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September 13, 2021

B.C. Sustainable Energy Association
c/o William J. Andrews, Barrister & Solicitor
70 Talbot Street
Guelph, ON.
N1G 2E9

Attention: Mr. William J. Andrews

Dear Mr. Andrews:

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 B.C. Sustainable Energy Association (BCSEA) Information Request (IR) No. 1

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

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

1.0 Topic: Project Need, Minimum Resiliency Planning Objective, Evaluation of Alternatives

Reference: Updated Public Application, Exhibit B-1-4, pages 35, 76

FEI states its new Minimum Resiliency Planning Objective as follows:

> "Having the ability to withstand, and recover from, a 3-day 'no-flow' event on the T-South system without having to shut down portions of FEI's distribution system or otherwise lose significant firm load." [p.35]

In Step 1 of its two-step alternatives analysis, FEI examined whether it would be feasible to meet the project objective by focusing exclusively on identified alternatives to on-system above-ground storage at Tilbury. [p.78]

Specifically, FEI examined load management ("Automated Metering Infrastructure"), pipeline(s) ("Diversify pipeline supply, e.g., T-South, Gorge, SCP to Kingsvale, SCP Huntingdon"), and storage ("On-system underground storage, On-system LNG storage at a new site, and At least 2 Bcf [LNG] storage at Tilbury"). [Figure 4-1, p.77]

FEI concluded that load management and pipeline development would complement, but would not provide a suitable substitute for, on-system storage as a means of meeting the Minimum Resiliency Planning Objective.

FEI also concluded that the only feasible storage option that would meet the Minimum Resiliency Planning Objective is a new LNG storage tank of at least 2 Bcf and associated regasification capacity on the existing Tilbury site. [p.76]

1.1 Is FEI asking the Commission to approve FEI's Minimum Resiliency Planning Objective?

Response:

Please refer to the response to BCUC IR1 8.4.

1.2 Please confirm, or otherwise explain, that FEI's examination of alternatives to the Project concluded that none of the alternatives is a feasible means of meeting the Minimum Resiliency Planning Objective, and that only a new LNG storage tank of at least 2 Bcf with regasification at Tilbury is a feasible means of meeting the Minimum Resiliency Planning Objective.

Response:

FEI's analysis concluded that the only feasible means of meeting the Minimum Resiliency Planning Objective (MRPO) is on-system storage of between 2 and 3 Bcf. In theory, a new tank of less than 2 Bcf, in conjunction with maintaining the existing Tilbury Base Plant, could provide the minimum required amount of storage; however, as explained in Section 4.3.5.6 of the Application and in the response to BCUC IR1 16.22, the Base Plant is already 50 years old and it is far more cost effective to replace the Tilbury Base Plant now.

Please refer to Table 4-1 in the Application, which summarizes FEI's justification for eliminating all other Step One alternatives. Section 4.3.6 in the Application provides an additional summary of FEI's Step One analysis and its results.

1.3 For greater certainty, please confirm, or otherwise explain, that alternatives to the Project (at 2 Bcf or 3 Bcf) were rejected because they were not a feasible means of meeting the Minimum Resiliency Planning Objective.

Response:

FEI confirms that on-system storage of between 2 and 3 Bcf was identified as the only feasible means of meeting the MRPO. All other Step One alternatives (as outlined in Table 4-1 in the Application) were eliminated due to either inability to meet the MRPO, or because they were deemed infeasible. Please refer to Section 4.3.6 in the Application, which provides a summary of FEI's conclusion that on-system storage between 2 and 3 Bcf on the existing Tilbury site is the only feasible project alternative.

1.4 Does FEI's Minimum Resiliency Planning Objective have a countervailing objective that involves setting limits on costs? What is the wording of FEI's policy or guideline that describes when the cost of achieving the Minimum Resiliency Planning Objective would be unacceptable?

Response:

The MRPO is simply a way of articulating an identified risk and minimum resiliency need associated with a no-flow event on the T-South system; it is not a general planning standard. Similarly, FEI does not have a policy or guideline that defines a specific cost threshold for which achieving the MRPO would be considered unacceptable. As with all identified system needs, FEI clarifies the problem, identifies and evaluates possible solutions (including a comparison of their

costs and benefits), and ultimately selects a preferred alternative. FEI followed this process during the development of the TLSE Project and has identified what it considers to be a reasonable-cost solution to mitigate the risk related to a no-flow event. For additional discussion on cost-reasonableness, please refer to the response to BCUC IR1 9.2.

1.5 Would FEI agree that the minimum size of the proposed new LNG storage at Tilbury is driven by the number of days in the Minimum Resiliency Planning Objective?

Response:

The minimum size of the proposed new LNG storage at Tilbury is driven by the number of days that a no-flow event lasts (the MRPO is based on 3 days) and the cumulative demand over those days. The relationship between tank size and these two factors is described in Section 4.3.5.2 of the Application (Determining the Necessary Storage and Regasification Reflects the Distinction Between Energy and Capacity Planning).

1.6 In determining that the Minimum Resiliency Planning Objective should be three days, did FEI take into account the cost of new LNG storage at Tilbury sized to meet the Objective?

1.6.1 If so, did FEI consider other 'withstand and recover' durations and the corresponding costs of storage? If yes, please provide the details.

1.6.2 If not, would FEI agree that the size, and hence the cost, of the TLSE Project is driven exclusively by the choice of a three day 'withstand and recover' criterion?

Response:

The MRPO is a way of articulating a specific identified risk and minimum resiliency need associated with a no-flow event on the T-South system. The risk and minimum need reflected in the MRPO were identified independently from potential solutions based on several factors, including the potential duration of a no-flow event on the T-South system and the customer peak demand during that event (please refer to Section 3.4.2 of the Application).

Following the identification of the risk and minimum need as reflected in the MRPO, FEI followed a two-step process to identify and evaluate viable alternatives, each of which must first meet the MRPO. During that process, FEI evaluated the costs and benefits of the alternatives to select a preferred solution.

FEI agrees that the size and cost of each alternative, including the preferred solution (the TLSE Project), is influenced by the TLSE Project need (in this case, the amount of storage required to meet the MRPO), but not exclusively. FEI notes that the sizing of the preferred alternative has also considered the flexibility afforded by an additional Bcf of capacity in terms of providing a margin above the minimum resiliency need and the opportunity to provide ancillary benefits for customers and capture economies of scale (as discussed in Section 4.4.1 of the Application).

1.7 In determining that the Minimum Resiliency Planning Objective should be three days, did FEI take into account the size of the new LNG storage in the Tilbury Phase 2 LNG Expansion Project?

Response:

There is no storage associated with the Tilbury Phase 2 LNG Expansion Project environmental assessment (EA) application other than the TLSE Project. The Tilbury Phase 2 LNG Expansion Project is comprised of the TLSE Project storage tank and a Liquefaction Facility.

2.0 Topic: Project Need

Reference: Updated Public Application, Exhibit B-1-4, pp.36-37; Appendix A, Guidehouse Report on Natural Gas Resiliency (Redacted), pdf p.225

In the Updated Public Application, FEI states that "Guidehouse characterizes resiliency investments as akin to insurance. It articulates a risk-based approach consistent with what FEI has applied to the Project." FEI continues, "For example:" and then quotes Guidehouse as follows:

> "As a component of system redundancy in the form of reserve supply, the Tilbury Tank expansion project can be viewed as insurance that mitigates the risk of a significant supply disruption.
>
> The critical factors to consider when purchasing insurance include defining the risk, both in terms of the probability of the risk and the consequences of the risk and identifying prudent means to manage the risk. In other words, it is important to understand the likelihood, i.e., the probability of a major system disruption, and the significance, i.e. the potential cost and socio-economic implications of a major system disruption. Another critical consideration in managing risk is the cost to mitigate the risk, e.g. the cost of building infrastructure, or the cost of insurance.
>
> Section 3.2 of this paper demonstrates that on-system storage provides an effective means to address the risk of a failure on the Enbridge BC pipeline by enabling FEI to respond to such a situation with the appropriate operational control, redundancy and emergency actions and
>
> capabilities. In keeping with the abovementioned principles that define risk and effective risk management, Guidehouse concludes that on- system storage is the most effective means of risk management for FEI to mitigate the risk of an upstream supply disruption." [underline added]

2.1 Does FEI agree with the characterization of resiliency investments as being akin to insurance? Aren't resiliency investments intended to reduce the frequency and size of harmful events in the first place, whereas insurance is intended to shift the allocation of financial responsibility for harmful events after the fact?

