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~~**CONFIDENTIAL**~~

September 13, 2021

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

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: FortisBC Energy Inc. (FEI)

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

Response to the Commercial Energy Consumers Association of British Columbia (CEC) CONFIDENTIAL Information Request (IR) No. 1

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

Treatment of Confidential Material

Due to the sensitive and confidential nature of some of the information in the Application, FEI is filing some responses and attachments to information requests on a confidential basis pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents, as set out in Order G-15-19. FEI's treatment of security-sensitive and commercially-sensitive information in these responses is consistent with BCUC Order G-161-21 and the Revised Confidential Application (Exhibit B-1-3). All of that information will be available to interveners who have previously signed and provided the BCUC Confidentiality Declaration and Undertaking form (Undertaking) and the revised non-disclosure agreement (NDA). In the case of interveners who have only provided the signed Undertaking, they will receive all commercially-sensitive information only.

While some parties submitted information requests on a confidential basis, in order to maximize the amount of information on the public record, FEI has reviewed the preambles, questions, responses, and related attachments and in instances where confidential information is not disclosed, FEI has filed the information publicly, redacting all confidential information (both commercially-sensitive and security-sensitive). In cases where the information requests were submitted publicly, if the responses or related attachments disclose security-sensitive or commercially-sensitive confidential information, FEI has redacted those portions for the public record.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary

APPENDIX A – GUIDEHOUSE REPORT

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66. Reference: Exhibit B-1-1, Appendix A, Guidehouse Report on Natural Gas System Resiliency, Page 20

Guidehouse concludes that natural gas industry participants do not have a direct regulatory mandate to provide resiliency.

66.1 Does FEI agree that there is not a regulatory requirement to provide resiliency and as such that cost reasonableness is an important criterion for resiliency planning?

Response:

FEI considers cost reasonableness to be an important criterion for all investments.

Please refer to the response to BCOAPO IR1 2.3 with respect to the regulatory requirement for resiliency.

67. Reference: Exhibit B-1-1, Appendix A, Guidehouse Report on Natural Gas System Resiliency, Page 21

Guidehouse says that depending upon the resiliency needed, developing additional transportation or storage capacity may provide system redundancy or increased resiliency. These assets may be under-utilized for a period of time, creating a risk that these costs to customers could be viewed as unreasonable. However, weighted against that consideration is the potentially significant socio-economic consequences of a loss of service.

67.1 Does FEI agree that the under-utilization risk and the socio-economic consequences of a loss of service are significant issues?

Response:

FEI agrees that under-utilization risk and socio-economic consequences of a loss of service are significant issues to be considered. Please refer to the response to BCUC IR1 9.1 for further discussion of these issues.

67.2 Does FEI also agree that the cost of the provision of the resiliency would also be a critical factor. For instance, if the cost of the on system storage were the marginal cost of additional capacity over top of another significant requirement for the storage then the considerations Guidehouse highlights could be very different than considered just considering the whole cost?

Response:

FEI agrees that cost considerations are critical, but not the sole factor, in determining the need for resiliency enhancements. As cited by Guidehouse, the consequences of an event, if it occurs, are also a critical factor. In the Application, FEI has identified a known risk that could impact the supply to hundreds of thousands of Lower Mainland customers. As discussed in the response to BCUC IR1 8.5, supply disruptions during cold weather could have significant customer impacts and result in serious societal harm.

With respect to the cited example, FEI has already employed a portfolio approach in identifying and screening the solutions to address the Lower Mainland resiliency need. These solutions considered a variety of pipeline and storage alternatives and considered how these solutions interrelate to each other (please refer to Table 4-3 and Section 4.3.4.5.2 of the Application). On this basis, the considerations highlighted by Guidehouse have already been accounted for in FEI's alternatives analysis.

68. Reference: Exhibit B-1-1, Appendix A, Guidehouse Report on Natural Gas System Resiliency, Page 23

Guidehouse notes that the Southern Crossing pipeline carries natural gas from Nova Gas Transmission and can carry about 100 MMcf/day. Also, FEI dispatched trucks carrying CNG into the Lower Mainland during December. (They are not clear about which December.)

68.1 Given that FEI is committed to the on-system storage of LNG at Tilbury, what would be the conditions that would appear to FEI to trigger a commitment to increase capacity across the Southern crossing so that supply would have substantially less dependence on the Enbridge T-South pipelines.

Response:

The gas supply conditions that would trigger FEI to commit to increasing capacity across the Southern Crossing Pipeline (SCP) already exist. This includes periods of Sumas pricing volatility at Huntingdon, which occur when increased demand in the Pacific Northwest (PNW) region exceeds the delivery capacity of pipelines into the region. Further, the Sumas forward prices are currently trading at a significant premium to Station 2 for the winter season, which also reflects supply risk and volatility in the future, absent new pipeline infrastructure. These conditions are detailed in Sections 3.4.3.1 to 3.4.3.3 of the 2020-2021 Annual Contracting Plan L-31-20 Compliance Report, which is provided in Appendix C of the Application.

FEI has recently submitted a request for the creation of a deferral account (i.e., the Regional Gas Supply Diversity (RGSD) Project Development Costs deferral account) to capture the costs of developing the option of extending the SCP to Huntingdon in FEI's Annual Review for 2022 Delivery Rates application filed with the BCUC in July 2021. FEI believes additional pipeline infrastructure in the region is a part of the resiliency solution. Additional pipeline infrastructure would also facilitate load growth opportunities and would support the transition to cleaner energy.

68.2 How much CNG did FEI truck into the Lower Mainland in GJs for which years in the December month and what was the delivered cost of the CNG and where was it injected into the lower mainland system at what pressures?

Response:

The referenced scenario occurred in December 2018, when CNG was trucked from the Interior to the Lower Mainland to augment gas supplies during cold weather conditions while T-South flow restrictions were in place following the T-South Incident.

A total of approximately 462,000 GJs (approximately 408 MMcf) were delivered between December 2018 and January 2019. CNG was compressed at a location near Princeton, and

injected into the system in the Aldergrove/Abbotsford area. Gas was injected into FEI's IP system at 280 psi (1930 kPa). Total costs incurred were approximately $7.8 million, for a cost of approximately $16.90 per GJ delivered. This cost includes the contractor's charges as well as FEI's operational costs. Please also refer to the response to BCUC IR1 4.6 for a discussion of the overall gas supply incremental costs related to the T-South Incident.

69. Reference: Exhibit B-1-1, Appendix A, Guidehouse Report on Natural Gas System Resiliency, Page 24 & 25

Guidehouse notes that the BC electric system and the natural gas system are complementary, with the electric system supplying approximately 20% of BC end use energy and natural gas supplying 33% of BC end use energy (oil base energy and biomass being other major sources). Guidehouse says it is estimated that 18,000 MW of electrical system supply would be needed to replace the space and water heating on the coldest day of the year.

69.1 Please supply the calculations and assumptions made in determining the 18,000 MW.

Response:

On January 14, 2020, FEI experienced a peak hourly throughput of 65,709 GJ at 9 am. This is equivalent to 18,253 MW[1]. Almost all of this load was to supply space and water heating needs across FEI's system. This means that on a simplified one-to-one basis approximately 18,000 MW would be theoretically needed to completely substitute load with electricity generation. This does not account for different end-use efficiencies of natural gas and electric heating appliances.

69.2 Given that heat can be stored for a period of time and that the electric system in BC potentially has capacity over night that is not being used fully at that time has FEI explored what might be done with these complementary systems to jointly enable cost-effective displacement of some of the FEI peaking capacity requirements?

Response:

The options posed in the question would not allow FEI to meet its Minimum Resiliency Planning Objective (MRPO).

One of the premises of this question (the storage of heat for a period of time) implies that there would be some forewarning of a no-flow event in order to prepare by storing heat. Depending on the initiating cause, if a no-flow event occurs during cold weather conditions, FEI has no certainty that it will receive forewarning or that it will be able to provide sufficient advance notice to customers. Further, as described in Section 3.3.3.2.1 of the Application, FEI has a limited amount of time to respond in an attempt to prevent a hydraulic collapse. If customer demand exceeds FEI's currently limited resiliency resources during the event, the resulting sudden, wide-scale gas

[1] Unit conversion: 1 MW = 3.6 GJ/hour.

outages would impact a large number of gas customers. Further, the ensuing outages would last weeks to months and so any locally-stored heat would quickly be depleted.

With respect to the use of the electric system as an alternate source of energy during a no-flow event, please refer to the response to MS2S IR1 4.iii.

70. Reference: Exhibit B-1-1, Appendix A, Guidehouse Report on Natural Gas System Resiliency, Page 26-29

Guidehouse references some case examples in the US of regulators approving on site storage and the push back from some consumers with respect to the costs and rate increases among other arguments. They note that the final decisions involved approvals and regulator adoption of conditions related to the approvals.

70.1 Could Guidehouse confirm that there were no requested LNG facilities in any US jurisdiction turned down by regulators over the last 10 to 20 years, and if there were some could they summarize those cases as well?

Response:

The following response has been provided by Guidehouse:

In our project research Guidehouse did not find evidence of requested LNG facilities being turned down.

70.2 Please confirm that FEI would accept conditions placed on an approval of this Tilbury LNG Expansion project if the Commission were to issue them as part of an approval.

