-27	01-Mar-27
E18011	C/S/A Standard Drawings & Details - IFC	30d	18-Jan-27	01-Mar-27
Specification		30d	18-Jan-27	01-Mar-27
E18031	C/S/A Specifications - IFC	30d	18-Jan-27	01-Mar-27
Requisition		45d	18-Jan-27	22-Mar-27



Remaining Level of Effort | Actual Work | Critical Remaining Work
Actual Level of Effort | Remaining Work | Critical Secondary

Date	Revision	Checked	Approved
19-Aug-24	IFI		

Activity ID	Activity Name	Rem. Duration	Start	Finish
20014-C-5301: BOG Building		45d	18-Jan-27	22-Mar-27
E15821	20014-C-5301 - BOG Building - Prepare IFP Data Sheets & Specifications	20d	18-Jan-27	12-Feb-27
E19721	20014-C-5301 - BOG Building - Receive Vendor Info	0d	09-Mar-27	
E19731	20014-C-5301 - BOG Building - Review Vendor Data	10d	09-Mar-27	22-Mar-27
E19741	20014-C-5301 - BOG Building - Code 1 Vendor Data	0d		22-Mar-27
20014-C-5302: Galvanized Steel		20d	18-Jan-27	12-Feb-27
E17331	20014-C-5302: Galvanized Steel - Prepare IFP Data Sheets & Specifications	20d	18-Jan-27	12-Feb-27
20014-C-5303: Concrete		20d	18-Jan-27	12-Feb-27
E17371	20014-C-5303 - Concrete - Prepare IFP Data Sheets & Specifications	20d	18-Jan-27	12-Feb-27
20014-C-53XX: Fill Materials		20d	18-Jan-27	12-Feb-27
E17431	20014-C-53XX - Fill Materials - Prepare IFP Data Sheets & Specifications	20d	18-Jan-27	12-Feb-27
Mechanical		135d	18-Jan-27	29-Jul-27
Equipment List		100d	09-Mar-27	29-Jul-27
E15291	Equipment List - IFH	30d	09-Mar-27	21-Apr-27
E18391	Fire Fighting Equipment List - IFH	30d	09-Mar-27	21-Apr-27
E17731	Equipment List - IFC	30d	17-Jun-27	29-Jul-27
E18401	Fire Fighting Equipment List - IFC	30d	17-Jun-27	29-Jul-27
Spare Parts		75d	18-Jan-27	04-May-27
E19701	Equipment Specifications - IFC	30d	18-Jan-27	01-Mar-27
E18411	Spare Parts Listing	10d	21-Apr-27	04-May-27
Requisition		85d	02-Mar-27	30-Jun-27
20014-M-5101: Cryo Pumps		85d	02-Mar-27	30-Jun-27
E15311	20014-M-5101 - Cyro Pumps - Prepare RFP Data Sheets & Specifications	20d	02-Mar-27	29-Mar-27
E15321	20014-M-5101 - Cyro Pumps - Receive Vendor Info	0d	21-Apr-27	
E15331	20014-M-5101 - Cyro Pumps - Review Vendor Data	10d	21-Apr-27	04-May-27
E15341	20014-M-5101 - Cyro Pumps - Code 1 Vendor Data	0d		04-May-27
E15351	20014-M-5101 - Cyro Pumps - Receive Vendor Data Books	0d	17-Jun-27	
E15361	20014-M-5101 - Cyro Pumps - Review Vendor Data Books	10d	17-Jun-27	30-Jun-27
E15371	20014-M-5101 - Cyro Pumps - Issue Approval For Payment	0d		30-Jun-27
20014-M-5102: BOG Compressor		85d	02-Mar-27	30-Jun-27
E16371	20014-M-5102 - BOG Compressor - Prepare RFP Data Sheets & Specifications	20d	02-Mar-27	29-Mar-27
E16381	20014-M-5102 - BOG Compressor - Receive Vendor Info	0d	21-Apr-27	
E16391	20014-M-5102 - BOG Compressor - Review Vendor Data	10d	21-Apr-27	04-May-27
E16401	20014-M-5102 - BOG Compressor - Code 1 Vendor Data	0d		04-May-27
E16411	20014-M-5102 - BOG Compressor - Receive Vendor Data Books	0d	17-Jun-27	
E16421	20014-M-5102 - BOG Compressor - Review Vendor Data Books	10d	17-Jun-27	30-Jun-27
E16431	20014-M-5102 - BOG Compressor - Issue Approval For Payment	0d		30-Jun-27
Piping Engineering		184d	18-Jan-27	08-Oct-27
Stress		10d	30-Aug-27	13-Sep-27
E18421	Stress Analysis Reports - IFC	10d	30-Aug-27	13-Sep-27
Line Designation Table (LDT)		100d	09-Mar-27	29-Jul-27
E15511	LDT Development - IFH	30d	09-Mar-27	21-Apr-27
E16041	LDT Development - IFC	30d	17-Jun-27	29-Jul-27
Specialty Items		30d	30-Jul-27	13-Sep-27

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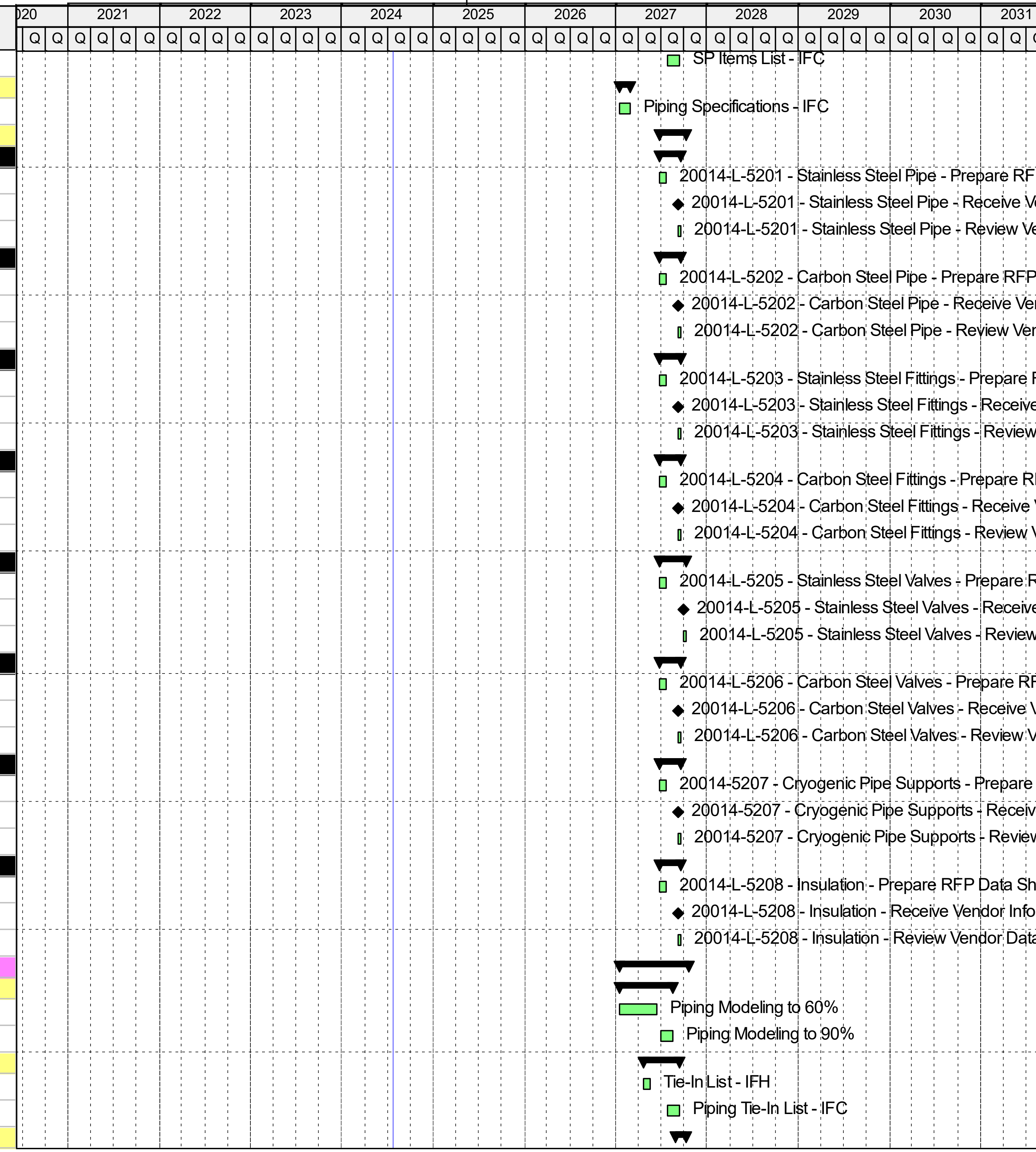
Tilbury Island LNG Facility Expansion (3 BCF)
TLSE Sub-Projects Integrated Schedule-Detailed

SOLARIS MANAGEMENT CONSULTANTS INC.

Activity ID	Activity Name	Rem. Duration	Start	Finish
E18431	SP Items List - IFC	30d	30-Jul-27	13-Sep-27
Specifications		30d	18-Jan-27	01-Mar-27
E19881	Piping Specifications - IFC	30d	18-Jan-27	01-Mar-27
Requisition		74d	24-Jun-27	08-Oct-27
20014-L-5201 - Stainless Steel Pipe		60d	24-Jun-27	20-Sep-27
E17031	20014-L-5201 - Stainless Steel Pipe - Prepare RFP Data Sheets & Specifications	20d	24-Jun-27	22-Jul-27
E17041	20014-L-5201 - Stainless Steel Pipe - Receive Vendor Info	0d	07-Sep-27	
E17051	20014-L-5201 - Stainless Steel Pipe - Review Vendor Data	10d	07-Sep-27	20-Sep-27
20014-L-5202 - Carbon Steel Pipe		60d	24-Jun-27	20-Sep-27
E16971	20014-L-5202 - Carbon Steel Pipe - Prepare RFP Data Sheets & Specifications	20d	24-Jun-27	22-Jul-27
E16981	20014-L-5202 - Carbon Steel Pipe - Receive Vendor Info	0d	07-Sep-27	
E16991	20014-L-5202 - Carbon Steel Pipe - Review Vendor Data	10d	07-Sep-27	20-Sep-27
20014-L-5203 - Stainless Steel Fittings		60d	24-Jun-27	20-Sep-27
E17171	20014-L-5203 - Stainless Steel Fittings - Prepare RFP Data Sheets & Specificatior	20d	24-Jun-27	22-Jul-27
E17181	20014-L-5203 - Stainless Steel Fittings - Receive Vendor Info	0d	07-Sep-27	
E17191	20014-L-5203 - Stainless Steel Fittings - Review Vendor Data	10d	07-Sep-27	20-Sep-27
20014-L-5204 - Carbon Steel Fittings		60d	24-Jun-27	20-Sep-27
E20131	20014-L-5204 - Carbon Steel Fittings - Prepare RFP Data Sheets & Specifications	20d	24-Jun-27	22-Jul-27
E20141	20014-L-5204 - Carbon Steel Fittings - Receive Vendor Info	0d	07-Sep-27	
E20151	20014-L-5204 - Carbon Steel Fittings - Review Vendor Data	10d	07-Sep-27	20-Sep-27
20014-L-5205 - Stainless Steel Valves		74d	24-Jun-27	08-Oct-27
E15431	20014-L-5205 - Stainless Steel Valves - Prepare RFP Data Sheets & Specification:	20d	24-Jun-27	22-Jul-27
E15441	20014-L-5205 - Stainless Steel Valves - Receive Vendor Info	0d	27-Sep-27	
E15451	20014-L-5205 - Stainless Steel Valves - Review Vendor Data	10d	27-Sep-27	08-Oct-27
20014-L-5206 - Carbon Steel Valves		60d	24-Jun-27	20-Sep-27
E20281	20014-L-5206 - Carbon Steel Valves - Prepare RFP Data Sheets & Specifications	20d	24-Jun-27	22-Jul-27
E20291	20014-L-5206 - Carbon Steel Valves - Receive Vendor Info	0d	07-Sep-27	
E20301	20014-L-5206 - Carbon Steel Valves - Review Vendor Data	10d	07-Sep-27	20-Sep-27
20014-5207 - Cryogenic Pipe Supports		60d	24-Jun-27	20-Sep-27
E17091	20014-5207 - Cryogenic Pipe Supports - Prepare RFP Data Sheets & Specificatio	20d	24-Jun-27	22-Jul-27
E17101	20014-5207 - Cryogenic Pipe Supports - Receive Vendor Info	0d	07-Sep-27	
E17111	20014-5207 - Cryogenic Pipe Supports - Review Vendor Data	10d	07-Sep-27	20-Sep-27
20014-L-5208 - Insulation		60d	24-Jun-27	20-Sep-27
E17251	20014-L-5208 - Insulation - Prepare RFP Data Sheets & Specifications	20d	24-Jun-27	22-Jul-27
E17261	20014-L-5208 - Insulation - Receive Vendor Info	0d	07-Sep-27	
E17271	20014-L-5208 - Insulation - Review Vendor Data	10d	07-Sep-27	20-Sep-27
Piping Design		190d	18-Jan-27	19-Oct-27
Modeling		150d	18-Jan-27	20-Aug-27
G146	Piping Modeling to 60%	104d	18-Jan-27	15-Jun-27
E15531	Piping Modeling to 90%	35d	02-Jul-27	20-Aug-27
Tie-In		100d	21-Apr-27	13-Sep-27
E18441	Tie-In List - IFH	20d	21-Apr-27	18-May-27
E18451	Piping Tie-In List - IFC	30d	30-Jul-27	13-Sep-27
Key Plan		30d	30-Aug-27	12-Oct-27



Remaining Level of Effort | Actual Work | Critical Remaining Work
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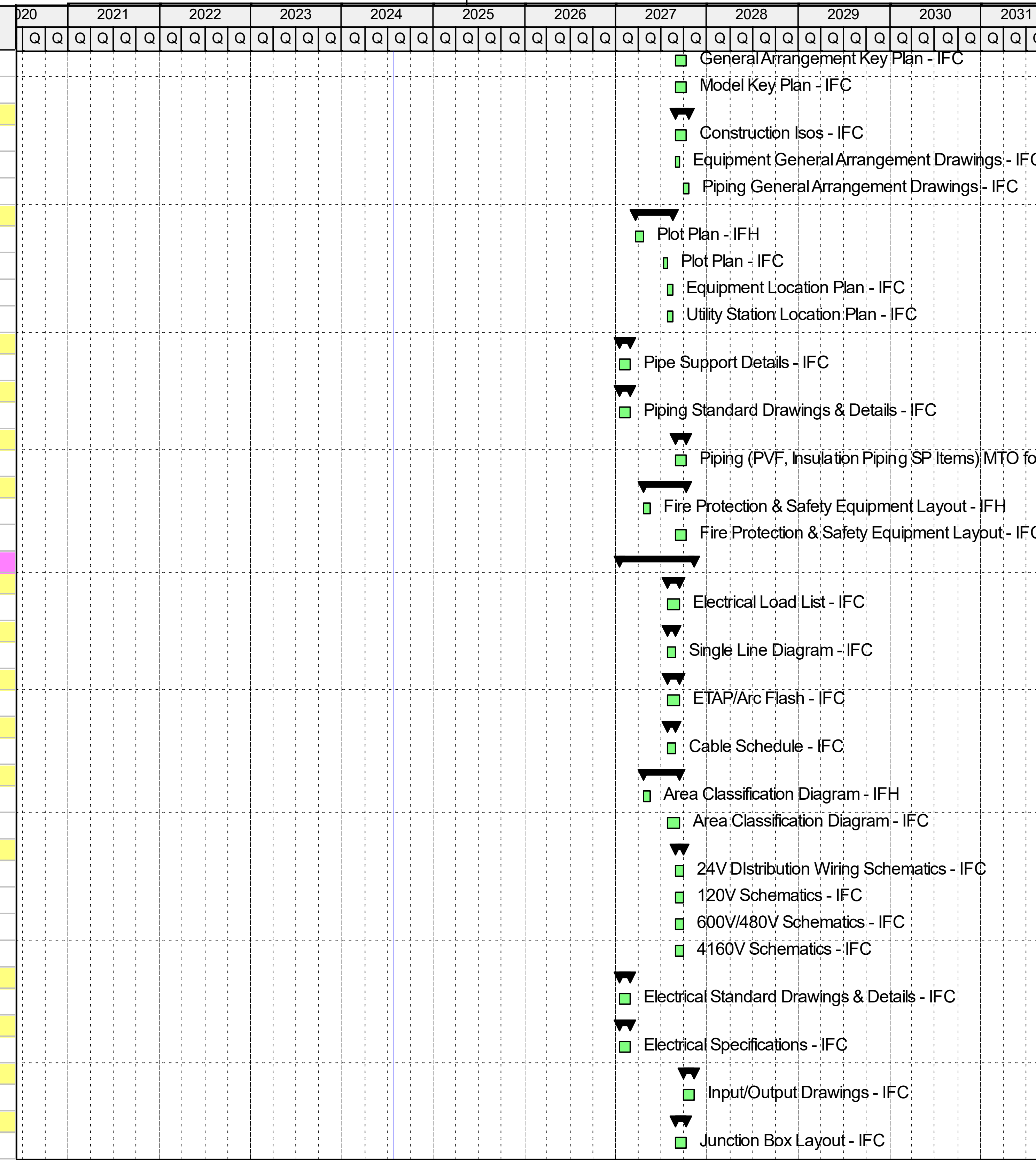
Tilbury Island LNG Facility Expansion (3 BCF)
TLSE Sub-Projects Integrated Schedule-Detailed

SOLARIS MANAGEMENT CONSULTANTS INC.

Activity ID	Activity Name	Rem. Duration	Start	Finish
E18461	General Arrangement Key Plan - IFC	30d	30-Aug-27	12-Oct-27
E18481	Model Key Plan - IFC	30d	30-Aug-27	12-Oct-27
Piping General Arrangements/Isos		35d	30-Aug-27	19-Oct-27
E15581	Construction Isos - IFC	30d	30-Aug-27	12-Oct-27
E18471	Equipment General Arrangement Drawings - IFC	10d	30-Aug-27	13-Sep-27
E15571	Piping General Arrangement Drawings - IFC	15d	28-Sep-27	19-Oct-27
Location Plan		105d	23-Mar-27	20-Aug-27
E19711	Plot Plan - IFH	20d	23-Mar-27	21-Apr-27
E19071	Plot Plan - IFC	15d	09-Jul-27	29-Jul-27
E16061	Equipment Location Plan - IFC	15d	30-Jul-27	20-Aug-27
E18491	Utility Station Location Plan - IFC	15d	30-Jul-27	20-Aug-27
Pipe Support		30d	18-Jan-27	01-Mar-27
E18501	Pipe Support Details - IFC	30d	18-Jan-27	01-Mar-27
Standard Drawings & Details		30d	18-Jan-27	01-Mar-27
E18511	Piping Standard Drawings & Details - IFC	30d	18-Jan-27	01-Mar-27
Material Take Off		30d	30-Aug-27	12-Oct-27
E15541	Piping (PVF, Insulation Piping SP Items) MTO for Estimating	30d	30-Aug-27	12-Oct-27
Fire Protection		120d	21-Apr-27	12-Oct-27
E18521	Fire Protection & Safety Equipment Layout - IFH	20d	21-Apr-27	18-May-27
E18531	Fire Protection & Safety Equipment Layout - IFC	30d	30-Aug-27	12-Oct-27
Electrical Engineering & Design		205d	18-Jan-27	09-Nov-27
Load List		30d	30-Jul-27	13-Sep-27
E18171	Electrical Load List - IFC	30d	30-Jul-27	13-Sep-27
Single Line Diagram		20d	30-Jul-27	27-Aug-27
E18381	Single Line Diagram - IFC	20d	30-Jul-27	27-Aug-27
ETAP/Arc Flash		30d	30-Jul-27	13-Sep-27
E19421	ETAP/Arc Flash - IFC	30d	30-Jul-27	13-Sep-27
Cable		20d	30-Jul-27	27-Aug-27
E18191	Cable Schedule - IFC	20d	30-Jul-27	27-Aug-27
Area Classification		100d	21-Apr-27	13-Sep-27
E15721	Area Classification Diagram - IFH	20d	21-Apr-27	18-May-27
E18371	Area Classification Diagram - IFC	30d	30-Jul-27	13-Sep-27
Schematics		20d	30-Aug-27	27-Sep-27
E18291	24V DIstribution Wiring Schematics - IFC	20d	30-Aug-27	27-Sep-27
E18301	120V Schematics - IFC	20d	30-Aug-27	27-Sep-27
E18311	600V/480V Schematics - IFC	20d	30-Aug-27	27-Sep-27
E18321	4160V Schematics - IFC	20d	30-Aug-27	27-Sep-27
Standard Drawings & Details		30d	18-Jan-27	01-Mar-27
E18351	Electrical Standard Drawings & Details - IFC	30d	18-Jan-27	01-Mar-27
Specifications		30d	18-Jan-27	01-Mar-27
E18361	Electrical Specifications - IFC	30d	18-Jan-27	01-Mar-27
Input/Output Drawings		30d	28-Sep-27	09-Nov-27
E18341	Input/Output Drawings - IFC	30d	28-Sep-27	09-Nov-27
Junction Box & Panel Drawings/Layout		30d	30-Aug-27	12-Oct-27
E18261	Junction Box Layout - IFC	30d	30-Aug-27	12-Oct-27



Remaining Level of Effort	Actual Level of Effort
Actual Work	Remaining Work
Critical Remaining Work	Critical Secondary