Response:

FEI agrees with the characterization of resiliency investments as being akin to "insurance" when using the Guidehouse definition[1] of insurance as being "a thing that provides protection from an unforeseen event" (please also refer to the response to BCUC IR1 10.8).

[1] One definition provided by Merriam Webster for "insurance" is "a means of guaranteeing protection or safety", which is consistent with the Guidehouse definition. https://www.merriam-webster.com/dictionary/insurance.

It is FEI's perspective that resiliency investments are intended to reduce the consequences of harmful events (e.g., a no-flow event on the T-South system). Given that resiliency investments provide protection from undesirable, unforeseen events they are also consistent with the definition of insurance provided above.

FEI would agree that there are limits to the insurance analogy in practice to the extent that resiliency investments are not providing financial compensation after the fact, akin to a payout under a home insurance policy. Not all of the impacts of a widespread outage can be mitigated through financial compensation after the fact.

2.2 If resiliency investments by the utility can characterized as akin to insurance then would FEI agree that this would be insurance in the hands of the customers; that is, customers can pay for resiliency investments through their rates or pay for insurance against damages resulting from an absence of resiliency investments?

Response:

As described in the response to BCSEA IR1 2.1, there are practical limitations to the insurance analogy which limit the potential interchangeability of paying for resiliency investments through rates or paying for insurance against damages. FEI elaborates below:

- Customers expect their utility to provide reliable and resilient service, as discussed in the responses to BCUC IR1 7.1 and 7.5. It is on that basis that FEI has proposed the TLSE Project.
- FEI does not believe the insurance options alluded to in the question (i.e., insurance that would provide financial protection from the resulting personal and societal disruption that would occur if all FEI gas customers in the Lower Mainland including residential, commercial, institutional and industrial were suddenly and simultaneously without service) are either commercially or broadly available to all customers.
- As noted in the response to CEC Confidential IR1 76.1, FEI expects that the impacts of a wide-scale supply disruption to the Lower Mainland would impact more than just FEI customers. As such, many individuals—who may not even be customers of FEI—would be exposed to the resulting harm from the outage.
- Not all of the losses resulting from a wide-scale supply disruption during cold winter temperatures can be compensated for financially. This was dramatically illustrated by the loss of life which occurred in the state of Texas during the February 2021 winter storm.[2]

[2] https://www.dallasnews.com/news/weather/2021/04/30/number-of-texas-deaths-linked-to-winter-storm-grows-to-151-including-23-in-dallas-fort-worth-area/.

As such, FEI does not agree that customers have the ability to purchase insurance to protect against the type of incident that the TLSE Project is intended to prevent.

2.3 Does FEI agree with Guidehouse's view that "Another critical consideration in managing risk is the cost to mitigate the risk, e.g. the cost of building infrastructure, or the cost of insurance"?

Response:

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

2.3.1 If so, does FEI acknowledge that it has not provided any evidence of the cost of insurance as compared to the cost of building infrastructure?

Response:

FEI is not aware of insurance coverage that would protect against the risks that the TLSE Project is intended to prevent. Please also refer to the response to BCSEA IR1 2.2.

2.3.2 If not, please explain how FEI is able to accept Guidehouse's conclusion that on-system storage is the most effective means of risk management for FEI to mitigate the risk of an upstream supply disruption.

Response:

Please refer to the responses to BCSEA IR1 2.2 and 2.3.1.

2.4 Would FEI agree that there is a big difference between a determination that "on-system storage provides an effective means to address the risk of a failure on the Enbridge BC pipeline" and a conclusion that "on-system storage is the most

effective means of risk management for FEI to mitigate the risk of an upstream supply disruption"?

Response:

FEI notes that Guidehouse's final conclusion is that on-system storage is the most effective means of risk management for FEI to mitigate the risk of an upstream supply disruption. FEI does not observe a distinction or contradiction between the introductory and concluding statements made by Guidehouse in the preamble above with regard to on-system storage.

2.5 Would FEI agree that Guidehouse's consideration of alternatives to on- system storage consists of explaining why, in Guidehouse's view, several identified approaches are not actually viable alternatives to on-system storage?

Response:

Guidehouse did provide commentary with respect to several approaches for addressing gaps in resiliency in their report, including their limitations. The detailed identification, screening, and evaluation of solutions to provide the necessary resiliency for the Lower Mainland system were developed by FEI using its extensive knowledge of its system and operating environment.

2.6 Would FEI agree that the Guidehouse report provides no financial comparison of on-system storage and any alternative means of addressing the risk of a failure on the Enbridge BC pipeline?

Response:

FEI confirms that Guidehouse was not asked to provide a financial comparison of on-system storage and any alternative means of addressing the risk of a failure on the Westcoast T-South (Enbridge BC) pipeline. Guidehouse was engaged to provide its opinion on the following set of questions:

1. What does resiliency mean in the context of a natural gas market, supply, and delivery system, and why is it important?

2. How is the resiliency of FEI's distribution system affected by the characteristics of the natural gas value chain, including midstream pipeline capacity and availability of storage (both off-system and on-system) and the composition of the load/customer base?

3. In the case of FEI, to what extent is on-system storage either an alternative to, or complementary to, other resiliency measures such as midstream pipeline infrastructure, off-system storage, or interruptible service and or other demand control measures?

4. What considerations should go into determining the optimal amount of on-system storage for FEI?

2.7 Would FEI agree that (a) the Guidehouse report in effect concludes that on-system storage is the only effective means to address the risk of a failure on the Enbridge BC pipeline, and that (b) the Guidehouse report is silent regarding whether the cost of on-system storage would be a worthwhile investment for FEI's customers.

Response:

FEI confirms that the Guidehouse report concludes that on-system storage is the most effective means to address the risk of a "failure" on the Westcoast T-South (Enbridge BC) pipeline.

With respect to whether the cost of on-system storage would be a worthwhile investment for FEI's customers, Guidehouse made the following two statements in their conclusion on pages 50 and 51 of their report:

> From a risk management perspective, the proposed Tilbury Tank expansion provides a prudent, necessary and effective means of mitigating the risk of a disruption on the Enbridge BC system, especially during a period of peak demand.
>
> Given an LDC's obligation to serve, a gas utility must seek to strengthen its resiliency while balancing the need for operational control, redundancy and emergency response capabilities, at a reasonable cost to ratepayers.

Please also refer to the response to BCUC IR1 16.3 for additional discussion relating to the resiliency benefits of pipeline alternatives.

3.0 Topic: Project Need, Phase Two Project

Reference: Updated Public Application, Exhibit B-1-4,

The first mention of the Phase 2 LNG Expansion Project in the Updated Public Application is in Table 5-9: TLSE Project Schedule and Milestones on page 145 which lists "Phase 2 EA Certificate - Provincial/Federal Jul 2022."

