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May 22, 2025

My Sea to Sky
P.O. Box 2668
Squamish, BC
V8B 0B8

Attention: Mr. Eoin Finn, Research Director

Dear Mr. Finn:

Re: FortisBC Energy Inc. (FEI)

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

Response to My Sea to Sky (MS2S) Information Request (IR) No. 6

On December 29, 2020, FEI filed the Application referenced above and on October 24, 2024, FEI filed its Supplemental Evidence to the Application. In accordance with the regulatory timetable established in British Columbia Utilities Commission Order G-324-24 for the review of the Application, FEI respectfully submits the attached response to MS2S IR No. 6.

As in prior rounds of information requests from MS2S, for procedural reasons FEI has not sought to verify, nor does it accept MS2S's statements and assertions in the lengthy preambles to its questions in this round. FEI focuses its response on the specific question posed.

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

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Commission Secretary
Registered Interveners

1 NEED FOR THE PROJECT - IMPACT OF AMI

In its response to BCUC IR#5 120.x, FEI outlined the impact of the length of the regulatory outage on the province's economy under various cold-weather circumstances. In particular, the capability afforded by AMI to significantly reduce the economic impact of a disruption is of particular interest, as that project was/is being justified[1], in part, on its resiliency benefits.

In a public notice of its approval of the AMI project , BCUC commented that *"FEI noted that AMI technology would enable more accurate and convenient billing processes, reduce meter reading costs and service risks, help customers access their energy consumption information and conserve energy, and support the resiliency of the gas network by enabling FEI to remotely shut off portions of the gas system for maintenance or in the case of a natural disaster".*

We understand that the full implementation of AMI should allow, immediately after the rupture/pressure loss is discovered, the rapid tight closure of (i) major pipeline junction valves (ii) compressor stations and (iii) to-the- meter valves at customer sites. We further understand that this will leave a fraction (50,000 - around 5%) of the customer base/ demand to be manually shut off[2]. In an earlier response, FEI reported little leak loss of gas/pipeline pressure, as measured by the mass balance technique, in the CTS pipeline system. Given these characteristics, it would seem that the outage would have to be very lengthy indeed to allow such a closed system, initially at up to 2130psi, to offgas to near 1-atmosphere (14.7psi) pressure with sufficient oxygen (i.e. between the 5% LFL and 15% UFL air: methane mix) to constitute a hazard requiring widespread venting before device relighting.

In its decision[3] to approve the AMI project, BCUC summarized the case thus [emphasis added]: "*FEI states that AMI would enable FEI to execute a controlled shutdown in the event of an extended gas supply emergency. A controlled shutdown allows FEI to maintain pressure within the section of the system that has been shut down throughout the duration the gas supply emergency. This is in opposition to an uncontrolled shutdown, or hydraulic collapse, which occurs when the gas system experiences a reduction in pressure down to atmospheric pressure. At atmospheric pressure, infiltration of air into the gas line is possible. AMI will provide FEI with the ability to monitor customer consumption in near real-time, allowing FEI to determine which parts of the system are vulnerable to a pressure collapse. Further, FEI states that it expects that AMI would provide a small reduction in the recovery time following a pressure collapse. Customers, who were shut off before the pressure collapse, would not have to be isolated from the system when re-pressurization occurs. FEI expects customers may elect to be remotely reconnected following an emergency but expects many other customers may not be comfortable relighting their own appliances. Consequently, during a larger gas supply emergency following a shut-down,*

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[1] https://www.globenewswire.com/news-release/2023/05/15/2669433/0/en/BCUC-Approves-FortisBC-s- Advanced-Metering-Infrastructure-Project.html

[2] In its AMI CPCN application, FEI stated this: "*If at any point during a gas supply emergency FEI deems it necessary to reduce load to balance the system, AMI would allow for surgical reduction of load to minimize the disruption of service to customers. AMI would also allow FEI to confirm that interruptible customers have complied with any requests to adjust their gas usage. Finally, the Company would be capable of measuring the impact of appeals to the public to reduce load, minimizing the service interruption to customers".*

[3] https://docs.bcuc.com/Documents/Other/2023/DOC_71425_C-2-23-FEI-AMI-CPCN-Decision.pdf

customers would likely have to a wait for a field technician to attend their premises to perform relighting".