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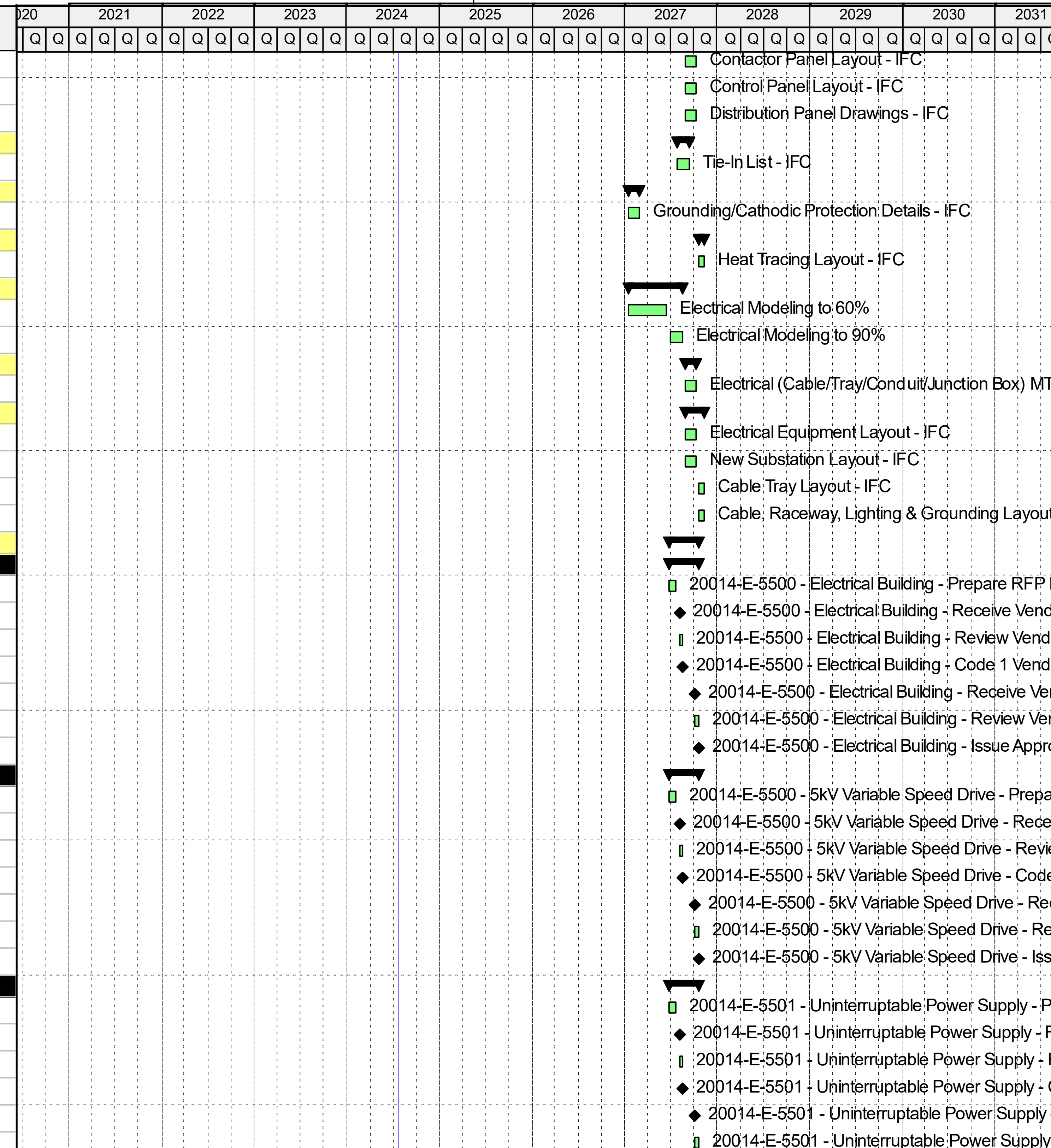
Activity ID	Activity Name	Rem. Duration	Start	Finish
E18271	Contactor Panel Layout - IFC	30d	30-Aug-27	12-Oct-27
E18281	Control Panel Layout - IFC	30d	30-Aug-27	12-Oct-27
E18331	Distribution Panel Drawings - IFC	30d	30-Aug-27	12-Oct-27
Tie-In		30d	30-Jul-27	13-Sep-27
E18241	Tie-In List - IFC	30d	30-Jul-27	13-Sep-27
Grounding/Cathodic Protection		30d	18-Jan-27	01-Mar-27
E18201	Grounding/Cathodic Protection Details - IFC	30d	18-Jan-27	01-Mar-27
Heat Trace		15d	20-Oct-27	09-Nov-27
E18251	Heat Tracing Layout - IFC	15d	20-Oct-27	09-Nov-27
Modeling		150d	18-Jan-27	20-Aug-27
E20121	Electrical Modeling to 60%	104d	18-Jan-27	15-Jun-27
E15731	Electrical Modeling to 90%	35d	02-Jul-27	20-Aug-27
Material Take Off		30d	30-Aug-27	12-Oct-27
E15741	Electrical (Cable/Tray/Conduit/Junction Box) MTO for Estimating	30d	30-Aug-27	12-Oct-27
Electrical Layouts/Isos		50d	30-Aug-27	09-Nov-27
E18221	Electrical Equipment Layout - IFC	30d	30-Aug-27	12-Oct-27
E18231	New Substation Layout - IFC	30d	30-Aug-27	12-Oct-27
E18181	Cable Tray Layout - IFC	15d	20-Oct-27	09-Nov-27
E18211	Cable, Raceway, Lighting & Grounding Layout - IFC	15d	20-Oct-27	09-Nov-27
Requisition		80d	24-Jun-27	19-Oct-27
20014-E-5500: Electrical Building		80d	24-Jun-27	19-Oct-27
E20381	20014-E-5500 - Electrical Building - Prepare RFP Data Sheets & Specifications	20d	24-Jun-27	22-Jul-27
E20391	20014-E-5500 - Electrical Building - Receive Vendor Info	0d	09-Aug-27	
E20401	20014-E-5500 - Electrical Building - Review Vendor Data	10d	09-Aug-27	20-Aug-27
E20411	20014-E-5500 - Electrical Building - Code 1 Vendor Data	0d		20-Aug-27
E20421	20014-E-5500 - Electrical Building - Receive Vendor Data Books	0d	05-Oct-27	
E20431	20014-E-5500 - Electrical Building - Review Vendor Data Books	10d	05-Oct-27	19-Oct-27
E20441	20014-E-5500 - Electrical Building - Issue Approval for Payment	0d		19-Oct-27
20014-E-5500: 5kV Variable Speed Drive		80d	24-Jun-27	19-Oct-27
E16491	20014-E-5500 - 5kV Variable Speed Drive - Prepare RFP Data Sheets & Specifica	20d	24-Jun-27	22-Jul-27
E16501	20014-E-5500 - 5kV Variable Speed Drive - Receive Vendor Info	0d	09-Aug-27	
E16511	20014-E-5500 - 5kV Variable Speed Drive - Review Vendor Data	10d	09-Aug-27	20-Aug-27
E16521	20014-E-5500 - 5kV Variable Speed Drive - Code 1 Vendor Data	0d		20-Aug-27
E16531	20014-E-5500 - 5kV Variable Speed Drive - Receive Vendor Data Books	0d	05-Oct-27	
E16541	20014-E-5500 - 5kV Variable Speed Drive - Review Vendor Data Books	10d	05-Oct-27	19-Oct-27
E16551	20014-E-5500 - 5kV Variable Speed Drive - Issue Approval for Payment	0d		19-Oct-27
20014-E-5501: Uninterruptable Power Supply (UPS)		80d	24-Jun-27	19-Oct-27
E16731	20014-E-5501 - Uninterruptable Power Supply - Prepare RFP Data Sheets & Spe	20d	24-Jun-27	22-Jul-27
E16741	20014-E-5501 - Uninterruptable Power Supply - Receive Vendor Info	0d	09-Aug-27	
E16751	20014-E-5501 - Uninterruptable Power Supply - Review Vendor Data	10d	09-Aug-27	20-Aug-27
E16761	20014-E-5501 - Uninterruptable Power Supply - Code 1 Vendor Data	0d		20-Aug-27
E16771	20014-E-5501 - Uninterruptable Power Supply - Receive Vendor Data Books	0d	05-Oct-27	
E16781	20014-E-5501 - Uninterruptable Power Supply - Review Vendor Data Books	10d	05-Oct-27	19-Oct-27



Remaining Level of Effort | Actual Work | Critical Remaining Work
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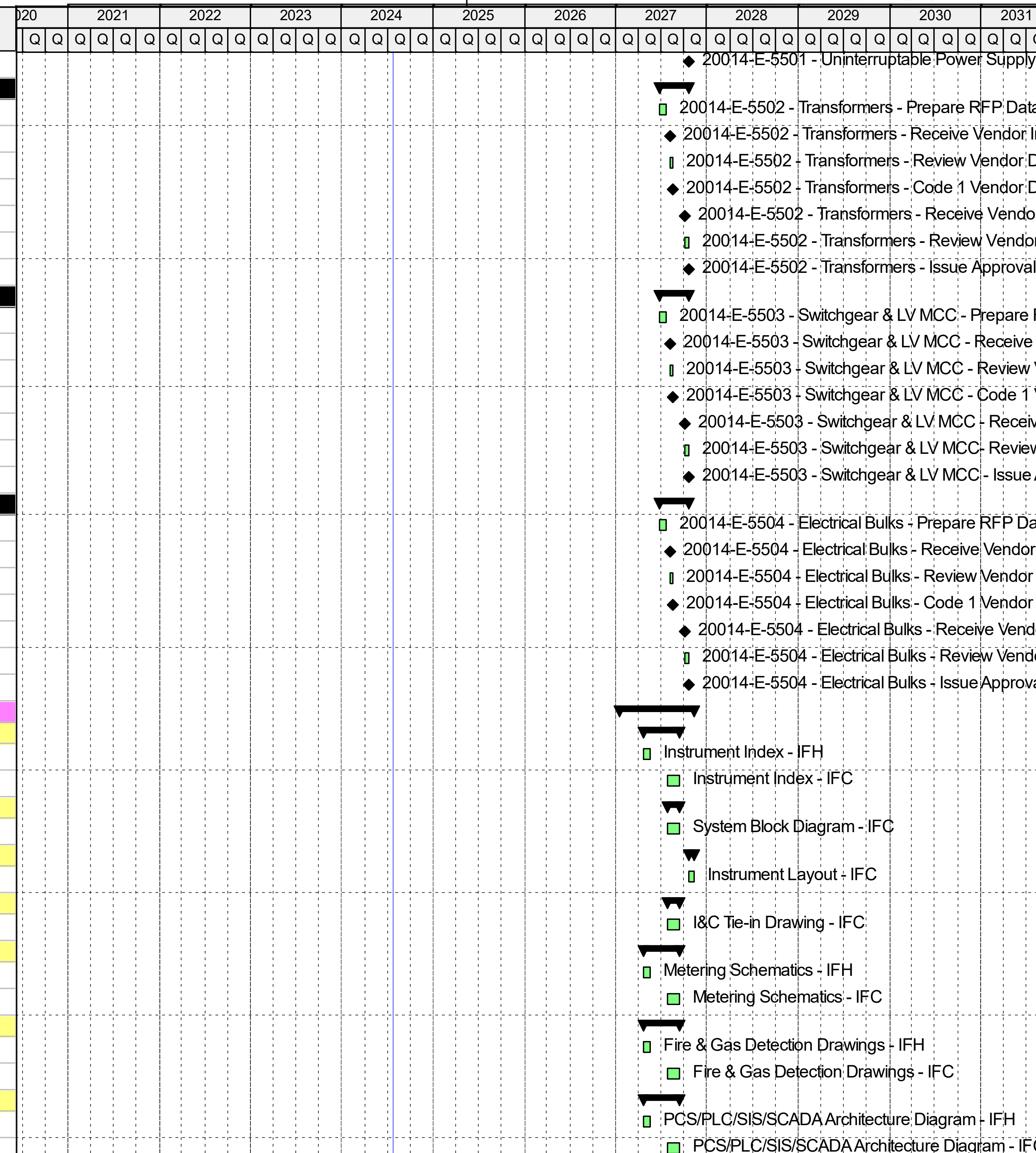
Activity ID	Activity Name	Rem. Duration	Start	Finish
E16791	20014-E-5501 - Uninterruptable Power Supply - Issue Approval for Payment	0d		19-Oct-27
20014-E-5502: Transformers		**80d**	**24-Jun-27**	**19-Oct-27**
E16851	20014-E-5502 - Transformers - Prepare RFP Data Sheets & Specifications	20d	24-Jun-27	22-Jul-27
E16861	20014-E-5502 - Transformers - Receive Vendor Info	0d	09-Aug-27	
E16871	20014-E-5502 - Transformers - Review Vendor Data	10d	09-Aug-27	20-Aug-27
E16881	20014-E-5502 - Transformers - Code 1 Vendor Data	0d		20-Aug-27
E16891	20014-E-5502 - Transformers - Receive Vendor Data Books	0d	05-Oct-27	
E16901	20014-E-5502 - Transformers - Review Vendor Data Books	10d	05-Oct-27	19-Oct-27
E16911	20014-E-5502 - Transformers - Issue Approval for Payment	0d		19-Oct-27
20014-E-5503: Switchgear & LV MCC		**80d**	**24-Jun-27**	**19-Oct-27**
E16611	20014-E-5503 - Switchgear & LV MCC - Prepare RFP Data Sheets & Specificatior	20d	24-Jun-27	22-Jul-27
E16621	20014-E-5503 - Switchgear & LV MCC - Receive Vendor Info	0d	09-Aug-27	
E16631	20014-E-5503 - Switchgear & LV MCC - Review Vendor Data	10d	09-Aug-27	20-Aug-27
E16641	20014-E-5503 - Switchgear & LV MCC - Code 1 Vendor Data	0d		20-Aug-27
E16651	20014-E-5503 - Switchgear & LV MCC - Receive Vendor Data Books	0d	05-Oct-27	
E16661	20014-E-5503 - Switchgear & LV MCC- Review Vendor Data Books	10d	05-Oct-27	19-Oct-27
E16671	20014-E-5503 - Switchgear & LV MCC - Issue Approval for Payment	0d		19-Oct-27
20014-E-5504: Electrical Bulks		**80d**	**24-Jun-27**	**19-Oct-27**
E15601	20014-E-5504 - Electrical Bulks - Prepare RFP Data Sheets & Specifications	20d	24-Jun-27	22-Jul-27
E15611	20014-E-5504 - Electrical Bulks - Receive Vendor Info	0d	09-Aug-27	
E15621	20014-E-5504 - Electrical Bulks - Review Vendor Data	10d	09-Aug-27	20-Aug-27
E15631	20014-E-5504 - Electrical Bulks - Code 1 Vendor Data	0d		20-Aug-27
E15641	20014-E-5504 - Electrical Bulks - Receive Vendor Data Books	0d	05-Oct-27	
E15651	20014-E-5504 - Electrical Bulks - Review Vendor Data Books	10d	05-Oct-27	19-Oct-27
E15661	20014-E-5504 - Electrical Bulks - Issue Approval for Payment	0d		19-Oct-27
Instrumentation Engineering & Design		**205d**	**18-Jan-27**	**09-Nov-27**
Instrument Index		**100d**	**21-Apr-27**	**13-Sep-27**
E15911	Instrument Index - IFH	20d	21-Apr-27	18-May-27
E17751	Instrument Index - IFC	30d	30-Jul-27	13-Sep-27
System Block Diagram		**30d**	**30-Jul-27**	**13-Sep-27**
E18061	System Block Diagram - IFC	30d	30-Jul-27	13-Sep-27
Instrument Layout		**15d**	**20-Oct-27**	**09-Nov-27**
E18071	Instrument Layout - IFC	15d	20-Oct-27	09-Nov-27
Tie-in		**30d**	**30-Jul-27**	**13-Sep-27**
E18081	I&C Tie-in Drawing - IFC	30d	30-Jul-27	13-Sep-27
Metering Schematics		**100d**	**21-Apr-27**	**13-Sep-27**
E18091	Metering Schematics - IFH	20d	21-Apr-27	18-May-27
E18101	Metering Schematics - IFC	30d	30-Jul-27	13-Sep-27
Fire & Gas Detection Drawings		**100d**	**21-Apr-27**	**13-Sep-27**
E18111	Fire & Gas Detection Drawings - IFH	20d	21-Apr-27	18-May-27
E18121	Fire & Gas Detection Drawings - IFC	30d	30-Jul-27	13-Sep-27
Architectural Diagram		**100d**	**21-Apr-27**	**13-Sep-27**
E18131	PCS/PLC/SIS/SCADA Architecture Diagram - IFH	20d	21-Apr-27	18-May-27
E18141	PCS/PLC/SIS/SCADA Architecture Diagram - IFC	30d	30-Jul-27	13-Sep-27



Remaining Level of Effort | Actual Work | Critical Remaining Work
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Standard Drawings & Details		30d	18-Jan-27	01-Mar-27
E18151	Standard Drawings & Details - IFC	30d	18-Jan-27	01-Mar-27
Specifications		30d	18-Jan-27	01-Mar-27
E18161	I&C Specifications - IFC	30d	18-Jan-27	01-Mar-27
Alarm/Set Point Table		100d	21-Apr-27	13-Sep-27
E15931	Alarm Set Point Table - IFH	20d	21-Apr-27	18-May-27
E16091	Alarm Set Point Table - IFC	30d	30-Jul-27	13-Sep-27
Shutdown Key		90d	23-Mar-27	29-Jul-27
E15891	Shut Down Key - IFH	20d	23-Mar-27	21-Apr-27
E16071	Shut Down Key - IFC	30d	17-Jun-27	29-Jul-27
Material Take Off		30d	30-Aug-27	12-Oct-27
E15951	Instrumentation & Controls MTO	30d	30-Aug-27	12-Oct-27
Programming		10d	14-Sep-27	27-Sep-27
E15881	Programming Package	10d	14-Sep-27	27-Sep-27
Requisition		140d	01-Feb-27	20-Aug-27
20014-J-5600 - ESDV		45d	01-Feb-27	06-Apr-27
E15761	20014-J-5600 - ESDV - Prepare Instrument Data Sheet - RFP	20d	01-Feb-27	01-Mar-27
E19681	20014-J-5600 - ESDV - Receive Vendor Info	0d	23-Mar-27	
E19751	20014-J-5600 - ESDV - Review Vendor Data	10d	23-Mar-27	06-Apr-27
E19761	20014-J-5600 - ESDV - Code 1 Vendor Data	0d		06-Apr-27
20014-J-5601: Orifice Plate Meter		40d	24-Jun-27	20-Aug-27
E17611	20014-J-5601: Orifice Plate Meter - Prepare Instrument Data Sheet - RFP	15d	24-Jun-27	15-Jul-27
E19661	20014-J-5601: Orifice Plate Meter - Receive Vendor Info	0d	09-Aug-27	
E19811	20014-J-5601: Orifice Plate Meter - Review Vendor Data	10d	09-Aug-27	20-Aug-27
E19821	20014-J-5601: Orifice Plate Meter - Code 1 Vendor Data	0d		20-Aug-27
20014-J-5602 - Flow Control Valve		45d	01-Feb-27	06-Apr-27
E17491	20014-J-5602 - Flow Control Valve - Prepare Instrument Data Sheet - RFP	20d	01-Feb-27	01-Mar-27
E19651	20014-J-5602 - Flow Control Valve - Receive Vendor Info	0d	23-Mar-27	
E19771	20014-J-5602 - Flow Control Valve - Review Vendor Data	10d	23-Mar-27	06-Apr-27
E19781	20014-J-5602 - Flow Control Valve - Code 1 Vendor Data	0d		06-Apr-27
20014-J-5602 - PSV's		40d	24-Jun-27	20-Aug-27
E17551	20014-J-5602 - PSV's - Prepare Instrument Data Sheet - RFP	15d	24-Jun-27	15-Jul-27
E19671	20014-J-5602 - PSV's - Receive Vendor Info	0d	09-Aug-27	
E19791	20014-J-5602 - PSV's - Review Vendor Data	10d	09-Aug-27	20-Aug-27
E19801	20014-J-5602 - PSV's - Code 1 Vendor Data	0d		20-Aug-27
20014-J-56XX: Fire/Gas Detedtion System		20d	24-Jun-27	22-Jul-27
E17671	20014-J-56XX - Fire/Gas Detection System - Prepare Instrument Data Sheet - RF	20d	24-Jun-27	22-Jul-27
Procurement		359d	18-Jan-27	27-Jun-28
Civil/Structural/Architectural		180d	18-Jan-27	05-Oct-27
20014-C-5301: BOG Building		180d	18-Jan-27	05-Oct-27
E15831	20014-C-5301 - BOG Building - Refresh/Renegotiate	20d	18-Jan-27	12-Feb-27
E15841	20014-C-5301 - BOG Building - Develop MRP	20d	18-Jan-27	12-Feb-27
E15851	20014-C-5301 - BOG Building - Issue PO to Vendor	0d		12-Feb-27
E19441	20014-C-5301 - BOG Building - Manufacture	155d	16-Feb-27	27-Sep-27

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E15861	20014-C-5301 - BOG Building - Ready to Ship	0d		27-Sep-27
E15871	20014-C-5301 - BOG Building - ETA to Site	0d		04-Oct-27
E20001	WBS-002 Receive at Site - BOG Building	0d	05-Oct-27	
20014-C-5302: Galvanized Steel		20d	18-Jan-27	12-Feb-27
E17341	20014-C-5302 - Galvanized Steel - Refresh/Renegotiate	20d	18-Jan-27	12-Feb-27
E17351	20014-C-5302 - Galvanized Steel - Develop MRP	20d	18-Jan-27	12-Feb-27
E17361	20014-C-5302 - Galvanized Steel - Issue PO to Vendor	0d		12-Feb-27
20014-C-5303: Concrete		40d	18-Jan-27	16-Mar-27
E17381	20014-C-5303 - Concrete - Refresh/Renegotiate	20d	18-Jan-27	12-Feb-27
E17391	20014-C-5303 - Concrete - Develop MRP	20d	18-Jan-27	12-Feb-27
E17401	20014-C-5303 - Concrete - Issue PO to Vendor	0d		12-Feb-27
E19631	20014-C-5303 - Concrete - Manufacture	15d	16-Feb-27	08-Mar-27
E17411	20014-C-5303 - Concrete - Ready to Ship	0d		08-Mar-27
E17421	20014-C-5303 - Concrete - ETA to Site	0d		15-Mar-27
E19981	WBS-002 Receive at Site Concrete & Foundation Materials	0d	16-Mar-27	
E19991	WBS-002 Receive at Site Structural Steel Materials	0d	16-Mar-27	
20014-C-53XX: Fill Materials		40d	18-Jan-27	16-Mar-27
E17441	20014-C-53XX - Fill Materials - Refresh/Renegotiate	20d	18-Jan-27	12-Feb-27
E17451	20014-C-53XX - Fill Materials - Develop MRP	20d	18-Jan-27	12-Feb-27
E17461	20014-C-53XX - Fill Materials - Issue PO to Vendor	0d		12-Feb-27
E19641	20014-C-53XX - Fill Materials - Manufacture	15d	16-Feb-27	08-Mar-27
E17471	20014-C-53XX - Fill Materials - Ready to Ship	0d		08-Mar-27
E17481	20014-C-53XX - Fill Materials - ETA to Site	0d		15-Mar-27
E19971	WBS-002 Receive at Site Fill Materials	0d	16-Mar-27	
Mechanical		315d	02-Mar-27	07-Jun-28
20014-M-5101: Cyro Pump		315d	02-Mar-27	07-Jun-28
E15381	20014-M-5101 - Cyro Pump - Refresh/Renegotiation	20d	02-Mar-27	29-Mar-27
E15391	20014-M-5101 - Cyro Pump - Develop MRP	20d	02-Mar-27	29-Mar-27
E15401	20014-M-5101 - Cyro Pump - Issue PO to Vendor	0d		29-Mar-27
E19461	20014-M-5101 - Cyro Pump - Manufacture	285d	30-Mar-27	23-May-28
E18551	20014-M-5101 - Cyro Pump - Testing & Inspection	2d	24-May-28	25-May-28
E15411	20014-M-5101 - Cyro Pump - Ready to Ship	0d		30-May-28
E15421	20014-M-5101 - Cyro Pump - ETA to Site	0d		06-Jun-28
E20741	WBS-002 Receive at Site - Cryo Pump	0d	07-Jun-28	
20014-M-5102: BOG Compressor		315d	02-Mar-27	07-Jun-28
E16441	20014-M-5102 - BOG Compressor - Refresh/Renegotiation	20d	02-Mar-27	29-Mar-27
E16451	20014-M-5102 - BOG Compressor - Develop MRP	20d	02-Mar-27	29-Mar-27
E16461	20014-M-5102 - BOG Compressor - Issue PO to Vendor	0d		29-Mar-27
E19451	20014-M-5102 - BOG Compressor - Manufacture	285d	30-Mar-27	23-May-28
E18541	20014-M-5102 - BOG Compressor - Testing & Inspection	2d	24-May-28	25-May-28
E16471	20014-M-5102 - BOG Compressor - Ready to Ship	0d		30-May-28
E16481	20014-M-5102 - BOG Compressor - ETA to Site	0d		06-Jun-28
E20751	WBS-002 Receive at Site - BOG Compressor	0d	07-Jun-28	