On page 157, FEI states:

> "FEI notes that the Tilbury Phase 2 LNG Expansion under review by the BC EAO and the IAAC encompasses a larger expansion of the Tilbury site than what FEI is seeking approval for as part of this Application, as components of the larger project will not be owned by FEI." [underline added]

On pages 169, 183-184, and 197, FEI refers to the TLSE Project as a "component" of the Phase 2 Project, for example:

> "As discussed in Section 5.8.1, the Tilbury Phase 2 LNG Expansion Project, of which the TLSE Project is a component, triggers the requirements for both a Federal Impact Assessment and a Provincial Environmental Assessment." [p.169, underline added]

FEI says it is synchronizing consultation activities for the Tilbury Phase 2 LNG Expansion Project and the TLSE Project:

> "Given the BC EAO and IAAC assessment is occurring concurrently with the CPCN Application, and involves overlapping stakeholders and Indigenous groups, FEI's approach has been to synchronize consultation activities for both the Tilbury Phase 2 LNG Expansion Project and the TLSE Project in order to ensure engagement is robust, efficient and transparent." [p.185, underline added]

FEI says that the capital costs of the Tilbury Phase 2 LNG Expansion Project that are outside the scope of the TLSE Project will not be passed on to FEI customers:

> "The Company clarified that the capital costs of the entire Tilbury Phase 2 LNG Expansion would not be passed on to customers, as elements outside of the scope of the Project will be unregulated assets." [194, underline added]

In two of the environmental assessment documents for the "FortisBC Tilbury LNG Storage Expansion Project," the terms FortisBC Energy Inc. and FortisBC are used interchangeably: "FortisBC Energy Inc. (FortisBC)." [Appendix O, Environmental Assessment Overview Report, pdf p.398; and Appendix P, Archaeological Overview Assessment Report, pdf p.544]

In Appendix Q1, Tilbury Phase 2 LNG Expansion Project, Initial Project Description, FortisBC is nominally distinguished from FortisBC Energy Inc.":

> "FortisBC Holdings Inc (FortisBC) with its natural gas subsidiary FortisBC Energy Inc. is proposing to expand its existing liquefied natural gas (LNG) facility at 7651 Hopcott Road, on Tilbury Island in the City of Delta (Delta), British Columbia (BC) (Figure 1-1) (the Project Site)." [pdf p.622]

However, the body of the document uses "FortisBC" to refer to FortisBC Holdings Inc. and FortisBC Energy Inc. collectively.

In the Phase 2 Initial Project Description (Appendix Q1), the Tilbury Phase 2 LNG Expansion Project is described as follows:

> "The Tilbury Phase 2 LNG Expansion Project (the Project) is being proposed to increase the production and storage of LNG to improve security of supply to FortisBC's [sic] approximately 1.1 million natural gas customers in BC and to supply incremental LNG to the marine transportation and export markets. The Project also introduces opportunities to upgrade existing infrastructure to current design standards and technologies and to align with the Government of BC's CleanBC Plan. [pdf p.622, underline added]
>
> ...
>
> "The Project comprises an expansion of up to 162,000 cubic metres (m3) (approximately 4.0 petajoules [PJ]) of LNG storage and up to 11,000 tonnes per day (t/d) of LNG production. The Project will receive natural gas at the Project Site through established pipeline systems. It will connect to FortisBC's [sic] existing LNG facilities (such as, vapourization and gas send-out facilities) to support security of natural gas supply to gas utility customers and the proposed WesPac Midstream Ltd. (WesPac) Tilbury Marine Jetty project for marine LNG bunkering and LNG export."
>
> ...
>
> There is a need to increase the LNG storage in the Region as back-up to the Regional gas supply system. LNG production will be constructed as LNG market demand is realized. This could be in the form of two or more LNG production trains built initially or phased over multiple years with ultimate completion anticipated prior to 2028. Detailed engineering and construction for the Project is expected to begin in 2021/22."

3.1 Would FEI agree that the environmental assessment documents for the FortisBC Tilbury Phase 2 LNG Expansion Project conflate FortisBC Holdings Inc. and FortisBC Energy Inc.?

Response:

The environmental assessment Initial Project Description (IPD) document is clear in this regard. The Corporate Overview (section 1.1.2 on page 1-5 of the IPD, included as Appendix Q-1 to the Application) clearly differentiates the different corporate entities, specifically identifying the entity that is the owner/operator of the Tilbury LNG facility.

3.2 Would FEI agree that the environmental assessment documents for the FortisBC Tilbury Phase 2 LNG Expansion Project make no distinction between the FortisBC Tilbury Phase 2 LNG Expansion Project and the TLSE Project?

Response:

As explained further in the responses to BCUC IR1 23.1 and 23.2 as well as in BCSEA IR1 1.7, the Tilbury Phase 2 LNG Expansion Project being considered in the environmental assessment process has two components: (i) the 3 Bcf storage tank (for which FEI is seeking approval in this CPCN Application as part of the TLSE Project); and (ii) the Liquefaction Facility (which is not part of the TLSE Project). The following figure elaborates:

Element/Component	Description	Environmental Assessment Scope	TLSE CPCN Scope
Storage	3 Bcf (142,400 m3 working capacity)	Yes	Yes
Liquefaction	7,700 tpd	Yes	No
Regasification	800 MMcf per day	No	Yes

Accordingly, FEI agrees that the Tilbury Phase 2 LNG Expansion Project as described in the Environmental Assessment (EA) is inclusive of the 3 Bcf storage tank requested as part of the TLSE Project. For context, environmental and impact assessments and the CPCN applications are conducted under different legislative requirements that affect the scope of the information that must be presented. The *Environmental Assessment Act*, S.B.C. 2018, c. 51 (BCEAA) and the *Impact Assessment Act*, S.C. 2019, c. 28, s. 1 (IAA) are laws of general application, and govern any party (a "proponent") who proposes to conduct activity (a "project") falling within the scope of those enactments. The information that must be provided by a proponent in an assessment is determined in accordance with the provisions of those enactments and by statutory officials (the chief executive assessment office under BCEAA and the Impact Assessment Agency of Canada under the IAA) exercising their respective statutory powers.

By contrast, the BCUC regulates "public utilities" as defined by the *Utilities Commission Act* and issues CPCNs for regulated projects advanced by a public utility. Hence, the scope of this proceeding before the BCUC is limited to the TLSE Project proposed by FEI. FEI confirms that

the description of, and need for, the storage represented by this TLSE Project before the BCUC is articulated correctly in the Application to the BCUC.

A distinction between the two components of the Tilbury Phase 2 LNG Expansion project being assessed under the BCEAA and the IAA, the 3 Bcf storage tank and the Liquefaction Facility, is provided in the Initial Project Description submitted in the context of those processes. As noted in the response to BCSEA IR1 3.1, the Initial Project Description for the Tilbury Phase 2 LNG Expansion project was filed early in the overall development of the TLSE Project resiliency solution. A Detailed Project Description has since been filed with input from stakeholders as part of the assessment processes, and it contains a revised description of the need for and purpose of the Tilbury Phase 2 LNG Expansion Project (which includes but is not limited to the 3 Bcf storage tank).

The BCUC is only assessing the TLSE Project as presented in this Application.

3.3 Would FEI agree that the environmental assessment documents for the FortisBC Tilbury Phase 2 LNG Expansion Project express the purpose of the Project as an undifferentiated combination of FEI-system resilience and LNG for marine transportation and exports?

Response:

Please refer to the response to BCSEA IR1 3.2.

3.4 Would FEI agree that its Indigenous engagement and public consultation for the Tilbury Phase 2 LNG Expansion Project does not distinguish the Phase 2 Project and the TLSE Project?

Response:

FEI does not agree. FEI's approach to engagement has been to synchronize consultation activities for the TLSE Project with the parallel Provincial Environmental Assessment and Federal Impact Assessment processes in order to ensure engagement is robust, efficient and transparent. Given the BC Environmental Assessment Office and the Impact Assessment Agency of Canada assessment is occurring concurrently with the CPCN Application, and involves overlapping stakeholders and Indigenous groups, and, given that the LNG storage tank is subject to review in this Application and in the assessment process, FEI's engagement objectives have included

ensuring these groups are notified of regulatory activities and that they are aware of the potential impacts of each project.

While the engagement and consultation process covers both projects, FEI and FortisBC Holdings Inc. have engaged with Indigenous groups and stakeholders to help them understand the purpose and components of the distinct projects, and the overlap between them (i.e., the LNG storage tank), to help ensure meaningful engagement. This includes the development of specific materials that distinguish the projects, including a webpage, a presentation on the history of the development of the Tilbury LNG Facility to Indigenous groups and government agencies, and a factsheet for Indigenous groups. Please also refer to the response to BCUC IR1 54.2 for copies of these materials.

3.5 Please provide a table indicating the elements of Phase 2 Project, the elements of the TLSE Project, and the elements of the Phase 2 Project that are not part of the TLSE Project. Please use consistent units of measurement.

Response:

Please refer to the table provided in the response to BCSEA IR1 3.2.

3.6 Please confirm, or otherwise explain, that the elements of the Phase 2 Project that are not part of the TLSE Project would not constitute a viable project if the TLSE Project was not completed.

Response:

Not confirmed. The component of the Phase 2 Project which is not part of the TLSE Project is the Liquefaction Facility. The Liquefaction Facility would be viable without the TLSE Project. Please also refer to the response to BCUC IR1 23.2.