Response:

The BCUC has the power to impose terms on a CPCN under section 46(3) of the UCA. FEI is unable to comment in a general way as to the type of conditions that would, or would not, impede the TLSE Project; FEI would need to consider all relevant circumstances at the time of the BCUC's decision. As described in Section 4 of the Application, FEI has identified and evaluated a range of alternatives and, based on FEI's two-step alternatives analysis, has proposed what it believes is the best option for customers.

71. Reference: Exhibit B-1-1, Appendix A, Guidehouse Report on Natural Gas System Resiliency, Page 30

Guidehouse has found that Pipeline utilization in the Pacific Northwest has reached 100% in recent years, resulting in large gas price spikes. They also indicate that demand growth in the Pacific Northwest is expected to grow, putting pressure on regional infrastructure. Also noted, are the higher prices as Sumas at critical supply times.

71.1 What are the options for providing supply and resiliency support for the Pacific Northwest?

Response:

The following response has been provided by Guidehouse:

Options to provide supply and resiliency support need to be viewed from two perspectives. The first addresses physical adjacency; for example, whether or not there is a physical asset in the area that can provide incremental supply and/or resiliency support. The second perspective addresses if there is physical capacity that is available for contracting. For example, there may be natural gas storage or pipeline infrastructure in the region that could serve the resiliency requirements of FEI, but it is fully contracted. Alternatively, it may not be fully contracted, but the necessary pipeline connectivity is not available.

Guidehouse describes the options to provide supply and resiliency to FEI and its customers in its report in Section 2.3: Regional Natural Gas Distribution and Section 2.4: Regional Natural Gas Storage Infrastructure in the context of the regional system to which FEI is connected. However, a direct evaluation for providing supply and resiliency support to the wider Pacific Northwest region as a whole is not part of Guidehouse's mandate.

FEI adds the following response:

In addition to what Guidehouse has provided above, FEI's evaluation for providing supply and resiliency support to the wider PNW region could include: expanding the storage facilities at Jackson Prairie (JPS) and at Mist, expanding on-system storage in FEI's service area, and/or a pipeline expansion in the region.

Each utility in the PNW will have its own preferred options, based on the accessibility and the size of the resource they require, as Guidehouse mentioned above. This is important because the supply and resiliency solutions are not uniform across all PNW jurisdictions.

Both the JPS and Mist facilities have the potential to expand further; however, this would have little benefit in terms of resiliency support. As discussed in the response to CEC IR1 9.3, these facilities already store 44 Bcf of supply, so the utilities in the US PNW have sufficient amount of adjacent storage to utilize for a short-duration high-deliverability event. Further, these options

would not be helpful to FEI, as they are not connected to FEI's system and do not provide FEI with any supply assurance during a no-flow event on the T-South system.

Expanding on-system storage in FEI's service area (i.e., the TLSE Project) significantly enhances resiliency for FEI for short-duration high-deliverability events; however, it does not provide any substantial benefit to the US PNW. This is because the TLSE Project will reserve 2 Bcf for FEI's own minimum resiliency requirements, and any amount from the remaining 1 Bcf that is available at the time of a no-flow event would also provide valuable resiliency to FEI. Also, the volume would be insufficient to provide the PNW with any significant benefit over and above what is already available from JPS and Mist.

There may be support from other utilities and customers within the PNW for a new pipeline option that would provide supply and resiliency support for the region. As discussed in the preamble above, market conditions exist in the region that should trigger a response to address the pipeline constrained environment. Overall, any new pipeline infrastructure would help meet the demand growth in the PNW, as well as alleviate the high prices at Sumas during the winter. However, certain projects will be a better fit for some shippers from a resiliency standpoint, depending on the proposed pipeline route. Possible pipeline options are discussed in Section 4.3.4.1 of the Application and further explored in the responses to BCUC IR1 16.3 to 16.11.

Although the PNW utilities are generally supportive of a pipeline option, at this time FEI does not believe there is enough support to build a sufficiently large pipeline to replace the need for the TLSE Project. This was discussed in the response to BCUC IR1 16.3.

71.2 Please evaluate the future supply and resiliency options in the Pacific Northwest and point out which of the options would or could be more attractive to FEI should they be realized.

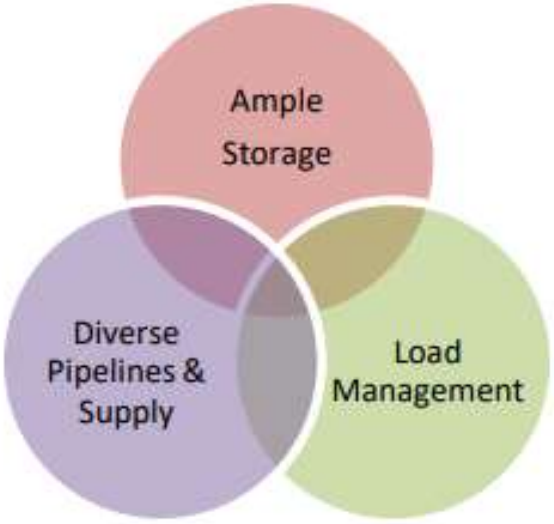
Response:

The following response has been provided by Guidehouse:

The scope of the Guidehouse engagement did not include an exploration of the future supply and resiliency options in the Pacific Northwest region for the Pacific Northwest region. Guidehouse did conduct an evaluation of physical assets that are available in the region and their suitability to FEI. Sections 2.2, 2.3 and 2.4 of the Guidehouse Report describe regional natural gas infrastructure. Section 2.5 discusses the implications for FEI and concluded that there is a lack of diversity of upstream pipeline and storage options for FEI to reduce its reliance on the T-South pipeline. In addition, Guidehouse has not identified a project that is more attractive to FEI to address the resiliency issues for the Lower Mainland system.

FEI adds the following response:

As discussed in the response to BCUC IR1 10.6, FEI is pursuing a suite of investments that will enhance all three elements that contribute to system resiliency (see the figure below).



FEI will focus on the supply-side investment options in the PNW (Ample Storage and Diverse Pipelines & Supply), given that load management does not increase supply, and is ideally used in conjunction with supply-side solutions.

- **Ample Storage –** As discussed in the Application, ample storage would help meet a short-duration high-deliverability supply event. In Sections 4.3.5.4 to 4.3.5.7 of the Application, FEI detailed the storage options within the Lower Mainland service area, and the reasons why adding storage at the existing Tilbury site is the preferred option. Additionally, there are potential expansions of the JPS and Mist storage facilities that could also help support resiliency in the PNW. However, expanding these facilities does not address FEI's Lower Mainland resiliency issue, given that FEI would remain dependent on the T-South system to access these storage resources (refer to Section 3.5.4.3 of the Application for further discussion).

  FEI's proposed solution to meet a short-duration high-deliverability supply event is the TLSE Project. The asset will be on-system, in FEI's control, and will significantly improve the resiliency in the Lower Mainland, which currently makes up the largest share of the demand on FEI's system while also having the least amount of system resiliency.

- **Diverse Pipelines & Supply** – Having diverse pipelines and supply would help manage a long-duration disruption of supply. As discussed in Section 4.3.4, FEI assessed four possible pipeline projects within two main categories:

  - An expansion to the existing T-South system; or
  - A new regional pipeline, including the following:
    - An expansion to Northwest Pipeline's (NWP) Gorge Capacity;
    - An expansion of SCP to Kingsvale;

- An expansion of SCP to Huntingdon.

FEI's preferred approach for future supply and resiliency options from a pipeline project perspective would be an expansion of SCP to Huntingdon, given that it provides the greatest resiliency benefit amongst the pipeline options. FEI is completing initial scoping and planning to proceed with developing this solution. This expansion would be optimally sized to form a cost-effective resiliency solution in combination with FEI's other gas supply assets, and would meet the future load requirements in the PNW region.

FEI's preferred solution is to employ a mix of pipeline redundancy and expanded peaking resources (i.e., on-system LNG storage), as it will be the most cost effective way to enhance resiliency, while also creating flexibility within FEI's gas supply resources.

71.3 Please comment upon how the higher Sumas prices affect the FEI supply portfolio, how they may affect the FEI portfolio going forward under no LNG expansion and under the proposed LNG expansion.

Response:

Please refer to the response to Sentinel IR1 15a.

71.4 Please confirm that the Mist natural gas storage facility just recently increased its capacity from 1.4 Bcf to 4 Bcf in May of 2019

Response:

Not confirmed. FEI understands the increase in capacity referred to in the question is relating to one of the fields and not the entire facility. The working capacity at the Mist natural gas storage facility is 19 Bcf, which includes the 2.5 Bcf North Mist Expansion that came into service in May 2019.

71.5 Please discuss the risks in the Pacific Northwest for gas supply disruptions affecting electricity system peaking capacities and whether or not this could be a significant driver for additional capabilities in the Pacific Northwest.

Response:

The following response has been provided by Guidehouse:

The scope of the Guidehouse engagement did not include a risk assessment of gas supply disruptions affecting electricity system peaking capacities. Guidehouse observes that gas supply disruptions could pose a significant risk to electric system reliability and resiliency; however, Guidehouse did not evaluate this question in greater detail as it was not part of Guidehouse's mandate.

FEI adds the following response:

The increasing reliance on natural gas based power generation in the region could be a significant driver for additional pipeline capacity in the PNW. However, there is no certainty that this will occur, nor that any developments would be configured to allow FEI to meet its MRPO.