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Activity ID	Activity Name	Rem. Duration	Start	Finish
Piping		**249d**	**24-Jun-27**	**27-Jun-28**
20014-L-5201: Stainless Steel Pipe		**20d**	**24-Jun-27**	**22-Jul-27**
E17061	20014-L-5201 - Stainless Steel Pipe - Refresh/Renegotiate	20d	24-Jun-27	22-Jul-27
E17071	20014-L-5201 - Stainless Steel Pipe - Develop MRP	20d	24-Jun-27	22-Jul-27
E17081	20014-L-5201 - Stainless Steel Pipe - Issue PO to Vendor	0d		22-Jul-27
20014-L-5202: Carbon Steel Pipe		**20d**	**24-Jun-27**	**22-Jul-27**
E17001	20014-L-5202 - Carbon Steel Pipe - Refresh/Renegotiate	20d	24-Jun-27	22-Jul-27
E17011	20014-L-5202 - Carbon Steel Pipe - Develop MRP	20d	24-Jun-27	22-Jul-27
E17021	20014-L-5202 - Carbon Steel Pipe - Issue PO to Vendor	0d		22-Jul-27
20014-L-5203: Stainless Steel Fittings		**125d**	**24-Jun-27**	**23-Dec-27**
E17201	20014-L-5203 - Stainless Steel Fittings - Refresh/Renegotiate	20d	24-Jun-27	22-Jul-27
E17211	20014-L-5203 - Stainless Steel Fittings - Develop MRP	20d	24-Jun-27	22-Jul-27
E17221	20014-L-5203 - Stainless Steel Fittings - Issue PO to Vendor	0d		22-Jul-27
E19511	20014-L-5203 - Stainless Steel Fittings - Manufacture	100d	23-Jul-27	15-Dec-27
E17231	20014-L-5203 - Stainless Steel Fittings - Ready to Ship	0d		15-Dec-27
E17241	20014-L-5203 - Stainless Steel Fittings - ETA to Site	0d		22-Dec-27
E20601	WBS-002 Receive at Site - Stainless Steel Fittings	0d	23-Dec-27	
20014-L-5204: Carbon Steel Fittings		**125d**	**24-Jun-27**	**23-Dec-27**
E20161	20014-L-5204 - Carbon Steel Fittings - Refresh/Renegotiate	20d	24-Jun-27	22-Jul-27
E20171	20014-L-5204 - Carbon Steel Fittings - Develop MRP	20d	24-Jun-27	22-Jul-27
E20181	20014-L-5204 - Carbon Steel Fittings - Issue PO to Vendor	0d		22-Jul-27
E20211	20014-L-5204 - Carbon Steel Fittings - Manufacture	100d	23-Jul-27	15-Dec-27
E20191	20014-L-5204 - Carbon Steel Fittings - Ready to Ship	0d		15-Dec-27
E20201	20014-L-5204 - Carbon Steel Fittings - ETA to Site	0d		22-Dec-27
E20611	WBS-002 Receive at Site - Carbon Steel Fittings	0d	23-Dec-27	
20014-L-5205: Stainless Steel Valves		**235d**	**15-Jul-27**	**27-Jun-28**
E15461	20014-L-5205 - Stainless Steel Valves - Refresh/Renegotiate	20d	15-Jul-27	12-Aug-27
E15471	20014-L-5205 - Stainless Steel Valves - Develop MRP	20d	15-Jul-27	12-Aug-27
E15481	20014-L-5205 - Stainless Steel Valves - Issue PO to Vendor	0d		12-Aug-27
E19491	20014-L-5205 - Stainless Steel Valves - Manufacture	200d	13-Aug-27	05-Jun-28
E15491	20014-L-5205 - Stainless Steel Valves - Ready to Ship	0d		05-Jun-28
E15501	20014-L-5205 - Stainless Steel Valves - ETA to Site	0d		26-Jun-28
E20011	WBS-002 Receive at Site - Stainless Steel Valves	0d	27-Jun-28	
20014-L-5206: Carbon Steel Valves		**235d**	**24-Jun-27**	**07-Jun-28**
E20221	20014-L-5206 - Carbon Steel Valves - Refresh/Renegotiate	20d	24-Jun-27	22-Jul-27
E20231	20014-L-5206 - Carbon Steel Valves - Develop MRP	20d	24-Jun-27	22-Jul-27
E20241	20014-L-5206 - Carbon Steel Valves - Issue PO to Vendor	0d		22-Jul-27
E20271	20014-L-5206 - Carbon Steel Valves - Manufacture	200d	23-Jul-27	15-May-28
E20251	20014-L-5206 - Carbon Steel Valves - Ready to Ship	0d		15-May-28
E20261	20014-L-5206 - Carbon Steel Valves - ETA to Site	0d		06-Jun-28
E20621	WBS-002 Receive at Site - Carbon Steel Valves	0d	07-Jun-28	
20014-L-5207: Cryogenic Pipe Supports		**100d**	**24-Jun-27**	**18-Nov-27**
E17121	20014-L-5207 - Cryogenic Pipe Supports - Refresh/Renegotiate	20d	24-Jun-27	22-Jul-27

Remaining Level of Effort — Actual Work — Critical Remaining Work

Actual Level of Effort — Remaining Work — Critical Secondary

Date	Revision	Checked	Approved
19-Aug-24	IFI		

Activity ID	Activity Name	Rem. Duration	Start	Finish
E17131	20014-L-5207 - Cryogenic Pipe Supports - Develop MRP	20d	24-Jun-27	22-Jul-27
E17141	20014-L-5207 - Cryogenic Pipe Supports - Issue PO to Vendor	0d		22-Jul-27
E19501	20014-L-5207 - Cryogenic Pipe Supports - Manufacture	75d	23-Jul-27	09-Nov-27
E17151	20014-L-5207 - Cryogenic Pipe Supports - Ready to Ship	0d		09-Nov-27
E17161	20014-L-5207 - Cryogenic Pipe Supports - ETA to Site	0d		17-Nov-27
E20591	WBS-002 Receive at Site - Cryogenic Pipe Supports	0d	18-Nov-27	
20014-L-5208: Insulation		75d	24-Jun-27	13-Oct-27
E17281	20014-L-5208 - Insulation - Refresh/Renegotiate	20d	24-Jun-27	22-Jul-27
E17291	20014-L-5208 - Insulation - Develop MRP	20d	24-Jun-27	22-Jul-27
E17301	20014-L-5208 - Insulation - Issue PO to Vendor	0d		22-Jul-27
E19521	20014-L-5208 - Insulation - Manufacture	50d	23-Jul-27	04-Oct-27
E17311	20014-L-5208 - Insulation - Ready to Ship	0d		04-Oct-27
E17321	20014-L-5208 - Insulation - ETA to Site	0d		12-Oct-27
E20071	WBS-002 Receive at Site Insulation	0d	13-Oct-27	
Electrical		230d	24-Jun-27	31-May-28
20014-E-5500 - Electrical Building		195d	24-Jun-27	11-Apr-28
E20311	20014-E-5500 - Electrical Building - Refresh/Renegotiate	20d	24-Jun-27	22-Jul-27
E20321	20014-E-5500 - Electrical Building - Develop MRP	20d	24-Jun-27	22-Jul-27
E20331	20014-E-5500 - Electrical Building - Issue PO to Vendor	0d		22-Jul-27
E20371	20014-E-5500 - Electrical Building - Manufacture	150d	23-Jul-27	03-Mar-28
E20361	20014-E-5500 - Electrical Building - Testing & Inspection	2d	06-Mar-28	07-Mar-28
E20341	20014-E-5500 - Electrical Building - Ready to Ship	0d		10-Mar-28
E20351	20014-E-5500 - Electrical Building - ETA to Site	0d		10-Apr-28
E20671	WBS-002 Receive at Site - Electrical Building	0d	11-Apr-28	
20014-E-5500 - 5kV Variable Speed Drive		150d	24-Jun-27	04-Feb-28
E16561	20014-E-5500 - 5kV Variable Speed Drive - Refresh/Renegotiate	20d	24-Jun-27	22-Jul-27
E16571	20014-E-5500 - 5kV Variable Speed Drive - Develop MRP	20d	24-Jun-27	22-Jul-27
E16581	20014-E-5500 - 5kV Variable Speed Drive - Issue PO to Vendor	0d		22-Jul-27
E19531	20014-E-5500 - 5kV Variable Speed Drive - Manufacture	105d	23-Jul-27	22-Dec-27
E18581	20014-E-5500 - 5kV Variable Speed Drive - Testing & Inspection	2d	23-Dec-27	24-Dec-27
E16591	20014-E-5500 - 5kV Variable Speed Drive - Ready to Ship	0d		06-Jan-28
E16601	20014-E-5500 - 5kV Variable Speed Drive - ETA to Site	0d		03-Feb-28
E20631	WBS-002 Receive at Site - 5kV Variable Speed Drive	0d	04-Feb-28	
20014-E-5501 - Uninterruptable Power Supply		175d	24-Jun-27	13-Mar-28
E16801	20014-E-5501 - Uninterruptable Power Supply - Refresh/Renegotiate	20d	24-Jun-27	22-Jul-27
E16811	20014-E-5501 - Uninterruptable Power Supply - Develop MRP	20d	24-Jun-27	22-Jul-27
E16821	20014-E-5501 - Uninterruptable Power Supply - Issue PO to Vendor	0d		22-Jul-27
E19541	20014-E-5501 - Uninterruptable Power Supply - Manufacture	120d	23-Jul-27	20-Jan-28
E18591	20014-E-5501 - Uninterruptable Power Supply - Testing & Inspection	2d	21-Jan-28	24-Jan-28
E16831	20014-E-5501 - Uninterruptable Power Supply - Ready to Ship	0d		27-Jan-28
E16841	20014-E-5501 - Uninterruptable Power Supply - ETA to Site	0d		10-Mar-28
E20651	WBS-002 Receive at Site - Uninterruptable Power Supply	0d	13-Mar-28	
20014-E-5502 - Transformers		230d	24-Jun-27	31-May-28

Remaining Level of Effort — Actual Level of Effort — Actual Work — Remaining Work — Critical Remaining Work — Critical Secondary

Date	Revision	Checked	Approved
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Activity ID	Activity Name	Rem. Duration	Start	Finish
E16921	20014-E-5502 - Transformers - Refresh/Renegotiate	20d	24-Jun-27	22-Jul-27
E16931	20014-E-5502 - Transformers - Develop MRP	20d	24-Jun-27	22-Jul-27
E16941	20014-E-5502 - Transformers - Issue PO to Vendor	0d		22-Jul-27
E19551	20014-E-5502 - Transformers - Manufacture	200d	23-Jul-27	15-May-28
E18601	20014-E-5502 - Transformers - Testing & Inspection	2d	16-May-28	17-May-28
E16951	20014-E-5502 - Transformers - Ready to Ship	0d		23-May-28
E16961	20014-E-5502 - Transformers - ETA to Site	0d		30-May-28
E20661	WBS-002 Receive at Site - Transformers	0d	31-May-28	
20014-E-5503 - Switchgear & LV MCC		**165d**	**24-Jun-27**	**28-Feb-28**
E16681	20014-E-5503 - Switchgear & LV MCC - Refresh/Renegotiate	20d	24-Jun-27	22-Jul-27
E16691	20014-E-5503 - Switchgear & LV MCC - Develop MRP	20d	24-Jun-27	22-Jul-27
E16701	20014-E-5503 - Switchgear & LV MCC - Issue PO to Vendor	0d		22-Jul-27
E19561	20014-E-5503 - Switchgear & LV MCC - Manufacture	130d	23-Jul-27	03-Feb-28
E18611	20014-E-5503 - Switchgear & LV MCC - Testing & Inspection	2d	04-Feb-28	07-Feb-28
E16711	20014-E-5503 - Switchgear & LV MCC - Ready to Ship	0d		10-Feb-28
E16721	20014-E-5503 - Switchgear & LV MCC - ETA to Site	0d		25-Feb-28
E20641	WBS-002 Receive at Site - Switchgear & LV MCC	0d	28-Feb-28	
20014-E-5504 - Electrical Bulks		**110d**	**24-Jun-27**	**02-Dec-27**
E15671	20014-E-5504 - Electrical Bulks - Refresh/Renegotiate	20d	24-Jun-27	22-Jul-27
E15681	20014-E-5504 - Electrical Bulks - Develop MRP	20d	24-Jun-27	22-Jul-27
E15691	20014-E-5504 - Electrical Bulks - Issue PO to Vendor	0d		22-Jul-27
E19571	20014-E-5504 - Electrical Bulks - Manufacture	80d	23-Jul-27	17-Nov-27
E15701	20014-E-5504 - Electrical Bulks - Ready to Ship	0d		17-Nov-27
E15711	20014-E-5504 - Electrical Bulks - ETA to Site	0d		01-Dec-27
E20091	WBS-002 Receive at Site - Electrical Bulks	0d	02-Dec-27	
Instrumentation		**330d**	**01-Feb-27**	**31-May-28**
20014-J-5600: ESDV		**60d**	**01-Feb-27**	**28-Apr-27**
E15771	20014-J-5600 - ESDV - Refresh/Renegotiate	20d	01-Feb-27	01-Mar-27
E15781	20014-J-5600 - ESDV - Develop MRP	20d	01-Feb-27	01-Mar-27
E15791	20014-J-5600 - ESDV - Issue PO to Vendor	0d		01-Mar-27
E19591	20014-J-5600 - ESDV - Manufacture	35d	02-Mar-27	20-Apr-27
E15801	20014-J-5600 - ESDV - Ready to Ship	0d		20-Apr-27
E15811	20014-J-5600 - ESDV - ETA to Site	0d		27-Apr-27
E20051	WBS-002 Receive at Site - ESDV	0d	28-Apr-27	
20014-J-5601 Orifice Plate Meter		**65d**	**17-Jun-27**	**21-Sep-27**
E17621	20014-J-5601: Orifice Plate Meter - Refresh/Renegotiate	20d	17-Jun-27	15-Jul-27
E17631	20014-J-5601: Orifice Plate Meter - Develop MRP	20d	17-Jun-27	15-Jul-27
E17641	20014-J-5601: Orifice Plate Meter - Issue PO to Vendor	0d		15-Jul-27
E19621	20014-J-5601: Orifice Plate Meter - Manufacture	40d	16-Jul-27	13-Sep-27
E17651	20014-J-5601: Orifice Plate Meter - Ready to Ship	0d		13-Sep-27
E17661	20014-J-5601: Orifice Plate Meter - ETA to Site	0d		20-Sep-27
E20701	WBS-002 Receive at Site - Orifice Plate Meter	0d	21-Sep-27	
20014-J-5602: Flow Control Valve		**165d**	**01-Feb-27**	**28-Sep-27**

Legend: Remaining Level of Effort; Actual Level of Effort; Actual Work; Remaining Work; Critical Remaining Work; Critical Secondary

Date	Revision	Checked	Approved
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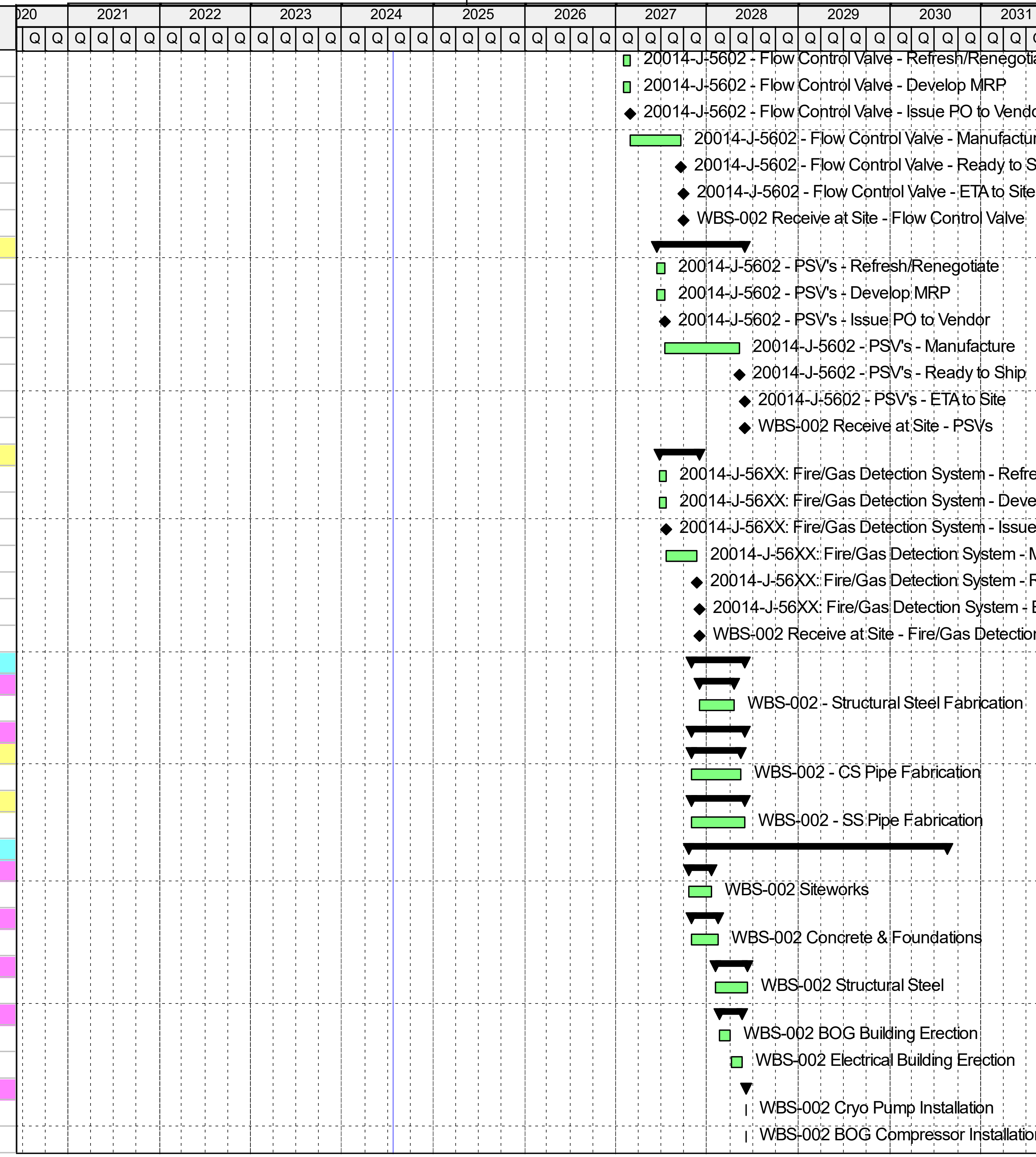
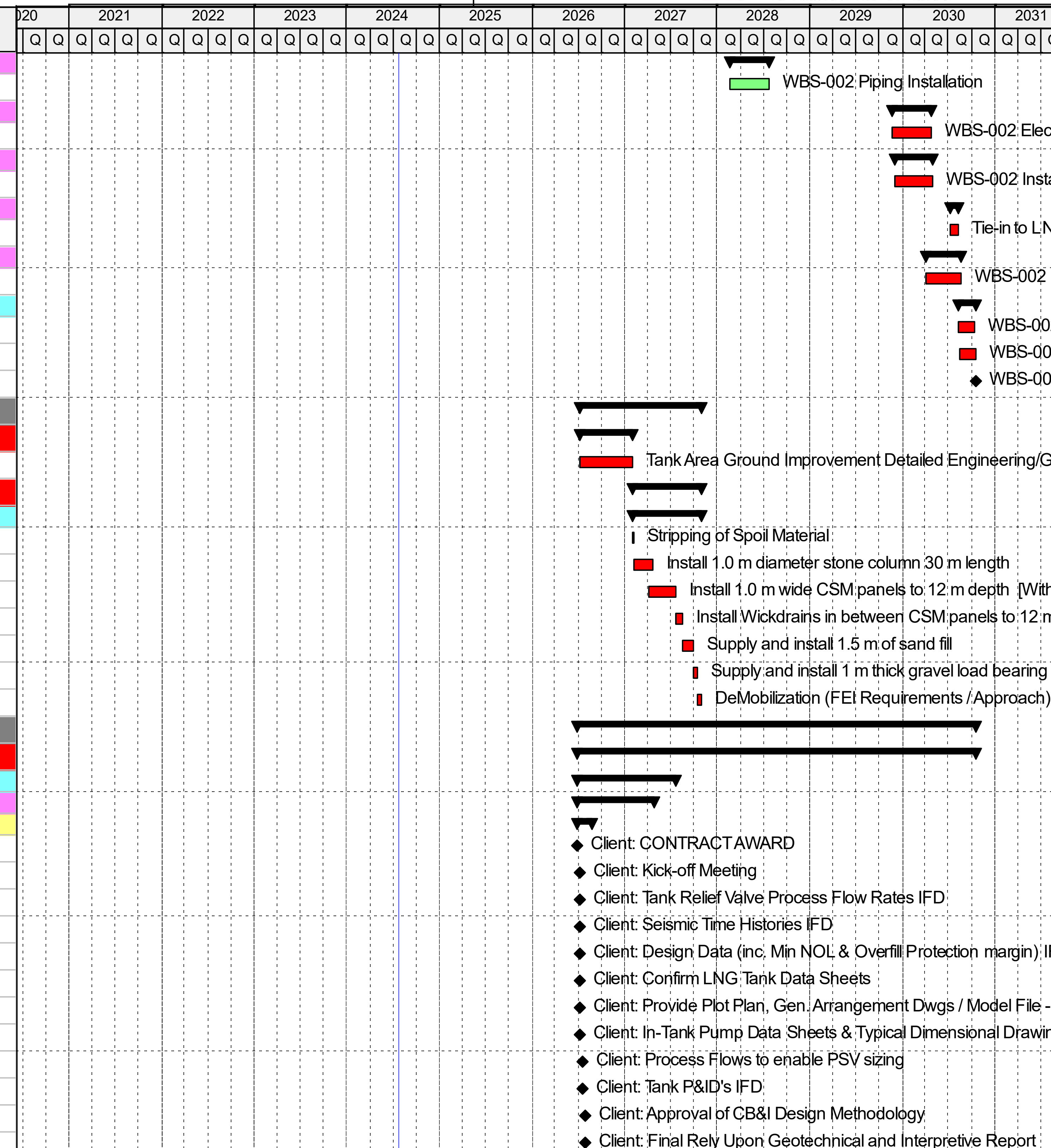
Activity ID	Activity Name	Rem. Duration	Start	Finish
E17501	20014-J-5602 - Flow Control Valve - Refresh/Renegotiate	20d	01-Feb-27	01-Mar-27
E17511	20014-J-5602 - Flow Control Valve - Develop MRP	20d	01-Feb-27	01-Mar-27
E17521	20014-J-5602 - Flow Control Valve - Issue PO to Vendor	0d		01-Mar-27
E19601	20014-J-5602 - Flow Control Valve - Manufacturing	140d	02-Mar-27	20-Sep-27
E17531	20014-J-5602 - Flow Control Valve - Ready to Ship	0d		20-Sep-27
E17541	20014-J-5602 - Flow Control Valve - ETA to Site	0d		27-Sep-27
E20681	WBS-002 Receive at Site - Flow Control Valve	0d	28-Sep-27	
20014-J-5602: PSV's		235d	17-Jun-27	31-May-28
E17561	20014-J-5602 - PSV's - Refresh/Renegotiate	20d	17-Jun-27	15-Jul-27
E17571	20014-J-5602 - PSV's - Develop MRP	20d	17-Jun-27	15-Jul-27
E17581	20014-J-5602 - PSV's - Issue PO to Vendor	0d		15-Jul-27
E19611	20014-J-5602 - PSV's - Manufacture	200d	16-Jul-27	08-May-28
E17591	20014-J-5602 - PSV's - Ready to Ship	0d		08-May-28
E17601	20014-J-5602 - PSV's - ETA to Site	0d		30-May-28
E20691	WBS-002 Receive at Site - PSVs	0d	31-May-28	
20014-J-56XX: Fire/Gas Detection System		110d	24-Jun-27	02-Dec-27
E17681	20014-J-56XX: Fire/Gas Detection System - Refresh/Renegotiate	20d	24-Jun-27	22-Jul-27
E17691	20014-J-56XX: Fire/Gas Detection System - Develop MRP	20d	24-Jun-27	22-Jul-27
E17701	20014-J-56XX: Fire/Gas Detection System - Issue PO to Vendor	0d		22-Jul-27
E19581	20014-J-56XX: Fire/Gas Detection System - Manufacture	85d	23-Jul-27	24-Nov-27
E17711	20014-J-56XX: Fire/Gas Detection System - Ready to Ship	0d		24-Nov-27
E17721	20014-J-56XX: Fire/Gas Detection System - ETA to Site	0d		01-Dec-27
E20711	WBS-002 Receive at Site - Fire/Gas Detection System	0d	02-Dec-27	
Fabrication		139d	03-Nov-27	29-May-28
Structural Steel		90d	02-Dec-27	17-Apr-28
E19941	WBS-002 - Structural Steel Fabrication	90d	02-Dec-27	17-Apr-28
Piping		139d	03-Nov-27	29-May-28
Carbon Steel		130d	03-Nov-27	15-May-28
E19921	WBS-002 - CS Pipe Fabrication	130d	03-Nov-27	15-May-28
Stainless Steel		139d	03-Nov-27	29-May-28
E19931	WBS-002 - SS Pipe Fabrication	139d	03-Nov-27	29-May-28
Construction		700d	20-Oct-27	20-Aug-30
Civil		60d	20-Oct-27	20-Jan-28
E19951	WBS-002 Siteworks	60d	20-Oct-27	20-Jan-28
Concrete & Foundations		70d	03-Nov-27	17-Feb-28
E19961	WBS-002 Concrete & Foundations	70d	03-Nov-27	17-Feb-28
Structural Steel		90d	04-Feb-28	13-Jun-28
E20021	WBS-002 Structural Steel	90d	04-Feb-28	13-Jun-28
Buildings		65d	18-Feb-28	23-May-28
E20101	WBS-002 BOG Building Erection	30d	18-Feb-28	03-Apr-28
E20821	WBS-002 Electrical Building Erection	30d	11-Apr-28	23-May-28
Equipment		2d	07-Jun-28	08-Jun-28
E20791	WBS-002 Cryo Pump Installation	2d	07-Jun-28	08-Jun-28
E20801	WBS-002 BOG Compressor Installation	2d	07-Jun-28	08-Jun-28