In its AMI CPCN application, FEI stated this: "*If at any point during a gas supply emergency FEI deems it necessary to reduce load to balance the system, AMI would allow for surgical reduction of load to minimize the disruption of service to customers. AMI would also allow FEI to confirm that interruptible customers have complied with any requests to adjust their gas usage. Finally, the Company would be capable of measuring the impact of appeals to the public to reduce load, minimizing the service interruption to customers*".

From FEI's TLSE application (Document B1-1):

https://docs.bcuc.com/documents/proceedings/2021/doc_62642_b-1-fei-cpcn-ami-project-application.pdf), this, under the heading "*Load Management: Controlled Load Shedding Is Partially within FEI's Control Today, and Control Will Be Enhanced by AMI": …… "The AMI project would include the installation of new gas meters equipped with remotely-operable shutoff valves for the vast majority of FEI's customers. These shutoff valves could be used to provide more direct and near real-time ability to flexibly manage load during times of system constraint, thereby reducing the probability of a hydraulic collapse or uncontrolled shutdown of the entire gas system. The AMI project would thus complement the Project as a resiliency tool*". And this "*However, a controlled disruption, as enabled by AMI technology, is preferable to an uncontrolled hydraulic collapse of the system*".

Information Requests

1.1 Please discuss what impact(s) the $752[4] Million AMI project will have on FEI's resiliency needs, especially with regard to FEI's capability to use AMI tech. to rapidly isolate large segments of the distribution/transmission network from "hydraulic collapse" following a significant T-South rupture.

Response:

As in prior rounds of information requests from MS2S, for procedural reasons FEI has not sought to verify, nor does it accept MS2S's statements and assertions in the lengthy preambles to its questions in this round. FEI focuses its response on the specific question posed.

FEI identified the anticipated impact of the AMI project on resiliency in Section 7.1.1.2 of the 2024 Resiliency Plan.

1.2 To what extent, and with what effect, did the Exponent/ PWC studies incorporate the yet-to-be approved AMI project (especially its capabilities for quick response

[4] https://www.globenewswire.com/news-release/2023/05/15/2669433/0/en/BCUC-Approves-FortisBC-s-Advanced-Metering-Infrastructure-Project.html

and problem isolation) in their calculations of the economic impacts of a T-South failure?

Response:

Both the Exponent and PwC studies assumed the AMI project was in place.

Please refer to Section 7.1.1.2.1 of the 2024 Resiliency Plan which states “Gas AMI has already been accounted for in all 19 risk calculations included in the 2024 Resiliency Plan.” In the same section, FEI also discusses the effect of the AMI project on FEI’s gas system, including an increased likelihood of performing a controlled shutdown, reduced total outage durations, and increased visibility of system pressure during the upset condition.

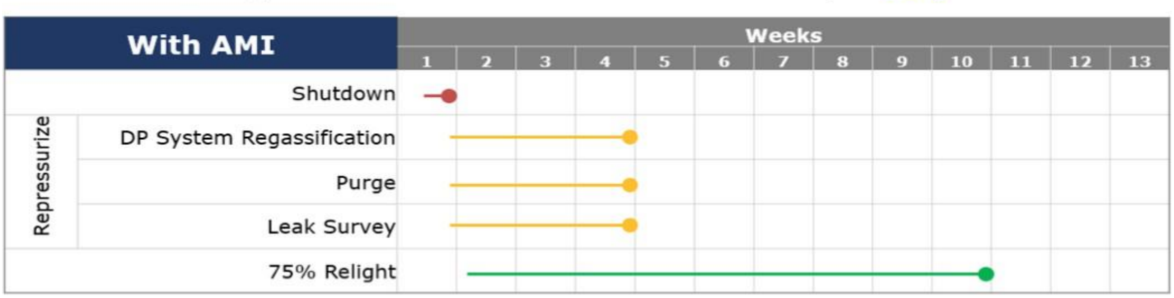
1.3 Please elaborate on the role of automatic shutoff sensors, which detect pressure drops in the input supply, and shut off the meter’s (and/or appliances’, many of whom have their own pressure loss shutoff sensors) inlet valve in a significant loss of pressure on T-South. In particular, why would these not all trigger long before the onset of “hydraulic collapse” conditions, thereby reducing /eliminating the need for relights and hastening the early return to economic activity?