3.7 If the TLSE Project is approved by the BCUC, would FEI proceed with the TLSE Project regardless of whether FEI and/or other entities proceed with the Phase 2 Project?

Response:

FEI confirms that, if approved by the BCUC, FEI intends to proceed with the TLSE Project independent of any further liquefaction development at the Tilbury site.

3.8 Would FEI agree that the financial value of the Phase 2 Project to its proponents depends to a large degree on completion of the TLSE Project at the expense of FEI customers?

Response:

As previously explained in this IR series, the 3 Bcf storage tank proposed as part of the TLSE Project is a component of the Tilbury Phase 2 Expansion Project included in the EA process, with the other component being the Liquefaction Facility. The financial value of the Liquefaction Facility is not dependent on the completion of the TLSE Project. Please refer to the response to BCUC IR1 23.2 for further discussion.

3.9 Would FEI agree that if corporate entities other than FEI would benefit financially from the Tilbury Phase 2 LNG Expansion Project then they should contribute financially to completion of the TLSE Project?

Response:

The TLSE Project storage tank, while a component of the Tilbury Phase 2 LNG Expansion Project in the EA, is being constructed for resiliency purposes for the benefit of FEI customers. Please refer to the response to BCUC IR1 23.2.1.

3.10 Please provide a chronology of milestones in the development of the Phase 2 Project and the TLSE Project. Please include responses to the following questions.

Response:

This response addresses BCSEA IR1 3.10, 3.10.1, 3.10.3, 3.10.5, and 3.10.6.

The Tilbury Phase 2 LNG Expansion Project, of which the TLSE Project is a part, was initiated in response to the T-South Incident. This incident underscored the risks of customer outages due to a no-flow event, and soon after the T-South Incident, FEI identified that investments were required to address the need for additional resiliency in the Lower Mainland service area, as discussed in the responses to BCUC IR1 14.5 and 15.1. As discussed in Section 3 of the Application, in late 2018 and early 2019 FEI then identified potential solutions to provide the needed resiliency. The alternatives evaluated included additional storage at the Tilbury facility, as described in Section 4 of the Application.

During the evaluation of alternatives, it became apparent that additional storage at Tilbury had many benefits. It was also evident that the amount of storage required would trigger an environmental assessment (EA), so in late 2019 FEI began preparing to submit an EA application. FortisBC Holdings Inc. was also considering additional liquefaction at the site and included this liquefaction within the EA process.

Given the timeline of an EA, combined with the need to enhance the resiliency of FEI's system as soon as practicable, an Initial Project Description (IPD) was submitted to the BC Environmental Assessment Office (BCEAO) and Impact Assessment Agency of Canada (IAAC) on February 27, 2020. The purpose of the IPD is to initiate the Early Engagement process of the EA. It provided sufficient detail about the project to begin engaging the various Indigenous groups involved in the process. As consultation proceeded, the IPD was refined and edited using feedback gathered during engagement to become the Detailed Project Description, which has been filed in accordance with the assessment process. Concurrently, FEI also refined the final size of the storage and regasification facilities required for the TLSE Project. Additional conceptual work was completed on the potential Liquefaction Facility. As a result of all of this work, the proposed storage volume and liquefaction capacity within the EA was revised downward to 3 Bcf and 7,700 tpd, respectively, in April of 2021. The 3 Bcf of storage was determined based on the final alternatives analysis for the TLSE Project (as discussed in Section 4.4 of the Application).

As part of the EA process, FEI and FortisBC Holdings Inc. worked with BC EAO and IAAC and engaged with various participating Indigenous groups to finalize the Detailed Project Description.

The current step in the process is the Readiness Decision phase, with a decision on the EA application's readiness to move to the Process Planning stage expected towards the end of 2021.

3.10.1 Was the Phase 2 Project designed from the outset with the intention that it would include the TLSE Project (or what is now called the TLSE Project)?

Response:

Please refer to the response to BCSEA IR1 3.10.

3.10.2 Was the intention from the beginning that FEI customers would pay for the LNG storage and regasification required for system resiliency?

Response:

Yes, as the TLSE Project is intended to benefit FEI customers, FEI has always contemplated that the cost of the TLSE Project would be recovered through customer rates.

3.10.3 How did the sizing of the LNG storage in the Phase 2 Project evolve over time and where does it stand currently?

Response:

Please refer to the response to BCSEA IR1 3.10.

3.10.4 Did, or does, the Phase 2 Project contemplate physically separate LNG storage facilities for system resilience and for LNG for marine transportation and export, respectively? If not, has there been a notional allocation of storage between the two purposes? Has this changed over time? Where does it stand now?

Response:

The Tilbury Phase 2 LNG Expansion Project includes the TLSE Project storage for resiliency purposes, but no other storage. Also, no notional allocation of TLSE Project storage been contemplated. This has not changed over time.

Section 4.4.1.5.5 of the Application describes the potential for commercial arrangements to contract storage space.

3.10.5 Was the Phase 2 Project conceived originally as including system resiliency as a central purpose along with LNG for marine transportation

and export? Did the role of system resilience in the Phase 2 Project change over time? Did it change after the 2018 T- South Incident?

Response:

Please refer to the response to BCSEA IR1 3.10.

3.10.6 Was the TLSE Project contemplated when the Phase 2 Project environmental assessment documents were filed with the BC government?

Response:

Please refer to the response to BCSEA IR1 3.10.

3.10.7 When and how did FEI first publicly differentiate the Phase 2 Project and the TLSE Project?

Response:

The TLSE Project storage tank, along with the Liquefaction Facility, together comprise the Tilbury Phase 2 Expansion Project that is the subject of the EA process.

A webpage for the Tilbury Phase 2 LNG Expansion Project was launched on FortisBC's major projects website[3] on February 27, 2020. The webpage included information about the anticipated filing of a CPCN application for the TLSE Project. The website was updated when the CPCN Application was filed to notify site visitors of the filing and provide information about the TLSE Project and the BCUC regulatory review process. Please refer to the response to BCUC IR1 54.2 for a copy of the webpage, and other materials where the TLSE Project and the Tilbury Phase 2 Expansion Project are differentiated.

3.11 Please provide a table showing the LNG storage volumes and regasification flow rates for the Phase 2 Project and the TLSE Project using the units of measurement in both the Phase 2 EA documents and the TLSE description. Please specify

[3] https://talkingenergy.ca/.

whether LNG storage volume is in liquefied form or in gas equivalent (reference to T1:23, lines 11-12).

Response:

As explained in the response to BCSEA IR1 3.2, the Tilbury Phase 2 EA has two components: (i) the 3 Bcf storage tank (which is part of the TLSE Project); and (ii) the Liquefaction Facility. The regasification capacity proposed as part of the TLSE Project is not included as part of the Tilbury Phase 2 EA.

In the TLSE Project CPCN Application, the LNG storage tank size is noted at 3 Bcf, which is the natural gas equivalent. In the Tilbury Phase 2 EA, the same storage tank is referred to as 3 Bcf or 3.5 petajoules or PJs (natural gas equivalent) as well as 142,400 m3 (LNG volume).

Please refer to the response to BCSEA IR1 3.2 for a table showing which components (i.e., the storage tank, regasification capacity and Liquefaction Facility) are in each of the EA and TLSE Project scopes and the associated units of measurement.

4.0 Topic: Operation of TLSE Assets

Reference: Updated Public Application, Exhibit B-1-4, page 1, Section 1.3 (p. 12), page 35, page 62, Section 5.8.2 (p. 157), and Appendix T-2 (pdf p. 793 – 795); Workshop Transcript, pp. 237 – 238

In the February 2020 Initial Project Description for the Phase 2 Project, FEI says Project's purpose is to improve system resiliency and to supply incremental LNG to the marine transportation and export markets [Exhibit B-1-4, pdf p.622]

In the TLSE Workshop, FEI said the TLSE assets might be used to rent LNG storage space to third parties in the future. [T1: 237-238]

The TLSE Project would replace the existing Tilbury Base Plant [Exhibit B-1-4, p.1] which "was built and sized to support peak demand" [Exhibit B-1-4, p.62).