Remaining Level of Effort
Actual Level of Effort
Actual Work
Remaining Work
Critical Remaining Work
Critical Secondary

Date	Revision	Checked	Approved
19-Aug-24	IFI		

Activity ID	Activity Name	Rem. Duration	Start	Finish
Piping		110d	18-Feb-28	26-Jul-28
E20031	WBS-002 Piping Installation	110d	18-Feb-28	26-Jul-28
Electrical		105d	20-Nov-29	25-Apr-30
E20041	WBS-002 Electrical Installation	105d	20-Nov-29	25-Apr-30
Instrumentatiion & Controls		100d	04-Dec-29	02-May-30
E20061	WBS-002 Install Instrumentation	100d	04-Dec-29	02-May-30
Tie-ins		20d	11-Jul-30	08-Aug-30
E20031.1	Tie-in to LNG Tank Grade Rack (Piping and EIC)	20d	11-Jul-30	08-Aug-30
Insulation		95d	04-Apr-30	20-Aug-30
E20081	WBS-002 Install Insulation	95d	04-Apr-30	20-Aug-30
Commissioning & Start up		50d	08-Aug-30	18-Oct-30
E15971	WBS-002 Pre-Commissioning/Tie-ins	45d	08-Aug-30	11-Oct-30
E19911	WBS-002 Commissioning	45d	15-Aug-30	18-Oct-30
E15981	WBS-002 Start Up	0d		18-Oct-30
Ground Improvement & Early Works - LNG Tank Area		327d	07-Jul-26	29-Oct-27
Geotech Work/Detailed Engineering		140d	07-Jul-26	01-Feb-27
GIT500030	Tank Area Ground Improvement Detailed Engineering/Geotech Inv.	140d	07-Jul-26	01-Feb-27
Construction		187d	02-Feb-27	29-Oct-27
LNG Tank Area Civil Work		187d	02-Feb-27	29-Oct-27
GR4.1	Stripping of Spoil Material	5d	02-Feb-27	08-Feb-27
GR3.2	Install 1.0 m diameter stone column 30 m length	50d	09-Feb-27	21-Apr-27
GR3.3	Install 1.0 m wide CSM panels to 12 m depth [Within LNG Tank Foundation Footpı	75d	05-Apr-27	20-Jul-27
GR3.4	Install Wickdrains in between CSM panels to 12 m	20d	21-Jul-27	18-Aug-27
GR4.2	Supply and install 1.5 m of sand fill	30d	19-Aug-27	30-Sep-27
GR4.3	Supply and install 1 m thick gravel load bearing pad	10d	01-Oct-27	15-Oct-27
GR5	DeMobilization (FEI Requirements / Approach)	10d	18-Oct-27	29-Oct-27
LNG Storage Tank		1065d	29-Jun-26	18-Oct-30
EPC (Contractor)		1065d	29-Jun-26	18-Oct-30
Detailed Engineering		264d	30-Jun-26	23-Jul-27
MILESTONES		203d	30-Jun-26	28-Apr-27
CLIENT MILESTONES		38d	30-Jun-26	24-Aug-26
MS1000	Client: CONTRACT AWARD	0d	30-Jun-26	
MS1000.1	Client: Kick-off Meeting	0d	06-Jul-26	
MS1010	Client: Tank Relief Valve Process Flow Rates IFD	0d		06-Jul-26
MS1020	Client: Seismic Time Histories IFD	0d		06-Jul-26
MS1030	Client: Design Data (inc. Min NOL & Overfill Protection margin) IFD	0d		06-Jul-26
MS1040	Client: Confirm LNG Tank Data Sheets	0d		06-Jul-26
MS1050	Client: Provide Plot Plan, Gen. Arrangement Dwgs / Model File - Tank Grade Rack	0d	07-Jul-26	
MS1060	Client: In-Tank Pump Data Sheets & Typical Dimensional Drawings	0d		10-Jul-26
MS1070	Client: Process Flows to enable PSV sizing	0d		17-Jul-26
MS1080	Client: Tank P&ID's IFD	0d		17-Jul-26
MS1090	Client: Approval of CB&I Design Methodology	0d		31-Jul-26
MS1100	Client: Final Rely Upon Geotechnical and Interpretive Report	0d		31-Jul-26



Remaining Level of Effort
Actual Level of Effort
Actual Work
Remaining Work
Critical Remaining Work
Critical Secondary

Date	Revision	Checked	Approved
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Activity ID	Activity Name	Rem. Duration	Start	Finish
MS1110	Client: Piping Material Specs IFD	0d		31-Jul-26
MS1120	Client: Approval of CB&I's Tank Orientation Drawing	0d		17-Aug-26
MS1130	Client: Approval of CB&I's Battery Limit Sketch	0d		17-Aug-26
MS1140	Client: Valve Data Sheets IFP	0d		24-Aug-26
MS1150	Client: In-Tank Pump Data Sheets & Detailed Dimensional Drawings IFD	0d		24-Aug-26
MS1160	Client: Control Valve Data Sheets IFD	0d		24-Aug-26
ENGINEERING MILESTONES		155d	09-Sep-26	28-Apr-27
MS2000	Engineering: Model Review 1 (30%)	0d	09-Sep-26	
MS3000	Engineering: Issue Adv Bill / MRP for 9% Nickel Materials	0d		11-Sep-26
MS3010	Engineering: Issue MTO / MRP for Galv. CS & Low Temp Pipe	0d		07-Oct-26
MS3020	Engineering: Issue Adv Bill / MRP For LNG CS Plates	0d		09-Oct-26
MS2010	Engineering: Model Review 2 (60%)	0d	18-Jan-27	
TTK296114	Start Preparing Gate 4 Deliverables	0d		28-Apr-27
MS2020	Engineering: Model Review 3 (90%)	0d	28-Apr-27	
PROJECT MANAGEMENT		80d	07-Jul-26	29-Oct-26
PM1755	Project Management Plans & Project Schedule	80d	07-Jul-26	29-Oct-26
461 PIPING		229d	07-Jul-26	09-Jun-27
ENPI5040	Calcs: Modeling & Dwgs - Tank Grade Rack Piping	150d	07-Jul-26	16-Feb-27
ENPI0010	Specs: Piping & Valve Material Specifications	73d	21-Jul-26	03-Nov-26
ENPI0020	Lists: Piping & Manual Valve List	65d	21-Jul-26	22-Oct-26
ENPI0030	Model: Piping Modeling	150d	16-Sep-26	27-Apr-27
ENPI0040	Calcs: Pipe Stress Analysis	85d	23-Sep-26	29-Jan-27
ENPI0080	MTO/Req: Galv. CS, Low Temp. & SS Pipe/Fittings/Flanges (Advanced)	7d	29-Sep-26	07-Oct-26
ENPI0090	MTO/Req: CS & SS Manual Valves	8d	23-Oct-26	03-Nov-26
ENPI5050	MTO/MRQ: Piping & Component Matls - Tank Grade Rack	10d	12-Jan-27	25-Jan-27
ENPI0050	Dwgs: Piping Iso's & Area Dwgs	33d	01-Feb-27	18-Mar-27
ENPI0110	MTO/Req: Gaskets & Fasteners	10d	01-Feb-27	12-Feb-27
ENPI0120	MTO/Req: CS & SS Cold Shoes & Misc. Pipe Supports	10d	19-Mar-27	01-Apr-27
ENPI0060	Dwgs: Shop Generate Spool Dwgs	37d	19-Mar-27	11-May-27
ENPI0070	Subct Pkg: Engineering Docs for Module Yard Fab Pkg	27d	03-May-27	09-Jun-27
454 CONCRETE		222d	07-Jul-26	31-May-27
ENCI1620	Calcs: Calcs, Modeling & Dwgs - Tank Grade Rack Fdns	55d	07-Jul-26	23-Sep-26
ENCI0010	Specs: Concrete Tank Design Methodolgy	25d	04-Aug-26	08-Sep-26
ENCI0020	Specs: Concrete Construction & Material Specs	20d	18-Aug-26	15-Sep-26
ENCI0030	Calcs: Design Specification for Analysis & Preliminary Pre-stress Design	25d	18-Aug-26	22-Sep-26
ENCI0040	Calcs: Concrete Design Analyses	155d	09-Sep-26	27-Apr-27
ENCI0050	Subct Pkg: Early Engineering Docs for Concrete Subct	5d	23-Sep-26	29-Sep-26
ENCI1630	Subct Pkg: Engineering Docs for Subct Bids - Tank Grade Rack Fdns	10d	24-Sep-26	07-Oct-26
ENCI0060	Dwgs: Concrete Slab Design & Dwgs	67d	16-Oct-26	27-Jan-27
ENCI0070	Dwgs: Concrete Wall Design & Dwgs	75d	29-Oct-26	22-Feb-27
ENCI0080	MTO/Req: Cryogenic Reinforcing Steel / Krybar	15d	28-Jan-27	18-Feb-27
ENCI0090	Dwgs: Concrete Roof Design & Dwgs	58d	09-Mar-27	31-May-27

Remaining Level of Effort — Actual Work — Critical Remaining Work
Actual Level of Effort — Remaining Work — Critical Secondary

Date	Revision	Checked	Approved
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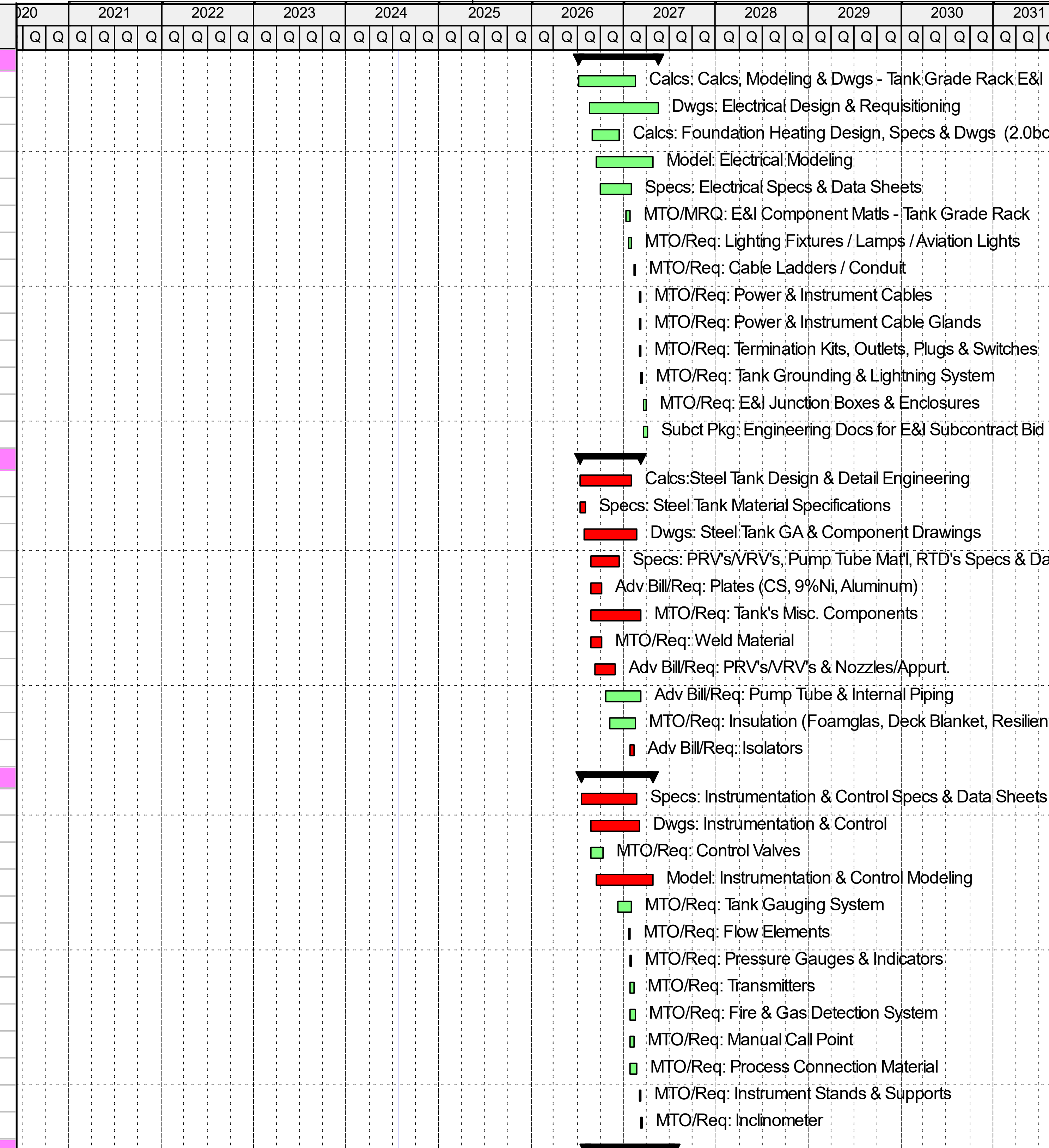
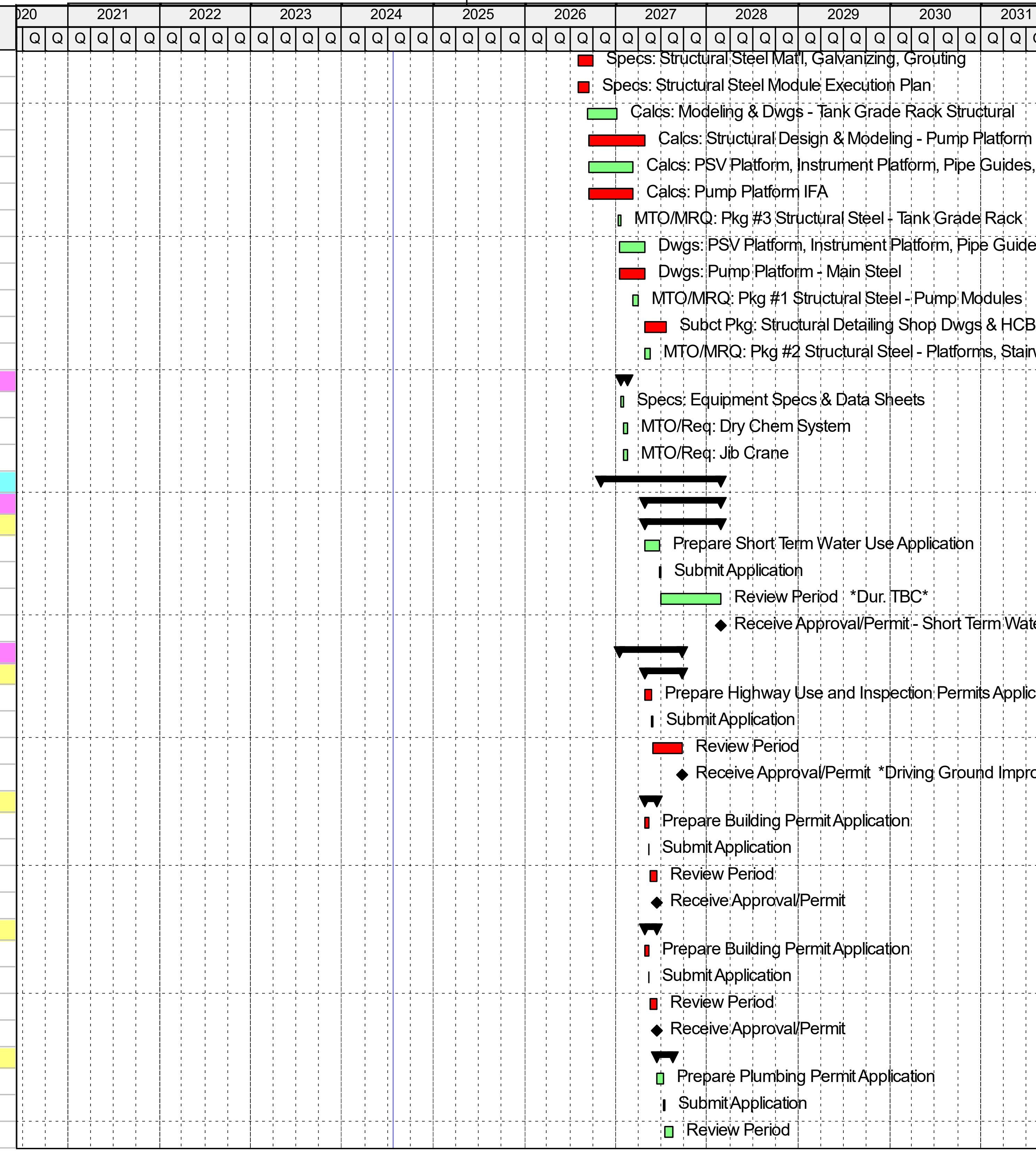
Activity ID	Activity Name	Rem. Duration	Start	Finish
471 ELECTRICAL		217d	07-Jul-26	21-May-27
ENPI5060	Calcs: Calcs, Modeling & Dwgs - Tank Grade Rack E&I	150d	07-Jul-26	16-Feb-27
ENEL0010	Dwgs: Electrical Design & Requisitioning	188d	18-Aug-26	21-May-27
ENEL0020	Calcs: Foundation Heating Design, Specs & Dwgs (2.0bcf Tank Only)	75d	01-Sep-26	17-Dec-26
ENEL0030	Model: Electrical Modeling	150d	16-Sep-26	27-Apr-27
ENEL0040	Specs: Electrical Specs & Data Sheets	83d	30-Sep-26	03-Feb-27
ENPI5070	MTO/MRQ: E&I Component Matls - Tank Grade Rack	10d	12-Jan-27	25-Jan-27
ENEL0050	MTO/Req: Lighting Fixtures / Lamps / Aviation Lights	10d	21-Jan-27	03-Feb-27
ENEL0060	MTO/Req: Cable Ladders / Conduit	5d	11-Feb-27	18-Feb-27
ENEL0070	MTO/Req: Power & Instrument Cables	5d	05-Mar-27	11-Mar-27
ENEL0080	MTO/Req: Power & Instrument Cable Glands	5d	05-Mar-27	11-Mar-27
ENEL0090	MTO/Req: Termination Kits, Outlets, Plugs & Switches	5d	05-Mar-27	11-Mar-27
ENEL0100	MTO/Req: Tank Grounding & Lightning System	4d	12-Mar-27	17-Mar-27
ENEL0110	MTO/Req: E&I Junction Boxes & Enclosures	10d	19-Mar-27	01-Apr-27
ENEL2030	Subct Pkg: Engineering Docs for E&I Subcontract Bid	11d	19-Mar-27	05-Apr-27
454 PLATE STRUCTURES		162d	14-Jul-26	11-Mar-27
ENTK0010	Calcs:Steel Tank Design & Detail Engineering	135d	14-Jul-26	01-Feb-27
ENTK0020	Specs: Steel Tank Material Specifications	15d	14-Jul-26	04-Aug-26
ENTK0030	Dwgs: Steel Tank GA & Component Drawings	142d	28-Jul-26	25-Feb-27
ENTK0040	Specs: PRV's/VRV's, Pump Tube Mat'l, RTD's Specs & Data Sheets	76d	26-Aug-26	14-Dec-26
ENTK0050	Adv Bill/Req: Plates (CS, 9%Ni, Aluminum)	32d	26-Aug-26	09-Oct-26
ENTK0060	MTO/Req: Tank's Misc. Components	132d	26-Aug-26	11-Mar-27
ENTK0070	MTO/Req: Weld Material	32d	26-Aug-26	09-Oct-26
ENTK0080	Adv Bill/Req: PRV's/VRV's & Nozzles/Appurt.	55d	10-Sep-26	27-Nov-26
ENTK0090	Adv Bill/Req: Pump Tube & Internal Piping	92d	23-Oct-26	11-Mar-27
ENTK0100	MTO/Req: Insulation (Foamglas, Deck Blanket, Resilient Blanket, Perlite)	65d	06-Nov-26	16-Feb-27
ENTK100	Adv Bill/Req: Isolators	10d	28-Jan-27	10-Feb-27
481 INSTRUMENT & CONTROL		190d	20-Jul-26	27-Apr-27
ENIC0010	Specs: Instrumentation & Control Specs & Data Sheets	148d	20-Jul-26	25-Feb-27
ENIC0020	Dwgs: Instrumentation & Control	128d	25-Aug-26	04-Mar-27
ENIC0030	MTO/Req: Control Valves	35d	25-Aug-26	14-Oct-26
ENIC0040	Model: Instrumentation & Control Modeling	150d	16-Sep-26	27-Apr-27
ENIC0050	MTO/Req: Tank Gauging System	33d	11-Dec-26	03-Feb-27
ENIC0060	MTO/Req: Flow Elements	5d	21-Jan-27	27-Jan-27
ENIC0070	MTO/Req: Pressure Gauges & Indicators	5d	28-Jan-27	03-Feb-27
ENIC0080	MTO/Req: Transmitters	10d	28-Jan-27	10-Feb-27
ENIC0090	MTO/Req: Fire & Gas Detection System	15d	28-Jan-27	18-Feb-27
ENIC0100	MTO/Req: Manual Call Point	10d	28-Jan-27	10-Feb-27
ENIC0110	MTO/Req: Process Connection Material	20d	28-Jan-27	25-Feb-27
ENIC0120	MTO/Req: Instrument Stands & Supports	5d	05-Mar-27	11-Mar-27
ENIC0130	MTO/Req: Inclinometer	5d	12-Mar-27	18-Mar-27
432 STRUCTURAL		240d	05-Aug-26	23-Jul-27