Response:

FEI gas AMI meters do not have automatic shut-off in the event of a low-pressure scenario. Please refer to the response to MS2S IR6 2.2 for an explanation on why automatic shutoff sensors would not be effective in the way MS2S is suggesting even if the functionality was available on FEI’s AMI implementation.

Further, appliances will need to be relit when a gas meter has been shutoff for any reason. As shown in Figure 3-8 from the Supplemental Evidence (reproduced below), this relight process drives much of the service restoration duration. Thus, even if the automatic shutoff sensors were technically possible, they would not reduce or eliminate the need for relights.

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



1.4 In a significant T-South no-flow event with AMI fully deployed and triggered to electronically shut off the meters of over 1 Million customers, please outline how long would it take to degas, to atmospheric pressure (i) transmission lines downstream of Sumas/Mission intersect with the Spectra/T-South pipeline; and (ii) before-the-meter distribution pipes.

Response:

FEI interprets this request as being similar to RCIA IR5 70.1, but instead of waiting 8 hours to shut-in, the shut-in happens at the same time as the rupture.

FEI used its transient modelling tool to model the scenario described below to determine the time from when FEI's supply from T-South ceases to when the hydraulic collapse occurs. FEI notes that the hydraulic collapse of the gas system will initiate at pressures higher than atmospheric pressure and, as such, FEI has reported the time from when FEI's supply from T-South ceases to when the hydraulic collapse occurs, not the time until atmospheric conditions are reached throughout the gas system.

Modelling Assumptions:

- FEI engages the remote disconnect feature of its AMI meters in the Lower Mainland as soon as the T-South rupture occurs. This assumption does not reflect real world conditions. To avoid the situation where FEI unnecessarily shuts-in these customers, FEI must be confident that doing so is the optimal decision. Receiving the full information required to make such a decision takes time; thus, remotely disconnecting all Lower Mainland customers the moment the T-South rupture occurs is premature and not realistic. Further, FEI would not be aware of a rupture on T-South the moment it occurred. It would take time for FEI to be alerted to the rupture event. However, to show the impact that the customers without the remote disconnect feature have on the system pressure, FEI has included this assumption in the modelling.
- FEI manually disconnects the remaining Lower Mainland customers at a rate of 12,257 customers per day. These customers come off the system at 8 AM each day, starting the day following the AMI shutdown occurs (i.e., on Day 2).
- Due to the significant manual effort required to simulate the shutdown assumptions on the individual customer level, FEI has instead modelled the loads coming off the system at the system level. This was done by determining the percentage of the Lower Mainland load from customers that will not receive the remote disconnect module (referred to as manual shutdown customers). This was found to be approximately 50 percent of the load. That is, approximately half of the Lower Mainland load is from manual shutdown customers, while

the other half is from customers who will receive the remote disconnect module (referred to as remote shutdown customers). FEI describes the revised modeling timeline below:

1. Day 1 at 12:00 AM:
   - A no-flow event occurs off-system on the T-South pipeline.
   - FEI is made aware of the event and begins preparing the Tilbury Base Plant for send-out.
   - FEI shuts-in all Lower Mainland customers equipped with the remote disconnect module enabled through gas AMI. The total Lower Mainland load is reduced by 50 percent to simulate the remote shutoff customers being disconnected (50 percent of the total firm Lower Mainland load remains online).
   - The rupture occurs at average Lower Mainland winter temperatures (4°C).
2. Day 1 at 2:00 AM:
   - Gas supply from T-South to the Lower Mainland ceases.
   - LNG send-out from the Tilbury Base Plant begins. It is assumed that the resiliency modelling parameters contemplated in Supplemental Alternative 1 (Contingent w/ T1A) are available (i.e., 0.75 Bcf at 150 MMcf/d).
3. Day 1 at 4:00 AM:
   - Interruptible customers are offline.
4. Day 2 at 4:30 AM (Output from modelling):
   - Uncontrolled shutdown occurs. Approximately 26.5 hours after supply from T-South ceases, the continued consumption of gas from the manual shutdown customers results in an uncontrolled shutdown of the system.
5. Day 2 at 8:00 AM:
   - 17 percent[5] of the total Lower Mainland load goes offline to simulate the first set of manual shutdown customers being disconnected (33 percent of the total firm Lower Mainland load remains online).
6. Day 3 at 8:00 AM:
   - 17 percent of the total Lower Mainland load goes offline to simulate the second set of manual shutdown customers being disconnected (17 percent of the total firm Lower Mainland load remains online).
7. Day 4 at 8:00 AM:
   - 17 percent of the total Lower Mainland load goes offline to simulate the third set of manual shutdown customers being disconnected (0 percent of