In section 5.8.2 of the Updated Public Application, FEI states:

> "The Oil and Gas Activities Act governs the construction and operation of the Project." [p. 157]

4.1 Please list the various purposes for which the TLSE assets would be operated.

Response:

As discussed in the response to BCUC IR1 22.7, the TLSE Project is a resiliency investment; therefore, the storage volume and regasification capacity will be primarily for resiliency purposes. From a planning perspective, FEI will maintain 2 Bcf in the tank as a minimum resiliency reserve. The incremental 1 Bcf will provide a resiliency margin above that minimum, but also offers some flexibility to be used for gas supply and operational purposes such as:

- Replacing the storage provided by the existing Base Plant, which is a part of FEI's gas supply portfolio (please refer to the response to BCUC IR1 22.7 for additional details);
- Accommodating future load growth (Section 4.4.1.4 of the Application);
- Mitigating third-party storage risk (Section 4.4.1.5.1 of the Application);
- Providing improved security of supply (Section 4.4.1.5.2 of the Application); and
- Increasing operational flexibility and efficiency (Section 4.4.1.5.4 of the Application).

4.2 Please outline how the TLSE assets would be operated in order to coordinate and prioritize fulfillment of the various purposes.

Response:

FEI will maintain 2 Bcf in the tank as a minimum resiliency reserve, which will only be used during a supply disruption event. The remaining 1 Bcf will provide a resiliency margin above that minimum, but also offers some flexibility to be used for gas supply and operational purposes. FEI will manage that remaining 1 Bcf of storage in a manner consistent with how FEI operates the existing Base Plant today, which includes the following functions:

- Emergency supply & capacity;
- Peaking supply; and
- Operations support/flexibility.

These functions are discussed in Appendix C of the Application, Section 3.2.1 (Existing On-System Storage In the Region).

4.3 Would the potential use of the TLSE assets for system resiliency be a first priority? Would a certain volume of LNG storage be reserved exclusively for system resiliency? Would system resiliency be the first priority for use of the TLSE regasification assets?

Response:

Yes, the use of the TLSE assets for system resiliency will be a first priority, such that 2 Bcf of LNG storage volume will be maintained as a minimum reserve that will only be used during a supply disruption event and the remainder will be managed as discussed in the responses to BCSEA IR1 4.1 and 4.2. System resiliency will be the first priority for use of the TLSE regasification assets.

4.4 If a certain volume of LNG storage was reserved exclusively for system resiliency would the amount vary at different times of year, for example corresponding to expected system load?

Response:

The amount of LNG storage reserved exclusively for system resiliency will be 2 Bcf and would not vary throughout the year as a supply disruption event could occur at any time in the year. The total amount of LNG stored in the TLSE tank may fluctuate between 2 and 3 Bcf depending on the specific needs of FEI throughout the year. However, FEI will ensure that the LNG storage

tank is full by the start of the winter heating season each year, which will offer additional resiliency while providing some flexibility to utilize the additional 1 Bcf of LNG storage for ancillary benefits as described in Section 4.4.1.5 of the Application.

4.5 In the event that the TLSE assets were used for LNG for marine transportation and export markets or rental of storage space to third parties, how would this be carried out operationally?

Response:

Operationally, any use of the TLSE assets would require interconnections to future developments. The design of any future interconnections would be completed to ensure the ongoing reliability and safety of the plant and would be the subject of regulatory approvals at a minimum from both the BCUC and the BC Oil and Gas Commission (BCOGC).

Please refer to Section 4.4.1.5.5 of the Application for further details.

4.6 Please describe how the Oil and Gas Commission's governance of the operation of the TLSE assets relates to the BCUC's governance of the operation of the TLSE assets.

Response:

The BCOGC and the BCUC have distinct roles in the governance and regulation of LNG storage assets such as the TLSE Project.

The BCUC is governed by the *Utilities Commission Act* (UCA) and it regulates public utilities within British Columbia with the stated mission to "[…] ensure that ratepayers receive safe, reliable and non-discriminatory energy services at fair rates from the utilities it regulates, and that shareholders of those utilities are afforded a reasonable opportunity to earn a fair return on their invested capital."[4]

With regard to the TLSE Project assets, FEI requires approval from the BCUC of a Certificate of Public Convenience and Necessity (CPCN) pursuant to sections 45 and 46 of the UCA in order to construct and operate the assets. This assessment involves consideration of the public interest, which includes cost, environmental impacts and other benefits or impacts. The recovery

[4] https://www.bcuc.com/about/who-we-are.html.

of the costs of the assets, if approved, will occur through FEI's delivery rates in accordance with sections 59 to 61 of the UCA and would be recovered from FEI's non-bypass customers.

The BCOGC is responsible for technical permitting and oversight of intra-provincial oil and gas operations in BC. The BCOGC will regulate the design, construction, and operations of the TLSE assets to ensure the environment and public safety are protected. Financial considerations such as capital or operating costs are generally not factors in BCOGC determinations. The BCOGC also conducts periodic audits to ensure that facility permit holders meet the applicable regulatory requirements. Finally, as an agent of the Crown (the BC Government), the BCOGC also holds the legal duty to consult when Aboriginal interests (rights and title) may be adversely affected by a Crown decision and consequently consults with affected Indigenous Nations and seeks to resolve potential adverse impacts to Aboriginal interests.[5]

4.6.1 If the TLSE assets were used in part to supply incremental LNG to marine transportation and export or to rent storage to third parties would these operations be regulated by the OGC or the BCUC?

Response:

As noted in the response to BCSEA IR1 4.6, if approved by the BCUC, the TLSE Project assets (i.e., the 3 Bcf storage tank and regasification capacity) would be constructed and operated by FEI and therefore subject to economic regulation by the BCUC. The BCUC approves rates for the provision of LNG service to customers. The BCUC would also have oversight over arrangements for contracting storage space. Please also refer to the response to the BCUC IR1 23 series of questions.

Also as noted, the BCOGC would continue to regulate the ongoing operations to ensure the environment and public safety interests are protected.

[5] https://www.bcogc.ca/how-we-regulate/engage-with-indigenous-communities/consultation-engagement/.

5.0 Topic: Project Need, Advanced Metering Initiative

Reference: Updated Public Application, Exhibit B-1-4, pp.28, 31-32, 42, 54; FEI Application for a CPCN for Advanced Metering Initiative (AMI) Project;

FEI says in the Updated Public Application:

> "Once a segment of the system is shut-in and depressurized, it can take weeks to resume service." [p. 54, underline added]

During the March 11, 2021 Workshop an FEI representative explained the time-consuming steps needed to resume service after a loss of pressure:

> "The outage duration [In the case of electricity] could be hours or in some cases in the Lower Mainland we have had hundreds of thousands of customers that lost initial supply and were out to, say, three to five days. The duration of a gas supply outage to customers could be orders of magnitude greater.
>
> If we lose pressure in our gas system for even a hour, there are a number of steps that need to be taken to restore service safely to our customers. First, we need the dispatch technicians to go to all of the customers' premises to manually close the valve at your house. In the absence of gas pressure within the system, we need to assume and expect that we may have air in our gas lines that can enter through fittings, leaks, or
>
> third-party damages. And when that happens and if we were to just reintroduce house -- reintroduce gas to your house, appliances may not light, they may light and then go out, and that could cause and create a gas concentration in my building that could cause a safety risk.
>
> Once we close every premise valve, we will then need to pressurize the system with natural gas. We will do a manual leak patrol. Effectively, we will walk every kilometre of the line that we suspect may have been damaged to confirm that we do not have any damages or leaks. If we find leaks, we will need to repair them, and then purge the effected system with nitrogen to remove any air. We will then cycle this process until we confirm no leaks and no air are in our lines. And it is this leak detection repair and purging cycle which creates the greatest unknown in predicting how long our customers will be out of gas. And in a worst-case scenario we have 20,000 kilometres of pipeline in the Lower Mainland that could require the step.
>
> Once that purging is complete, we will travel to the customer's premise to open the valve and re-light their appliances. So how much time is that all going to take? Thankfully our industry does not, and our company does not have a lot of

experience with outages of this magnitude. However, there are a few proxies that we can use.

To manually close the valves, we know that we can do that relatively quickly. Days, or a couple of weeks, depending on whether we have to say, close 10,000 valves or substantially more, and how many technicians are available for the task.