Activity ID	Activity Name	Rem. Duration	Start	Finish
ENST0010	Specs: Structural Steel Mat'l, Galvanizing, Grouting	40d	05-Aug-26	30-Sep-26
ENST0020	Specs: Structural Steel Module Execution Plan	30d	05-Aug-26	16-Sep-26
ENST2050	Calcs: Modeling & Dwgs - Tank Grade Rack Structural	80d	09-Sep-26	08-Jan-27
ENST0030	Calcs: Structural Design & Modeling - Pump Platform	150d	17-Sep-26	28-Apr-27
ENST0040	Calcs: PSV Platform, Instrument Platform, Pipe Guides, Stair Tower, Roof Walkway	115d	17-Sep-26	09-Mar-27
ENST0050	Calcs: Pump Platform IFA	115d	17-Sep-26	09-Mar-27
ENST2060	MTO/MRQ: Pkg #3 Structural Steel - Tank Grade Rack	10d	11-Jan-27	22-Jan-27
ENST0060	Dwgs: PSV Platform, Instrument Platform, Pipe Guides, Stair Tower, Roof Walkway	70d	19-Jan-27	28-Apr-27
ENST0070	Dwgs: Pump Platform - Main Steel	70d	19-Jan-27	28-Apr-27
ENST2020	MTO/MRQ: Pkg #1 Structural Steel - Pump Modules	15d	10-Mar-27	30-Mar-27
ENST0080	Subct Pkg: Structural Detailing Shop Dwgs & HCBI Review - Pump Modules	60d	29-Apr-27	23-Jul-27
ENST0090	MTO/MRQ: Pkg #2 Structural Steel - Platforms, Stairways, Walkways & Handrail	16d	29-Apr-27	20-May-27
441 MECHANICAL		**20d**	**21-Jan-27**	**18-Feb-27**
ENME0010	Specs: Equipment Specs & Data Sheets	10d	21-Jan-27	03-Feb-27
ENME0020	MTO/Req: Dry Chem System	10d	04-Feb-27	18-Feb-27
ENME0030	MTO/Req: Jib Crane	10d	04-Feb-27	18-Feb-27
Regulatory Permits (Contractor Scope)		**318d**	**05-Nov-26**	**23-Feb-28**
BCER		**203d**	**28-Apr-27**	**23-Feb-28**
Short Term Water Use Permit Water Sustainability Act		**203d**	**28-Apr-27**	**23-Feb-28**
RGT616731	Prepare Short Term Water Use Application	40d	28-Apr-27	23-Jun-27
RGT616732	Submit Application	3d	24-Jun-27	28-Jun-27
RGT616733	Review Period *Dur. TBC*	160d	29-Jun-27	23-Feb-28
RGT616734	Receive Approval/Permit - Short Term Water Use	0d		23-Feb-28
City Of Delta MD		**173d**	**18-Jan-27**	**23-Sep-27**
Highway Use Permit - Delta Bylaw No. 6922		**103d**	**28-Apr-27**	**23-Sep-27**
RGT406182	Prepare Highway Use and Inspection Permits Application	20d	28-Apr-27	26-May-27
RGT406184	Submit Application	3d	27-May-27	31-May-27
RGT406186	Review Period	80d	01-Jun-27	23-Sep-27
RGT406188	Receive Approval/Permit *Driving Ground Improvement*	0d		23-Sep-27
Buildings Permit - Delta Building/Plumbing Bylaw (No. 6060)		**33d**	**28-Apr-27**	**14-Jun-27**
RGT406382	Prepare Building Permit Application	10d	28-Apr-27	11-May-27
RGT406384	Submit Application	3d	12-May-27	14-May-27
RGT406386	Review Period	20d	17-May-27	14-Jun-27
RGT406388	Receive Approval/Permit	0d		14-Jun-27
Temporary Buildings Permit - Delta Building/Plumbing Bylaw (No. 6060)		**33d**	**28-Apr-27**	**14-Jun-27**
RGT616767	Prepare Building Permit Application	10d	28-Apr-27	11-May-27
RGT616770	Submit Application	3d	12-May-27	14-May-27
RGT616768	Review Period	20d	17-May-27	14-Jun-27
RGT616769	Receive Approval/Permit	0d		14-Jun-27
Plumbing Permit - Delta Building/Plumbing Bylaw (No. 6060)		**43d**	**15-Jun-27**	**16-Aug-27**
RGT616735	Prepare Plumbing Permit Application	20d	15-Jun-27	13-Jul-27
RGT616736	Submit Application	3d	14-Jul-27	16-Jul-27
RGT616737	Review Period	20d	19-Jul-27	16-Aug-27



Remaining Level of Effort | Actual Work | Critical Remaining Work
Actual Level of Effort | Remaining Work | Critical Secondary

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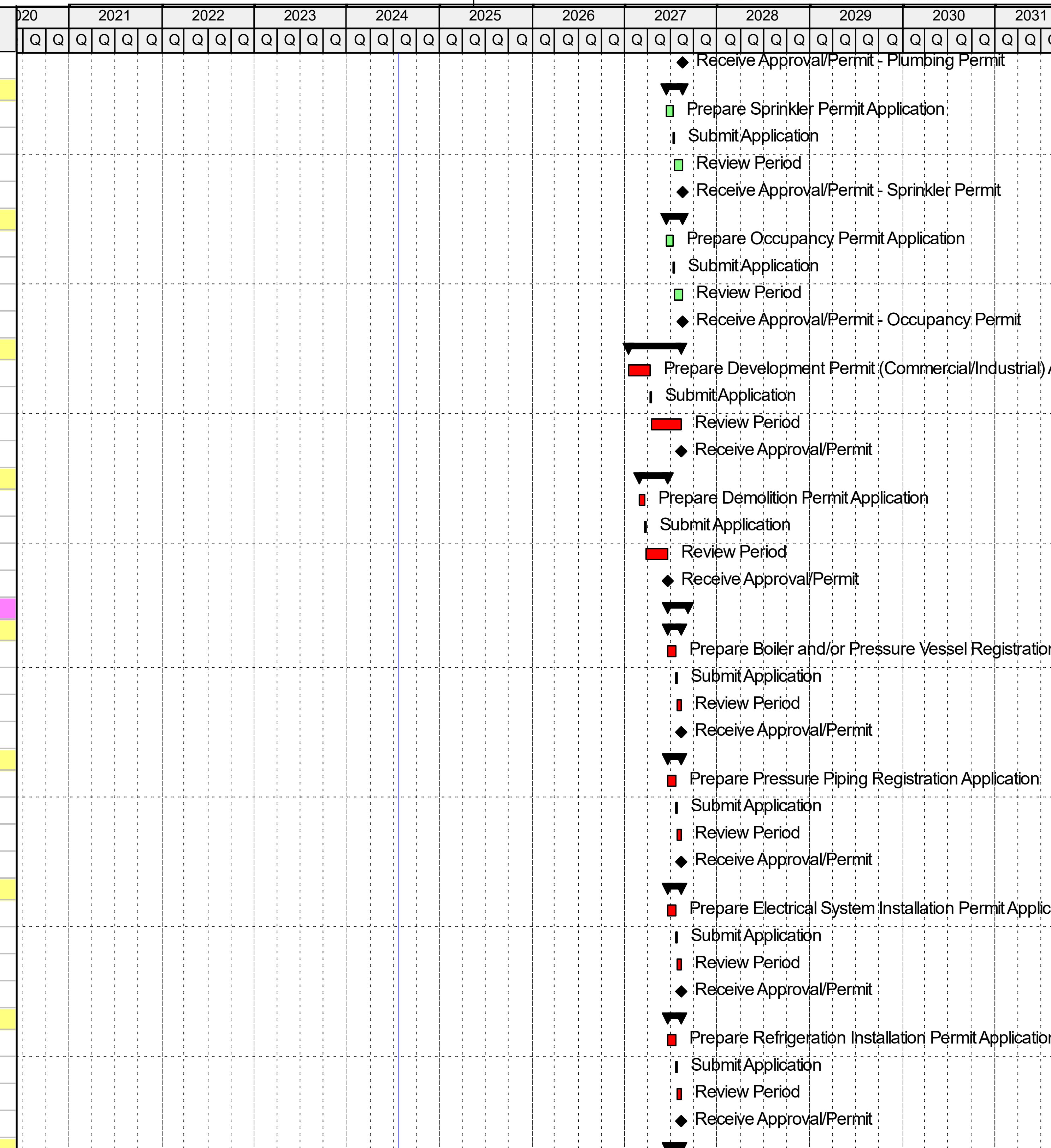
19-Aug-24	IFI		

Activity ID	Activity Name	Rem. Duration	Start	Finish
RGT616738	Receive Approval/Permit - Plumbing Permit	0d		16-Aug-27
Sprinkler Permit - Delta Building/Plumbing Bylaw (No. 6060)		**43d**	**15-Jun-27**	**16-Aug-27**
RGT616739	Prepare Sprinkler Permit Application	20d	15-Jun-27	13-Jul-27
RGT616740	Submit Application	3d	14-Jul-27	16-Jul-27
RGT616741	Review Period	20d	19-Jul-27	16-Aug-27
RGT616742	Receive Approval/Permit - Sprinkler Permit	0d		16-Aug-27
Occupancy Permit - Delta Building/Plumbing Bylaw (No. 6060)		**43d**	**15-Jun-27**	**16-Aug-27**
RGT616743	Prepare Occupancy Permit Application	20d	15-Jun-27	13-Jul-27
RGT616744	Submit Application	3d	14-Jul-27	16-Jul-27
RGT616745	Review Period	20d	19-Jul-27	16-Aug-27
RGT616746	Receive Approval/Permit - Occupancy Permit	0d		16-Aug-27
Development Permit (Commercial/Industrial) - Delta Official Community Plan Bylaws		**143d**	**18-Jan-27**	**11-Aug-27**
RGT406482	Prepare Development Permit (Commercial/Industrial) Application	60d	18-Jan-27	13-Apr-27
RGT406484	Submit Application	3d	14-Apr-27	16-Apr-27
RGT406486	Review Period	80d	19-Apr-27	11-Aug-27
RGT406488	Receive Approval/Permit	0d		11-Aug-27
Demolition Permit - Delta Official Community Plan Bylaws		**78d**	**02-Mar-27**	**21-Jun-27**
RGT406682	Prepare Demolition Permit Application	15d	02-Mar-27	22-Mar-27
RGT406684	Submit Application	3d	23-Mar-27	25-Mar-27
RGT406686	Review Period	60d	26-Mar-27	21-Jun-27
RGT406688	Receive Approval/Permit	0d		21-Jun-27
TSBC - Safety Standards Act		**55d**	**22-Jun-27**	**09-Sep-27**
Boiler and/or Pressure Vessel Registration / Approval		**35d**	**22-Jun-27**	**11-Aug-27**
RGT415182	Prepare Boiler and/or Pressure Vessel Registration Application	22d	22-Jun-27	23-Jul-27
RGT415184	Submit Application	3d	23-Jul-27	27-Jul-27
RGT415186	Review Period	10d	28-Jul-27	11-Aug-27
RGT415188	Receive Approval/Permit	0d		11-Aug-27
Pressure Piping Registration / Approval		**35d**	**22-Jun-27**	**11-Aug-27**
RGT415282	Prepare Pressure Piping Registration Application	22d	22-Jun-27	23-Jul-27
RGT415284	Submit Application	3d	23-Jul-27	27-Jul-27
RGT415286	Review Period	10d	28-Jul-27	11-Aug-27
RGT415288	Receive Approval/Permit	0d		11-Aug-27
Installation permits - Electrical System		**35d**	**22-Jun-27**	**11-Aug-27**
RGT415382	Prepare Electrical System Installation Permit Application	22d	22-Jun-27	23-Jul-27
RGT415384	Submit Application	3d	23-Jul-27	27-Jul-27
RGT415386	Review Period	10d	28-Jul-27	11-Aug-27
RGT415388	Receive Approval/Permit	0d		11-Aug-27
Installation permits - Refrigeration System		**35d**	**22-Jun-27**	**11-Aug-27**
RGT415482	Prepare Refrigeration Installation Permit Application	22d	22-Jun-27	23-Jul-27
RGT415484	Submit Application	3d	23-Jul-27	27-Jul-27
RGT415486	Review Period	10d	28-Jul-27	11-Aug-27
RGT415488	Receive Approval/Permit	0d		11-Aug-27
Installation permits - Gas		**35d**	**22-Jun-27**	**11-Aug-27**



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Tilbury Island LNG Facility Expansion (3 BCF)
TLSE Sub-Projects Integrated Schedule-Detailed

FORTIS BC | SOLARIS MANAGEMENT CONSULTANTS INC.

Activity ID	Activity Name	Rem. Duration	Start	Finish
RGT415582	Prepare Gas Installation Permit Application	22d	22-Jun-27	23-Jul-27
RGT415584	Submit Application	3d	23-Jul-27	27-Jul-27
RGT415586	Review Period	10d	28-Jul-27	11-Aug-27
RGT415588	Receive Approval/Permit	0d		11-Aug-27
Operation permits - Electrical System		35d	21-Jul-27	09-Sep-27
RGT415682	Prepare Electrical System Operation Permit Application	22d	21-Jul-27	20-Aug-27
RGT415684	Submit Application	3d	23-Aug-27	25-Aug-27
RGT415686	Review Period	10d	26-Aug-27	09-Sep-27
RGT415688	Receive Approval/Permit	0d		09-Sep-27
Operation permits - Refrigenation System		35d	21-Jul-27	09-Sep-27
RGT415782	Prepare Electrical System Operation Permit Application	22d	21-Jul-27	20-Aug-27
RGT415784	Submit Application	3d	23-Aug-27	25-Aug-27
RGT415786	Review Period	10d	26-Aug-27	09-Sep-27
RGT415788	Receive Approval/Permit	0d		09-Sep-27
Operation permits (Boiler, Pressure Vessels)		35d	21-Jul-27	09-Sep-27
RGT415882	Prepare Boiler & Pressure Vessels Operation Permit Application	22d	21-Jul-27	20-Aug-27
RGT415884	Submit Application	3d	23-Aug-27	25-Aug-27
RGT415886	Review Period	10d	26-Aug-27	09-Sep-27
RGT415888	Receive Approval/Permit	0d		09-Sep-27
Port of Vancouver		25d	23-Aug-27	27-Sep-27
Notice to Shipping - Canada Marine Act		25d	23-Aug-27	27-Sep-27
RGT413184	Notice to Shipping Registration	5d	23-Aug-27	27-Aug-27
RGT413188	Receive Info/Confirmation	20d	30-Aug-27	27-Sep-27
BC One Call		4d	15-Oct-27	20-Oct-27
BC One Call Registration		4d	15-Oct-27	20-Oct-27
RGT401184	BC One Call Registration	1d	15-Oct-27	15-Oct-27
RGT401188	Receive Info/Confirmation	3d	18-Oct-27	20-Oct-27
MOTI		85d	30-Mar-27	29-Jul-27
Highway Use Permit - Transportation Act		85d	30-Mar-27	29-Jul-27
RGT410182	Prepare Highway Use Permit Application	20d	30-Mar-27	28-Apr-27
RGT410184	Submit Application	3d	28-Apr-27	30-Apr-27
RGT410186	Review Period	62d	03-May-27	29-Jul-27
RGT410188	Receive Approval/Permit	0d		29-Jul-27
Work Safe BC - Worker Compenstion Act/OHS Regulation		6d	09-Aug-27	16-Aug-27
Guidelines 20.3-2 Qualified coordinators		6d	09-Aug-27	16-Aug-27
RGT416182	Prepare Application of Guidelines 20.3-2 Qualified coordinators	1d	09-Aug-27	09-Aug-27
RGT416184	Submit Application	3d	10-Aug-27	12-Aug-27
RGT416186	Review Period	2d	13-Aug-27	16-Aug-27
RGT416188	Receive Approval/Permit	0d		16-Aug-27
G20.2(1)/20.2.1(1) Notice of Project, Section 20.2(1) of the OHS Regulation		6d	09-Aug-27	16-Aug-27
RGT416282	Prepare Work Safe BC Application - Notice of Project	1d	09-Aug-27	09-Aug-27
RGT416284	Submit Application	3d	10-Aug-27	12-Aug-27
RGT416286	Review Period	2d	13-Aug-27	16-Aug-27
RGT416288	Receive Approval/Permit	0d		16-Aug-27

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Tilbury Island LNG Facility Expansion (3 BCF)

TLSE Sub-Projects Integrated Schedule-Detailed

FORTIS BC™ | SOLARIS MANAGEMENT CONSULTANTS INC.

Activity ID	Activity Name	Rem. Duration	Start	Finish
30M33 Permit - OHS Regulation Sections 19		6d	09-Aug-27	16-Aug-27
RGT416382	Prepare Work Safe BC Application - 30M33 Permit	1d	09-Aug-27	09-Aug-27
RGT416384	Submit Application	3d	10-Aug-27	12-Aug-27
RGT416386	Review Period	2d	13-Aug-27	16-Aug-27
RGT416388	Receive Approval/Permit	0d		16-Aug-27
CBSA/CRA/Other		18d	09-Jul-27	04-Aug-27
Modular Units built outside of BC		18d	09-Jul-27	04-Aug-27
RGT405182	Prepare Modular Units Built Outside of BC Permit Application	10d	09-Jul-27	23-Jul-27
RGT405184	Submit Application	3d	23-Jul-27	27-Jul-27
RGT405186	Review Period	5d	28-Jul-27	04-Aug-27
RGT405188	Receive Approval/Permit	0d		04-Aug-27
Nav Canada		135d	19-Apr-27	29-Oct-27
Boundary Bay Airport Email Notification		15d	19-Apr-27	07-May-27
Email Notification		15d	19-Apr-27	07-May-27
RGT404184	Prepare and Send Notification Email	5d	19-Apr-27	26-Apr-27
RGT404188	Receive Confirmation Response	10d	26-Apr-27	07-May-27
Land Use Program - Crane		128d	28-Apr-27	29-Oct-27
RGT411182	Prepare Land Use Crane Permit Application	5d	28-Apr-27	04-May-27
RGT411184	Submit Application	3d	05-May-27	07-May-27
RGT411186	Review Period *Chk duration with Andrew/Matyia*	120d	10-May-27	29-Oct-27
RGT411188	Receive Approval/Permit	0d		29-Oct-27
Transport Canada		183d	05-Nov-26	04-Aug-27
Aeronautical Clearance - Canadian Aviation Regulations (CARs)		128d	18-Jan-27	20-Jul-27
RGT414182	Prepare Aeronautical Clearance Permit Application	5d	18-Jan-27	22-Jan-27
RGT414184	Submit Application	3d	25-Jan-27	27-Jan-27
RGT414186	Review Period	120d	28-Jan-27	20-Jul-27
RGT414188	Receive Approval/Permit	0d		20-Jul-27
Navigable Waters Act Approval - Canadian Navigable Waters Act		183d	05-Nov-26	04-Aug-27
RGT414282	Prepare Navigable Water Permit Application	60d	05-Nov-26	05-Feb-27
RGT414284	Submit Application	3d	08-Feb-27	10-Feb-27
RGT414286	Review Period	120d	11-Feb-27	04-Aug-27
RGT414288	Receive Approval/Permit	0d		04-Aug-27
Procurement		625d	29-Jun-26	11-Jan-29
PROCUREMENT MILESTONES		404d	29-Jun-26	18-Feb-28
STRUCTURAL MATERIAL		371d	29-Jun-26	04-Jan-28
TRP296222.1	LNG Tank Proc. Hold Release (after receiving ph2 EAC)	0d		29-Jun-26
PRST1080	ROS: To Customs Clearance: Pkg #1 Structural Steel - Pump Platform Modules	0d		15-Oct-27
PRST2080	ROS: Structural Steel Pkg #2 Platforms, Stairs, Walkways & Handrail (Shop)	0d		07-Dec-27
PRST3080	ROS: Structural Steel Pkg #3 - Tank Grade Rack	0d		15-Dec-27
FBMO1020	ROS: Receive Structural Steel at Fab Yard	0d		04-Jan-28
LNG TANK MATERIAL		205d	02-Mar-27	23-Dec-27
MS4100	ROS: Nelson Studs (SS)	0d		02-Mar-27
MS4110	ROS: Nelson Studs (CS)	0d		02-Mar-27
MS4120	ROS Shop: CS Embeds	0d		08-Mar-27

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MS4130	ROS Shop: Capping Material	0d		09-Mar-27
MS4140	ROS: Weld Material (CS)	0d		11-Mar-27
MS4150	ROS Shop: Temp. Erection Matls (Roof Framing & Doorsheet Stiffening)	0d		26-Mar-27
MS4160	ROS: Foamglas	0d		07-Apr-27
MS4170	ROS Shop: Nozzles & Apperts	0d		14-Apr-27
MS4180	ROS: Resilient Blanket	0d		28-Apr-27
MS4190	ROS: Fiberglass Deck Blanket	0d		19-May-27
MS4200	ROS: Aluminum Plates - Suspended Deck	0d		25-May-27
MS4210	ROS Shop: Plates CS (Roof Plates)	0d		27-May-27
MS4220	ROS Shop: Plates CS (Compression Bar)	0d		27-May-27
MS4230	ROS Shop: Plates CS (Shell Plates)	0d		27-May-27
MS4240	ROS Shop: Plates CS (Bottom Plates)	0d		27-May-27
MS4250	ROS: Weld Material (Aluminum)	0d		10-Jun-27
MS4260	ROS Shop: Internal Piping	0d		10-Jun-27
MS4280	ROS Shop: Pump Tubes	0d		17-Jun-27
MS4270	ROS Shop: Misc. Plate, Bar, Angle (Stiffeners, Door Sheets, Embeds, Framing)	0d		17-Jun-27
MS4290	ROS: Cryogenic Reinforcing Steel / Krybar	0d		25-Jun-27
MS4300	ROS: Weld Material (9% Nickel)	0d		13-Jul-27
MS4310	ROS: Perlite	0d		09-Aug-27
MS4320	ROS: Tank RTD's	0d		13-Aug-27
MS4330	ROS: Isolators	0d		20-Aug-27
MS4340	ROS Shop: Roof Embeds	0d		03-Nov-27
MS4350	ROS Shop: Internal Stairways, Platforms & Pipe Supports	0d		24-Nov-27
MS4360	ROS: 9% Ni Plates	0d		16-Dec-27
MS4370	ROS: PRV's & VRV's	0d		23-Dec-27
MECHANICAL MATERIAL		**5d**	**04-Feb-28**	**11-Feb-28**
MS4000	ROS: Jib Crane	0d		04-Feb-28
MS4010	ROS: Dry Chem System	0d		11-Feb-28
PIPING MATERIAL		**234d**	**10-Mar-27**	**18-Feb-28**
MS4400	ROS: Field (Small Bore) CS & SS Pipe, Fittings & Flanges	0d		10-Mar-27
MS4410	ROS Shop: (Large Bore) CS & SS Pipe, Fittings	0d		21-Apr-27
MS4420	ROS: CS & SS Fasteners	0d		02-Jun-27
MS4430	ROS: Hose Connections	0d		13-Aug-27
MS4440	ROS: Spiral Wound / Garlok / Neoprene Gaskets	0d		20-Sep-27
MS4450	ROS: Cold Shoes & Misc. Pipe Supports	0d		06-Oct-27
MS4460	ROS: Manual Ball Valves	0d		21-Jan-28
MS4470	ROS: Manual Gate/Globe/Check Valves	0d		21-Jan-28
MS4480	ROS: Manual Butterfly Valves	0d		18-Feb-28
MS4490	ROS: Piping & Component Matls - Tank Grade Rack	0d		18-Feb-28
ELECTRICAL MATERIAL		**48d**	**28-Jun-27**	**07-Sep-27**
MS4510	ROS: Lighting Fixtures & Lamps	0d		28-Jun-27
MS4500	ROS: Cable Ladders & Conduit	0d		05-Jul-27