[5] Based on the shutoff rate of 12,257, the remainder of customers (i.e., the manual shutdown customers) are shutoff based on equal proration for 3 days. Thus, on Days 2 – 4, one third of 50 percent of the total Lower Mainland load comes offline. One third of 50 percent is approximately 17 percent.

the total firm Lower Mainland load remains online). All customers are now offline.

Under the conditions assumed in this hypothetical scenario, the manual shutdown customers would cause a hydraulic collapse in 26.5 hours. This is the duration, accounting for load support provided by the Base Plant and CTS linepack, between when gas supply from T-South ceases to when the hydraulic collapse occurs. As noted above, shutting in the remote shutoff customers at the same moment that the rupture occurs does not reflect real world conditions. In reality, FEI would require much more time to acquire the full information needed to make such a decision. During this time the remote shutdown customers would continue to consume gas from the system, resulting in a much shorter time to pressure collapse than the 26.5 hours reported in this hypothetical scenario. For example, as reported in Table 3-2 of the Supplemental Evidence, at average winter conditions, the Base Plant provides approximately 7 hours of load support, which reflects all firm Lower Mainland customers being supported. This duration is extended to 9 hours in the scenario described in the response to RCIA IR5 70.1, where it is assumed that the remote shutdown customers are shut-in 8 hours after the rupture occurs.

1.5 Please confirm (or explain why not, why other sources contribute to the depressurization) that the principal cause of depressurization after AMI deployment is the 50,000 customer meters that have to be manually shut off?

Response:

Confirmed. The main cause of depressurization on FEI's system, during a T-South no-flow event where FEI has determined the best course of action is to execute a system shutdown, would be from customers with meters that do not have a remote disconnect module after full AMI deployment. To shut-in these customers, FEI personnel would need to travel to the customer's site and shut them in manually. These customers are physically able to continue consuming gas until this operation is carried out. During the supply disruption, and without sufficient on-system LNG volumes, this would result in the depressurization of the gas system.

1.6 Please discuss what impact the $4 Billion T-South ("Sunrise") expansion project will have on the resiliency and integrity of gas supply, and, consequentially, the need for this (TLSE) resiliency project.

Response:

Please refer to pages 90-91 of the Supplemental Evidence. The proposed T-South Sunrise Expansion Project will have no impact on the need for the TLSE Project.

1.7 Please confirm the accuracy of the following statement, which is an extract from Enbridge's 2025 annual report[6] (emphasis and amounts added): "**T-South Expansion (Sunrise)** – *An expansion of Westcoast's BC Pipeline's T-South section that includes pipeline looping, additional compressor units and other ancillary station modifications to support 300 mmcf/d of additional capacity. <u>The [$4B] expansion is driven primarily by an anticipated shortfall in capacity to deliver gas to the BC Lower Mainland and US Pacific Northwest markets following the commencement of deliveries to the [~ 280mmcf/d] Woodfibre LNG project, which is expected to come into service in 2027</u>. The [Sunrise] project is underpinned by a cost-of-service commercial model and is expected to be placed in service in 2028. We filed the regulatory application with the CER in May 2024*".

Response:

FEI believes this statement is accurate.

1.8 In light of Enbridge's public statement in 1.7 above, please outline the impact of the proposed Tilbury Phase 2 expansion (if approved as proposed) on the resiliency requirements of TLSE. In particular, please comment on the adequacy of the $4B T- South Expansion (Sunrise) project to supply the additional gas demand of TLE Phase 2?