The re-pressurization and purging cycle is a big unknown. We do have an example from another company in Canada that had an event that reportedly took them two weeks to repair and purge the system of just 20,000 customers during summer weather.

Appliance relights. People may have read about the Black Hills Company Service disruption in Aspen Colorado that occurred last December. The reports indicate that it took 170 technicians, 36 hours to complete 3,500 relights. Effectively on average, it took a technician in excess of 1.5 hours per relight.

It's very easy to translate these numbers, to see that an outage of say 100,000 customers would extend very quickly into weeks, if not months for some customers. And as we know, we have hundreds of thousands of customers in the Lower Mainland." [T1:86-89, underlined added]

FEI has applied to the BCUC for approval of an Advanced Metering Infrastructure (AMI) project. FEI says the AMI project "is needed to ... enhance system resiliency by providing FEI with the ability to strategically manage system load and prevent system pressure collapse during an extended loss of supply." [Exhibit B-1, FEI AMI proceeding, pdf p.1, underline added]

In the Updated Public Application, FEI states:

> "Newer technology (for example, the deployment of Advanced Metering Infrastructure (AMI) with remote-shutoff valves) instead allows the utility operator to quickly, accurately, and directly target any required customer load shedding. Relying on load management inherently means disrupting service to customers, and is ideally used in conjunction with other supply- based solutions." [Exhibit B-1-4, p.28, underline added]

Later, FEI states:

> "However, a controlled disruption, as enabled by AMI technology, is preferable to an uncontrolled hydraulic collapse of the system. An uncontrolled and widespread hydraulic collapse is a worst-case scenario for customers, the utility and society generally. It results in undefined customer outages and unknown outage propagation. Hydraulic collapse can create safety situations on the customer level. It can take months to reinstate service to all customers following hydraulic collapse." [pp.31-32, underline added]

During the Workshop, an FEI representative said:

> "And as a last resort, AMI would enable us to execute a more efficient controlled shutdown as the system could be shut-in in a manner that maintains the gas pressure in the system and that is something that we cannot do today. This would eliminate the need for the manual shut-ins and avoid all of the pressurization and purging activities, all of which would effectively reduce the customers outage duration to just that of the time required to perform the relights activity, but customers would still see an outage and that outage could still be lengthy." [T1:158-159, underline added]

5.1 Would having AMI in place allow FEI to curtail customer service without losing pressure in pipelines?

Response:

Please refer to the responses to BCUC IR1 16.1 and 16.2.

5.2 Please describe the steps for resuming service after a controlled shutdown with AMI in place.

Response:

Please refer to the response to BCUC IR1 16.2.

5.3 By how much time would AMI reduce the "weeks to resume service" in the event that a segment of the system is shut-in and depressurized?

Response:

Please refer to the response to BCUC IR1 16.2.

5.4 Would FEI agree that implementation of AMI would reduce the potential harm to FEI and its customers of a disruption in the Enbridge BC pipeline?

Response:

Please refer to the responses to BCUC IR1 16.1 and 16.2.

5.5 Is it FEI's position that the AMI project would 'pay for itself' in reduced costs?

Response:

As discussed in Section 6.3.3 of FEI's application for a CPCN for the AMI project, over the course of the analysis period, annual operating cost reductions as a result of the AMI project are expected to largely offset the project costs. As such, the impact on delivery rates as a result of the AMI project is expected to be minimal.[6] Further, the AMI project is expected to have numerous benefits. The term "pay for itself" is not one that FEI has used and suggests an analysis that FEI would not adopt in terms of focusing purely on cost measures.

5.6 Is there any difference between the "Automated Metering Infrastructure" examined as a potential alternative means of meeting the Minimum Resiliency Planning Objective and the "Advanced Metering Initiative" for which FEI has applied for a CPCN?

Response:

The previous references to "Automated Metering Infrastructure" in the TLSE Application (filed with the BCUC on December 29, 2020) are synonymous with the Advanced Metering Infrastructure CPCN (filed on May 5, 2021).

[6] As set out in Exhibit B-1, Schedule 10 of Appendix G-5 of the AMI CPCN, on a net present value basis over the analysis period of 26 years, the expected change to delivery rates is an increase of 0.125 percent.

6.0 Topic: Project Need, Emergency Planning

Reference: Updated Public Application, Exhibit B-1-4,

The Minimum Resiliency Planning Objective is defined exclusively in relation to a 3-day 'no-flow' event on the T-South system [p.35].

6.1 In addition to an interruption in supply from the T-South system, has FEI examined other potential causes of a substantial disruption in FEI's ability to serve its customers, such as a large earthquake, wildfire, flood, windstorm, loss of grid electricity, or IT failure?

Response:

Integrity-related causes of potential supply interruptions include earthquakes, wildfires, floods, and windstorms. As part of its Integrity Management Program for Pipelines (IMP-P), FEI reviews threats to its pipeline system and develops mitigation activities. Although IMP-P activities can be highly successful in mitigating the potential for integrity-related failures, FEI recognizes that residual risk can never be zero.

Cyber-attacks could also disrupt Westcoast's ability to control or operate the T-South system resulting in a shutdown similar to that which caused a multi-day outage on the Colonial Pipeline oil pipeline in the eastern US.[7]

FEI's Emergency Program employs an all-hazards approach which accounts for multiple mechanisms or causes of system emergencies (including earthquakes, wildfires, floods, etc.). FEI has developed a specific set of protocols for managing seismic events and their potential impacts on the natural gas transmission system. IT failures have also been considered and exercises have occurred to simulate failures of technology infrastructure.

FEI has not identified other failure risks within its system that are comparable to the T-South system risk which is driving the resiliency need for the TLSE Project.

6.2 Please confirm, or otherwise explain, that a widespread outage in grid electrical power could disable FEI's ability to provide gas service to customers.

Response:

FEI assumes that this question refers to a relatively short-term outage (hours to days) on BC Hydro's electric network, and not to a long-term outage of BC Hydro's transmission network.

[7] https://www.reuters.com/business/energy/us-govt-top-fuel-supplier-work-secure-pipelines-closure-enters-4th-day-2021-05-10/.

Not confirmed. FEI would not expect a widespread outage in grid electrical power to disable FEI's ability to provide gas service to customers.

FEI's natural gas system is generally operable during widespread electrical outages. FEI's existing compressor stations within the Lower Mainland are gas powered, using natural gas from FEI's own system. FEI has backup power generation for auxiliary systems at compressor stations which do rely on electrical power.

FEI's gate and district stations (which regulate gas pressure in the system) do not rely on electrical power to regulate pressure. Gas pressure regulators are mechanical devices which will maintain safe pressures throughout FEI's systems in the absence of electrical power. Where required to operate, sites with electronic controls or communications have a backup power source or Uninterruptible Power Supply system.

6.3 Is the "3-day 'no-flow' event on the T-South system" intended to also serve as a proxy for other causes of disruption of the system? If so, is the TLSE Project a robust solution? If not, does FEI anticipate developing system resiliency criteria specific to other potential causes of disruption of the system?

Response:

The "3-day 'no-flow' event on the T-South system" is one example of a scenario that results in no-flow into the Lower Mainland system. However, regardless of the cause of the no-flow event, the TLSE Project will significantly improve the resiliency of FEI's system, either by withstanding a no-flow event (for up to three days), or buying time to shut down the system in a controlled manner (if the no-flow event lasts longer than three days).

6.4 Has FEI discussed the TLSE Project with other entities in the context of emergency planning in BC? If so, please summarize the results. If not, why not?

Response:

Improved resiliency of gas supply has been generally discussed with other stakeholders (including in the context of emergency planning), but due to the informal and general nature of the discussions regarding emergency planning, there are no results to summarize. Should the Project be approved, the added resiliency it would bring would be considered and incorporated as required within FEI's gas supply and operational emergency plans.