FEI has noted an increased reliance on natural gas-based power generation in the region. While this is an ongoing development, the increase in gas demand for power plants in the region appears to be due in large part to the coal retirements across Western North America, now and into the future. Policies aimed at reducing GHG emissions in an effort to meet environmental objectives and targets have pushed for renewable resources including hydro, solar, and wind to offset the loss of supply from coal plants. However, renewable resources are not firm and when they are not available, natural gas power plants are needed to meet the region's electricity demand. Given these developments, it is apparent that the natural gas and power markets in the region are becoming increasingly connected. This connection can affect electricity system peaking capabilities if gas supply in the region is disrupted. This was evident during phase three of the T-South incident when the commodity prices at the Sumas/Huntingdon market reached the highest daily settlement price on record between March 2 and 4, 2019 ($200 per GJ). Section 3.4.2.2.3 of the Application discussed the factors that led to these high prices, which included increased demand for electricity in the PNW that caused competing demand for natural gas supply to generate electricity. It is also possible that even when the gas system is fully operational, there may be a risk to the electricity system peaking capabilities in the PNW, depending on certain weather and market conditions, not only within the I-5 corridor but the West in general.

72. Reference: Exhibit B-1-1, Appendix A, Guidehouse Report on Natural Gas System Resiliency, Page 38

Guidehouse notes that lack of diversity of the upstream pipeline options, being primarily Enbridge's T-South pipelines, for supply to FEI is a risk to resiliency and is further compounded because the FEI Aitken Creek underground storage is also dependent on the same Enbridge T-South pipeline system.

72.1 What is the size of the Williams, Northwest Pipeline Connection to the Enbridge T-South line at Huntingdon?

Response:

The size (capacity) of the Williams Northwest Pipeline connection to the Westcoast (Enbridge) T-South pipeline at Huntingdon is 1.3 Bcf/day.

72.2 Williams describes its Northwest Pipeline system a bi-directional, please provide an understanding as to whether or not this means that they could deliver supply to BC from US sources.

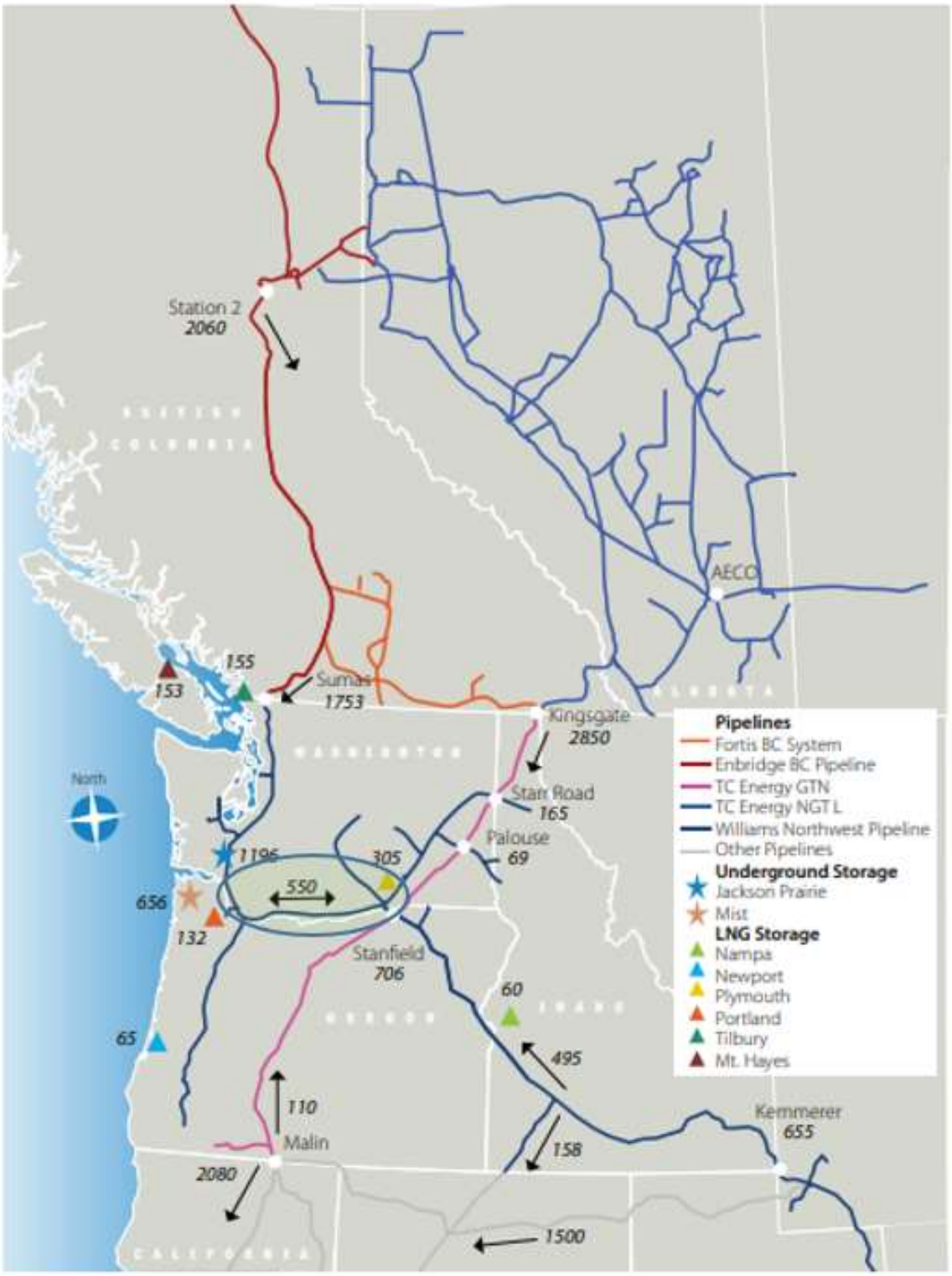
Response:

As mentioned on the Northwest Pipeline website, the 4,000-mile transmission system is bi-directional, and crosses the states of Washington, Oregon, Idaho, Wyoming, Utah and Colorado.

The bi-directional aspect refers to the Gorge segment of this system and is illustrated in the figure below from the 2020 Pacific Northwest Gas Market Outlook[2] (Gorge segment circled in blue). For example, during the winter season the Gorge pipeline typically flows east to west, allowing the Rocky Mountain, San Juan, and Alberta gas supplies to meet a portion of gas demand in Oregon and Washington. The Gorge pipeline gas flow then reverses to west to east in the summer. This is because the natural gas produced in Northeast BC flowing down T-South can be in excess of that required by customers in BC, Washington, and Oregon. This excess supply can flow west to east on the Gorge pipeline to satisfy the gas requirements either downstream or upstream of Stanfield.

Although Northwest Pipeline has some ability to deliver supply from US sources to BC, it would be extremely rare for the pipeline to transport any gas across the border from the US during the winter season. The NWP system is designed to physically transport gas north to south (i.e. from Westcoast to NWP) in normal operations, which as illustrated in the figure below is critical to serving the region as a whole (FEI and the US PNW) during the winter season.

[2] Northwest Gas Association. 2020 Pacific Northwest Gas Market Outlook. "Figure C1. Pacific Northwest Natural Gas Infrastructure and Capacities (MDth/day)." https://www.nwga.org/gas-outlook/2020-outlook-study/.


Station 2
2060
AECO
155
153
Sumas
1753
Kingsgate
2850
Stanfield Road
165
Palouse
69
1196
305
550
656
132
Stanfield
706
60
65
495
110
Malin
158
Kemmerer
655
2080
1500
North
Pipelines
Fortis BC System
Enbridge BC Pipeline
TC Energy GTN
TC Energy NGTL
Williams Northwest Pipeline
Other Pipelines
Underground Storage
Jackson Prairie
Mist
LNG Storage
Nampa
Newport
Plymouth
Portland
Tilbury
Mt. Hayes

1

2

73. Reference: Exhibit B-1-1, Appendix A, Guidehouse Report on Natural Gas System Resiliency, Page 40

Guidehouse points out that holding long haul natural gas transportation capacity is mission critical for managing the duration of the 151 day winter heating season. The utility of a long haul pipeline is enhanced by underground storage facilities with connectivity to the market demand. They point out that increased supply from the T-South system would increase the risk to failure on the T-South system.

73.1 While the Tilbury LNG Expansion may deal with a resiliency risk it has not been presented in the context of potential long-term plans for meeting FEI's anticipated market growth and also in the context of the Pacific Northwest anticipated market growth. Please provide a long term 30 to 40 year projection and the potential mix of pipeline, underground storage and LNG that may needed to service future requirements (particularly assuming that FEI succeeds in transitioning to renewable/synthetic natural gas supply).

Response:

The TLSE Project is specifically designed and sized for FEI and its unique circumstances, location, and system configuration; its relatively small size (3 Bcf) is not material to the needs of the much larger PNW region. Please refer to the response to CEC IR1 16.2 for how enhancing supply resiliency in the context of the PNW could be best met over the long term.