Response:

FEI clarifies that the Tilbury Phase 2 LNG Expansion Project includes components of the TLSE Project (e.g., the TLSE tank). If constructed, the TLSE Project will materially improve FEI's ability to withstand a winter T-South no-flow event. As explained in the response to MS2S IR6 1.6, the

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[6] https://www.enbridge.com/~/media/Enb/Documents/Investor-Relations/NoticeAndAccess/2025/ENB_2024_Annual_Report_EN.pdf?rev=2d08f5fa3c7c460b825f91660a634862&hash=4F3F4F693AE065AEE4D85D836A3D0EDC.

proposed T-South Sunrise Expansion Project will have no impact on the need for the TLSE Project.

Please also refer to the response to CEC IR5 152.1, provided by Ray Mason, for a discussion of upstream infrastructure needs to supply load centers, including the Lower Mainland.

1.9 Please outline the impact of the $160 Million/2,500 tpy Hazer (hydrogen via methane pyrolysis) project[7] on FEI's TLSE resiliency needs. How much methane and power will the facility use, and from which BC utility(ies) will these be supplied?

Response:

The Hazer project is expected to use approximately 800,000 gigajoules (GJ) of natural gas as feedstock and approximately 4 megawatts (MW) of electricity in production. Depending on where the facility is situated, FEI expects the electricity will be provided either from BC Hydro or FortisBC Inc. The Hazer project is not expected to have an impact on FEI's resiliency needs or the TLSE Project.

1.10 Does FEI have force majeure clauses in all of its uninterruptible supply contracts (that would protect the utility from charges of breach of contract for uninterruptible customers)? What proportion (in terms of annual supply volumes) do not?

Response:

Section 13 of the General Terms & Conditions (GT&Cs) of FEI's tariff allows for interruptions of service when supply or capacity is constrained. In addition, all firm service rate schedules, as well as interruptible and Transportation Service rate schedules, include a force majeure provision. FEI also has a Gas Supply Shortfall System Preservation and Service Restoration (P&R) Plan that, by Letter L-32-18, the BCUC found is consistent with FEI's approved GT&Cs and tariff, is in the public interest, and is not unduly discriminatory as it is in accordance with FEI's approved tariff.

[7] FortisBC is collaborating with Hazer Group, an Australian company, to develop a hydrogen production facility in British Columbia, Canada. This facility will utilize Hazer's proprietary technology to produce low-emission hydrogen and graphite from natural gas, with a capacity of up to 2,500 tonnes of hydrogen [from ~ 10,000 tonnes methane] per year. Source: https://fuelcellsworks.com/news/hazer-and-fortisbc-advance-with-160m-hydrogen-facility-in-canada.

FEI's P&R Plan contemplates how FEI should respond in a supply emergency. While FEI is entitled to curtail or interrupt customers in the above circumstances, the purpose of the TLSE Project is to avoid having to do so, as customers must ultimately bear the consequences.

1.11 Please confirm, or otherwise explain, that the LNG storage tank in this (TLSE) application and the LNG storage tank referenced in the TLE Phase 2 expansion are indeed the same entity, as outlined in FEI's response to BCUC IR5 Q. 24.1?.

Response:

Confirmed. Please refer to the response to BCUC IR1 23.1.

2 NEED FOR THE PROJECT- GAS UTILITY INDUSTRY STANDARDS

In BCUC IR#5 120.37[8], BCUC asked: **Please discuss whether FEI is aware of other natural gas utilities that plan on system storage capacity based on a supply outage duration of three days**. FEI provided the following response:

"FEI is not aware of other natural gas utilities that plan on-system storage capacity based on a supply outage duration for days. Each utility will have its own resiliency requirements, based on the accessibility and the size of the resource they require. This approach was endorsed in the independent expert report provided by Guidehouse as follows (see page of Appendix A to the Application): There is no single industry standard approach to determine duration, i.e., the amount of natural gas required for a resiliency reserve. A standard calculation is challenged for several reasons, including:

- *Access to Existing Infrastructure: Gas supply redundancy varies across different natural gas utilities and is a function of access, both physical and contractual, to existing pipeline and underground storage infrastructure.*
- *Demand Profile: Design day and peak load requirements are a function of a natural gas utility's customer count, profile and seasonality of demand. Implications of this include that if a utility has more diversity of supply (i.e., is less dependent on a single pipeline for the majority of its supply) its resiliency reserve will be less than a utility that is highly dependent on a single pipeline. This explains why no two natural gas utilities will have the same reserve resiliency requirements.*
- *The following response has been provided by Exponent: Exponent is not aware of specific supply durations planned by other natural gas utilities. We expect supply duration to be circumstance-specific".*

Information Requests

2.1 Please elaborate on the role of automatic shutoff sensors[9], which detect pressure drops in the input supply, and shut off the meter's (and/or appliances', many of

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[8] Exhibit B-63.