7.0 Topic: Project Need, renting storage to third parties

Reference: Updated Public Application, Exhibit B-1-4, Section 4.4.1.5.5; Workshop Transcript, T1:237-8; Exhibit A-12, BCUC IR 1.23

During the March 11, 2021 Workshop, FEI indicated that in the future it would consider selling storage to third parties using the Project assets:

> "COMMISSIONER MASON: Thank you. I'm wondering if somebody can let me know whether Fortis anticipates ever selling storage type services to third parties using the assets that are currently being applied for under the CPCN or is the purpose of the assets purely and solely to serve existing Fortis customers through the resiliency service?
>
> MR. SLATER: Thank you for that question. So we did outline in the application towards the end of Section 4.4.1.5 that while this project is primarily proposed to support the resiliency of FEI's system and provide ancillary benefits, one of those ancillary benefits could be, as you described, sort of renting storage space, if you will, to third parties. While we don't have any plans, I think the -- you know, including it in the application was a signal that we would consider that in the future if there was a benefit to ratepayers and if the opportunity presented itself." [underline added]

7.1 Is it section 4.4.1.5.5, "Larger Tank Provides the Potential to Reduce Customer Rates," in which FEI provides a signal that in the future it could consider renting storage space in the Project to third parties? If not, please explain.

Response:

Confirmed, Section 4.4.1.5.5 of the Application is where FEI explains the potential benefit that could arise for FEI customers if the opportunity to contract storage space were to materialize.

Section 4.4.1.5.5 begins:

> "The construction of a 3 Bcf tank versus a 2 Bcf tank provides opportunities for load growth that would have the potential to reduce rates for customers."

7.2 Is the concept of potentially renting storage space in the Project to third parties limited to the 'third Bcf,' i.e., the additional storage capacity provided by a 3 Bcf LNG storage tank over a 2 Bcf LNG storage tank?

Response:

Confirmed. The potential storage space available for contract would be limited to the "third Bcf". FEI will maintain a minimum of 2 Bcf storage at all times as a minimum resiliency reserve, and the third Bcf provides both resiliency and flexibility to pursue ancillary benefits.

Section 4.4.1.5.5 then states:

> "The construction of a new pipeline in BC will proceed when supported by load growth in the region. Additional pipeline capacity into the region could provide the opportunity for further expansion of the Tilbury site with additional liquefaction to support LNG for export."

7.3 Does the possibility of renting storage space in the Project to third parties arise only in scenarios involving construction of a new pipeline in BC and additional liquefaction at Tilbury to support LNG exports? If so, why? If not, why not?

Response:

The potential scenario described in Section 4.4.1.5.5 of the Application in which FEI could contract storage space is based on substituting resilience in the TLSE Project tank for resilience associated with new pipeline capacity into the region and/or additional liquefaction. However, it is also possible that opportunities to contract storage space could occur in other scenarios (e.g., to support gas supply needs of operators in the region that seek to firm intermittent renewable electricity generation during peaks using gas-fired generation).

After describing discussions about exporting LNG from Tilbury to destinations in Asia, Section 4.4.1.5.5 states:

> "This potential scenario provides significant future optionality and a potential reduction in FEI's customer rates in the scenario where a new pipeline into the Lower Mainland is constructed that follows an entirely separate corridor from the T-South system along with an expansion at the Tilbury site. FEI explains in further detail below..."

7.4 Please explain what FEI means by "a new pipeline into the Lower Mainland is constructed that follows an entirely separate corridor from the T-South system." A pipeline from where? A pipeline to where (to the Tilbury site)? What corridor

separate from the T-South system? Built and operated by whom? At whose expense? In what time frame?

Response:

A "new pipeline into the Lower Mainland or the Huntington/Sumas delivery area that follows an entirely separate corridor from the T-South system" refers to a new pipeline that is distinctly separate and has no proximal location to the existing T-South system. For example, such a pipeline could source gas from the AECO/NIT supply hub for delivery to the Lower Mainland.

FEI is unaware of any third-party pipeline proposals for new physical gas delivery options to the Lower Mainland at this time. However, FEI is conducting a detailed assessment of the potential to extend FEI's existing SCP pipeline to the Lower Mainland (the Regional Gas Supply Diversity or RGSD project).

The SCP extension from Oliver to Huntingdon (i.e., the RGSD project) would constitute a new pipeline built in a new corridor that is completely independent of the T-South system. This extension would allow gas sourced from Alberta to be delivered directly to the Lower Mainland via a contiguous network of pipelines emanating from the AECO/NIT market hub. Part of the feasibility assessment for this project will involve the determination of an appropriate interconnection point with FEI's existing pipeline system in the Lower Mainland. An expansion also represents a significant opportunity to advance Indigenous reconciliation through the potential for Indigenous ownership in the pipeline and facilities. The new pipeline would be an extension of FEI's BCUC-regulated SCP line, and the net annual cost of service of the new line would be recovered in customer rates. Subject to commercial discussions, other parties in the region may be willing to contract for firm capacity on this line, which would aid in mitigating costs. If the project is approved for construction, the new pipeline could possibly be in-service before the end of the decade.

7.5 Please confirm, or otherwise explain, that "a new pipeline into the Lower Mainland" is unrelated to the "30 inch Feed Pipe" shown in green on slide 55 of the Workshop Presentation.

Response:

Confirmed.

7.6 Please confirm, or otherwise explain, that "a new pipeline into the Lower Mainland" is unrelated to FEI's Coastal Transmission System Project.

Response:

Confirmed.

7.7 If there was a new pipeline into the Lower Mainland following a separate corridor from the T-South system, would this in itself mitigate the risk to FEI's existing customers of a whole or partial disruption of supply from the T-South system (by providing an alternative source of supply)?

Response:

Please refer to the responses to BCUC IR1 16.3 and 16.9.

Section 4.4.1.5.5 continues:

> "While an uncertain and contingent event, the expansion of the Tilbury LNG site would likely include a large amount of liquefaction capacity up to 3 million tonnes per annum (approximately 12 times the size of Tilbury 1A and 60 times the size of the Tilbury Base Plant liquefaction). This amount of liquefaction capacity at the Tilbury LNG site could change FEI's operating paradigm, including its storage needs. For example, FEI could enter into a commercial arrangement to utilize a small amount of the bulk export liquefaction capacity to backstop liquefaction outages associated with Tilbury 1A and 1B liquefaction, thereby freeing up 1 Bcf of storage capacity from the Tilbury 1A tank. With the additional pipeline supply into the Lower Mainland, as discussed in Section 4.2.4.5 above, FEI could potentially further reduce its storage needs by entering into commercial arrangements to provide access to other contingency resources. This could potentially allow FEI to lease storage space to the export entity, thereby recovering a portion of the cost of service of the Project while maintaining an enhanced level of resiliency. Should this opportunity materialize, there is the potential to reduce FEI customers' costs; however, it is unlikely that a 2 Bcf tank under this scenario would free up enough space to take advantage of such an opportunity. Therefore, the construction of storage capacity above the minimum requirements enhances FEI's potential to reduce rates through storage lease opportunities." [Exhibit B-1-4, pdf p.129, underline added]

7.8 Section 4.2.4.5 does not appear to exist. Please provide the intended reference in the clause: "With the additional pipeline supply into the Lower Mainland, as discussed in Section 4.2.4.5 above...".

Response:

The reference in the Application to Section 4.2.4.5 was a typographical error. The correct reference is Section 4.3.4.5.

7.9 Is "liquefaction capacity up to 3 million tonnes per annum" a reference specifically to the Phase 2 LNG Expansion Project, described in the Phase 2 Initial Project Description as including "up to 11,000 tonnes per day (t/d) of LNG production"?

Response:

Confirmed. The Tilbury LNG Phase 2 Expansion Project Initial Project Description liquefaction capacity of 11,000 tonnes per day equates to roughly 3.5 million tonnes per annum, once downtime and outages are considered. This was subsequently reduced to 7,700 tonnes per day in an April 22, 2021 letter to the EAO (provided in Attachment 7.9 to this response) regarding changes to the project. FEI has referred to these liquefaction facilities as the "Liquefaction Facility" in various responses to information requests in this proceeding.

7.10 If the reference is more general, to FEI's knowledge is this concept already being developed? If so, is it being developed by FEI or an affiliate?

Response:

As set out in the response to BCSEA IR1 7.9, the reference was specific.

7.11 Please explain how "a commercial arrangement to utilize a small amount of the bulk export liquefaction capacity to backstop liquefaction outages associated with Tilbury 1A and 1B liquefaction" would "free[] up 1 Bcf of storage capacity from the Tilbury 1A tank."