FEI does not prepare 30 to 40 year projections of the potential mix of pipeline and storage resources that will be needed. However, FEI's Long Term Gas Resource Plan (LTGRP) provides FEI's long range (20-year) outlook on infrastructure requirements. Infrastructure requirements in the later part of this 20-year planning period are subject to high levels of uncertainty, making a forecast of needs beyond 20 years of little practical value, since this uncertainty grows as the planning period is further extended. The changing nature of the planning environment means that updated Resource Plans are prepared and submitted on a frequent basis and contain action plans for the nearest 5-years in order to capture the impact of such changes. A 20-year planning horizon is viewed as appropriate for assessing the need for new infrastructure.

The 2017 LTGRP, accepted by the BCUC in 2019, is the most recently filed long term plan and contains the outlook of regional (FEI and utilities along the I-5 corridor) infrastructure needs for growth and system sustainment out to 2036. These requirements remain relevant today, including the importance of the Tilbury storage facility to FEI's system. Two examples of new developments (since the 2017 LTGRP was submitted) that have impacted this long term infrastructure needs assessment are the T-South Incident, and FEI's commitment to reducing carbon emissions on behalf of its customers through demand-side management (DSM) and renewable gas supplies. These developments and their implications for long-term infrastructure needs will be assessed and discussed in FEI's 2022 LTGRP currently being prepared for submission to the BCUC in 2022.

Although the updated infrastructure assessment for the 2022 LTGRP is not yet completed, it is not required for a full and complete consideration of the TLSE Application. A long-term

assessment of the need for and benefits of the TLSE Project has been provided in Sections 3 and 4 of the Application. This assessment takes into consideration the 2017 LTGRP as well as the updated resiliency and carbon reduction requirements.

In summary, although the long-term assessment has not yet been completed, it will not change the identified need for additional resiliency in the Lower Mainland service area which will be addressed by the TLSE Project.

74. Reference: Exhibit B-1-1, Appendix A, Guidehouse Report on Natural Gas System Resiliency, Page 42 & 43

[redacted]

Industrial curtailment is posed as conditional on 2 hours' notice window to enable stopping use or switching to alternative supply, and the importance of AMI options is also emphasized.

74.1 Please provide the total size of the interruptible demand, which may be subject to shut down in the event of an emergency and the size of firm demand, both as graphically shown in Figure 18.

Response:

FEI clarifies that the intent of Figure 18 was to illustrate that during the winter period there is little change in terms of how much supply FEI can curtail from interruptible customers in the event of a supply emergency.

Figure 3-12 was based on 10 years of data (2010 to 2019) for the winter seasons only (November to March). Based on the 10-year winter average, the total amount of the interruptible demand (Rate Schedules 7, 22, and 27) and firm demand (Rate Schedules 1 to 3, 23 and 25) in the Lower Mainland, as shown in Figure 18, was 55 TJ/day and 433 TJ/day, respectively.

74.2 What would be the ideal response timeframe for supporting the line pack pressures.

Response:

The following response is provided by FEI:

The ideal response timeframe would be an immediate response, in order to maximize system supply including line pack, and to maintain pressure for delivery to customers. However, FEI recognizes that industrial customers will need some time to curtail load in a manner that protects their equipment and operations. FEI presently has no means to remotely curtail supply to these customers, so the two hour window is a more realistic planning estimate to allow the time for these customers to react and curtail.

The following response was provided by Guidehouse:

The scope of the Guidehouse engagement did not include performing an analysis of the ideal response timeframe for supporting line pack pressures. Guidehouse did evaluate the efficacy of line pack in supporting a curtailment of upstream supply. Guidehouse observes that line pack is

used to respond to intra-day fluctuations between supply and demand and it is not considered a resilience asset because, in the event of an upstream supply disruption, line pack will be depleted once consumed.

[redacted]

Response:

The following response has been provided by Guidehouse:

The line pack information was provided by FEI. [redacted]

The scope of the Guidehouse engagement did not include performing an analysis of the downstream implications at the Huntington border connection with respect to demand and potential support from mutual cooperation. Guidehouse observes that during periods of peak usage in the region, pipeline utilization is 100 percent and that the ability to address a supply curtailment on the T-South pipeline with additional deliveries from pipelines south of Huntington and storage in Washington and Oregon would be highly limited.

The following response has been provided by FEI:

Please also refer to the response to MS2S IR1 6.i.

75. Reference: Exhibit B-1-1, Appendix A, Guidehouse Report on Natural Gas System Resiliency, Page 44

Guidehouse provides the details of the vaporization capacity at Tilbury Legacy 150 mmcf/day and the proposed Tilbury LNG Expansion of 800 mmcf/day and the Mt. Hayes facility of 150 mmcf/day.

75.1 Please describe the time required to safely shut down regional components of the supply to the FEI customers region by region in an emergency and the describe the FEI resources required to effect this sort of emergency shut down. Also provide the processes FEI has for ensuring this capacity to shut down is continuously available for on demand response.

Response:

FEI is required to perform two distinct activities when safely shutting down a system. The first activity is traveling to the stations and valves that feed the system in danger of a pressure collapse (the affected system), and closing these valves. This allows FEI to isolate the affected system from other connected systems in an attempt to restore the supply and demand balance to ensure a potential pressure collapse does not spread to more of the system. The second activity is to disconnect every customer on the isolated system. This would be achieved by going from customer to customer and manually closing the meter set valve(s) servicing the customers' premises.

The time required to safely shut down regional components of the supply to FEI customers region-by- region during an emergency is dependent on multiple factors, including: the size of the region, the number of available resources, the prevailing weather conditions which may affect travel (i.e., rain, ice, snow), and complicating factors such as the need to shut down multiple regions simultaneously. Notwithstanding this uncertainty, if a no-flow event occurred on T-South and the Lower Mainland system experienced a pressure collapse, it would take FEI multiple days to properly isolate the affected system and multiple weeks to disconnect all customers.

FEI maintains a certain workforce level on an ongoing basis to respond to emergencies as they occur. If the work to isolate all or a portion of the system exceeded available resources, FEI would bring in additional field crews to accelerate the disconnect process. These additional resources could come from other FEI field employees (who normally work in other parts of the province), local gas contractors, and/or other utilities (through FEI's mutual aid agreements).

75.2 Please describe the redundancy available for the LNG facilities to ensure performance on demand.

Response:

For the regasification package at full sendout rates of 800 MMcf/day, all four units would be in operation. At times when gas sendout demand is 600 MMcf/day or less, one unit would be available on standby. As full sendout would only be necessary periodically, this is considered an appropriate level of redundancy. Further, the need for all four regasification units would only occur during high demand periods, namely the winter months. The regasification units can be rotated out of service to ensure ongoing maintenance activities are performed at other times of the year. An allowance has been made for inventory spares as part of the Class 3 cost estimate to ensure that parts are available for maintenance.

For the in-tank pumps, two full-capacity pumps are provided, one for normal service and one as standby. These pumps have higher expected utilization and are difficult to access, therefore more redundancy will be provided.

Please also refer to the response to BCUC IR1 31.6.

75.3 Please provide a cost for the recovery from a complete shutdown of the FEI natural gas supply.

Response:

[redacted]

[redacted]

PWC REPORT

76. Reference: Exhibit B-1, Page 4 – Confidential Report & Questions

> FEI retained PricewaterhouseCoopers (PwC) to assess the consequences of a widespread system outage on FEI's customers and society. PwC's report, included as Appendix B, examined three natural gas disruption scenarios to model the social, environmental and economic impacts of natural gas system disruptions. The magnitude of these potential impacts, considered in concert with the non-negligible risk of a significant disruption on the T-South system, justifies new investments in resiliency.

76.1 Please confirm that this PwC report is FEI's primary evidence in support of defining the risks with respect to availability of natural gas supply for the economic, social and environmental impacts of a failure in availability of natural gas supply.

Response:

The PwC report is FEI's primary evidence that assists in describing and quantifying the magnitude of societal harm that would result from a wide-scale gas outage to customers in the Lower Mainland during various scenarios, including cold winter conditions.

Further, FEI's residential, commercial, institutional, and industrial customers depend on a reliable supply of natural gas for heating, hot water, cooking, and industrial process purposes. A sudden, prolonged, and wide-scale gas supply interruption could directly or indirectly affect the livelihood, health, and safety of virtually every resident of the Lower Mainland, regardless of whether they are a customer of FEI or not. As discussed in the PwC report, these impacts would include:

- Possible permanent business/industry shutdown and job loss;
- Disruption to health and education services;
- Strained emergency response;
- Severe reputational damage to FEI and upstream suppliers; and
- Switching to high-carbon alternative fuels.

A no-flow event resulting in a loss of supply to hundreds of thousands of Lower Mainland customers for several months would result in societal disruption and harm on an unprecedented scale within BC.

77. Reference: Exhibit B-1-1, Appendix B, PwC Report (A Case for Improved System Resilience), Page 2

PwC reports that on October 9, 2018, as a consequence of a rupture on the Enbridge T-South line near Prince George, that 700,000 FEI customers were asked to reduce their usage to help mitigate the impact of the rupture.

77.1 Please confirm that PwC had the information with respect to: (a) the total number of FEI customers and normal GJ usage levels; (b) the GJ usage levels for the 700,000 customers asked to voluntarily reduce usage; (c) the number of FEI customers for whom no appeal for reduced usage was required and their GJ usage levels; (d) the total number of customers for whom natural gas supply service was suspended and for how long and their normal GJ usage levels; and (e) the mitigation efforts FEI was able to bring into effect and the GJ levels these provided and for how long they were needed. Please supply this information in a table form.