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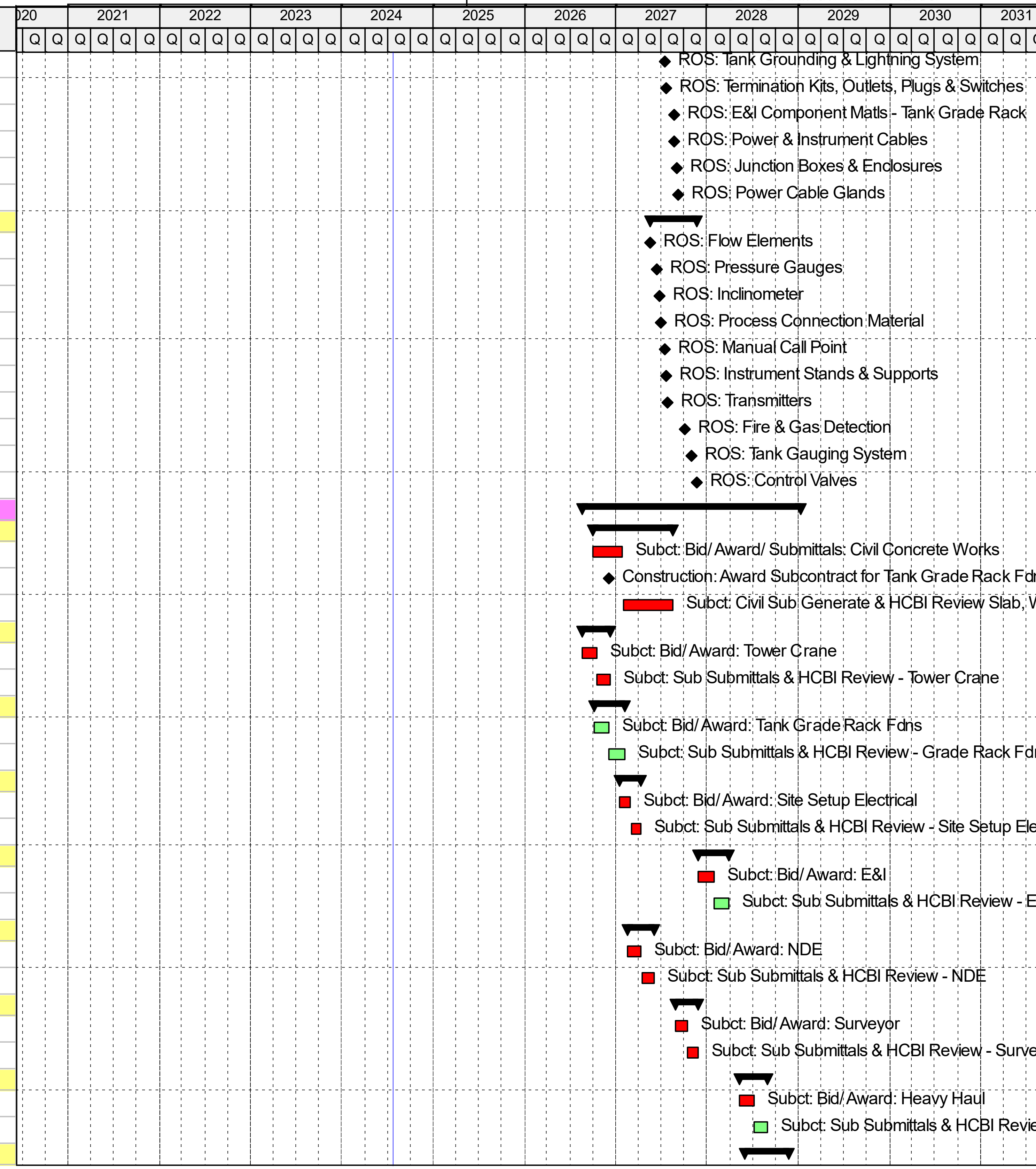
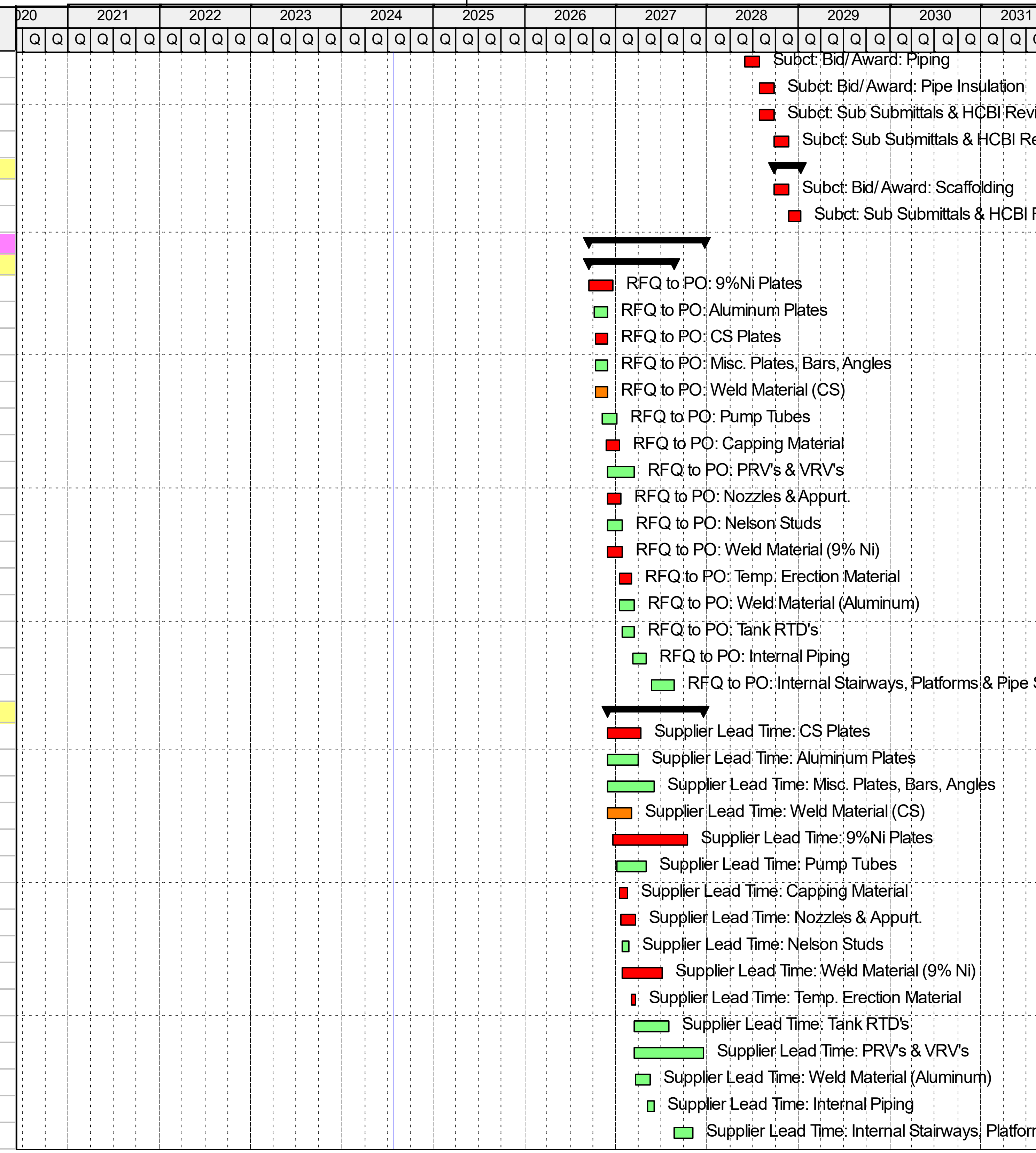
Activity ID	Activity Name	Rem. Duration	Start	Finish
MS4520	ROS: Tank Grounding & Lightning System	0d		15-Jul-27
MS4530	ROS: Termination Kits, Outlets, Plugs & Switches	0d		22-Jul-27
MS4570	ROS: E&I Component Matls - Tank Grade Rack	0d		23-Aug-27
MS4540	ROS: Power & Instrument Cables	0d		24-Aug-27
MS4550	ROS: Junction Boxes & Enclosures	0d		01-Sep-27
MS4560	ROS: Power Cable Glands	0d		07-Sep-27
INSTRUMENTATION MATERIAL		127d	21-May-27	24-Nov-27
MS4600	ROS: Flow Elements	0d		21-May-27
MS4610	ROS: Pressure Gauges	0d		16-Jun-27
MS4620	ROS: Inclinometer	0d		23-Jun-27
MS4630	ROS: Process Connection Material	0d		28-Jun-27
MS4640	ROS: Manual Call Point	0d		15-Jul-27
MS4650	ROS: Instrument Stands & Supports	0d		22-Jul-27
MS4660	ROS: Transmitters	0d		26-Jul-27
MS4670	ROS: Fire & Gas Detection	0d		07-Oct-27
MS4680	ROS: Tank Gauging System	0d		29-Oct-27
MS4690	ROS: Control Valves	0d		24-Nov-27
SUBCONTRACT BID, EVALUATE & AWARD		591d	19-Aug-26	11-Jan-29
Civil Concrete Works		220d	30-Sep-26	20-Aug-27
SUBC1000	Subct: Bid/ Award/ Submittals: Civil Concrete Works	80d	30-Sep-26	29-Jan-27
MS3030	Construction: Award Subcontract for Tank Grade Rack Fdns	0d		04-Dec-26
SUBC2220	Subct: Civil Sub Generate & HCBI Review Slab, Wall & Roof Construction Dwgs T	140d	01-Feb-27	20-Aug-27
Tower Crane		80d	19-Aug-26	11-Dec-26
SUBC2080	Subct: Bid/ Award: Tower Crane	40d	19-Aug-26	15-Oct-26
SUBC2110	Subct: Sub Submittals & HCBI Review - Tower Crane	40d	16-Oct-26	11-Dec-26
Tank Grade Rack Fdns		80d	08-Oct-26	08-Feb-27
SUBC2090	Subct: Bid/ Award: Tank Grade Rack Fdns	40d	08-Oct-26	04-Dec-26
SUBC2160	Subct: Sub Submittals & HCBI Review - Grade Rack Fdns	40d	07-Dec-26	08-Feb-27
Site Setup Electrical		60d	19-Jan-27	14-Apr-27
SUBC2070	Subct: Bid/ Award: Site Setup Electrical	30d	19-Jan-27	02-Mar-27
SUBC2200	Subct: Sub Submittals & HCBI Review - Site Setup Electrical	30d	03-Mar-27	14-Apr-27
E&I		80d	26-Nov-27	27-Mar-28
SUBC2040	Subct: Bid/ Award: E&I	40d	26-Nov-27	28-Jan-28
SUBC2120	Subct: Sub Submittals & HCBI Review - E&I	40d	31-Jan-28	27-Mar-28
NDE		75d	17-Feb-27	03-Jun-27
SUBC2170	Subct: Bid/ Award: NDE	40d	17-Feb-27	14-Apr-27
SUBC2190	Subct: Sub Submittals & HCBI Review - NDE	35d	15-Apr-27	03-Jun-27
Surveyor		60d	31-Aug-27	25-Nov-27
SUBC2020	Subct: Bid/ Award: Surveyor	30d	31-Aug-27	13-Oct-27
SUBC2210	Subct: Sub Submittals & HCBI Review - Surveyor	30d	14-Oct-27	25-Nov-27
Heavy Haul		80d	10-May-28	31-Aug-28
SUBC2060	Subct: Bid/ Award: Heavy Haul	40d	10-May-28	06-Jul-28
SUBC2100	Subct: Sub Submittals & HCBI Review - Heavy Haul	40d	07-Jul-28	31-Aug-28
Piping & Insulation		120d	02-Jun-28	22-Nov-28



Remaining Level of Effort — Actual Work — Critical Remaining Work
Actual Level of Effort — Remaining Work — Critical Secondary

Date	Revision	Checked	Approved
19-Aug-24	IFI		

Activity ID	Activity Name	Rem. Duration	Start	Finish
SUBC2030	Subct: Bid/ Award: Piping	40d	02-Jun-28	28-Jul-28
SUBC2050	Subct: Bid/ Award: Pipe Insulation	40d	31-Jul-28	25-Sep-28
SUBC2130	Subct: Sub Submittals & HCBI Review - Piping	40d	31-Jul-28	25-Sep-28
SUBC2140	Subct: Sub Submittals & HCBI Review - Pipe Insulation	40d	26-Sep-28	22-Nov-28
Scaffolding		70d	26-Sep-28	11-Jan-29
SUBC2150	Subct: Bid/ Award: Scaffolding	40d	26-Sep-28	22-Nov-28
SUBC2180	Subct: Sub Submittals & HCBI Review - Scaffolding	30d	23-Nov-28	11-Jan-29
13 LNG TANK MATERIALS		318d	14-Sep-26	23-Dec-27
RFQ to PO		233d	14-Sep-26	23-Aug-27
PRTK0100	RFQ to PO: 9%Ni Plates	68d	14-Sep-26	18-Dec-26
PRTK0140	RFQ to PO: Aluminum Plates	35d	08-Oct-26	27-Nov-26
PRTK0070	RFQ to PO: CS Plates	33d	13-Oct-26	27-Nov-26
PRTK0410	RFQ to PO: Misc. Plates, Bars, Angles	35d	13-Oct-26	01-Dec-26
PRTK0620	RFQ to PO: Weld Material (CS)	35d	13-Oct-26	01-Dec-26
PRTK0290	RFQ to PO: Pump Tubes	35d	06-Nov-26	04-Jan-27
PRTK0710	RFQ to PO: Capping Material	35d	23-Nov-26	18-Jan-27
PRTK0380	RFQ to PO: PRV's & VRV's	70d	30-Nov-26	16-Mar-27
PRTK0530	RFQ to PO: Nozzles & Appurt.	32d	30-Nov-26	20-Jan-27
PRTK0560	RFQ to PO: Nelson Studs	35d	30-Nov-26	25-Jan-27
PRTK0650	RFQ to PO: Weld Material (9% Ni)	35d	02-Dec-26	27-Jan-27
PRTK0590	RFQ to PO: Temp. Erection Material	35d	14-Jan-27	04-Mar-27
PRTK0680	RFQ to PO: Weld Material (Aluminum)	45d	14-Jan-27	18-Mar-27
PRTK0350	RFQ to PO: Tank RTD's	35d	26-Jan-27	16-Mar-27
PRTK0320	RFQ to PO: Internal Piping	38d	12-Mar-27	05-May-27
PRTK0440	RFQ to PO: Internal Stairways, Platforms & Pipe Supports	63d	25-May-27	23-Aug-27
Supply		260d	30-Nov-26	16-Dec-27
PRTK0080	Supplier Lead Time: CS Plates	90d	30-Nov-26	14-Apr-27
PRTK0150	Supplier Lead Time: Aluminum Plates	81d	30-Nov-26	31-Mar-27
PRTK0420	Supplier Lead Time: Misc. Plates, Bars, Angles	122d	02-Dec-26	02-Jun-27
PRTK0630	Supplier Lead Time: Weld Material (CS)	60d	02-Dec-26	04-Mar-27
PRTK0110	Supplier Lead Time: 9%Ni Plates	200d	21-Dec-26	13-Oct-27
PRTK0300	Supplier Lead Time: Pump Tubes	85d	05-Jan-27	05-May-27
PRTK0720	Supplier Lead Time: Capping Material	20d	19-Jan-27	16-Feb-27
PRTK0540	Supplier Lead Time: Nozzles & Appurt.	43d	21-Jan-27	23-Mar-27
PRTK0570	Supplier Lead Time: Nelson Studs	20d	26-Jan-27	23-Feb-27
PRTK0660	Supplier Lead Time: Weld Material (9% Ni)	110d	28-Jan-27	06-Jul-27
PRTK0600	Supplier Lead Time: Temp. Erection Material	11d	05-Mar-27	19-Mar-27
PRTK0360	Supplier Lead Time: Tank RTD's	95d	17-Mar-27	30-Jul-27
PRTK0390	Supplier Lead Time: PRV's & VRV's	190d	17-Mar-27	16-Dec-27
PRTK0690	Supplier Lead Time: Weld Material (Aluminum)	43d	19-Mar-27	19-May-27
PRTK0330	Supplier Lead Time: Internal Piping	20d	06-May-27	03-Jun-27
PRTK0450	Supplier Lead Time: Internal Stairways, Platforms & Pipe Supports	50d	24-Aug-27	03-Nov-27



Remaining Level of Effort | Actual Work | Critical Remaining Work
Actual Level of Effort | Remaining Work | Critical Secondary

Date	Revision	Checked	Approved
19-Aug-24	IFI		

Activity ID	Activity Name	Rem. Duration	Start	Finish
Delivery		215d	17-Feb-27	23-Dec-27
PRTK0730	Delivery: Capping Material	15d	17-Feb-27	09-Mar-27
PRTK0580	Delivery: Nelson Studs	5d	24-Feb-27	02-Mar-27
PRTK0640	Delivery: Weld Material (CS)	5d	05-Mar-27	11-Mar-27
PRTK0610	Delivery: Temp. Erection Material	5d	22-Mar-27	26-Mar-27
PRTK0550	Delivery: Nozzles & Appurt.	15d	24-Mar-27	14-Apr-27
PRTK0160	Delivery: Aluminum Plates	37d	01-Apr-27	25-May-27
PRTK0090	Delivery: CS Plates	30d	15-Apr-27	27-May-27
PRTK0310	Delivery: Pump Tubes	30d	06-May-27	17-Jun-27
PRTK0120	Delivery: 9%Ni Plates (1st Shipment to Everett Shop)	45d	20-May-27	23-Jul-27
PRTK0700	Delivery: Weld Material (Aluminum)	15d	20-May-27	10-Jun-27
PRTK0430	Delivery: Misc. Plates, Bars, Angles	11d	03-Jun-27	17-Jun-27
PRTK0340	Delivery: Internal Piping	5d	04-Jun-27	10-Jun-27
PRTK0670	Delivery: Weld Material (9% Ni)	5d	07-Jul-27	13-Jul-27
PRTK0370	Delivery: Tank RTD's	8d	03-Aug-27	13-Aug-27
PRTK0130	Delivery: 9%Ni Plates (2nd Shipment to Site)	45d	14-Oct-27	16-Dec-27
PRTK0460	Delivery: Internal Stairways, Platforms & Pipe Supports	14d	04-Nov-27	24-Nov-27
PRTK0400	Delivery: PRV's & VRV's	5d	17-Dec-27	23-Dec-27
15 PIPING MATERIALS		335d	08-Oct-26	18-Feb-28
RFQ to PO		192d	08-Oct-26	20-Jul-27
PRPI0010	RFQ to PO: Field (Small Bore) CS & SS Pipe, Fittings & Flanges	88d	08-Oct-26	19-Feb-27
PRPI0040	RFQ to PO: Process Piping (Large Bore) CS & SS Pipe, Fittings & Flanges	83d	08-Oct-26	11-Feb-27
PRPI0070	RFQ to PO: Manual Butterfly Valves	51d	13-Nov-26	01-Feb-27
PRPI0100	RFQ to PO: Manual Ball Valves	51d	13-Nov-26	01-Feb-27
PRPI0130	RFQ to PO: Manual Gate/Globe/Check Valves	51d	13-Nov-26	01-Feb-27
PRPI1990	RFQ to PO: Piping & Component Matls - Tank Grade Rack	55d	26-Jan-27	14-Apr-27
PRPI0190	RFQ to PO: Spiral Wound / Garlok / Neoprene Gaskets	108d	16-Feb-27	20-Jul-27
PRPI0220	RFQ to PO: CS & SS Fasteners	40d	16-Feb-27	13-Apr-27
PRPI0250	RFQ to PO: Hose Connections	75d	16-Feb-27	02-Jun-27
PRPI0160	RFQ to PO: Cold Shoes & Misc. Pipe Supports	40d	05-Apr-27	31-May-27
Supply		255d	07-Dec-26	16-Dec-27
PRPI0020	Supplier Lead Time: Field (Small Bore) CS & SS Pipe, Fittings & Flanges	56d	07-Dec-26	03-Mar-27
PRPI0050	Supplier Lead Time: Process Piping (Large Bore) CS & SS Pipe, Fittings & Flanges	85d	07-Dec-26	14-Apr-27
PRPI0080	Supplier Lead Time: Manual Butterfly Valves	220d	02-Feb-27	16-Dec-27
PRPI0110	Supplier Lead Time: Manual Ball Valves	200d	02-Feb-27	18-Nov-27
PRPI0140	Supplier Lead Time: Manual Gate/Globe/Check Valves	200d	02-Feb-27	18-Nov-27
PRPI0230	Supplier Lead Time: CS & SS Fasteners	20d	14-Apr-27	11-May-27
PRPI2000	Supplier Lead Time: Receive Material & Fabricate - Piping & Component Matls - Ta	168d	15-Apr-27	14-Dec-27
PRPI0170	Supplier Lead Time: Cold Shoes & Misc. Pipe Supports	75d	01-Jun-27	16-Sep-27
PRPI0260	Supplier Lead Time: Hose Connections	35d	03-Jun-27	22-Jul-27
PRPI0200	Supplier Lead Time: Spiral Wound / Garlok / Neoprene Gaskets	28d	21-Jul-27	30-Aug-27
Delivery		239d	04-Mar-27	18-Feb-28

Remaining Level of Effort | Actual Work | Critical Remaining Work
Actual Level of Effort | Remaining Work | Critical Secondary

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Activity ID	Activity Name	Rem. Duration	Start	Finish
PRPI0030	Delivery: Field (Small Bore) CS & SS Pipe, Fittings & Flanges	5d	04-Mar-27	10-Mar-27
PRPI0060	Delivery: Process Piping (Large Bore) CS & SS Pipe, Fittings & Flanges	5d	15-Apr-27	21-Apr-27
PRPI0240	Delivery: CS & SS Fasteners	15d	12-May-27	02-Jun-27
PRPI0270	Delivery: Hose Connections	15d	23-Jul-27	13-Aug-27
PRPI0210	Delivery: Spiral Wound / Garlok / Neoprene Gaskets	14d	31-Aug-27	20-Sep-27
PRPI0180	Delivery: Cold Shoes & Misc. Pipe Supports	14d	17-Sep-27	06-Oct-27
PRPI0120	Delivery: Manual Ball Valves	40d	19-Nov-27	21-Jan-28
PRPI0150	Delivery: Manual Gate/Globe/Check Valves	40d	19-Nov-27	21-Jan-28
PRPI2010	Delivery: Piping & Component Matls - Tank Grade Rack	42d	15-Dec-27	18-Feb-28
PRPI0090	Delivery: Manual Butterfly Valves	40d	17-Dec-27	18-Feb-28
03 CONCRETE MATERIALS		263d	13-Oct-26	03-Nov-27
RFQ to PO		192d	13-Oct-26	22-Jul-27
PRTK0470	RFQ to PO: CS Bottom Embeds	25d	13-Oct-26	17-Nov-26
PRTK0010	RFQ to PO: Isolators	11d	11-Feb-27	26-Feb-27
PRTK0040	RFQ to PO: Cryogenic Rebar	11d	19-Feb-27	05-Mar-27
PRTK0500	RFQ to PO: CS Roof Embeds	42d	25-May-27	22-Jul-27
Supply		220d	18-Nov-26	07-Oct-27
PRTK0480	Supplier Lead Time: CS Bottom Embeds	53d	18-Nov-26	08-Feb-27
PRTK0020	Supplier Lead Time: Isolators	100d	01-Mar-27	21-Jul-27
PRTK0050	Supplier Lead Time & Fabrication - Cryogenic Rebar	70d	08-Mar-27	15-Jun-27
PRTK0510	Supplier Lead Time: CS Roof Embeds	53d	23-Jul-27	07-Oct-27
Delivery		185d	09-Feb-27	03-Nov-27
PRTK0490	Delivery: CS Bottom Embeds	19d	09-Feb-27	08-Mar-27
PRTK0060	Delivery: Cryogenic Rebar	8d	16-Jun-27	25-Jun-27
PRTK3380	Delivery: Isolators	21d	22-Jul-27	20-Aug-27
PRTK0520	Delivery: CS Roof Embeds	18d	08-Oct-27	03-Nov-27
17 INSTRUMENT & CONTROL MATERIALS		275d	15-Oct-26	24-Nov-27
RFQ to PO		138d	15-Oct-26	07-May-27
PRIC0130	RFQ to PO: Control Valves	45d	15-Oct-26	17-Dec-26
PRIC0040	RFQ to PO: Flow Elements	45d	28-Jan-27	01-Apr-27
PRIC0070	RFQ to PO: Pressure Gauges & Indicators	45d	04-Feb-27	09-Apr-27
PRIC0220	RFQ to PO: Tank Gauging System	55d	04-Feb-27	23-Apr-27
PRIC0100	RFQ to PO: Transmitters	45d	11-Feb-27	16-Apr-27
PRIC0280	RFQ to PO: Manual Call Point	45d	11-Feb-27	16-Apr-27
PRIC0250	RFQ to PO: Fire & Gas Detection	55d	19-Feb-27	07-May-27
PRIC0190	RFQ to PO: Process Connection Material	35d	26-Feb-27	16-Apr-27
PRIC0160	RFQ to PO: Instrument Stands & Supports	35d	12-Mar-27	30-Apr-27
PRIC0010	RFQ to PO: Inclinometer	35d	19-Mar-27	07-May-27
Supply		193d	18-Dec-26	30-Sep-27
PRIC0140	Supplier Lead Time: Control Valves	190d	18-Dec-26	27-Sep-27
PRIC0050	Supplier Lead Time: Flow Elements	30d	05-Apr-27	14-May-27
PRIC0080	Supplier Lead Time: Pressure Gauges & Indicators	32d	12-Apr-27	26-May-27
PRIC0110	Supplier Lead Time: Transmitters	64d	19-Apr-27	19-Jul-27