Response:

The Tilbury 1A storage tank was sized and constructed to serve LNG customers during annual outages, including routine maintenance of Tilbury 1A liquefaction and, once constructed, Tilbury 1B liquefaction facilities. Accordingly, a commercial arrangement to provide sufficient liquefaction capacity during such outages would allow FEI to serve its LNG customers during outages while also freeing up the Tilbury 1A storage tank (1 Bcf) for other uses.

7.12 Please explain more broadly the discussion in section 4.4.1.5.5.

Response:

There is an opportunity provided by the 3 Bcf tank to contract storage space while maintaining the level of resiliency required for FEI customers. FEI will maintain a minimum of 2 Bcf of storage at all times as a minimum resiliency reserve. The remaining 1 Bcf of storage not only offers additional resiliency above that minimum level, it also provides some flexibility to pursue ancillary benefits. One potential benefit could arise by contracting some or all of the "third Bcf" either to a single or multiple parties and these arrangements could have stipulated term limits to provide revenue certainty. The contracting of this storage would result in additional sales revenue which would flow back to FEI customers through reduced rates.

7.12.1 What is the connection between "construction of a new pipeline in BC [that] will proceed when supported by load growth in the region" and the potential to rent storage space in the Project to third parties?

Response:

Please refer to the response to BCSEA IR1 7.3.

7.12.2 Please explain how "Additional pipeline capacity into the region could provide the opportunity for further expansion of the Tilbury site with additional liquefaction to support LNG for export" relates to the potential to rent storage space in the Project to third parties. Is the premise that additional pipeline capacity into the Lower Mainland could support LNG exports out of the Tilbury site in addition to supplying domestic customers?

Response:

Please refer to the response to BCSEA IR1 7.3.

7.13 Would renting storage space in the Project to third parties require additional regasification capacity? Would it require additional liquefaction capacity?

Response:

It is not expected that contracting storage space would require additional liquefaction or regasification capacity. If additional liquefaction or regasification capacity were required, FEI would seek approval for this through an application to the BCUC.

8.0 Topic: Risk of a significant resiliency event

Reference: Updated Public Application, Exhibit B-1-4, p.50

FEI says the T-South Incident "is not an isolated event."

8.1 What is FEI's estimate of the annual probability of occurrence of a T- South interruption requiring full use of the three-day Minimum Resiliency Planning Objective?

Response:

Please refer to the response to BCUC IR1 1.5.

8.2 In FEI's view, should the probability of occurrence of a T-South interruption requiring full use of the three-day Minimum Resiliency
Planning Objective be taken into account in determining whether the cost of the TLSE Project is reasonable? If so, how? If not, why not?

Response:

Please refer to the responses to BCUC IR1 1.5 and 9.2.

9.0 Topic: GHG emissions from regasification

Reference: Updated Public Application, Exhibit B-1-4, Section 4.4.2.1, page 116

FEI says it selected submerged combustion vessel technology for regasification according to the criteria of: response time; proven technology; physical size; and reliability.

9.1 What rates of GHG emissions are associated with using submerged combustion vessel technology? How does the choice of submerged combustion vessel technology affect the GHG emissions intensity of the gas that is liquefied and then regasified?

Response:

For the submerged combustion vessel vapourizer technology selected for the TLSE Project, the GHG emissions are expected to be 37 tonnes per hour of CO_2 over a three-day period (when operating at the full vapourization capacity of 800 MMcf/day).

Since medium- to full-capacity usage (i.e., 200 to 800 MMcf/day) of the vapourizers is expected to be very infrequent, the GHG emissions associated with regasification will not be significant. For that reason, GHG emissions were not specifically evaluated as part of the selection criteria between the various regasification units considered. The thermal load required to convert the LNG to natural gas is the same regardless of the technology selected. Had GHG emissions formed part of the selection criteria, the relative emissions for the various technologies would have been similar and therefore would not have impacted the outcome of the decision process.

9.2 How does submerged combustion vessel technology compare with other regasification technologies in terms of GHG emissions, GHG intensity and efficiency of use?

Response:

Please refer to the response to BCSEA IR1 9.1.

10.0 Topic: GHG emissions from venting

Reference: Updated Public Application, Exhibit B-1-4, p.127

FEI states:

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

10.1 Please explain why vapour during the initial filling would not be contained by the boil off gas system and returned to the pipeline.

Response:

The primary reason that the vapour during initial filling cannot be sent back to the pipeline is that it is not practical to design the boil-off gas compressors to accommodate natural gas and nitrogen flows at ambient temperatures. To further clarify, there are several steps which take place during the initial cooling of an LNG tank. The first step is to displace the air in the tank with nitrogen gas. This step is necessary to purge the tank of any impurities prior to the introduction of natural gas and LNG and does not result in any GHG emissions. The next step is to introduce natural gas to displace the nitrogen. This step results in venting to atmosphere as the boil-off gas compressors cannot accommodate natural gas and nitrogen flows at ambient temperatures. The final step is to introduce LNG to the tank. Venting will continue until the internal tank temperature is cold enough to permit the boil-off gas compressors to begin recompressing the gas for injection into the pipeline.

10.2 Please provide the expected amount of methane and CO2e that would be vented during the initial fill operations.

Response:

Please refer to the response to BCSEA IR1 10.1 for a description of the cool-down process during the initial tank fill. The expected amount of venting that will occur during the initial tank fill will be calculated during detailed design. It is not possible to avoid venting any methane during this process; however, it will be minimized as far as practicable.

10.3 What upset conditions might result in an exceedance of the capacity of the boil-off gas system?

Response:

The boil-off gas system is designed for the maximum possible boil-off gas rate, so no emissions are expected to be released during normal operations.

In the unlikely event of a boil-off gas system failure (i.e., an upset condition), the tank is designed to vent to the atmosphere to prevent excessive pressure buildup. Emissions from the tank in this instance would be equivalent to the boil-off gas generated in the tank which is estimated to be approximately 1.7 MMcf/day. Since the boil-off gas is essentially the same as natural gas, this would consist of primarily methane and nitrogen, with trace concentrations of carbon dioxide.

As noted in the Application, the design of the equipment considers reliability through redundancy; as such, the probability of a situation where the boil-off gas system fails to operate is very unlikely.

10.4 In the event that the capacity of the boil-off gas system was exceeded, what range of volumes of methane, and CO2e, might be released to the atmosphere?

Response:

Please refer to the response to BCSEA IR1 10.3.

10.5 Does FEI consider the venting of boil-off gas to the atmosphere to be an appropriate practice in the context of the Province's policies on the reduction of methane emissions?

Response:

FEI does not consider that designing and constructing a modern day LNG storage tank that leads to repeated or ongoing venting of boil-off gas to the atmosphere under normal operating conditions to be appropriate practice. The TLSE Project will be designed not to vent boil-off gas in normal operations. Venting would only occur during an emergency or upset condition for safety reasons.

10.6 What is the power source for the boil-off gas compressors, and does it result in GHG emissions to the atmosphere?

Response:

The boil-off gas compressor is electrically driven and will be powered from the BC Hydro system. As such, it will not result in GHG emissions to the atmosphere.

Attachment 7.9

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April 22, 2021

Via email: Fern.Stockman@gov.bc.ca

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Re: Tilbury Phase 2 LNG Expansion project: Change to the Project

We write to advise that FortisBC intends to make certain changes to the proposed Project.

The changes to the Project are as follows:

- The proposed net working storage capacity of the liquefied natural gas (LNG) tank will be 142,400 cubic metres (3.5 petajoules). This amounts to a reduction of 12% in proposed storage capacity; and
- The proposed liquefaction capacity will be up to 7,700 tonnes per day (equivalent to 2.5 million tonnes per annum when planned maintenance down-time is accounted for). This amounts to a reduction of 28% in the proposed production capacity.

FortisBC is making these changes for the following reasons:

1. With respect to the amount of LNG storage, engineering and planning work completed in 2020 has resulted in FortisBC being able to more accurately state the amount of LNG storage required to meet the need for enhancing the resiliency of its natural gas system.
2. The maximum size of liquefaction has been reduced as a result of additional early stage engineering.

More information on the changes will be provided in the Detailed Project Description and described in the workshop to be scheduled later this year.

Sincerely,

Dan Murray
Senior Project Director, LNG Operations & Engineering
FortisBC