[9] From FEI's TLSE application, this, under the heading "Load Management: Controlled Load Shedding Is Partially within FEI's Control Today, and Control Will Be Enhanced by AMI": …… "The AMI project would include the installation of *new gas meters equipped with remotely-operable shutoff valves for the vast majority of FEI's customers. These shutoff valves could be used to provide more direct and near* real-time ability to flexibly manage load during times of system constraint, thereby reducing the probability of a hydraulic collapse or uncontrolled shutdown of the entire gas system. The AMI project would thus complement the Project as a resiliency tool". And this "However, a controlled disruption, as enabled by AMI technology, is preferable to an uncontrolled hydraulic collapse of the system". And, from the TLSE CPCN application (P.31), this FEI statement:
*" **Load shedding in a supply emergency involves interrupting service to those who want uninterrupted service:** In cases where customers have taken interruptible service or entered peaking gas agreements, the customer has made an economic decision that it can do without the gas supply for periods of time. Planning for broader load shedding as a means of improving resiliency inherently means planning to disrupt service to segments of customers who want a consistent gas supply. Resiliency solutions that aim to preserve continuity of service for those customers who want firm supply (e.g., on-system storage or pipeline redundancy) are, other things being equal, preferable to disruptions. However, a controlled disruption, as enabled by AMI technology, is preferable to an uncontrolled hydraulic collapse of the system".*

whom have their own pressure loss shutoff sensors) inlet valve in a significant loss of pressure on T-South. In particular, why would these not all trigger long before the onset of "hydraulic collapse" conditions, thereby reducing /eliminating the need for relights and hastening the early return to economic activity?

Response:

This question is a duplicate of MS2S IR6 1.3. Please refer to that response.

2.2 Assuming AMI is implemented with automatic shutoff sensors, how long, approximately, does FEI expect it will take to degas to atmospheric pressure at: (i) transmission lines downstream of the Sumas/Mission intersect with the Spectra/T-South pipeline and; (ii) before-the-meter distribution pipes?

Response:

FEI clarifies that the approved implementation of AMI will not include automatic shutoff sensors. Even if the project scope included automatic shutoff sensors, they would not improve the results over those provided in the response to MS2S IR6 1.4 due to how typical meter sets are designed for the reasons below.

The distribution pipe (DP) system has a maximum operating pressure of either 60 psig (Coastal Transmission System and Interior Transmission System) or 80 psig (Vancouver Island Transmission System). As gas travels through the DP system, the pressure decreases due to line losses. Meter set pressure regulators are installed just upstream of customer meters to reduce the pressure of the gas stream to delivery pressure. Delivery pressure for residential customers is typically 2 psig or less.

Because the pressure is regulated upstream of the meter, the sensors in the meter will only sense a lower delivery pressure. Thus, in order for the meter to automatically sense that there was insufficient gas upstream, the distribution system would have to be operating at less than the 2-psig delivery pressure. If this were the case, given variability in pressure across the distribution system, FEI would have to assume that the system had already lost pressure and would need to treat the event as an uncontrolled shutdown.

2.3 Though the resiliency reserves of gas utilities are each somewhat different in their supply and terrain diversity and customer demand characteristics, information on these would nevertheless be informative in any decision to approve/reject the proposed Tilbury expansion. Please provide the customer base, peak demand and resiliency reserves (as a percentage of peak demand) for the major Canadian and U.S. Gas utilities (such as AltaGas/PNG, FortisBC, Enbridge, Epcor, Centra/Manitoba Hydro, and Energir in Canada, and Dominion, National Grid, Southern and Excel in the U.S.