Remaining Level of Effort | Actual Work | Critical Remaining Work
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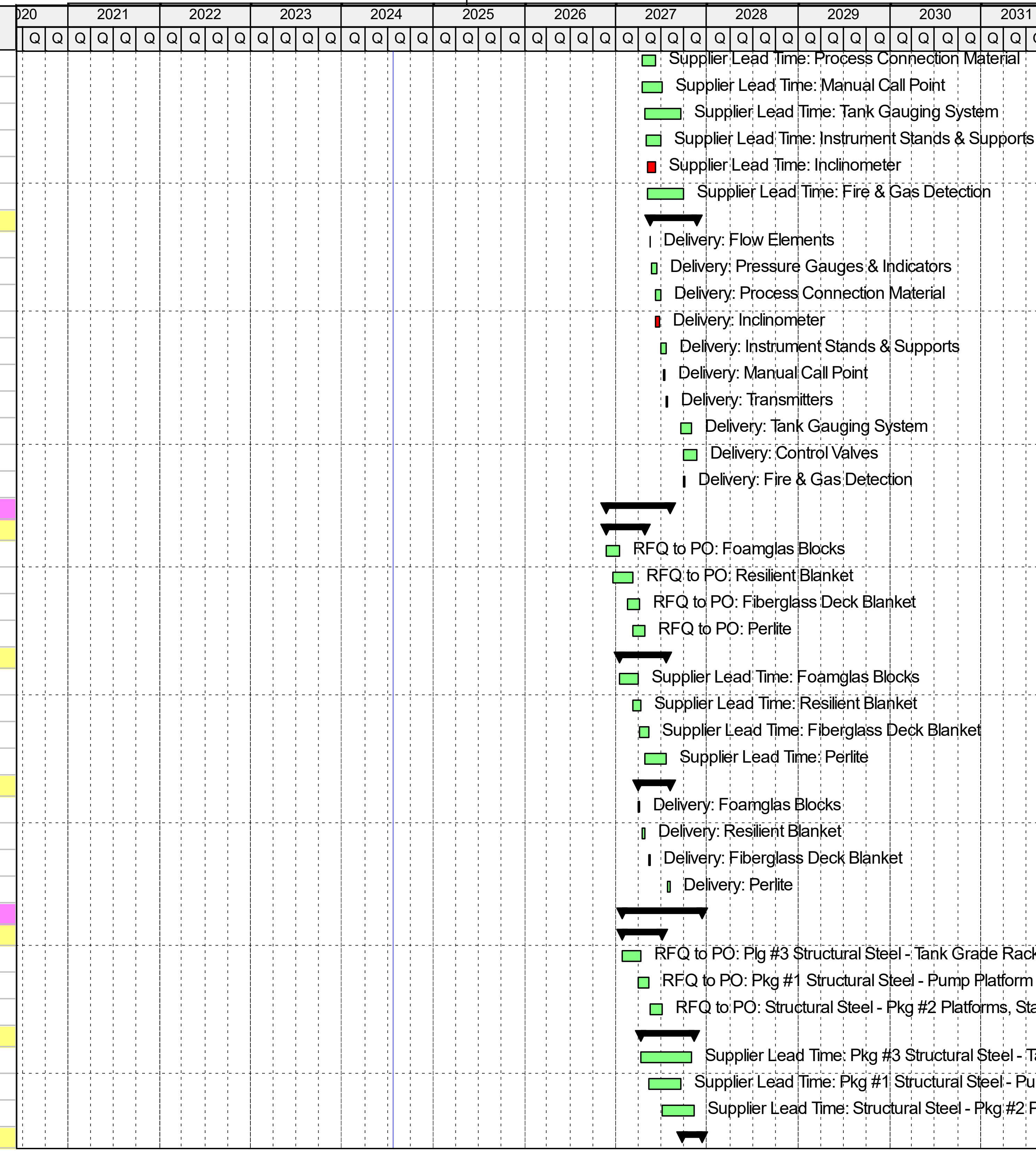
Tilbury Island LNG Facility Expansion (3 BCF)
TLSE Sub-Projects Integrated Schedule-Detailed

FORTIS BC — SOLARIS MANAGEMENT CONSULTANTS INC.

Activity ID	Activity Name	Rem. Duration	Start	Finish
PRIC0200	Supplier Lead Time: Process Connection Material	36d	19-Apr-27	08-Jun-27
PRIC0290	Supplier Lead Time: Manual Call Point	57d	19-Apr-27	08-Jul-27
PRIC0230	Supplier Lead Time: Tank Gauging System	100d	26-Apr-27	16-Sep-27
PRIC0170	Supplier Lead Time: Instrument Stands & Supports	42d	03-May-27	30-Jun-27
PRIC0020	Supplier Lead Time: Inclinometer	22d	10-May-27	09-Jun-27
PRIC0260	Supplier Lead Time: Fire & Gas Detection	100d	10-May-27	30-Sep-27
Delivery		132d	17-May-27	24-Nov-27
PRIC0060	Delivery: Flow Elements	5d	17-May-27	21-May-27
PRIC0090	Delivery: Pressure Gauges & Indicators	15d	27-May-27	16-Jun-27
PRIC0210	Delivery: Process Connection Material	14d	09-Jun-27	28-Jun-27
PRIC0030	Delivery: Inclinometer	10d	10-Jun-27	23-Jun-27
PRIC0180	Delivery: Instrument Stands & Supports	15d	02-Jul-27	22-Jul-27
PRIC0300	Delivery: Manual Call Point	5d	09-Jul-27	15-Jul-27
PRIC0120	Delivery: Transmitters	5d	20-Jul-27	26-Jul-27
PRIC0240	Delivery: Tank Gauging System	30d	17-Sep-27	29-Oct-27
PRIC0150	Delivery: Control Valves	40d	28-Sep-27	24-Nov-27
PRIC0270	Delivery: Fire & Gas Detection	5d	01-Oct-27	07-Oct-27
07 INSULATION MATERIALS		175d	23-Nov-26	09-Aug-27
RFQ to PO		105d	23-Nov-26	28-Apr-27
PRTK0170	RFQ to PO: Foamglas Blocks	35d	23-Nov-26	18-Jan-27
PRTK0230	RFQ to PO: Resilient Blanket	50d	21-Dec-26	09-Mar-27
PRTK0200	RFQ to PO: Fiberglass Deck Blanket	35d	17-Feb-27	07-Apr-27
PRTK0260	RFQ to PO: Perlite	35d	10-Mar-27	28-Apr-27
Supply		130d	19-Jan-27	23-Jul-27
PRTK0180	Supplier Lead Time: Foamglas Blocks	50d	19-Jan-27	30-Mar-27
PRTK0240	Supplier Lead Time: Resilient Blanket	25d	10-Mar-27	14-Apr-27
PRTK0210	Supplier Lead Time: Fiberglass Deck Blanket	25d	08-Apr-27	12-May-27
PRTK0270	Supplier Lead Time: Perlite	60d	29-Apr-27	23-Jul-27
Delivery		90d	31-Mar-27	09-Aug-27
PRTK0190	Delivery: Foamglas Blocks	5d	31-Mar-27	07-Apr-27
PRTK0250	Delivery: Resilient Blanket	10d	15-Apr-27	28-Apr-27
PRTK0220	Delivery: Fiberglass Deck Blanket	5d	13-May-27	19-May-27
PRTK0280	Delivery: Perlite	10d	26-Jul-27	09-Aug-27
05 STRUCTURAL MATERIALS		225d	25-Jan-27	15-Dec-27
RFQ to PO		112d	25-Jan-27	05-Jul-27
PRST3090	RFQ to PO: Plg #3 Structural Steel - Tank Grade Rack	55d	25-Jan-27	13-Apr-27
PRST0010	RFQ to PO: Pkg #1 Structural Steel - Pump Platform Modules	30d	31-Mar-27	12-May-27
PRST0040	RFQ to PO: Structural Steel - Pkg #2 Platforms, Stairs, Walkways & Handrai	30d	21-May-27	05-Jul-27
Supply		147d	14-Apr-27	12-Nov-27
PRST3100	Supplier Lead Time: Pkg #3 Structural Steel - Tank Grade Rack	140d	14-Apr-27	02-Nov-27
PRST0020	Supplier Lead Time: Pkg #1 Structural Steel - Pump Platform Modules	90d	13-May-27	21-Sep-27
PRST0050	Supplier Lead Time: Structural Steel - Pkg #2 Platforms, Stairs, Walkways & Handra	90d	06-Jul-27	12-Nov-27
Delivery		59d	22-Sep-27	15-Dec-27



Remaining Level of Effort | Actual Work | Critical Remaining Work
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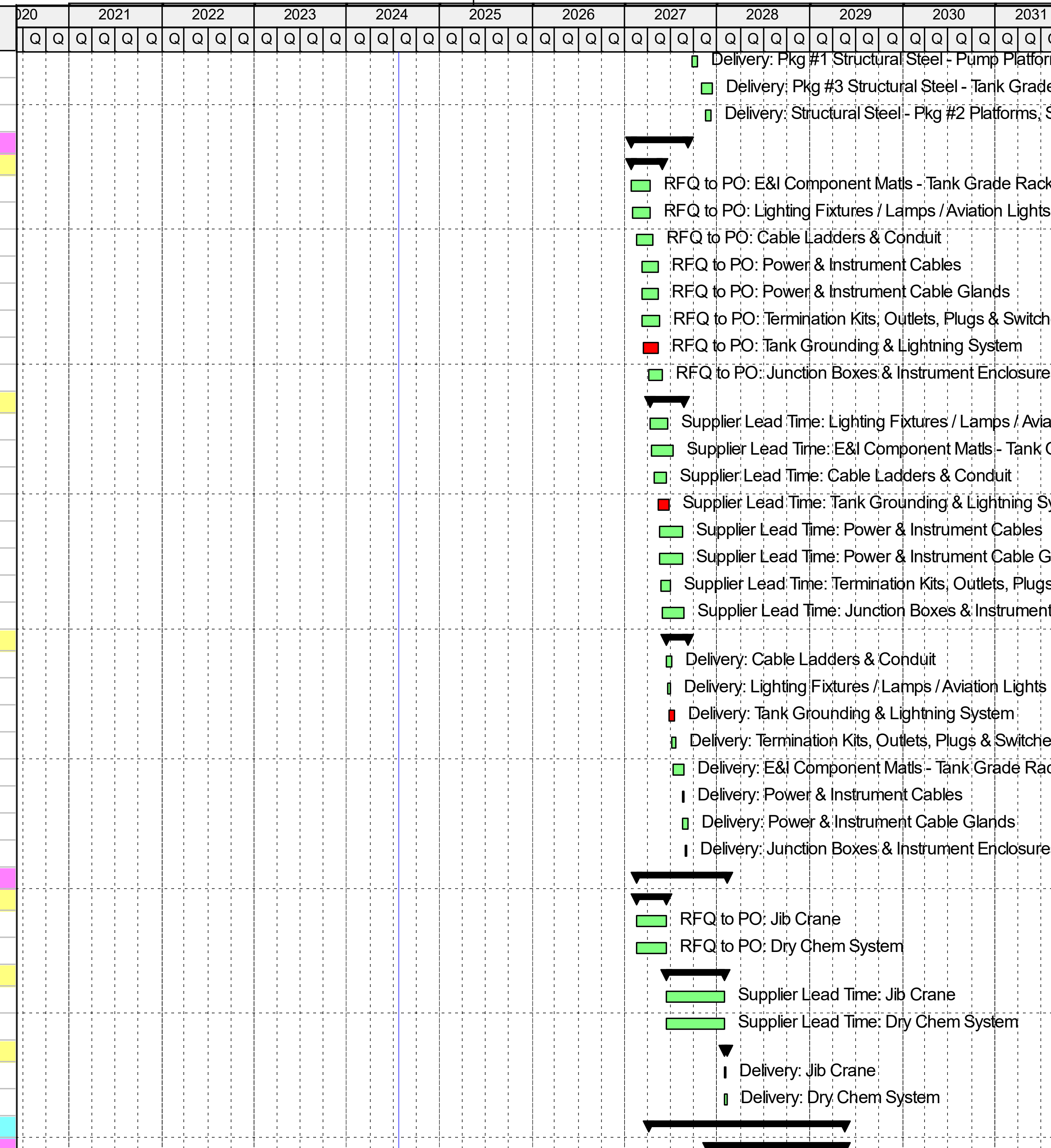
Tilbury Island LNG Facility Expansion (3 BCF)

TLSE Sub-Projects Integrated Schedule-Detailed

Activity ID	Activity Name	Rem. Duration	Start	Finish
PRST0030	Delivery: Pkg #1 Structural Steel - Pump Platform Modules	17d	22-Sep-27	15-Oct-27
PRST3110	Delivery: Pkg #3 Structural Steel - Tank Grade Rack	30d	03-Nov-27	15-Dec-27
PRST0060	Delivery: Structural Steel - Pkg #2 Platforms, Stairs, Walkways & Handrail	17d	15-Nov-27	07-Dec-27
16 ELECTRICAL MATERIALS		155d	26-Jan-27	07-Sep-27
RFQ to PO		87d	26-Jan-27	31-May-27
PREL1790	RFQ to PO: E&I Component Matls - Tank Grade Rack	55d	26-Jan-27	14-Apr-27
PREL0130	RFQ to PO: Lighting Fixtures / Lamps / Aviation Lights	45d	04-Feb-27	09-Apr-27
PREL0040	RFQ to PO: Cable Ladders & Conduit	45d	19-Feb-27	23-Apr-27
PREL0070	RFQ to PO: Power & Instrument Cables	45d	12-Mar-27	14-May-27
PREL0100	RFQ to PO: Power & Instrument Cable Glands	45d	12-Mar-27	14-May-27
PREL0160	RFQ to PO: Termination Kits, Outlets, Plugs & Switches	50d	12-Mar-27	21-May-27
PREL0010	RFQ to PO: Tank Grounding & Lightning System	39d	18-Mar-27	12-May-27
PREL0190	RFQ to PO: Junction Boxes & Instrument Enclosures	40d	05-Apr-27	31-May-27
Supply		95d	12-Apr-27	25-Aug-27
PREL0140	Supplier Lead Time: Lighting Fixtures / Lamps / Aviation Lights	50d	12-Apr-27	21-Jun-27
PREL1800	Supplier Lead Time: E&I Component Matls - Tank Grade Rack	60d	15-Apr-27	09-Jul-27
PREL0050	Supplier Lead Time: Cable Ladders & Conduit	35d	26-Apr-27	14-Jun-27
PREL0020	Supplier Lead Time: Tank Grounding & Lightning System	29d	13-May-27	23-Jun-27
PREL0080	Supplier Lead Time: Power & Instrument Cables	64d	17-May-27	17-Aug-27
PREL0110	Supplier Lead Time: Power & Instrument Cable Glands	64d	17-May-27	17-Aug-27
PREL0170	Supplier Lead Time: Termination Kits, Outlets, Plugs & Switches	28d	25-May-27	02-Jul-27
PREL0200	Supplier Lead Time: Junction Boxes & Instrument Enclosures	60d	01-Jun-27	25-Aug-27
Delivery		58d	15-Jun-27	07-Sep-27
PREL0060	Delivery: Cable Ladders & Conduit	14d	15-Jun-27	05-Jul-27
PREL0150	Delivery: Lighting Fixtures / Lamps / Aviation Lights	5d	22-Jun-27	28-Jun-27
PREL0030	Delivery: Tank Grounding & Lightning System	15d	24-Jun-27	15-Jul-27
PREL0180	Delivery: Termination Kits, Outlets, Plugs & Switches	14d	05-Jul-27	22-Jul-27
PREL1810	Delivery: E&I Component Matls - Tank Grade Rack	30d	12-Jul-27	23-Aug-27
PREL0090	Delivery: Power & Instrument Cables	5d	18-Aug-27	24-Aug-27
PREL0120	Delivery: Power & Instrument Cable Glands	14d	18-Aug-27	07-Sep-27
PREL0210	Delivery: Junction Boxes & Instrument Enclosures	5d	26-Aug-27	01-Sep-27
11 MECHANICAL EQUIPMENT		243d	19-Feb-27	11-Feb-28
RFQ to PO		80d	19-Feb-27	14-Jun-27
PREQ0010	RFQ to PO: Jib Crane	80d	19-Feb-27	14-Jun-27
PREQ0040	RFQ to PO: Dry Chem System	80d	19-Feb-27	14-Jun-27
Supply		153d	15-Jun-27	28-Jan-28
PREQ0020	Supplier Lead Time: Jib Crane	153d	15-Jun-27	28-Jan-28
PREQ0050	Supplier Lead Time: Dry Chem System	153d	15-Jun-27	28-Jan-28
Delivery		10d	31-Jan-28	11-Feb-28
PREQ0030	Delivery: Jib Crane	5d	31-Jan-28	04-Feb-28
PREQ0060	Delivery: Dry Chem System	10d	31-Jan-28	11-Feb-28
Offsite Fabrication		525d	06-Apr-27	17-May-29
FABRICATION MILESTONES		363d	26-Nov-27	17-May-29



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FORTIS BC | SOLARIS MANAGEMENT CONSULTANTS INC.

Activity ID	Activity Name	Rem. Duration	Start	Finish
MS3060	Fab: Start of Pump Platform Module Fabrication	0d	26-Nov-27	
MS4700	Fab: ROS: Off-Module Pipe Spools (Utility Lines, Risers, Under-Module & Misc)	0d		06-Jan-29
MS4710	ROS: Pump Platform Modules & Other Structures	0d		17-May-29
13 INNER TANK & SUSPENDED DECK FABRICATION		200d	09-Jul-27	28-Feb-28
FBTK0130	Fab: Inner Tank Stiffeners, Pump Tubes & Internal Piping	200d	09-Jul-27	28-Feb-28
FBTK0150	Fab: Suspended Deck Materials	85d	14-Oct-27	21-Jan-28
05 PUMP PLATFORM FABRICATION		392d	18-Oct-27	17-May-29
FBST1000	Customs: Pkg #1 Structural Steel - Customs Clearance	50d	18-Oct-27	04-Jan-28
FBMO0030	Fab: Pump Platform Modules	407d	26-Nov-27	15-Mar-29
FBMO0040	Fab: Off-Module Piping & Structural	260d	26-Nov-27	25-Sep-28
FBMO1080	Shipment: Off-Module Piping & Structural	78d	26-Sep-28	25-Dec-28
FBMO1060	Shipment: Off-Module Pipe Spools (Utility Lines, Risers, Under-Module & Misc)	49d	04-Nov-28	06-Jan-29
FBMO0010	Shipment: Pump Platform Modules	59d	19-Mar-29	17-May-29
05 MISC PLATFORMS, STAIRS, WALKWAYS & HANDRAIL FABRICATION		206d	17-Mar-28	13-Nov-28
FBMO1100	Fab: Structural Platforms, Stairs, Walkways & Handrail	164d	17-Mar-28	25-Sep-28
FBMO1090	Shipment: Structural Platforms, Stairs, Walkways & Handrail	42d	25-Sep-28	13-Nov-28
FBST2020	ROS: Structural Steel Pkg #2 Platforms, Stairs, Walkways & Handrail (Site)	0d		13-Nov-28
13 OUTER TANK FABRICATION		175d	06-Apr-27	15-Dec-27
FBTK0010	Fab: Outer Bottom Sketches & Embeds	90d	06-Apr-27	20-Jul-27
FBTK0110	Fab: Temporary Erection Material	53d	23-Apr-27	09-Jul-27
FBTK0070	Fab: Outer Tank (Roof Fittings & Nozzles)	20d	04-May-27	01-Jun-27
FBTK0030	Fab: Outer Liner Shell Rings #1 - #18 & Compression Bar	81d	15-Jun-27	17-Sep-27
FBTK0090	Fab: Outer Tank Roof & Supports	83d	16-Jun-27	14-Oct-27
FBTK0020	Fab: CS Wall & Roof Embeds	36d	03-Nov-27	15-Dec-27
Construction		716d	25-Oct-27	16-Sep-30
CONSTRUCTION MILESTONES		715d	26-Oct-27	16-Sep-30
MS3160	Construction: Mobilize @ Site	0d	26-Oct-27	
MS3050	Construction: Mobilize HCBI Site PMT	0d	24-Nov-27	
MS3070	Construction: Start of Outer Tank Steel Bottom	0d	10-Mar-28	
MS3080	Construction: Completion of Compression Bar & Top Embeds	0d		02-Feb-29
MS3090	Construction: Completion of Roof Air Raise	0d	13-Mar-29	
MS3100	Construction: Completion of Roof Plinths	0d		26-Jun-29
MS3120	Construction: Completion of Setting Pump Platform	0d		19-Sep-29
MS3110	Construction: Begin Tank Grade Rack Foundations	0d	10-Oct-29	
MS3130	Construction: Completion of Tank Hydrotest	0d		18-Apr-30
MS3150	Construction: LNG Tank Ready for Cooldown	0d		16-Sep-30
MS3140	Construction Completion - Base Scope	0d		16-Sep-30
CLIENT INTERFACE		716d	25-Oct-27	16-Sep-30
MS1170	Client: Full Access to LNG Tank Foundation Pad Area	0d	25-Oct-27	
MS1180	Client: Full Access to Temporary Facility Location	0d	25-Oct-27	
MS1190	Client: Full Access to Remote Laydown and Warehousing Area	0d	25-Oct-27	
MS4040	Client: MOF & Heavy Haul Route Availability & Clearance	0d	25-Oct-27	
MS4020	Client: Dummy Pumps (Supplied By Others)	0d		04-Mar-30

Remaining Level of Effort | Actual Work | Critical Remaining Work
Actual Level of Effort | Remaining Work | Critical Secondary