Response:

The following response has been provided by PwC:

Our report provided a list of recent natural gas disruption events for the purpose of highlighting that they do occur, and at a frequency that may not be widely understood. PwC did not conduct a detailed evaluation of the impact of Enbridge T-South disruption as scenario conditions for impact analysis were not explicitly based on data from any major natural gas disruption events that have occurred to date. This is intentional, as the nature of and the conditions under which FEI operates its natural gas infrastructure, and the impacts that would be felt, are unique.

Additional commentary:

- Natural gas disruption events are unique and their impact is influenced by a wide range of variables both known and unknown, thus precluding their utility as comparative references for purposes of impact assessment.

  Example: For illustrative purposes, FEIs Huntingdon facility represents a single connection point to upstream suppliers and in the event of disruption to it, supply of natural gas to hundreds of thousands of customers in BC would be at risk. In contrast, a similar disruption in a more resilient system may have an immaterial or no impact to consumers.

77.2 PwC references 3 other supply incidences in the 2009 to 2019 timeframe but does not indicate the degree of disruption each may have had and any mitigation efforts FEI may have used in response to these incidents. Was PwC supplied with this information?

Response:

The following response has been provided by PwC:

Our report provided a list of recent natural gas disruption events for the purpose of highlighting that they do occur, and at a frequency that may not be widely understood. PwC did not conduct a detailed evaluation of the impact of those natural gas disruption events.

Please refer to the response to question CEC Confidential IR1 77.1 above for additional commentary.

77.3 Please confirm that the probability of disruption incident types and the magnitude of the impacts from each incident type are relevant to assessing the needs for mitigation capability.

Response:

The following response has been provided by PwC:

Natural gas disruption in this context represents “black swan” events that are of an unforeseen, binary nature that either happen or they don’t. In other words, the possible cause of disruption is unknown as is the probability of it happening. For this reason a probabilistic or risk adjusted approach was not taken in our analysis. System resiliency investment decisions should be considered on the basis of total potential impact that may occur in the event of disruption.

While likelihood was considered at the highest level (i.e., disruption events do happen periodically), we did not undertake an assessment of this type. The intent was that the study would assess the potential impact of natural gas disruption and provide the province and the energy industry with data to help weigh the costs and benefits of different infrastructure investments to enhance system resiliency in the province.

77.4 Please describe the nature of the cause for the 2018 rupture incident on the Enbridge T-South line.

Response:

Section 3.1 of the Transportation Safety Board of Canada's *Pipeline Transportation Safety Investigation Report P18H0088* reported the following findings as to causes and contributing factors[3]:

1. While operating at normal operating pressures, the Westcoast 4AL2 pipeline segment (the 4AL2 segment) ruptured, and an explosion and fire ensued.

2. The rupture had originated at stress corrosion cracks on the outside surface of the pipe, consistent with near-neutral pH stress corrosion cracking.

3. The cracks had grown and coalesced over time, reducing the load-bearing capacity of the pipeline steel at normal operating pressures.

4. Over time, the tape coating on the 4AL2 segment had started to disbond from the pipe surface.

5. The disbonded coating allowed the moisture in the soil to contact the pipe surface and shield it from the beneficial effects of CP, creating the environment for stress corrosion cracking to initiate.

6. Although Westcoast's Stress Corrosion Cracking Hazard Management Plan recognized the pipeline's susceptibility to near-neutral pH stress corrosion cracking, the extent of the existing cracking on this segment of pipe was not identified.

7. The crack growth model did not sufficiently reflect the uncertainties in the measured values or the increase in crack size as a result of crack coalescence. As such, the predicted growth that was used in the model was less than the actual crack growth.

8. The stress corrosion cracking electromagnetic acoustic transducer in-line inspection (ILI) for the 4AL2 segment, scheduled for 2017, was deferred until fall 2018, resulting in the existing cracks remaining in the pipe undetected until failure.

77.5 Please provide any information FEI has with respect to the degree to which Enbridge did carry out in line inspection of the relevant T-South supply lines upon which FEI depends and the degree to which Enbridge is now committed to carry out in line inspection. What is known about the inspection status when the incident occurred?

[3] Report is available publically at: https://www.tsb.gc.ca/eng/rapports-reports/pipeline/2018/p18h0088/p18h0088.html.

Response:

FEI is aware of the following information from the TSB report cited in the response to CEC Confidential IR1 77.4:

- With respect to the degree to which Enbridge did carry out ILI of the relevant T-South supply lines, FEI is aware that Westcoast "conducted an inline pipeline inspection program for the 30- and 36-inch natural gas pipeline on the T-South system, which was completed on 09 July 2019."
- With respect to the degree to which Enbridge is now committed to carry out ILI, FEI is aware that the "maximum re-inspection interval for EMAT in-line inspection for all L2 pipeline segments was set to 6 years." (Note: L2 refers to the 36-inch natural gas pipeline which ruptured in the 2018 incident).
- With respect to the inspection status when the incident occurred, FEI is aware that an EMAT ILI tool was run in 2008, a re-inspection was originally scheduled for 2017, and that the re-inspection was ultimately deferred to 2018 but had not been completed at the time of the incident occurrence.

77.5.1 Please also confirm that FEI is establishing in line inspection for its pipelines (CTS, ITS and VITS) and does and will do this to enable actions to avoid rupture events (both probability of and potential magnitude of).

Response:

FEI has adopted ILI within its Integrity Management Program – Pipeline (IMP-P) since the late 1980s, and has taken and continues to take steps to increase its adoption for its transmission pipelines as follows:

- Through the Inland Gas Upgrade project, FEI is expanding its use of ILI for corrosion monitoring of all transmission pipelines of diameter of NPS 6 and greater. At this time, ILI tools for monitoring corrosion in smaller diameter lines (less than NPS 6) are not yet proven, commercialized, and adopted. FEI continues to monitor technology and industry practice.
- Through the Coastal Transmission System (CTS) Transmission Integrity Management Capabilities project, FEI is proposing to expand its use of ILI for crack detection of selected transmission pipelines of diameter of NPS 10 and greater in its CTS. Only lines susceptible to cracking threats are included in the application.

- FEI is planning an application in 2022 to expand its use of ILI for crack detection of selected transmission pipelines of diameter of NPS 10 and greater in its Interior Transmission System.

ILI is an effective integrity management action to reduce the probability of rupture failures of transmission pipelines. However, ILI does not mitigate the potential consequences of failure, should a rupture occur.

77.6 Please describe mitigation efforts taken by Enbridge in response to the incident and the degree to which they were helpful to FEI's efforts to respond to the 2018 incident.

Response:

As detailed in the TSB report cited in the response to CEC Confidential IR1 77.4, Enbridge's (Westcoast's) mitigation efforts in the immediate minutes and hours following the incident included the following:

- Activation of Westcoast's emergency response plan;
- Shut down / isolation of the pipeline on which the incident occurred (NPS 36 L2);
- Shut down / isolation of an adjacent pipeline (NPS 30 L1);
- Notification to Pembina due to a shared right-of-way with their Western NPS 12 pipeline;
- Notification to FEI of the incident; and
- Notification to all regulatory agencies.

During and following the incident, FEI and Westcoast had constant communication as well as with other regional parties through the Northwest Mutual Aid Assistance. On October 13, 2018, the incident transitioned out of Mutual Aid and back into commercial business operations with Westcoast providing updated information as circumstances warranted. This communication informed FEI in its response to the event.

The mitigation efforts to return the T-South system back to service were driven by CER safety inspections and integrity requirements for the entirety of both pipelines. It took Westcoast a considerable amount of time to return the T-South system to full capacity to fulfill these requirements (i.e., 2 days of no-flow and approximately 14 months of intense integrity inspections).

78. Reference: Exhibit B-1-1, Appendix B, PwC Report (A Case for Improved System Resilience), Page 4

PwC describes the 3 scenarios they have created for making their assessment. In making its assessment PwC is clear that it did not consider the (a) causes of disruptions, (b) likelihood of the disruptions or (c) the readiness to respond to the disruptions.

78.1 Accepting that the PwC simplifications are intended to enable a specific kind of focus on some factors of relevance to assessing the impacts of disruptions, would FEI agree that the above three factors are a relevant and necessary context for understanding appropriate investments in rupture disruption mitigation?

Response:

FEI agrees that the above three factors are, amongst others, relevant and necessary context for understanding appropriate investments in rupture disruption mitigation. However, as discussed in Section 1.2 of their report, PwC states they were engaged to "[…] to conduct a holistic assessment of the economic, social, and environmental impacts that could arise in the event of a disruption to natural gas supply." In other words, the PwC report explored the resulting consequences of outages, regardless of cause, likelihood, or readiness. PwC was not asked to opine on these three factors. Instead, these factors are all discussed in Section 3.4.2 of the Application which focuses on the greatest source of risk: an interruption on the T-South system resulting in a no-flow event.

PwC identifies the criteria for constructing their scenarios as; (a) duration of disruption (b) temperature and environment at the time of the incident (d) geographic area impacted by the disruption (c) the magnitude of the supply/demand imbalance.

78.2 Would FEI agree that the repair response capabilities and the alternative supply capabilities are also important criteria for assessing the impacts of a rupture disruption event?