Response:

FEI respectively declines to provide the requested information. Compiling the requested information would take considerable time and resources, and the information would not be useful to the BCUC's determinations in this proceeding for the reasons discussed below. Further, and in response to the BCUC's commentary in the Adjournment Decision, FEI has undertaken a holistic and data-driven resiliency plan (2024 Resiliency Plan filed as Exhibit B-61). This 2024 Resiliency Plan, which is specific to FEI's resiliency needs, supports the need for the TLSE Project.

As explained by Guidehouse in a 2022 report prepared for the American Gas Foundation, comparing gas system resilience across different jurisdictions is difficult due to the lack of standardized metrics and frameworks[10], the inapplicability of measures borrowed from other industries (like electric)[11], data limitations and scarcity[12], variations in regulatory approaches and priorities[13], and jurisdiction-specific practices and system interdependencies[14]. Therefore, if the resiliency reserves of other major Canadian and US gas utilities were publicly available, it would likely not be relevant to the needs of FEI's system.

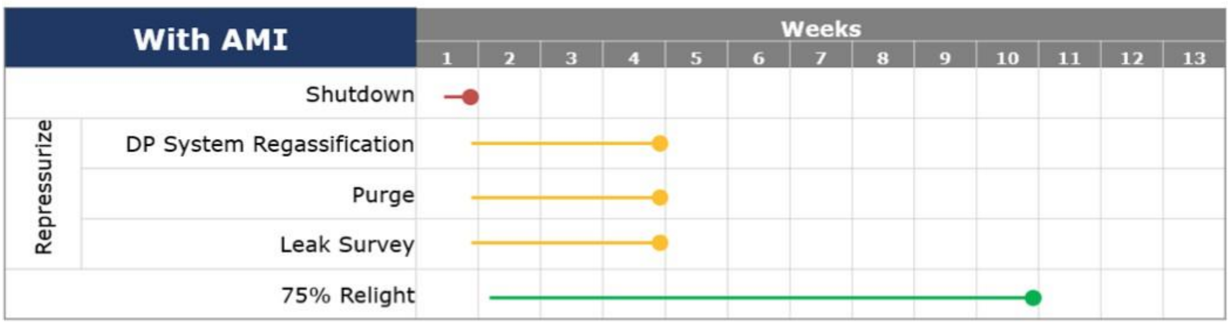
Despite a lack of standardized metrics and frameworks, it is clear that there is a growing effort by both energy utilities and their regulators to address resiliency in ways that have not been considered in the past.[15]

10 2022 Guidehouse Report, Section 2.1.1.
11 2022 Guidehouse Report, Section 2.1.1.
12 2022 Guidehouse Report, Section 1.1, Table 1-1.
13 2022 Guidehouse Report, Section 2.
14 2022 Guidehouse Report, Section 1.1, Table 1-1 and 2022 Guidehouse Report, Section 4.
15 2022 Guidehouse Report, Section 1.2.

3 NEED FOR THE PROJECT – OUTAGE DURATION, RESTORATION

From the TLSE Application , Supplementary evidence, Section 3.2.2.1, FEI states : "*Figure 3-8 below shows the timeline for restoring service to customers following a no-flow event on AV-3 at average winter temperatures (+4°C). The restoration timeline shown in Figure 3-8 is longer than the above timeline primarily because, due to the AV-3 failure location, <u>FEI expects that it will be unable to initiate a controlled shutdown before the system depressurizes in an uncontrolled manner</u>. Additionally, AV-3 results in approximately 40,000 more customer outages than AV-2. Figure 3-8: Timeline for AV-3 Service Restoration (with AMI)*

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



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

- *Shutdown: The shutdown stage in the uncontrolled scenario is the same as for the controlled scenario (i.e., AMI will be used to shut down the majority of meter valves; however, approximately 50,000 meters will need to be closed manually).*

Information Requests:

3.1 Please explain why, with AMI in place for the "*vast majority of customer accounts*", FEI "*will be unable to initiate a controlled shutdown before the system depressurizes in an uncontrolled manner*".

<u>Response:</u>

Even with AMI in place, AV-3 is expected to result in an uncontrolled shutdown for the following reasons:

1. While customer meters equipped with the remote disconnect feature could be shut-in remotely (i.e., the remote shutdown customers), the remaining customers (i.e., the manual shutdown customers) would have to be shut-in manually. During the time it takes to execute this operation, these customers would continue to consume gas. Please also refer to the response to MS2S IR6 1.5.