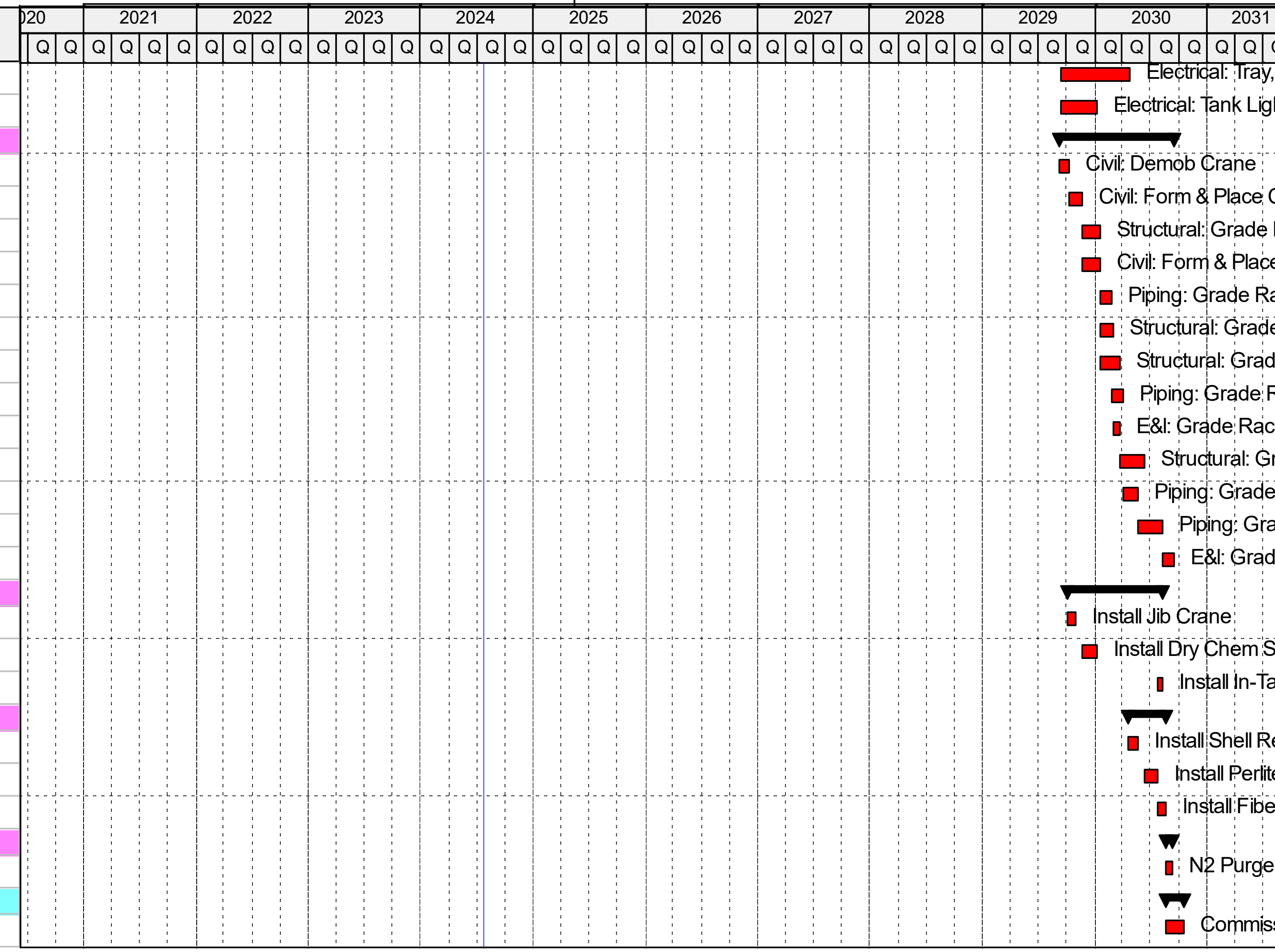
Date	Revision	Checked	Approved
19-Aug-24	IFI		

Activity ID	Activity Name	Rem. Duration	Start	Finish
MS4030	Client: Deliver Client Supplied In-Tank Pumps & Foot Valves	0d		22-Mar-30
MS4050	Client: BOP Subcontractor Start of BOG Compressor Bldg & Appurtenances	0d		16-Sep-30
MS4060	Client: Install In-Tank Pump Power Cable	0d		16-Sep-30
03 MOBILIZATION		25d	26-Oct-27	01-Dec-27
MOB1110	Site Mobilization	25d	26-Oct-27	01-Dec-27
05 STRUCTURAL STEEL		198d	16-Oct-28	04-Oct-29
CNST5110	Install Construction Elevator & Roof Perimeter Handrail	75d	16-Oct-28	08-Mar-29
CNST5120	Install Instrument & PSV/ VRV Platforms	60d	26-Jun-29	04-Oct-29
03 CONCRETE		435d	24-Nov-27	13-Sep-29
CNCO1000	Concrete: Foundation Bottom Slab	65d	24-Nov-27	10-Mar-28
CNCO0030	Concrete: Wall Lifts 1 thru 10	175d	04-Jul-28	28-Mar-29
CNCO0050	Concrete: Place Roof Concrete & Plinths	62d	28-Mar-29	26-Jun-29
CNCO0060	Concrete: Horizontal & Vertical Pre-Stress Tensioning Ring Beam	10d	28-Mar-29	12-Apr-29
CNCO1760	Concrete: Horizontal & Vertical Post Tensioning	54d	26-Jun-29	13-Sep-29
13 LNG TANK		652d	08-Dec-27	30-Jul-30
CNTK2360	Grd Assemble Outer Shell 3-Ring	45d	08-Dec-27	10-Mar-28
CNTK2490	Install Annular Embeds	15d	14-Feb-28	10-Mar-28
CNTK1100	Install Outer Shell Rings #1-#16	151d	10-Mar-28	27-Nov-28
CNTK2450	Ground Assemblies & Install Roof Liner	106d	10-Mar-28	11-Sep-28
CNTK2470	Install Outer Liner Bottom	35d	10-Mar-28	11-May-28
CNTK2460	Install Roof Nozzles	60d	03-Aug-28	14-Nov-28
CNTK2440	Install Suspended Deck	65d	11-Sep-28	16-Jan-29
CNTK2370	Install Compression Bar & Top Embeds	30d	27-Nov-28	02-Feb-29
CNTK2380	Air Raise Roof & Secure to Compression Bar	22d	02-Feb-29	13-Mar-29
CNTK2390	Install Leveling Concrete, Cellular Block, Bearing Ring, Inner Annular & TCP	70d	13-Mar-29	21-Jun-29
CNTK2400	Install Inner Tank Shell Rings #1-#13	174d	21-Jun-29	15-Mar-30
CNTK2410	Install Secondary & Inner Tank Bottoms	54d	02-Nov-29	04-Feb-30
CNTK2420	Install Inner Ladder, Platforms & Internal Piping / Nozzles	87d	02-Nov-29	22-Mar-30
CNTK2480	Grd Assemble, Install & Hydrotest Pump Tubes	60d	02-Nov-29	04-Mar-30
CNTK2250	Install Inner Shell Doorsheet	7d	11-Mar-30	22-Mar-30
CNTK2430	Hydrotest Inner Tank, Clean & Dry	15d	22-Mar-30	18-Apr-30
CNTK2260	Install TCP & Outer Shell at Doorsheet	10d	23-May-30	10-Jun-30
CNCO1750	Closure: TOC's Outer Tank Steel, Concrete & Pre-Stress	47d	23-May-30	30-Jul-30
CNTK2350	Pneumatic & Vacuum Test of Tank	3d	10-Jun-30	14-Jun-30
15 PUMP PLATFORM / PIPING		235d	29-Mar-29	23-May-30
CNMO1160	Install Shell Guides	65d	29-Mar-29	19-Jul-29
CNIN0010	Piping Ground Assemblies	52d	12-Apr-29	12-Jul-29
CNMO1060	Receive At Site: Modules At MOF & Transport to Tank Site	15d	17-May-29	12-Jun-29
CNMO1170	Prep & Install Pump Platform Modules	42d	12-Jul-29	19-Sep-29
CNMO1165	Install Structural Under-Platform	65d	20-Jul-29	05-Nov-29
CNMO1190	Install Module Inter-Connect Piping	80d	06-Nov-29	09-Apr-30
CNMO1200	Install Pipe Insulation	41d	14-Mar-30	23-May-30
16 / 17 ELECTRICAL & I&C		120d	13-Sep-29	25-Apr-30

Date	Revision	Checked	Approved
19-Aug-24	IFI		

Tilbury Island LNG Facility Expansion (3 BCF)
TLSE Sub-Projects Integrated Schedule-Detailed

Activity ID	Activity Name	Rem. Duration	Start	Finish
CNEI0010	Electrical: Tray, J-Box, Cable, Instruments & Terminations	120d	13-Sep-29	25-Apr-30
CNEI5010	Electrical: Tank Lighting	60d	13-Sep-29	10-Jan-30
22 TANK GRADE RACK		207d	06-Sep-29	16-Sep-30
CNCI5020	Civil: Demob Crane	20d	06-Sep-29	10-Oct-29
CNCI5100	Civil: Form & Place Concrete - Grade Rack Fdns Area A	25d	10-Oct-29	22-Nov-29
CNCI5030	Structural: Grade Rack - Lower Level 1A	25d	22-Nov-29	21-Jan-30
CNCI5110	Civil: Form & Place Concrete - Grade Rack Fdns Area B	25d	22-Nov-29	21-Jan-30
CNCI5040	Piping: Grade Rack - Lower Level 1A	20d	21-Jan-30	25-Feb-30
CNCI5060	Structural: Grade Rack - Lower Level 1B	25d	21-Jan-30	05-Mar-30
CNCI5090	Structural: Grade Rack - Upper Level 2A	35d	21-Jan-30	22-Mar-30
CNCI5160	Piping: Grade Rack - Lower Level 1B	20d	25-Feb-30	01-Apr-30
CNCI5050	E&I: Grade Rack - Lower Level	12d	05-Mar-30	26-Mar-30
CNCI5150	Structural: Grade Rack - Upper Level 2B	45d	22-Mar-30	10-Jun-30
CNCI5070	Piping: Grade Rack - Level 2A	29d	01-Apr-30	22-May-30
CNCI5170	Piping: Grade Rack - Level 2B	45d	22-May-30	08-Aug-30
CNCI5180	E&I: Grade Rack - Upper Level	23d	08-Aug-30	16-Sep-30
11 EQUIPMENT		168d	04-Oct-29	09-Aug-30
CNEQ1220	Install Jib Crane	15d	04-Oct-29	30-Oct-29
CNEQ1240	Install Dry Chem System	20d	19-Nov-29	07-Jan-30
CNEQ1230	Install In-Tank Pumps	12d	22-Jul-30	09-Aug-30
07 INSULATION		71d	18-Apr-30	20-Aug-30
CNIN1150	Install Shell Resilient Blanket	20d	18-Apr-30	23-May-30
CNIN1120	Install Perlite in Annular Space	21d	14-Jun-30	22-Jul-30
CNIN1130	Install Fiberglass Blanket on Deck & Nozzle Piping	17d	22-Jul-30	20-Aug-30
N2 PURGE		15d	20-Aug-30	13-Sep-30
PCOM0010	N2 Purge	15d	20-Aug-30	13-Sep-30
Commissioning		40d	22-Aug-30	18-Oct-30
TTK500030	Commissioning/Startup	40d	22-Aug-30	18-Oct-30



Remaining Level of Effort | Actual Work | Critical Remaining Work
Actual Level of Effort | Remaining Work | Critical Secondary

Data Date:26-Jul-24
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Date	Revision	Checked	Approved
19-Aug-24	IFI		

Appendix I

VALIDATION ESTIMATING CONTINGENCY REPORT

FILED CONFIDENTIALLY

Appendix J

VALIDATION ESTIMATING ESCALATION REPORT

FILED CONFIDENTIALLY

Appendix K

FINANCIAL SCHEDULES (PREFERRED ALTERNATIVE)

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

FILED CONFIDENTIALLY

Appendix L

NOTIFICATION LETTER TO POTENTIALLY AFFECTED INDIGENOUS GROUPS

16705 Fraser Highway
Surrey, B.C. V3L 5R7
Fortisbc.com

December 19, 2023

RE: FORTISBC TILBURY LNG STORAGE EXPANSION PROJECT UPDATE

FortisBC would like to update _________ regarding the regulatory review of the Tilbury LNG Storage Expansion Project (TLSE). In particular, one component of the Tilbury Phase 2 LNG Expansion Project, which includes the proposed addition of 142,400 m3 of Liquified Natural Gas (LNG) storage to the existing Tilbury LNG facility, is being reviewed as part of two simultaneous regulatory processes: (1) a regulated utility review process undertaken by the British Columbia Utilities Commission (BCUC); and (2) a provincially-led environmental assessment process. FortisBC provides an update regarding review process below.

Regulated Utility Review Process

As a regulated utility, FortisBC requires a Certificate of Public Convenience and Necessity (CPCN) from the BCUC for major projects that may affect rates paid by FortisBC customers. On December 29, 2020, FortisBC filed an Application for a CPCN for the Tilbury Liquefied Natural Gas (LNG) Storage Expansion Project with the BCUC to seek approval for the construction of a new LNG storage tank that will provide an additional backup source of natural gas for our customers in the Lower Mainland in the event of a gas supply disruption. If the CPCN is approved by the BCUC, we estimate that construction of the storage tank could begin as early as 2025 with projected completion by 2029.

On March 23, 2023, the BCUC released a decision adjourning the proceedings to permit FortisBC additional time to address specific comments raised by the BCUC and interveners in relation to its Application. The BCUC, among other things, requires further information on project alternatives and gas disruption risks throughout FortisBC's gas distribution system. FortisBC is addressing these comments and currently plans to file additional supplementary evidence in support of the planned LNG storage expansion in September, 2024. We will continue to provide you with updates on the process as well as a copy of the supplementary evidence to __________ concurrently with filing to the BCUC.

Environmental Review Process

FortisBC has continued to engage with ___________ regarding the Tilbury Phase 2 LNG Expansion project as it proceeds through the environmental assessment process led by the British Columbia Environmental Assessment Office and the Impact Assessment Agency of Canada. The Tilbury Phase 2 LNG Expansion encompasses a larger expansion of the Tilbury site, including both the new LNG storage tank which is part of the current CPCN process as well as additional LNG production capacity. As indicated above, the new LNG storage tank being assessed by the BCUC in the CPCN process is required to provide improved resiliency for FortisBC's gas customers in the event of a gas supply disruption.

As the next step in the environmental process, FortisBC expects to submit the Draft Environmental Assessment Application in September 2024 and will continue to engage with ___________ to discuss comments and feedback throughout the environmental assessment.

16705 Fraser Highway
Surrey, B.C. V3L 5R7
Fortisbc.com

FEI will continue to synchronize consultation activities for both the Tilbury Phase 2 LNG Expansion Project and the TLSE Project to ensure engagement is robust, efficient, and transparent, and help to reduce the overall burden placed on Indigenous nations by removing the duplicative efforts that would otherwise be required to review each process separately.

If you have any questions regarding the Tilbury Project or the BCUC process, please contact me at courtney.hodson@fortisbc.com or by phone at 604-592-7603.

Sincerely,

Courtney Hodson
Manager, Community & Indigenous Relations
FortisBC

cc.
Ian Finke, Director LNG Operations, FortisBC

Appendix M

DRAFT ORDERS

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
bcuc.com

P: 604.660.4700
TF: 1.800.663.1385

ORDER NUMBER
G-xx-xx

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

and

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

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On October 24, 2024, FortisBC Energy Inc. (FEI) filed its Supplemental Evidence (Supplemental Evidence) together with FEI's 2024 Resiliency Plan with the British Columbia Utilities Commission (BCUC) as part of its Application for a Certificate of Public Convenience and Necessity (CPCN) for the Tilbury Liquefied Natural Gas (LNG) Storage Expansion (TLSE) Project filed on December 29, 2020 (together, TLSE Application), in accordance with the BCUC Decision and Order G-62-23;

B. The TLSE Application requests approval of, among other things, a CPCN pursuant to sections 45 and 46 of the *Utilities Commission Act* (UCA) for the TLSE Project;

C. By Decision and Order G-62-23, dated March 23, 2023, the BCUC adjourned the TLSE Application proceeding (Adjournment Decision), pending the filing of evidence described in the Adjournment Decision;

D. FEI states that the Supplemental Evidence and the 2024 Resiliency Plan reinforce that the TLSE Project is in the public interest and should be approved as proposed, including the associated deferral account and depreciation and salvage rate approvals requested in the Application;

E. FEI requests that Appendices D, E, G, I, J, and K to the Supplemental Evidence be held confidential due to the operationally sensitive and commercially sensitive nature of the information. FEI further requests that redacted information in the 2024 Resiliency Plan and related Appendices RP 1, RP 2 and RP 4 be held confidential on a restricted basis due to the highly sensitive security related nature of the information and that it be available only to the BCUC (together, Confidential Information); and

F. The BCUC has commenced its review of the Supplemental Evidence and 2024 Resiliency Plan and finds that the establishment of a regulatory timetable to restart the proceeding is warranted.

NOW THEREFORE the BCUC orders as follows:

1. The written public hearing for the review of the TLSE Application is restarted and a regulatory timetable for the review of the Supplemental Evidence and 2024 Resiliency Plan is established as set out in Appendix A to this order.
2. FEI is to provide a copy of this Supplemental Evidence, the 2024 Resiliency Plan, and this order, electronically where possible, on or before Friday, December 8, 2024, to all registered interveners in the TLSE Application proceeding.
3. FEI is to publish the public versions of the Supplemental Evidence and 2024 Resiliency Plan, and a copy of this order, on its website at www.fortisbc.com as soon as practicable, but no later than Friday, December 6, 2024.
4. FEI is to provide confirmation to the BCUC that it has complied with Directives 2 and 3 of this order by Friday, December 13, 2024.
5. Appendices D, E, G, I, J, and K to the Supplemental Evidence will be held confidential until determined otherwise by the BCUC.
6. The redacted portions of the 2024 Resiliency Plan and related Appendices will be held by the BCUC on a restricted confidential basis, accessible to the BCUC only.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Attachment

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

REGULATORY TIMETABLE

Action	Date (2024)
FEI provides notice of Supplemental Evidence and this order	Friday, December 6
FEI provides confirmation of compliance with notice requirements	Friday, December 13
Action	**Date (2025)**
Technical Workshop on Exponent Inc. Risk and Consequence Determination Method*	Wednesday, January 29
BCUC Information Request (IR) No. 1	Thursday, February 20
Intervener IR No. 1	Thursday, February 27
FEI response to IRs No. 1	Thursday, April 3
BCUC IR No. 2	Thursday, April 17
Intervener IR No. 2	Thursday, April 24
FEI Response to IRs No. 2	Thursday, May 15
Letters of comment deadline	Thursday, May 22
FEI final argument	Thursday, June 12
Intervener final arguments	Thursday, July 3
FEI reply argument	Thursday, July 24

** The BCUC will conduct the workshop in person, commencing at 9am and will take place at [location]. FEI and registered interveners must register and provide a list of attendees by emailing the Commission Secretary at commission.secretary@bcuc.com to confirm their attendance at the workshop by Monday, January 27, 2025. Parties who cannot participate in person may submit a written request to the BCUC to attend virtually with an explanation supporting such a request, in confidence if necessary, by emailing commission.secretary@bcuc.com by the above-noted workshop registration deadline.*

bcuc
British Columbia
Utilities Commission

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ORDER NUMBER
C-xx-xx

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

and

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

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On October 24, 2024, FortisBC Energy Inc. (FEI) filed its Supplemental Evidence (Supplemental Evidence) together with FEI's 2024 Resiliency Plan with the British Columbia Utilities Commission (BCUC) as part of its Application for a Certificate of Public Convenience and Necessity (CPCN) for the Tilbury Liquefied Natural Gas (LNG) Storage Expansion (TLSE) Project filed on December 29, 2020 (together, TLSE Application), in accordance with the BCUC Decision and Order G-62-23;

B. The TLSE Application requests approval of, among other things, a CPCN pursuant to sections 45 and 46 of the *Utilities Commission Act* (UCA) for the TLSE Project which includes the following:

   i. Construction and operation of a 3 billion cubic feet (Bcf) LNG storage tank;

   ii. Construction and operation of 800 million cubic feet per day (MMcf/day) of regasification capacity;

   iii. Construction or modification and operation of any of the necessary auxiliary systems, including items such as utility pipe racks, in-tank pumps, piping, and connections to the sendout gas pipeline; and

   iv. Demolition of the above-ground portion of the Tilbury Base Plant LNG storage tank and liquefaction facilities;

C. FEI also seeks BCUC approval, pursuant to sections 59 to 61 of the UCA of the following:

i. The non-rate base TLSE Application and Preliminary Stage Development Costs deferral account, attracting a weighted average cost of capital return until the account enters rate base. FEI proposes to transfer the balance in the deferral account to rate base on January 1 of the year following BCUC approval of the Application and commence amortization over a three-year period thereafter;

ii. The non-rate base TLSE Foreign Exchange (FX) Mark to Market deferral account, with no financing return, to capture the mark-to-market valuation of any foreign currency forward contracts entered into related to construction of the TLSE Project; and

iii. Depreciation and net salvage rates of 1.67 percent and 0.67 percent, respectively, for the new 3 Bcf LNG storage tank;

D. By Decision and Order G-62-23 dated March 23, 2023, the BCUC adjourned the TLSE Application proceeding (Adjournment Decision), pending the filing of evidence described in the Adjournment Decision;

E. FEI states that the Supplemental Evidence and the 2024 Resiliency Plan reinforces that the TLSE Project is in the public interest and should be approved as proposed, including the associated deferral account and depreciation and salvage rate approvals requested in the Application;

F. In the proceeding, FEI has made various requests in its filings that certain information in the TLSE Application, responses to information requests (IRs), Rebuttal Evidence, Supplemental Evidence and the 2024 Resiliency Plan be held confidential due to operational sensitivity, security sensitivity or commercial sensitivity (together, Confidential Information);

G. By Order G-XX-24 dated ###, the BCUC restarted the proceeding and established a regulatory timetable for the review of the Supplemental Evidence and 2024 Resiliency Plan, which consisted of public notice, a technical workshop and two rounds of IRs, followed by written arguments. The BCUC also ordered that certain portions of the Supplemental Evidence and 2024 Resiliency Plan be held confidential; and

H. The BCUC has considered the TLSE Application, evidence and submissions in this proceeding and finds that the following determinations are warranted.

NOW THEREFORE pursuant to sections 45, 46 and 59 to 61 of the UCA, the BCUC orders as follows:

1. A CPCN is granted to FEI for the TLSE Project, which as described further in the TLSE Application and Supplemental Evidence, consists of the following:

    a. construction and operation of a 3 billion cubic feet (Bcf) LNG storage tank;

    b. construction and operation of 800 million cubic feet per day (MMcf/day) of regasification capacity;

    c. construction or modification and operation of any of the necessary auxiliary systems, including items such as utility pipe racks, in-tank pumps, piping, and connections to the sendout gas pipeline; and

    d. demolition of the above-ground portion of the Tilbury Base Plant LNG storage tank and liquefaction facilities.

2. FEI is approved to establish the following deferral accounts:

    a. A non-rate base TLSE Application and Preliminary Stage Development Costs deferral account, attracting a weighted average cost of capital (WACC) return until the account enters rate base. FEI is also approved to transfer the balance in the deferral account to rate base on January 1 of the year following the date of this Decision and commence amortization over a three-year period thereafter.

    b. A non-rate base TLSE FX Mark to Market deferral account, with no financing return, to capture the mark-to-market valuation of any foreign currency forward contracts entered into related to construction of the TLSE Project.

3. FEI is also approved to use the following for the new 3 Bcf LNG storage tank:

    a. A depreciation rate of 1.67 percent.

    b. A net salvage rate of 0.67 percent.

4. FEI is directed to file with the BCUC the following reports:

    a. Within 30 days of the finalization of the construction contract, a Contract Finalization Report;

    b. Within 30 days of the end of each semi-annual reporting period, starting after the submission of the Contract Finalization Report and ending upon the filing of the Final Report, Semi-Annual Progress Reports;

    c. As soon as practicable but no longer than 30 days upon the identification of a material change including any significant delays or material cost variances, a Material Change Report (which may be filed as part of the Semi-Annual Progress Report where time permits); and

    d. Within six months of the final in-service date, a Final Report.

5. FEI must comply with all other directives and determinations outlined in the decision accompanying this order.

6. The BCUC will continue to hold confidential the Confidential Information unless determined otherwise by the BCUC.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Attachment (Yes? No?)