Response:

FEI agrees that the repair response capabilities and the alternative supply capabilities are also important criteria for assessing the impacts of a rupture disruption event. These were explored in Section 3 and 4 of the Application which identified the need for the Project and evaluated possible alternatives.

78.3 In assessing temperatures would FEI agree that the temperatures at the site of the disruption and the areas for the affected demand would be relevant for assessing the impacts of a disruption event?

Response:

Temperatures at the site of the disruption may be relevant to the duration of the event; however, other factors are more significant. For example, the overall temperature at the Lower Mainland service area (which affects the actual and forecast customer demand at the time), and the weather conditions at the site of the disruption (e.g., snow, ice, fog, or rain which may impede the operator's access to the site of the disruption) are more significant considerations for assessing the impacts of a disruption event.

79. Reference: Exhibit B-1-1, Appendix B, PwC Report (A Case for Improved System Resilience), Page 6

[redacted]

Response:

[redacted]

79.2 What does FEI estimate as the probability of a single rupture failure in a year on one of the T-South pipelines and what does FEI estimate as the joint probability of a rupture failure on both T-South pipelines at roughly the same time (please define the relevant joint timing in this answer)?

Response:

Please refer to the response to BCUC IR1 1.5.

PwC for the temperature criteria used an extreme cold winter for the upper bound scenario and a mild shoulder season for the mid range and lower bound scenarios.

79.3 Please provide FEI's definition of extreme cold winter conditions and the frequency with which these conditions are present on any given day through the winter

months (including at least November, December, January, and February) at the levels defined as extreme cold.

Response:

FEI's uses a design winter to define an extreme cold winter. FEI calculates a design winter daily temperature profile using the five coldest years since 1961 (i.e., coldest 5 in 60 years). FEI replaces the coldest day in the Design Year with the one in 20 year extreme value calculated using the Gumbel Method of Moments extreme value analysis. This method uses local extreme weather history for determining the likelihood of recurrence of extreme weather. Using the Gumbel method, FEI cannot calculate frequencies of occurrence in specific months within the winter period using extreme value analysis, just the probability of a temperature of a specific severity occurring at some point within the winter period. The coldest day in a Design Winter would have a 1 in 20 possibility or 5 percent chance of occurring in any year. The 10th coldest day in a design year is closer to a 70 percent likelihood of occurring in any year.

[redacted]

79.4 Please define a major system outage as used for the purpose of the PwC assessment in terms of the initial disruption loss of supply and its duration until repair supply can be arranged and the duration for this initial repair-based supply and the duration to response of all mitigations options (including the capability of each response in terms of % of normally covered by the specific mitigation) and the time to full repair.

Response:

[redacted]

PwC defines the magnitude as the progressive restoration from the specific type of outage incident.

79.5 Please provide (a) the full set of progressive restoration/mitigation options, (b) response times for delivering each of them, (c) the duration of their contribution, and (d) the potential magnitude of their contribution.

Response:

The following response has been provided by PwC:

Our analysis defines Magnitude as the severity of the supply / demand imbalance, ranging from all demand being met as a lower bound to no demand is met as an upper bound.

Scenarios are hypothetical events used to evaluate potential impacts of supply disruption and were designed to be realistic (i.e., a mix of less extreme to more extreme scenarios, but all are real possibilities). In analyzing the impacts of these scenarios, we did not consider possible causes, likelihood or readiness to respond. Anticipated time to restore supply, was based on guidance from FEI and their experience from past disruptions.

Additional commentary:

- Natural gas disruption events are unique and their impact is influenced by a wide range of variables both known and unknown, precluding utility in comparison for purposes of impact assessment.

Example: For illustrative purposes, FEIs Huntingdon facility represents a single connection point to upstream suppliers and in the event of disruption to it, supply of natural gas to hundreds of thousands of customers in BC would be at risk. In contrast, a similar disruption in a more resilient system may have an immaterial or no impact to consumers.

79.6 Please provide a summary of the information provided to PwC for their purpose in assessing progressive restoration.

Response:

The following response has been provided by PwC:

Please refer to the response to CEC Confidential IR1 79.5.

80. Reference: Exhibit B-1-1, Appendix B, PwC Report (A Case for Improved System Resilience), Page 8

PwC assumes that industry has the same consumption and instead 100% uses diesel as a back-up alternative.

80.1 Please provide FEI's assessment industry by industry including commercial operations with respect to their use of diesel as a back up alternative for their natural gas supply and the likelihood and degree to which this would be 100% of normal use and a significant impact over the time scale of the scenario assessments.

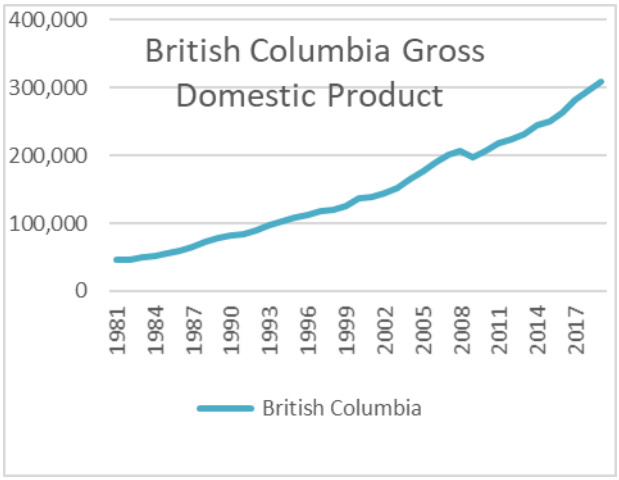
Response:

FEI has not conducted an assessment with respect to diesel as a backup alternative for natural gas supply for commercial operations. FEI is aware through ongoing discussions with interruptible customers that diesel is a common backup fuel. However, some customers may choose to not operate their facilities on a backup fuel or only operate at reduced capacity during gas supply curtailments. Ultimately, it would be up to the discretion of individual customers to determine an appropriate backup solution given the unique circumstances of their business.

81. Reference: Exhibit B-1-1, Appendix B, PwC Report (A Case for Improved System Resilience), Page 9 & 11

[redacted]

PwC notes that Covid-19 created an impact of a decline in BC GDP of 3.8% in 2020 or about $9 billion.



81.1 The data to the right is the history of the BC GDP and shows very few significant impacts on this measure of BC's economy. The only really significant impact in this long timeframe being the Great Recession. Covid-19 may show a similar impact if added to this chart. These significant economic impacts on BC were events having impacts for extended periods of time. Would FEI find it possible and potentially plausible that having a temporary supply disruption of natural gas may not create the same level of impact that the Great Recession and the Covid-19 Pandemic (major significant economic impacts) did have?

Response:

[redacted]

[redacted]

82. Reference: Exhibit B-1-1, Appendix B, PwC Report (A Case for Improved System Resilience), Page 14

PwC has identified numerous limitations applicable to their report including that PwC offers no opinion, attestation, or other assurance with respect to the reliability of the information in the report, given that they did not audit or verify any of the data used in the report.

82.1 Given the many qualifications with respect to the report, does FEI acknowledge that there is a considerable range of uncertainty about the report's conclusions?

Response:

The stated limitations and qualifications (i.e., that PwC did not audit or verify any of the data) would only affect the absolute quantification of the impact in monetary terms as cited in the report. This financial uncertainty does not affect the underlying conclusion in the report: that a no-flow event resulting in a loss of supply to hundreds of thousands of Lower Mainland customers for several months would result in societal disruption and harm on an unprecedented scale within BC. Please also refer to the response to CEC Confidential IR1 76.1.

83. Reference: Exhibit B-1-1, Appendix B, PwC Report (A Case for Improved System Resilience), Page 15

PwC assesses the upstream impacts on Enbridge and others based on no access to the pipeline and loss of revenue.

83.1 Please provide FEI's understanding of Enbridge's regulation and the degree to which it lost revenues as a consequence of the October 2018 rupture and disruption of pipeline supply on T-South. Please also describe the levels of pipeline capacity supply to Huntingdon as provided following the pipeline rupture October 9th 2018, through to full restoration December 1, 2018. Please confirm that this was the timeframe for this disruption.

Response:

The CER regulates the T-South system.

FEI assumes that "lost revenues" refers to the inability of Enbridge (Westcoast) to fully collect toll revenue from T-South shippers during the 14-month period while service was being restored on the T-South system following its rupture in October 2018. (FEI notes that the T-South system was fully restored on December 1, 2019 and not in 2018, as indicated in the question.) Shippers who failed to receive service as nominated during the 14-month period while the T-South system was being restored received demand charge credits as compensation. As demand charge credits are treated as a component of the cost of service on the T-South system, this cost is recovered from all T-South shippers and Westcoast faces no revenue loss.

In terms of the level of capacity available on the T-South system during the 14-months following its rupture and service restoration, please refer to Section 3.4.2.2 of the Application. This section provides a detailed review of capacity available on the T-South system immediately following its rupture and subsequent increases as service was restored.

83.2 Do Enbridge tolls for capacity on the T-South line apply regardless of the actual use (are they in fact reservation of capacity to flow natural gas)?

Response:

Firm shippers on T-South pay demand charges on their volume of contracted capacity, regardless of the actual use.