2. FEI's existing resiliency capabilities (i.e., without the TLSE Project, but including AMI for the purposes of the 2024 Resiliency Plan) do not provide a long enough load support duration to maintain system pressure while the manual shutdown customers are shut-in, and as such an uncontrolled shutdown would occur.

3. A controlled shutdown takes time to implement. To avoid the situation where FEI unnecessarily shuts-in its customers, FEI must be confident that doing so is the optimal decision. Receiving the full information required to make such a decision requires time. As such FEI remotely shutting in the vast majority of its customers shortly after the rupture incident is not a realistic scenario.

In contrast, AV-2 (i.e., a T-South failure, but at a different location than AV-3) is assumed to result in a controlled shutdown with FEI's existing resiliency capabilities. The failure location of AV-2 allows access to an additional existing resiliency capability that is unavailable to AV-3. While the capability is not sufficient to prevent an outage, FEI assumed it would provide sufficient time to implement a controlled shutdown in the Lower Mainland.

3.2 If the above statement is true, and a hydraulic collapse is inevitable no matter the presence or absence of the TLSE tank, why is there any need for TLSE?

Response:

The question incorrectly states that a hydraulic collapse is inevitable no matter the presence or absence of the TLSE tank. This is incorrect. Figure 3-8 from the Supplemental Evidence represents the restoration timeline for AV-3 under FEI's *existing* resiliency capabilities. It does not represent the scenario wherein the Preferred Alternative (Supplemental Alternative 9) is in place.

The Preferred Alternative will:

1. Prevent any outage in the event that the T-South no-flow duration is shorter than the load support duration provided by the Preferred Alternative; or

2. In a worst-case scenario where the T-South no-flow event exceeds the load support duration, the Preferred Alternative will provide enough time for FEI to execute a controlled shutdown. FEI's current resiliency capabilities do not provide a long enough load support duration to execute a controlled shutdown, and thus without the Preferred Alternative, an uncontrolled shutdown would result for AV-3.

3.3 If most of the economic impact of an uncontrolled shutdown is associated with the outage duration (ranging from 60 to 72 days per Table 1.2 of the TLSE CPCN application to complete the purge/vent/relight cycle), why not use AMI's control capability to shut down the entire valve system – supposedly attainable through AMI supplemented with 50,000 manual shutoffs – and altogether avoid the resource-limited purge/vent/relight cycle necessitated by “hydraulic collapse”? The outage length in that case would be the regulatory delay (2-3 days), plus the T-South repair time, less the overlap between them. Would this not result in far less economic loss than the “hydraulic collapse” vent/relight recovery alternative?

Response:

The question incorrectly implies that AMI alone can prevent an uncontrolled shutdown and thus allow for a controlled shutdown. AMI is a valuable tool that greatly improves FEI’s ability to execute a controlled shutdown. However, for certain asset failures (e.g., AV-3) an uncontrolled shutdown is still expected to occur (please refer to the response to MS2S IR6 3.1). Further, the question incorrectly implies that relights will not be required if a controlled shutdown is implemented instead of an uncontrolled shutdown.

When comparing a controlled shutdown to an uncontrolled shutdown, the outage duration for a controlled shutdown is shorter. However, the outage duration does not reduce to that suggested in the question. The duration suggested in the question (“…the regulatory delay (2-3 days), plus the T-South repair time, less the overlap between them”) does not account for the relight duration. Relighting customers will be required in both a controlled shutdown and an uncontrolled shutdown.

The main driver for the longer durations in an uncontrolled shutdown is due to the need to purge any air within the gas distribution system and then re-pressurize the segment. This purge and regasification/re-pressurization process extends the duration of the customer outage when compared to a controlled shutdown.

To contextualize the difference in outage durations between a controlled and uncontrolled shutdown, please refer to Figure 3-7 and Figure 3-8 in the Supplemental Evidence. Figure 3-7 represents the timeline for AV-2, a controlled shutdown, which has a 57-day outage duration. Figure 3-8 represents the timeline for AV-3, an uncontrolled shutdown that also results in 40,000 additional customer outages than AV-2, which has a 70-day outage duration.