This is an important factor as to why FEI's portfolio approach to resiliency is cost-effective, as shorter duration resiliency requirements are achieved economically with on-system storage, while

longer duration resiliency requirements are best achieved with pipeline capacity. Please also refer to the response to BCUC IR1 16.3.

PwC has used data from 18 interviews to assess the loss of production for various sectors of the BC economy.

83.3 Please identify the industries for which FEI needed to shut down supply for the incident in October 9th 2018 and the degree of shut down from October 9th through to December 1, 2019 for each sector month by month.

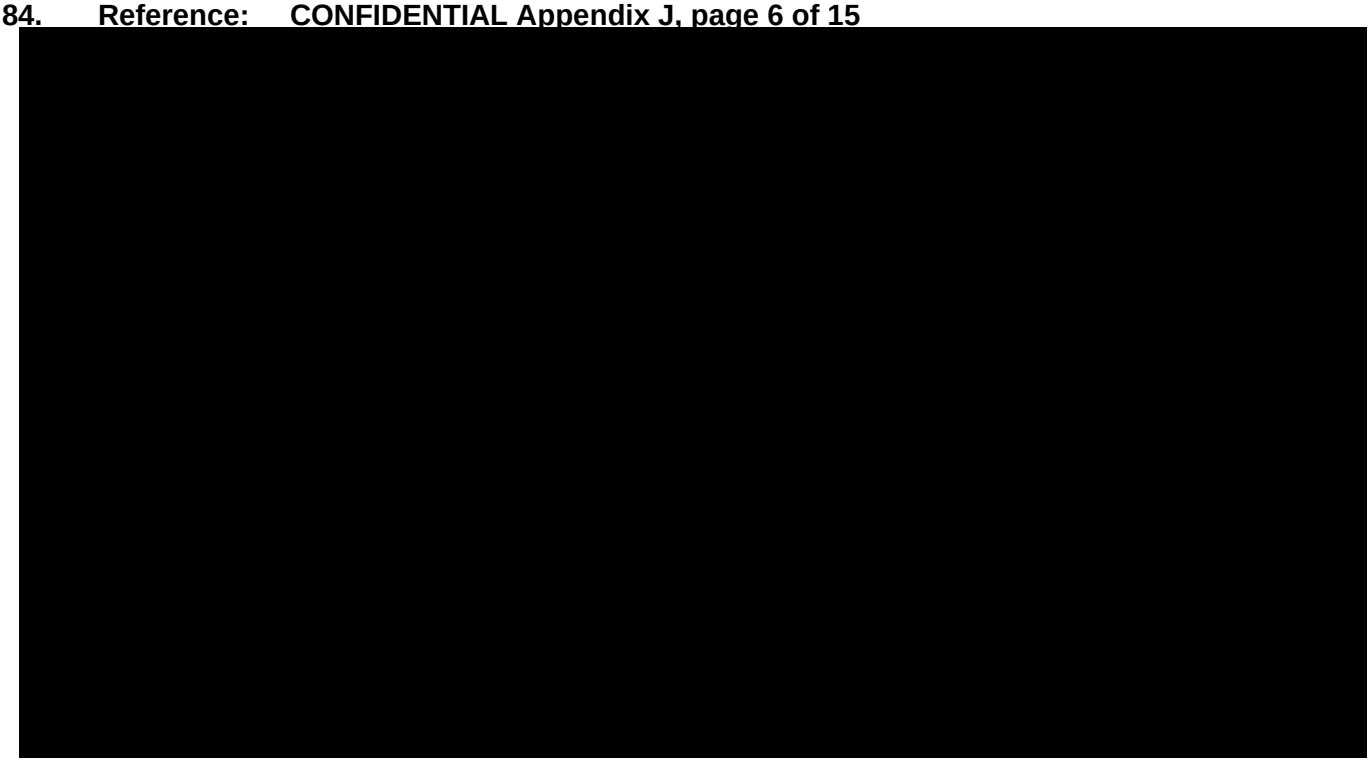
Response:

Please refer to the response to CEC IR1 3.4.

BASE COST ESTIMATE

CONFIDENTIAL

84. Reference: CONFIDENTIAL Appendix J, page 6 of 15



84.1 Please identify any expected changes to milestones that FEI is aware of at this time.

Response:

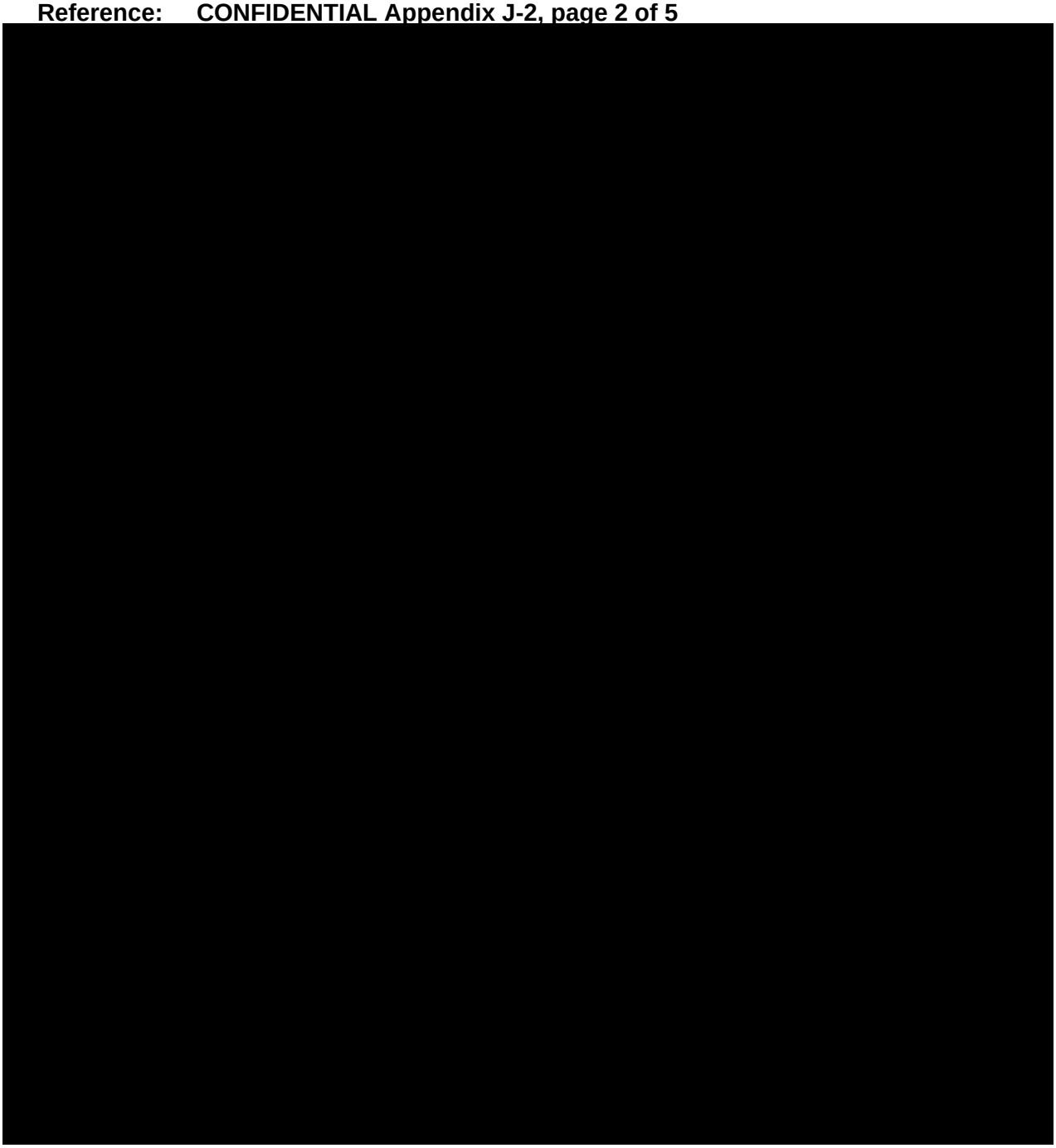
FEI has identified some delays as compared to the baseline schedule associated with the BCUC regulatory review process and the ongoing Phase 2 Environmental Assessment. As a result, it is expected that the proposed in service date for the TLSE Project will be in Q2 of 2027 as opposed to Q3 of 2026 as originally proposed in the Application.

As part of the selection process for the EPC contractor, FEI will identify critical milestone dates (e.g., in-service date for the entire project) that the contractor must meet. FEI will then work with the selected EPC contractor to optimize the overall construction of the project for cost and schedule efficiency as well as for safety and operability which will set the interim milestone dates for components such as the regasification package, auxiliary systems, and the Base Plant demolition.

85. Reference: CONFIDENTIAL Appendix J, page 12 of 15

[redacted]

86. Reference: CONFIDENTIAL Appendix J-2, page 2 of 5



86.1 For Table 5, are all positions internal unless otherwise identified as External?

Response:

As the Project has not yet been staffed, decisions on whether a particular position will be filled by an internal candidate, an external direct consultant, or third-party contractor have not yet been made.

FEI expects that the Project will be staffed with a significant number of internal candidates with knowledge of FEI practices and previous relevant experience. More specialized positions requiring skillsets specifically tailored to large project execution will likely be filled by directly-sourced external consultants and contractors. The individuals will only be contracted for the duration of the Project's requirements for these skills. Some positions may be suited to subcontracting to specialized third-party contractor organizations.

Generally, FEI expects that key leadership positions on the TLSE Project will be staffed by FEI employees, who will be in place for the duration of the Project to provide continuity. In particular, key leadership positions focused on external relations, Indigenous relations, government engagement, etc., will preferentially be filled by FEI employees to ensure that long-term relationships with Indigenous groups and local communities can be developed and maintained after the Project is complete.

[redacted]

Response:

[redacted]

86.3 Please describe the role of 'Communications Advisor' and how that differs from the roles of 'Community Relations Manager' and Liaison, and Indigenous Relations Manager and Liaison.

Response:

Communications Advisors are responsible for communications material related to projects. This can range from acting as a project spokesperson to updating content on project webpages.

Community Relations Managers are active in the community and communicate with stakeholders about FEI and, where relevant, share information and solicit feedback about FEI's major projects. Community Relations Managers undertake the bulk of community engagement activities related to projects and meet with residents, municipalities, businesses, and community organizations. Community Relations Liaisons support Community Relations Managers with these activities.

Indigenous Relations Managers are points of contact with Indigenous groups in areas where FEI operates. Indigenous Relations Managers are responsible for a range of activities including early engagement with potentially affected groups on projects such as the TLSE Project, and work collaboratively on energy projects with Indigenous Nations and assist with negotiating project agreements related to economic benefits for communities. Indigenous Relations Liaisons support Indigenous Relations Managers with these activities.

[redacted]

Response:

[redacted]

87. Reference: CONFIDENTIAL Appendix J-4 page 2 of 6

87.1 Please provide the Development costs to date.

Response:

The development costs to date are $11.026 million. Note that this amount includes the two lines from the table above that show actual costs up to March 2020 that were recorded in the deferral account of $498.6 thousand for the EA application development and the $1.047 million for the CPCN Application development.

87.2 Does FEI have any reason to expect the Development or other costs in the Base Cost estimate will change prior to CPCN approval? Please explain.

87.2.1 If yes, please identify and quantify any expected changes.

Response:

As discussed in the response to CEC Confidential IR1 84.1, given the ongoing regulatory process and the Tilbury Phase 2 LNG Expansion Project Environmental Assessment (of which the TLSE

Project is a component), FEI now expects the proposed in-service date of the TLSE Project will be delayed to at least Q2 of 2027.

FEI has not updated the development costs or base cost estimate at this time. As it is still early in the environmental assessment, there is uncertainty as to the final timelines and scope to be included, which could have impacts on the cost to complete that work. However, should FEI become aware of information before this proceeding record closes that indicates a variance to the base cost estimate, FEI will file an updated base cost estimate. Given the total cost of the TLSE Project, FEI considers that for this purpose, a 5 percent variance represents an appropriate threshold for reporting.

Additionally, FEI expects to update the cost estimate once the EPC contractor has been selected and work has been completed to optimize the TLSE Project for cost and schedule efficiencies, amongst other factors, which will occur after a BCUC decision if a CPCN is granted. These updates will be incorporated into the final control budget which will be used to monitor and control the Project's actual costs.

FEI notes that in granting a CPCN for a project, the BCUC makes a determination of the public interest regarding the project, which is in part based on the cost estimate provided in the CPCN application. Typically, the BCUC has directed periodic reporting on the progress of projects which includes updates to project expenditures, implementation schedules and, in some cases, a requirement to file a material change report if, for example, there is a material change in the project's cost estimate. Should the BCUC grant a CPCN for the TLSE Project, FEI anticipates there to be similar project progress reporting requirements.

RISK ANALYSIS

CONFIDENTIAL

88. Reference: CONFIDENTIAL Appendix K, page 9

[redacted]

88.1 Please update Table 5 with any changes of which FEI is already aware.

Response:

There are no changes to the major risks identified in Table 5-1. The delay to the environmental assessment certificate has been realized and the Project schedule will be updated accordingly (as discussed in the response to CEC Confidential IR1 84.1).

89. Reference: CONFIDENTIAL Appendix K, page 11 and page 21

[redacted]

90. Reference: CONFIDENTIAL Appendix K-3, page 2

90.9 Did FEI request any cost escalation for the different levels of regasification (i.e. 600 mmscfd or 800 mmscfd)? Please explain why or why not.

Response:

The cost escalation analysis was developed based on the complete project (either a 3 or 2 Bcf tank with 800 MMcf/day of regasification) as described in the Application, and not for the individual components that make up the project.

As described in Section 4.4.2 of the Application, 800 MMcf/day was determined to be necessary to meet the forecast load. Section 4.4.2.1 explains how vapourizers are typically supplied in units of 200 MMcf/day, and Section 4.4.2.2.1 also describes how 800 MMcf/day would provide adequate load coverage. As such, a 600 MMcf/day regasification option was not evaluated as it would not provide adequate load coverage and hence a cost escalation analysis was not completed for this level of regasification.

DETAILED PROJECT SCHEDULE

CONFIDENTIAL

91. Reference: CONFIDENTIAL Appendix L, page 9 of 16

91.1 Has FEI worked with Solaris in the past?

91.1.1 If yes, please identify any previous projects FEI has completed with Solaris.

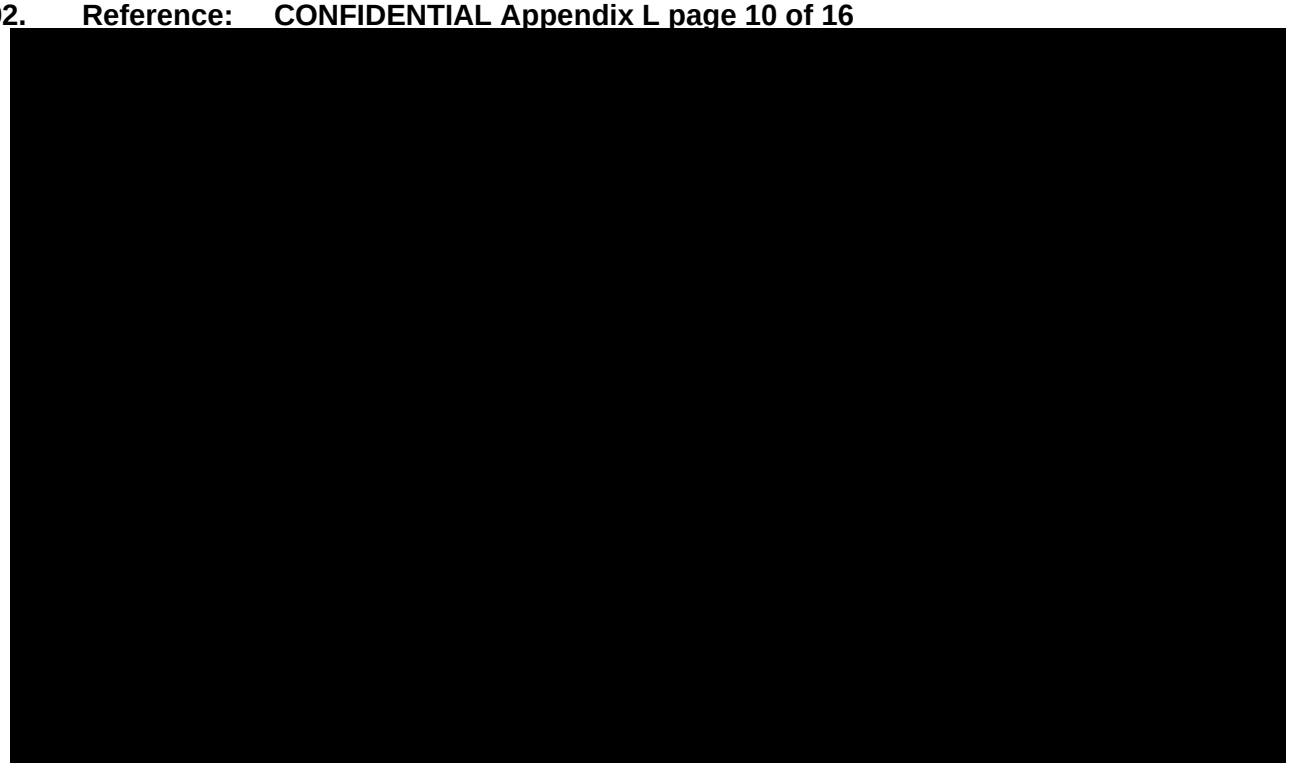
Response:

Confirmed, FEI has worked with Solaris on the following major projects:

- Okanagan Capacity Upgrade (OCU);
- Eagle Mountain Pipeline (facilities portion);
- Lower Mainland Intermediate Pressure System Upgrade (aerial crossing portion);
- Tilbury 1A Truck Loading; and
- Tilbury Interconnecting Pipe Project.

FEI has also engaged Solaris's services on several dozen smaller-scale sustainment projects.

92. Reference: CONFIDENTIAL Appendix L page 10 of 16



92.1 Are all aspects of the Project still expected to remain on schedule at the present time?

92.1.1 If no, please identify any areas that may not remain on schedule and explain why.

Response:

Please refer to the response to CEC Confidential IR1 84.1.

92.1.2 Please provide quantification of any additional costs that could arise as a result of the delay.

Response:

Please refer to the response to CEC Confidential IR1 87.2.

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